Application to the Public Utilities Commission of the State of South Dakota for a Facility Permit

MONTANA-DAKOTA UTILITIES CO. & OTTER TAIL POWER COMPANY

Big Stone South to Ellendale Project

AUGUST 14, 2013

EXHIBIT
1

BSS+E
Big Stone South to Ellendale

006136

Montana-Dakota Utilities Co. and
Otter Tail Power Company
APPLICATION TO THE
PUBLIC UTILITIES COMMISSION OF THE
STATE OF SOUTH DAKOTA
FOR A FACILITY PERMIT

Big Stone South-Ellendale Project
345-kV Transmission Line

August 14, 2013

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Big Stone South to Ellendale

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List of Acronyms and Abbreviations

Abbreviation	Meaning
ACSR	aluminum conductor steel reinforced
AM	amplitude modulated
APE	area of potential effects
APLIC	Avian Power Line Interaction Committee
Applicants	Montana-Dakota Utilities Co. and Otter Tail Power Company
ARSD	Administrative Rules of South Dakota
ASR	Antenna Structure Registration
BMPs	Best Management Practices
BPA	Bonneville Power Administration
Commission	Public Utilities Commission of the State of South Dakota (also PUC)
Coteau	Coteau des Prairies
dB	Decibels
dBA	A-weighted sound level in decibels
EF	electric field
ELF	extremely low frequency
EMF	electromagnetic field
EMI	electromagnetic interference
EPA	United States Environmental Protection Agency
FAA	Federal Aviation Administration
FCC	Federal Communications Commission
FEMA	Federal Emergency Management Agency
FM	frequency modulated
ft ASL	feet above sea level
G	Gauss
GIS	Geographic Information System
GLO	General Land Office
GPS	Global Positioning System
HVTL	high-voltage transmission line
ICNIRP	International Commission on Non-Ionizing Radiation Protection
IEEE	Institute of Electrical and Electronics Engineers
kcmil	thousand circular mils
kV	kilovolt
kV/m	kilovolts per meter
m	meter
mA	milliamperes
MF	magnetic field

Abbreviation	Meaning
mG	milliGauss
Midwest ISO	Midwest Independent Transmission System Operator
MISO	Midcontinent Independent System Operator, Inc., previously Midwest ISO
Montana-Dakota	Montana-Dakota Utilities Co.
MRO	Midwest Reliability Organization
MTEP	Midwest ISO Transmission Expansion Plan
MVP	Multi-Value Project
MW	megawatt
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NESC	National Electric Safety Code
NGO	non-governmental organization
NHPA	National Historic Preservation Act
NLCD	National Land Cover Database
NPDES	National Pollutant Discharge Elimination System
NRCS	Natural Resources Conservation Service
NRHP	National Register of Historic Places
NWI	National Wetlands Inventory
Otter Tail Power	Otter Tail Power Company
pH	A measure of the concentration of Hydrogen ions, indicating the acidity or basicity of a solution
ppm	parts per million
Project	Big Stone South to Ellendale Project
PUC	South Dakota Public Utilities Commission (also Commission)
RF	radio frequency
RGOS	Regional Generation Outlet Study
ROW	right-of-way
SDARC	South Dakota Archaeological Research Center
SDCL	South Dakota Codified Laws
SDGFP	South Dakota Department of Game, Fish and Parks
SDSHPO	South Dakota State Historic Preservation Office
SSURGO	Soil Survey Geographic
STATSGO	State Soil Geographic
SWPPP	Storm Water Pollution Prevention Plan
THPO	Tribal Historic Preservation Office
TMDL	Total Maximum Daily Load
TP	twisted pair

Abbreviation	Meaning
USACE	United States Army Corps of Engineers
USFWS	United States Fish and Wildlife Service
USGS	United States Geological Survey
WPA	Waterfowl Production Area

Definitions

Term	Definition
BMPs	Best Management Practices are used during construction to minimize adverse effects to the existing environment from the time the initial excavation begins until the transmission facility is operational.
desktop survey	A method of review completed for the first phase of planning that does not typically require on-site review of resources. This methodology helps to determine areas of potential difficulty through a review of aerial photography and GIS data.
Ellendale 230-kV Substation	Existing Ellendale 230-kV substation
Ellendale 345-kV Substation	New Ellendale 345-kV Substation (constructed as a part of this Project)
kilovolt	1,000 volts; 345-kV = 345,000 volts
MISO	Midcontinent Independent System Operator, Inc., an independently governed organization tasked with ensuring transmission network reliability and efficiency. Formerly named Midwest ISO.
North Dakota Facility	North Dakota portion of this Project consisting of approximately 9 to 11 miles of single-circuit 345-kilovolt (kV) transmission line and the Ellendale 345-kV Substation located in Dickey County, North Dakota,
North Dakota Facility ROW	The 150-foot-wide right-of-way in which the North Dakota Facility will be constructed as determined by final design.
Project	The Project will consist of approximately 160 to 170 miles of single-circuit 345-kilovolt (kV) transmission line in South Dakota and North Dakota and a new 345-kV substation located near Ellendale, North Dakota.
right-of-way (ROW)	The land that must be acquired through land rights to safely construct, operate, and maintain an electrical line.
South Dakota Facility	The South Dakota portion of this Project consisting of approximately 150 to 160 miles of single-circuit 345-kV transmission line traversing through Brown, Day, and Grant counties and associated facilities (two fiber optic regeneration stations and their access roads)
South Dakota Facility area	The vinicity of the South Dakota Facility
South Dakota Facility ROW	The 150-foot-wide right-of-way in which the South Dakota Facility will be constructed as determined by final design.

1.0 Executive Summary

Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., a Delaware corporation (Montana-Dakota), and Otter Tail Power Company, a Minnesota corporation (Otter Tail Power), (jointly, the Applicants), propose to construct the Big Stone South to Ellendale Project (Project). The Project consists of both a 345-kilovolt (kV) transmission line that is approximately 160 to 170 miles long traversing through North Dakota and South Dakota, and the Ellendale 345-kV Substation located near Ellendale, North Dakota. The Applicants submit this Application for a facility permit (Application) to the Public Utilities Commission of the State of South Dakota (the Commission) pursuant to South Dakota Codified Laws (SDCL) Chapter 49-41B and Administrative Rules of South Dakota (ARSD) Chapter 20:10:22. The South Dakota Facility for which the Applicants are seeking a facility permit in this Application consists of approximately 150 to 160 miles (for the purposes of this Application, the Applicants have used 155 miles in their calculations) of alternating current 345-kV transmission line and associated facilities. The line will cross the South Dakota and North Dakota border in Brown County, South Dakota and extend south and east through Brown, Day, and Grant counties to the Big Stone South Substation in Grant County, South Dakota near Big Stone City. Modifications to the South Dakota Facility may occur depending on the final route permitted, land rights, and final engineering design.

Exhibit 1 provides a map showing the route of the Project.

Exhibit 2 provides a more detailed map showing the South Dakota Facility.

The Project was identified as one of seventeen Multi-Value Projects (MVPs) by Midcontinent Independent System Operator, Inc. (MISO, formerly Midwest Independent Transmission System Operator [Midwest ISO]). The Applicants are MISO members. Significant study and input shows that MVPs will reduce the wholesale cost of energy delivery for consumers across the MISO region by enabling the delivery of low-cost generation to load, reducing congestion costs, and increasing system reliability.

The South Dakota Facility is anticipated to cost approximately $250 to $320 million in 2013 dollars. The total Project is expected to cost approximately $293 to $370 million in 2013 dollars and the cost will be allocated to and shared among MISO members in accordance with the MISO tariff. In general, the South Dakota Facility will be constructed with single-pole steel structures. The average height of the structures will range from approximately 100 to 155 feet. The average span between structures will range from 700 to 1,200 feet (typically about 1,000 feet) and will vary depending on geological or engineering constraints determined in final design. The right-of-way (ROW) for the South Dakota Facility will generally be 150-feet-wide. Two fiber optic regeneration stations about 100-feet-wide by 100-feet-long will be located outside of the ROW. A 30-foot-wide temporary travel path within the ROW will be used for construction. This temporary travel path is for vehicle traffic for work required to install structures and string conductors. In addition, the Project will require temporary laydown yards and wire stringing areas outside of the ROW. Specialty structures and foundations may be required in certain circumstances. Land rights procurement agreements with landowners of parcels crossed by the South Dakota Facility are currently underway. Construction on the South Dakota Facility is scheduled to begin in 2016 and is expected to be in-service in 2019.

The Applicants took a multi-faceted approach to identify a route for the South Dakota Facility. The process included more than one year of outreach to public, agency, and tribal stakeholders, publicly available data, and data gathered during route analysis such as a cultural resources literature review, bald eagle stick nest survey, and land cover modeling. Multiple alternative routes were considered and refined, and ultimately the proposed route was selected through this process. The Applicants have addressed the Application submittal requirements as described in in SDCL Chapter 49-41B and in ARSD Chapter 20:11:22 (Energy Facility Siting Rules).

1.1 Completeness Checklist

The contents required for an application with the Commission are described in SDCL 49-1-8 and further clarified in ARSD 20:10:13:01(1) et seq. The Commission submittal requirements are listed in Table 1, with cross-references indicating where the information can be found in this Application.

Table 1. Completeness Checklist

SDCL	ARSD	Required Information	Location
49-41B-35(2).	20:10:22:05	**List of Permits.** The application for a permit for a facility shall contain a list of each permit that is known to be required from any other governmental entity at the time of the filing. The list of permits shall be updated, if needed, to include any permit the applicant becomes aware of after filing the application. The list shall state when each permit application will be filed. The application shall also list each notification that is required to be made to any other governmental entity.	24.0
49-41B-11(1)	20:10:22:06	**Names of participants required.** The application shall contain the name, address, and telephone number of all persons participating in the proposed facility at the time of filing, as well as the names of any individuals authorized to receive communications relating to the application on behalf of those persons.	3.0
49-41B-11(7)	20:10:22:07	**Name of owner and manager.** The application shall contain a complete description of the current and proposed rights of ownership of the proposed facility. It shall also contain the name of the project manager of the proposed facility.	3.0
49-41B-11(8)	20:10:22:08	**Purpose of facility.** The applicant shall describe the purpose of the proposed facility.	4.0
49-41B-11(12)	20:10:22:09	**Estimated cost of facility.** The applicant shall describe the estimated construction cost of the proposed facility.	5.0

SDCL	ARSD	Required Information	Location
49-41B-11(9)	20:10:22:10	**Demand for facility.** The applicant shall provide a description of present and estimated consumer demand and estimated future energy needs of those customers to be directly served by the proposed facility. The applicant shall also provide data, data sources, assumptions, forecast methods or models, or other reasoning upon which the description is based. This statement shall also include information on the relative contribution to any power or energy distribution network or pool that the proposed facility is projected to supply and a statement on the consequences of delay or termination of the construction of the facility.	6.0
49-41 B-11	20:10:22:11	**General site description.** The application shall contain a general site description of the proposed facility including a description of the specific site and its location with respect to state, county, and other political subdivisions; a map showing prominent features such as cities, lakes and rivers; and maps showing cemeteries, places of historical significance, transportation facilities, or other public facilities adjacent to or abutting the plant or transmission site.	7.0
49-41B-11(6); 49-41B-21; 34A-9-7(4)	20:10:22:12	**Alternative sites.** The applicant shall present information related to its selection of the proposed site for the facility, including the following: (1) The general criteria used to select alternative sites, how these criteria were measured and weighed, and reasons for selecting these criteria; (2) An evaluation of alternative sites considered by the applicant for the facility; (3) An evaluation of the proposed plant or transmission site and its advantages over the other alternative sites considered by the applicant, including a discussion of the extent to which reliance upon eminent domain powers could be reduced by use of an alternative site, alternative generation method, or alternative waste handling method.	8.0
49-41B-11(11); 49-41B-21; 49-41B-22(2)	20:10:22:13	**Environmental information.** The applicant shall provide a description of the existing environment at the time of the submission of the application, estimates of changes in the existing environment which are anticipated to result from construction and operation of the proposed facility, and identification of irreversible changes which are anticipated to remain beyond the operating lifetime of the facility. The environmental effects shall be calculated to reveal and assess demonstrated or suspected hazards to the health and welfare of human, plant and animal communities which may be cumulative or synergistic consequences of siting the proposed facility in combination with any operating energy conversion facilities, existing or under construction. The applicant shall provide a list of other major industrial facilities under regulation which may have an adverse affect of the environment as a result of their construction or operation in the transmission site or siting area.	9.0 – 19.0

SDCL	ARSD	Required Information	Location
49-41B-11(11); 49-41B-22(2)	20:10:22:14	**Effect on physical environment.** The applicant shall provide information describing the effect of the proposed facility on the physical environment. The information shall include: (1) A written description of the regional land forms surrounding the proposed plant site or through which the transmission facility will pass; (2) A topographic map of the transmission site or siting area; (3) A written summary of the geological features of the siting area or transmission site using the topographic map as a base showing the bedrock geology and surficial geology with sufficient cross-sections to depict the major subsurface variations in the siting area; (4) A description and location of economic deposits such as lignite, sand and gravel, scoria, and industrial and ceramic quality clay existent within the plan or transmission site; (5) A description of the soil type at the plant site; (6) An analysis of potential erosion or sedimentation which may result from site clearing, construction, or operating activities and measures which will be taken for their control; (7) Information on areas of seismic risks, subsidence potential and slope instability for the siting area or transmission site; and (8) An analysis of any constraints that may be imposed by geological characteristics on the design, construction, or operation of the proposed facility and a description of plans to offset such constraints.	10.0

SDCL	ARSD	Required Information	Location
49-41B-11(11); 49-41B-21; 49-41B-22(2)	20:10:22:15	**Hydrology.** The applicant shall provide information concerning the hydrology in the area of the proposed plant or transmission site and the effect of the proposed site on surface and groundwater. The information shall include: (1) A map drawn to scale of the plant or transmission site showing surface water drainage patterns before and anticipated patterns after construction of the facility; (2) Using plans filed with any local, state, or federal agencies, indication on a map drawn to scale of the current planned water uses by communities, agriculture, recreation, fish, and wildlife which may be affected by the location of the proposed facility and a summary of those effects; (3) A map drawn to scale locating any known surface or groundwater supplies within the siting area to be used as a water source or a direct water discharge site for the proposed facility and all offsite pipelines or channels required for water transmission; (4) If aquifers are to be used as a source of potable water supply or process water, specifications of the aquifers to be used and definition of their characteristics, including the capacity of the aquifer to yield water, the estimated recharge rate, and the quality of ground water; (5) A description of designs for storage, reprocessing, and cooling prior to discharge of heated water entering natural drainage systems; (6) If deep well injection is to be used for effluent disposal, a description of the reservoir storage capacity, rate of injection, and confinement characteristics and potential negative effects on any aquifers and groundwater users which may be affected.	11.0
49-41B-11(11); 49-41B-21; 49-41B-22(2)	20:10:22:16	**Effect on terrestrial ecosystems.** The applicant shall provide information on the effect of the proposed facility on the terrestrial ecosystems, including existing information resulting from biological surveys conducted to identify and quantify the terrestrial fauna and flora potentially affected within the transmission site or siting area; an analysis of the impact of construction and operation of the proposed facility on the terrestrial biotic environment, including breeding times and places and pathways of migration; important species; and planned measures to ameliorate negative biological impacts as a result of construction and operation of the proposed facility.	12.0
49-41B-11(11); 49-41B-21; 49-41B-22(2)	20:10:22:17	**Effect on aquatic ecosystems.** The applicant shall provide information of the effect of the proposed facility on aquatic ecosystems, and including existing information resulting from biological surveys conducted to identify and quantify the aquatic fauna and flora, potentially affected within the transmission site or siting area, an analysis of the impact of the construction and operation of the proposed facility on the total aquatic biotic environment and planned measures to ameliorate negative biological impacts as a result of construction and operation of the proposed facility.	13.0

SDCL	ARSD	Required Information	Location
49-41B-11(11); 49-41B-22(2)	20:10:22:18	**Land use.** The applicant shall provide the following information concerning present and anticipated use or condition of the land: (1) A map or maps drawn to scale of the siting area and transmission site identifying existing land use according to the following classification system: (a) Land used primarily for row and nonrow crops in rotation; (b) Irrigated lands; (c) Pasturelands and rangelands; (d) Haylands; (e) Undisturbed native grasslands; (f) Existing and potential extractive nonrenewable resources; (g) Other major industries; (h) Rural residences and farmsteads, family farms, and ranches; (i) Residential; (j) Public, commercial, and institutional use; (k) Municipal water supply and water sources for organized rural water districts; and (l) Noise sensitive land uses; (2) Identification of the number of persons and homes which will be displaced by the location of the proposed facility; (3) An analysis of the compatibility of the proposed facility with present land use of the surrounding area, with special attention paid to the effects on rural life and the business of farming; and (4) A general analysis of the effects of the proposed facility and associated facilities on land uses and the planned measures to ameliorate adverse impacts.	14.0
49-41B-11; 49-41B-28	20:10:22:19	**Local land use controls.** The applicant shall provide a general description of local land use controls and the manner in which the proposed facility will comply with the local land use zoning or building rules, regulations or ordinances. If the proposed facility violates local land use controls, the applicant shall provide the commission with a detailed explanation of the reasons why the proposed facility should preempt the local controls. The explanation shall include a detailed description of the restrictiveness of the local controls in view of existing technology, factors of cost, economics, needs of parties, or any additional information to aid the commission in determining whether a permit may supersede or preempt a local control pursuant to SDCL 49-41B-28.	15.0
49-41B-11	20:10:22:20	**Water quality.** The applicant shall provide evidence that the proposed facility will comply with all water quality standards and regulations of any federal or state agency having jurisdiction and any variances permitted.	16.0

SDCL	ARSD	Required Information	Location
49-41B-11; 49-41B-21; 49-41B-22	20:10:22:21	**Air quality.** The applicant shall provide evidence that the proposed facility will comply with all air quality standards and regulations of any federal or state agency having jurisdiction and any variances permitted.	17.0
49-41B-11(3)	20:10:22:22	**Time schedule.** The applicant shall provide estimated time schedules for accomplishment of major events in the commencement and duration of construction of the proposed facility.	18.0
49-41B-11(3); 49-41B-22	20:10:22:23	**Community impact.** The applicant shall include an identification and analysis of the effects the construction, operation, and maintenance of the proposed facility will have on the anticipated affected area including the following: (1) A forecast of the impact on commercial and industrial sectors, housing, land values, labor market, health facilities, energy, sewage and water, solid waste management facilities, fire protection, law enforcement, recreational facilities, schools, transportation facilities, and other community and government facilities or services; (2) A forecast of the immediate and long-range impact of property and other taxes of the affected taxing jurisdictions; (3) A forecast of the impact on agricultural production and uses; (4) A forecast of the impact on population, income, occupational distribution, and integration and cohesion of communities; (5) A forecast of the impact on transportation facilities; (6) A forecast of the impact on landmarks and cultural resources of historic, religious, archaeological, scenic, natural, or other cultural significance. The information shall include the applicant's plans to coordinate with the local and state office of disaster services in the event of accidental release of contaminants from the proposed facility; and (7) An indication of means of ameliorating negative social impact of the facility development.	19.0

SDCL	ARSD	Required Information	Location
49-41B-11	20:10:22:24	**Employment estimates.** The application shall contain the estimated number of jobs and a description of job classifications, together with the estimated annual employment expenditures of the applicants, the contractors, and the subcontractors during the construction phase of the proposed facility. In a separate tabulation, the application shall contain the same data with respect to the operating life of the proposed facility, to be made for the first ten years of commercial operation in one-year intervals. The application shall include plans of the applicant for utilization and training of the available labor force in South Dakota by categories of special skills required. There shall also be an assessment of the adequacy of local manpower to meet temporary and permanent labor requirements during construction and operation of the proposed facility and the estimated percentage that will remain within the county and the township in which the facility is located after construction is completed.	20.0
49-41B-11(5)	20:10:22:25	**Future additions and modifications.** The applicant shall describe any plans for future modification or expansion of the proposed facility or construction of additional facilities which the applicant may wish to be approved in the permit.	21.0
49-41B-11	20:10:22:34	**Transmission facility layout and construction.** If a transmission facility is proposed, the applicant shall submit a policy statement concerning the route clearing, construction and landscaping operations, and a description of plans for continued right-of-way maintenance, including stabilization and weed control.	22.0
49-41B-11(2)(11)	20:10:22:35	**Information concerning transmission facilities.** If a transmission facility is proposed, the applicant shall provide the following information as it becomes available to the applicant: (1) Configuration of the towers and poles, including material, overall height and width; (2) Conductor configuration and size, length of span between structures, and number of circuits per pole or tower; (3) The proposed transmission site and major alternatives as depicted on overhead photographs and land use culture maps; (4) Reliability and safety; (5) Right-of-way or condemnation requirements; (6) Necessary clearing activities; and (7) If the transmission facility is placed underground, the depth of burial, distance between access points, conductor configuration and size, and number of circuits.	23.0

SDCL	ARSD	Required Information	Location
49-41B-7; 49-41B-22	20:10:22:36	**Additional information in application.** The applicant shall also submit as part of the application any additional information necessary for the local review committees to assess the effects of the proposed facility pursuant to SDCL 49-41B-7. The applicant shall also submit as part of its application any additional information necessary to meet the burden of proof specified in SDCL 49-41B-22.	25.0
	20:10:22:37	**Statement required describing gas or liquid transmission line standards of construction.** The applicant shall submit a statement describing existing pipeline standards and regulations that will be followed during construction and operation of the proposed transmission facility	Not Applicable
	20:10:22:38	**Gas or liquid transmission line description.** The applicant shall provide the following information describing the proposed gas or liquid transmission line: (1) A flow diagram showing daily design capacity of the proposed transmission facility; (2) Changes in flow in the transmission facilities connected to the proposed facility; (3) Technical specifications of the pipe proposed to be installed, including the certified maximum operating pressure, expressed in terms of pounds per square inch gauge (psig); (4) A description of each new compressor station and the specific operating characteristics of each station; and (5) A description of all storage facilities associated with the proposed facility.	Not Applicable

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2.0 Description of the Nature and Location of the South Dakota Facility

The Project will consist of approximately 160 to 170 miles of single-circuit 345-kilovolt (kV) transmission line and a new 345-kV substation located near Ellendale, North Dakota. The Project connects the new Ellendale 345-kV Substation in North Dakota and the Big Stone South Substation near Big Stone City, South Dakota. The Big Stone South Substation will be constructed as part of the Order issued by the Commission in South Dakota Docket EL-12-063. The South Dakota portion of this Project consists of about 150 to 160 miles (the Applicants have used approximately 155 miles for their calculations) of single-circuit 345-kV transmission line traversing through Brown, Day, and Grant counties and associated facilities (called the South Dakota Facility). The exact length of the South Dakota Facility will be determined during final design. The North Dakota portion of the Project consists of about 9 to 11 miles of single-circuit 345-kV transmission line and the new Ellendale 345-kV Substation all located in Dickey County, North Dakota (called the North Dakota Facility).

2.1 South Dakota Facility

The South Dakota Facility is located in Brown, Day, and Grant counties. See Exhibit 1 for a Project Overview, Exhibit 2 for a detailed view of the South Dakota Facility, and Exhibit 3 for the United States Geological Survey (USGS) topographic maps of the South Dakota Facility. At the South Dakota/North Dakota state border, the South Dakota Facility heads south, paralleling 388th Avenue in Brown County for about 19 miles. The South Dakota Facility then crosses through southeastern Brown County for approximately 20 miles, eventually turns east into Day County, paralleling 131st Street and crosses the James River. In Day County, the South Dakota Facility is generally located along the western and southern borders of the county paralleling 418th Avenue South, the South Dakota Facility then turns east along 148th Street. Eventually the South Dakota Facility turns south and follows quarter section lines through farm fields, then South Dakota Facility turns east to parallel 151st Street through Wheatland Township. The South Dakota Facility continues east, crossing Interstate 29, and continuing into southern Grant County. Once in the Melrose Township, the South Dakota Facility generally crosses farm fields, using section lines and field lines to connect with the Big Stone South Substation outside of Big Stone City, South Dakota. Please refer to Appendix A for a detailed South Dakota Facility description and table listing each section, township, and range crossed.

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3.0 Name of Owner, Manager, and Participants (ARSD 20:10:22:06; 20:10:22:07)

Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., a Delaware corporation (Montana-Dakota), and Otter Tail Power Company, a Minnesota corporation (Otter Tail Power), (jointly, the Applicants) will share an equal percentage of ownership of the South Dakota Facility.

Montana-Dakota is headquartered in Bismarck, North Dakota, and provides natural gas and/or electric service to parts of Montana, North Dakota, South Dakota, and Wyoming. Its service area covers about 168,000 square miles and includes approximately 312,000 customers.

Otter Tail Power is headquartered in Fergus Falls, Minnesota, and provides electric service to parts of Minnesota, North Dakota, and South Dakota. Its service area covers about 70,000 square miles and includes approximately 129,400 customers in 422 communities.

The Applicants and individuals authorized to receive communications relating to this Application on behalf of Montana-Dakota and Otter Tail Power are shown below in Table 2.

In conjunction with extensive public outreach, members of the public have been and continue to be encouraged to call the toll-free Project information line or visit the Project website with comments and questions:

Telephone: 1-888-283-4678

Website: www.bssetransmissionline.com

Table 2. Owner Contact Information

Montana-Dakota Utilities Co.	Otter Tail Power Company
Henry Ford Project Manager 400 N. 4th Street Bismarck, North Dakota, 58501-4092 Telephone: 701-222-7944	Dean Pawlowski Project Manager 215 S. Cascade Street Fergus Falls, Minnesota 56537-0496 Telephone: 218-739-8947
Project Counsel	
Thomas Welk Boyce, Greenfield, Pashby & Welk LLP 300 S. Main Avenue Sioux Falls, SD 57104 Phone: (605) 336-2424	

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4.0 Purpose of the Transmission Facility (ARSD 20:10:22:08)

The Big Stone South to Ellendale Multi-Value Project (MVP) is one of the seventeen MVPs approved by the Midcontinent Independent System Operator, Inc. (MISO, formerly Midwest Independent Transmission System Operator [Midwest ISO]). The purpose of these MVPs is to reduce the wholesale cost of energy delivery for the consumers across the MISO region by enabling the delivery of low-cost generation to load, reducing congestion costs, and increasing system reliability. Because of the need for the South Dakota Facility, as discussed in Section 6.0, there are expected to be both short-term and long-term benefits to South Dakota from Project completion.

Short-term economic benefits will be derived from activities associated with construction of the South Dakota Facility. Local businesses will likely see an increase in revenues from construction of the South Dakota Facility and positive economic gains will result from increased spending on lodging, meals, and other consumer goods and services. In addition, short-term economic benefits will be realized by landowners that will receive payments for land rights for the South Dakota Facility to cross their properties.

Long term benefits of the South Dakota Facility include supporting public policy, increasing system capacity, and adding to the tax base. By increasing the capability of the transmission system, there will be additional opportunities to transmit energy generated from renewable and other energy resources. It is anticipated that the construction of the South Dakota Facility will reduce obstacles impeding energy development, resulting in additional economic gains to the state and local areas. Another long-term benefit is that the Applicants will pay property taxes estimated to be about $1.75 to $2.25 million dollars plus contractor excise, sales, and use tax on the South Dakota Facility, which will increase the tax base for counties in which this facility is located.

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5.0 Estimated Cost of Facility (ARSD 20:10:22:09)

The total cost of the Project is estimated to be approximately $293 to $370 million in 2013 dollars and includes expenses for surveys, engineering, materials, construction, land rights, and project management. The Project and Facility costs are identified in Table 3. Customers throughout the MISO footprint will pay for the Project. It will not be solely borne by South Dakota customers.

Table 3. Approximate Project Costs

Facility	Cost [1]
Ellendale 345-kV Substation	$28 million
North Dakota Facility	$15 - 22 million
South Dakota Facility	$250 - 320 million
Total Project Cost	**$293 - 370 million**

[1]*All Project costs are approximate and will be refined with additional engineering information. Costs are in 2013 dollars.*

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6.0 Demand for Transmission Facility (ARSD 20:10:22:10)

MISO is a not-for-profit, member-based regional transmission organization administering wholesale electricity markets (see generally www.midwestiso.org). The Applicants are members of MISO. The Project is part of MISO's MVP portfolio, a regionally-planned portfolio of transmission projects supported by significant research and analysis. The MISO transmission planning report supporting the Project is, called "Multi-Value Project Portfolio – Results and Analysis" (Appendix B.1 – please refer to Section 5.7, page 30) (Midwest ISO 2012).

The Applicants participated in MISO's transmission planning efforts that identified the MVPs and concur with MISO's planning report as it pertains to the Project.

On December 8, 2011, the MISO Board of Directors approved a regional transmission plan for the construction of a portfolio of MVPs. In total, the MVPs represent 17 electric transmission projects across the Midwest designed to reduce the wholesale cost of energy delivery for the consumers in the MISO region by enabling the delivery of low-cost generation to load, reducing congestion costs, and increasing system reliability. The Project, a MISO-approved MVP, is shown on Exhibit 4 labeled as Project #6 (Midwest ISO 2011).

6.1 Description of Studies Developed

MISO conducted several studies dating back to 2002 to investigate the reliable transmission of electrical power in the Midwest and the integration of wind energy resources to provide the best value to electric consumers. The most notable studies that contributed to the identification of the Project were the Northwest Exploratory Study completed during the Midwest ISO Transmission Expansion Plan (MTEP) 2005 (Midwest ISO 2005) planning cycle (Appendix B.2 - please refer to Section 7, page 136 – 150), the Regional Generation Outlet Study (RGOS) completed during the MTEP09 and MTEP10 planning cycles (Midwest ISO 2010) (Appendix B.3 – please refer to Section 8, pages 97 – 98), and the "Multi-Value Project Portfolio – Results and Analyses" paraphrased in the MISO Transmission Expansion Plan 2011 (MTEP11) planning report (Midwest ISO 2011) (Appendix B.4 - please refer to Section 4, page 42-75). These studies are attached as electronic copies filed on CD (Appendix B).

The overall goal for the MVP portfolio analysis was to design a transmission portfolio that takes advantage of the linkages between regional reliability and economic benefits to promote a competitive and efficient electric market within the MISO territory. The Project was identified as one such project capable of providing regional electric reliability through the construction and operation of a higher-voltage transmission system. It would stabilize the regional network by providing a backbone system and contending with system contingencies. With the construction of a new 345-kV transmission line, the regional network of distribution and lower-voltage transmission lines will benefit from enhanced connections with the high voltage transmission system. In addition, the enhanced transmission system will be better able to withstand system failures. Furthermore, the Project would remove overloads on local transmission facilities, thereby improving reliability to the local transmission system as more generation facilities are constructed within North Dakota and South Dakota.

6.2 Consequences of Delay or Termination of Project

MISO's extensive regional expansion planning process involves a stakeholder process. One objective of the process is to derive the most cost-efficient transmission expansion plan that will meet local and regional needs for reliability, optimize access to low-cost power resources, and deliver other important values that benefit the ultimate consumer and society. If one key element of the regional expansion plan, especially a 'backbone' element such as the Project, designed for both reliability and economic attributes, is not constructed, considerable redesign could be required. This would result in possible delay, additional expense, and adverse impacts to the reliable addition of new generation supplies and service to load.

If the Project is not constructed as planned, the existing transmission system would be unable to continue to provide reliable service if significant new generation is interconnected. The MISO analyses of this Project identified several 230-kV and 115-kV transmission facilities that will be loaded above safe operating levels in the future without the Project (Midwest ISO 2012). The construction of the Project will provide a new high voltage transmission path to consumers of the MISO network, including consumers of the Applicants in South Dakota. In addition, the MISO MVP analysis identified economic benefits to North Dakota and South Dakota (and all Local Resource Zones within MISO) (reference Appendix B.1 "Multi-Value Project Portfolio – Results and Analyses" Section 10 on pages 80-86 (Midwest ISO 2012)). These economic benefits would not be realized by North Dakota and South Dakota without the Project. In summary, the short-term and long-term benefits listed in Section 4 (Purpose of the Transmission Facility) would not be recognized.

7.0 General Site Description (ARSD 20:10:22:11)

The South Dakota Facility crosses portions of Brown, Day, and Grant counties. Exhibit 2 displays the South Dakota Facility from the North Dakota/South Dakota state border to the Big Stone South Substation. Table 4 provides the location of the South Dakota Facility by township, range, and section identification numbers. Modifications to the South Dakota Facility may occur as a result of permitting, engineering design, and land rights.

Table 4. Proposed Location of the South Dakota Facility

County	Township Name	Township	Range	Section(s)
Grant	Grant Center	120N	49W	4-6
	Twin Brooks	120N	50W	1,2,5,7,8
	Mazeppa	120N	51W	9-12,16-18
	Mazeppa	120N	52W	13-15
	Lura	120N	51W	4,5,6
	Lura	120N	52W	1,2,7-11
	Big Stone	121N	47N	21-24,28-30
	Melrose	121N	48W	20-25,29,32
	Kilborn	121N	49W	31-34
	Osceola	121N	50W	36
Day	Egeland	120N	53W	11,12
	Egeland	120N	54W	19-24
	Wheatland	120N	55W	14-18,23,24
	Highland	120N	56W	3,5,6,8,14-17
	York	120N	57W	1
	Troy	120N	58W	3-6
	Old Gulch	120N	59W	1
	Butler	121N	57W	31,32,33,34,35
	Valley	121N	58W	33,34,35,36
	Scotland	121N	59W	1,12,13,24,25,36
	Andover	122N	59W	7-13,24,25,36
	Ordway	125N	63W	34

County	Township Name	Township	Range	Section(s)
Brown	East Hanson	122N	60W	1,12
	Groton	123N	60W	7-13,24,25,36
	Groton	123N	61W	11,12
	Henry	123N	61W	7-10
	Henry	123N	62W	11,12
	Bath	123N	62W	3,4,10
	Cambria	124N	62W	4-6,9,16,21,28,33
	Ordway	124N	63W	1-3
	Garland	125N	63W	15-17,22,27
	Westport	125N	63W	18
	Westport	125N	64W	1,12,13
	Oneota	126N	64W	1,12,13,24,25,36
	Frederick	127N	64W	12,13,24,25,36
	Richland	127N	63W	6,7
	Osceola	128N	64W	1,12,13,24,25,36
	Savo	128N	63W	31

Source: U.S. Geological Survey, 2008

8.0 Alternative Sites (ARSD 20:10:22:12)

8.1 Route Identification and Selection Process

The South Dakota Facility route selection process centered on a multi-faceted approach in which the Applicants considered state and federal requirements, public comments received at public meetings, and extensive analysis of available environmental data. The route development process was primarily driven by extensive public participation and agency coordination programs in both South Dakota and North Dakota. Table 5 provides a general overview of the public involvement efforts undertaken by the Applicants for the Project. Additional information on the public involvement activities conducted for the Project, including materials used during open house meetings, are available on the Project website at www.bssetransmissionline.com. The South Dakota Facility defined in this Application is shown in detail in Exhibit 2.

Table 5. Summary of Public, Agency, and Tribal Involvement Activities

Year	Month	Action
2012	**July**	• Project notification letter mailed to North Dakota and South Dakota state and federal agencies
	August	• Project notification letter mailed to county, state, and local representatives, and non-government organizations in North Dakota and South Dakota • Held meetings with North Dakota and South Dakota county zoning and planning representatives (Spink, Clark, Grant, Day, Hamlin, Codington, Brown, Deuel, Marshall, Roberts, Richland, Dickey, and Sargent counties) • Held two interagency meetings with state and federal agencies for North Dakota and South Dakota
	September	• Project website and toll-free Project information line made available to the public (www.bssetransmissionline.com and 888-283-4678) • Corridor notification letter for open house meetings mailed to the public, county, state, and city representatives, and non-government organizations in North Dakota, South Dakota, and Minnesota • Corridor notification letter for open house meetings mailed to township representatives in North Dakota, South Dakota, and Minnesota

<table>
<tr><th>Year</th><th>Month</th><th>Action</th></tr>
<tr><td rowspan="3">2012</td><td>October</td><td>Meeting with Sisseton Wahpeton Oyate and Standing Rock Sioux Tribal Historic Preservation Offices (THPOs) for Project introduction and study area discussion
Corridor notification postcard for open house meetings mailed to landowners within the study corridors
Paid advertisements and press releases sent to North Dakota, South Dakota, and Minnesota publications to notify the communities of the study corridor open house meetings
Corridor public open house meetings (October 15-18, 2012):
Wheaton, Minnesota
Milbank, South Dakota
Webster, South Dakota
Aberdeen, South Dakota
Ellendale, North Dakota
Britton, South Dakota</td></tr>
<tr><td>November</td><td>Power Delivered Project Newsletter (Issue 1) was posted to the website and hard copies were mailed to stakeholders in the Project open house meeting attendees and those who had commented or signed up for the mailing list</td></tr>
<tr><td>December</td><td>Power Delivered Project Newsletter from November sent electronically to contact persons above who provided email addresses</td></tr>
<tr><td rowspan="2">2013</td><td>January</td><td>Conducted interagency meetings for North Dakota and South Dakota state and federal agencies. Follow-up letter sent to agencies which included the meeting minutes and letter from the Applicants
Hosted an online webinar and conference call with county representatives in North Dakota and South Dakota including Day, Brown, Grant, Dickey, and Marshall counties to describe the routing process and gather input on preliminary routes followed up with meeting minutes and a message from the Applicants</td></tr>
<tr><td>February</td><td>Meeting with South Dakota State Historic Preservation Office (SDSHPO) to discuss expected cultural resource identification efforts and tribal involvement
Paid advertisements and press releases sent to North Dakota and South Dakota publications to notify the communities of the routing open house meetings
Notification letter for routing open house meetings sent to stakeholders including state, federal, and local agencies, elected officials, and non-governmental organizations (NGOs)
Notification postcards for routing open house meetings sent to landowners within the preliminary corridors of the Project and active participants who attended a meeting or submitted a comment
Routing public open house meetings (February 25-27, 2013):
Groton, South Dakota
Ellendale, North Dakota
Britton, South Dakota
Webster, South Dakota
Milbank, South Dakota</td></tr>
</table>

Year	Month	Action
2013	**March**	• A thank you postcard was sent to routing open house meeting attendees • Meeting with Sisseton Wahpeton Oyate and Standing Rock Sioux THPOs to discuss preliminary routes
	April	• Additional Route Segment notification letters were mailed to landowners within the 150-foot-wide right-of-way (ROW) of a new route segment added to the preliminary routes for review
	May	• Preferred route notification mailed to federal and state agencies including a map of the preferred route • Preferred route notification mailed to county officials and staff • Preferred route notification mailed to township chairs • Preferred route notification mailed to tribal representatives • Meeting held with Sisseton Wahpeton Oyate and Standing Rock Sioux THPOs to discuss general cultural resource identification and survey approach • Conference call with SDSHPO held to discuss cultural survey approach and schedule
	June	• Preferred route notification mailed to landowners within 500 feet of the South Dakota Facility centerline, landowners within the original corridors, and to people on the mailing list at the time of the mailing • Preferred route maps available on Project website • Paper and electronic copies of the Second Issue of *Power Delivered* Project Newsletter sent out to stakeholders and landowners within a half-mile of the preliminary routes, and to active participants in the Project
	July	• Meeting held with Sisseton Wahpeton Oyate and Standing Rock Sioux THPOs to finalize discussions on the South Dakota Facility and the cultural resources survey approach • Submitted Class I Literature Review report to SDSHPO

The Applicants began their analysis by collecting Geographic Information System (GIS) data from local, state, and federal agencies for much of northeastern South Dakota and southeastern North Dakota. The Applicants used these data, along with data collected during field visits to the South Dakota Facility area, to develop a Project study area and identify initial opportunities and constraints such as state and federal lands as shown on Exhibit 5. The Applicants then narrowed the study area into study corridors that were used for agency and public outreach to help identify additional opportunities and constraints to be considered during routing. Next, the Applicants developed a series of route segments within the study corridors, which were typically short linear segments in proximity to public roadways, section or quarter section field lines, or existing corridors that a potential transmission line route could be near. It was considered desirable to locate the new transmission line near facilities such as roadways, section lines, and existing corridors in order to minimize impacts to open land areas, avoid impacts to homes, businesses, or wind energy facilities, and allow for easier access to the right-of-way (ROW) for construction and maintenance purposes. The feasibility of using these segments was evaluated on an individual basis. Once evaluation of the route segments was completed, the segments were linked together into numerous alternative preliminary transmission line routes. The Applicants evaluated the preliminary routes, measuring them against both the transmission line routing considerations for the State of South Dakota (SDCL 49-41B-22) and input on sensitive and important resources identified by the public. The transmission line route in South Dakota was selected based on several considerations, including the following:

- Minimizing total length and construction costs
- Minimizing impacts to humans and human settlements, including (but not limited to) displacement, noise, aesthetics, cultural values, recreation, and public services
- Consideration of effects on public health and safety
- Offsetting existing ROW (roadway or other utility ROW) or section lines to minimize impacts to land-based economies, including (but not limited to) agricultural fields and mining facilities
- Minimizing effects on archaeological, cultural properties, and historic resources
- Minimizing impacts to wetlands, surface waters, and rivers
- Minimizing impacts to rare or endangered species and unique natural resources
- Minimizing effects to airports or other land use conflicts

During public open house meetings conducted during the route identification and selection process, the public identified several criteria that were also considered in the routing process. These criteria included:

- Constructing the transmission lines near existing roadway ROW or close to the half section lines to minimize impacts to agricultural fields
- Placing structures to minimize impacts to agricultural production/allow for the movement of farm equipment
- Avoiding a diagonal route across agricultural fields wherever possible
- Preference for mono-pole structures rather than H-frame structures

Upon determination of the preferred route, notifications were sent to federal and state agencies in May 2013, requesting comment on the preferred route, as shown in Table 5. A table outlining agency contact and copies of the agency material correspondences are provided in Appendix C.

8.2 Alternatives Considered and Selected

The Applicants initially considered multiple alternatives for the South Dakota Facility. The Applicants evaluated preliminary routes in South Dakota based on the factors listed above and the comments received from the public. The study corridor in Minnesota was considered but not selected for the following reasons:

- Need to complete permitting process in an additional state
- Crossing of the Bois de Sioux and Minnesota Rivers which are classified as Section 10 Rivers, regulated by the United States Army Corps of Engineers (USACE), and requiring additional federal review and permitting
- Increased length resulting in increased potential effects and cost
- Engineering challenges associated with crossing Big Stone Lake north of Ortonville, Minnesota

- High density and a high potential for cultural resources in Traverse County, Minnesota
- High density of homes along Big Stone Lake, Lake Traverse, and Little Minnesota River
- United States Fish and Wildlife Service (USFWS) Waterfowl Production Area clusters near the Traverse-Big Stone County line near Beardsley, Minnesota
- National Natural Landmark along Lake Traverse
- Density of federal lands south of Hankinson, North Dakota

The route of the South Dakota Facility proposed in this Application was selected in an effort to minimize the distance between the two substation endpoints, minimize adverse impacts to human settlements and the natural environment, minimize transmission line corridor congestion, and improve the reliability of the regional electrical system. Preliminary routes were evaluated and rejected based on comments and guidance from agencies, public, and tribes. In addition, preliminary routes parallel to Interstate 29, traveling north-south near Britton, South Dakota, and a route going near Waubay, South Dakota were rejected based on specific constraints and resources present within each area. These constraints included federal and state managed lands, archaeological resources, proximity to occupied homes, crossing existing transmission lines, large lakes and water bodies, river crossings, length, and the number of corner structures required. The preferred transmission line route avoided more constraints than the alternative routes and minimized the distance between substations to the greatest extent possible. At the time of this Application, the Applicants are working with and will continue to work directly with affected property owners to address routing issues and concerns. Applicants have no reason to believe that eminent domain powers could be reduced by use of an alternative site.

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9.0 Environmental Information (ARSD 20:10:22:13)

Chapters 10 through 19 provide a description of the existing environment at the time of the submission of the Application, an estimate of changes to the existing environment which are anticipated to result from construction and operation of the South Dakota Facility, and identification of irreversible changes which are anticipated to remain beyond the operating lifetime of the South Dakota Facility, along with mitigation measures to be taken by the Applicants. Documentation of formal consultation with agencies regarding the South Dakota Facility is discussed in Section 8 and Appendix C.

ARSD 20:10:22:13 states that "The environmental effects shall be calculated to reveal and assess demonstrated or suspected hazards to the health and welfare of human, plant and animal communities which may be cumulative or synergistic consequences of siting the proposed facility in combination with any operating energy conversion facilities, existing or under construction." No cumulative or synergistic consequences as to environmental effects contemplated by the regulation are known to exist for the South Dakota Facility.

In addition, the Applicants are not aware at this time of any major industrial facilities under regulations in the siting area which may have an adverse effect on the environment as a result of the construction or operation of the South Dakota Facility.

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10.0 Effect on Physical Environment (ARSD 20:10:22:14)

10.1 Existing Environment

10.1.1 *Description of Land Forms*

The South Dakota Facility traverses four physiographic regions in northeast South Dakota. From northwest to southeast, these are the James River Lowlands, the Lake Dakota Plain, the Coteau des Prairies, and the Minnesota River Lowlands. The Coteau des Prairies is the most conspicuous landform of eastern South Dakota and consists of a highland area (an erosional remnant) between the Minnesota-Red River Lowland to the east and the James River Lowland to the west (Patterson et al., 1995). It is drained to the south by the Big Sioux River, whose tributary streams enter mainly from the east. West of the Big Sioux River, the surface of the Coteau des Prairies is dotted with lakes and depressions, while very few lakes occur east of the river. The Minnesota River and its tributaries drain the eastern lowlands and the eastern flank of the Coteau des Prairies. The James River basin receives runoff from the western slope of the Coteau des Prairies. The Lake Dakota Plain region lies within the James River Lowlands and is bisected by the James River. Elevations along the South Dakota Facility range from 1,420 feet above sea level (ft ASL) in the north to about 1,300 ft ASL west of the Coteau des Prairies to the range of 1,700-1,850 ft ASL crossing the Coteau des Prairies and terminating near 1,000 ft ASL in the Minnesota River Lowlands. The topography of the South Dakota Facility is shown in Exhibit 3.

10.1.2 *Geological Features and Constraints*

During the Ice Age, the Coteau des Prairies was covered by glaciers that deposited glacial drift over its surface. Glacial cover in the South Dakota Facility area is thicker than the surrounding regions. Drift thicknesses on the Coteau area range from 600 to 700 feet (Patterson et al., 1995). The glacial drift is comprised of till from the Des Moines lobe deposited during the Late Wisconsin period. The geologic materials of the Minnesota River valley are similar to those on the Coteau des Prairies, but are at lower elevation and are limited to about 100 feet of thickness. In the James River Lowlands, the drift was deposited by the James lobe in the pre-Late Wisconsin period. The combined drift thicknesses of the James River Lowlands and Lake Dakota Plain are typically 100 feet or less.

The South Dakota Facility area is underlain by undifferentiated Cretaceous bedrock. The uppermost bedrock in Brown and Day counties is the Pierre Shale. This shale is dark-greenish gray to dark-blackish-gray, brittle, and fissile. In Grant County, the Pierre Shale is the uppermost bedrock in the western half and the Carlile Shale is the uppermost bedrock in the eastern half. The Carlile Shale is described as dark gray to blue-gray shale and contains numerous calcareous concretions and a few thin layers of sandstone. Neither of these bedrock formations are significantly developed for groundwater supplies.

Exhibit 6 illustrates the bedrock geology and Exhibit 7 illustrates the surficial geology in the area of the South Dakota Facility.

10.1.3 *Economic Deposits*

Based on data provided by the South Dakota Department of Environment and Natural Resources, review of aerial photographs, and field observations, one gravel pit was identified within the South Dakota Facility ROW. The gravel pit is located in Section 2 of Lura Township (T120N R52W). However, this gravel pit appears to have not been used in recent years.

10.1.4 *Seismic Risks*

Seismic risk of the South Dakota Facility area is considered low. Since 1900, five earthquakes have been recorded in the counties through which the South Dakota Facility passes and adjacent counties: two in Brown County in 1900, one in Marshall County (north of Day County) in 1934, one in Spink County (south of Brown County) in 1959, and one in Roberts County (north of Grant County) in 1995. The Applicants are not aware at this time of subsidence potential or slope instability problems associated with the Project.

10.1.5 *Soils*

Soils within the South Dakota Facility ROW can be grouped by soil associations. An association is a group of individual soil series that occur together in a characteristic geographic pattern or a distinctive pattern of soils, relief, and drainage. Each soil association is typically composed of one or more major soils and one or more minor soil components. Soil associations are defined by each county's Natural Resources Conservation Service (NRCS) office.

GIS soils data for general State Soil Geographic (STATSGO) soil associations and Soil Survey Geographic (SSURGO) data are made available by the NRCS. These data sets were analyzed using the ArcInfo license of ESRI® ArcMap™ 10.0 to determine which soil associations and series were located in the South Dakota Facility area. Fifteen soil associations comprised of 32 soil series were identified in the South Dakota Facility area. Descriptions and acreages of the soil associations within the South Dakota Facility ROW are tabulated in Appendix D.

Soil databases do not have attributes to identify erodible or highly erodible soils. In general, soils of six percent or greater slope have a higher potential for erosion due to surface runoff, if disturbed.

10.1.6 *Prime Farmland*

Prime farmlands are areas that have been determined by the South Dakota NRCS to have adequate pH, water supply, growing season length, and temperature for growing crops. Soils in prime farmlands are not excessively erodible or wet throughout the growing season. Table 6 shows the percent of farmland classifications for the South Dakota Facility ROW.

Table 6. Prime Farmland Classifications for South Dakota Facility ROW

Prime Farmland Classification	Percent of ROW
Prime farmland	49.9
Farmland of statewide importance	11.5
Prime farmland if drained	14.3
Prime farmland if irrigated	2.5
Total	**78.2**

Source: SSURGO

10.2 Potential Impacts

The characteristics of the geologic materials in the area generally limit the risks posed by the South Dakota Facility. Unconsolidated geologic and soil materials are glacial till or lacustrine sediments. These materials are generally of low permeability, although the potential exists for high permeability granular lenses of limited size.

The greatest risk to the geologic environment is soil erosion. Where land slopes are relatively flat, for example in the James River and Minnesota River Lowlands, the potential for soil erosion is low. However, steep slopes occur along the margins of the Coteau des Prairies and the topography of the Coteau des Prairies is variable. Where steep slopes, i.e., greater than 6 percent, occur, the potential for soil erosion significantly increases. Please see Appendix D for a list of soil associations and series and their respective slope ranges. Soil properties that also influence erosion from water runoff include soil texture, percent organic matter, structure infiltration capacity, and soil permeability. Soils containing high proportions of silt and fine sand are most erodible. Well-drained and well-graded gravels and gravel sand mixtures with little or no silt are the least erodible materials. General drainage ability is also described in Appendix D. Erosion from water runoff is also influenced by slope length and gradient, as well as frequency, intensity, and duration of rainfall and the amount of time bare soils are exposed. Erosion could be caused by site clearing and earthmoving in addition to natural processes.

Impacts to economic deposits are not anticipated. The Applicants will work with the owner of the gravel pit located within the ROW during negotiation of land rights agreements to minimize effects.

10.2.1 *Soils*

Construction of the South Dakota Facility will impact soils within the ROW. A 30-foot-wide temporary travel path within the ROW will be used for vehicle traffic to each structure location. In woodlands and shrublands, the full 150-foot-width of the ROW will be cleared. These activities will result in an estimated 1,580 acres of temporary impacts to soils. The Applicants estimate approximately 2.2 acres of permanent impacts to soils will occur from the installation of pole structures, regeneration stations and their associated access roads (1.47 acres from structure locations and 0.7 acres from regeneration stations and their associated access roads).

Impacts to soils could include compaction, potential loss of soil due to erosion, and the potential contamination of soils by spills from construction equipment.

10.2.2 *Prime Farmland Impacts*

Table 7 provides the estimated temporary and permanent impacts to prime farmland associated with construction and operation of the South Dakota Facility.

Table 7. Estimated Temporary and Permanent Impacts to Prime Farmland

South Dakota Facility	Farmland Classification	Temporary Impacts (acres)[1]	Permanent Impacts (acres)[2]
Structure locations and temporary travel path	Prime farmland	685.5	0.73
	Farmland of statewide importance	157.8	0.17
	Prime farmland if drained	197.0	0.21
	Prime farmland if irrigated	34.9	0.04
	Not prime farmland	298.7	0.32
Laydown areas and Wire stringing areas[3]	NA	202.9	0.0
Fiber optic regeneration stations and access roads[3]	NA	0.0	0.7
Total[3]		1,576.8	2.2

1. Temporary impacts are calculated assuming one acre of temporary impact around each structure locations and a 30-foot-wide temporary travel path within and along the entire ROW. Additional temporary impacts are anticipated from laydown areas and wire stringing areas.

2. Permanent impacts are calculated as a 5-foot radius (78.5 sq. ft) per structure. Temporary travel path has no permanent impact to prime farmland.

3. The exact locations of laydown areas, wire stringing areas, fiber optic regeneration station and their access roads are not known at this time but will be determined during final design – therefore it is not known what type of prime or statewide importance soil will be impacted by these facilities.

10.3 Mitigation

The South Dakota Facility has been routed to minimize impacts to land forms, geology, and economic deposits. Available geologic data indicate that the South Dakota Facility will not significantly affect soil conditions or bedrock geology. Seismic activity is not anticipated to affect the performance of the transmission line structures. The placement of structure foundations in the ground will have a minor impact to the underlying geologic conditions. Except as described in this application, the Applicants are not aware of any additional constraints that may be imposed by geological characteristics on the design, construction, or operation of the facility.

Soil erosion is possible in areas of steep slopes, particularly on the edges of the Coteau des Prairies. To reduce adverse effects to and from soils, the Project will develop and utilize Best Management Practices (BMPs) during construction to protect topsoil and adjacent wetland resources, and minimize soil erosion. Soils disturbed during construction will be decompacted and restored to preconstruction contours to the extent practicable and in accordance with landowner agreements so that all surfaces drain naturally, blend with the natural terrain, and are left in a condition that will facilitate re-vegetation, provide for proper drainage, and prevent erosion. Construction laydown areas and temporary travel paths will be restored per the landowner agreement.

11.0 Hydrology (ARSD 20:10:22:15)

11.1 Existing Environment

The South Dakota Facility area includes two distinct hydrologic regions. In the central portion of the South Dakota Facility lies the broad valley floor of the James River. The valley is situated in the sediments of glacial Lake Dakota. Topography is relatively flat, with well-defined creeks and streams. Small isolated wetlands are present but in relatively lower density than in the rest of the South Dakota Facility area. The eastern and western portions of the South Dakota Facility area tend to have a lower frequency of well-defined stream channels and a higher density of pothole lakes and wetlands; the topography tends to be more rolling and lacks a well-defined dendritic stream pattern. Exhibit 8 shows the hydrologic resources discussed in this section.

11.1.1 *Rivers and Streams*

Creeks and streams are generally meandering, limited to the toe slopes and stream valleys, and are intermittent or perennial depending on the watershed location. Stream channels along the edges of the James River valley tend to be linear.

The South Dakota Facility crosses 12 major watershed units, as defined by the USGS. They include: Maple River, Sand Lake-James River, Lower Elm River, Moccasin Creek – James River, Lower Mud Creek, Antelope Creek, Pierpont Lake, Upper Mud Creek, Grass Lake, Bitter Lake, Headwaters Big Sioux River, and South Fork Whetstone River.

Table 8 lists the USGS-named streams that are crossed by the South Dakota Facility as well as their floodplain listing. The James River is the widest river crossed by the South Dakota Facility, but is less than 1,000-feet-wide at the crossing location. The James River is identified as a Section 10 Navigable Waterway by USACE. Electronic Federal Emergency Management Agency (FEMA) floodplain data is only available for Brown County and part of Grant County. There are a total of 38 mapped floodplains crossed by the South Dakota Facility. Nine floodplain crossings are greater than 1,000 feet wide and cannot be spanned by the South Dakota Facility. The widest floodplains are associated with the James River and Mud Creek in Brown County and the Whetstone River in Grant County. Many other named and unnamed streams and water bodies have designated 100-year-floodplains.

Table 8. USGS-Named Streams/River Crossings

Surface Water Name	Number of Crossings	Floodplain Present at River Crossing[1]
Big Sioux River	3	Unknown
Elm River	1	Yes
Indian River	7	Unknown
James River	1	Yes
Maple River	1	Yes
Mud Creek	4	Unknown
South Fork Whetstone River	1	Yes
Whetstone River	2	Yes
Total Number	**20**	**NA**

[1.] *Includes review of available digital floodplain data for Brown County and part of Grant County.*

Source: National Hydrography Data set, USGS Streams data set and FEMA

11.1.2 *Wetlands*

According to the National Wetlands Inventory (NWI), the South Dakota Facility will cross mostly freshwater emergent wetlands. Table 9 provides a summary of the NWI wetland types within the South Dakota Facility ROW.

Table 9. NWI-Mapped Wetlands Identified within South Dakota Facility ROW

NWI Wetland Type	NWI-mapped Wetland Area within ROW (Acres)	Percent of ROW Containing Wetlands[1]
Freshwater Emergent Wetland	162.2	5.8%
Freshwater Forested/Shrub Wetland	2.4	0.1%
Freshwater Pond	3.1	0.1%
Riverine	5.0	0.2%
Total	172.7	6.2%

[1] *Total ROW area is 2,795.9 acres*

Source: National Wetlands Inventory data

Because the boundaries of NWI wetlands were determined by the use of aerial photography and is dependent on the year the photograph was taken and the level of water in the wetland at that time, the NWI data in South Dakota may not reflect the true size of wetlands. The NWI data were developed between 1977 and 2009, with 2009 listed as the most recent publication date.

Through field observation, conversations with stakeholders, and aerial photography interpretation, the Applicants attempted to address the known rise in water levels in the South Dakota Facility area. To provide an estimate of wetland size and potential impact, the Applicants performed a desktop analysis of wetlands within the South Dakota Facility ROW. This desktop assessment was based on recent aerial photography and the NWI mapping.

The resulting digitized boundaries are used for siting purposes and will be the basis for any field assessment of wetlands that may be performed. These digitized wetlands do not have specific wetland types associated with them, but are meant to provide a conservative estimate of wetlands in the South Dakota Facility ROW. Note that the conservative estimate of wetland area within the South Dakota Facility ROW based on current aerial photo interpretation, shown in Table 10, is more than double the estimate based on NWI data.

Table 10. Digitized Wetlands Identified within the South Dakota Facility ROW

Wetland	Wetland Area within ROW (Acres)	Percent of ROW Containing Wetlands
Digitized Wetlands	395.7	14.2%
Total	**395.7**	**14.2%**

Source: HDR Engineering, Inc.

The USFWS manages many wetland easements in the South Dakota Facility area. The habitat preserved by these easements supports the reproduction and habitat of wildlife species, particularly waterfowl and game-birds. Often the surrounding uplands in the wetland easements are in agricultural use such as crops or pasture. Within the South Dakota Facility ROW, about 264.3 acres of land contain USFWS wetland easements. Only the designated wetland portion of these parcels is actually encumbered by the easement.

11.1.3 *Other Water Resources*

No municipal wells are known to occur within the South Dakota Facility ROW. There are several locations where the South Dakota Facility crosses the edge of fields with center pivot irrigation. These agricultural irrigation systems are described in Section 19.3 and 19.4.

Water resources in the South Dakota Facility area are shown on Exhibit 8, and aquifers are shown on Exhibit 9.

11.2 Potential Impacts

11.2.1 *Rivers and Streams*

Given the flexibility of pole locations and a typical span distance of 1,000 feet, the South Dakota Facility is expected to span all rivers and streams, thus avoiding potential permanent impacts. Some structures may be placed within the designated floodplain; the locations will be determined during final design. Impacts to floodplain storage capacity will be negligible due to the long spans between transmission structures and the relatively small volume of foundation material used at the structures.

Temporary impacts to rivers and streams may occur during construction, due to travel path crossings. The location and extent of these temporary impacts will be determined during final design.

11.2.2 *Wetlands*

Given the flexibility of pole locations and a typical span distance of 1,000 feet, the South Dakota Facility can span most wetlands, thus minimizing permanent impacts. There are 19 digitized wetlands that cannot be spanned because the crossing length is greater than

1,000 feet. Assuming one structure would be placed in each of the 19 wetlands, with an estimated permanent impact of approximately 78.5 sq. ft. for each structure, the South Dakota Facility would permanently impact about 0.03 acres of wetlands. Note that NWI data was not used to calculate wetland impacts, because the digitized data is more conservative. In addition to these impacts, there may be other wetlands that cannot be avoided because of siting constraints on adjacent lands that result in placing a structure in a wetland. The location of these impacts will be determined during final design. Note that the exact location of the fiber optic regeneration stations and their associated access roads, laydown areas, and wire stringing areas are not known at this time. It is not anticipated that laydown areas and regeneration stations will be placed in a wetland and no permanent impacts are anticipated.

Temporary impacts to wetlands will occur during construction. A 30-foot-wide temporary travel path within the South Dakota Facility ROW will be used during construction, resulting in about 78.7 acres of temporary impact to the digitized wetlands. Temporary construction impacts for each pole structure are estimated to be about one acre. This amounts to about 19 acres of temporary impact for the 19 digitized wetlands that cannot be avoided by spanning. Total temporary impacts to wetlands will be about 97.7 acres. Note that the exact location of the fiber optic regeneration stations and their associated access roads, laydown areas, and wire stringing areas are not known. However, it is not anticipated that laydown areas and regeneration stations will be placed in a wetland and no temporary impacts are anticipated.

As stated above, the South Dakota Facility ROW crosses USFWS wetland easements. However, the easement pertains only to the actual wetland and the Applicants will work with the USFWS to span all wetlands in these easements. Once field delineations occur and the wetland boundaries are identified in coordination with USFWS Wetland Management District staff, the Applicants will work with the USFWS to document temporary and/or permanent wetland impacts on easement lands.

11.2.3 *Other Water Resources*

Permanent impacts to municipal, private, communities, agricultural, recreational, fish, and wildlife water users are not anticipated and permanent impacts to surface water and groundwater are also not expected to occur.

Construction of the South Dakota Facility has the potential to impact water resources on a temporary basis. Water crossings may be required to access structure locations, resulting in the potential for erosion or other impacts to aquatic resources.

There is risk for groundwater contamination resulting from releases of contaminants during construction. The unconsolidated geologic and soil materials (as discussed in Section 10.0) are generally of low permeability, although the potential exists for high permeability granular lenses of limited size. As a result, the potential for groundwater development is limited. Similarly, the uppermost bedrock units consist of shales that are not suitable for groundwater development and have low susceptibility to contamination. Groundwater dewatering may be necessary in localized areas during construction, but potential effects of dewatering such as drawdown are local and temporary.

Temporary dewatering may be required during construction. The appropriate permits will be obtained and BMPs implemented as needed, prior to dewatering activities. The South Dakota Facility does not require water storage, reprocessing, cooling, or deep well injection. Effects to aquifers and potable water supplies by the South Dakota Facility are not anticipated. Permanent impacts to surface waters or groundwater aquifers are not expected to occur. In addition, the South Dakota Facility will not alter surface water drainage patterns (Exhibit 7).

11.3 Mitigation

Direct impacts to rivers and streams are not anticipated.

To the extent practicable, wetland impacts will be avoided through the siting process. Should any structures be placed in wetlands, the Applicants will develop appropriate mitigation, if required, in coordination with USACE under the Section 404 permit process. The permit will cover both permanent and temporary impacts. Permanent impacts to wetlands under USFWS easements will require a permit from the USFWS.

To limit impacts to hydrologic resources caused by soil erosion, groundwater contamination or stormwater runoff, the Applicants will follow applicable permit conditions as appropriate and use BMPs to reduce impacts during construction. Should vehicle fueling be required within the South Dakota Facility ROW, BMPs will be employed to ensure that equipment fueling and lubricating occur at a distance from waterways.

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12.0 Effect on Terrestrial Ecosystems (ARSD 20:10:22:16)

12.1 Existing Environment

12.1.1 *Field and Mapping Methods*

A reconnaissance-level field review of the South Dakota Facility area was conducted in October 2012. This field visit was conducted to provide field verification of remote data by cataloging the presence of wetlands, native prairie resources and existing land uses. Observations were made from road rights-of-way within the South Dakota Facility area to verify the accuracy of remote data sources.

In addition, a GIS model was developed using infrared imagery and an on-the-ground assessment method to map areas of native prairie and other land covers within the South Dakota Facility. The main purpose of this analysis was to focus on native communities in the South Dakota Facility area, particularly native prairie habitat (Appendix E) (Applicants have requested confidential treatment). The prairie habitats were ranked as high or low quality by identifying species assemblages, estimating anthropogenic disturbance, and noting other dominant land-use types in the South Dakota Facility area. This system is used to standardize prairie habitat ranking by considering the diversity of native grasses and forbs, the degree of human disturbance, the presence of non-native vegetation, the presence of woody vegetation, and evidence of fire suppression, among other factors. Those grasslands featuring native communities and those lacking non-native or woody species with little to moderate levels of human disturbance were ranked as high quality. Highly disturbed grasslands, those with low native species diversity or those dominated by non-natives were considered low quality habitat. The extents of several additional land cover types were also recorded to enhance the classification process of high quality native prairies. Table 11 provides more information on the land cover types identified by the GIS habitat model, along with their approximate corresponding National Land Cover Database (NLCD) classification.

Table 11. Land-cover Types in South Dakota Facility Area as Identified by GIS Habitat Model

Land Cover Type[1]	Characteristics
Dry Hill Prairie – High Quality NLCD category: Grassland	High diversity of native grasses and forbs dominate Minimal or absent non-native species Moderate to steep slopes Abundant glacial material, such as cobble or boulders
Dry Hill Prairie – Low Quality NLCD category: Pasture/Hay	Native grasses and forbs present Non-native species persist throughout area Moderate to steep slopes Abundant glacial material, such as cobble or boulders
Mesic Prairie – High Quality NLCD category: Grassland	High diversity of native grasses and forbs dominate Minimal or absent non-native species Flat to gently rolling terrain Somewhat poorly drained

Land Cover Type[1]	Characteristics
Mesic Prairie – Low Quality NLCD category: Pasture/Hay	Native grasses and forbs present Non-native species persist throughout area Flat to gently rolling terrain Somewhat poorly drained
Non-native Grassland NLCD category: Pasture/Hay	Dominated by non-native grasses (*Bromus inermis, Poa pratensis*, etc) Native species absent
Cropland NLCD category: Cultivated crops	Row crops, corn, soybeans etc.
Small Grains NLCD category: Cultivated crops	Wheat or alfalfa
Emergent Wetland NLCD category: Emergent Herbaceous Wetland	Wetland area dominated by *Typha spp, Spartina pectinata* or other hydrophytes Open, standing water minimal
Open Water NLCD category: Open Water	Lakes, ponds, rivers
Woodland NLCD category: Deciduous Forest and/or Shrub	Mature deciduous or evergreen canopy
Gravel NLCD category: NA	Gravel pits or other aggregate extraction facilities
Pavement NLCD category: Developed, Open Space	Roads, parking lots, airport runways
Urban NLCD category: Developed, Open Space	Commercial, downtown core (not present in corridor)
Exposed Rock NLCD category: NA	Exposed granite
Cloud Cover/No Data NLCD category: NA	Areas with pervasive data gaps or significant cloud cover were not available for this portion

[1] There is not an exact correlation between the GIS habitat model categories and NLCD categories – there may be overlaps or discrepancies (e.g., two parcels both quantified as "Pasture" in the NLCD database may be classified as different types of prairie or grassland under the GIS habitat model)

12.1.2 *Terrestrial Vegetation and Wildlife Cover/Habitat Types*

The South Dakota Facility ROW is located in the Prairie Parkland (Temperate) and the Great Plains Steppe Ecological Provinces as defined in the Ecological Subregions of the United States (McNab, 1994). Historically, land cover in the North Central Glaciated Plains Section of the Prairie Parkland (Temperate) Province near the South Dakota and Minnesota state border was characterized by a predominance of treeless fire-dependent grassland and brushland types interrupted by lakes, rivers, streams, marshes, and pothole wetlands. The western portion of the South Dakota Facility area lies within the Northeastern Glaciated Plains Section of the Great

Plains Steppe and occurs as an area of nearly level to undulating continental glacial till and glacial lake plains dominated by fire-dependent grasslands, wetlands, and stream courses.

The geomorphology in the area is characterized by nearly level to gently rolling till plains with potholes and well defined drainages. Moderate to steep slopes occur along river and creek valleys. The Coteau des Prairies occurs on the eastern portion of the South Dakota Facility area. This landform is a moderately dissected, relatively high plateau that rises out of a nearly level till plain. This feature and the Minnesota River's broad valley were created by the Pleistocene draining of Glacial Lake Agassiz.

The South Dakota Facility ROW includes five general habitat or cover types: native grassland, non-native grassland, upland/riparian woodland, wetland, and cropland. However, native plant communities largely have been removed or degraded by agricultural activities in the South Dakota Facility ROW. Land uses are generally dictated by the terrain of a given area. Level stream valley floors and the drier portions of the till plains are cultivated and steeper slopes or drainage slopes are used for pasture, remain as native prairie, or have been degraded by intensive grazing. Roadways generally follow section or half-section lines where the terrain allows. Farms are typically located along roadways and may feature woody groves or wind breaks.

Cropland is the most common type of land cover in the South Dakota Facility ROW. These areas generally present limited and seasonal habitat opportunities for local wildlife, but they can provide cover or serve as food sources for a variety of mammals and birds. Agricultural products such as soybeans, wheat, sunflower and corn are common.

Grasslands are mostly restricted to the Coteau des Prairies or to slopes adjacent to riparian corridors. The varied topography (Exhibit 3) in these areas has prevented agricultural production from occurring directly adjacent to the river channel, so the uneven terrain serves as pastureland. This has allowed for some native characteristics to persist. Stands of little bluestem, big bluestem, grama species, prairie cordgrass, and native forbs such as pale purple coneflower among others were observed to persist alongside introduced species such as smooth brome in some grasslands. Moderate to heavy grazing has reduced the quality of these grasslands.

The results of the GIS habitat model described above identified blocks of high and low quality native prairie in the South Dakota Facility area, along with other cover types, including non-native grasslands, croplands, and others. In general the grassland areas in the South Dakota Facility ROW (high and low quality prairie, and non-native grasslands) are currently being used for pasture. It also should be noted that cover types from the GIS model are not exact matches with the NLCD data as discussed in Section 14.1; rather both of these land cover files should be considered as separate data giving information on the vegetation types in the ROW. Table 12 provides the percentage that each of these GIS habitat model cover types represents in the South Dakota Facility ROW.

Table 12. Habitat Model Land Cover Types in South Dakota Facility ROW

GIS Habitat Model Land Cover Category	Acres in ROW	Percent of ROW
Cropland	1,346.0	48.2%
Dry Hill Prairie - High Quality	109.8	3.9%
Dry Hill Prairie - Low Quality	231.9	8.3%
Emergent wetland	348.0	12.4%
Grains	361.0	12.9%
Gravel	4.4	0.2%
Mesic Prairie - High Quality	97.9	3.5%
Mesic Prairie - Low Quality	120.6	4.3%
Non-native grassland	106.9	3.8%
Open water	26.7	1.0%
Pavement	3.3	0.1%
Rock	10.6	0.4%
Urban	2.7	0.1%
Woodland	26.0	0.9%
Total	**2,795.8**	**100.0%**

12.1.3 *Local Terrestrial Wildlife*

The South Dakota Facility area supports fauna associated with agricultural lands, a fragmented grassland landscape that contains small parcels of non-native grassland, and tallgrass prairie in the prairie pothole region. Species typical of the Upper Great Plains can be found here, although densities and relative abundance have not been determined. Those species most likely to occur in the South Dakota Facility area are those filling a general ecological niche, or demonstrating a capacity to adapt to an agricultural landscape with patchy grasslands and wetlands. Common mammals could include raccoon, Virginia opossum, mink, eastern cottontail, white-tailed deer, coyote, thirteen-striped ground squirrel, muskrat, and striped skunks. Avian species found in the area will likely include red-winged blackbird, yellow-headed blackbird, mourning dove, mallard, ruddy duck, gadwall, killdeer, horned lark, barn swallow, house wren, common yellowthroat, vesper sparrow, common grackle, western meadowlark, American robin, and American goldfinch. The South Dakota Facility area also includes stopover habitat during migration for large numbers of waterfowl, shorebirds, and sandhill cranes. Wintering habitat for snow buntings and longspurs is also likely present.

Reptiles or amphibians likely present in and near the South Dakota Facility area could include snapping turtle, western painted turtle, plains garter snake, common garter snake, Canadian toad, American toad, gray tree frog, and northern leopard frog. These species are generally associated with wetlands, riparian corridors, or grasslands located in the South Dakota Facility ROW.

Native plant communities support higher densities of vertebrate and native invertebrate use than areas used for row crop production. Additionally, these areas may provide habitat characteristics preferred by sensitive species including prairie obligate butterflies such as the Dakota skipper and Poweshiek skipperling. Outside of these areas, native characteristics are generally absent and row crop production has diminished the quality of habitat available to grassland species.

Wetland features are relatively numerous throughout this portion of the state. The pothole features attract high numbers of migratory waterfowl to the area. Waterfowl flight paths are likely present along stream valleys and between lakes, wetlands, and agricultural fields that can serve as feeding areas. The presence of numerous waterfowl and fish using these wetlands and lakes also attract predatory species such as bald eagles and osprey. Mammals utilizing these resources include species such as red fox, muskrat, and mink.

The prevalence of pasture and grasslands near the South Dakota Facility area provides moderate to high quality habitat for grassland-dependent species such as red fox, loggerhead shrike, ring-necked pheasant, sharp-tailed grouse, marbled godwit, and predatory raptors, such as great horned owls, short-eared owls, Swainson's and red-tailed hawks.

Agricultural lands are used by species that tolerate or thrive on grain or seed crops such as corn, wheat, and sunflowers. Ring-necked pheasants, horned lark, vesper sparrow, killdeer, American robins among others are present within agricultural lands but occur at lower densities than areas that provide year-round food and cover such as native grassland or woodlands.

A review of the USFWS South Dakota Field Office list of endangered species by county (2013) indicated that the federally listed threatened (T), endangered (E), and candidate (C) species present within Brown, Day and Grant counties are the whooping crane (E), piping plover (T), Topeka shiner (T), Dakota skipper (C), and Poweshiek skipperling (C). Given the native characteristics found along portions of the transmission line, it is possible that listed species may be found in these areas.

The South Dakota Department of Game, Fish and Parks (SDGFP) also publishes a list of threatened, endangered, and candidate species (SDCL Chapter 34A-8 and 34A-8A). The South Dakota Natural Heritage Program maintains a database of observations of South Dakota special status species. Table 13 identifies the South Dakota special status species that have been observed within one mile of the South Dakota Facility.

Table 13. Special Status Species Observed Within One Mile of the South Dakota Facility

Species Type	Common Name	Scientific Name	Federal Status	South Dakota Status	State Conservation Rank[1]
Aquatic-Fish	Blackside Darter	*Percina maculata*	Not Listed	Not Listed	S2
Aquatic-Fish	Carmine Shiner	*Notropis percobromus*	Not Listed	Not Listed	S2
Aquatic-Fish	Golden Redhorse	*Moxostoma erythrurum*	Not Listed	Not Listed	SH
Aquatic-Fish	Hornyhead Chub	*Nocomis biguttatus*	Not Listed	Not Listed	S3
Aquatic-Fish	Slenderhead Darter	*Percina phoxocephala*	Not Listed	Not Listed	SX
Aquatic-Fish	Topeka Shiner	*Notropis topeka*	Threatened	Not Listed	S2

Species Type	Common Name	Scientific Name	Federal Status	South Dakota Status	State Conservation Rank[1]
Aquatic-Mussel	Creek Heelsplitter	*Lasmigona compressa*	Not Listed	Not Listed	S1
Aquatic-Mussel	Creeper	*Strophitus undulatus*	Not Listed	Not Listed	S3
Aquatic-Mussel	Lilliput	*Toxolasma parvus*	Not Listed	Not Listed	S3
Aquatic-Mussel	Pink Heelsplitter	*Potamilus alatus*	Not Listed	Not Listed	S3
Aquatic-Mussel	Plain Pocketbook	*Lampsilis cardium*	Not Listed	Not Listed	S1
Aquatic-Mussel	Threeridge	*Amblema plicata*	Not Listed	Not Listed	S2
Aquatic-Mussel	Wabash Pigtoe	*Fusconaia flava*	Not Listed	Not Listed	S1
Aquatic-Mussel	Yellow Sandshell	*Lampsilis teres*	Not Listed	Not Listed	S1
Aquatic-Plant	Spiny Naiad	*Najas marina*	Not Listed	Not Listed	SNR
Aquatic-Reptile	Spiny Softshell	*Apalone spinifera*	Not Listed	Not Listed	S2
Avian	Black-necked Stilt	*Himantopus mexicanus*	Not Listed	Not Listed	S1B
Avian	Osprey	*Pandion haliaetus*	Not Listed	Threatened	S1B
Insect	Dakota Skipper	*Hesperia dacotae*	Candidate	Not Listed	S2
Mammal	Eastern Gray Squirrel	*Sciurus carolinensis*	Not Listed	Not Listed	SU
Mammal	Northern River Otter	*Lontra canadensis*	Not Listed	Threatened	S2

[1] G1/S1: Critically imperiled because of extreme rarity (5 or fewer occurrences or very few remaining individuals or acres) or because of some factor(s) making it especially vulnerable to extinction.

G2/S2: Imperiled because of rarity (6 to 20 occurrences or few remaining individuals or acres) or because of some factor(s) making it very vulnerable to extinction throughout its range.

G3/S3: Either very rare and local throughout its range, or found locally (even abundantly at some of its locations) in a restricted range, or vulnerable to extinction throughout its range because of other factors; in the range of 21 of 100 occurrences.

GU/SU: Possibly in peril, but status uncertain, more information needed.

GH/SH: Historically known, may be rediscovered.

GX/SX: Believed extinct, historical records only.

GNR/SNR: Not ranked at this time

**Bird species may have two state ranks, one for breeding (S#B) and one for nonbreeding seasons (S#N)*

Source: South Dakota Natural Heritage Database, South Dakota Department of Game, Fish and Parks, 2012

12.3 Potential Impacts

Temporary impacts to terrestrial communities will include increased human use and heavy equipment activity during construction. As part of these activities, vehicle traffic could also increase between pole locations, which will likely compact soils, trample vegetation, or create areas of exposed soil.

Impacts to native communities and listed species will be minimized by minimizing structure placement within native habitat to the extent practicable.

Approximately 14 percent of the South Dakota Facility ROW crosses wetlands or open water habitats that can serve as resting areas, foraging areas, and as source areas for local trading flights for waterfowl. Many avian species also use agricultural fields for foraging. Due to the matrix of wetland and agricultural habitat types along the South Dakota Facility ROW, there may be daily movements between areas used for roosting, nesting, and foraging. The presence of a transmission line in these areas could create a potential for avian species to collide with the South Dakota Facility during daily and seasonal movements.

The South Dakota Facility will introduce additional perching opportunities that could attract hunting raptors. Electrocution of large birds, such as raptors, is a concern generally associated with smaller distribution lines. Electrocution occurs when birds with large wingspans come in contact with either two conductors or a conductor and a grounding device. The Applicants' transmission line design standards provide adequate spacing to minimize the risk of raptor electrocution. Therefore, avian electrocution is not a significant concern for the South Dakota Facility.

12.3.1 *Raptor and Eagle Nests*

Impacts to raptor stick nests will be limited to habitat loss and inactive nest removal during construction. If a bald eagle or golden eagle nest is identified prior to construction, the Applicants will comply with the Bald and Golden Eagle Protection Act. Woodlands will be cleared from the South Dakota Facility ROW, which will be surveyed for nesting birds if tree removal is to occur during the breeding season. If tree removal occurs outside of the breeding season (April 1-July 31), impacts to nesting birds are not anticipated. Eight raptor stick nests (including bald eagle nests) were observed within one mile of the South Dakota Facility ROW and two of the eight are located within the South Dakota Facility ROW. To consider impacts to nesting bald eagles, the Applicants conducted a bald eagle nest survey in April/May 2013 and found two active bald eagle nests were located within one mile of the South Dakota Facility ROW, but the closest is approximately 0.8 miles east of the South Dakota Facility ROW in northern Brown County, South Dakota along the Maple River (Appendix F) (Applicants have requested confidential treatment). No bald eagle stick nests were located within the South Dakota Facility ROW during the survey; therefore, no impacts are anticipated to bald eagle nests.

12.3.2 *Sharp-Tailed Grouse Leks*

No sharp-tailed grouse leks were located within the South Dakota Facility area during the April 29 to May 2, 2013 field surveys. According to the SDGFP, there are no known lek sites within the South Dakota Facility ROW, two known lek sites within one mile of the South Dakota Facility ROW, and six known lek sites with two miles of the South Dakota Facility

ROW. The impact to sharp-tailed grouse may be displacement from a lek site during construction near the lek within the lekking period.

12.3.3 *Waterbird Colonies*

There are records of 11 waterbird colonies within 0.5 mile of the South Dakota Facility. The GIS records, as provided by the SDGFP, are one-mile radius plots somewhere within which are the documented colonies. Four of the 11 records are "active sites" and seven are listed as having "no evidence of breeding." Of the 11 documented colonies within one mile of the South Dakota Facility, seven of the one-mile radius polygons intersect the South Dakota Facility ROW, of which there are four "active sites" and three that show "no evidence of breeding." The impact to waterbird colonies may be displacement during construction near an active site within the breeding period.

12.3.4 *Whooping Crane*

There are no known records of whooping cranes within one mile of the South Dakota Facility ROW (Cooperative Whooping Crane Tracking Project, 2007).

Potential direct effects to whooping cranes include collisions with transmission lines. According to USFWS, collisions with power lines are the greatest known source of mortality for fledged whooping cranes. Specifically, Stehn and Wassenich (2007) stated that shield wires are the wires most often struck by birds in flight. About 15 miles of the South Dakota Facility is located within the 95th percentile band of the whooping crane migration corridor. Migrating cranes are most vulnerable to collisions with structures in the early morning or late evening when light levels are diminished, as they fly at very low altitudes between roost and foraging sites, or when flying at low altitude when starting or ending a migration flight, especially when thermal currents are minimal.

The primary indirect effect is the potential for complete avoidance of the stopover habitat located near the South Dakota Facility by the whooping cranes. Loss of migration habitat is a growing concern for the Aransas-Wood Buffalo population. Searching for suitable stopover habitat may cause increased exposure to hazards as birds are required to fly low for longer distances. However, due to the location of the Facility near existing roadways and other facilities and the abundance of suitable habitat nearby, the observed loss of suitable habitat is presumed to be low. The increased disturbance within the migration route could also place the cranes at greater risk of exposure to other hazards encountered during migration such as structures, hunters, disease, and predation.

12.3.5 *Piping Plover*

Possible impacts to piping plover include potential collision, potential for impacts to nesting habitat, and potential disruption during nesting. A direct impact to piping plover could occur in the event of a collision with the transmission line. While typical flight height information is not readily available, at times piping plovers walk or run rather than fly (Elliott-Smith et al. 2004). However, trading flights between nesting and foraging locations do occur.

There is no known nesting habitat or designated critical habitat near the South Dakota Facility area. Piping plovers typically utilize alkali wetlands and river courses with broad beaches for nesting. They may stop at flooded fields, along lake edges, or along wetland shores during migratory periods. The Applicants propose to conduct pre-construction surveys for active nesting piping plovers within the South Dakota Facility ROW. If active nesting areas are identified during the surveys, the Applicants propose to maintain a 0.5-mile buffer from active piping plover nesting areas. Therefore, no indirect effects due to construction are anticipated. Prudent construction activities will help to minimize direct and indirect impacts to the piping plover and its associated aquatic beach habitat.

12.3.6 *Topeka Shiner*

The Topeka shiner is a small minnow inhabiting slow moving, small- to mid-sized prairie streams with sand, gravel, or rubble bottoms that are consistent with some of the stream types crossed in Brown County. They prefer pool and oxbow areas that are outside main channel courses. Pools occupied by this species are in contact with groundwater and usually contain vegetation and areas of exposed gravel.

The Topeka shiner has occurred in a branch of the Maple River. The South Dakota Facility will not include the permanent placement of structures in any streams or tributaries so no permanent impacts to the Topeka shiner or aquatic species habitat are anticipated. Direct impacts to the Topeka shiner will be avoided by spanning appropriate aquatic habitats. Indirect impacts will be minimized by utilizing erosion and sedimentation control measures that reduce or prevent sediment from reaching adjacent waterways.

12.3.7 *Prairie Butterflies – Dakota Skipper and Poweshiek Skipperling*

The Dakota skipper and Poweshiek skipperling prefer native dry mesic to dry prairie where mid-height grasses such as little bluestem, prairie dropseed, and side oats grama are a major component of the vegetation. Potential habitat for both of these species is limited to prairie remnants or wetland areas surrounded by prairie remnants. The majority of known sites occur along the Coteau des Prairies at the eastern end of the South Dakota Facility area. Habitats used by both of these species are limited to remnant prairie located on steep slopes within the South Dakota Facility ROW.

The direct effect to the Dakota skipper is possible loss of habitat. Generally, South Dakota Facility impacts will be limited to localized permanent impacts due to structure installation or temporary impacts due to construction activities. Much of the South Dakota Facility ROW is located in disturbed lands. The Applicants will conduct pre-construction surveys for the prairie butterflies in high probability areas and reasonable efforts will be made to avoid impacting these areas.

12.4 Mitigation

Tree removal, ground clearing, or mowing within the South Dakota Facility ROW in late fall or early spring (before the bird breeding season) to discourage tree and ground nesting within temporary or permanent disturbance areas is anticipated. If the South Dakota Facility ROW is not cleared between late fall and early spring (outside of the typical bird nesting period), a survey of the South Dakota Facility ROW for active nests of protected species will be conducted and if an active nest is found a construction buffer around the nest will be established. Restricting construction activities in the uncleared areas during this timeframe will allow nesting birds to breed without direct disturbance. In areas where construction activity disturbs vegetative cover, the Applicants will reseed these areas using a native seed mix to restore habitat to a similar condition as it was before construction and as per landowner agreements.

In continuing discussion with USFWS, the Applicants will develop a line marking plan to reduce the potential for bird strikes with the transmission line. In addition, the transmission line will be designed following Avian Power Line Interaction Committee's (APLIC) *Suggested Practices for Avian Protection On Power Lines: State of the Art in 2006*.

The Applicants propose to conduct pre-construction surveys for active nesting piping plovers within the South Dakota Facility ROW. If active nesting areas are identified during the surveys, the Applicants propose to maintain a 0.5-mile buffer from active piping plover nesting areas.

Terrestrial habitats will be managed by avoidance of alterations to stream channels or drainage patterns, minimizing placement of fill in wetlands and restoration of areas temporary impacted, installation and maintenance of appropriate erosion control measures, and replanting disturbed areas, if necessary, with a diverse mix of native cool and warm season grasses.

Wetland mitigation will occur as required by applicable permits. Temporary impacts will be minimized by utilizing erosion and sedimentation control BMPs that minimize or prevent sediment from reaching adjacent waterways and protect topsoil.

Prior to construction, the Applicants will conduct lek surveys for new and verified lek sites. If during surveys, a lek site is found that is active and within one mile of the South Dakota Facility, construction activity timing will be restricted so that construction does not occur between sunrise and 3 hours after sunrise during the active lekking season (March 1st through June 30th), to avoid disturbance to the birds attending the lek.

The Applicants will attempt to span suitable Dakota skipper and Poweshiek skipperling habitat and limit disturbance in these areas to the extent practicable.

13.0 Effect on Aquatic Ecosystems (ARSD 20:10:22:17)

13.1 Existing Environment

Aquatic resources are present as lakes, rivers, wetlands, creeks, and intermittent streams. These aquatic resources have been altered to various levels, ranging from wetlands that are annually cultivated to channelized watercourses to naturally occurring pothole wetlands that have little physical alteration. Wetland resources are discussed in Section 11.0.

13.1.1 *Fisheries*

Many of the lakes and rivers present within the South Dakota Facility area likely support large fish populations used by wildlife and sportsmen. These fisheries can be of high value and produce desirable game species, such as northern pike, walleye, perch, and other game fish.

In South Dakota, SDGFP maintains public access for fishing and other water recreation. There are no public accesses for fishing within the South Dakota Facility ROW.

13.1.2 *Aquatic Invertebrates*

A comprehensive inventory of aquatic invertebrates was not conducted since the South Dakota Facility will span most aquatic environments and utilize sediment and erosion control BMPs to minimize impacts to aquatic invertebrates. However, it is reasonable to assume that aquatic invertebrate populations occur in many or most of the surface water resources crossed by the South Dakota Facility. Aquatic invertebrates are a primary food source for many other species, such as fish and waterfowl.

13.2 Potential Impacts

Potential impacts to aquatic resources are primarily related to installation of structures within the aquatic habitat area or sediment deposition related to construction activities. To the extent practicable, the Applicants will avoid major disturbance of individual wetlands and drainage systems during construction.

It is anticipated that the South Dakota Facility will span the rivers and streams it crosses, depending on geologic or engineering constraints determined in final design.

During construction there is the possibility of sediment reaching surface waters as the ground is disturbed by excavation, grading, and construction traffic. Maintaining water quality during construction of the transmission line through the use of BMPs will minimize potential impacts to rare and common aquatic organisms and the aquatic environment. Once the transmission line is completed, it will have no impact on surface water quality.

13.3 Mitigation

In the event construction activities could cause a disturbance to aquatic ecosystems, the Applicants will ensure BMPs are utilized to minimize impacts to surface waters. Temporary erosion and sediment control methods will be properly placed, monitored, and maintained adjacent to water resources. These erosion control methods will remain in place until work areas become re-vegetated or are stable. BMPs may include vegetative buffers, silt fencing, mulching, seeding, and straw wattles. Where appropriate, the Applicants will revegetate disturbed areas to as close to preconstruction conditions as possible in consultation with the landowner and as per appropriate permit requirements.

14.0 Land Use (ARSD 20:10:22:18)

The following section discusses the existing environment of, potential impacts on, and mitigation measures to land use features within or adjacent to the South Dakota Facility. It includes a discussion of land use, displacement, noise, communication facilities, and aesthetics. Land use and land cover in the South Dakota Facility area are shown in Exhibit 10.

14.1 Current Land Use

14.1.1 *Existing Environment*

The South Dakota Facility will be located primarily on private land that is zoned as agriculture under the Brown, Day and Grant county zoning ordinances. The prevailing land use within the South Dakota Facility ROW is cultivated agricultural land used for planted row crops, grassland herbaceous, and pastureland/hay. Planted row crops include corn and soybeans, along with other miscellaneous crops. The South Dakota Facility will also cross lands used for open pasture and grazing. Along the South Dakota Facility, the land crossed is characterized as a mixture of flat and rolling hillside terrain, depending on location, with relatively steep slopes on the edges of the Coteau des Prairies. Typically, small patches of trees are clustered around rural homes and natural water features. Table 14 illustrates the types of land cover crossed by the South Dakota Facility ROW, according to the National Land Cover Dataset.

Table 14. Land Cover Crossed by South Dakota Facility ROW

NLCD Land Cover Category	Acres in ROW	Percent in ROW
Barren Land (Rock/Sand/Clay)	0.2	0.01%
Cultivated Crops	1,592.7	57.0%
Deciduous Forest	7.1	0.3%
Developed, Low Intensity	4.3	0.2%
Developed, Medium Intensity	0.1	0%
Developed, Open Space	93.7	3.4%
Emergent Herbaceous Wetlands	88.1	3.2%
Grassland/Herbaceous	519.8	18.6%
Open Water	38.2	1.4%
Pasture/Hay	449.8	16.1%
Shrub/Scrub	1.7	0.1%
Total	**2,795.8**	**100%**

Source: USGS NLCD 2006 Data

As stated in Section 12.0, the Applicants also performed a South Dakota Facility-specific habitat analysis using infrared imagery and an on-the-ground assessment to map areas of native prairie and other land covers within the South Dakota Facility area. The main purpose of this analysis was to focus on native communities in the South Dakota Facility area, particularly native prairie habitat. The prairie habitats were ranked as high or low quality by identifying species assemblages, estimating anthropogenic disturbance, and noting other dominant land-use types in the South Dakota Facility area. See Section 12.0 for more information on the habitat model and a definition of the land cover types it identifies. The Habitat Analysis is included in Appendix E.

The results of the habitat model identified blocks of high and low quality native prairie in the South Dakota Facility area, along with other cover types, including non-native grasslands, croplands and others. In general, the grassland areas (high and low quality prairie and non-native grasslands) are currently being used for pasture. It also should be noted that cover types from the GIS model are not exact matches with the NLCD data; rather both of these land cover files should be considered as separate data giving information on the land cover in the South Dakota Facility area.

The South Dakota Facility area is lightly populated. Rural residential development is widely dispersed throughout the South Dakota Facility area and some residences (typically less than one home per linear mile) are found along each of the roads paralleled by the South Dakota Facility. No vacant or occupied home is within the South Dakota Facility ROW. There are a total of 21 occupied homes and six vacant homes within 500 feet of the South Dakota Facility (Table 15). The South Dakota Facility is not anticipated to affect the use or operation of any commercial or industrial establishment. During negotiation of land rights agreements, the Applicants will work with the owners of any businesses located within the South Dakota Facility ROW, such as the inactive gravel pit, to minimize impacts.

Table 15. Occupied and Vacant Homes within 500 Feet of the South Dakota Facility

Home (west to east)	County	Civil Township Name	Township	Range	Section	Comment
1	Brown	Frederick	127	64	1	Vacant
2	Brown	Frederick	127	64	1	Occupied
3	Brown	Frederick	127	64	1	Occupied
4	Brown	Brainard	126	63	6	Occupied
5	Brown	Oneota	126	64	12	Occupied
6	Brown	Garland	125	63	8	Occupied
7	Brown	Garland	125	63	9	Occupied
8	Brown	Cambria	124	62	5	Occupied
9	Brown	Cambria	124	62	34	Vacant
10	Brown	Cambria	124	62	34	Vacant
11	Brown	Bath	123	62	4	Occupied
12	Day	Andover	122	59	5	Vacant
13	Day	Troy	120	58	1	Occupied
14	Grant	Mazeppa	120	51	2	Occupied
15	Grant	Mazeppa	120	51	1	Occupied
16	Grant	Twin Brooks	120	50	4	Occupied
17	Grant	Twin Brooks	120	50	3	Occupied
18	Grant	Kilborn	121	49	35	Occupied
19	Grant	Melrose	121	48	31	Occupied
20	Grant	Melrose	121	48	31	Occupied

Home (west to east)	County	Civil Township Name	Township	Range	Section	Comment
21	Grant	Melrose	121	48	20	Occupied
22	Grant	Melrose	121	48	27	Occupied
23	Grant	Melrose	121	48	27	Occupied
24	Grant	Melrose	121	48	27	Occupied
25	Grant	Melrose	121	48	25	Occupied
26	Grant	Big Stone	121	47	22	Vacant
27	Grant	Big Stone	121	47	22	Vacant

All homes are within 500 ft of the South Dakota Facility centerline, and are either field or desktop verified. Home points are buffered by a 25 ft radius to provide conservative estimates

In recent years, the growth of the wind energy industry in eastern South Dakota has contributed to the industrial development of the landscape. There are existing wind projects near the South Dakota Facility area. There is a wind energy facility about two miles from the South Dakota Facility in Brown County and a second wind energy facility approximately 0.8 miles from the South Dakota Facility in Day County. It is possible more development will occur in the future.

Several USFWS wetland and grassland easement parcels are located along or are crossed by the South Dakota Facility. Approximately 13.1 percent of the South Dakota Facility parallels or crosses USFWS easement parcels (3.0 percent grassland, 9.5 percent wetland, and 1.0 percent grassland/wetland). In addition, State School & Public Lands, NRCS easements, and state-funded walking/hunting areas are crossed by the South Dakota Facility (Exhibit 2). There are no Nature Conservancy lands, Wildlife Protection Areas, National Wildlife Refuges, Game Protection Areas, or parks within the South Dakota Facility ROW.

14.1.2 *Potential Impacts*

The South Dakota Facility is compatible with and will have minimal impacts on land uses in the South Dakota Facility area. Land uses within the South Dakota Facility ROW are not expected to change as a result of construction and operation of the line. Agriculture is the principal land use surrounding the South Dakota Facility and the majority of land within the South Dakota Facility ROW will still be usable for agricultural production following construction. The land no longer suitable for agricultural production will be associated with the structure locations and fiber optic regeneration stations and their associated access roads.

Short-term construction impacts to agricultural lands resulting from construction are anticipated. The Applicants will purchase land rights for private property crossed by the South Dakota Facility pursuant to state and federal land acquisition requirements, which will be recorded as part of the property record. Agricultural impacts are discussed further in Section 19.2.

Structure placement will attempt to minimize impacts to farming operations. Several grassland and wetland easements are located in the South Dakota Facility area; however, the South Dakota Facility will not substantially impact the easements. The South Dakota Facility will not affect existing wind developments.

14.1.3 *Mitigation*

Because the South Dakota Facility is generally compatible with the existing land uses in the area, no additional mitigation is required. As described above, the South Dakota Facility has been chosen to minimize impacts to farming operations. The Applicants will coordinate with the USFWS and NRCS in order to obtain necessary permits to cross easement lands, and determine appropriate mitigation measures for these crossings.

14.2 Displacement

14.2.1 *Existing Environment*

Displacement results from ROW acquisitions that require the use of property occupied by a residence or business. A displacement was defined by the Applicants as an impact to an occupied home or business whose structure is located within the South Dakota Facility ROW.

Residences near the South Dakota Facility were identified through field observation, analysis of aerial photography, and comments received at Applicant-sponsored public open house meetings.

14.2.2 *Potential Impacts*

No occupied homes are located within the South Dakota Facility ROW; therefore, no homes are expected to be displaced by the South Dakota Facility. One inactive gravel pit was identified within the South Dakota Facility ROW. The gravel pit is located in Section 2 of Lura Township (T120N R52W). During negotiation of land rights agreements, the Applicants will work with the owners of any businesses located within the South Dakota Facility ROW, such as the inactive gravel pit, to minimize impacts. The South Dakota Facility will not displace any businesses.

14.2.3 *Mitigation*

No mitigation is proposed because no displacement of residences or businesses is occurring.

14.3 Noise

14.3.1 *Existing Environment*

Noise is defined as unwanted sound. Noise may include a variety of sounds of different intensities across the entire frequency spectrum. Noise is measured in units of decibels (dB) on a logarithmic scale. Because human hearing is not equally sensitive to all frequencies of sound, certain frequencies are given more "weight." The A-weighted decibel (dBA) scale corresponds to the frequency sensitivity range for human hearing. Noise levels capable of being heard by humans are measured in dBA. A noise level change of 3 dBA is barely perceptible to average human hearing. A 5 dBA change in noise levels, however, is clearly noticeable. A 10 dBA change in noise levels is perceived as a doubling or halving of noise loudness, while a 20 dBA change is considered a dramatic change in loudness.

Cumulative noise increases occur on a logarithmic scale. If a noise source is doubled, there is a 3 dBA increase in noise, which is barely discernible to the human ear. For cumulative increases resulting from sources of different magnitudes, the rule of thumb is that if there is a difference of greater than 10 dBA between noise sources, there will be no additive effect (i.e., only the louder source will be heard and the quieter source will not contribute to louder noise levels). Table 16 provides noise levels associated with common, everyday sources and places the magnitude of noise levels discussed here into context.

Table 16. Noise Levels Associated with Common Sources

Sound Pressure Level (dBA)	Noise Source
140	Jet Engine (at 25 meters)
130	Jet Aircraft (at 100 meters)
120	Concert
110	Pneumatic chipper (powered by compressed air or hydraulics)
100	Jointer/planer
90	Chainsaw
80	Heavy truck traffic
70	Busy business office
60	Conversational speech at 3 feet
50	Library
40	Bedroom
30	Secluded woods
20	Whisper

Source: A Guide to Noise Control in Minnesota, MPCA (revised, 1999)

The State of South Dakota does not regulate noise from transmission lines (corona noise) with measureable standards. Also, corona noise does not contain high levels of low frequency noise. Generally, background noise levels in rural areas vary between 40 and 50 dBA, while in suburban areas these levels increase to 50 to 60 dBA. In urban areas, noise levels vary between 60 and 70 dBA (FRA 2006). Most of the South Dakota Facility area has background levels consistent with rural areas. Windy conditions in the South Dakota Facility area tend to increase ambient noise levels compared to other rural areas. Additionally, higher levels exist near roads and other areas of human activity. Exhibit 2 shows noise sensitive land uses in the South Dakota Facility area. These were conservatively estimated to be homes within 1,000 feet of the South Dakota Facility.

14.3.2 *Potential Impacts*

Construction activities will generate short-term and intermittent noise. Construction noise will affect nearby residences on a short-term basis. During operation, transmission lines produce noise under certain conditions, called corona noise. The level of noise depends on conductor conditions, voltage level, and weather conditions. In foggy, damp, or rainy weather, transmission lines can create a crackling sound due to a small amount of electricity ionizing the moist air near the conductors. During heavy rain, the background noise level of the rain is usually greater than the noise from the transmission line. As a result, people do not normally hear noise from a transmission line during heavy rain. During light rain, dense fog, snow, and other times when there is moisture in the air, transmission lines will produce audible noise approximately equal to household background levels.

The South Dakota Facility was modeled to evaluate audible noise from high voltage transmission lines using the Bonneville Power Administration's Corona and Field Effects Program CORONAII version 3.0 (U.S. Department of Energy – Undated). The model was executed under normal and maximum operating conditions for an H-frame and mono-pole structure at the edge of the South Dakota Facility ROW, to ensure that noise was not under-predicted. Model results are expressed as a mean average sound pressure level (L50), which means that 50 percent of the data points are greater and 50 percent of the data points are less than the stated value for a given time period. Noise from the transmission line is expected to be below average rural background noise levels. Table 17 lists the calculated audible noise.

Table 17. Calculated Audible Noise Levels

Structure Type	Normal Operating Condition[1]	Maximum Operating Condition[2]
H-Frame Structure	17.0 dBA (L50)	42.0 dBA (L50)
Mono-Pole Structure (Delta)	18.2 dBA (L50)	43.2 dBA (L50)

[1] Normal Operating Condition value is based on fair weather noise level.

[2] Maximum Operating Condition is based on foul weather noise level.

Source: Bonneville Power Administration's Corona and Field Effects Program CORONAII version 3.0

14.3.3 *Mitigation*

During construction, noise levels will be minimized by ensuring that construction equipment is equipped with mufflers that are in good working order. Construction activities will generally be limited to the hours of 7 a.m. to 9 p.m. No additional mitigation measures are necessary since there will be minimal noise impacts from the operation of the South Dakota Facility.

14.4 Satellite, Cellular, Radio, TV, and GPS Reception

Corona, which consists of the breakdown or ionization of air within a few centimeters of conductors and hardware, can generate electromagnetic "noise" at the same frequencies that radio waves are transmitted. This noise can cause interference with the reception of these signals depending on the frequency and strength of the radio signal. The effects of corona "noise" can intensify during wet weather (Chen, 2012). Routine maintenance activities such as tightening loose hardware on the transmission line can help minimize corona noise.

If radio interference from transmission line corona does occur, satisfactory reception from amplitude modulated (AM) radio stations can be restored by appropriate modification of (or addition to) the receiving antenna system. Moreover, AM radio frequency interference typically occurs immediately under a transmission line and dissipates rapidly outside of the ROW.

Frequency modulated (FM) radio receivers usually do not pick up interference from transmission lines because:

- Corona-generated radio frequency noise currents decrease in magnitude with increasing frequency and are quite small in the FM broadcast band (88-108 Megahertz).
- The interference rejection properties inherent in FM radio systems make them virtually immune to amplitude-type disturbances.

Cellular phones are not expected to pick up interference from transmission lines because cellular phones operate on a wide range of radio frequencies which continue to increase as telecommunication carriers broaden the abilities of cellular phones. Corona-generated noise has too small of a frequency to be significant. Coupled with satellite communication capabilities built into almost all phones today, interference is not expected to occur with cellular phones.

Two-way mobile radios may experience interference because of signal-blocking effects in the immediate vicinity of transmission lines and metallic transmission structures. Movement of mobile units away from the transmission line ROW should restore communications.

Television interference is rare but may occur when a large transmission structure is aligned between the receiver and a weak distant signal, creating a shadow effect. Loose and/or damaged hardware may also cause television interference.

Global Positioning System (GPS) units collect location data from at least three or more satellites at any given time to triangulate location. The accuracy of the location data is affected by the number of satellites, how they are dispersed across the sky at any instant and atmospheric and satellite information factors. Since satellites are in constant motion above the earth, GPS units are constantly picking up and dropping satellite signals.

In 2002, the Institute of Electrical and Electronics Engineers (IEEE) published a study that investigated the effects of overhead power lines on GPS receivers (Silva & Olsen, 2002). Measurements evaluated whether GPS signals could be blocked by overhead conductors or whether use of a GPS signal could be affected by electromagnetic interference (EMI) (i.e., corona discharge or gap discharge noise). The study found that neither occurred.

The 2002 IEEE study found that conductors and associated EMI will not block or affect use of GPS satellite signal. However, it should be noted that a GPS receiver may experience less accuracy due to temporarily poor satellite alignment and/or outages to the base station or transmitter. On rare occasions, a transmission line structure may cause a temporary drop in GPS accuracy due to blockage of line-of-sight to one satellite, but this will only occur if the receiver, structure, and satellite are in a line, which is rare. Connection is usually restored within moments and the GPS units return to normal function.

14.4.1 *Existing Environment*

One Federal Communications Commission (FCC)-licensed communication tower is located within 1,000 feet of the South Dakota Facility ROW. This tower is listed in the data provided by the FCC as a “Land Mobile – Private” tower. These types of towers are the most common type of FCC-licensed tower and their uses and function vary widely from private wireless providers to local governments (FCC, 1996). Because of the wide array of uses, private land mobile towers operate on a large spectrum of frequencies they frequently share with other private entities registered to use the tower.

There are 29 additional FCC-licensed towers (24 Land Mobile – Private, two Directional Microwave, one Antenna Structure Registration (ASR), one Cellular, and one unknown use as it was identified in the field) within one mile of the South Dakota Facility ROW.

14.4.2 *Potential Impacts*

The South Dakota Facility hardware will be designed and maintained to minimize gap and corona discharges. There is a potential for interference impacts to occur to omnidirectional communication towers (communication towers that radiate radio waves uniformly in one direction across a plane). The height of the transmission line may interfere with beam paths if they are aligned at the same height.

14.4.3 *Mitigation*

As stated above, the South Dakota Facility hardware will be designed and maintained to minimize gap and corona discharges. If interference to any communication facilities occurs, the Applicants will work with the tower owner to mitigate the impacts. If the transmission line results in radio or television interference to any residences within the South Dakota Facility area, the Applicants will work with the residents to achieve satisfactory reception. Mitigation may include making the appropriate modifications to the receiving antenna system.

The nation-wide transition to digital TV broadcasts was completed June 12, 2009. Digital reception is in most cases more tolerant of "noise" and somewhat less resistant to multipath reflections (i.e., reflections from structures) than analog broadcasts. Although digital reception is more tolerant of radio frequency noise, if the noise levels or reflections are great enough, they will impact digital television reception. In the unlikely event that the South Dakota Facility causes interference within a television station's primary coverage area, the Applicants will work with the affected viewers to correct the problem at the Applicants' expense. This problem can usually be corrected with the addition of an outside antenna.

No impacts to GPS navigation systems are anticipated. No mitigation measures are necessary.

14.5 Aesthetics

Determining the relative scenic value or visual importance of an area is a complex process involving both the philosophical and/or psychological response to what may be perceived as beautiful by an individual. Generally, landscapes that incorporate a balanced mixture of diversity and harmony have the greatest potential for high scenic value and may be considered important to persons living in or traveling through a region. Viewer response is based on the sensitivity and exposure of the viewer to a particular viewshed. Sensitivity relates to the magnitude of the viewer's concern for the viewshed, while exposure is a function of the type, distance, perspective, and duration of the view. The discussion of visual quality and aesthetics contained in this section is based on a qualitative review of the existing landscape environment surrounding the South Dakota Facility area. Visual and aesthetic resources within the South Dakota Facility area were identified through review of county comprehensive land use plans, comments received from participating citizens at public open house meetings, and through a review of high-resolution aerial photography and field observation. Generally, sensitive visual and aesthetic resources within the area include historical structures, open space areas, designated scenic routes, and water resources.

14.5.1 *Existing Environment*

The visual character and quality along the South Dakota Facility can be characterized in many different ways that include cultivated lands, natural habitats, topography, existing man-made structures, and parks. Within the South Dakota Facility ROW, the dominant visual characteristic is agricultural land (both cultivated and grazed). The remaining land cover is a mixture of rural residential, wetland, and water features.

Man-made infrastructure including homes, cities, transmission lines, highways, county roads, railroads, barns, silos, communication towers, and other structures exist throughout the South Dakota Facility area.

Along the eastern portion of the South Dakota Facility lies the Coteau des Prairies, extending from eastern South Dakota to southwestern Minnesota. This feature consists of a relatively high plateau, rising from a nearly level till plain, including prairie flatlands with slopes along its borders. The slopes of the Coteau des Prairies that intersect the South Dakota Facility ROW are near the cities of Marvin and Twin Brooks and also near the cities of Andover and Groton. Where the Coteau des Prairies ascends and descends, visual characteristics of the area include a higher concentration of rivers and creeks while the top of the Coteau des Prairies includes a larger viewshed of flat prairie grasses. Within the South Dakota Facility area, the top of the Coteau des Prairies extends south of areas near the cities of Webster, Waubay, and Ortley.

In the area west of the Coteau des Prairies, the topography remains relatively flat, dominated by cultivated agricultural land and with scattered infrastructure and gentle slopes leading to the James River which runs from north to south in the South Dakota Facility area.

14.5.2 *Potential Impacts*

The South Dakota Facility and associated facilities will create a new visual element within the South Dakota Facility area, but the degree to which the transmission line will be visible will vary by location. The visual impact of the transmission line could affect landowners who live along or near the South Dakota Facility, or community residents who travel along the roads regularly. The natural landscape in the South Dakota Facility area is often characterized as rolling or flat terrain used for agricultural purposes, with the exception of the steeper slopes at the edges of the Coteau des Prairies. The exact viewshed of the South Dakota Facility will be determined by the engineering of the individual structures, elevation, and natural and man-made objects. Depending on a viewer's physical location, the terrain conditions, and natural landscape features such as tree cover or man-made features such as a barn, the transmission line structures could be visible for distances up to two miles. A viewer's degree of discernible detail decreases as the physical distance from an object increases.

The South Dakota Facility will be visible to landowners and community residents who live near the South Dakota Facility ROW and travel along the roads and highways adjacent to or crossing the transmission line. While the South Dakota Facility will be located outside of local communities, using two miles as an extreme for viewshed possibilities, it may be visible from several communities including Frederick, Westport, Columbia, Groton, Andover, Butler, Marvin, Twin Brooks, Milbank, and Big Stone City. There are nine properties on the National Historic Register within one mile of the South Dakota Facility (see Sections 20.7.1-7 for more detailed information). No state parks or scenic highways are within two miles of the South Dakota Facility.

14.5.3 *Mitigation*

The Applicants will continue to work with landowners and public agencies to identify concerns related to the transmission line and aesthetics. Many of these areas have already been impacted visually by the existing roadways, transmission lines, and railroads. In general, mitigation includes enhancing positive effects as well as minimizing or eliminating negative effects. Potential mitigation measures include the following:

- Where feasible, the location of structures, fiber optic regeneration stations, and other disturbed areas will be determined by considering input from landowners or land management agencies to minimize visual impacts.
- Structure types (designs) will be uniform to the extent practical. In general, the Applicants propose to use single pole steel structures ranging in height from approximately 125 to 155 feet. H-frame structures would potentially allow for lower structure height; however, during public meetings a strong preference for mono-pole structures was expressed by the public. This was primarily voiced by area farmers as a way to limit the footprint of a pole and concerns about navigating farm equipment around the pole.
- Care will be used to preserve the natural landscape; construction and operation will be conducted to prevent any unnecessary destruction, scarring, or defacing of the natural surroundings. During operation, clearing of trees and shrubs will be conducted only as necessary per North American Electric Reliability Corporation (NERC) standards and to allow safe operation and inspection of the South Dakota Facility.
- Most of the lands crossed by the South Dakota Facility are currently used for agriculture. Following construction, most of these lands will return to their current agricultural use and visual characteristics.

15.0 Local Land Use Controls (ARSD 20:10:22:19)

The South Dakota Facility will be constructed on agricultural land regulated by the Brown, Day, and Grant counties' zoning ordinances and land use control policies specified in county plans or specific ordinances. Comprehensive land use plans were available for Brown and Grant counties. A comprehensive land use plan is not available for Day County at this time. Construction of the Project will comply with the applicable local ordinances and may require those permits set forth in Section 24.0.

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16.0 Water Quality (ARSD 20:10:22:20)

16.1 Existing Environment

Pursuant to the Clean Water Act, every two years, the State releases a list of streams and lakes that are not meeting their designated uses because of excess pollutants (impaired waters). The impaired waters list, known as the 303(d) list, is based on violations of water quality standards. Table 18 lists the water bodies crossed by the South Dakota Facility that are listed as impaired by the United States Environmental Protection Agency (EPA).

Table 18. Crossings of EPA-Designated Impaired Waters

Waterbody Name	Cause of Impairment for Reach Within South Dakota Facility Area
Big Sioux River	Dissolved Oxygen and Escherichia Coli (E. Coli)
James River	Dissolved Oxygen
South Fork Whetstone River	E. Coli

Source: South Dakota Department of Environment & Natural Resources, 2010

16.2 Potential Impacts

During construction there is a limited possibility of sediment reaching surface waters as the ground is disturbed by excavation, grading, and construction traffic. This could potentially affect water quality if the erosion is not controlled.

16.3 Mitigation

It is anticipated that all rivers and streams will be spanned by the South Dakota Facility, and no structures will be located within these features. Therefore, direct impacts to these features are not expected. The Applicants anticipate receiving a National Pollutant Discharge Elimination System (NPDES) permit, as applicable. The Applicants will also prepare and follow the commitments set forth in the associated Storm Water Pollution Prevention Plan (SWPPP). As necessary, the SWPPP will identify BMPs specific for impaired waters.

Once the South Dakota Facility is constructed, there will be no significant impact on surface water quality because wetland and waterway impacts will be minimized and mitigated, disturbed soil will be restored to previous conditions and the amount of land area converted to an impervious surface will be small.

The Applicants will implement BMPs during construction of the South Dakota Facility to protect topsoil and adjacent water resources and minimize soil erosion. Construction practices will be completed in accordance with the NPDES permit requirements. BMPs may include:

- Containment of stockpiled material away from stream banks and shorelines as required by the NPDES permit
- Stockpiling and respreading topsoil at laydown areas and/or permitted areas
- Reseeding and revegetating disturbed areas as required by the NPDES permit
- Implementing erosion and sediment controls as required by the NPDES permit
- Waste waters generated by construction will be minimized by following BMPs

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17.0 Air Quality (ARSD 20:10:22:21)

17.1 Existing Environment

South Dakota has adopted the federal government's ambient air quality standards regarding permissible concentrations of air pollutants (ARSD 74:36:02). The areas crossed by the South Dakota Facility are currently in attainment for both national and South Dakota Ambient Air Quality Standards, as is the entire state. The nearest Ambient Air Quality Monitoring Site is located at the Brookings City Hall in Brookings County, South Dakota, which is southeast of the South Dakota Facility.

17.2 Potential Impacts

Temporary air quality impacts caused by emissions from construction vehicles and concrete batch plants, and by fugitive dust from South Dakota Facility ROW clearing and construction may occur. Exhaust emissions from diesel equipment will vary during construction, but only minor short-term impacts are anticipated. The concentration of pollutants during construction will be greatest near the South Dakota Facility ROW, but will decrease rapidly with distance from the South Dakota Facility ROW. Concentrations of all air pollutants during construction are expected to remain well below the National Ambient Air Quality Standards (NAAQS).

No impacts to air quality due to the operation of the transmission line are anticipated. Corona consists of the breakdown or ionization of air within a few centimeters of transmission line conductors and hardware. Usually water or some imperfection such as a sharp edge, a protrusion on hardware, or a scratch on the conductor is necessary to cause corona. Corona can produce small concentrations of ozone and oxides of nitrogen in the air surrounding the conductor. Ozone also forms in the lower atmosphere from lightning discharges and from reactions between solar ultraviolet radiation and air pollutants, such as hydrocarbons from auto emissions. The natural production rate of ozone is directly proportional to temperature and sunlight and inversely proportional to humidity. Thus, humidity or moisture, the same factor that increases corona discharges from transmission lines, inhibits the production of ozone. Ozone is a very reactive form of oxygen molecules and combines readily with other elements and compounds in the atmosphere. Because of its reactivity, ozone is relatively short-lived.

The ambient air quality standard for ozone is 0.075 parts per million (ppm), based on a 3-year average of the annual fourth-highest daily maximum 8-hour averaging period. Numerous environmental assessments cite calculations of ozone concentrations from 345-kV transmission lines using the Corona and Field Effects Program Version 3, supplied by the Bonneville Power Administration. These environmental assessments cite maximum one-hour concentrations during foul weather (worst case) of 0.0007 ppm, which is well below federal and South Dakota standards for ozone.

17.3 Mitigation

BMPs may be used to control fugitive dust during construction; this could include use of water or other dust minimization methods, per NPDES permit. Dust suppression will be required of the construction contractors who will access and maintain the South Dakota Facility ROW during construction, as necessary.

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18.0 Time Schedule (ARSD 20:10:22:22)

The Applicants propose that the South Dakota Facility be in-service in 2019. A preliminary permitting and construction schedule for the South Dakota Facility is provided below.

This schedule is based on information known as of the date of this filing and upon planning assumptions. This schedule may be subject to adjustment and revision as further information is developed. The Applicants plan to give milestone updates through the Project's newsletter and website.

Submit PUC Facility Permit Application .... August 2013
Land Rights Acquisition Initiated.. 2013
Applicants' Anticipated Date of Commission Decision on Facility Permit..... August 2014
Material Procurement Commitments 2015
Final Transmission Line and Substation Connection Design... 2016
Construction Start... 2016
In-Service Operations 2019
Final Project Close-out 2020

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19.0 Community Impact (ARSD 20:10:22:23)

This section describes the primary community characteristics within the South Dakota Facility area, and identifies the impacts of the South Dakota Facility with respect to socioeconomics, community resources, agriculture, transportation, and cultural resources. Socioeconomic factors evaluated include population, race and ethnicity, poverty, and per capita income. A forecast of the impact on community and government facilities and services is provided, in addition to detailed estimates of projected tax impacts. A forecast of the impact on income and integration of communities is provided.

19.1 Socioeconomic and Community Resources

19.1.1 *Existing Environment*

The South Dakota Facility is located in Brown, Day, and Grant counties on land used primarily for agricultural purposes. The largest residential areas near the South Dakota Facility area are Ellendale, North Dakota and Groton, Bristol, and Big Stone City, South Dakota. Table 19 provides a comparison of demographic characteristics of the South Dakota Facility area by Census Tract.

Table 19. Demographic Characteristics of the South Dakota Facility Area

Location	Population	Race Percentage (White)	Percentage of Population Below Poverty Level	Per Capita Income
Census Tract 952700 – Day County	1,379	95.4	7.7	$20,701
Census Tract 952600 – Day County	764	98.4	20.3	$19,325
Census Tract 940600 – Day and Grant Counties	290	93.3	19.3	$18,868
Census Tract 951100 – Brown County	928	81.6	7.1	$23,156
Census Tract 951200 – Brown County	1,978	96.8	5.9	$26,287
Census Tract 951900 – Brown County	850	98.7	7.2	$24,576
Census Tract 953200 – Grant County	608	97.9	10.4	$23,317
Census Tract 953100 – Grant County	701	96.0	12.8	$22,577
Brown County	37, 331	93.6	9.7	$24,671
Day County	5,613	88.3	16.7	$20,870
Grant County	7,259	89.1	12.6	$24,344
South Dakota	833,354	86.6	13.8	$24,952

Source: U.S. Census Bureau, Census Tract 2010.

The Census Bureau provides periodic socioeconomic estimates for selected geographies to help provide information on the changing demographics of the population between decennial censuses. Through the American Community Survey, the Census provided 3-year population estimates for Brown County and the State of South Dakota. American Community Survey Data for Day and Grant counties were unavailable. These statistics are provided in Table 20.

Table 20. Population Demographic Forecasts

Location	Population	Race Percentage (White)	Percentage of Population Below Poverty Level	Per Capita Income
Brown County	36,547	93.5	8.0	$25,488
South Dakota	815,914	86.1	14.0	$24,706

Source: U.S. Census Bureau, American Community Survey, 3-Year Population Estimates, 2009-2011

19.1.2 *Socioeconomic and Community Resource Impacts and Mitigation*

There will be short- and long-term benefits to the South Dakota Facility area. These benefits include an increase to the counties' tax base resulting from the incremental increase in revenues from utility property taxes, which are based on the value of the Project. Also, the capability of the transmission line to transmit energy generated from renewable and other energy resources could spur energy development in the area, resulting in additional economic gains to the area. For further information on benefits of the South Dakota Facility, refer to Section 4.0.

Construction and operation of the South Dakota Facility is not anticipated to affect the local distribution of jobs or occupations in the community. The South Dakota Facility is not anticipated to have significant short- or long-term effects on commercial and industrial sectors, housing, land values, labor markets, health facilities, sewer or water treatment facilities, solid waste management facilities, fire or police facilities, schools, recreational facilities, and other government facilities or services. Therefore, no mitigation is proposed. The Applicants do not expect a permanent impact on the population, income, occupation distribution, or integration or cohesion of communities.

The South Dakota Facility will be offset from road ROW and section lines; the transmission structures and South Dakota Facility ROW are not expected to be located within the road ROW. The final engineering design will take into account planned or programmed future improvements to area roadways to ensure sufficient road ROW is maintained for future roadway widening.

No adverse impacts are anticipated to other major industrial facilities as a result of the construction or operation of the South Dakota Facility.

19.2 Agriculture

19.2.1 *Existing Environment*

According to the U.S. Census Bureau, Brown County has a total land area of 1,731 square miles, with 1,713 square miles of land and 18 square miles of water (rounded to the nearest whole number) (United States Census Bureau, 2013). According to the Census of Agriculture for 2007 (the most recent year that data is available), approximately 1,695 square miles (97 percent) of the county were used for agricultural purposes. The number of full-time farms decreased by 10.3 percent from 2002 to 2007, and the number of land acres used for farming decreased by 6.1 percent. The average farm size also grew by 4.7 percent. Sales of farm goods (including grain, crops, and livestock) in 2007 totaled $248,765,000, an increase of 47 percent from 2002. Crop sales were primarily soybeans, corn, and wheat, while cattle and hogs comprised the majority of livestock sales (United States Census Bureau, 2007).

Day County has a total land area of 1,028 square miles, with 965 square miles of land and 63 square miles of water (rounded to the nearest whole number) (United States Census Bureau, 2013). According to the Census of Agriculture, approximately 886 square miles (81 percent) of the county were used for agricultural purposes. The number of full-time farms decreased by 4.2 percent from 2002 to 2007, and the number of land acres used for farming increased by 6.8 percent. The average farm size also grew by 11.4 percent. Sales of farm goods increased 72 percent from 2002 to 2007, and totaled $97,814,000 in 2007. Livestock sales consisted primarily of cattle and hogs, while soybeans, corn, and wheat comprised the majority of crop sales (United States Census Bureau, 2007).

Grant County has a total land area of 681 square miles, with 676 square miles of land and 5 square miles of water (rounded to the nearest whole number) (United States Census Bureau, 2013). According to the Census of Agriculture for 2007, approximately 568 square miles (82 percent) of the county were used for agricultural purposes. The number of full-time farms increased by 1.2 percent from 2002 to 2007, and the number of land acres used for farming increased by 3.8 percent. The average farm size also grew by 2.5 percent. Sales of farm goods totaled $133,526,000 in 2007, an increase of 62 percent from 2002. Crop sales were primarily soybeans, corn, and wheat, while cattle and hogs comprised the majority of livestock sales (United States Census Bureau, 2007).

19.2.2 *Agriculture Impacts and Mitigation*

The South Dakota Facility will create temporary and permanent impacts to farmland along the South Dakota Facility; however, no impacts are anticipated to livestock operations. Permanent impacts to agricultural lands are primarily the result of structure installation along the South Dakota Facility. Construction of the South Dakota Facility is anticipated to result in a permanent loss of approximately 4.6 acres of agricultural land (3.3 acres from structures in cropland, 0.6 acres from structures in non-cropland, and 0.7 acres from fiber optic regeneration station and associated access road). The permanent impacts associated with each structure in non-cropland were calculated by assuming a five-foot radius (approximately 78.5 square feet) of permanent impact. The permanent impacts to crop production associated with each structure in cropland were calculated by assuming a ten-foot radius (approximately 314 square feet), which includes an additional five-foot radius (total of ten-foot radius) around the structure foundation since landowners may not wish to cultivate the land any closer than five feet from the structure base. At the time of this Application the exact locations of the fiber optic stations and their associated access roads are not known. Construction of the South Dakota Facility will result in an estimated 986 acres of temporary impacts to farmland due to the preparation of structure foundations, laydown areas, structure assembly areas, wire stringing areas, and travel paths. This impact is estimated based on the NLCD land cover breakdown of the ROW, the 1,000-foot average span for the South Dakota Facility, the temporary use of a 30-foot-wide travel path within the South Dakota Facility ROW, installation of pole structures and stringing of conductors.

Areas disturbed during construction will be repaired and restored to preconstruction contours to the extent practicable so that all surfaces drain naturally, blend with the natural terrain, and are left in a condition that will facilitate natural re-vegetation, provide for proper drainage, and prevent erosion. Construction laydown areas and temporary transmission line travel paths will be restored per the landowner agreement. Drain tile lines may be present along the South Dakota Facility. The Applicants will work with the landowners to identify and mark drain tile lines to avoid damage during construction. Where locations are known, temporary travel paths will avoid drain tiles where they can and when they are unavoidable, matting may be required. If drain tile lines are inadvertently damaged by construction of the South Dakota Facility, the Applicants will repair the tile lines. Landowners will be compensated for any crop damage that occurs during construction.

There are several locations where the South Dakota Facility crosses the edge of fields with center pivot irrigation. Coordination with the landowners will be conducted to identify potential impacts to these systems; however, it is anticipated that given the 1,000-foot-wide span of the structures, they can be placed so that minimal effects to the pivot will occur.

19.3 Transportation

19.3.1 *Existing Environment*

Much of the South Dakota Facility is within 500 feet of existing surface transportation routes, including county roads and township streets. The transportation network that will be used during construction and for maintenance during operation is comprised largely of rural or section line roadways. The South Dakota Facility crosses active railroads in four locations (T124N R62W, T123N R60W, T120N R50W, T121N R48W) and inactive railroad lines in two locations (T124N R63W, T120N R57W). In addition, the closest registered airport facility is about 2.5 miles from the South Dakota Facility. There is one private landing strip located about 0.9 miles south of the South Dakota Facility. Based on a preliminary glide slope review no impacts to the landing strip are anticipated. No impacts to registered commercial facilities are expected.

19.3.2 *Transportation Impacts and Mitigation*

The South Dakota Facility will not result in any permanent impacts to the area's transportation resources. Therefore, no mitigation is proposed. There may be some temporary impacts to local roads during construction phases of the South Dakota Facility. The Applicants will work with state and local highway departments regarding applicable permitting requirements. The Applicants will also coordinate with the railroads to span the active and inactive lines and to ensure construction and operation of the South Dakota

Facility will not affect the use of the railroad lines. There will be no anticipated impacts to registered commercial aviation facilities. The South Dakota Facility may alter the approach to landing strips by causing aircraft to fly over the South Dakota Facility during take-off and landing. The Applicants will work with owners of the landing strip to address concerns.

19.4 Cultural Resources

This section presents the results of a records search and literature review of previously recorded cultural resources. In September 2012, the Applicants requested information for the initial records search from the South Dakota Archaeological Research Center (SDARC). This data request included an approximate 13- to 22-mile-wide study corridor since the South Dakota Facility had not yet been determined.

On September 19, 2012, the SDARC provided cultural resources data including GIS data that document the location of all previous cultural surveys, previously identified archaeological sites, miscellaneous site files, and recorded architectural properties within the provided study corridor. As Project plans progressed, the study corridor was evaluated through a desktop review, taking into account the data received from SDARC, and the South Dakota Facility was selected.

Additional background research included online research of the National Park Service's National Register of Historic Places (NRHP), online research of historical General Land Office (GLO) plat maps, and a review of the South Dakota State Historic Preservation Office (SDSHPO) planning document, "*Guidelines for Cultural Resource Surveys and Survey Reports for Review and Compliance*" (SDSHPO 2005).

A Level I Records Search was completed for the South Dakota Facility area and was submitted to the SDSHPO on July 24, 2013 for review and comment. Information provided in the Level I Records Search is considered confidential and was filed with requested confidential treatment pursuant ARSD 20:10:01:41 with this Application (Appendix G). The findings presented below represent a summary of that information. Specific locational information has been removed.

19.4.1 *Existing Environment*

The Records Search of one mile on either side of the South Dakota Facility documented 24 previously recorded archaeological sites, 12 miscellaneous files, 182 previously recorded standing structures, 26 previously recorded historic bridges, and three previously recorded cemeteries. Miscellaneous files are not considered sites. They are usually based on archival information and have not been field-verified. Consequently, they have not been assigned official state site numbers or other individualized numbers for identification purposes.

Nine NRHP-listed properties have been identified within the one-mile buffer of the South Dakota Facility.

19.4.1.1 Previously Identified Archaeological Sites

Three of the 24 previously recorded archaeological sites intersect the South Dakota Facility. Sites include two Native American artifact scatters (39BN0062 and 39BN0063) and one railroad (39GT2007). The 24 archaeological sites include 16 precontact sites, five historic sites, one multicomponent site, and two sites with unknown cultural affiliation (Appendix G, Table 1).

Precontact sites include 14 artifact scatters, one occupation, and one isolated find. Of the 16 previously recorded precontact sites, 15 have not been evaluated and one site, the precontact isolated find (39BN0093), is not eligible for the NRHP.

The five historic sites include one Euro-American artifact scatter (39GT0031), one farmstead (39GT0034), and three railroads (39DA2007, 39GT2007, and 39GT2042). The artifact scatter is not eligible, the farmstead is unevaluated, and the three railroads are eligible for the NRHP.

The multicomponent site includes one precontact occupation and Euro-American artifact scatter (39GT0024). The site has not been evaluated for listing on the NRHP.

The two previously recorded sites with unknown cultural affiliation include two cairns (39DA0074 and 39DA0081). Site 39DA0074 is recorded as an unknown cairn with a well-sodded base, topped with barbed wire. Site 39DA0081 is recorded as a stone pile with a well-sodded base and several large stones placed on top. These two sites have not been evaluated for the NRHP.

19.4.1.2 Miscellaneous Files

Two of the 12 previously recorded miscellaneous files transect the South Dakota Facility; both files are railroad grades. The remaining 10 miscellaneous files are situated outside the South Dakota Facility ROW. These include seven mounds/mound groups, two cemeteries, and one trail (Appendix G, Table 2).

19.4.1.3 Previously Identified Standing Structures

Within the one-mile buffer of the South Dakota Facility, 182 previously recorded standing structures have been identified (Appendix G, Table 3). Structures include homes, agricultural buildings, farmsteads, churches, schools, and commercial buildings. One standing structure was identified within the South Dakota Facility ROW (GT00000392). The standing structure consists of a farm.

Of the 182 previously recorded standing structures, 11 are eligible, 40 have not been evaluated, and 131 are not eligible for the NRHP. Eligible structures include the Welsh Presbyterian Church (BN00000264), the Plana School (BN00000268), the Oneota Township Hall (BN00000594), the Andover Waldorf Hotel (DA00000020), the Eddie Hinze House (DA00000195), and an unnamed school (DA00000513). Remaining NRHP-eligible structures are included in the Charles Russman Farm and have been recorded as a district. Structures include the house (GT00000456), the barn (GT00001175), the silo (GT00001177), the granary (GT00001178), and the shed (GT00001179).

19.4.1.4 Previously Identified Historic Bridges

Twenty-six previously recorded historic bridges have been identified within the one-mile buffer of the South Dakota Facility (Appendix G, Table 4). Four of the bridges intersect the South Dakota Facility ROW. The bridges include BN00001302, DA00000954, DA00000956, and GT00001090. Of the 26 previously recorded historic bridges, six are eligible, 19 are not eligible, and one has not been evaluated for the NRHP. Eligible bridges include BN00000010, BN00000011, BN00000166, BN00000170, DA00000006, and GT00000507.

19.4.1.5 Previously Identified Historic Cemeteries

Three previously recorded cemeteries have been identified within the one-mile buffer of the South Dakota Facility (Appendix G, Table 5). None of the cemeteries intersect the South Dakota Facility ROW. The three historic cemeteries are not eligible for the NRHP.

19.4.1.6 Previously Identified NRHP-Listed Properties

Nine NRHP-listed properties have been identified within the one-mile buffer of the South Dakota Facility (Appendix G, Table 6). They include the Welsh Presbyterian Church (BN00000264), the Plana School (BN00000268), the Oneota Township Hall (BN00000594), the Andover Waldorf Hotel (DA00000020) and the Charles Russman Farm district. Structures within the district include the house (GT00000456), the barn (GT00001175), the silo (GT00001177), the granary (GT00001178), and the shed (GT00001179). None of the NRHP-listed properties intersect the South Dakota Facility ROW.

19.4.1.7 General Land Office Review

A review of GLO maps reveal that from 1865-1883, twenty-three townships contained evidence of Euro-American settlement. Euro-American settlement was first identified in Brown County in 1879, in Day County in 1875, and in Grant County in 1865 (United States Department of the Interior 1865-83). Most evidence of settlement includes named and unnamed residences or structures scattered across the landscape, along with roads and railroads.

The Chicago, Milwaukee, St. Paul and Pacific Railroad (the "Milwaukee Road"), which is within two miles of the South Dakota Facility, was first identified in 1865. In many cases, the current track remains in the same position today as it did then. There was also evidence of several schools in Grant County by 1883, and an Old Military Camp with Entrenchments [sic] in Day County by 1878. Also present by 1865 were the Sisseton and Wahpeton Sioux Reservation boundaries in Grant and Day counties.

The densest concentration of Euro-American settlement was identified west of Big Stone City in Township 121N, Ranges 46W, 47W, and 48W. Many named residences, roads, railroads, and agricultural fields were present in the area by 1883. A complete description of identified GLO features can be found in Appendix G, Table 7.

19.4.2 *Potential Impacts*

Construction activities for the South Dakota Facility may occur in the vicinity of previously identified archaeological and historic resources, some of which have been evaluated for listing on the NRHP and determined ineligible, and others that have not been evaluated for listing. Potential impacts include direct physical effects, indirect effects through long-term continuing operation and maintenance activities, and visual effects attributable to the intrusion of the South Dakota Facility on the setting of properties whose integrity of setting contributes to their significance.

Potential effects to archaeological sites and miscellaneous files (suspected sites that have not been formally recorded) may occur within the South Dakota Facility ROW as a result of direct construction impacts. Therefore, the survey strategy for archaeological sites will be limited to the South Dakota Facility ROW and any other areas where direct construction impacts are likely to occur. These additional areas may include travel paths, laydown areas, and other areas necessary for construction outside of the South Dakota Facility ROW.

Potential effects to architectural properties may include visual impacts. Therefore, a 0.5-mile-wide visual impacts area of potential effects (APE) will be established to evaluate architectural properties. The purpose of the 0.5-mile-wide visual impacts APE is to account for the diminishment of integrity of setting for standing architectural properties for which setting contributes to their significance.

19.4.2.1 Level III Survey

As a part of Project planning, the Applicants are in discussions with SDSHPO and the Tribal Historic Preservation Offices (THPOs) to develop a Level III survey approach to locate and direct the identification of important cultural resources that may be vulnerable to the effects of South Dakota Facility construction and operation or to visual effects. This survey strategy will focus on locating properties that may qualify for listing on the NRHP.

Potential conditions that merit a Level III survey include properties listed on the NRHP, previously recorded properties determined eligible or unevaluated, undisturbed areas including rangelands and grasslands, proximity to certain environmental and/or physical features, and portions of the South Dakota Facility identified by the tribes as sensitive areas.

Potential conditions that may not merit survey include areas of recent industrial development and disturbance, cultivated lands, inundated areas, and areas that exhibit a slope of greater than 20 percent.

The survey approach is anticipated to include three components: a component focused on locating traditional cultural properties important for tribal associations with historic events or cultural beliefs and their contributions to the continuation of traditional communities' sense of identity; a component for locating and evaluating archaeological properties that may retain important information; and a component for locating important historic architectural or engineering properties. The review and consideration of effects to important cultural resources in those portions of the South Dakota Facility that are subject to a federal permit or approval will be reviewed in accordance with Section 106 of the National Historic Preservation Act (NHPA) and the National Environmental Policy Act (NEPA), as determined by the responsible federal agencies.

The Applicants will also design a discovery plan to be implemented during construction to account for the possibility of encountering previously unknown archaeological resources or human remains. This plan will specify procedures for handling such discoveries in an efficient and expeditious manner. The discovery plan will include the following topics: monitoring methods, construction contractor training, identification of resources in the field, contact information, procedures for avoidance, and associated tasks in the event of work stoppage.

If human remains are discovered during construction, work will cease on the site and appropriate authorities will be contacted in accordance with state law (SDCL Chapter 34-27).

19.4.4 *Mitigation*

The Level I Records Search identified three previously recorded archaeological sites, one previously recorded architectural property, four bridges, and two miscellaneous site files which intersect the South Dakota Facility ROW. One of the three archaeological sites (39GT2007), a railroad, is considered eligible for the NRHP. The two remaining archaeological sites (39BN0062 and 39BN0063) and the two miscellaneous site files have not been evaluated for the NRHP. The one architectural property (GT00001090) and the four historic bridges (BN00001302, DA00000954, DA0000956, and GT00001090) are not eligible for the NRHP.

Following the completion of a Level III survey, the Applicants will seek to avoid impacts to NRHP-eligible cultural resources and properties of traditional cultural importance. Avoidance measures may include placing poles so that sites are avoided by spanning, the use of fencing for site protection during construction, and burial of the resource under a protective buffer.

In addition, potential visual impacts to architectural properties or traditional cultural properties will be considered. Mitigation measures may include vegetative screening, additional documentation and research, or other mitigation measures deemed appropriate through SDSHPO and THPO consultation. The Applicants will consult with the SDSHPO as the mitigation measures are further developed.

If avoidance of a NRHP-listed or eligible archaeological site or architectural property is not feasible, the Applicants will consult further with the SDSHPO to determine an appropriate course of action prior to plan implementation.

Applicants do not expect any risk of accidental release of contaminants once the South Dakota Facility is complete. Any risk of release of contaminants during construction will be managed through use of BMPs and no impacts to landmarks and cultural resources of historic, religious, archaeological, scenic, natural, or other cultural significance are anticipated.

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20.0 Employment Estimates (ARSD 20:10:22:24)

The Project is expected to employ between 75 and 150 workers to support construction. The positions created during construction of the South Dakota Facility are expected to include the following categories of employment:

- Land rights
- Survey
- Structure foundations
- Structure assembly
- Wire stringing

The majority of the positions may require specialized skills and expertise. It is possible that positions will be filled by qualified individuals from South Dakota as part of the Project. The contractor, who will be responsible for determining employment needs for the construction, will determine the estimated annual employment expenditures during the construction phase of the South Dakota Facility, the plans for utilizing and training the existing South Dakota labor market for the specialized positions, the adequacy of the local manpower to meet the temporary labor positions arising from construction of the South Dakota Facility, and the percentage of temporary employees who will remain in the county and township after the construction of the South Dakota Facility.

No permanent or long-term employees are expected to be hired in South Dakota. In the South Dakota Facility area, the population and the types and number of jobs are not expected to change in the long term as a result of construction, maintenance and operation of the South Dakota Facility. It is not anticipated that the South Dakota Facility will create new permanent jobs, but it will create temporary construction jobs that will provide a one-time influx of income to the area.

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21.0 Future Additions and Modifications (ARSD 20:10:22:25)

The Applicants are unaware of any system upgrades related to the South Dakota Facility that will be needed in the future, and present planning studies have not identified any additional modifications that will result from this South Dakota Facility.

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22.0 Transmission Facility Layout and Construction (ARSD 20:10:22:34)

22.1 Route Clearing

During the land rights process, individual property owners will be advised as to the construction schedule, needed access to the South Dakota Facility ROW, and any vegetation clearing required for the South Dakota Facility. To maintain NERC reliability standards, the South Dakota Facility ROW will be cleared of vegetation as necessary to construct, operate, and maintain the South Dakota Facility. Clear cutting (the removal of all trees, brush and other low-growing vegetation) will occur within the South Dakota Facility ROW, along construction and maintenance travel paths, and at structure erection sites. Trees that could present a danger to the safe operation of the South Dakota Facility ("Danger trees") will also be removed or pruned to ensure safety. Danger trees include trees outside of the South Dakota Facility ROW that could hit the transmission line should they fall. Disposal of timber, tree tops, limbs, and slash will comply with state and local ordinances. Wood from the clearing operation will be offered to the landowner or removed from the site.

22.2 Transmission Construction Procedures

Construction will begin after federal, state, and local approvals are obtained and land rights determined for the area to be constructed. The precise timing of construction will consider various requirements that may be in place due to permit conditions, prudent construction timing, and available workforce. Once access to the South Dakota Facility ROW has been granted and the necessary permits are received, site preparation activities could begin. These activities include clearing the South Dakota Facility ROW of vegetation that will interfere with construction or the safe operation of the transmission line. All materials resulting from the clearing operations will either be chipped on site or stacked in the South Dakota Facility ROW, per landowner agreement. If temporary removal or relocation of fences is necessary, installation of temporary or permanent gates will be coordinated with the landowner. The Applicants anticipate working with landowners to minimize disruptions.

Transmission line structure sites are typically selected in areas that would require minimal grading. Therefore, structure sites with slopes of 10 percent or less would typically not be graded or leveled, unless it is necessary to provide a reasonably level area for construction access and activities. At sites with more than 10 percent slope, working areas may require grading or fill to develop a suitable work area. If the landowner permits, leveled areas and working pads will remain in place for use in future maintenance activities.

Typical construction equipment consists of tree removal equipment, mowers, cranes, backhoes, digger-derrick line trucks, track-mounted drill rigs, dump trucks, front end loaders, bucket trucks, bulldozers, flatbed trucks, pickup trucks, concrete trucks, helicopters, and various construction trailers. Many types of excavation equipment are set on wheel or track-driven vehicles. Structures are transported on tractor-trailer trucks, usually in three sections.

The Applicants employ standard construction and mitigation practices that have been developed from experience as well as industry-specific BMPs. These BMPs are described further in Section 22.3.

For structures that require concrete foundations, concrete will be delivered to the structure site by concrete truck. Foundations are typically allowed to cure for approximately three weeks prior to attaching the structures. Any excess soil from the excavation will be offered to the landowner or removed from the site.

From the construction staging areas, the steel structures and components are transported to the structure assembly areas by truck. The structure assembly areas are typically located within the South Dakota Facility ROW immediately adjacent to the structure site. At each structure assembly area, the steel structure sections are connected, the davit arms are attached, and insulators and other hardware are attached while the steel structure is on the ground. The structure is then lifted and placed into the excavation (direct embedded) or set on top of the concrete foundation. Any temporary laydown areas that are outside of the South Dakota Facility ROW will be obtained from affected landowners through rental agreements.

After the structures have been erected, conductors are installed by establishing stringing setup areas. These stringing setup areas are typically located every two to five miles along the South Dakota Facility and usually occupy approximately 1,600 square feet of land. Conductor stringing operations require access to each structure to secure the conductor wire to the insulators or to install shield wire clamps once final sag is established. Temporary guard or clearance structures are installed as needed over existing distribution or communication lines, roads and highways, railways or other obstructions to ensure that construction operations would not obstruct traffic and to prevent the conductors from contacting existing energized conductors or other cables.

22.2.1 *Best Management Practices During Construction*

The Applicants employ standard construction and mitigation practices that have been developed from experience with past practices as well as industry-specific BMPs. These BMPs address ROW clearance, erecting transmission line structures, stringing transmission lines, and minimizing environmental impacts. BMPs for each specific construction task are based on the proposed schedules for activities, permit requirements, terrain and land use characteristics, maintenance guidelines, inspection procedures and other practices.

In areas where construction occurs close to waterways, BMPs will be employed to help prevent soil erosion and siltation of waterways. Should vehicle fueling be required within the South Dakota Facility ROW, BMPs will be employed to ensure that equipment fueling and lubricating occur at a distance from waterways.

22.3 Restoration Procedures

During construction, ground disturbance at the structure sites and structure assembly areas may occur. Following the completion of construction, disturbed areas including staging areas, structure assembly areas, and stringing areas will be restored according to the agreement negotiated with the landowner.

Unless otherwise agreed to by the landowner, all construction materials and debris will be removed from the site once construction is complete. Post-construction reclamation activities also include dismantling all temporary facilities (including staging areas), employing appropriate erosion control measures, and reseeding areas disturbed by construction activities unless directed by the landowner. Seed mixes will be determined in consultation with the regulatory agencies or landowner. Native grasses that will not interfere with the safe operation of the transmission line facility will be allowed to reestablish in the South Dakota Facility ROW. The Applicants will work to ensure that restoration activities are completed to the satisfaction of the affected landowners.

22.4 Maintenance Procedures

Access to the South Dakota Facility ROW once it is completed is required periodically to perform inspections, conduct maintenance, and repair damage. Regular maintenance and inspections will be performed during the life of the South Dakota Facility to ensure its continued integrity. Generally, the Applicants inspect the transmission lines at least once per year. Inspections are typically limited to the immediate South Dakota Facility ROW and travel paths. If problems are found during inspections, repairs will be performed and the landowners and agencies will be notified if appropriate.

The South Dakota Facility ROW will be managed to remove trees and vegetation that interfere with the operation and maintenance of the transmission line. ROW clearing practices include a combination of mechanical and hand clearing, and may include application of herbicides, where allowed, to remove or control vegetation and weed growth.

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23.0 Information Concerning Transmission Facilities (ARSD 20:10:22:35)

A high-voltage transmission line (HVTL) consists of three phases, each at the end of a separate insulator string, all physically supported by structures. Each phase consists of one or more conductors. When more than one conductor is used to make up a phase, the term "bundled" conductors is used. Conductors are metal cables consisting of multiple strands of steel and aluminum wire wound together. There are also two shield wires strung above the electrical phases to prevent damage from lightning strikes that may also include a fiber optic communication cable. The conductors will be approximately one to two inches in diameter. Transmission lines are constructed on a ROW, the width of which is primarily dependent on structure design, span length, and electrical safety requirements associated with the transmission line's voltage. The South Dakota Facility ROW typically will be 150 feet wide.

23.1 Configuration of Towers

The Applicants propose to use single pole steel single-circuit structures for the South Dakota Facility, unless engineering or environmental conditions require the use of steel H-frame or guyed mono-pole structures. Public input was a consideration in the selection of the structure type. Single steel pole structures are typically placed on concrete foundations measuring about 6 to 11 feet in diameter. Specialty structures, including dead-end structures, H-frame structures, or guyed mono-pole structures, may be used in certain circumstances. Typically, H-frame structures consist of two steel poles with cross bracing. A guyed mono-pole structure is a mono-pole with guy wires that extend diagonally out to the ground. Concrete pier foundations may be used for angle structures or if soil conditions are poor. As engineering continues, it will be determined if and where specialty structures may be used. Table 21 shows a summary of the configuration of the structures that are under consideration for the South Dakota Facility.

The South Dakota Facility will be designed to meet or surpass all relevant local and state codes, National Electric Safety Code (NESC) requirements and APLIC and Applicant standards. Appropriate standards will be met for construction and installation and all applicable safety procedures will be followed during and after installation.

Table 21. Structure Design/Configuration Summary

Structure Type	Structure Material	ROW Width (feet)	Approx. Structure Height (feet)	Approx. Structure Base Diameter (feet)	Approx. Foundation Diameter (feet)	Average Span Between Structures (feet)	Pole to Pole Span on Single H-Frame Structure (feet)
Single Pole Davit Arm (majority of route)	Steel	150	125-155	3-4 (tangent structures) 4-6 (angle structures)	6-11	1,000 (range of 700 – 1200)	N/A

Structure Type	Structure Material	ROW Width (feet)	Approx. Structure Height (feet)	Approx. Structure Base Diameter (feet)	Approx. Foundation Diameter (feet)	Average Span Between Structures (feet)	Pole to Pole Span on Single H-Frame Structure (feet)
Guyed Mono-Pole	Steel	150	125-155	3-4 (tangent structures) 4-6 (angle structures)	3-5	1,000 (range of 700 – 1200)	N/A
H-Frame (if necessary)	Steel	150	100-130	3-4 (tangent structures)	3-5	1,000 (range of 700 – 1200)	30

23.2 Conductor Configuration

It is anticipated that each phase will consist of two conductor bundled (2x), TP (twisted pair) 477 kcmil (thousand circular mils), 26/7, Hawk, aluminum conductor steel reinforced (ACSR) or conductors of comparable capacity.

23.3 Proposed Transmission Site and Major Alternatives

The site of the South Dakota Facility is described in Sections 2.1 and 7.0, Appendix A, and shown on Exhibit 2. Section 8.0 outlines the route identification and selection process.

23.4 Reliability and Safety

23.4.1 *Transmission Line Reliability*

In general, transmission infrastructure is built to withstand weather extremes that can be encountered within this region. With the exception of severe weather conditions such as tornadoes and extreme ice, transmission lines usually only fail when they are subjected to conditions beyond the design parameters.

Transmission lines are automatically taken out of service by the operation of protective relaying equipment when a fault is detected on the system. Such interruptions are usually only momentary. Scheduled maintenance outages are also infrequent on high voltage transmission lines. As a result, the average annual availability of transmission infrastructure is very high, in excess of 99 percent.

23.4.2 *Safety*

The South Dakota Facility will be designed to meet the local, state, NESC and the Applicants' standards regarding clearance to ground, clearance to crossing utilities, clearance to buildings, strength of materials, and ROW widths. Construction crews will comply with local, state, NESC and the Applicants' standards regarding installation of facilities and standard construction practices. The Applicants' and industry safety procedures will be followed during and after installation of the transmission line.

The South Dakota Facility will be equipped with protective devices to safeguard the public from the transmission line if an accident occurs and a structure or conductor falls to the ground. The protective devices are breakers and relays located where the transmission line connects to the substation. The protective equipment will de-energize the transmission line should such an event occur. In addition, the substation will be fenced and access limited to authorized personnel. The costs associated with these measures have not been tabulated separately from the overall facility costs since these measures are standard practice for the Applicants.

23.4.3 *Electric and Magnetic Fields*

The term electromagnetic field (EMF) refers to electric and magnetic fields that are coupled together such as in high-frequency radiating fields. For the lower frequencies associated with power lines, EMF should be separated into electric fields (EFs) and magnetic fields (MFs), which arise from the flow of electricity and the voltage of a line and are measured in kilovolts per meter (kV/m) and milliGauss (mG), respectively. The intensity of the electric field is proportional to the voltage of the line, and the intensity of the magnetic field is proportional to the current flow through the conductors. Transmission lines operate at a power frequency of 60 hertz (cycles per second). See

Table 23, below, for more information.

23.4.3.1 Electric Fields

The electric field from a transmission line can couple with a conductive object, such as a vehicle or a metal fence, which is in close proximity to the line. This will induce a voltage on the object, and the magnitude of this voltage is dependent on many factors, including the weather condition, object shape, object size, object orientation, object to ground resistance, object capacitance, and location along the ROW. If the object is insulated or semi-insulated from the ground and a person touches it, a small current could pass through the person's body to the ground. This might be accompanied by a spark discharge and mild shock, similar to what can occur when a person walks across a carpet and touches a grounded object or another person.

To ensure that any discharge does not reach unsafe levels, the NESC requires that any discharge be less than 5 milliamperes (mA). Based on the Applicants' transmission line operating experience, the discharge from any large mobile object—such as a bus, truck, or farm machinery—parked under or adjacent to the line would be unlikely to reach levels considered to be an annoyance, and will be less than the 5 mA NESC limit. The Applicants will also ensure that any fixed object, such as a fence or other large permanent conductive object close to or parallel to the line, will be grounded such that any discharge would be less than the 5 mA NESC limit.

Currently, there are no state regulations within South Dakota for maximum electric field limits for transmission line siting. The facilities will comply with the recommended NESC standards.

23.4.3.2 Magnetic Fields

Current passing through any conductor, including a wire, produces a magnetic field in the area around the wire. The magnetic field associated with an HVTL surrounds the conductor and decreases rapidly with increasing distance from the conductor. Considerable research has been conducted to determine whether exposure to power-frequency (60 hertz) magnetic fields causes biological responses and health effects.

EMF research expert Dr. Peter A. Valberg provided testimony in 2010 (Valberg, 2010) on EMF calculation and potential health effects, and the conclusions of his 2009 literature review (Valberg, 2009) of the status of scientific research on potential health effects. He summarized scientific research on HVTLs and MFs as:

> [T]hese studies do not change the factual conclusion that power-line MF exposure is not an established cause of health effects, as has been detailed throughout this report. As has been noted, the overall weight of evidence, combing the epidemiology with laboratory-animal and mechanistic research, fails to support a role for power-line MF in disease risk... [overall] the scientific research literature to date remains an insufficient basis for assigning any actual health risk to power-line MF exposure levels.

23.4.3.3 <u>Recent Research on EMF Exposure and Human Health</u>

Many organizations have conducted recent research on EMFs from extremely low frequency (ELF) source to study their potential effects on human health and safety as a follow-up to studies conducted primarily in the 1980s and 1990s which correlated EMFs and adverse health risks.

In 2007, the World Health Organization (WHO, 2007) made the following statement regarding effects of EMFs on health:

> Given both the weakness of the evidence for a link between exposure to ELF magnetic fields and childhood leukemia, and the limited impact on public health if there is a link, the benefits of exposure reduction on health are unclear. Thus, the costs of precautionary measure should be very low.

The 2009 President's Cancer Panel heard testimony concerning ELF, radio frequency (RF), and MFs and discussed that prior to 1996, the epidemiologic studies shared weaknesses that once recognized and accounted for, along with the testimony heard, "U.S. environmental organizations... generally conclude that the link between ELF-MF and cancer is controversial or weak." (Reuben, 2010).

The International Commission on Non-Ionizing Radiation Protection (ICNIRP) reviewed scientific studies performed since its last published guidelines in 1998 that established exposure limitations to EMFs and published their recommendations in 2010 (ICNIRP, 2010), concluding:

> [S]cientific data available so far do not indicate that low frequency electric and/or magnetic fields affect the neuroendocrine system in a way that these would have an adverse impact on human health. There is no substantial evidence for an association between ELF exposure and diseases such as Parkinson's disease, multiple sclerosis, and cardiovascular diseases. The evidence for an association between low frequency exposure and Alzheimer's disease and amyotrophic lateral sclerosis is inconclusive. The evidence for an

association between low frequency exposure and developmental and reproductive effects is very weak.

In addition, the 2010 ICNIRP recommendations stated "evidence that prolonged exposure to ELF-MF is causally related with an increased risk of childhood leukemia is too weak to form the basis for exposure guidelines."

There is no federal standard for transmission line electric fields, nor state standards in South Dakota. EMF levels for the Project and how the calculated levels at any location within the ROW are below the ICNIRP guidelines (2,000 mG and 4.2 kV/m) for public exposure to EMF. Table 22 shows the calculated EMF levels for the Project. The H-frame structure produced the highest levels of electric and magnetic fields.

Table 23 shows the calculated EMF levels for the H-frame structure on ROW and at the ROW edge. Computations were performed using Bonneville Power Administration's Corona and Field Effects Program CORONAII version 3.0 (U.S. Department of Energy, undated).

Table 22. Calculated EMF Levels for the Project

Project Load Condition	Electric Field (kV/m)[1]		Magnetic Field (mG)	
	H-Frame Structure	Mono-pole Structure	H-Frame Structure	Mono-pole Structure
Normal Operating Condition[1]	6.7	5.8	55.7	39.3
Maximum Operating Condition[2]	6.7	5.8	267.3	188.6

[1] Normal Operating Condition value is for predicted flow of 140 megawatt (MW) (~250 Amps).

[2] Maximum Operating Condition value is based on 1200 Amps (line rating).

Source: Bonneville Power Administration's Corona and Field Effects Program CORONAII version 3.0

Table 23. Calculated EMF Levels for the H-Frame Structure

Project Load Condition	Electric Field (kV/m)[1]		Magnetic Field (mG)	
	On ROW	Edge ROW	On ROW	Edge
Normal Operating Condition[2]	6.7	1.9	55.7	15.3
Maximum Operating Condition[3]	6.7	1.9	267.3	73.6

[1] This value depends on voltage and is expected to be relatively constant (will vary slightly if the operating voltage changes). Results are calculated at the operating voltage of 1.05 per unit

[2] Normal Operating Condition value is for predicted flow of 140 megawatt (MW) (~250 Amps).

[3] Maximum Operating Condition value is based on 1200 Amps (line rating).

Source: Bonneville Power Administration's Corona and Field Effects Program CORONAII version 3.0

To date, the most exhaustive research done on HVTL and cancer was conducted over a 35-year span with one of the largest study groups of persons near HVTLs ever used for EMF research in March of 2013 (Shaddick et al., 2013). Their case-controlled study investigating cancer risks and ELF-MF from high-voltage lines concluded that their "results do not support an epidemiologic association of adult cancers with residential magnetic fields in proximity to high-voltage overhead power lines."

While the general scientific consensus is that electric fields pose no risk to humans, the question of whether exposure to magnetic fields potentially can cause biological responses or even health effects continues to be the subject of research and debate despite current scientific evidence showing no correlation with distance to HVTL and adverse health effects. In addressing this issue, the Applicants provide information on EMF to the public, interested customers and employees to assist them in making an informed decision on EMF. The Applicants will provide measurements for landowners, customers, and employees who request them. In addition, the Applicants have followed the "prudent avoidance" guidance suggested by most public agencies. This includes using structure designs that minimize magnetic field levels and attempting to site facilities in locations with lower residential densities.

23.4.4 *Stray Voltage*

"Stray voltage" is a condition that can occur on the electric service entrances to structures from distribution lines—not transmission lines. More precisely, stray voltage is a voltage that exists between the neutral wire of the service entrance and grounded objects in buildings such as barns and milking parlors.

Transmission lines do not, by themselves, create stray voltage because they do not connect to businesses or residences. However, transmission lines can induce stray voltage on a distribution circuit that is parallel to and immediately under the transmission line. Appropriate measures will be taken to address stray voltage concerns on a case-by-case basis.

23.4.5 *Farming Operations, Vehicle Use, and Metal Buildings Near Power Lines*

All current farming operations in the area are compatible with the construction and operation of the South Dakota Facility.

Insulated electric fences used in livestock operations can pick up an induced charge from transmission lines. Shocks can be caused when a charger is disconnected. This can be prevented by either shortening an insulator with a wire or installing an electric filter.

Farm equipment, passenger vehicles, and trucks may be safely used under and near power lines. The power lines will be designed to meet or exceed minimum clearance requirements over roads, driveways, cultivated fields, and grazing lands as specified by the NESC. Recommended clearances within the NESC are designed to accommodate a relative vehicle height of 14 feet.

There is a potential for vehicles under HVTLs to build up an electric charge. If this occurs, the vehicle can be grounded by attaching a grounding strap to the vehicle long enough to touch the earth. The Applicants do not recommend refueling vehicles directly under or within 100 feet of a power line 200 kV or greater.

Buildings are permitted near transmission lines but are generally prohibited within the ROW. Any person with questions about new or existing metal structures near the ROW may contact the Applicants for further information about proper grounding requirements.

23.4.6 *Right-of-Way or Condemnation Requirements*

The schedule for contacting landowners will be developed by the Applicants and formal option easement negotiations began in the summer of 2013. The Project will require the acquisition of easements to cross private property and the coordination with appropriate agencies where the line shares ROW with other public utilities or public roads. The majority of affected landowners are aware of the South Dakota Facility. Land rights agents will continue to work with the landowners to answer questions about the South Dakota Facility and to obtain permission for route surveys, environmental surveys, and soil investigations to occur prior to construction. As the design of the transmission line is further developed, contacts with the owners of affected properties will continue.

In the event soil investigation is required to assist with the design of the foundations, the Applicants will inform the landowners at the initial survey consultation that soil borings or environmental surveys may occur. An independent geotechnical testing company will take and analyze these borings. Survey crews will also work with local utilities to identify underground utilities along the South Dakota Facility. This minimizes conflicts or impacts to existing utilities. Environmental crews will gather specific information such as wetland boundaries and cultural resource site boundaries.

Where possible, staging and laydown areas will be limited to previously disturbed or developed areas. When additional property is temporarily required for construction, temporary limited easements may be obtained from landowners for the duration of construction. Temporary limited easements will be limited to special construction access needs or additional staging or laydown areas required outside of the transmission line ROW.

The width of the South Dakota Facility ROW will generally be 150 feet throughout the length of the transmission line, depending on final route, ROW acquisition and final design. Appendix H contains diagrams of the proposed structures. In the event that negotiations with landowners to acquire ROW are unsuccessful, as the last resort, the condemnation procedures in SDCL 21-35 et seq. would be utilized.

23.4.7 *Necessary Clearing Activities*

The Applicants do not anticipate that the South Dakota Facility will require extensive tree clearing. Trees will need to be removed pursuant to easement requirements. Wood from the clearing operation will be offered to the landowner or removed from the site, dependent upon the preference of the landowner. General easement clearing and maintenance is described in Section 23.1.

23.4.8 *Underground Transmission*

No portion of the South Dakota Facility will require underground transmission. While it is common for lower voltage lines to be buried, it is rare for high voltage transmission lines to be constructed underground. Transmission lines can be placed underground but the cost to construct underground can be in the range of 15-20 times the cost of overhead construction. Because of the significantly greater expense associated with underground transmission construction, the use of underground technology is limited to locations where the impacts of overhead construction are completely unacceptable or where physical circumstances allow for no other option. The Applicants concluded that the environmental and land use setting did not warrant underground construction on any portion of the route.

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24.0 List of Potential Permits (ARSD 20:10:22:05)

The Applicants need to obtain approvals from a variety of applicable federal, state, and local agencies prior to constructing the South Dakota Facility in a specific permit-required area. Agencies with primary approval/permitting authority include USFWS, USACE, and the Commission. Table 24 identifies permits, approvals, and other coordination that may be needed with federal agencies, State of South Dakota, and counties. This listing of regulatory requirements is subject to change as South Dakota Facility development continues.

Table 24. Potential Required Permits and Approvals

Agency	Type of Permit, Regulatory Compliance, or Coordination	Status[1]	Need
Federal			
U.S. Fish and Wildlife Service	Section 7 of the Endangered Species Act, Migratory Bird Treaty Act	3	Section 7 Consultation under NEPA required for USFWS Permit, USACE Section 10 Permit, and NRCS easement modification
	Special Use Permit or Right-of-Way Permit	3	If construction in wetlands within wetland easements or in grassland easements, then compatibility analysis is required. Special Use Permit or a Right-of-Way Permit may be needed for disturbance to land subject to a grassland easement or wetland subject to a wetland easement.
U.S. Army Corps of Engineers	Section 10 of the Rivers and Harbors Act of 1899	2	Section 10 Permit - Required for the James River crossing.
	Section 404 of the Clean Water Act	3	Nationwide Permit 12 required for dredging or fill in jurisdictional waters of the United States for utility line projects.
U.S. Department of Agriculture - Natural Resources Conservation Service	Easement Modifications	3	Easement modification needed to span two easements

Agency	Type of Permit, Regulatory Compliance, or Coordination	Status[1]	Need
Federal Aviation Administration	FAA Form 7460-1, Notice of Proposed Construction or Alteration	3	The Federal Aviation Administration (FAA) issues determination that construction of the South Dakota Facility does not constitute a hazard to air navigation.
	FAA Form 7460-2 - Notice of Actual Construction or Alteration	3	Notifies FAA of actual constructed or altered structures.
	FAA Form 7461-1, Notice of Proposed Construction Hazard Determination	3	Notifies FAA of structures that might affect navigable airspace. Form requires proposed markings and lighting. FAA must review possible impacts to air safety and navigation, as well as the potential for adverse effects on radar systems.
State of South Dakota			
Public Utilities Commission	Facility Permit	1	Included herein.
Department of Environment & Natural Resources	Section 401 Water Quality Certification	3	Required for fill in jurisdictional waters of the United States.
	NPDES Permit: General Permit for Storm Water Discharges Associated with Construction Activities	2	Required for disturbance of over one acre of land. Must prepare a SWPPP.
	Temporary water use permit for construction activities	3	Compliance with the Water Pollution Control Act. Temporary permits for the use of public water for construction, testing, or drilling purposes; issuance of a temporary permit is not a grant of a water right. Contractors will obtain as necessary.
	General Permit for Temporary Dewatering	3	Compliance with the Water Pollution Control Act. Temporary permit for the discharge of water for construction dewatering. Contractors will obtain as necessary.
Aeronautics Commission	Aeronautical Hazard Permit	3	Permit lighting plan determined with FAA coordination, if required.
State Historic Preservation Office	Section 106 of the National Historic Preservation Act Coordination	3	Compliance with SDCL 1-19A-11.1 and consultation under Section 106 of the NHPA is required for federal permits (USFWS and USACE).

Agency	Type of Permit, Regulatory Compliance, or Coordination	Status[1]	Need
Department of Transportation	Oversize/Overweight Permit	2	Permit required for heavy hauling construction equipment and materials on state highways. Contractors will obtain as necessary.
	Highway Access Permit	2	Permit required for construction of access roads from state highways.
	Utility Permit	2	Permit required for utility crossings on state highway ROW.
Local			
Grant County	Conditional Use Permit	2	Permit may be required
Day County	Conditional Use Permit	2	Permit may be required
	County Road Right of Way Permit	2	Permits may be required for utility poles installed along county highways if within 50 feet of the ROW.
Brown County	Special Exception	2	Required for high voltage transmission line located in applicable zoning districts.

[1] *Status Explanation:*

1: Applied – decision pending

2: Will apply once Facility Permit is received

3: Final layout will determine whether the permit/approval is needed, or final layout is needed for permit application or pre-construction notification

24.1 Local Permits and Approvals

Typical local approvals associated with transmission line construction are listed below.

24.1.1 *Road Crossing/Right-of-Way Permits*

These permits are required to cross or occupy county road ROW.

24.1.2 *Land Use Permits*

These permits may be required to occupy county or township lands administered by these entities. A Conditional Use Permit may be required in Day and Grant counties and a Special Exception Permit may be required in Brown County.

24.1.3 *Building Permits*

These permits may be required by the local jurisdiction for construction of fiber optic regeneration stations, and may be required for other buildings and structures, and their attachments, located in Brown County and Day County.

24.1.4 *Over-Width/Load Permits*

These permits may be required to move over-width or heavy loads on county, township, or municipal roads.

24.1.5 *Approach/Access Permits*

These permits may be required to construct access roads or driveways from county or township roadways.

25.0 Additional Information in Application (ARSD 20:10:22:36)

The Applicants believe that this Application, including appendices, contains all the information required to meet Applicants' burden of proof specified in SDCL 49-41B-22. The Applicants have provided correspondence and meeting notes pertinent to the South Dakota Facility in Appendix C, which outline the coordination efforts taken with the State of South Dakota and federal agencies to date.

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26.0 Testimony and Exhibits (ARSD 20:10:22:39)

The testimony and exhibits in support of the Application will depend on the issues that are disputed. The Applicants are filing with this application a motion for scheduling order to request a prehearing conference to set a schedule for the filing of prefiled testimony and exhibits after the disputed issues are determined. However, the Applicants will at a minimum have individuals from the following entities available to testify in support of the Application:

Montana-Dakota Utilities Co.
400 North 4th Street
Bismarck, North Dakota 58501-4092
701-222-7944

Otter Tail Power Company
P.O. Box 496
Fergus Falls, Minnesota 56538-0496
218-739-8947

HDR Engineering, Inc.
701 Xenia Avenue South, Suite 600
Minneapolis, Minnesota 55416
763-591-5400

POWER Engineers, Inc.
401 South Mechanic Street
Jackson, Michigan 49201
501-789-7367

Kadrmas, Lee and Jackson, Inc.
3203 32nd Avenue South, Suite 201
Fargo, North Dakota 58103-6242
701-232-5353

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27.0 Applicants' Verification

VERIFIED APPLICANT'S SIGNAURE

STATE OF NORTH DAKOTA)
) :SS
COUNTY OF BURLIEGH)

Garret Senger, being duly sworn, deposes and says that he is the authorized agent of Montana-Dakota Utilities Co.

He states that he does not have personal knowledge of all the facts recited in the foregoing application, but the information in the application has been gathered by and from employees, contractors of the owners of Big Stone South to Ellendale Project; and that the information in the application is verified by him as being true and correct on behalf of Big Stone South to Ellendale Project.

Dated this 14th day of August, 2013. Garret Senger

Garret Senger
Vice President – Regulatory Affairs and Chief Accounting Officer
Montana-Dakota Utilities Co.

Subscribed and sworn to before me this
14th day of August, 2013.

Denys Schwartz
Notary Public
My Commission Expires:

DENYS SCHWARTZ
Notary Public
State of North Dakota
My Commission Expires December 31, 2018

VERIFIED APPLICANT'S SIGNAURE

STATE OF MINNESOTA)
) SS
COUNTY OF OTTER TAIL)

Tim Rogelstad, being duly sworn, deposes and says that he is the authorized agent of Otter Tail Power Company.

He states that he does not have personal knowledge of all the facts recited in the foregoing application dated August 14, 2013, but the information in the application has been gathered by and from employees, contractors of the owners of Big Stone South to Ellendale Project; and that the information in the application dated August 14, 2013 is verified by him as being true and correct on behalf of Big Stone South to Ellendale Project.

Dated this 15 day of August, 2013.

Tim Rogelstad
Vice President – Asset Management
Otter Tail Power Company

Subscribed and sworn to before me this
15 day of August, 2013.

Notary Public
My Commission Expires:

DAVID EDWIN KANTRUD
Notary Public
Minnesota
My Commission Expires January 31, 2016

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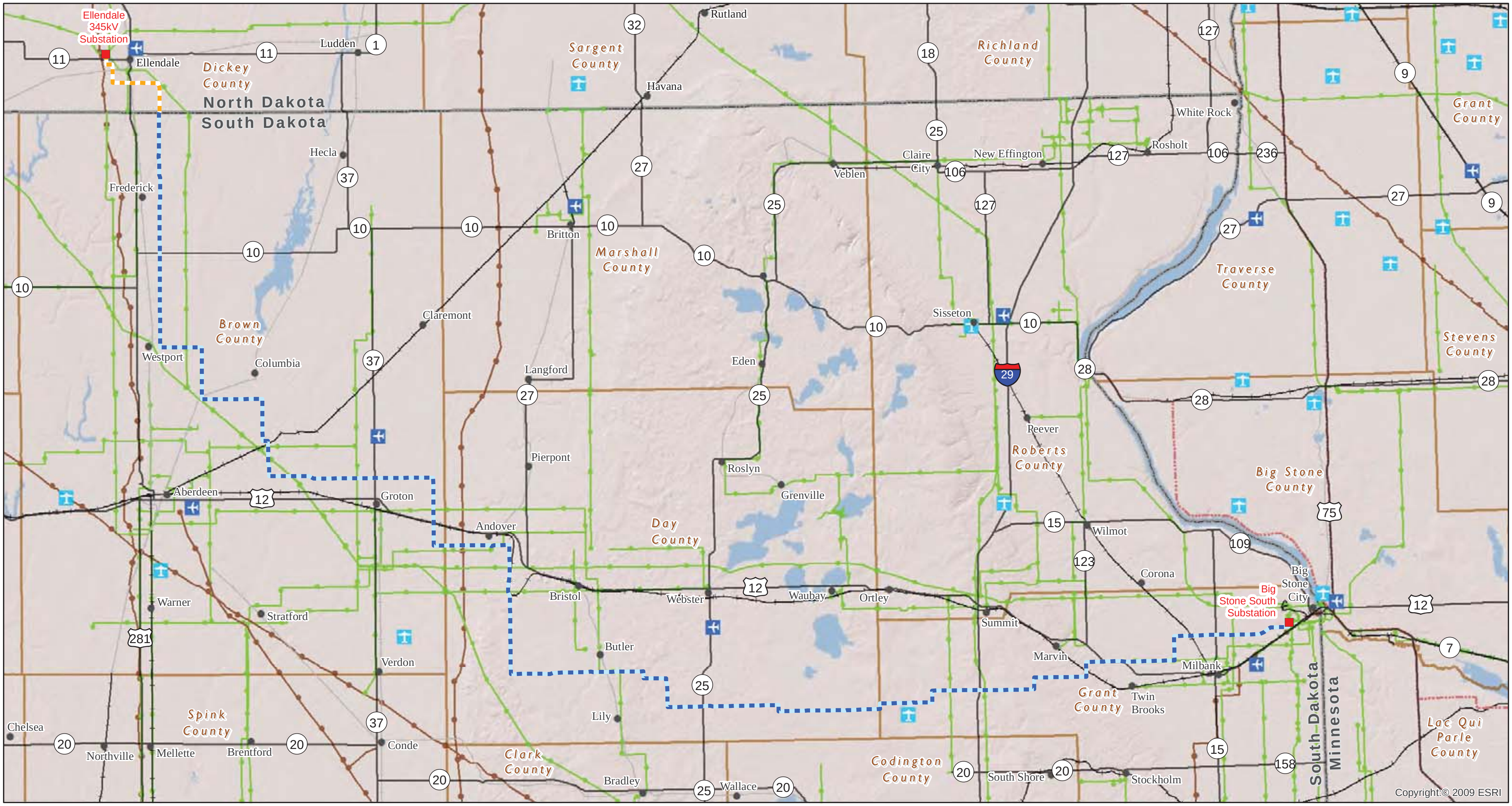

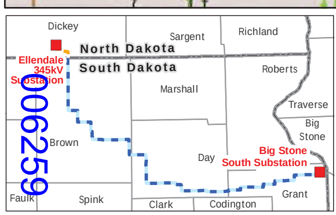

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South Dakota Facility
North Dakota Facility
Project End Point
Private-use Airport
Public-use Airport
Electric
Pipeline
Scenic Byway
Highway
Railroad
Abandoned Railroad
City
County Boundary
State Boundary

Exhibit 1
Project Overview
Big Stone South to Ellendale
345 kV Transmission Line Project

Miles
0 10

BSS+E
Big Stone South to Ellendale

Scale 1:500,000

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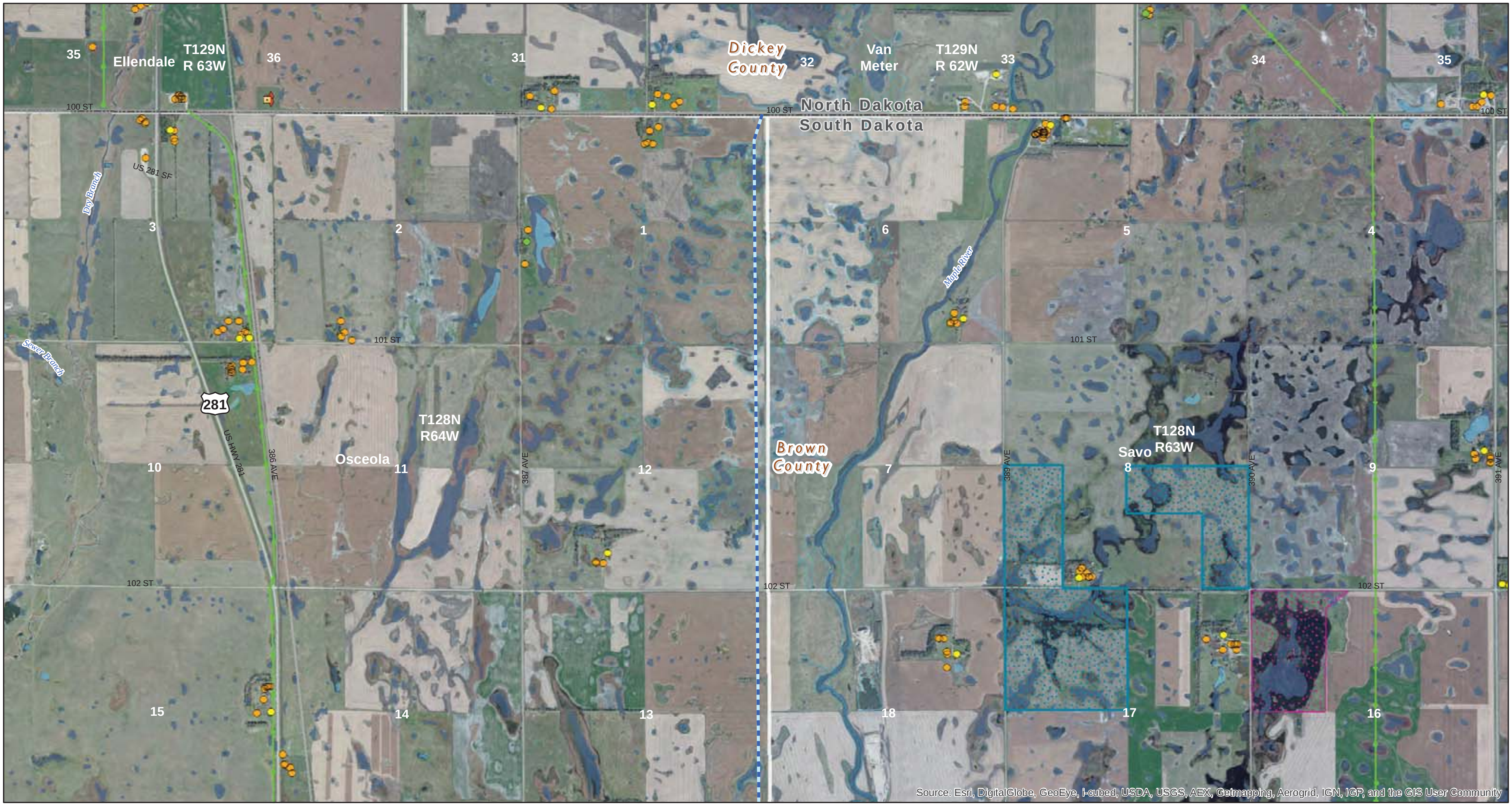

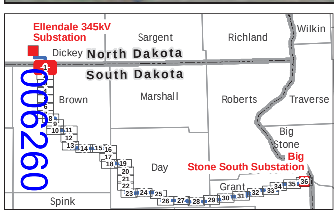

South Dakota Facility
Project End Point
Dwelling - Occupied
Dwelling - Unknown/Vacant
Ag/Other Structure
Gravel Pit/Mining
Cemetery
Church
School
Recreation
Utility
Communication Tower
NRHP Listed Property
Center Pivot
Noise Sensitive Land Use
Electric
Pipeline
State Park or Recreation Area
State School & Public Lands
Waterfowl Production Area (WPA)
National Wildlife Refuge (NWR)
Walk-In Areas (General Hunting Access)
National Conservation Easements (NRCS)
Private-use Airport
Public-use Airport
City Boundary
Township Boundary
County Boundary
State Boundary
Railroad
Abandoned Railroad
Highway
River or Stream
Waterbody
Wetland (NWI)
Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility.
Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.1
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

N

0 0.5 Miles

BSS+E Big Stone South to Ellendale

Scale 1:24,000

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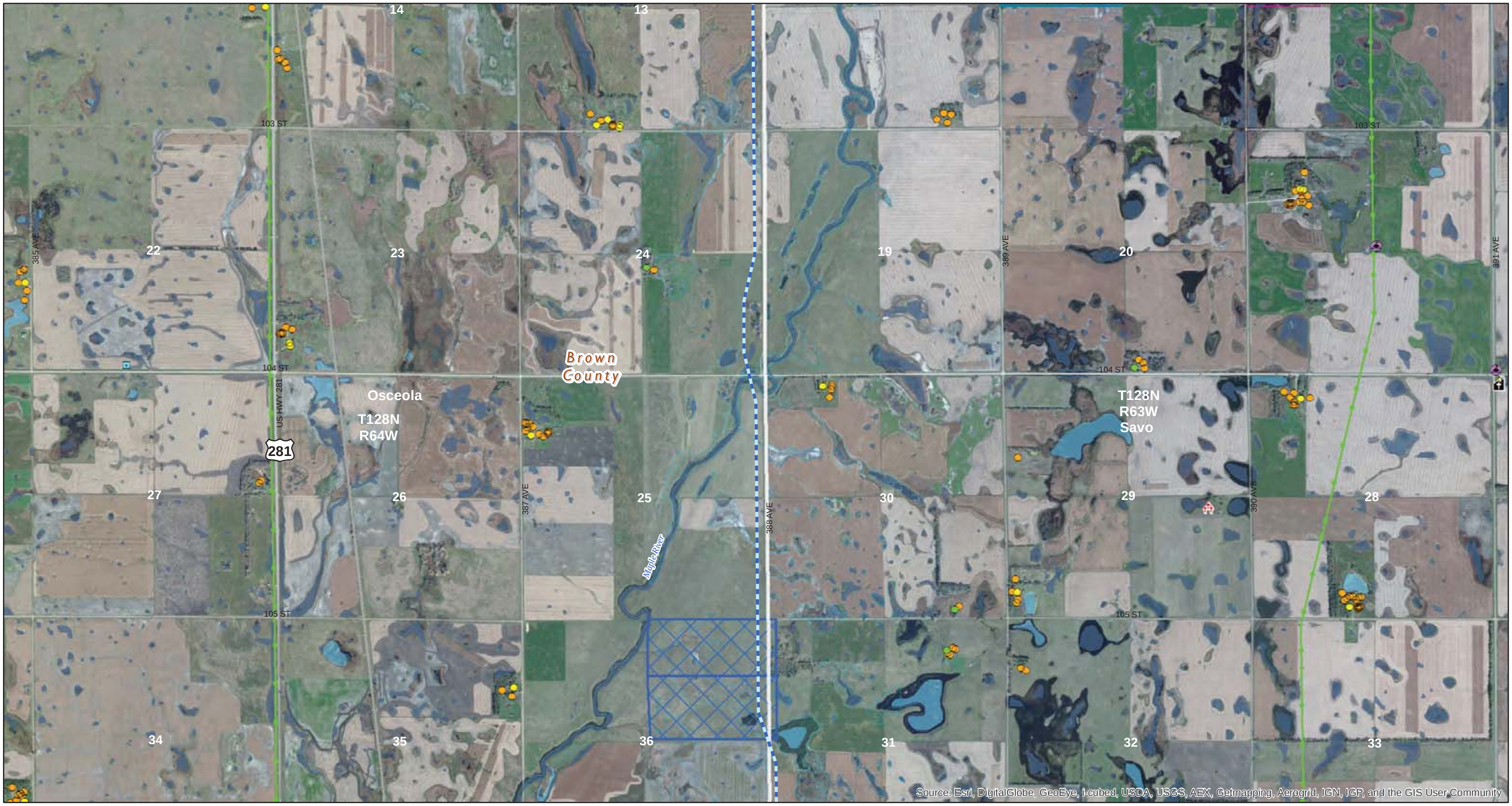

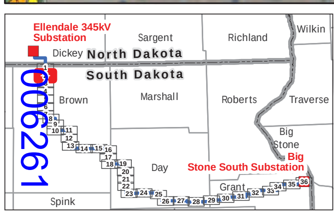

South Dakota Facility
Project End Point
Dwelling - Occupied
Dwelling - Unknown/Vacant
Ag/Other Structure
Gravel Pit/Mining
Cemetery
Church
School
Recreation
Utility
Communication Tower
NRHP Listed Property
Center Pivot
Noise Sensitive Land Use
Electric
Pipeline
State Park or Recreation Area
State School & Public Lands
Waterfowl Production Area (WPA)
National Wildlife Refuge (NWR)
Walk-In Areas (General Hunting Access)
National Conservation Easements (NRCS)
Private-use Airport
Public-use Airport
City Boundary
Township Boundary
County Boundary
State Boundary
Railroad
Abandoned Railroad
Highway
River or Stream
Waterbody
Wetland (NWI)
Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility.
Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.2
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

N

0 0.5 Miles

BSS+E
Big Stone South to Ellendale

Scale 1:24,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

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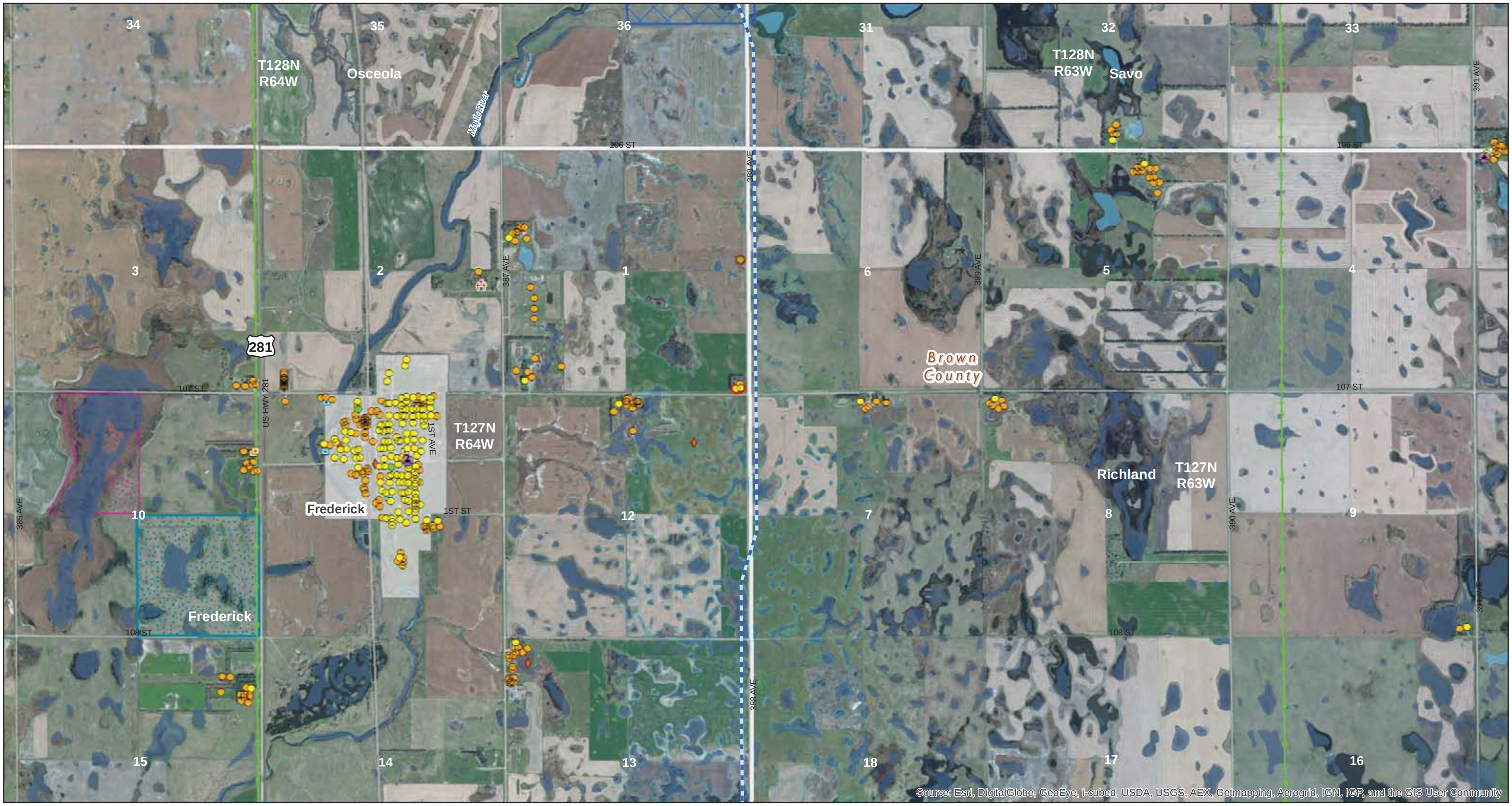

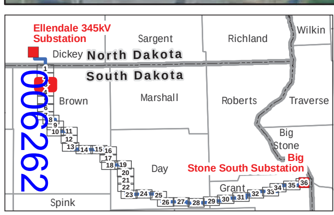

South Dakota Facility
Project End Point
Dwelling - Occupied
Dwelling - Unknown/Vacant
Ag/Other Structure
Gravel Pit/Mining
Cemetery
Church
School
Recreation
Utility
Communication Tower
NRHP Listed Property
Center Pivot
Noise Sensitive Land Use
Electric
Pipeline
State Park or Recreation Area
State School & Public Lands
Waterfowl Production Area (WPA)
National Wildlife Refuge (NWR)
Walk-In Areas (General Hunting Access)
National Conservation Easements (NRCS)
Private-use Airport
Public-use Airport
City Boundary
Township Boundary
County Boundary
State Boundary
Railroad
Abandoned Railroad
Highway
River or Stream
Waterbody
Wetland (NWI)
Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility.
Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.3
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

N

0 0.5 Miles

BSS+E Big Stone South to Ellendale

Scale 1:24,000

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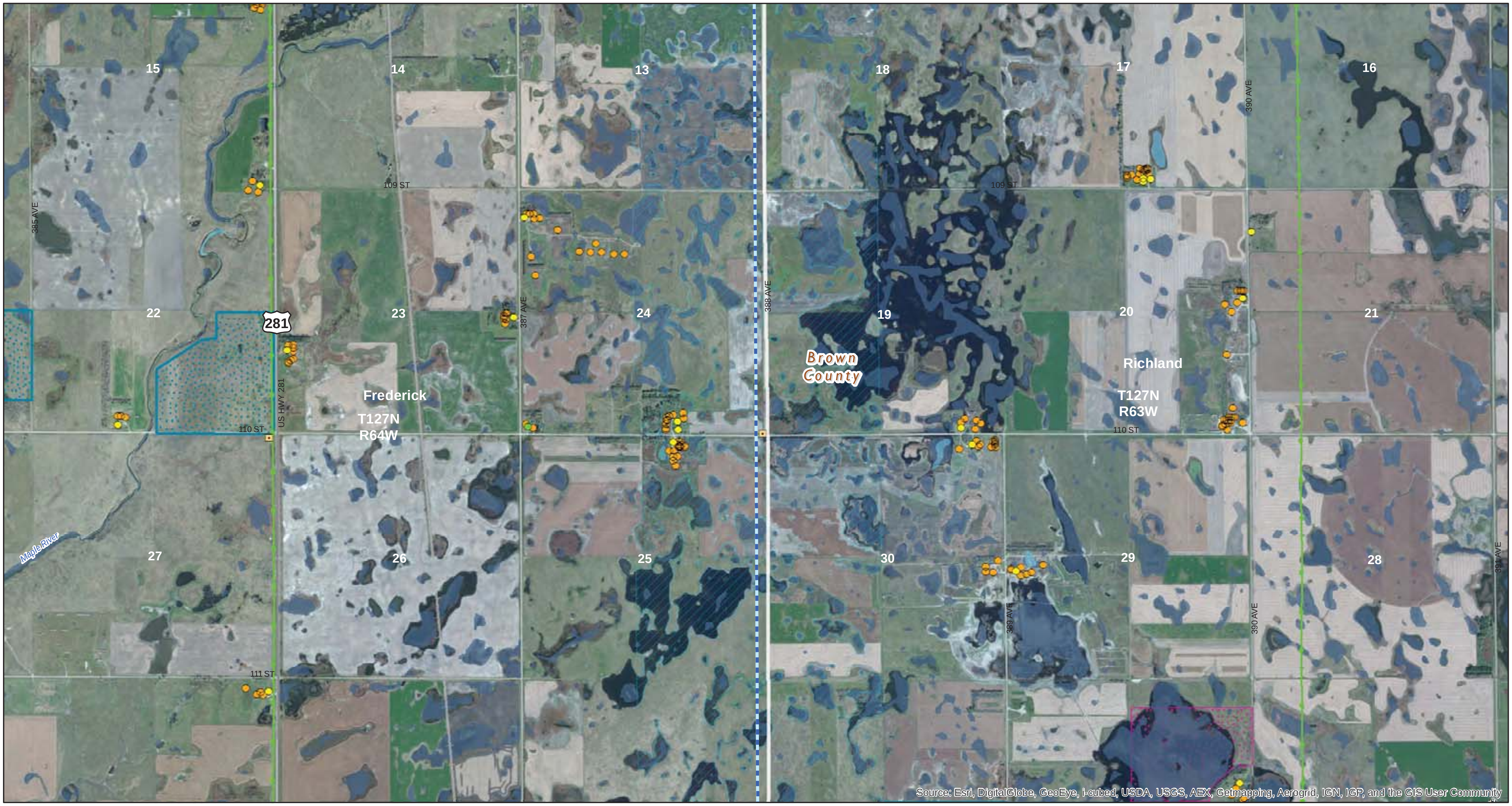

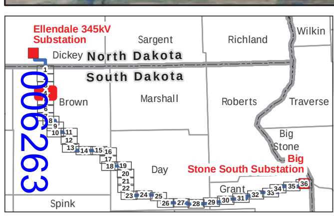

South Dakota Facility
Project End Point
Dwelling - Occupied
Dwelling - Unknown/Vacant
Ag/Other Structure
Gravel Pit/Mining
Cemetery
Church
School
Recreation
Utility
Communication Tower
NRHP Listed Property
Center Pivot
Noise Sensitive Land Use
Electric
Pipeline
State Park or Recreation Area
State School & Public Lands
Waterfowl Production Area (WPA)
National Wildlife Refuge (NWR)
Walk-In Areas (General Hunting Access)
National Conservation Easements (NRCS)
Private-use Airport
Public-use Airport
City Boundary
Township Boundary
County Boundary
State Boundary
Railroad
Abandoned Railroad
Highway
River or Stream
Waterbody
Wetland (NWI)
Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility. Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.4
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

N
0 0.5 Miles

BSSE Big Stone South to Ellendale

Scale 1:24,000

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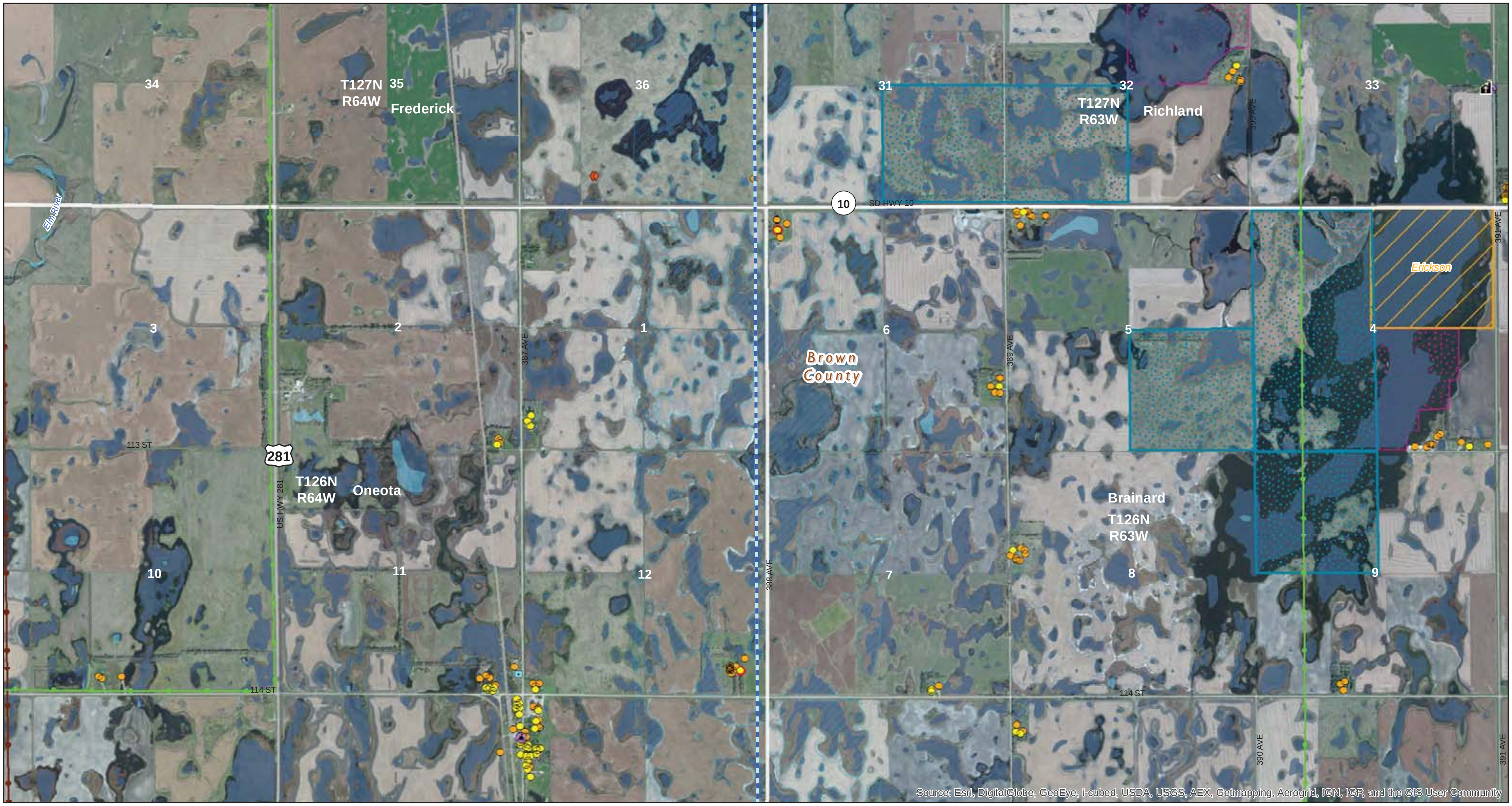

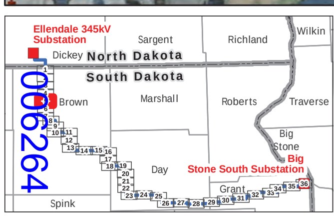

South Dakota Facility
Project End Point
Dwelling - Occupied
Dwelling - Unknown/Vacant
Ag/Other Structure
Gravel Pit/Mining
Cemetery
Church
School
Recreation
Utility
Communication Tower
NRHP Listed Property
Center Pivot
Noise Sensitive Land Use
Electric
Pipeline
State Park or Recreation Area
State School & Public Lands
Waterfowl Production Area (WPA)
National Wildlife Refuge (NWR)
Walk-In Areas (General Hunting Access)
National Conservation Easements (NRCS)
Private-use Airport
Public-use Airport
City Boundary
Township Boundary
County Boundary
State Boundary
Railroad
Abandoned Railroad
Highway
River or Stream
Waterbody
Wetland (NWI)
Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility.
Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.5
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

Miles
0 0.5

BSSE Big Stone South to Ellendale

Scale 1:24,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

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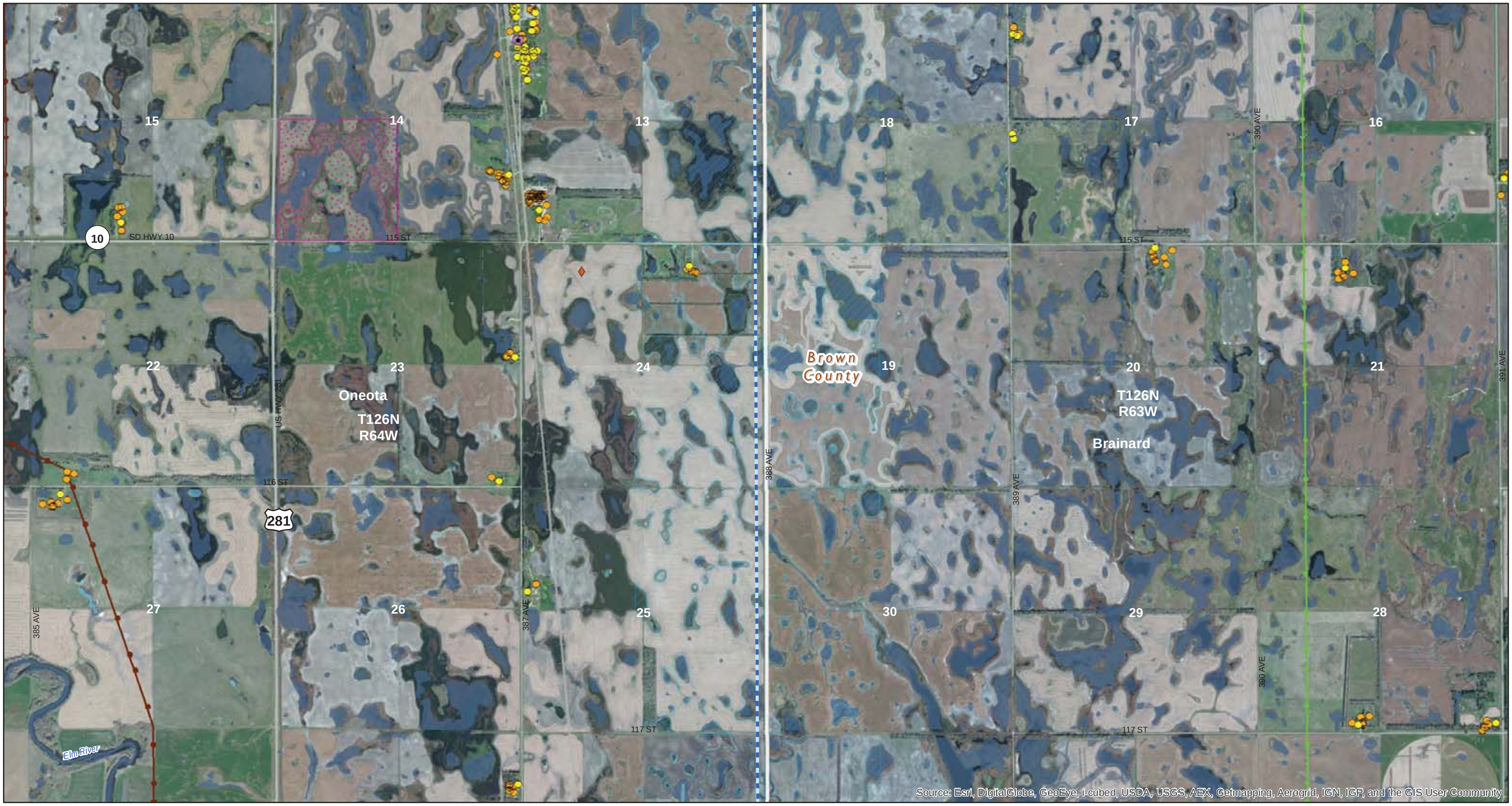

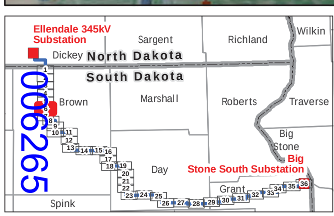

South Dakota Facility
Project End Point
Dwelling - Occupied
Dwelling - Unknown/Vacant
Ag/Other Structure
Gravel Pit/Mining
Cemetery
Church
School
Recreation
Utility
Communication Tower
NRHP Listed Property
Center Pivot
Noise Sensitive Land Use
Electric
Pipeline
State Park or Recreation Area
State School & Public Lands
Waterfowl Production Area (WPA)
National Wildlife Refuge (NWR)
Walk-In Areas (General Hunting Access)
National Conservation Easements (NRCS)
Private-use Airport
Public-use Airport
City Boundary
Township Boundary
County Boundary
State Boundary
Railroad
Abandoned Railroad
Highway
River or Stream
Waterbody
Wetland (NWI)
Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility.
Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.6
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

Miles
0 0.5

BSSE Big Stone South to Ellendale

Scale 1:24,000

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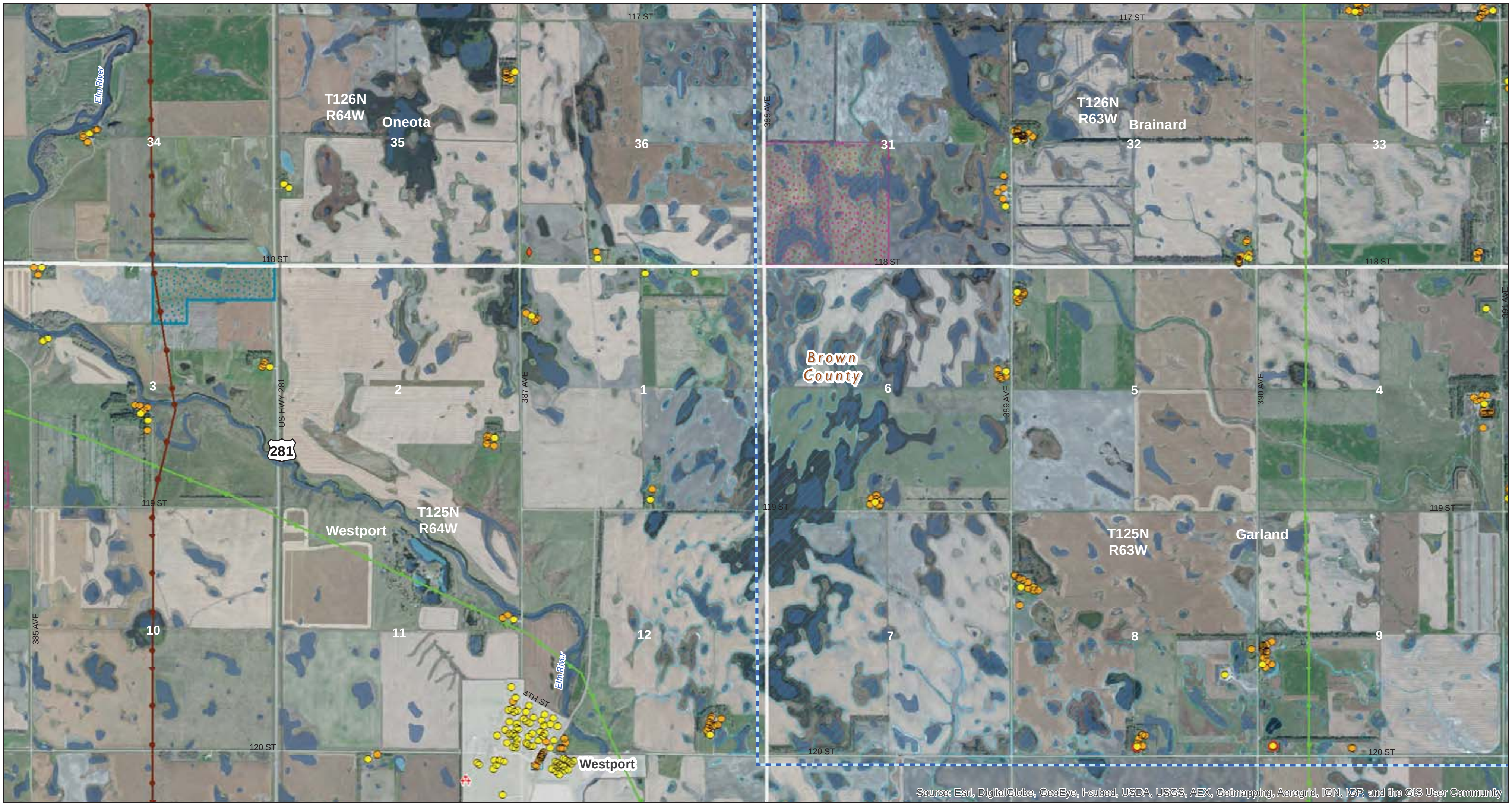

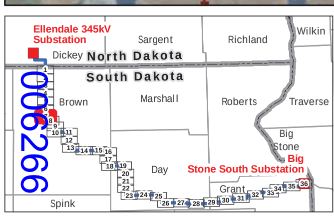

South Dakota Facility
Project End Point
Dwelling - Occupied
Dwelling - Unknown/Vacant
Ag/Other Structure
Gravel Pit/Mining
Cemetery
Church
School
Recreation
Utility
Communication Tower
NRHP Listed Property
Center Pivot
Noise Sensitive Land Use
Electric
Pipeline
State Park or Recreation Area
State School & Public Lands
Waterfowl Production Area (WPA)
National Wildlife Refuge (NWR)
Walk-In Areas (General Hunting Access)
National Conservation Easements (NRCS)
Private-use Airport
Public-use Airport
City Boundary
Township Boundary
County Boundary
State Boundary
Railroad
Abandoned Railroad
Highway
River or Stream
Waterbody
Wetland (NWI)
Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility. Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.7
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

N
0 0.5 Miles

BSS+E Big Stone South to Ellendale

Scale 1:24,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

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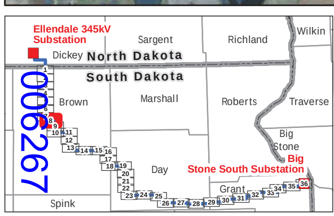

- South Dakota Facility
- Project End Point
- Dwelling - Occupied
- Dwelling - Unknown/Vacant
- Ag/Other Structure
- Gravel Pit/Mining
- Cemetery
- Church
- School
- Recreation
- Utility
- Communication Tower
- NRHP Listed Property
- Center Pivot
- Noise Sensitive Land Use
- Electric
- Pipeline
- State Park or Recreation Area
- State School & Public Lands
- Waterfowl Production Area (WPA)
- National Wildlife Refuge (NWR)
- Walk-In Areas (General Hunting Access)
- National Conservation Easements (NRCS)
- Private-use Airport
- Public-use Airport
- City Boundary
- Township Boundary
- County Boundary
- State Boundary
- Railroad
- Abandoned Railroad
- Highway
- River or Stream
- Waterbody
- Wetland (NWI)
- Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility. Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.8
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

Miles
0 0.5

BSS+E Big Stone South to Ellendale

Scale 1:24,000

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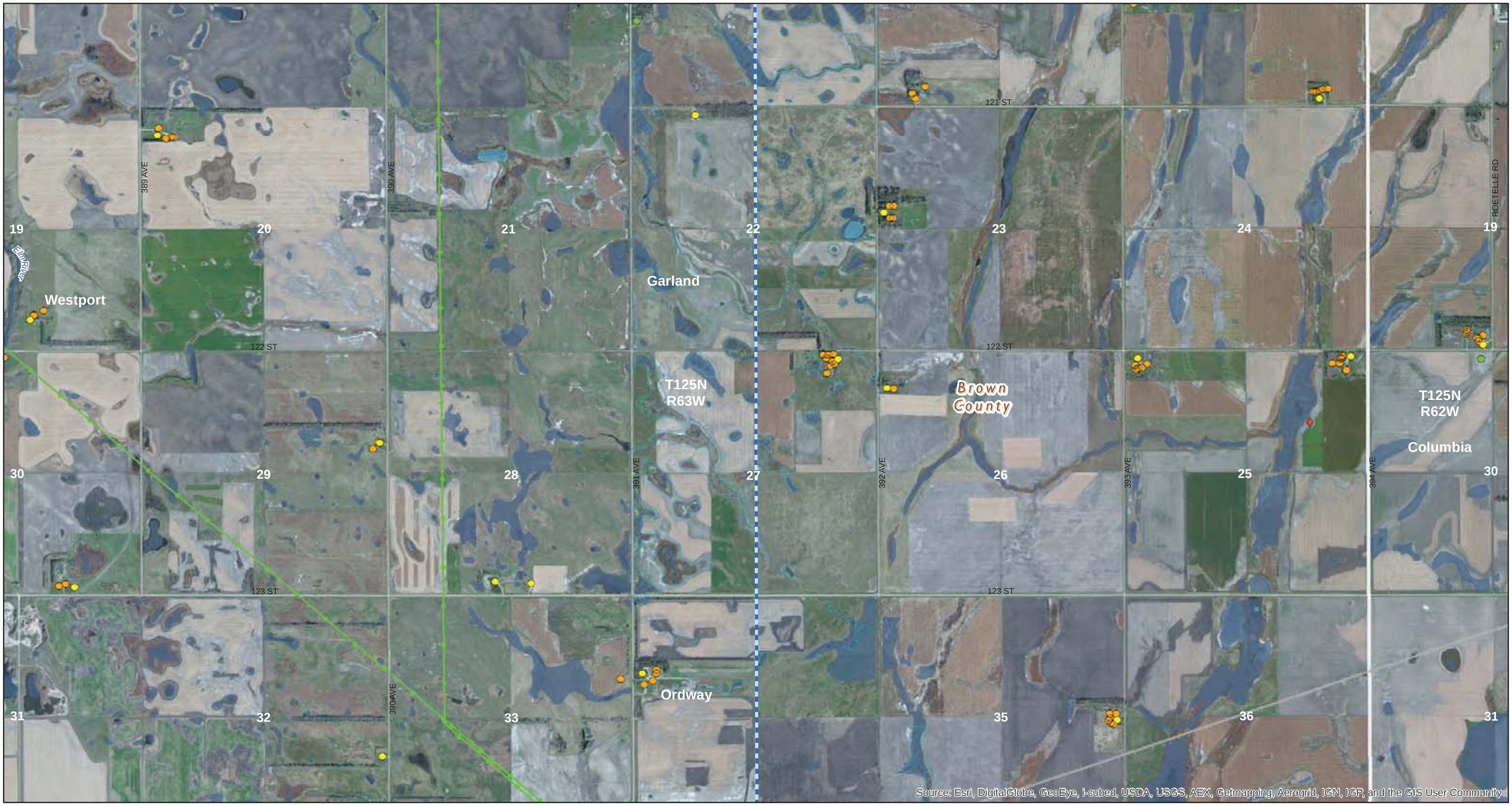
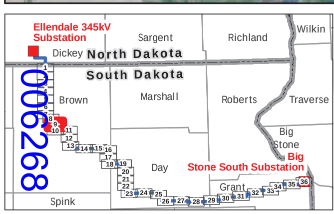




South Dakota Facility	Cemetery	Communication Tower	State Park or Recreation Area	Walk-In Areas (General Hunting Access)	City Boundary	Highway
Project End Point	Church	NRHP Listed Property	State School & Public Lands	National Conservation Easements (NRCS)	Township Boundary	River or Stream
Dwelling - Occupied	School	Center Pivot	Waterfowl Production Area (WPA)	Private-use Airport	County Boundary	Waterbody
Dwelling - Unknown/Vacant	Recreation	Noise Sensitive Land Use	National Wildlife Refuge (NWR)	Public-use Airport	State Boundary	Wetland (NWI)
Ag/Other Structure	Utility	Electric			Railroad	Wetland (Desktop Digitized)
Gravel Pit/Mining		Pipeline			Abandoned Railroad	

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility. Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

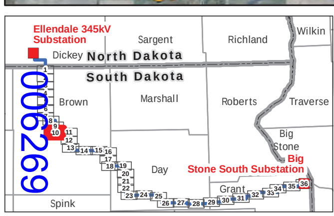
Exhibit 2.9
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

0 0.5 Miles

BSS+E Big Stone South to Ellendale

Scale 1:24,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd



- South Dakota Facility
- Project End Point
- Dwelling - Occupied
- Dwelling - Unknown/Vacant
- Ag/Other Structure
- Gravel Pit/Mining
- Cemetery
- Church
- School
- Recreation
- Utility
- Communication Tower
- NRHP Listed Property
- Center Pivot
- Noise Sensitive Land Use
- Electric
- Pipeline
- State Park or Recreation Area
- State School & Public Lands
- Waterfowl Production Area (WPA)
- National Wildlife Refuge (NWR)
- Walk-In Areas (General Hunting Access)
- National Conservation Easements (NRCS)
- Private-use Airport
- Public-use Airport
- City Boundary
- Township Boundary
- County Boundary
- State Boundary
- Railroad
- Abandoned Railroad
- Highway
- River or Stream
- Waterbody
- Wetland (NWI)
- Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility. Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.10
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

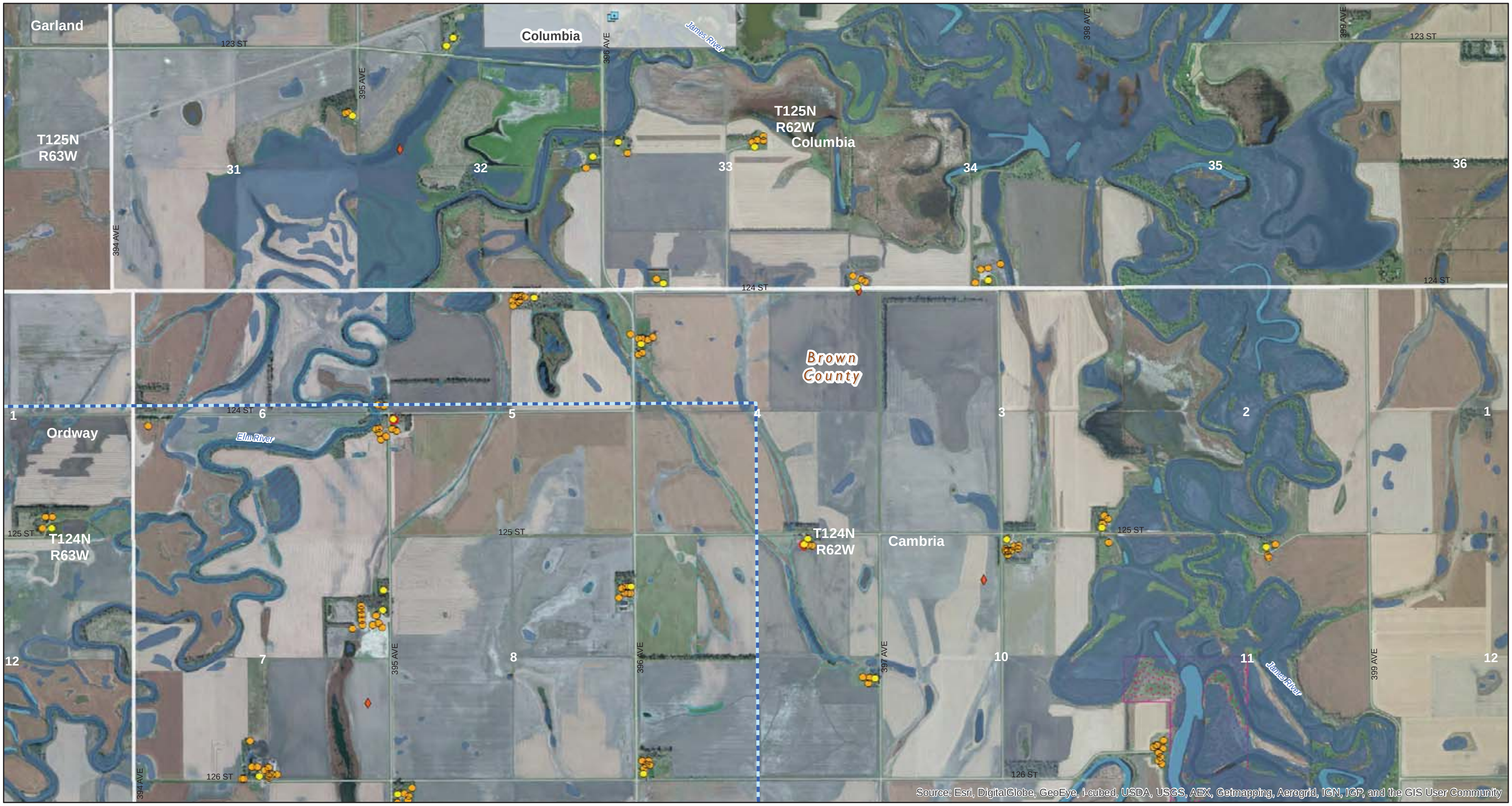
N
0 0.5 Miles

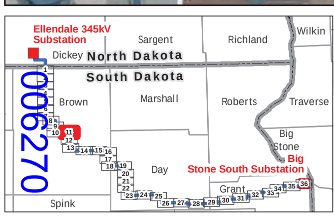
BSS+E Big Stone South to Ellendale

Scale 1:24,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

Date: 8/13/2013





South Dakota Facility
Project End Point
Dwelling - Occupied
Dwelling - Unknown/Vacant
Ag/Other Structure
Gravel Pit/Mining
Cemetery
Church
School
Recreation
Utility
Communication Tower
NRHP Listed Property
Center Pivot
Noise Sensitive Land Use
Electric
Pipeline
State Park or Recreation Area
State School & Public Lands
Waterfowl Production Area (WPA)
National Wildlife Refuge (NWR)
Walk-In Areas (General Hunting Access)
National Conservation Easements (NRCS)
Private-use Airport
Public-use Airport
City Boundary
Township Boundary
County Boundary
State Boundary
Railroad
Abandoned Railroad
Highway
River or Stream
Waterbody
Wetland (NWI)
Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility.
Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.11
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

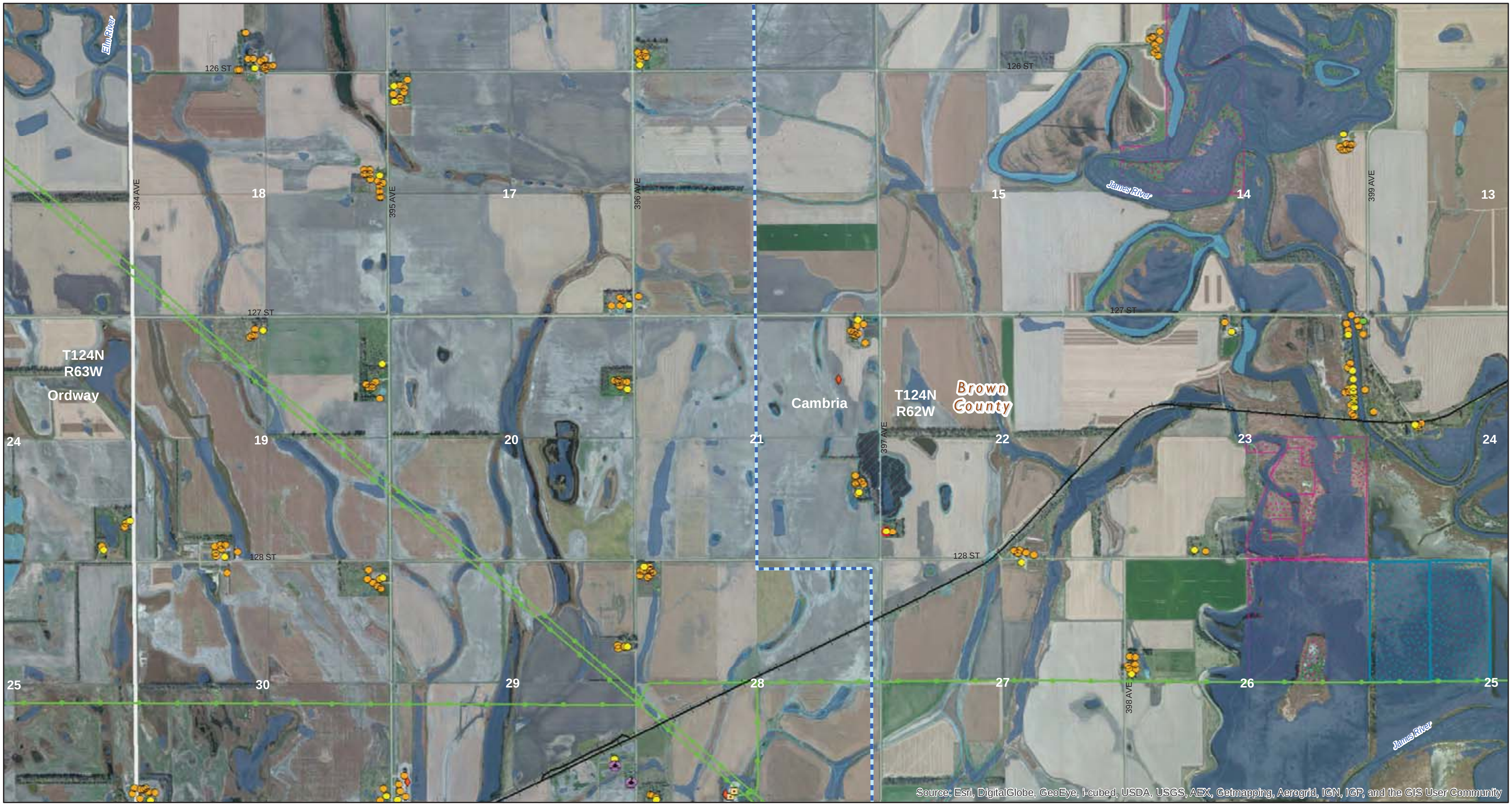
Miles
0 0.5

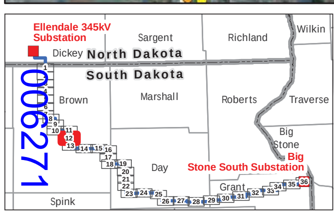
Scale 1:24,000

006270

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

Date: 8/13/2013





South Dakota Facility
Project End Point
Dwelling - Occupied
Dwelling - Unknown/Vacant
Ag/Other Structure
Gravel Pit/Mining
Cemetery
Church
School
Recreation
Utility
Communication Tower
NRHP Listed Property
Center Pivot
Noise Sensitive Land Use
Electric
Pipeline
State Park or Recreation Area
State School & Public Lands
Waterfowl Production Area (WPA)
National Wildlife Refuge (NWR)
Walk-In Areas (General Hunting Access)
National Conservation Easements (NRCS)
Private-use Airport
Public-use Airport
City Boundary
Township Boundary
County Boundary
State Boundary
Railroad
Abandoned Railroad
Highway
River or Stream
Waterbody
Wetland (NWI)
Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility.
Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.12
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

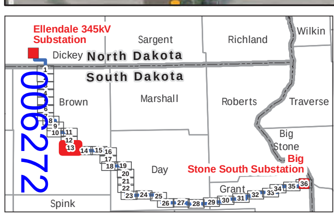
N
Miles
0 0.5

BSS+E
Big Stone South to Ellendale

Scale 1:24,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

Date: 8/13/2013



006272

South Dakota Facility
Project End Point
Dwelling - Occupied
Dwelling - Unknown/Vacant
Ag/Other Structure
Gravel Pit/Mining
Cemetery
Church
School
Recreation
Utility
Communication Tower
NRHP Listed Property
Center Pivot
Noise Sensitive Land Use
Electric
Pipeline
State Park or Recreation Area
State School & Public Lands
Waterfowl Production Area (WPA)
National Wildlife Refuge (NWR)
Walk-In Areas (General Hunting Access)
National Conservation Easements (NRCS)
Private-use Airport
Public-use Airport
City Boundary
Township Boundary
County Boundary
State Boundary
Railroad
Abandoned Railroad
Highway
River or Stream
Waterbody
Wetland (NWI)
Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility. Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.13
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

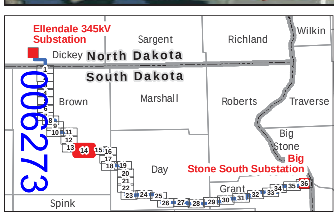
Miles
0 0.5

BSSE Big Stone South to Ellendale

Scale 1:24,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

Date: 8/13/2013



000273

- South Dakota Facility
- Project End Point
- Dwelling - Occupied
- Dwelling - Unknown/Vacant
- Ag/Other Structure
- Gravel Pit/Mining
- Cemetery
- Church
- School
- Recreation
- Utility
- Communication Tower
- NRHP Listed Property
- Center Pivot
- Noise Sensitive Land Use
- Electric
- Pipeline
- State Park or Recreation Area
- State School & Public Lands
- Waterfowl Production Area (WPA)
- National Wildlife Refuge (NWR)
- Walk-In Areas (General Hunting Access)
- National Conservation Easements (NRCS)
- Private-use Airport
- Public-use Airport
- City Boundary
- Township Boundary
- County Boundary
- State Boundary
- Railroad
- Abandoned Railroad
- Highway
- River or Stream
- Waterbody
- Wetland (NWI)
- Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility. Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.14
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

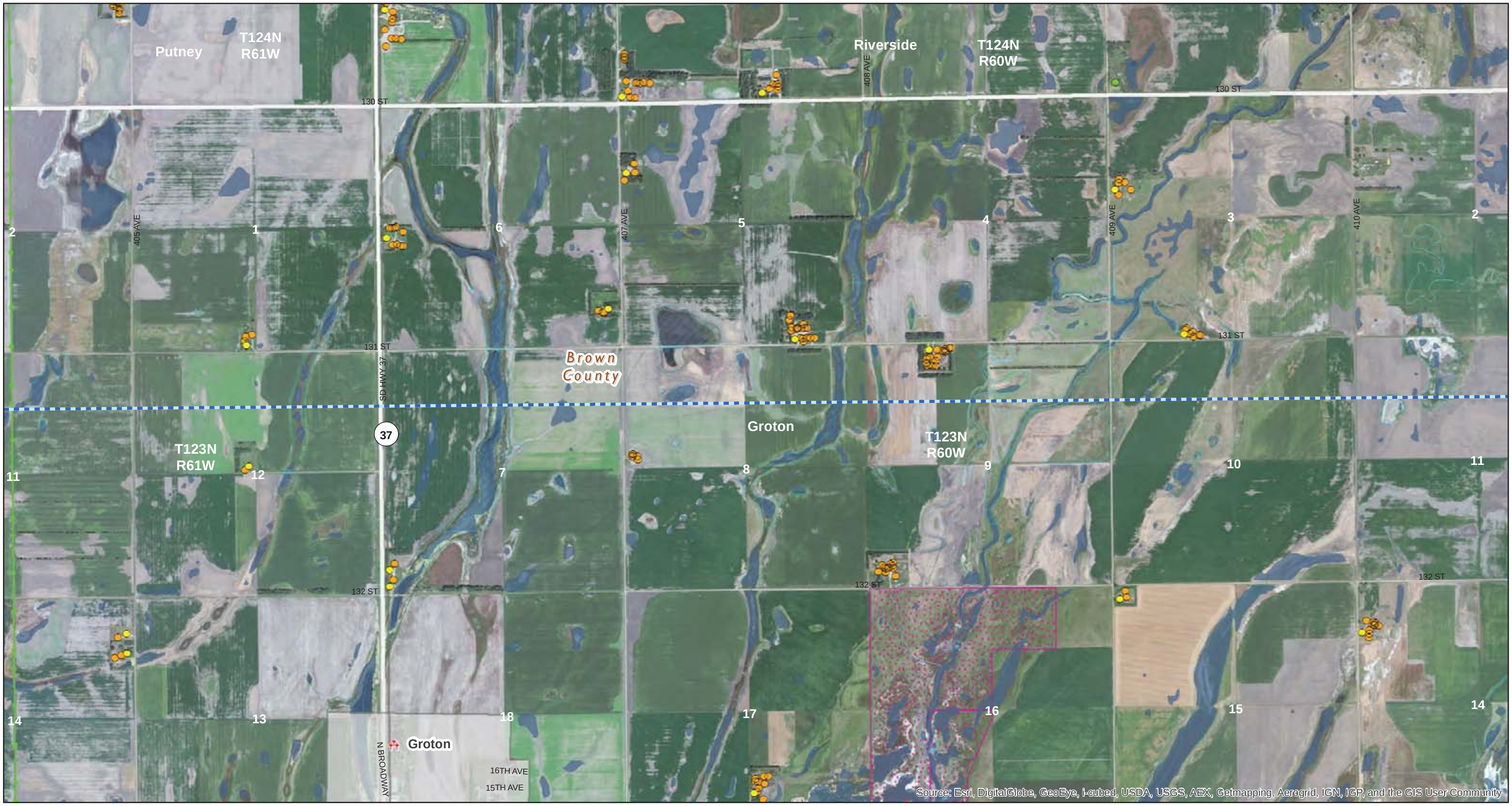
Miles
0 0.5

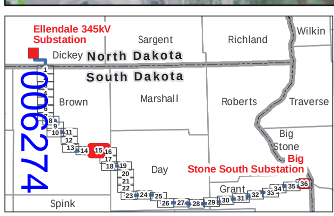
BSS+E Big Stone South to Ellendale

Scale 1:24,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

Date: 8/13/2013





South Dakota Facility
Project End Point
Dwelling - Occupied
Dwelling - Unknown/Vacant
Ag/Other Structure
Gravel Pit/Mining
Cemetery
Church
School
Recreation
Utility
Communication Tower
NRHP Listed Property
Center Pivot
Noise Sensitive Land Use
Electric
Pipeline
State Park or Recreation Area
State School & Public Lands
Waterfowl Production Area (WPA)
National Wildlife Refuge (NWR)
Walk-In Areas (General Hunting Access)
National Conservation Easements (NRCS)
Private-use Airport
Public-use Airport
City Boundary
Township Boundary
County Boundary
State Boundary
Railroad
Abandoned Railroad
Highway
River or Stream
Waterbody
Wetland (NWI)
Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility. Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.15
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

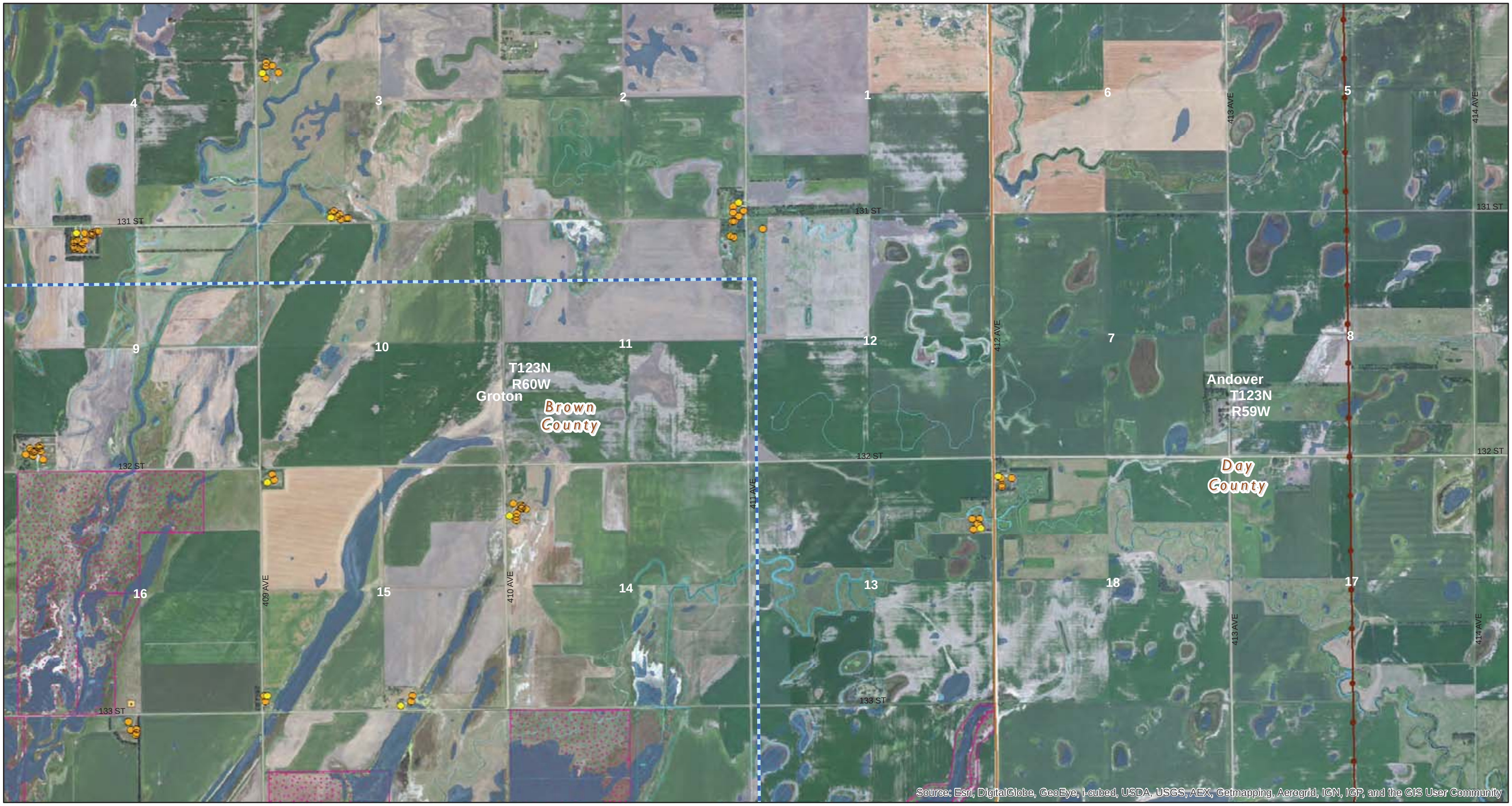
N
Miles
0 0.5

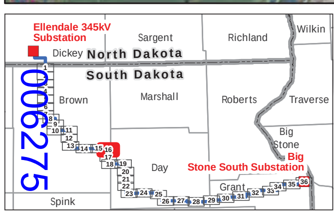
BSS+E Big Stone South to Ellendale

Scale 1:24,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

Date: 8/13/2013





South Dakota Facility
Project End Point
Dwelling - Occupied
Dwelling - Unknown/Vacant
Ag/Other Structure
Gravel Pit/Mining
Cemetery
Church
School
Recreation
Utility
Communication Tower
NRHP Listed Property
Center Pivot
Noise Sensitive Land Use
Electric
Pipeline
State Park or Recreation Area
State School & Public Lands
Waterfowl Production Area (WPA)
National Wildlife Refuge (NWR)
Walk-In Areas (General Hunting Access)
National Conservation Easements (NRCS)
Private-use Airport
Public-use Airport
City Boundary
Township Boundary
County Boundary
State Boundary
Railroad
Abandoned Railroad
Highway
River or Stream
Waterbody
Wetland (NWI)
Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility. Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.16
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

N

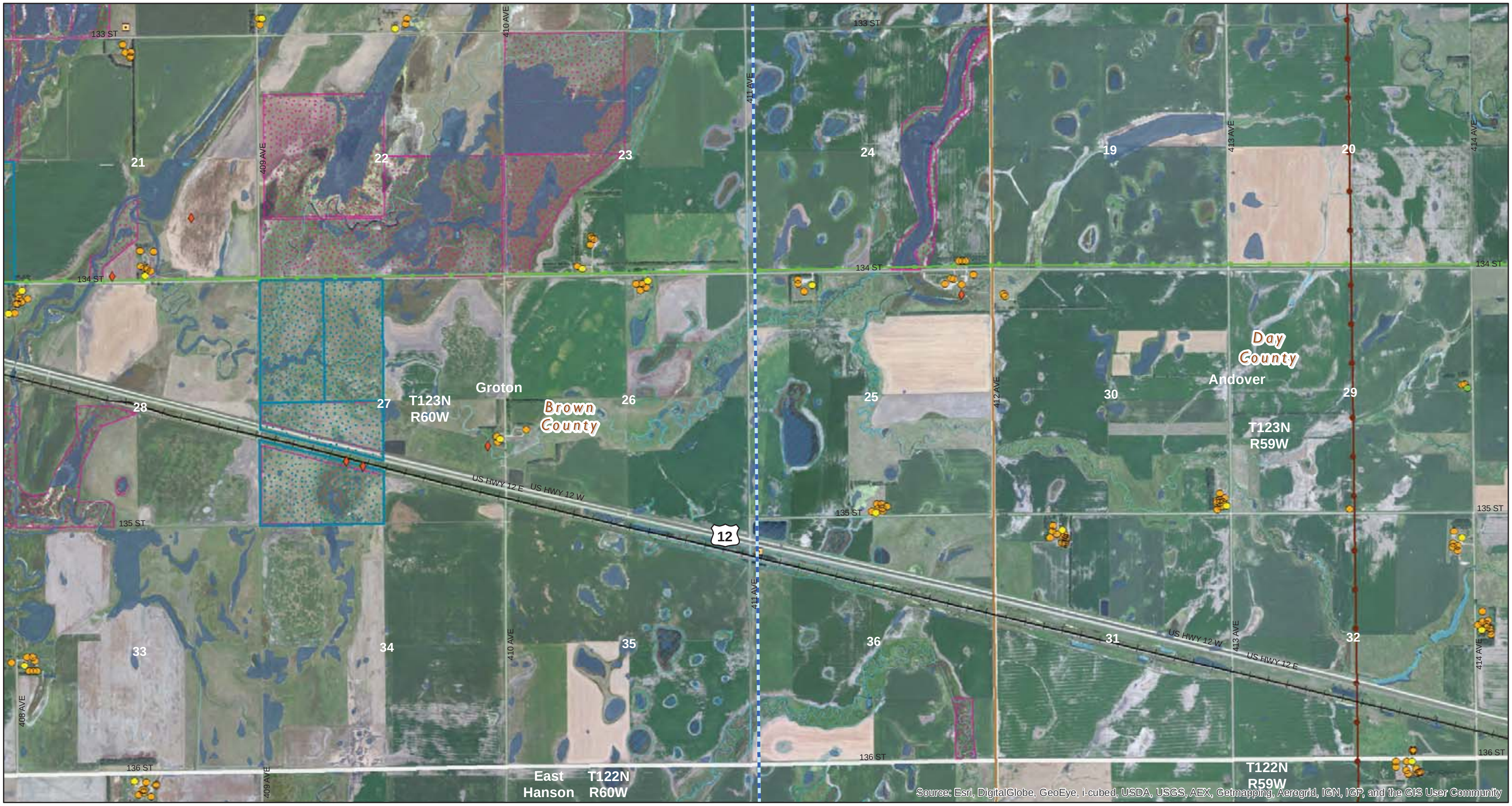
0 0.5 Miles

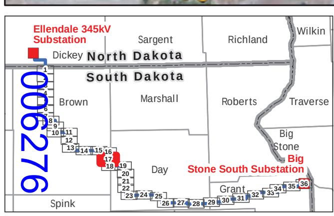
BSS+E Big Stone South to Ellendale

Scale 1:24,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

Date: 8/13/2013





- South Dakota Facility
- Project End Point
- Dwelling - Occupied
- Dwelling - Unknown/Vacant
- Ag/Other Structure
- Gravel Pit/Mining
- Cemetery
- Church
- School
- Recreation
- Utility
- Communication Tower
- NRHP Listed Property
- Center Pivot
- Noise Sensitive Land Use
- Electric
- Pipeline
- State Park or Recreation Area
- State School & Public Lands
- Waterfowl Production Area (WPA)
- National Wildlife Refuge (NWR)
- Walk-In Areas (General Hunting Access)
- National Conservation Easements (NRCS)
- Private-use Airport
- Public-use Airport
- City Boundary
- Township Boundary
- County Boundary
- State Boundary
- Railroad
- Abandoned Railroad
- Highway
- River or Stream
- Waterbody
- Wetland (NWI)
- Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility. Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.17
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

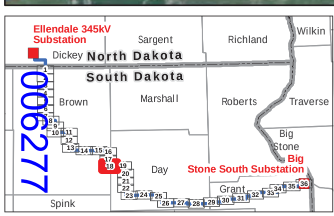
Miles
0 0.5

BSS+E Big Stone South to Ellendale

Scale 1:24,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

Date: 8/13/2013



South Dakota Facility
Project End Point
Dwelling - Occupied
Dwelling - Unknown/Vacant
Ag/Other Structure
Gravel Pit/Mining
Cemetery
Church
School
Recreation
Utility
Communication Tower
NRHP Listed Property
Center Pivot
Noise Sensitive Land Use
Electric
Pipeline
State Park or Recreation Area
State School & Public Lands
Waterfowl Production Area (WPA)
National Wildlife Refuge (NWR)
Walk-In Areas (General Hunting Access)
National Conservation Easements (NRCS)
Private-use Airport
Public-use Airport
City Boundary
Township Boundary
County Boundary
State Boundary
Railroad
Abandoned Railroad
Highway
River or Stream
Waterbody
Wetland (NWI)
Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility. Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.18
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

N

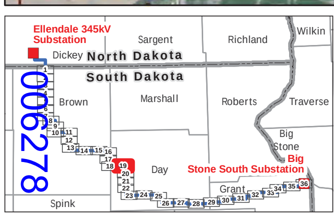
0 0.5 Miles

BSSE Big Stone South to Ellendale

Scale 1:24,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

Date: 8/13/2013



South Dakota Facility
Project End Point
Dwelling - Occupied
Dwelling - Unknown/Vacant
Ag/Other Structure
Gravel Pit/Mining
Cemetery
Church
School
Recreation
Utility
Communication Tower
NRHP Listed Property
Center Pivot
Noise Sensitive Land Use
Electric
Pipeline
State Park or Recreation Area
State School & Public Lands
Waterfowl Production Area (WPA)
National Wildlife Refuge (NWR)
Walk-In Areas (General Hunting Access)
National Conservation Easements (NRCS)
Private-use Airport
Public-use Airport
City Boundary
Township Boundary
County Boundary
State Boundary
Railroad
Abandoned Railroad
Highway
River or Stream
Waterbody
Wetland (NWI)
Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility. Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.19
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

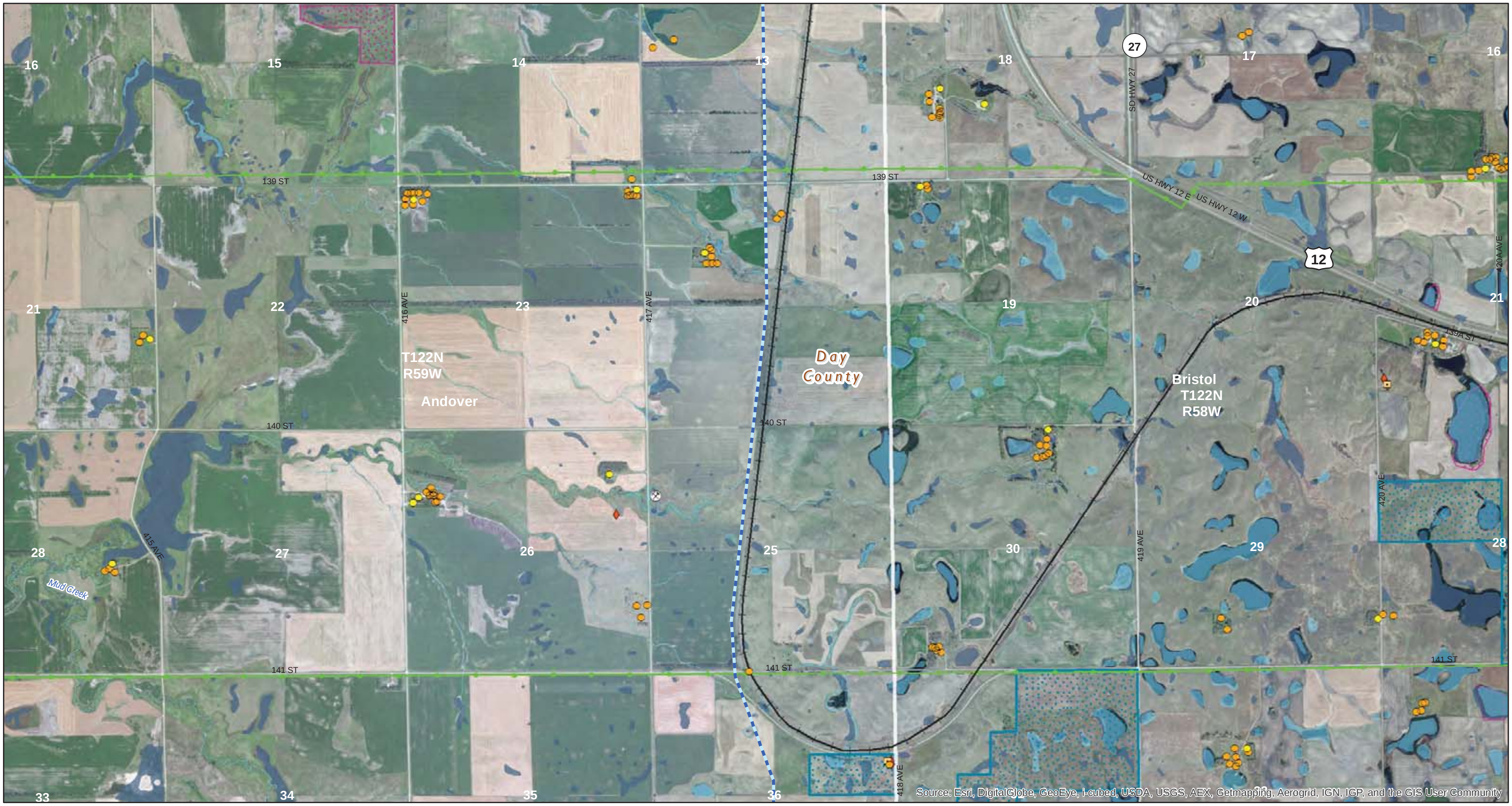
Miles
0 0.5

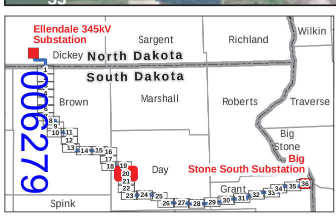
BSS+E Big Stone South to Ellendale

Scale 1:24,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

Date: 8/13/2013





006279

- South Dakota Facility
- Project End Point
- Dwelling - Occupied
- Dwelling - Unknown/Vacant
- Ag/Other Structure
- Gravel Pit/Mining
- Cemetery
- Church
- School
- Recreation
- Utility
- Communication Tower
- NRHP Listed Property
- Center Pivot
- Noise Sensitive Land Use
- Electric
- Pipeline
- State Park or Recreation Area
- State School & Public Lands
- Waterfowl Production Area (WPA)
- National Wildlife Refuge (NWR)
- Walk-In Areas (General Hunting Access)
- National Conservation Easements (NRCS)
- Private-use Airport
- Public-use Airport
- City Boundary
- Township Boundary
- County Boundary
- State Boundary
- Railroad
- Abandoned Railroad
- Highway
- River or Stream
- Waterbody
- Wetland (NWI)
- Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility. Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.20
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

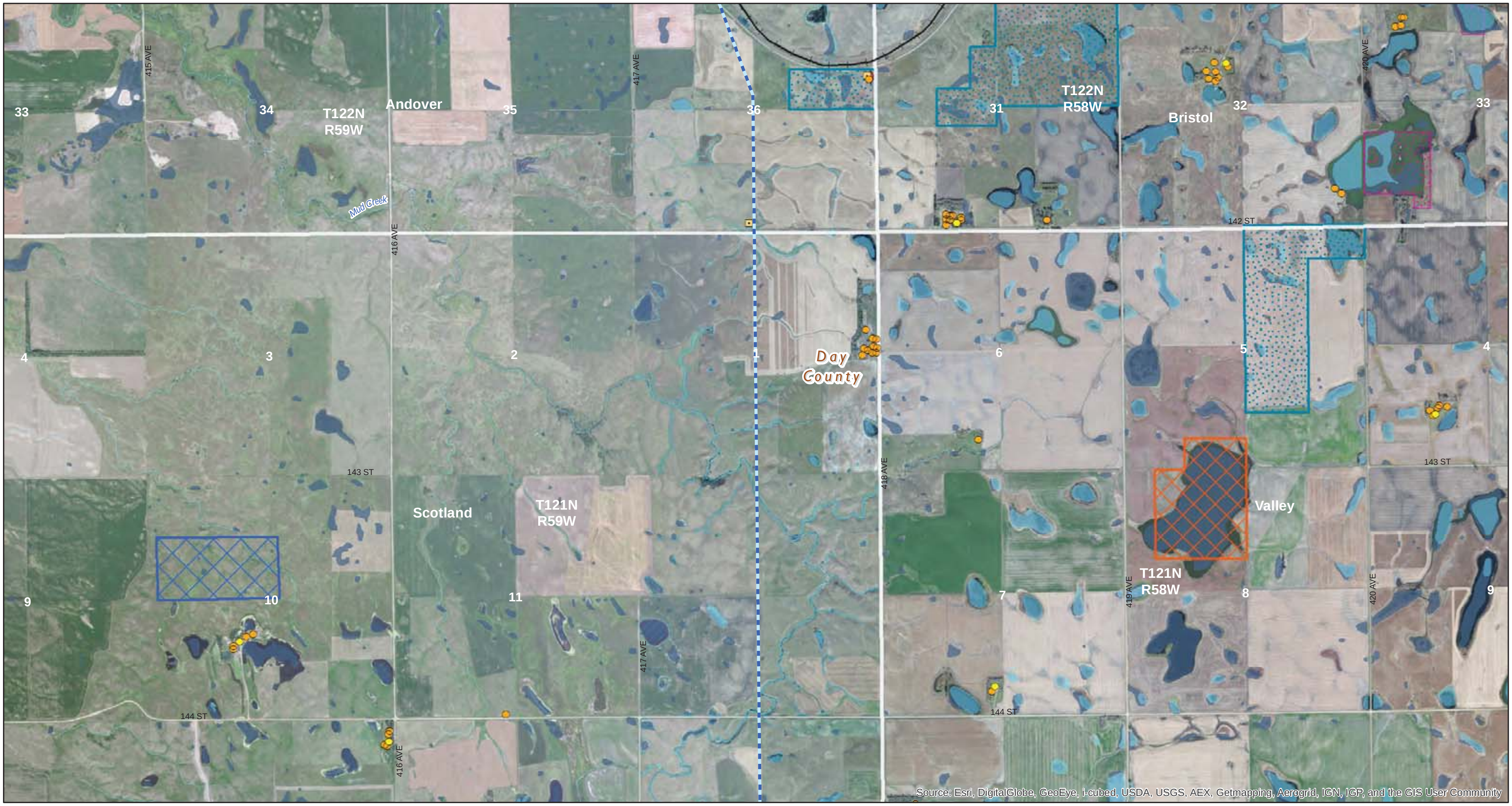
0 0.5 Miles

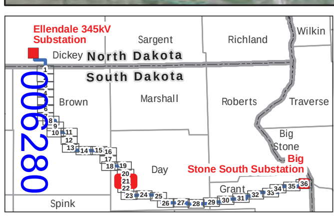
BSS-E Big Stone South to Ellendale

Scale 1:24,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

Date: 8/13/2013





South Dakota Facility
Project End Point
Dwelling - Occupied
Dwelling - Unknown/Vacant
Ag/Other Structure
Gravel Pit/Mining
Cemetery
Church
School
Recreation
Utility
Communication Tower
NRHP Listed Property
Center Pivot
Noise Sensitive Land Use
Electric
Pipeline
State Park or Recreation Area
State School & Public Lands
Waterfowl Production Area (WPA)
National Wildlife Refuge (NWR)
Walk-In Areas (General Hunting Access)
National Conservation Easements (NRCS)
Private-use Airport
Public-use Airport
City Boundary
Township Boundary
County Boundary
State Boundary
Railroad
Abandoned Railroad
Highway
River or Stream
Waterbody
Wetland (NWI)
Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility.
Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.21
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

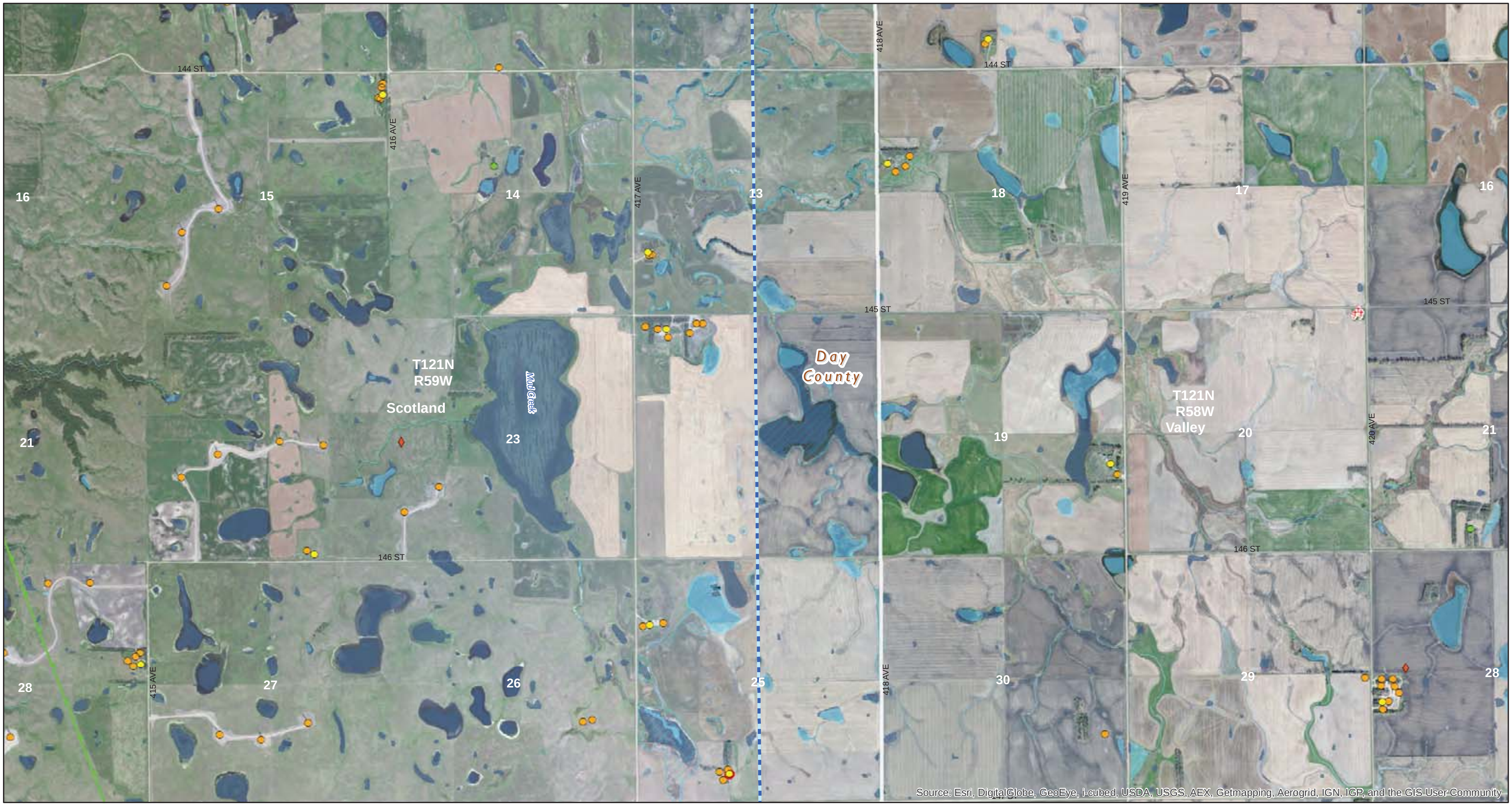
Miles
0 0.5

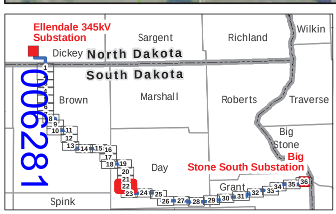
BSSE
Big Stone South to Ellendale

Scale 1:24,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

Date: 8/13/2013





000281

- South Dakota Facility
- Project End Point
- Dwelling - Occupied
- Dwelling - Unknown/Vacant
- Ag/Other Structure
- Gravel Pit/Mining
- Cemetery
- Church
- School
- Recreation
- Utility
- Communication Tower
- NRHP Listed Property
- Center Pivot
- Noise Sensitive Land Use
- Electric
- Pipeline
- State Park or Recreation Area
- State School & Public Lands
- Waterfowl Production Area (WPA)
- National Wildlife Refuge (NWR)
- Walk-In Areas (General Hunting Access)
- National Conservation Easements (NRCS)
- Private-use Airport
- Public-use Airport
- City Boundary
- Township Boundary
- County Boundary
- State Boundary
- Railroad
- Abandoned Railroad
- Highway
- River or Stream
- Waterbody
- Wetland (NWI)
- Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility. Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.22
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

N

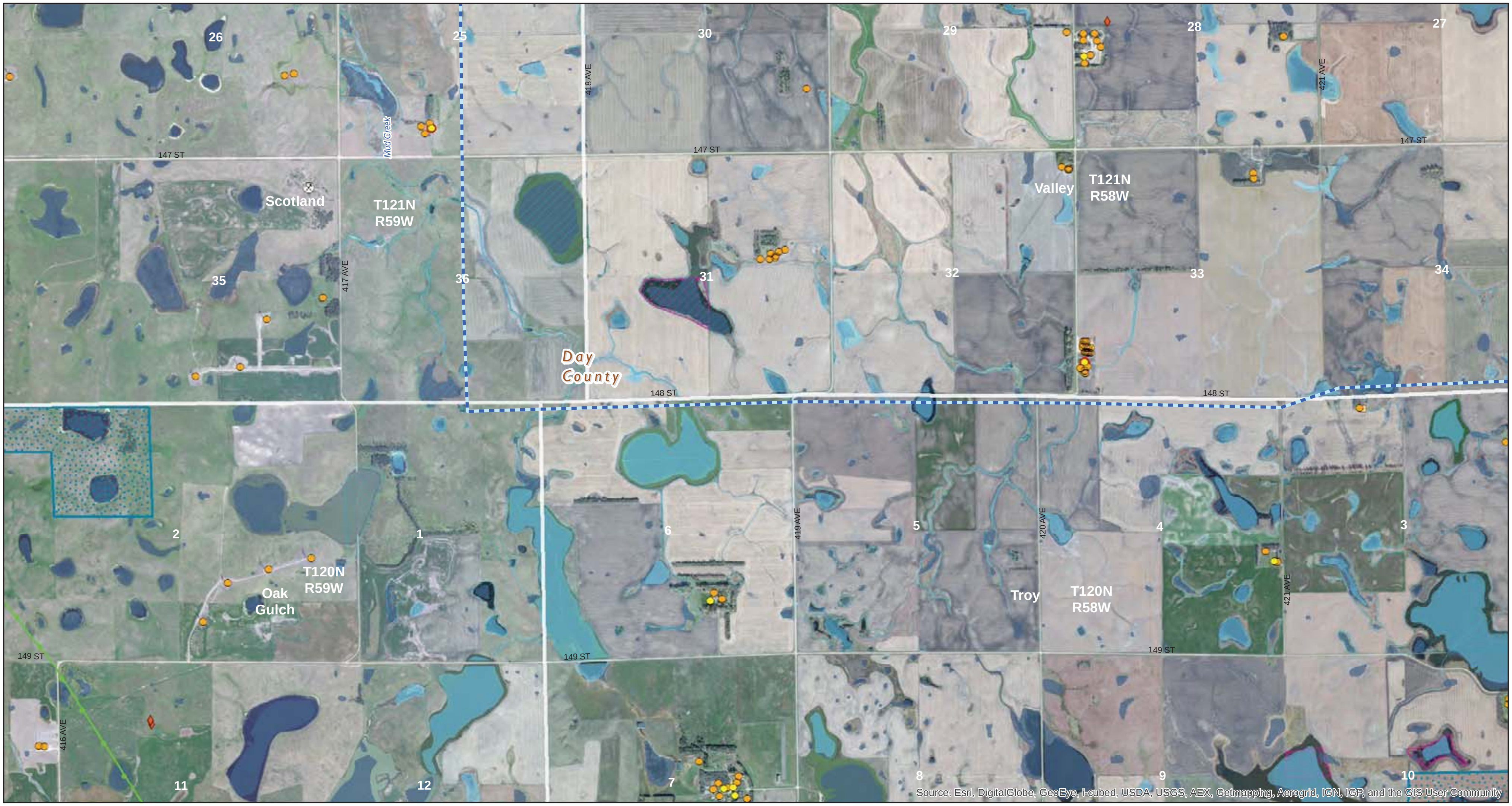
0 0.5 Miles

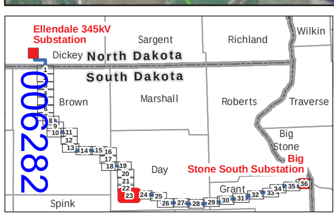
BSS+E Big Stone South to Ellendale

Scale 1:24,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

Date: 8/13/2013





South Dakota Facility
Project End Point
Dwelling - Occupied
Dwelling - Unknown/Vacant
Ag/Other Structure
Gravel Pit/Mining
Cemetery
Church
School
Recreation
Utility
Communication Tower
NRHP Listed Property
Center Pivot
Noise Sensitive Land Use
Electric
Pipeline
State Park or Recreation Area
State School & Public Lands
Waterfowl Production Area (WPA)
National Wildlife Refuge (NWR)
Walk-In Areas (General Hunting Access)
National Conservation Easements (NRCS)
Private-use Airport
Public-use Airport
City Boundary
Township Boundary
County Boundary
State Boundary
Railroad
Abandoned Railroad
Highway
River or Stream
Waterbody
Wetland (NWI)
Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility. Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.23

Detail of South Dakota Facility

Big Stone South to Ellendale

345 kV Transmission Line Project

Miles

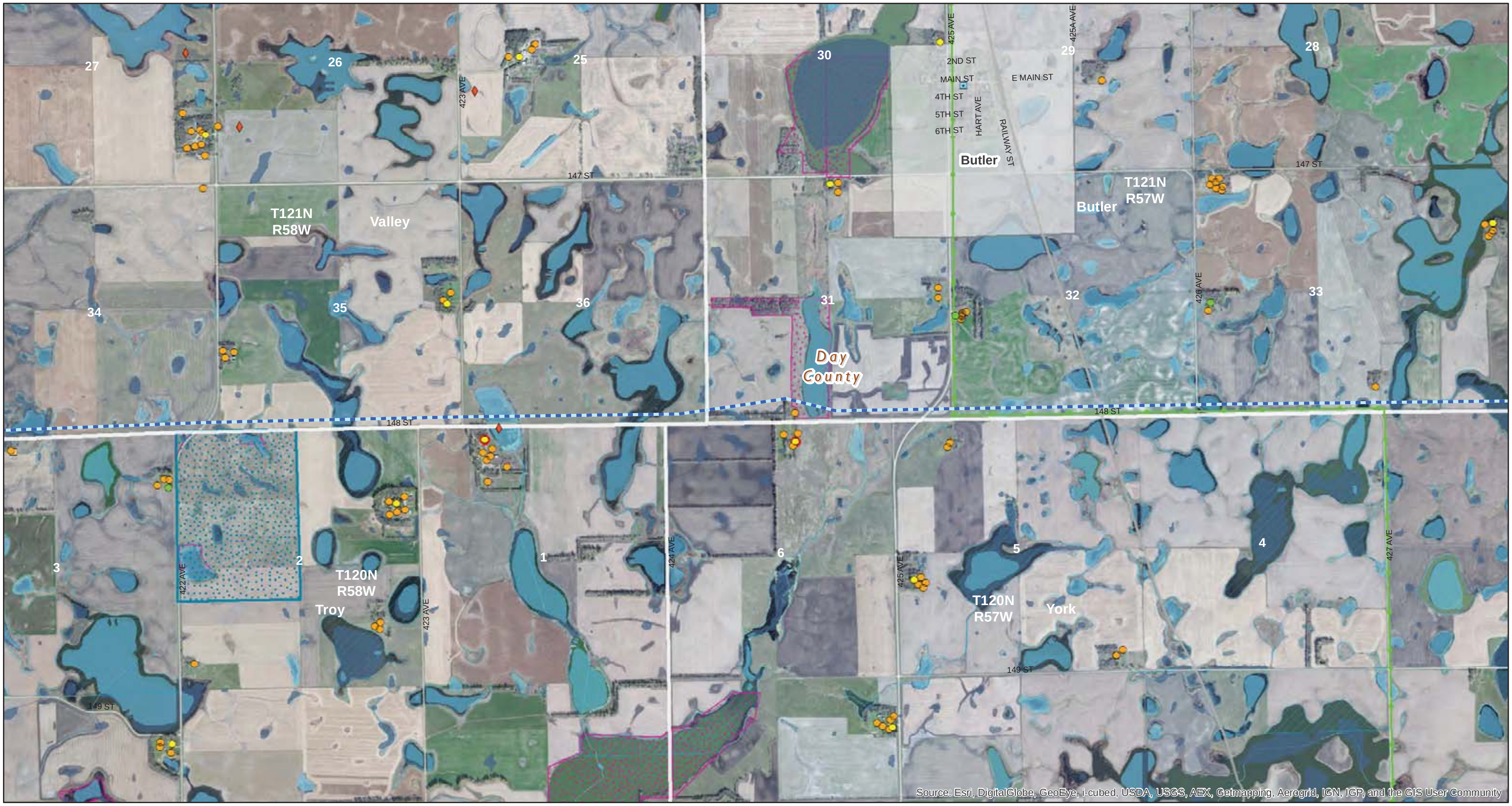
0 0.5

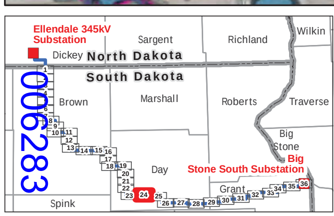
BSSE Big Stone South to Ellendale

Scale 1:24,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

Date: 8/13/2013





- South Dakota Facility
- Project End Point
- Dwelling - Occupied
- Dwelling - Unknown/Vacant
- Ag/Other Structure
- Gravel Pit/Mining
- Cemetery
- Church
- School
- Recreation
- Utility
- Communication Tower
- NRHP Listed Property
- Center Pivot
- Noise Sensitive Land Use
- Electric
- Pipeline
- State Park or Recreation Area
- State School & Public Lands
- Waterfowl Production Area (WPA)
- National Wildlife Refuge (NWR)
- Walk-In Areas (General Hunting Access)
- National Conservation Easements (NRCS)
- Private-use Airport
- Public-use Airport
- City Boundary
- Township Boundary
- County Boundary
- State Boundary
- Railroad
- Abandoned Railroad
- Highway
- River or Stream
- Waterbody
- Wetland (NWI)
- Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility. Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.24
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

N

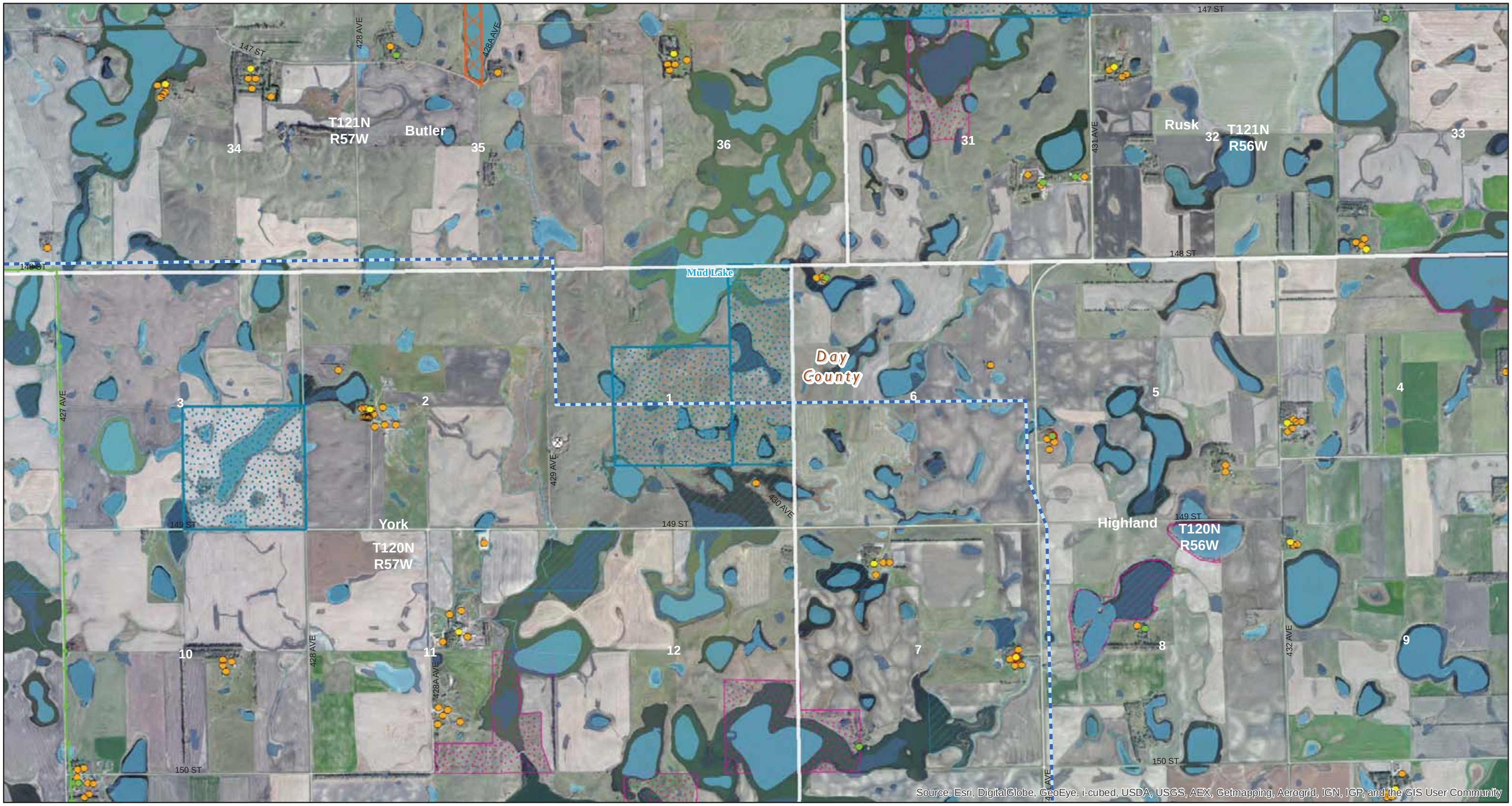
0 0.5 Miles

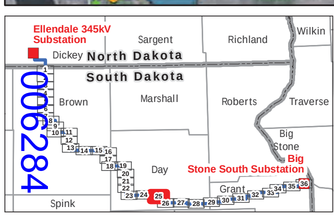
BSSE Big Stone South to Ellendale

Scale 1:24,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

Date: 8/13/2013





South Dakota Facility
Project End Point
Dwelling - Occupied
Dwelling - Unknown/Vacant
Ag/Other Structure
Gravel Pit/Mining
Cemetery
Church
School
Recreation
Utility
Communication Tower
NRHP Listed Property
Center Pivot
Noise Sensitive Land Use
Electric
Pipeline
State Park or Recreation Area
State School & Public Lands
Waterfowl Production Area (WPA)
National Wildlife Refuge (NWR)
Walk-In Areas (General Hunting Access)
National Conservation Easements (NRCS)
Private-use Airport
Public-use Airport
City Boundary
Township Boundary
County Boundary
State Boundary
Railroad
Abandoned Railroad
Highway
River or Stream
Waterbody
Wetland (NWI)
Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility. Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.25
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

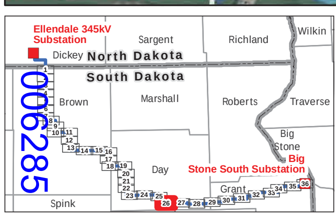
N
0 0.5 Miles

BSSE Big Stone South to Ellendale

Scale 1:24,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

Date: 8/13/2013



South Dakota Facility
Project End Point
Dwelling - Occupied
Dwelling - Unknown/Vacant
Ag/Other Structure
Gravel Pit/Mining
Cemetery
Church
School
Recreation
Utility
Communication Tower
NRHP Listed Property
Center Pivot
Noise Sensitive Land Use
Electric
Pipeline
State Park or Recreation Area
State School & Public Lands
Waterfowl Production Area (WPA)
National Wildlife Refuge (NWR)
Walk-In Areas (General Hunting Access)
National Conservation Easements (NRCS)
Private-use Airport
Public-use Airport
City Boundary
Township Boundary
County Boundary
State Boundary
Railroad
Abandoned Railroad
Highway
River or Stream
Waterbody
Wetland (NWI)
Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility. Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.26
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

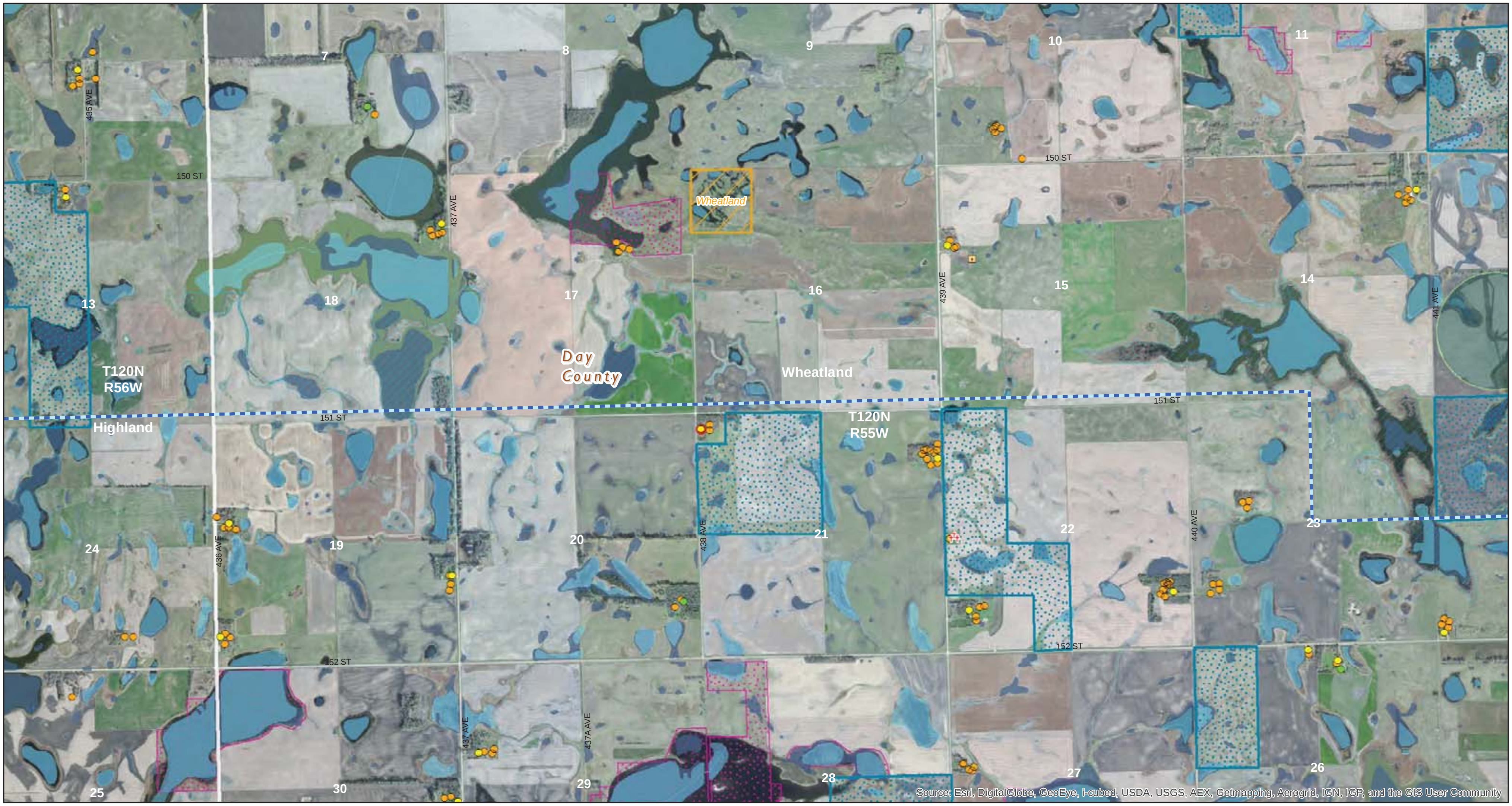
N
0 0.5 Miles

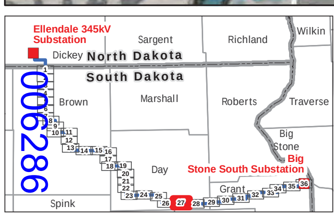
BSSE Big Stone South to Ellendale

Scale 1:24,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

Date: 8/13/2013





South Dakota Facility
Project End Point
Dwelling - Occupied
Dwelling - Unknown/Vacant
Ag/Other Structure
Gravel Pit/Mining
Cemetery
Church
School
Recreation
Utility
Communication Tower
NRHP Listed Property
Center Pivot
Noise Sensitive Land Use
Electric
Pipeline
State Park or Recreation Area
State School & Public Lands
Waterfowl Production Area (WPA)
National Wildlife Refuge (NWR)
Walk-In Areas (General Hunting Access)
National Conservation Easements (NRCS)
Private-use Airport
Public-use Airport
City Boundary
Township Boundary
County Boundary
State Boundary
Railroad
Abandoned Railroad
Highway
River or Stream
Waterbody
Wetland (NWI)
Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility. Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.27
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

Miles
0 0.5

BSSE
Big Stone South to Ellendale

Scale 1:24,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

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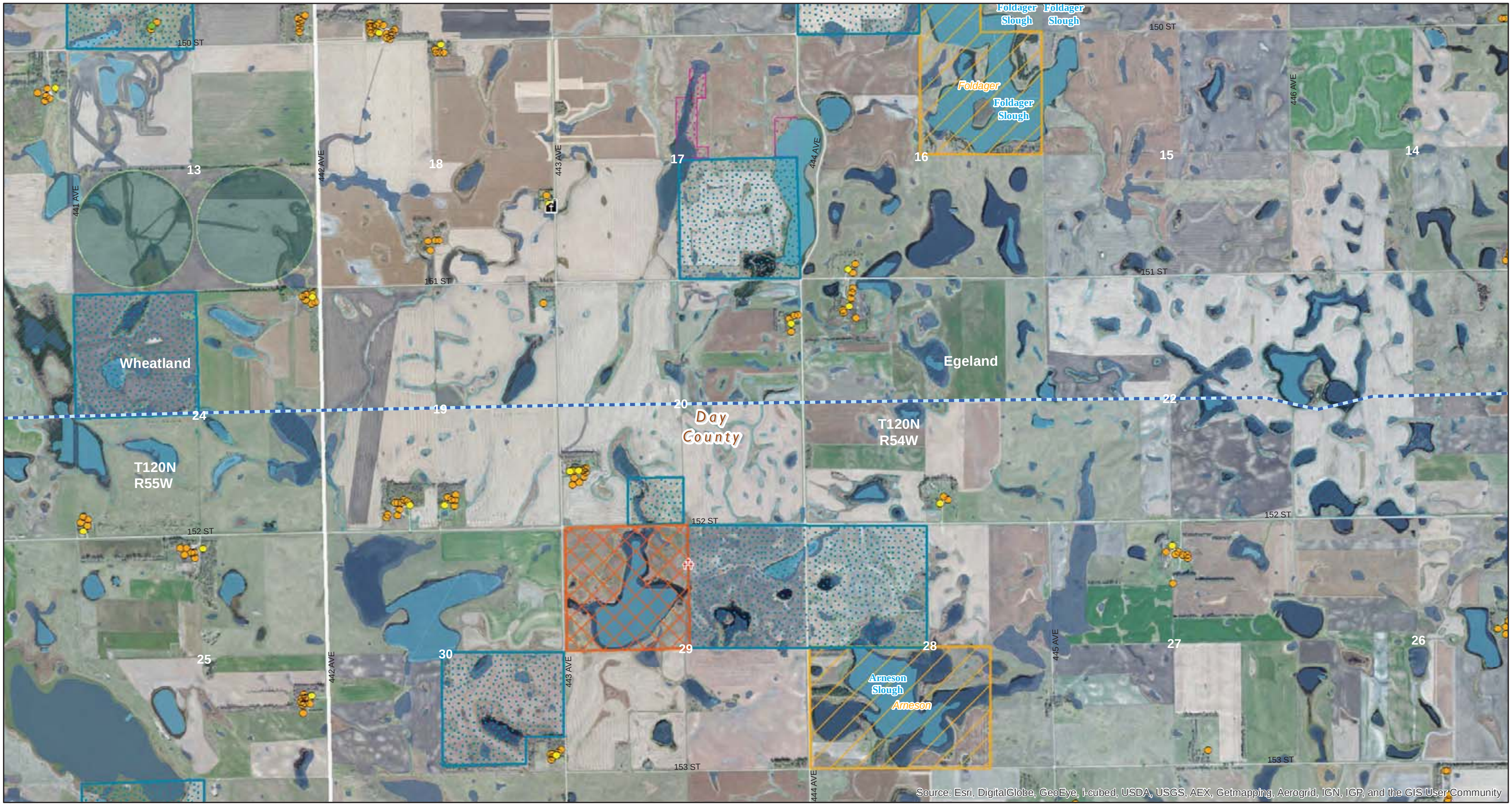

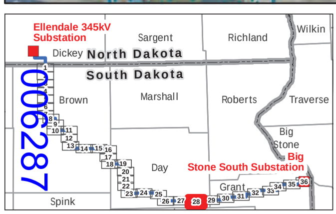

South Dakota Facility
Project End Point
Dwelling - Occupied
Dwelling - Unknown/Vacant
Ag/Other Structure
Gravel Pit/Mining
Cemetery
Church
School
Recreation
Utility
Communication Tower
NRHP Listed Property
Center Pivot
Noise Sensitive Land Use
Electric
Pipeline
State Park or Recreation Area
State School & Public Lands
Waterfowl Production Area (WPA)
National Wildlife Refuge (NWR)
Walk-In Areas (General Hunting Access)
National Conservation Easements (NRCS)
Private-use Airport
Public-use Airport
City Boundary
Township Boundary
County Boundary
State Boundary
Railroad
Abandoned Railroad
Highway
River or Stream
Waterbody
Wetland (NWI)
Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility.
Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.28
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

Miles
0 0.5

BSSE
Big Stone South to Ellendale

Scale 1:24,000

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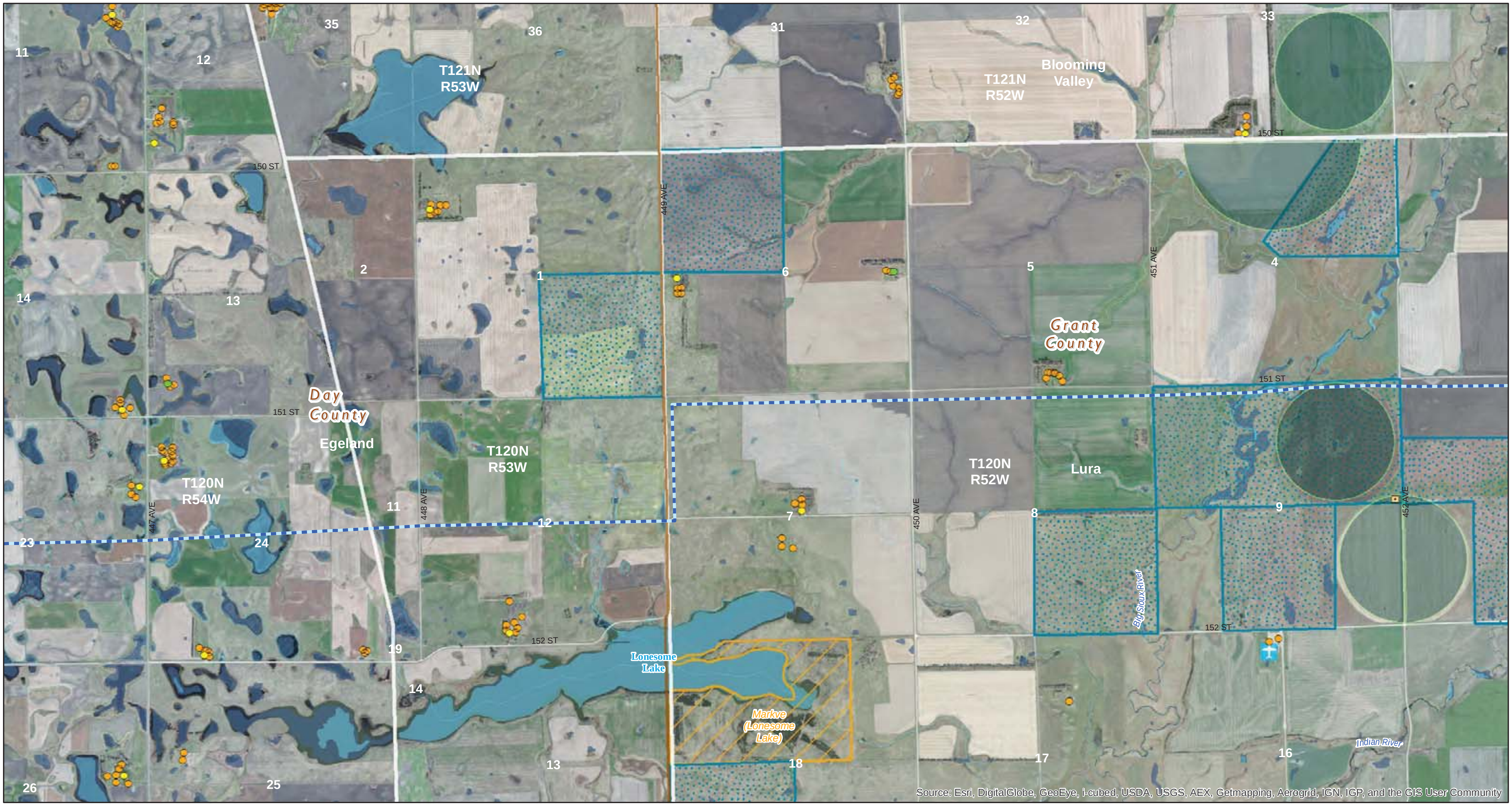
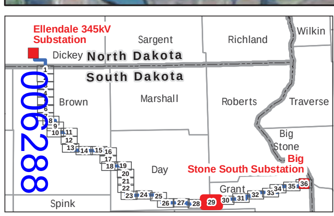
Date: 8/13/2013





South Dakota Facility
Project End Point
Dwelling - Occupied
Dwelling - Unknown/Vacant
Ag/Other Structure
Gravel Pit/Mining
Cemetery
Church
School
Recreation
Utility
Communication Tower
NRHP Listed Property
Center Pivot
Noise Sensitive Land Use
Electric
Pipeline
State Park or Recreation Area
State School & Public Lands
Waterfowl Production Area (WPA)
National Wildlife Refuge (NWR)
Walk-In Areas (General Hunting Access)
National Conservation Easements (NRCS)
Private-use Airport
Public-use Airport
City Boundary
Township Boundary
County Boundary
State Boundary
Railroad
Abandoned Railroad
Highway
River or Stream
Waterbody
Wetland (NWI)
Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility.
Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.29
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

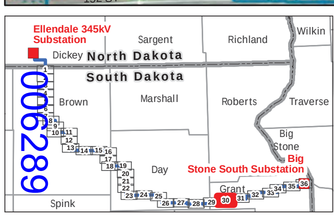
N
Miles
0 0.5

BSS+E
Big Stone South to Ellendale

Scale 1:24,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

Date: 8/13/2013



South Dakota Facility
Project End Point
Dwelling - Occupied
Dwelling - Unknown/Vacant
Ag/Other Structure
Gravel Pit/Mining
Cemetery
Church
School
Recreation
Utility
Communication Tower
NRHP Listed Property
Center Pivot
Noise Sensitive Land Use
Electric
Pipeline
State Park or Recreation Area
State School & Public Lands
Waterfowl Production Area (WPA)
National Wildlife Refuge (NWR)
Walk-In Areas (General Hunting Access)
National Conservation Easements (NRCS)
Private-use Airport
Public-use Airport
City Boundary
Township Boundary
County Boundary
State Boundary
Railroad
Abandoned Railroad
Highway
River or Stream
Waterbody
Wetland (NWI)
Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility. Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.30
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

Miles
0 0.5

BSSE
Big Stone South to Ellendale

Scale 1:24,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

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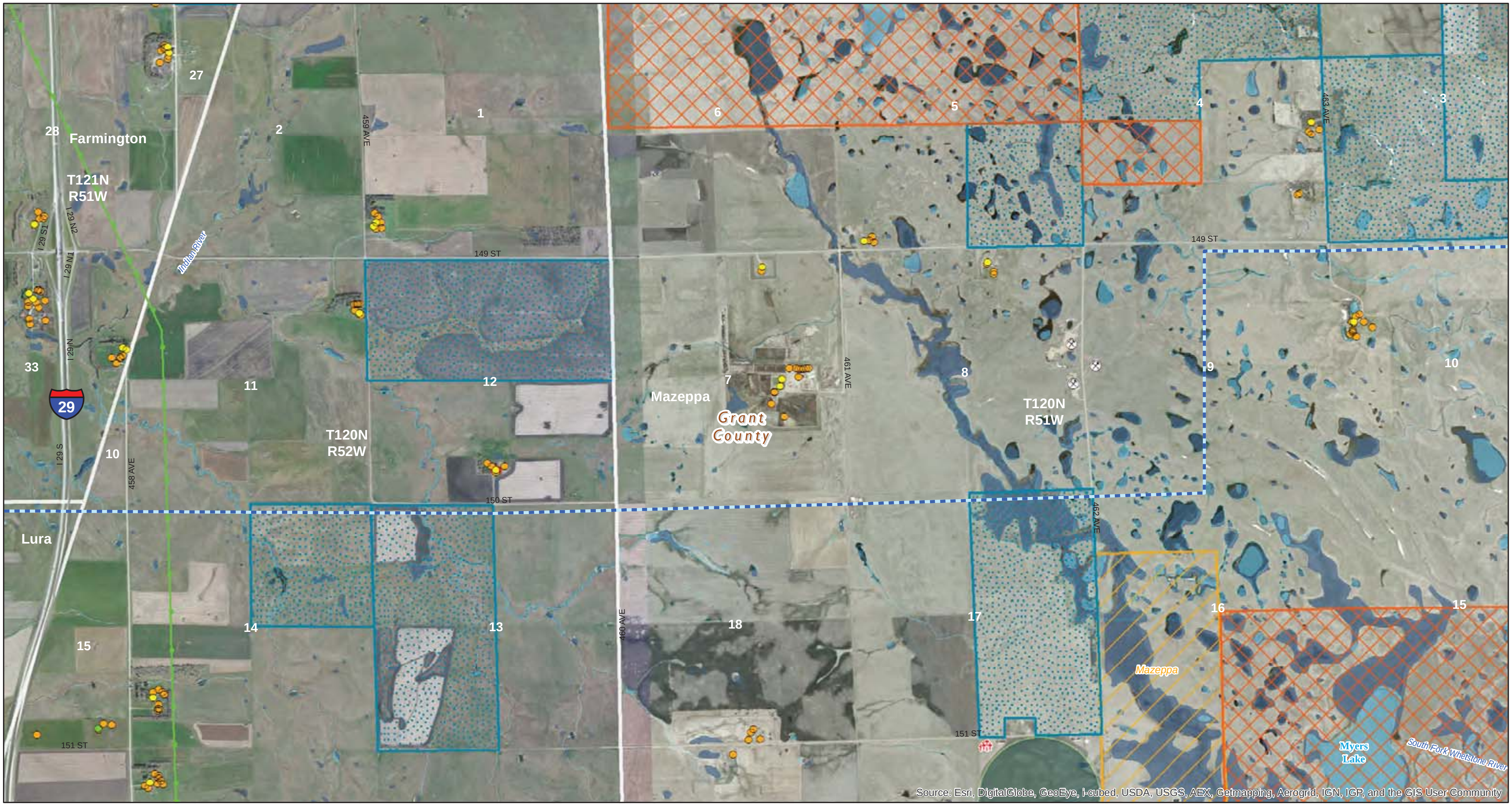
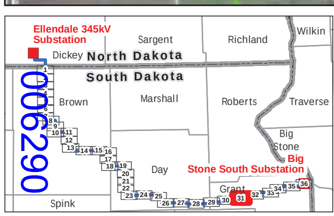




- South Dakota Facility
- Project End Point
- Dwelling - Occupied
- Dwelling - Unknown/Vacant
- Ag/Other Structure
- Gravel Pit/Mining
- Cemetery
- Church
- School
- Recreation
- Utility
- Communication Tower
- NRHP Listed Property
- Center Pivot
- Noise Sensitive Land Use
- Electric
- Pipeline
- State Park or Recreation Area
- State School & Public Lands
- Waterfowl Production Area (WPA)
- National Wildlife Refuge (NWR)
- Walk-In Areas (General Hunting Access)
- National Conservation Easements (NRCS)
- Private-use Airport
- Public-use Airport
- City Boundary
- Township Boundary
- County Boundary
- State Boundary
- Railroad
- Abandoned Railroad
- Highway
- River or Stream
- Waterbody
- Wetland (NWI)
- Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility.
Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.31
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

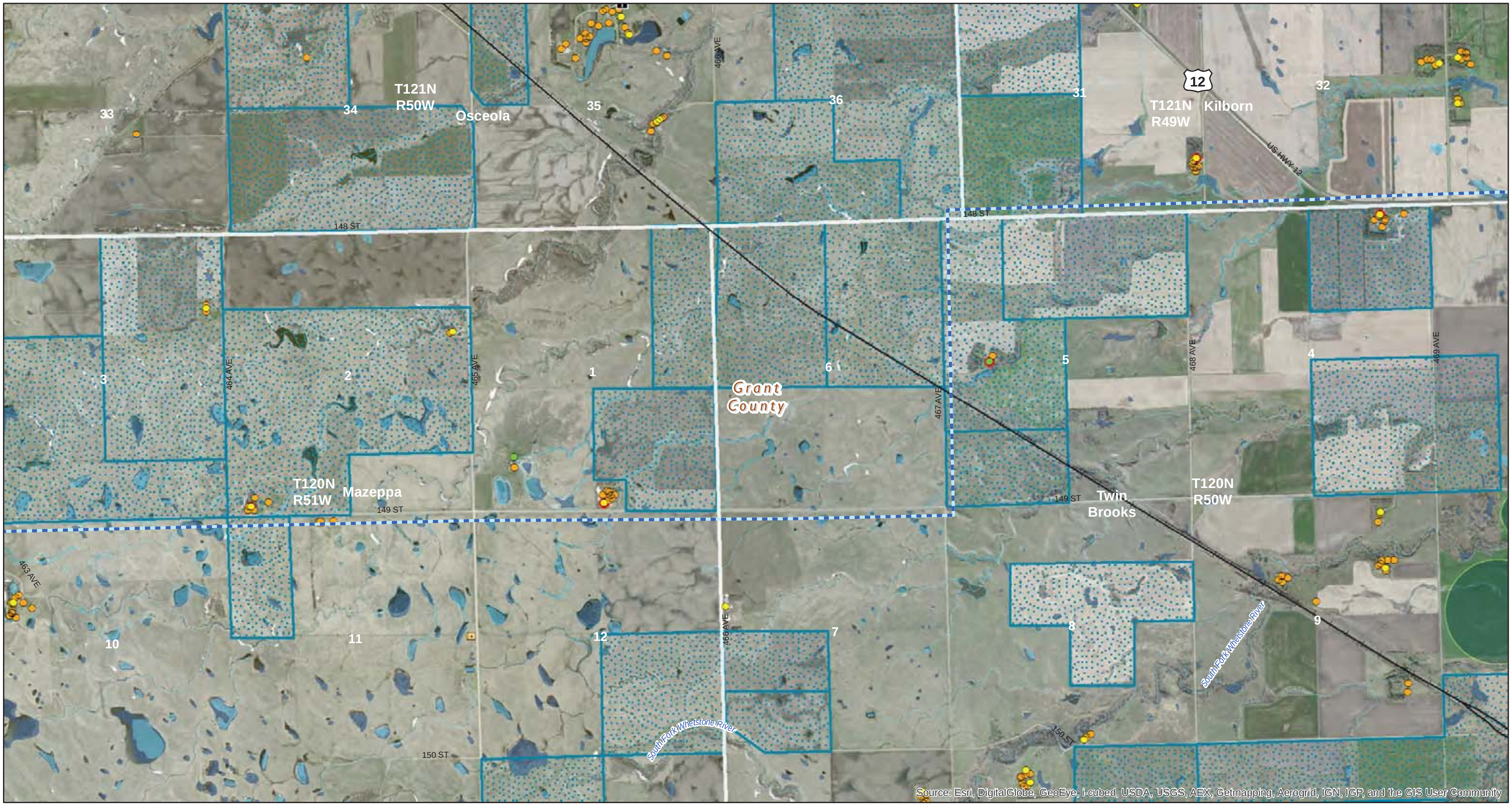
Miles
0 0.5

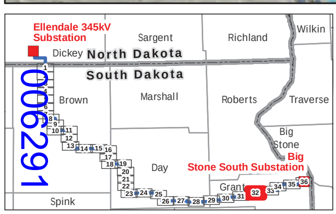
BSS+E Big Stone South to Ellendale

Scale 1:24,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

Date: 8/13/2013





South Dakota Facility
Project End Point
Dwelling - Occupied
Dwelling - Unknown/Vacant
Ag/Other Structure
Gravel Pit/Mining
Cemetery
Church
School
Recreation
Utility
Communication Tower
NRHP Listed Property
Center Pivot
Noise Sensitive Land Use
Electric
Pipeline
State Park or Recreation Area
State School & Public Lands
Waterfowl Production Area (WPA)
National Wildlife Refuge (NWR)
Walk-In Areas (General Hunting Access)
National Conservation Easements (NRCS)
Private-use Airport
Public-use Airport
City Boundary
Township Boundary
County Boundary
State Boundary
Railroad
Abandoned Railroad
Highway
River or Stream
Waterbody
Wetland (NWI)
Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility. Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.32
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

N
0 0.5 Miles

BSSE
Big Stone South to Ellendale

Scale 1:24,000

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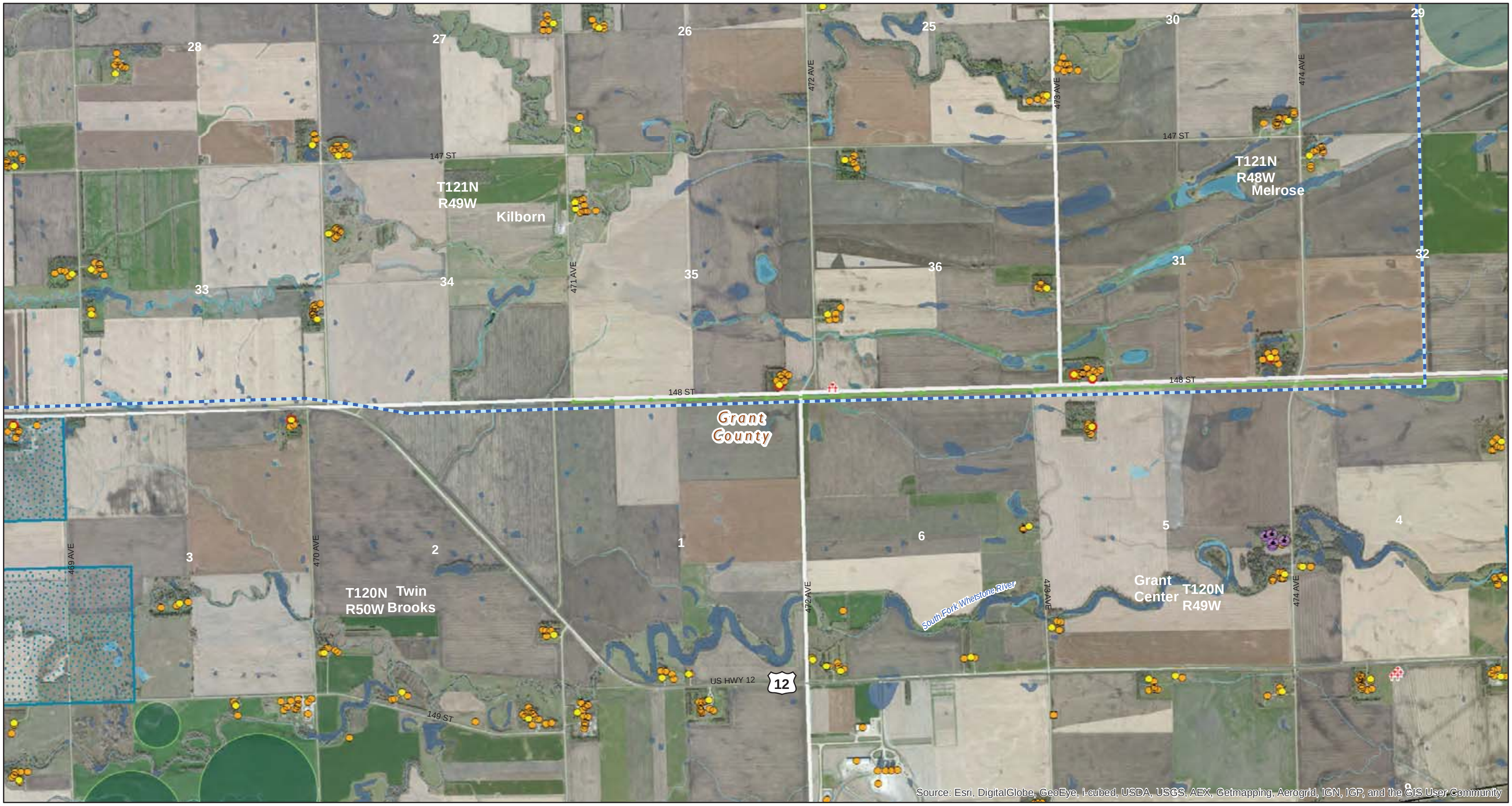

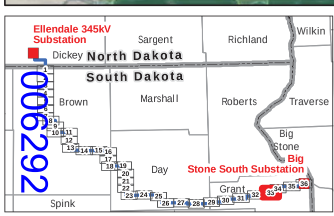

- South Dakota Facility
- Project End Point
- Dwelling - Occupied
- Dwelling - Unknown/Vacant
- Ag/Other Structure
- Gravel Pit/Mining
- Cemetery
- Church
- School
- Recreation
- Utility
- Communication Tower
- NRHP Listed Property
- Center Pivot
- Noise Sensitive Land Use
- Electric
- Pipeline
- State Park or Recreation Area
- State School & Public Lands
- Waterfowl Production Area (WPA)
- National Wildlife Refuge (NWR)
- Walk-In Areas (General Hunting Access)
- National Conservation Easements (NRCS)
- Private-use Airport
- Public-use Airport
- City Boundary
- Township Boundary
- County Boundary
- State Boundary
- Railroad
- Abandoned Railroad
- Highway
- River or Stream
- Waterbody
- Wetland (NWI)
- Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility.
Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.33
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

0 0.5 Miles

BSSE Big Stone South to Ellendale

Scale 1:24,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

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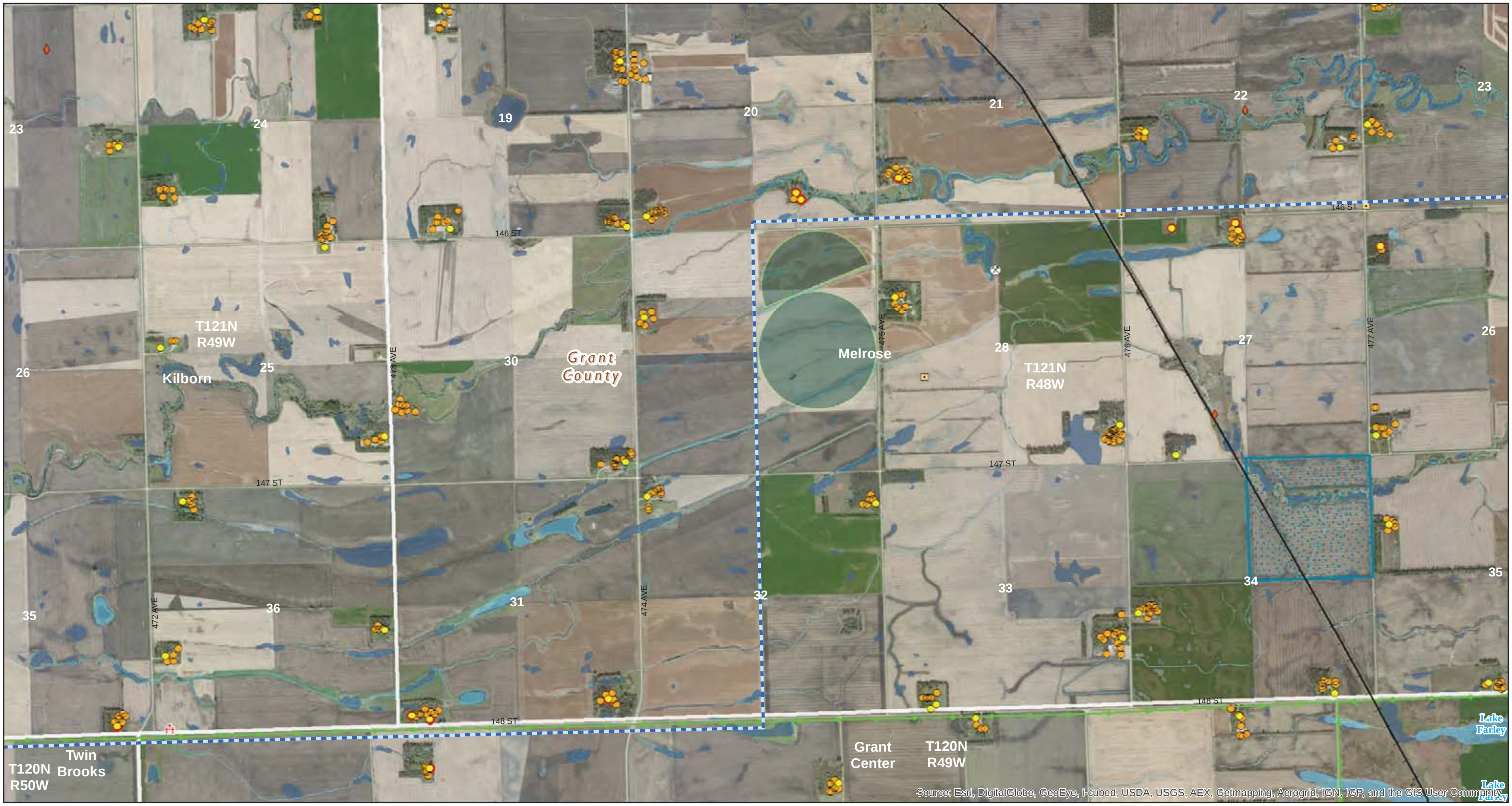
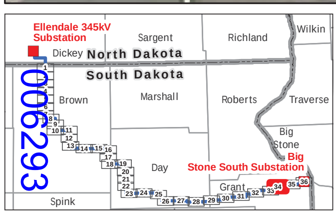




South Dakota Facility
Project End Point
Dwelling - Occupied
Dwelling - Unknown/Vacant
Ag/Other Structure
Gravel Pit/Mining
Cemetery
Church
School
Recreation
Utility
Communication Tower
NRHP Listed Property
Center Pivot
Noise Sensitive Land Use
Electric
Pipeline
State Park or Recreation Area
State School & Public Lands
Waterfowl Production Area (WPA)
National Wildlife Refuge (NWR)
Walk-In Areas (General Hunting Access)
National Conservation Easements (NRCS)
Private-use Airport
Public-use Airport
City Boundary
Township Boundary
County Boundary
State Boundary
Railroad
Abandoned Railroad
Highway
River or Stream
Waterbody
Wetland (NWI)
Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility. Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.34
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

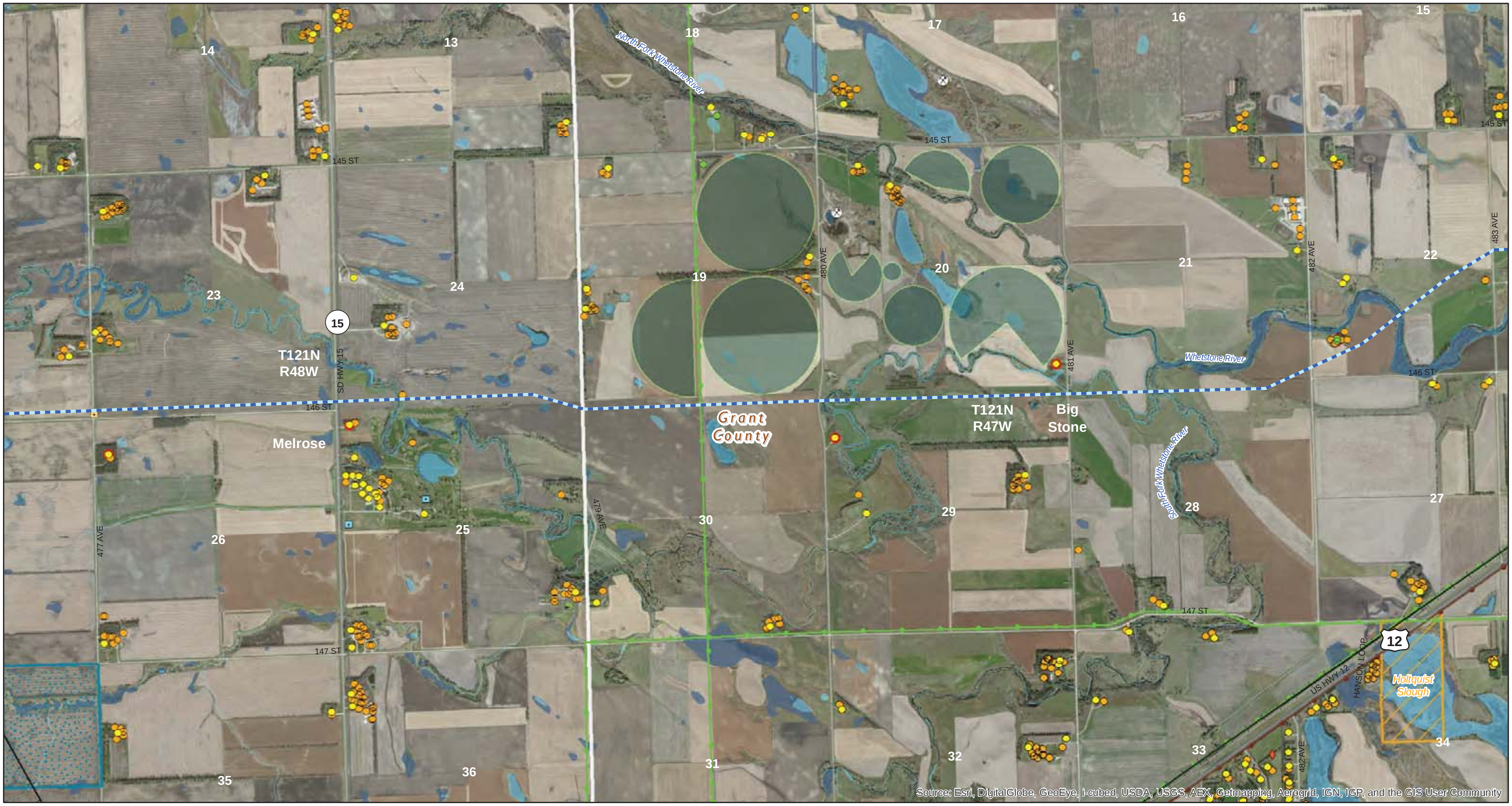
Miles
0 0.5

BSS+E Big Stone South to Ellendale

Scale 1:24,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

Date: 8/13/2013



South Dakota Facility
Project End Point
Dwelling - Occupied
Dwelling - Unknown/Vacant
Ag/Other Structure
Gravel Pit/Mining
Cemetery
Church
School
Recreation
Utility
Communication Tower
NRHP Listed Property
Center Pivot
Noise Sensitive Land Use
Electric
Pipeline
State Park or Recreation Area
State School & Public Lands
Waterfowl Production Area (WPA)
National Wildlife Refuge (NWR)
Walk-In Areas (General Hunting Access)
National Conservation Easements (NRCS)
Private-use Airport
Public-use Airport
City Boundary
Township Boundary
County Boundary
State Boundary
Railroad
Abandoned Railroad
Highway
River or Stream
Waterbody
Wetland (NWI)
Wetland (Desktop Digitized)

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility. Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.35
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

Miles 0 0.5

BSS+E Big Stone South to Ellendale

Scale 1:24,000

006294

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit02_DetailSouthDakotaFacility_11X17_24k_SD.mxd

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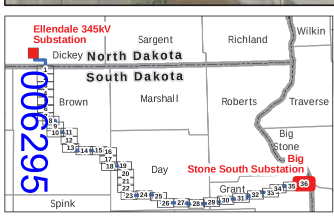

South Dakota Facility	Cemetery	Communication Tower	State Park or Recreation Area	Walk-In Areas (General Hunting Access)	City Boundary	Highway
Project End Point	Church	NRHP Listed Property	State School & Public Lands	National Conservation Easements (NRCS)	Township Boundary	River or Stream
Dwelling - Occupied	School	Center Pivot	Waterfowl Production Area (WPA)	Private-use Airport	County Boundary	Waterbody
Dwelling - Unknown/Vacant	Recreation	Noise Sensitive Land Use	National Wildlife Refuge (NWR)	Public-use Airport	State Boundary	Wetland (NWI)
Ag/Other Structure	Utility	Electric			Railroad	Wetland (Desktop Digitized)
Gravel Pit/Mining		Pipeline			Abandoned Railroad	

Note - There are no known municipal water supply locations, and commercial or industrial land uses along the South Dakota Facility. Public Use include State Parks or Recreation Areas, State School & Public Lands, Walk-in-Areas (General Hunting Access).

Exhibit 2.36
Detail of South Dakota Facility
Big Stone South to Ellendale
345 kV Transmission Line Project

Miles
0 0.5

BSS+E Big Stone South to Ellendale

Scale 1:24,000

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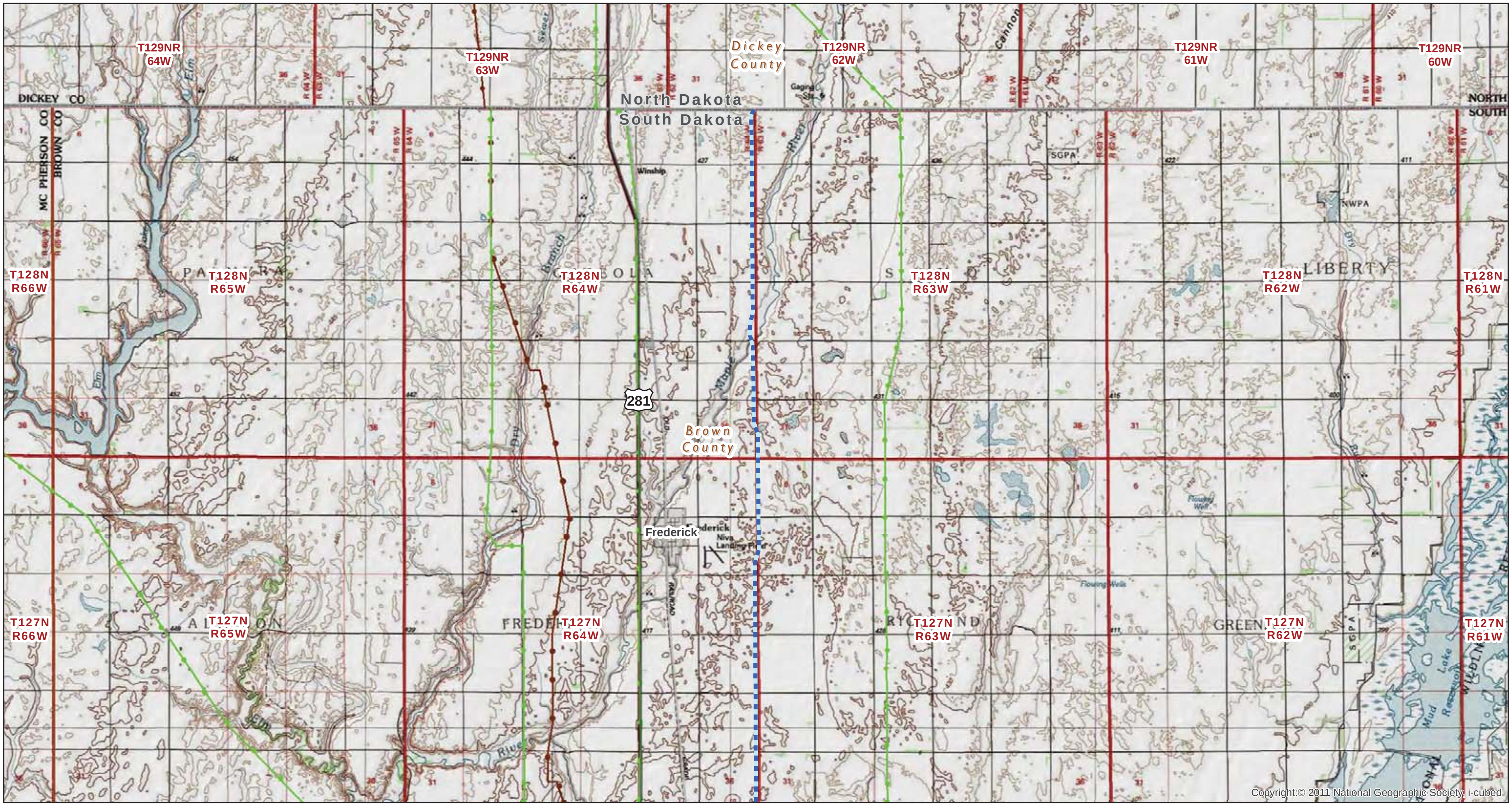

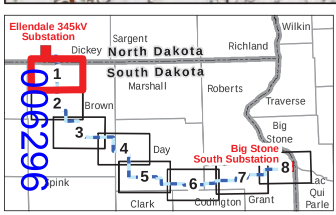

South Dakota Facility
Project End Point
Electric
Pipeline
Highway
Railroad
Abandoned Railroad
City Boundary
Township Boundary
County Boundary
State Boundary

Exhibit 3.1
Topography (USGS 1:100,000 Map)
Big Stone South to Ellendale
345 kV Transmission Line Project

Miles
0 2

Scale 1:100,000

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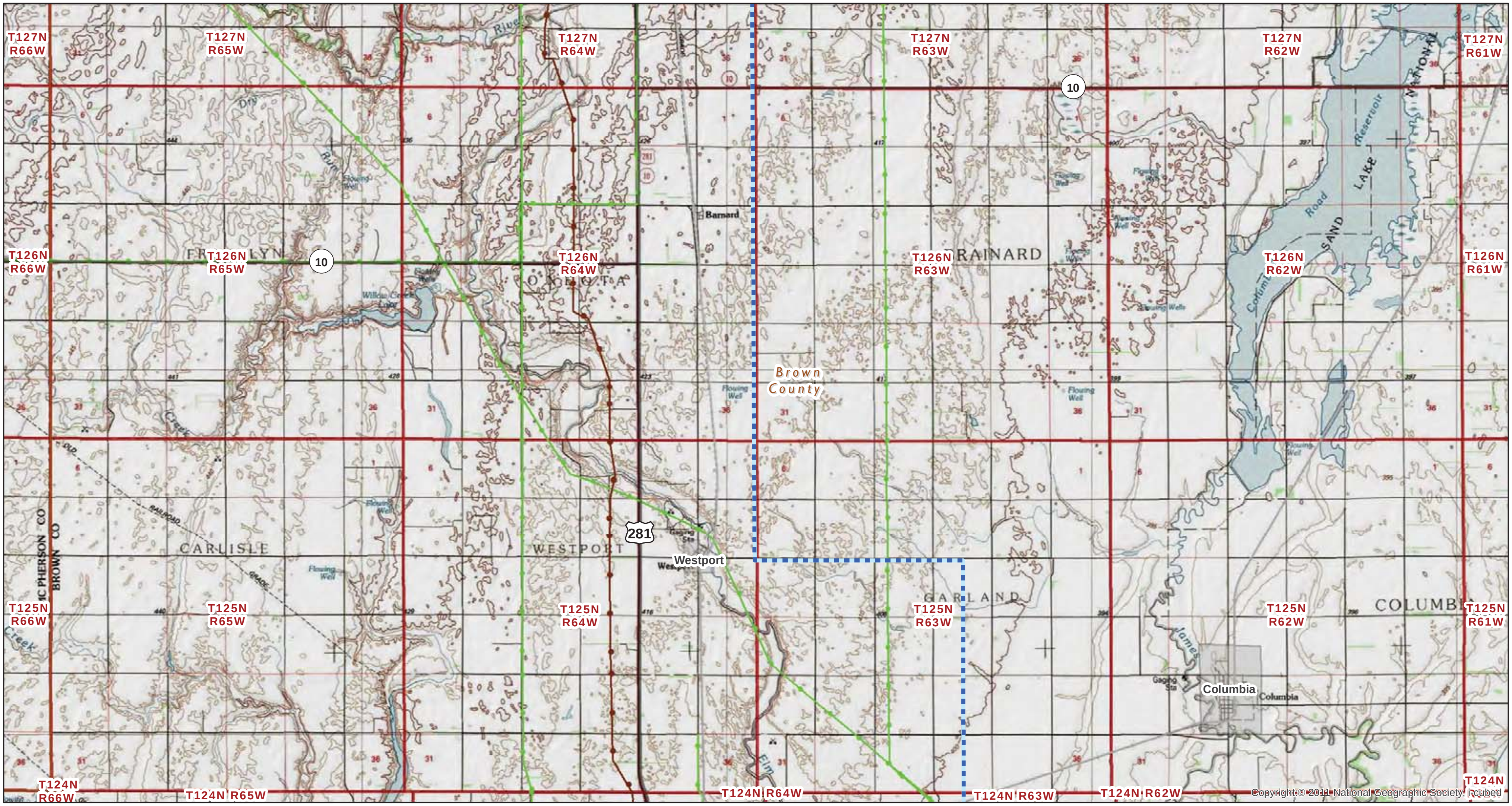
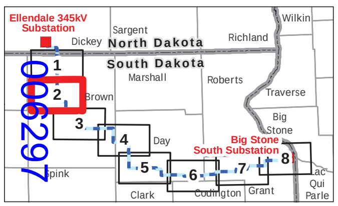




South Dakota Facility
Project End Point
Electric
Pipeline
Highway
Railroad
Abandoned Railroad
City Boundary
Township Boundary
County Boundary
State Boundary

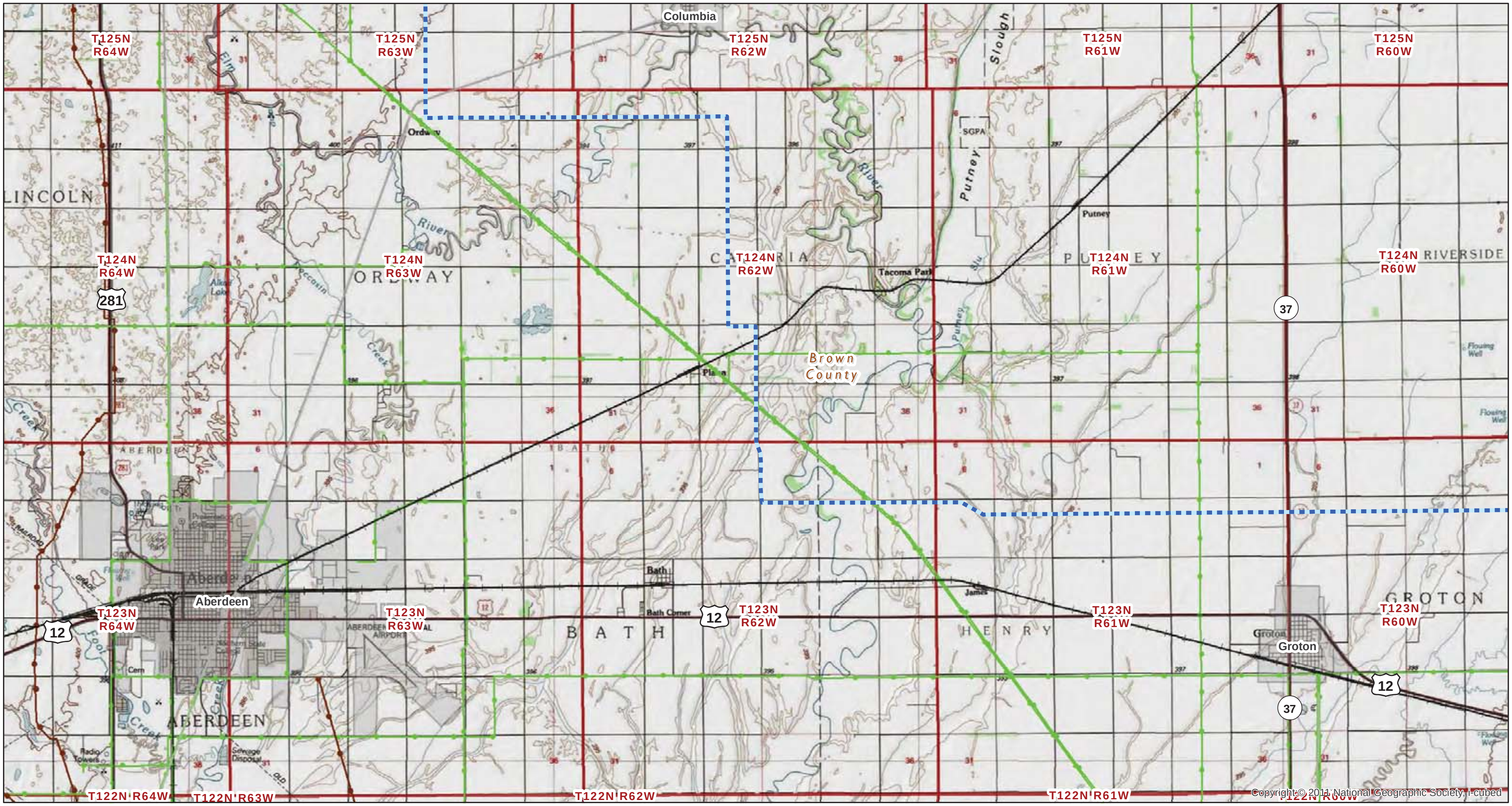
Exhibit 3.2
Topography (USGS 1:100,000 Map)
Big Stone South to Ellendale
345 kV Transmission Line Project

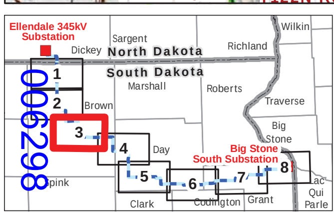
N
0 2 Miles

BSS+E Big Stone South to Ellendale

Scale 1:100,000

Date: 8/13/2013





South Dakota Facility
Project End Point
Electric
Pipeline
Highway
Railroad
Abandoned Railroad
City Boundary
Township Boundary
County Boundary
State Boundary

Exhibit 3.3
Topography (USGS 1:100,000 Map)
Big Stone South to Ellendale
345 kV Transmission Line Project

N
0 2 Miles

BSSE
Big Stone South to Ellendale

Scale 1:100,000

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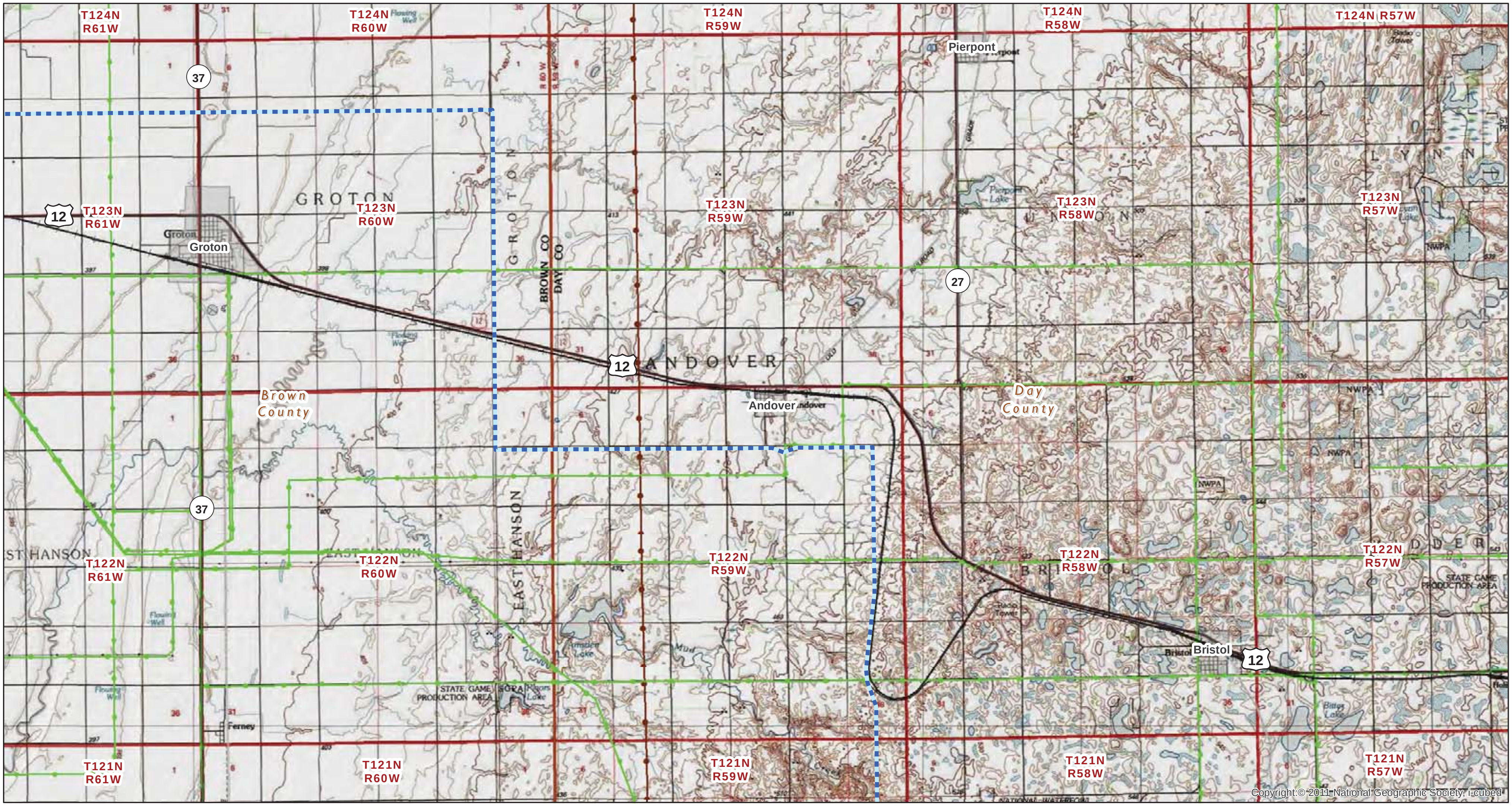
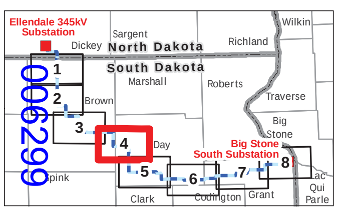




South Dakota Facility
Project End Point
Electric
Pipeline
Highway
Railroad
Abandoned Railroad
City Boundary
Township Boundary
County Boundary
State Boundary

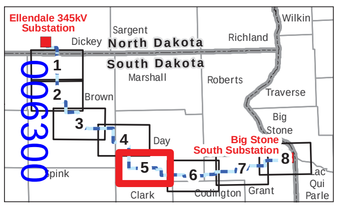
Exhibit 3.4
Topography (USGS 1:100,000 Map)
Big Stone South to Ellendale
345 kV Transmission Line Project

Miles
0 2

Scale 1:100,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit03_Topography_Maps_11X17_100k_SD.mxd

Date: 8/13/2013



- South Dakota Facility
- Project End Point
- Electric
- Pipeline
- Highway
- Railroad
- Abandoned Railroad
- City Boundary
- Township Boundary
- County Boundary
- State Boundary

Exhibit 3.5
Topography (USGS 1:100,000 Map)
Big Stone South to Ellendale
345 kV Transmission Line Project

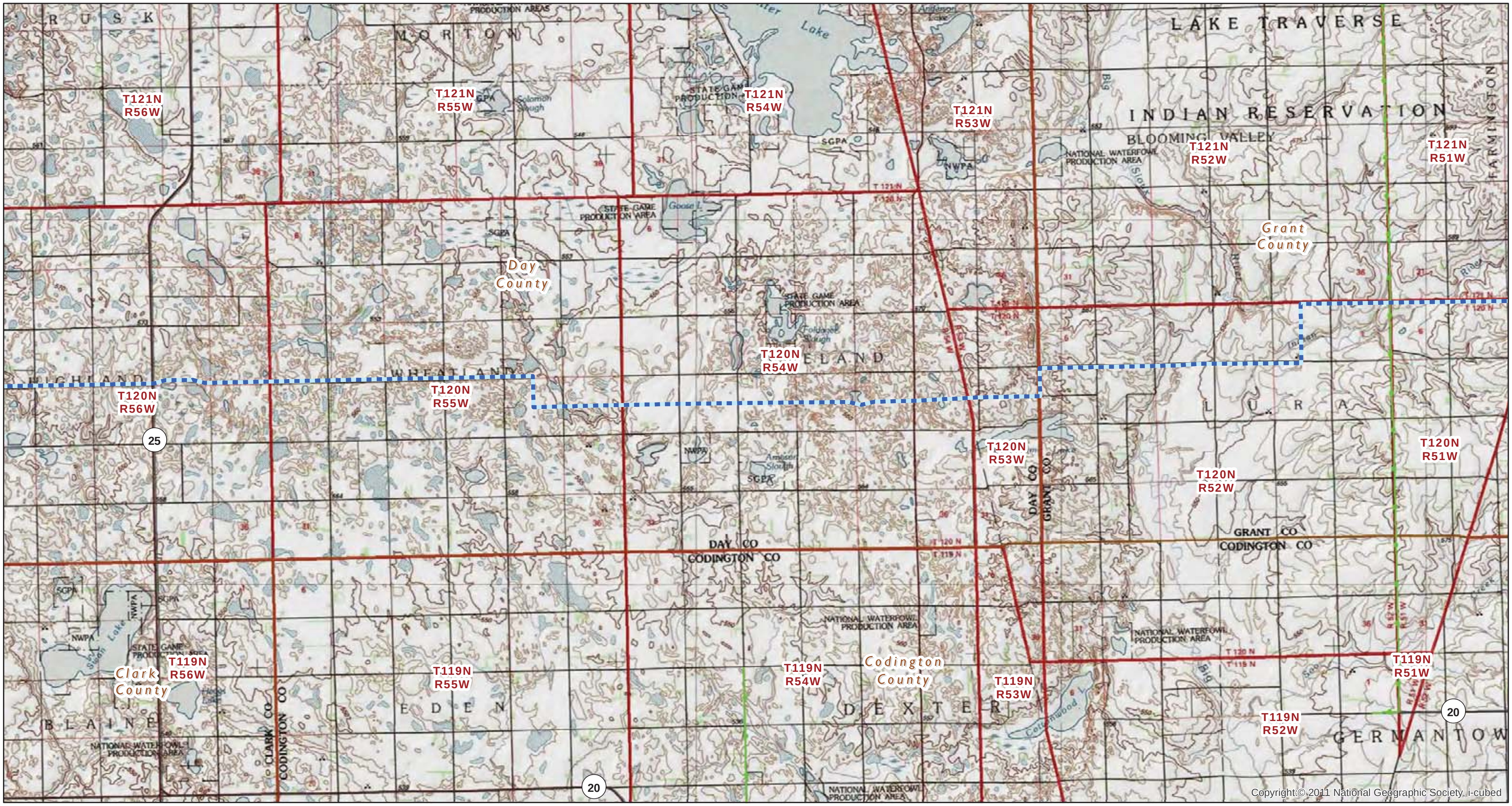
Miles 0 2

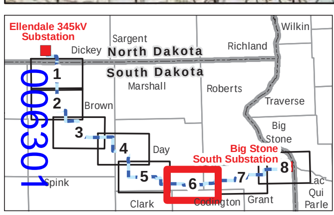
BSS+E Big Stone South to Ellendale

Scale 1:100,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit03_Topography_Maps_11X17_100k_SD.mxd

Date: 8/13/2013





006301

- South Dakota Facility
- Project End Point
- Electric
- Pipeline
- Highway
- Railroad
- Abandoned Railroad
- City Boundary
- Township Boundary
- County Boundary
- State Boundary

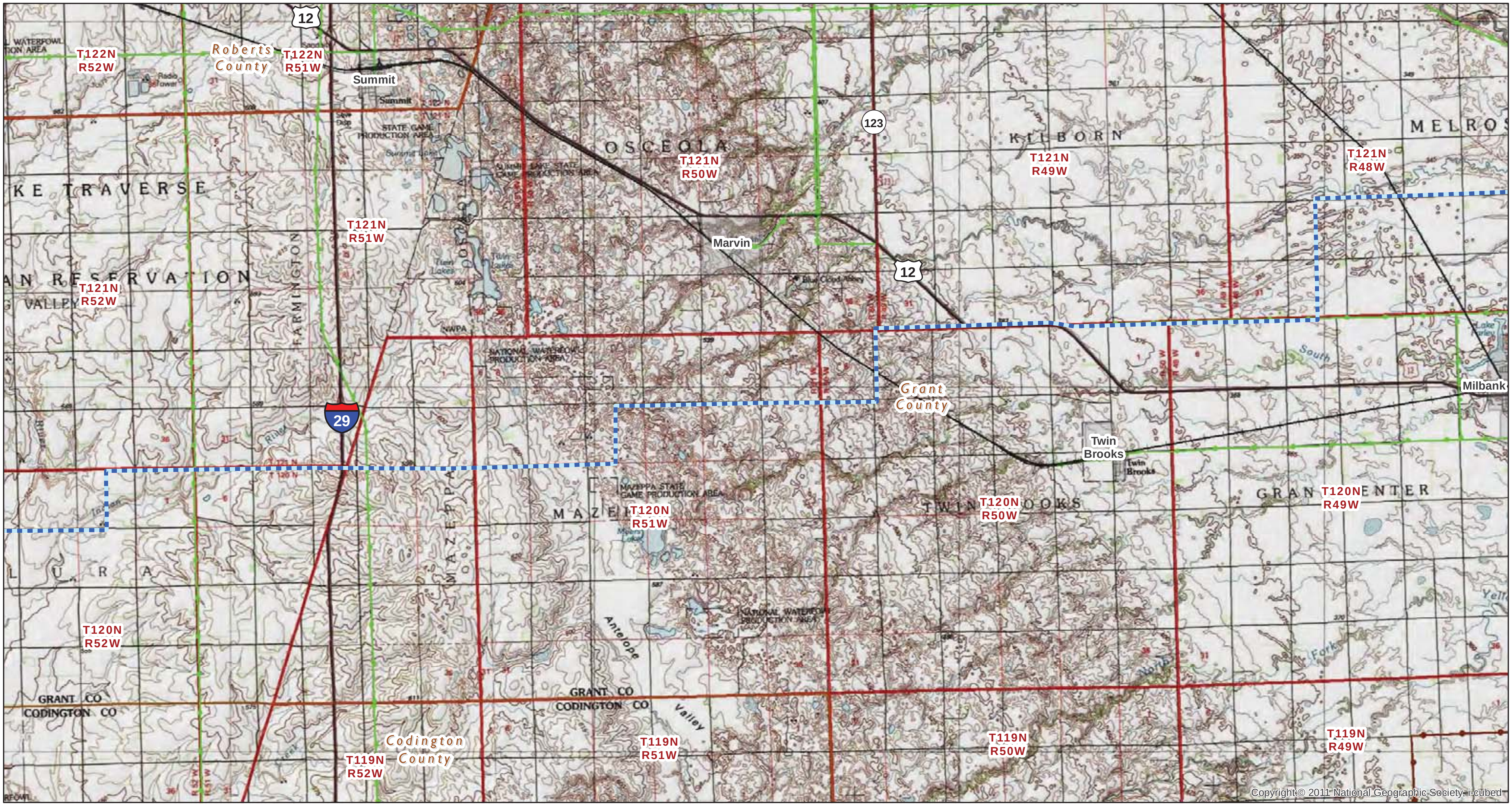
Exhibit 3.6
Topography (USGS 1:100,000 Map)
Big Stone South to Ellendale
345 kV Transmission Line Project

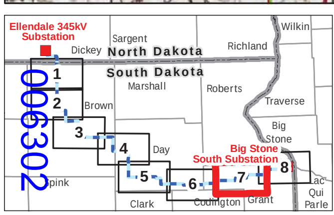
Miles
0 2

Scale 1:100,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit03_Topography_Maps_11X17_100k_SD.mxd

Date: 8/13/2013





006302

South Dakota Facility	Electric	City Boundary
Project End Point	Pipeline	Township Boundary
	Highway	County Boundary
	Railroad	State Boundary
	Abandoned Railroad	

Exhibit 3.7
Topography (USGS 1:100,000 Map)
Big Stone South to Ellendale
345 kV Transmission Line Project

Miles
0 2

Scale 1:100,000

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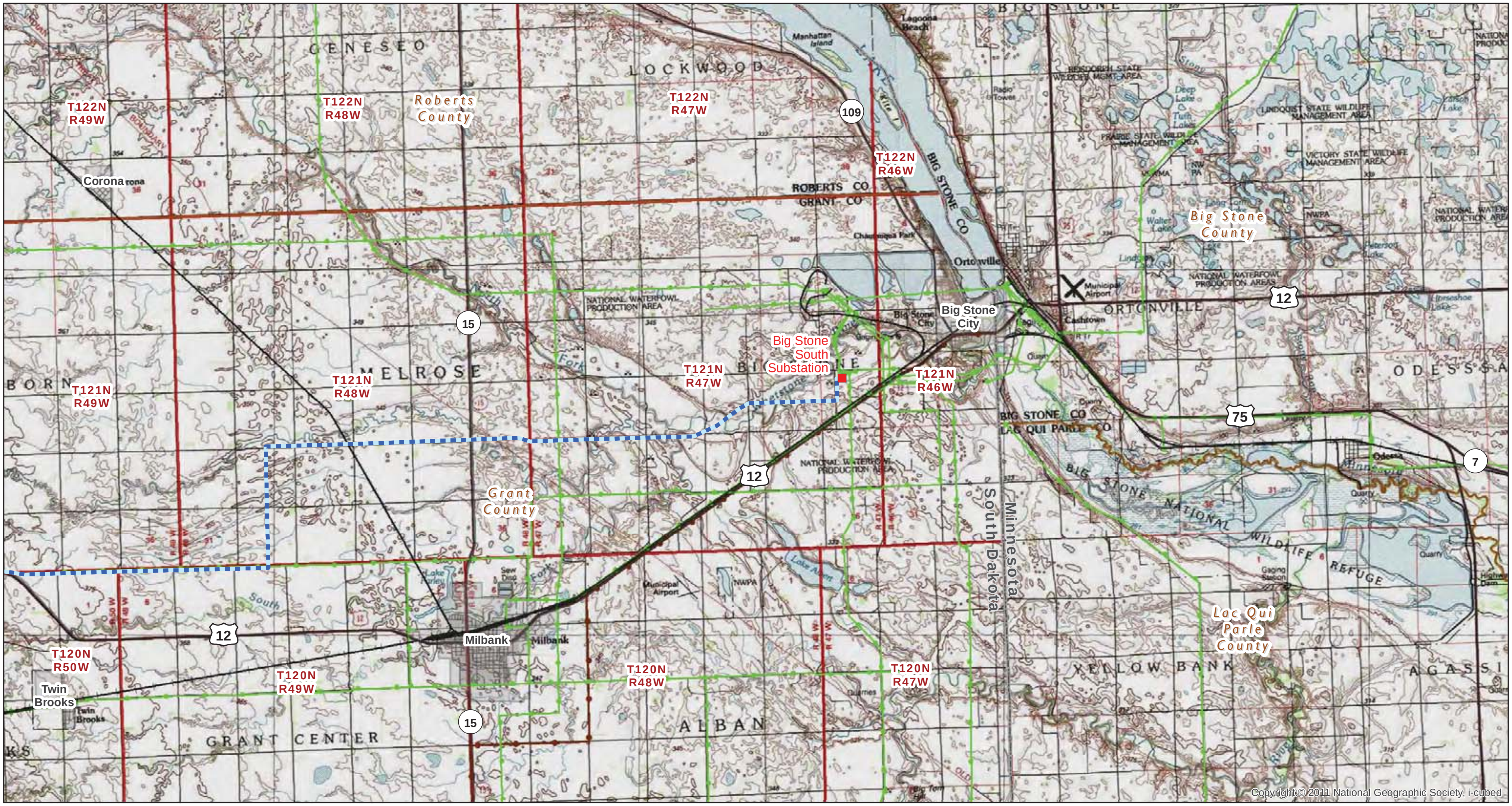

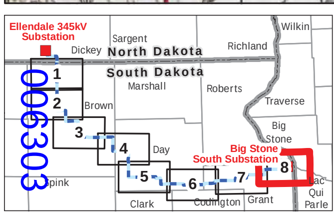

South Dakota Facility

Project End Point

Electric

Pipeline

Highway

Railroad

Abandoned Railroad

City Boundary

Township Boundary

County Boundary

State Boundary

Exhibit 3.8

Topography (USGS 1:100,000 Map)

Big Stone South to Ellendale

345 kV Transmission Line Project

Miles

0 2

BSSE

Scale 1:100,000

006303

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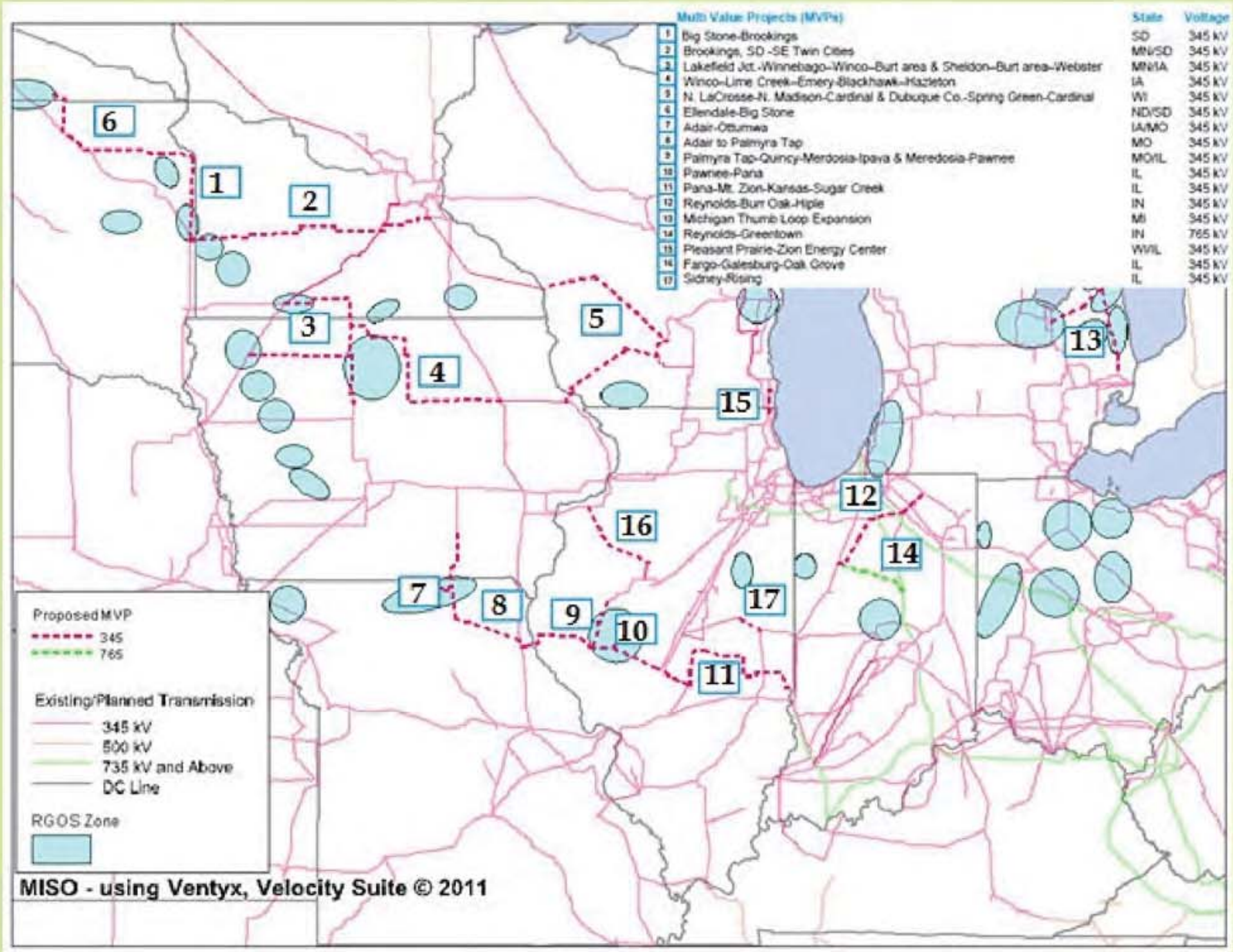
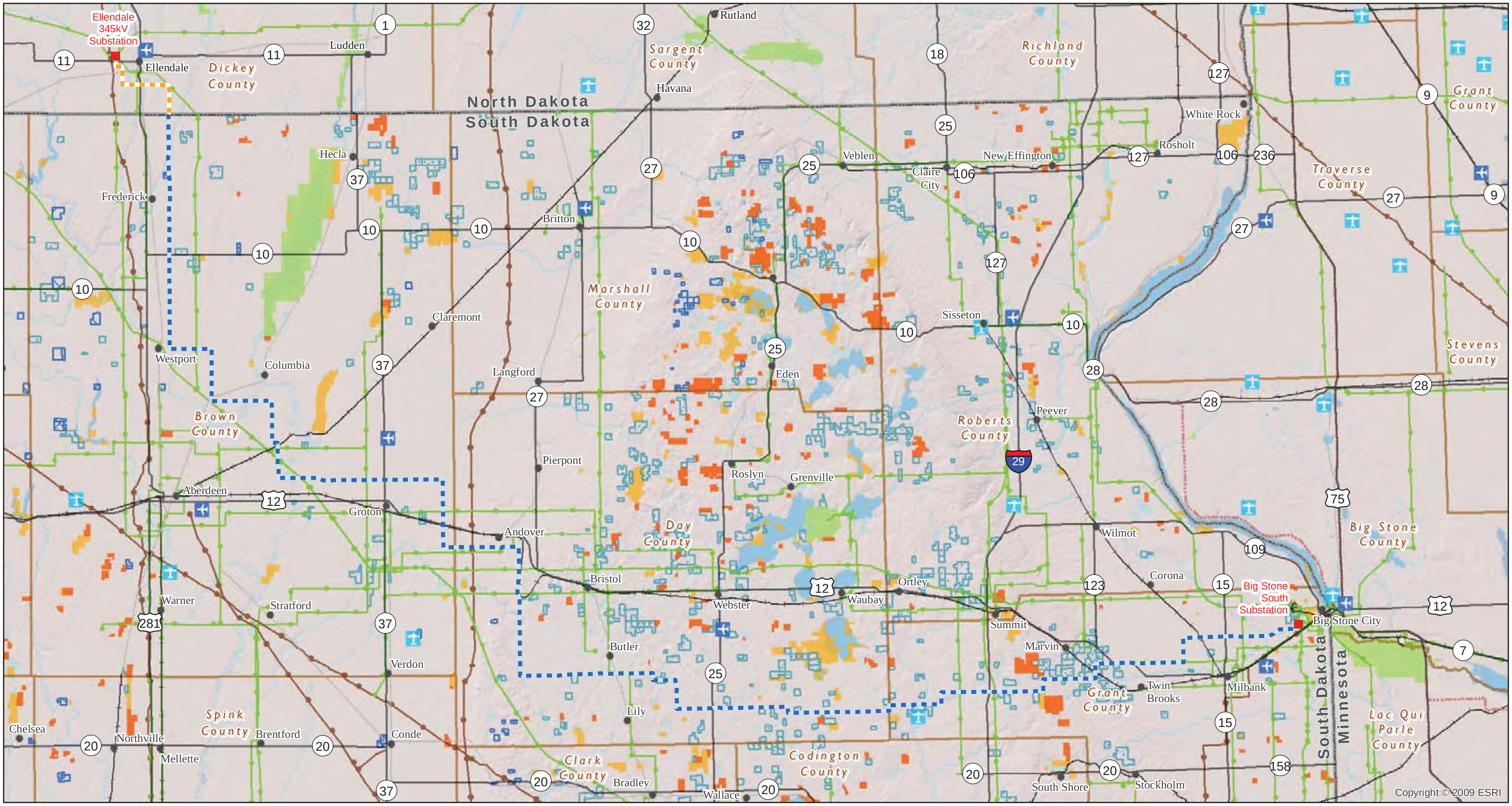
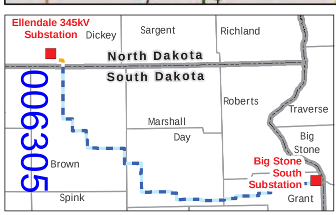


1.	Big Stone – Brookings	SD
2.	Brookings, SD-SE Twin Cities	MN/SD
3.	Lakefield Jct.-Winnebago – Winco – Burt Area and Sheldon – Burt Area – Webster	MN/IA
4.	Winco – Lime Creek – Emery-Blackhawk – Hazleton	IA
5.	N. LaCrosse – N. Madison – Cardinal and Dubuque Co. – Spring Green – Cardinal	WI
6.	Ellendale – Big Stone	ND/SD
7.	Adair – Ottumwa	IA/MO
8.	West Adair to Palmyra Tap	MO
9.	Palmyra-Quincy-Merdosia – Ipava and Meredosia – Pawnee	MO/IL
10.	New Pawnee – Pana	IL
11.	Pana-Mt Zion – Kansas – Sugar Creek	IL
12.	New Reynolds – Burr Oak – Hiple	IN
13.	Michigan Thumb Loop Expansion	MI
14.	New Reynolds – Greentown	IN
15.	Pleasant Prairie – Zion Energy Center	WI/IL
16.	Fargo – Oak Grove	IL
17.	Sidney-Rising	IL

Exhibit 4
MISO MVP Project Map
Big Stone South to Ellendale
345 kV Transmission Line Project

Source: MISO Transmission Expansion Plan 2011





006305

- South Dakota Facility
- North Dakota Facility
- Project End Point
- Private-use Airport
- Public-use Airport
- State Park or Recreation Area
- State School & Public Lands
- Walk-In Areas (General Hunting Access)
- Waterfowl Production Area (WPA)
- National Wildlife Refuge (NWR)
- Electric
- Pipeline
- Railroad
- Abandoned Railroad
- Scenic Byway
- River or Stream
- Waterbody
- City
- County Boundary
- State Boundary

Exhibit 5
State and Federal Lands
Big Stone South to Ellendale
345 kV Transmission Line Project

Miles
0 10

BSSE
Big Stone South to Ellendale

Scale 1:500,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit05_StateFedLands_11X17_SD.mxd

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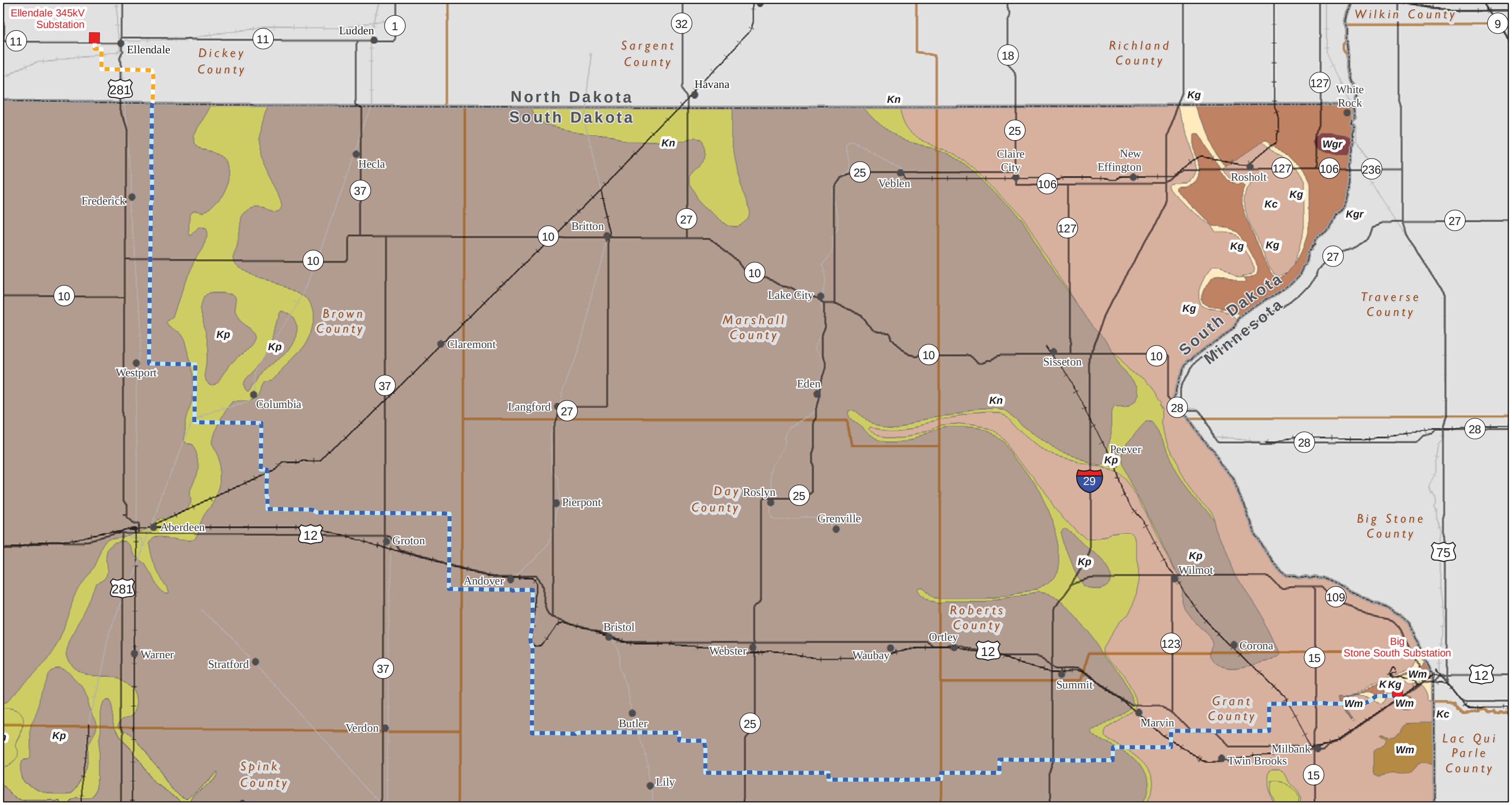

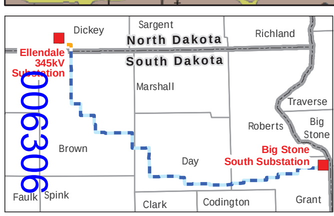

006306

- South Dakota Facility
- North Dakota Facility
- Project End Point

Bedrock Geology
- (Kc) Carlile Shale
- (Kg) Greenhorn Limestone
- (Kgr) Graneros Shale
- (Kn) Niobrara Formation
- (Kp) Pierre Shale
- (Wgr) Precambrian Granite
- (Wm) Milbank Granite

- Railroad
- Abandoned Railroad
- Highway
- City
- County Boundary
- State Boundary

Exhibit 6
Bedrock Geology
Big Stone South to Ellendale
345 kV Transmission Line Project

Miles
0 10

Scale 1:450,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit06_BedrockGeology_11X17_SD.mxd

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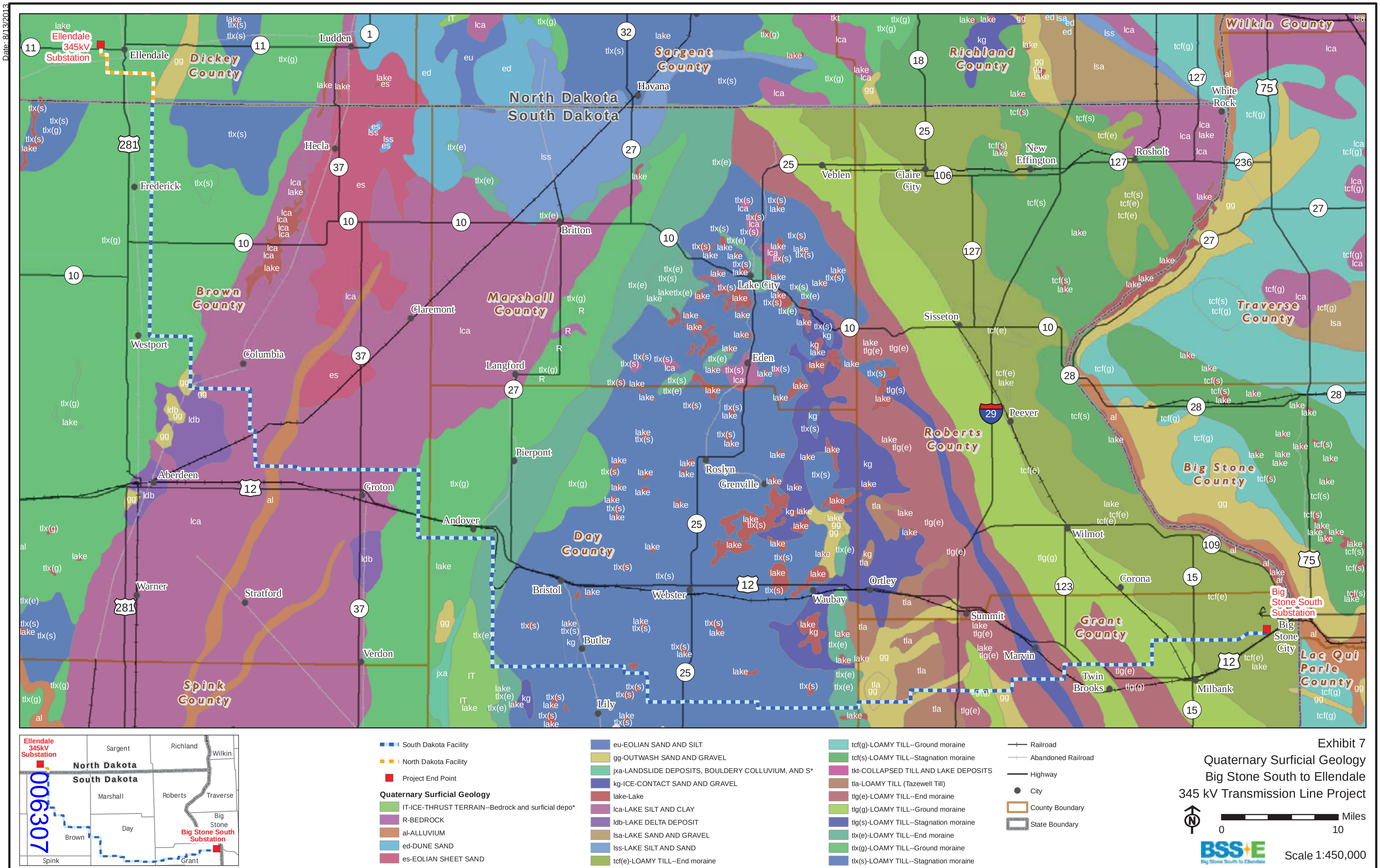

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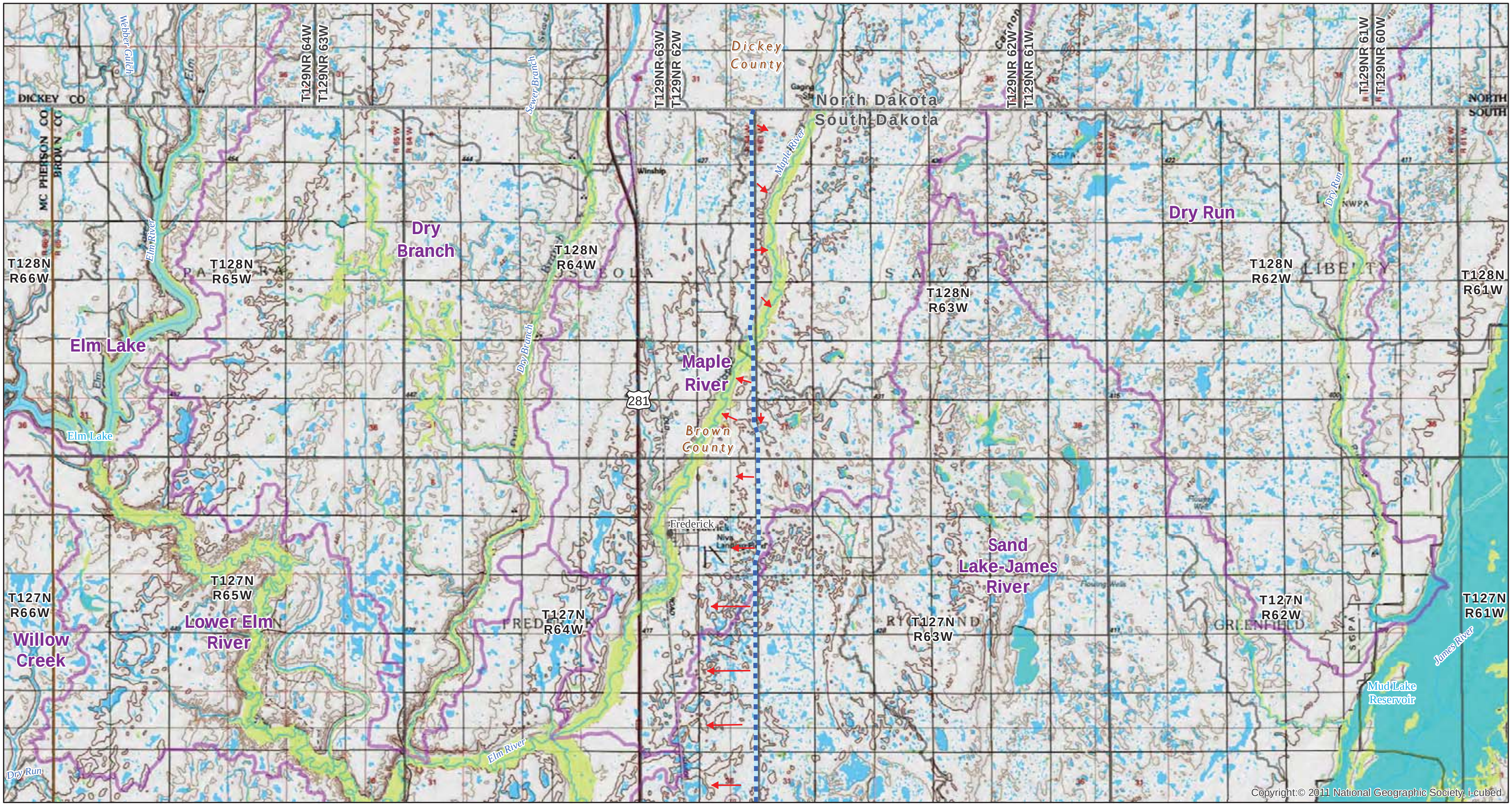

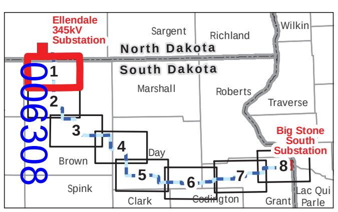

South Dakota Facility
Project End Point
Drainage Pattern
River or Stream
Lake, Pond, or River
Freshwater Emergent Wetland
Freshwater Forested/Shrub Wetland
Watershed Boundary (HU10)
Watershed Sub-Division (HU12)
Floodplain (Zones A, AE, AO)
Highway
Railroad
Abandoned Railroad
City
Township Boundary
County Boundary
State Boundary

Exhibit 8.1
Water Resources
Big Stone South to Ellendale
345 kV Transmission Line Project

Miles 0 2

BSSE Big Stone South to Ellendale

Scale 1:100,000

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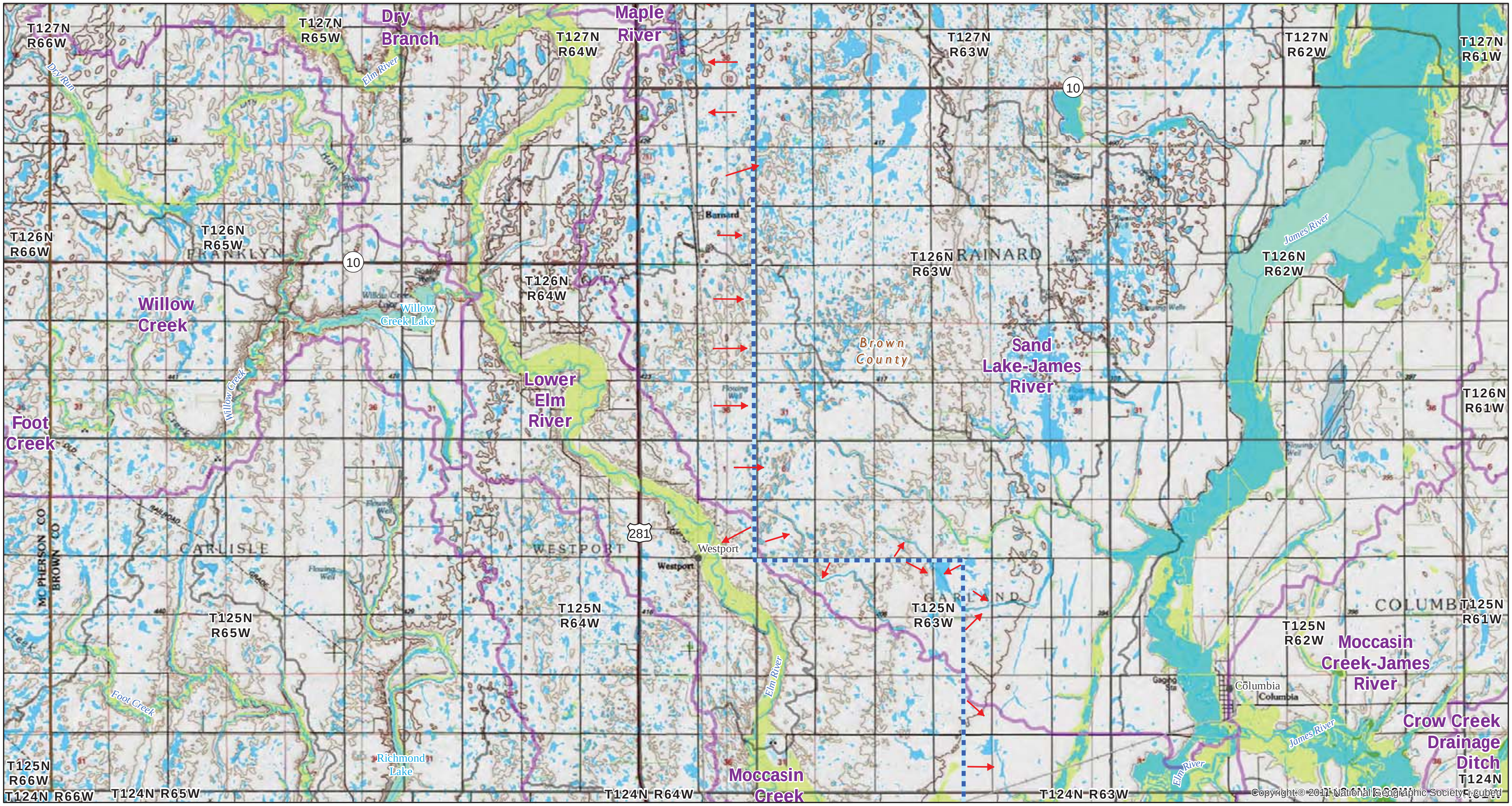

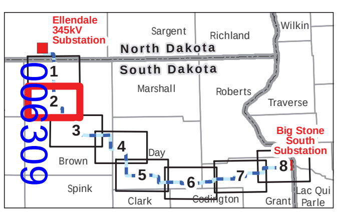

South Dakota Facility
Project End Point
Drainage Pattern
River or Stream
Lake, Pond, or River
Freshwater Emergent Wetland
Freshwater Forested/Shrub Wetland
Watershed Boundary (HU10)
Watershed Sub-Division (HU12)
Floodplain (Zones A, AE, AO)
Highway
Railroad
Abandoned Railroad
City
Township Boundary
County Boundary
State Boundary

Exhibit 8.2
Water Resources
Big Stone South to Ellendale
345 kV Transmission Line Project

Miles 0 2

BSSE Big Stone South to Ellendale

Scale 1:100,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit08_WaterResources_Maps_11X17_100k_SD.mxd

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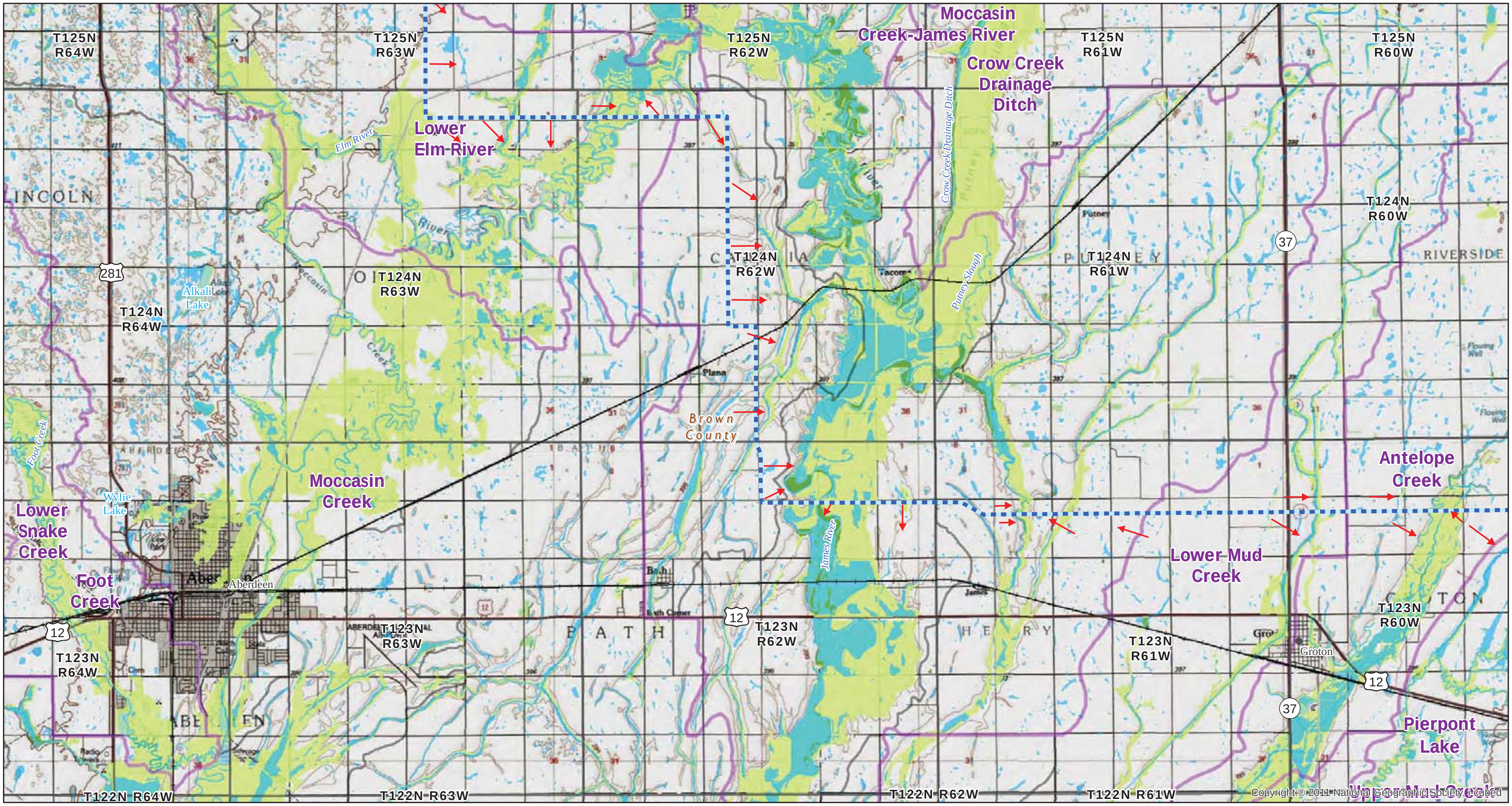

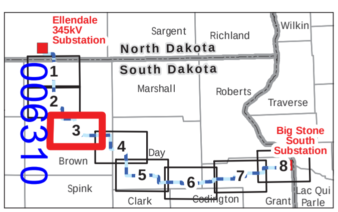

South Dakota Facility
Project End Point
Drainage Pattern
River or Stream
Lake, Pond, or River
Freshwater Emergent Wetland
Freshwater Forested/Shrub Wetland
Watershed Boundary (HU10)
Watershed Sub-Division (HU12)
Floodplain (Zones A, AE, AO)
Highway
Railroad
Abandoned Railroad
City
Township Boundary
County Boundary
State Boundary

Exhibit 8.3
Water Resources
Big Stone South to Ellendale
345 kV Transmission Line Project

Miles
0 2

BSSE Big Stone South to Ellendale

Scale 1:100,000

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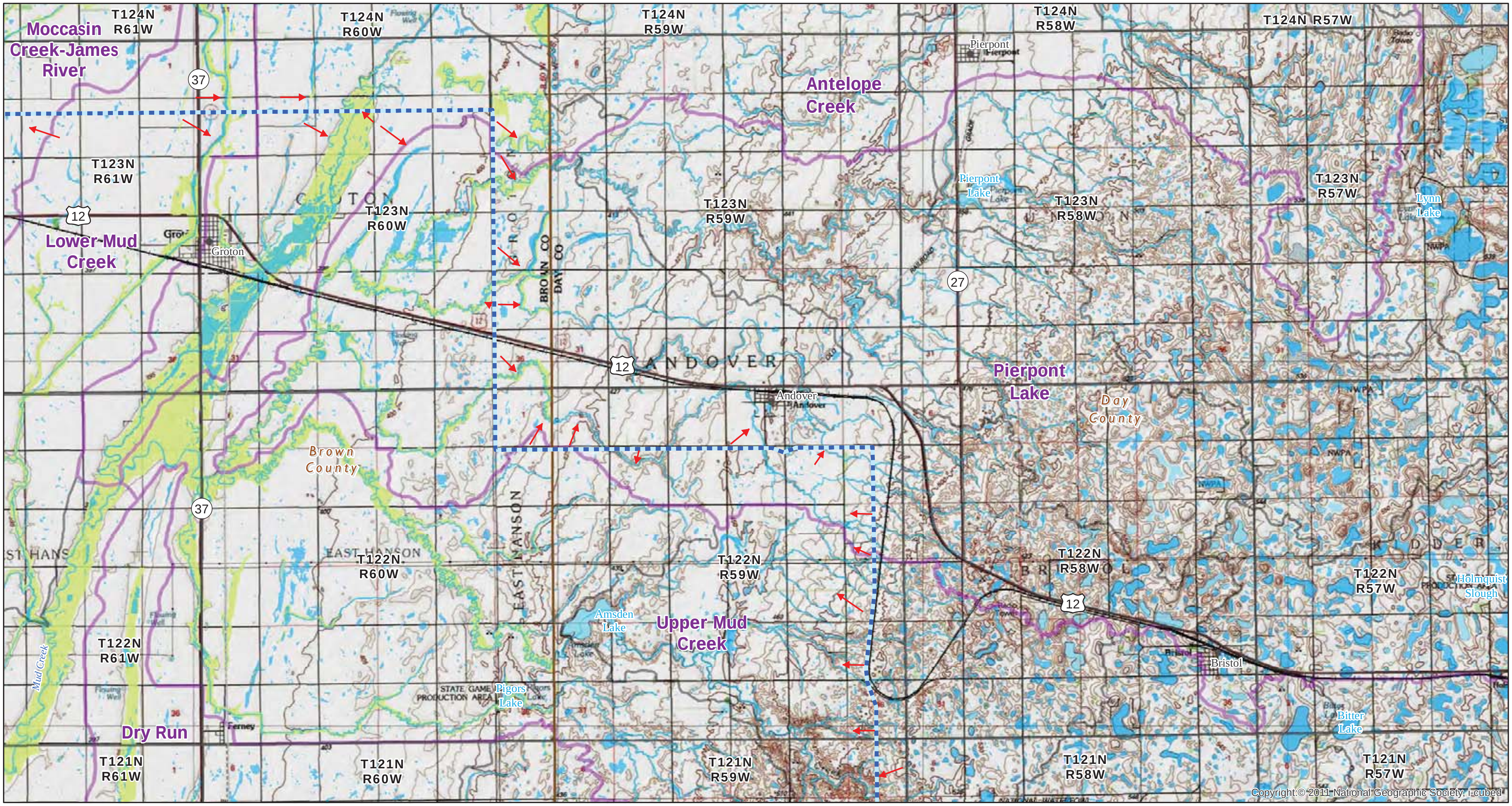

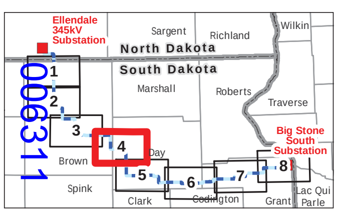

006311

South Dakota Facility
Project End Point
Drainage Pattern
River or Stream
Lake, Pond, or River
Freshwater Emergent Wetland
Freshwater Forested/Shrub Wetland
Watershed Boundary (HU10)
Watershed Sub-Division (HU12)
Floodplain (Zones A, AE, AO)
Highway
Railroad
Abandoned Railroad
City
Township Boundary
County Boundary
State Boundary

Exhibit 8.4
Water Resources
Big Stone South to Ellendale
345 kV Transmission Line Project

Miles
0 2

Scale 1:100,000

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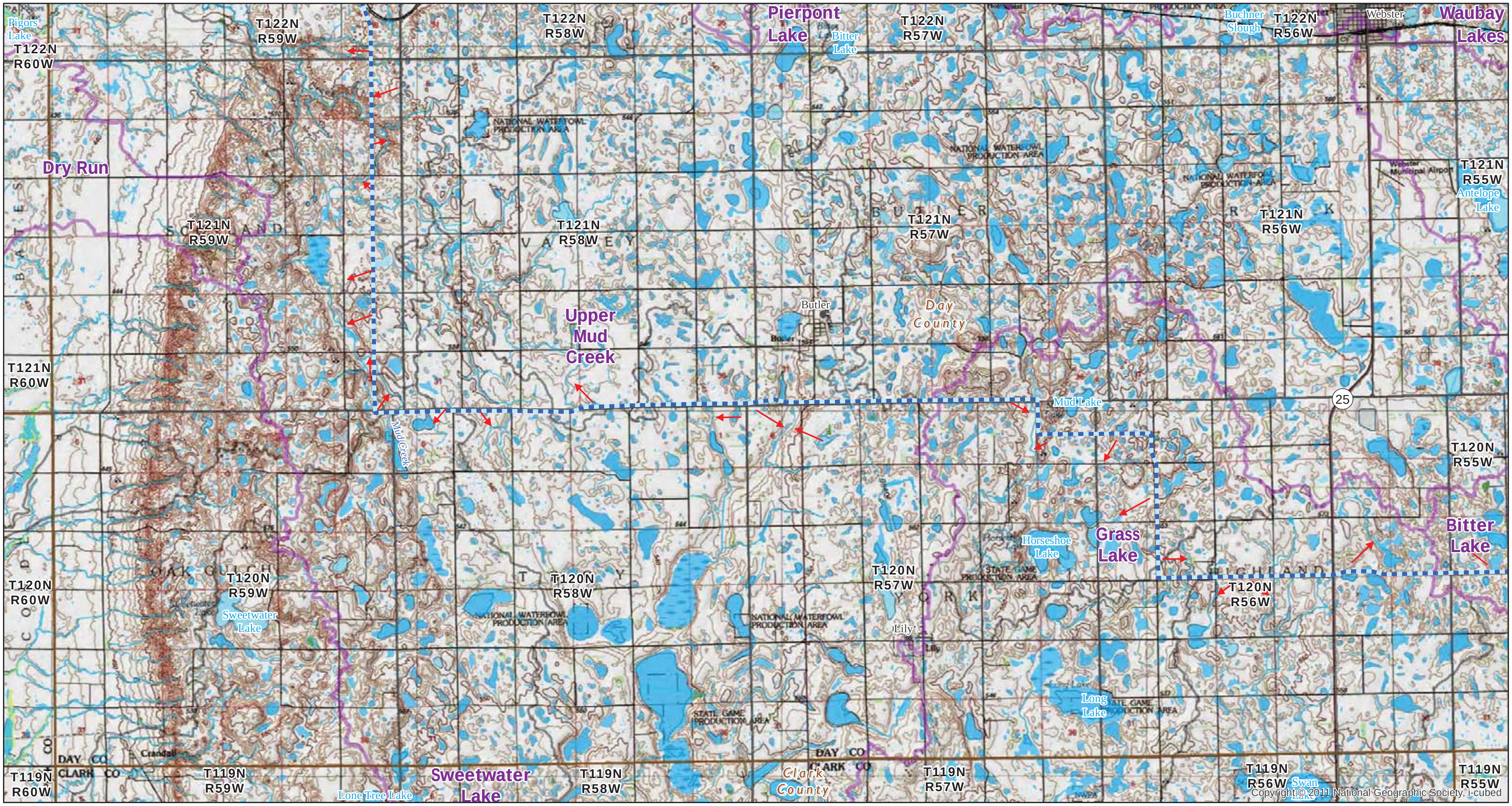

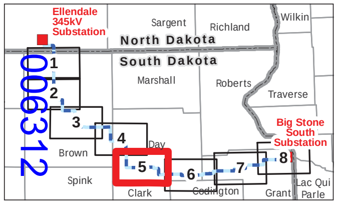

- South Dakota Facility
- Project End Point
- Drainage Pattern
- River or Stream
- Lake, Pond, or River
- Freshwater Emergent Wetland
- Freshwater Forested/Shrub Wetland
- Watershed Boundary (HU10)
- Watershed Sub-Division (HU12)
- Floodplain (Zones A, AE, AO)
- Highway
- Railroad
- Abandoned Railroad
- City
- Township Boundary
- County Boundary
- State Boundary

Exhibit 8.5
Water Resources
Big Stone South to Ellendale
345 kV Transmission Line Project

Miles
0 2

BSSE Big Stone South to Ellendale

Scale 1:100,000

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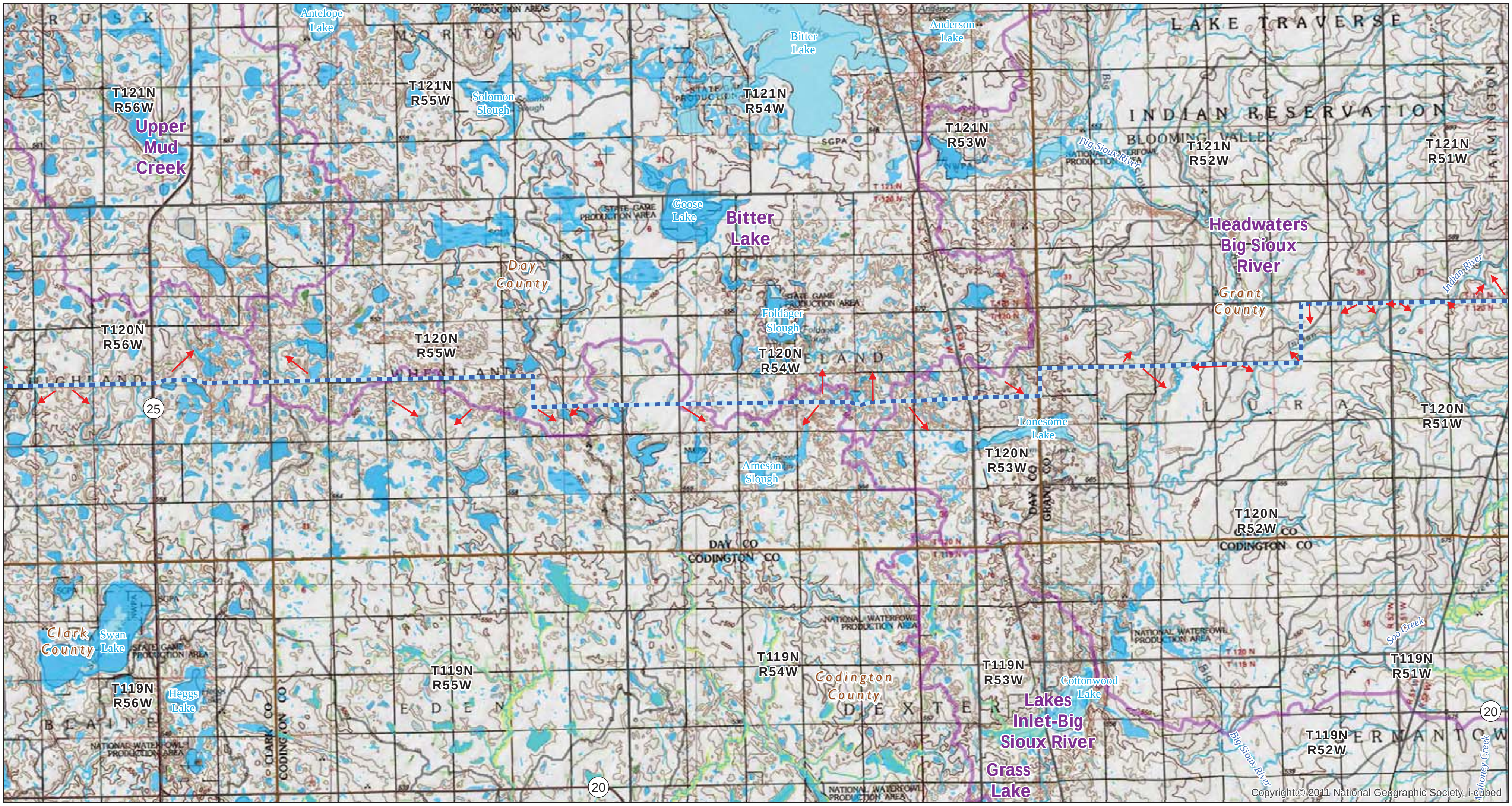

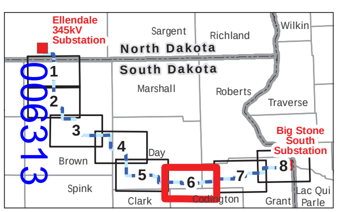

006313

South Dakota Facility
Project End Point
Drainage Pattern
River or Stream
Lake, Pond, or River
Freshwater Emergent Wetland
Freshwater Forested/Shrub Wetland
Watershed Boundary (HU10)
Watershed Sub-Division (HU12)
Floodplain (Zones A, AE, AO)
Highway
Railroad
Abandoned Railroad
City
Township Boundary
County Boundary
State Boundary

Exhibit 8.6
Water Resources
Big Stone South to Ellendale
345 kV Transmission Line Project

N

0 2 Miles

BSS+E Big Stone South to Ellendale

Scale 1:100,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit08_WaterResources_Maps_11X17_100k_SD.mxd

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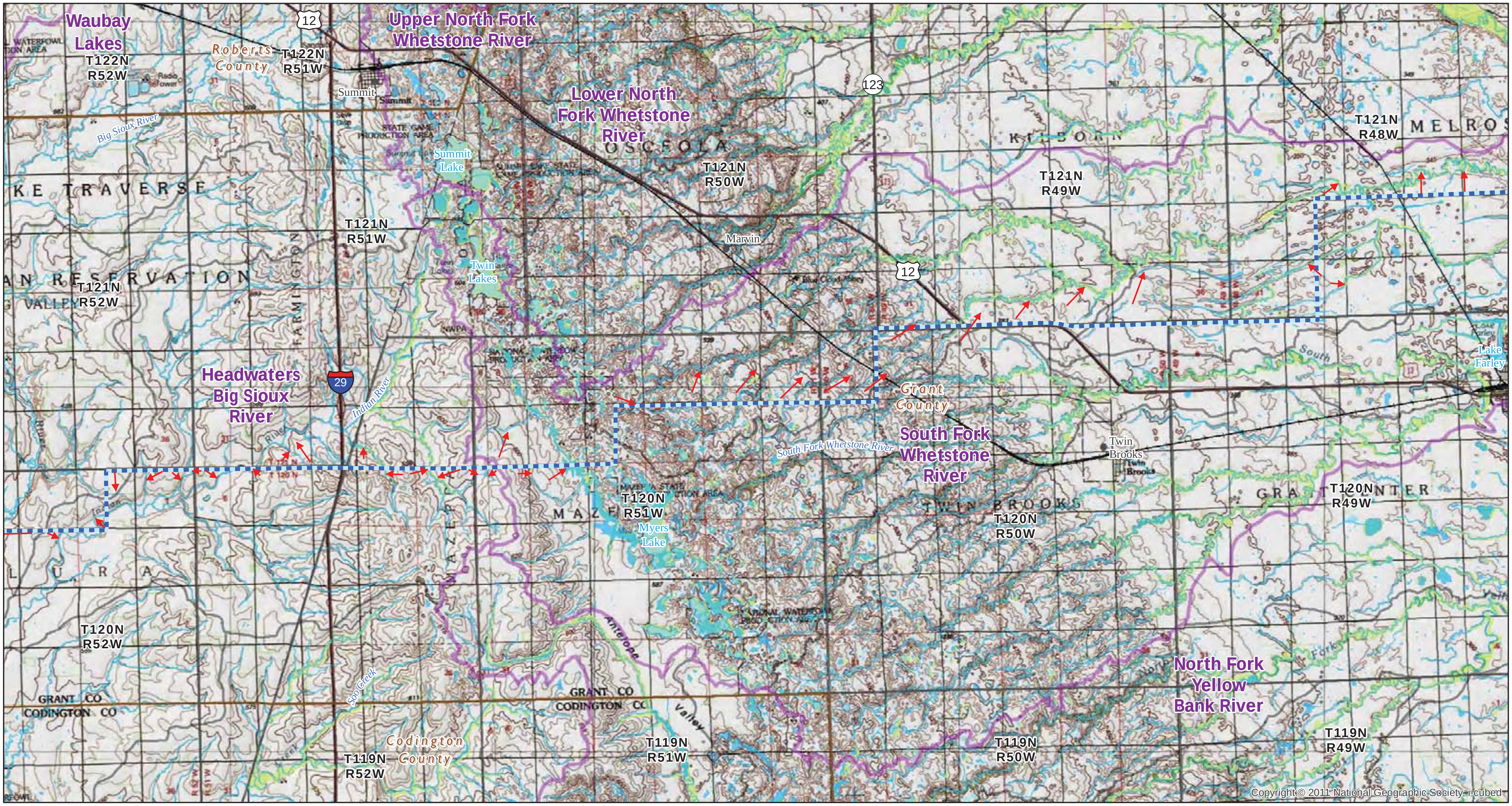

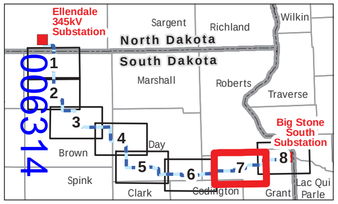

- South Dakota Facility
- Project End Point
- Drainage Pattern
- River or Stream
- Lake, Pond, or River
- Freshwater Emergent Wetland
- Freshwater Forested/Shrub Wetland
- Watershed Boundary (HU10)
- Watershed Sub-Division (HU12)
- Floodplain (Zones A, AE, AO)
- Highway
- Railroad
- Abandoned Railroad
- City
- Township Boundary
- County Boundary
- State Boundary

Exhibit 8.7
Water Resources
Big Stone South to Ellendale
345 kV Transmission Line Project

0 2 Miles

BSS·E Big Stone South to Ellendale

Scale 1:100,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit08_WaterResources_Maps_11X17_100k_SD.mxd

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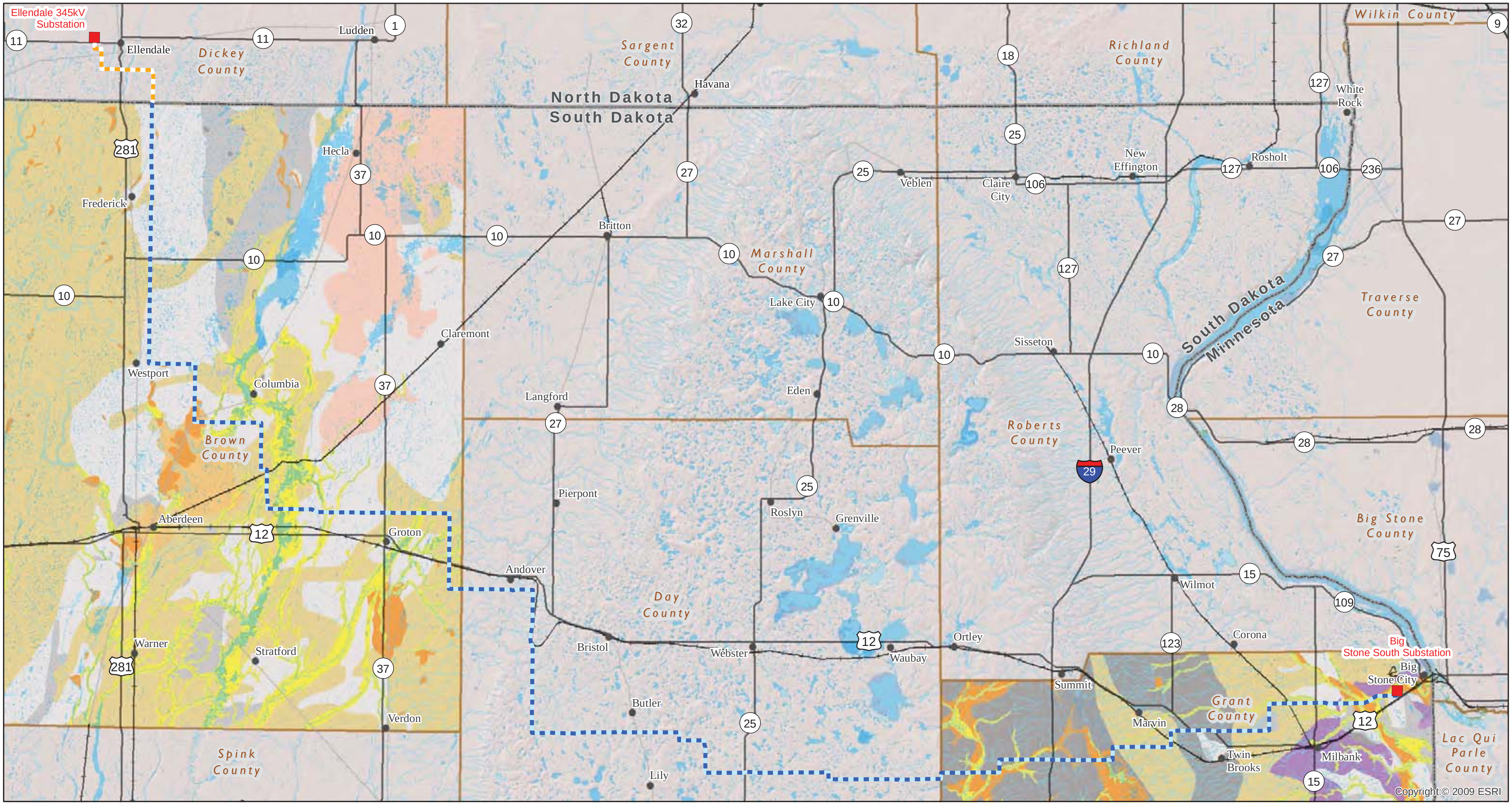
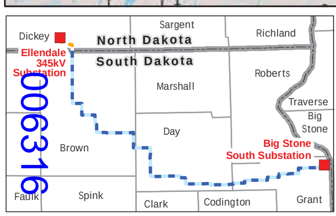
Date: 8/13/2013





South Dakota Facility	Aquifer Materials	Millbank Granite Wash 100+	River or Stream	Railroad	City
North Dakota Facility	Deltaic Deposits	Millbank Granite Wash 50-100	Lake, Pond, or River	Abandoned Railroad	County Boundary
Project End Point	Eolian Sands	Outwash	Freshwater Emergent Wetland	Highway	State Boundary
	Alluvium	Sand and Gravel 0-50	Freshwater Forested/Shrub Wetland		
	Dakota Formation 100+	Sand and Gravel 100+			
	Millbank Granite Wash 0-50	Sand and Gravel 50-100			

Note : No digital Aquifer data available for Day County

Exhibit 9
Aquifers
Big Stone South to Ellendale
345 kV Transmission Line Project

N

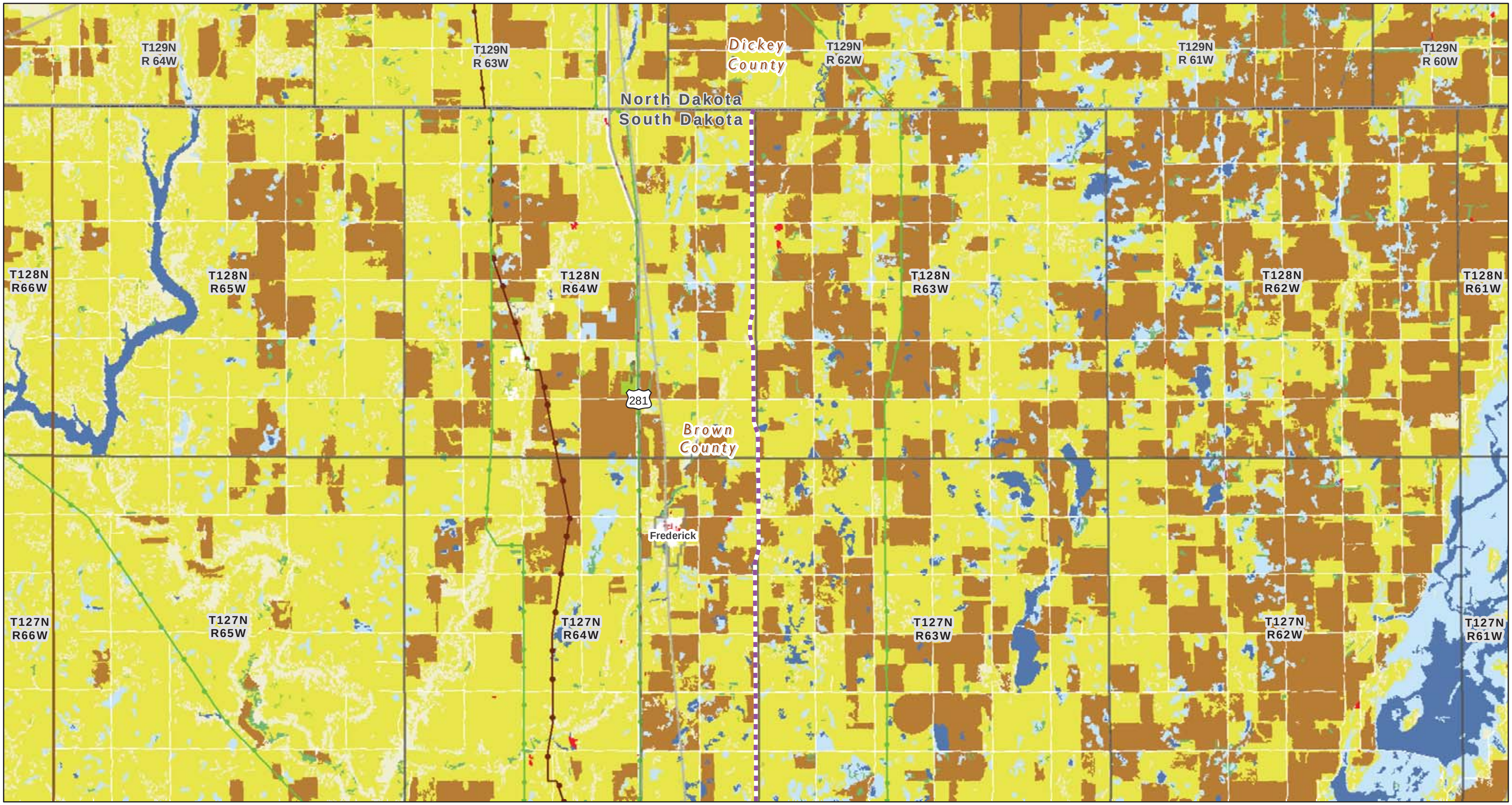
0 10 Miles

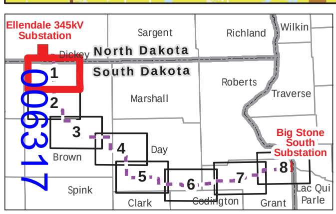
BSS+E Big Stone South to Ellendale

Scale 1:450,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit09_Aquifers_11X17_SD.mxd

Date: 8/13/2013





Source : NLCD 2006

South Dakota Facility
Project End Point

NLCD Land Cover
Developed
Woodlands
Shrublands
Grassland
Pasture/Hay
Cultivated Crops
Wetland
Open Water

Electric
Pipeline
Highway
Railroad
Abandoned Railroad

City Boundary
Township Boundary
County Boundary
State Boundary

Exhibit 10.1
Land Cover (NLCD)
Big Stone South to Ellendale
345 kV Transmission Line Project

Miles 0 2

Scale 1:100,000

006317

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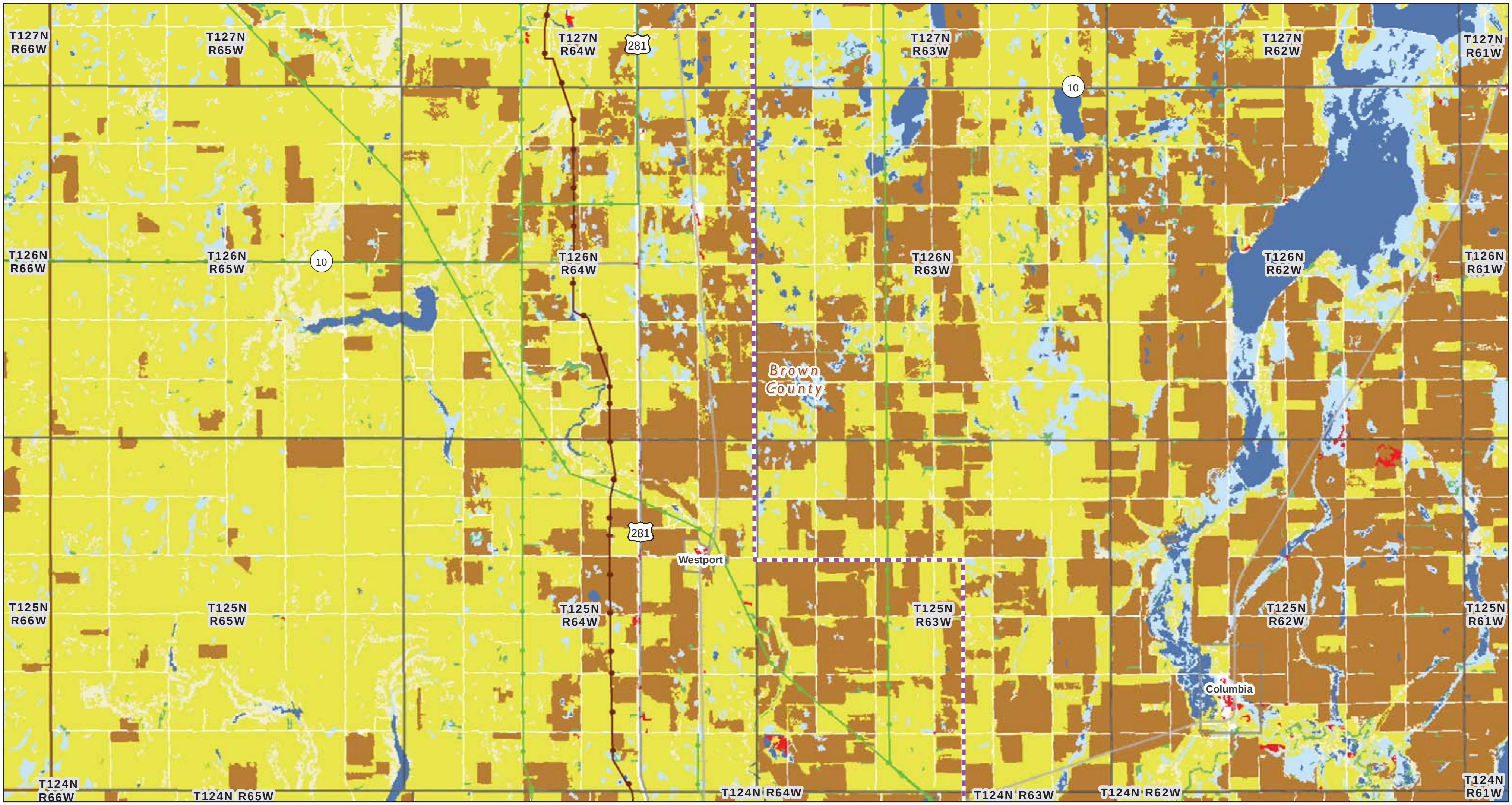
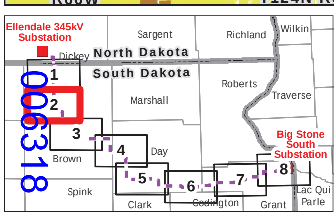




006318

Source : NLCD 2006

South Dakota Facility
Project End Point

NLCD Land Cover
- Developed
- Woodlands
- Shrublands
- Grassland
- Pasture/Hay
- Cultivated Crops
- Wetland
- Open Water

- Electric
- Pipeline
- Highway
- Railroad
- Abandoned Railroad

- City Boundary
- Township Boundary
- County Boundary
- State Boundary

Exhibit 10.2
Land Cover (NLCD)
Big Stone South to Ellendale
345 kV Transmission Line Project

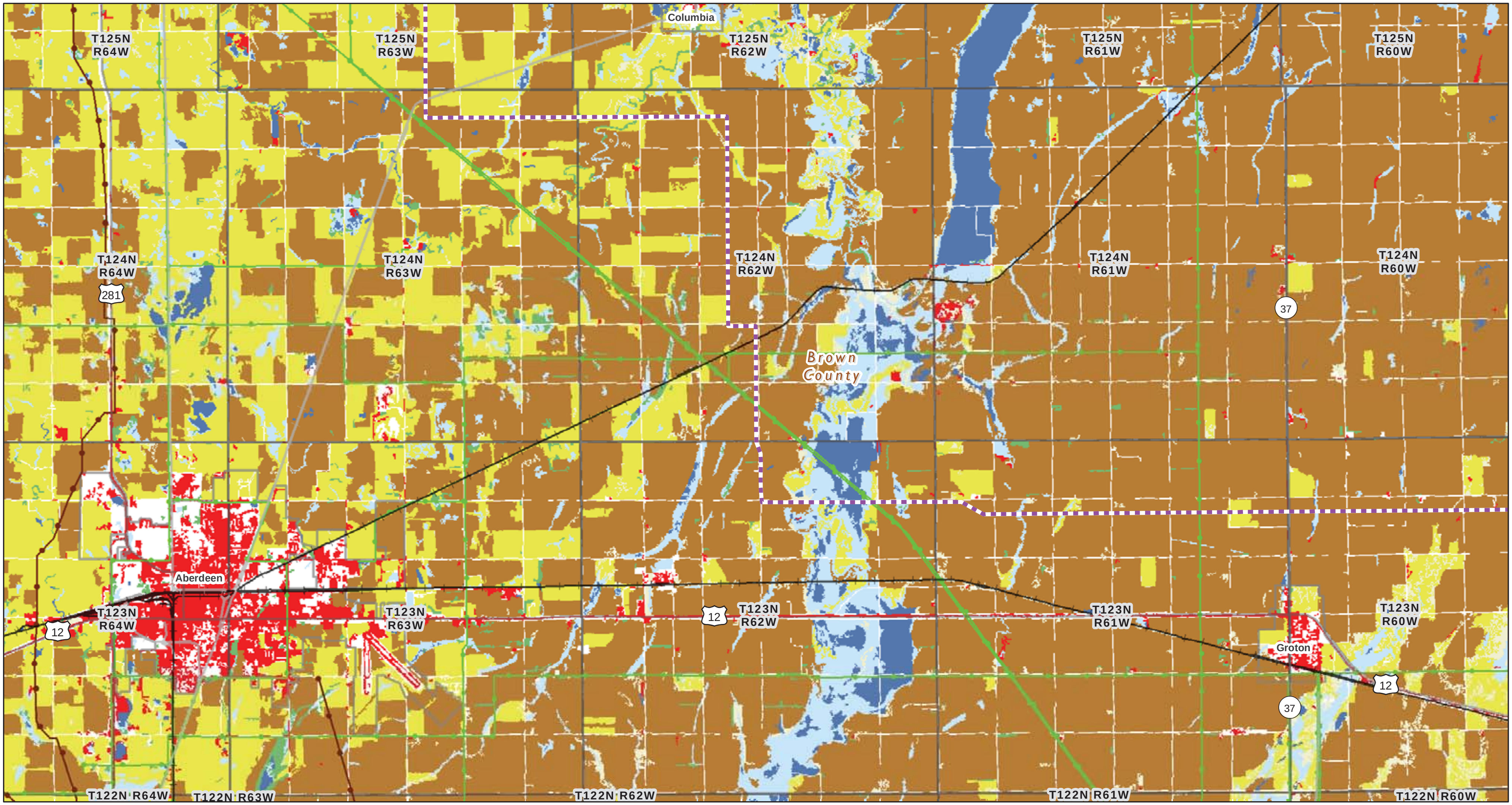
0 2 Miles

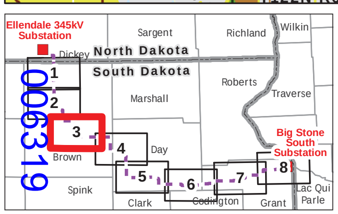
BSS+E Big Stone South to Ellendale

Scale 1:100,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit10_LandCover_Maps_11X17_100k_SD.mxd

Date: 8/13/2013





006319

Source : NLCD 2006

South Dakota Facility
Project End Point

NLCD Land Cover
Developed
Woodlands
Shrublands
Grassland
Pasture/Hay
Cultivated Crops
Wetland
Open Water

Electric
Pipeline
Highway
Railroad
Abandoned Railroad

City Boundary
Township Boundary
County Boundary
State Boundary

Exhibit 10.3
Land Cover (NLCD)
Big Stone South to Ellendale
345 kV Transmission Line Project

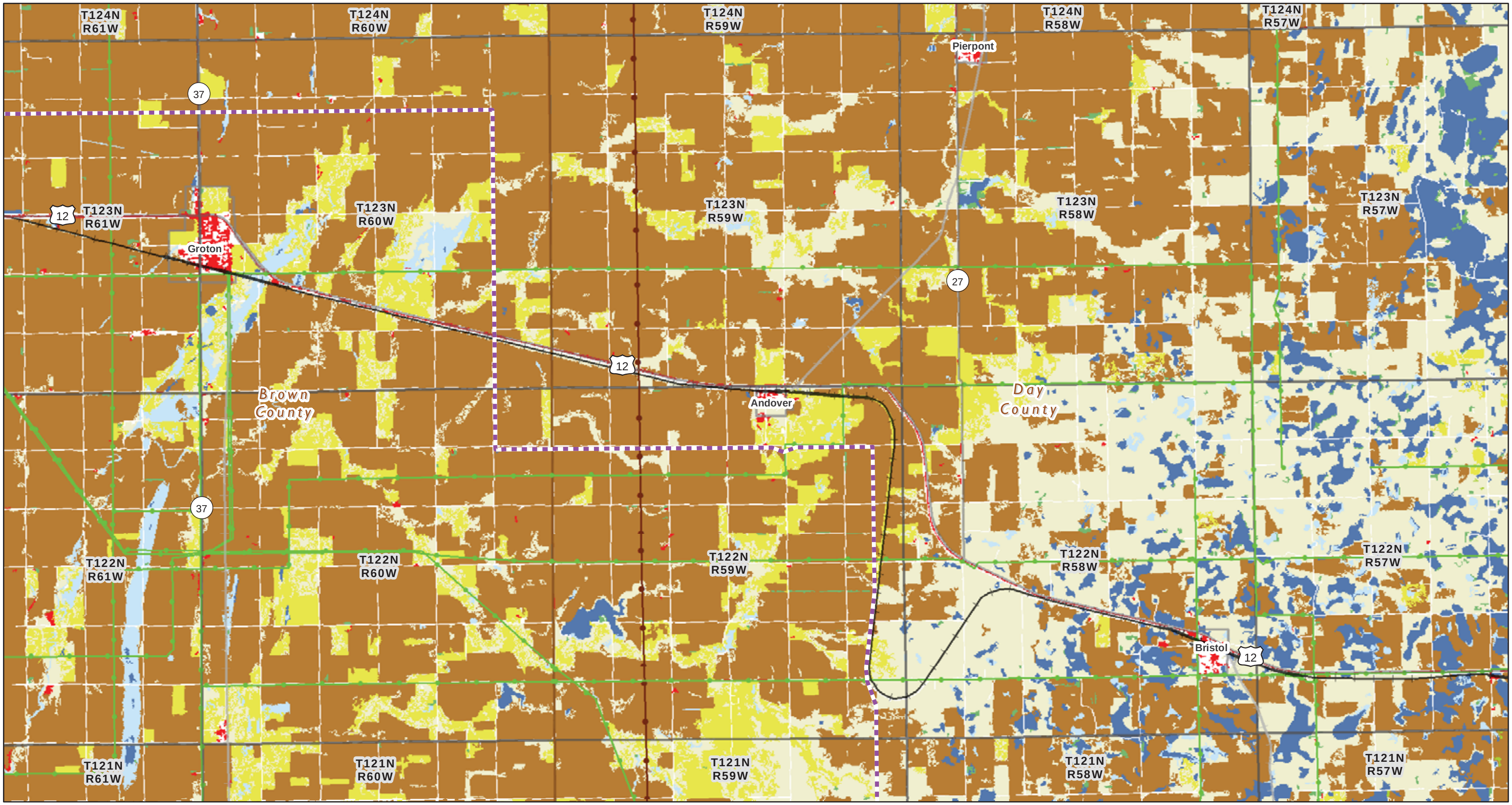
Miles
0 2

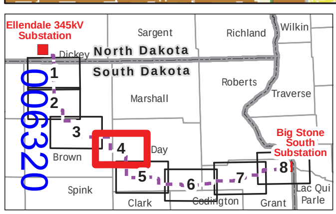
BSS+E Big Stone South to Ellendale

Scale 1:100,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit10_LandCover_Maps_11X17_100k_SD.mxd

Date: 8/13/2013





Source : NLCD 2006

South Dakota Facility
Project End Point

NLCD Land Cover
Developed
Woodlands
Shrublands
Grassland
Pasture/Hay
Cultivated Crops
Wetland
Open Water

Electric
Pipeline
Highway
Railroad
Abandoned Railroad

City Boundary
Township Boundary
County Boundary
State Boundary

Exhibit 10.4
Land Cover (NLCD)
Big Stone South to Ellendale
345 kV Transmission Line Project

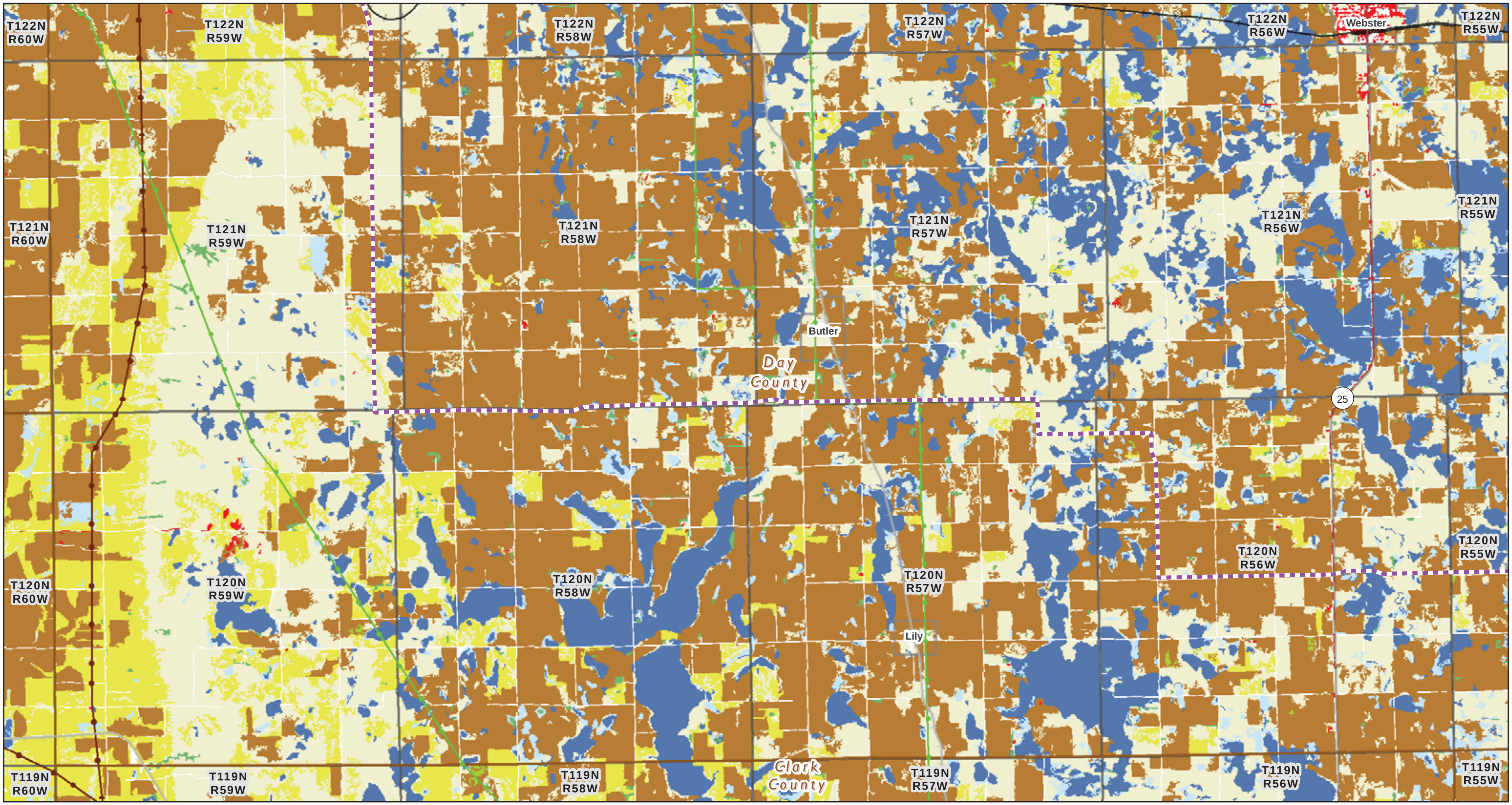
Miles
0 2

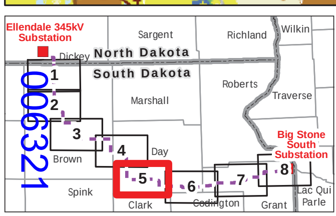
BSSE

Scale 1:100,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit10_LandCover_Maps_11X17_100k_SD.mxd

Date: 8/13/2013





006321

Source : NLCD 2006

South Dakota Facility

Project End Point

NLCD Land Cover

- Developed
- Woodlands
- Shrublands
- Grassland
- Pasture/Hay
- Cultivated Crops
- Wetland
- Open Water

Electric

Pipeline

Highway

Railroad

Abandoned Railroad

City Boundary

Township Boundary

County Boundary

State Boundary

Exhibit 10.5

Land Cover (NLCD)

Big Stone South to Ellendale

345 kV Transmission Line Project

N

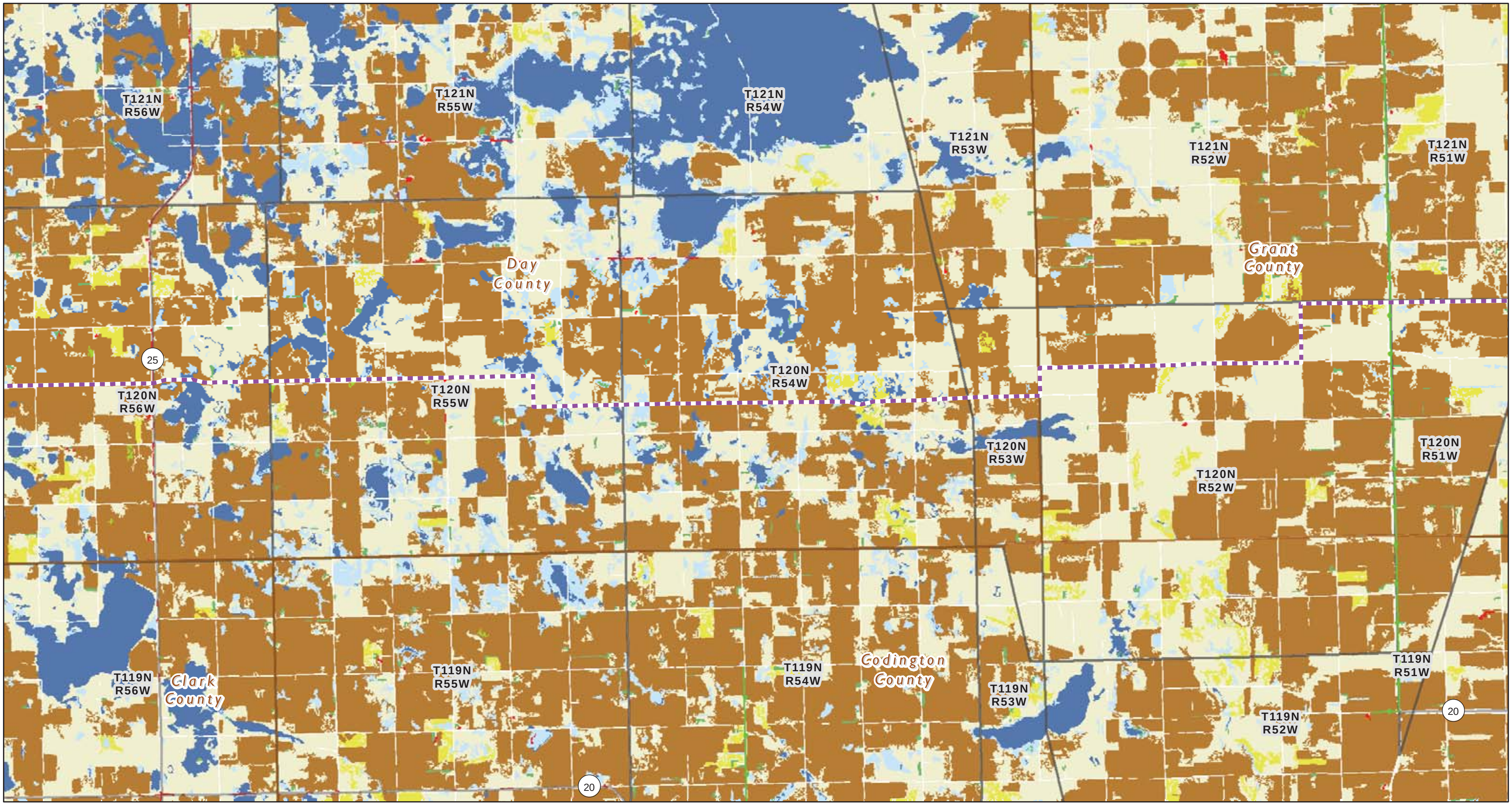
0 2 Miles

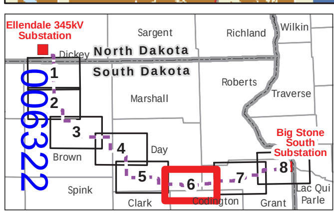
BSSE Big Stone South to Ellendale

Scale 1:100,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit10_LandCover_Maps_11X17_100k_SD.mxd

Date: 8/13/2013





Source : NLCD 2006

- South Dakota Facility
- Project End Point

NLCD Land Cover

- Developed
- Woodlands
- Shrublands
- Grassland
- Pasture/Hay
- Cultivated Crops
- Wetland
- Open Water

- Electric
- Pipeline
- Highway
- Railroad
- Abandoned Railroad

- City Boundary
- Township Boundary
- County Boundary
- State Boundary

Exhibit 10.6
Land Cover (NLCD)
Big Stone South to Ellendale
345 kV Transmission Line Project

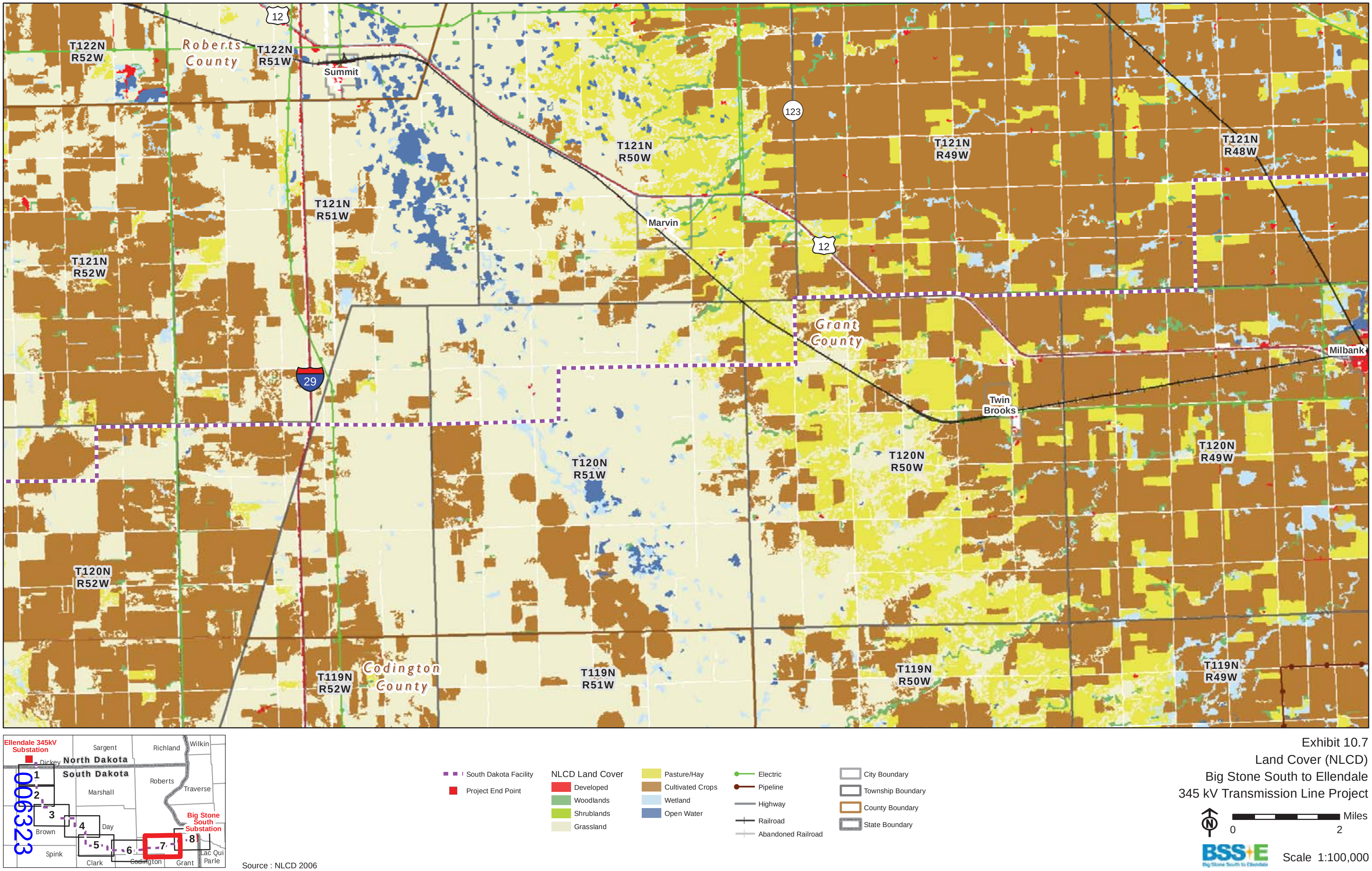
Miles
0 2

BSS+E

Scale 1:100,000

Path: \\mspe-gis-file\GISProjLarge\MDU_OTP\186675\map_docs\Permits\SD-PUC\Exhibit10_LandCover_Maps_11X17_100k_SD.mxd

Date: 8/13/2013



006323

Source : NLCD 2006

Exhibit 10.7
Land Cover (NLCD)
Big Stone South to Ellendale
345 kV Transmission Line Project

Scale 1:100,000

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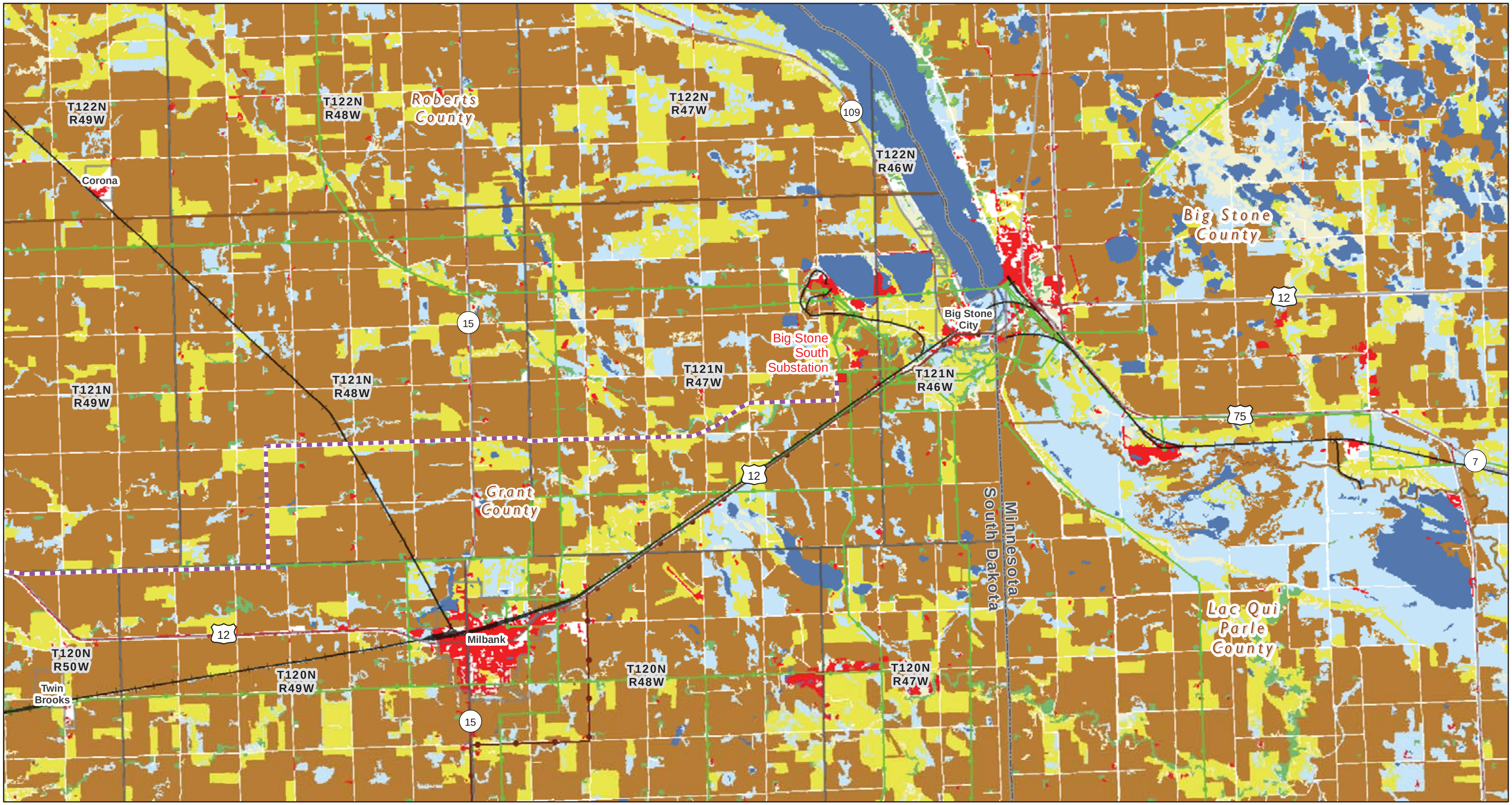
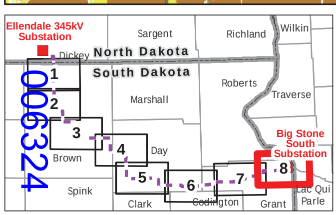
Date: 8/13/2013





006324

Source : NLCD 2006

South Dakota Facility
Project End Point

NLCD Land Cover
Developed
Woodlands
Shrublands
Grassland
Pasture/Hay
Cultivated Crops
Wetland
Open Water

Electric
Pipeline
Highway
Railroad
Abandoned Railroad

City Boundary
Township Boundary
County Boundary
State Boundary

Exhibit 10.8
Land Cover (NLCD)
Big Stone South to Ellendale
345 kV Transmission Line Project

Miles
0 2

BSSE

Scale 1:100,000

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APPENDIX A

SOUTH DAKOTA FACILITY DESCRIPTION

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SOUTH DAKOTA FACILITY SITE DESCRIPTION

The South Dakota Facility is located in Brown, Day, and Grant counties, South Dakota. See Figure 1 for a Project Overview and Figure 2 for a detailed review of the South Dakota Facility and Figure 3 for the United States Geological Survey (USGS) topographic maps. At the North Dakota/South Dakota state border in north-central Brown County the South Dakota Facility continues south along 388th Avenue for about 20 miles. The South Dakota Facility turns east along 120th Street for about 3.5 miles and then turns south along the half section for approximately 4.5 miles between 391st and 392nd Avenues. It then turns east along 124th Street for about 5 miles, turns south along half sections for approximately 3.5 miles, and turns east for nearly 0.5 miles along 128th Street. The South Dakota Facility then turns south for approximately 3.0 miles along 397th Avenue, and then turns east for about 3.5 miles along 131st Street. The South Dakota Facility turns southeast for approximately 0.75 miles and then continues east, south of 131st Street for approximately 10.25 miles. The South Dakota Facility turns south along 411th Avenue for about 5.75 miles, crossing US Highway 12 and a railway, and then turns east along 137th Street for nearly 6 miles, extending slightly south of Andover. The South Dakota Facility heads south through the half sections between 417th and 418th Avenues for about 11 miles, curving west to follow the railway near 141st Street, and then turns east along 148th Street for approximately 11.5 miles. The South Dakota Facility turns south along 429th Avenue for about 0.5 miles, then turns east along half section lines between 148th Street and 149th Street for approximately 2 miles, and then turns south for about 2.5 miles along 431st Avenue. The South Dakota Facility turns east for almost 9.5 miles along 151st Street and then turns south for about 0.5 miles along the half section. The South Dakota Facility then heads east through half sections between 151st and 152nd Street for about 8.5 miles and then turns north for approximately 0.5 miles along 449th Avenue. The South Dakota Facility turns east along 151st Street for nearly 4.5 miles, turns north for about 1 mile, and then continues east along 150th Street for approximately 9.0 miles. The South Dakota Facility turns north for almost 1.0 mile and then turns east along 149th Street for about 4.5 miles, turns north for approximately 1.5 miles along 467th Avenue then continues east for nearly 7.5 miles and then continues north for about 2.0 miles through half sections. The South Dakota Facility then heads east along 146th Street for about 7.5 miles, heads northeast at a diagonal for approximately 1.0 miles, turns east through half sections for approximately 1.5 miles, and turns north at 484th Avenue for approximately 0.5 miles to the Big Stone South Substation.

Table 1 provides a segment-by-segment description of the South Dakota Facility, beginning at the North Dakota and South Dakota border in Brown County, and terminating at the Big Stone South Substation in Grant County. The location provided is the township (T), range (R), and section number, while the direction refers to the direction of the transmission line as if one were traveling the South Dakota Facility from west to east. The linear feature column identifies existing land features that may be near the South Dakota Facility.

Table 1. South Dakota Facility Route Description

Location	Direction	Linear Feature	Route Miles*
T128N, R64W Section 1 North/South Dakota Border	South	388th Avenue	20
T125N, R64W Section 13	East	120th Street	3.5
T125N, R63W Section 15	South	Half Section	4.5
T124N, R63W Section 3	East	124th Street	5
T124N,R62W Section 4	South	Half Section	3.5
T124N, R62W Section 28	East	128th Street	0.5
T124N, R62W Section 28	South	397th Avenue	3
T123N,R62W Section 10	East	131st Street moves to quarter section in T123N,R61W Section 7 (James River Crossing)	14
T123N,R60W Section 12	South	411th Avenue	6
T122N,R60W Section 12	East	137th Street	6.5
T122N,R59W Section 12	South	Half section line until paralleling the railroad in sections 24 and 25 then moves to half section line in section 36	11
T120N,R59W Section 1	East	148th street	11.5
T121N,R57W Section 35	South	429th Avenue	0.5
T120N,R57W Section 1	East	Half Section	2
T120N,R56W Section 6	South	431st Avenue	2.5
T120N,R56W Section 17	East	151st Street	9.5
T120N,R55W Section 14	South	Half Section	0.5

Location	Direction	Linear Feature	Route Miles*
T120N,R55W Section 23	East	Half Section	8.5
T120N,R52W Section 7	North	449th Avenue	0.5
T120N,R52W Section 7	East	151st Street	4.5
T120,R52W Section 11	North	Half Section	1
T120N,R52W Section 2	East	150th Street	9
T120N,R51W Section 16	North	Half Section	1
T120N,R51W Section 9	East	149th Street	4.5
T120N,R50W Section 8	North	467th Avenue	1.5
T121N,R50W Section 36	East	148th Street	7.5
T120N,R49W Section 4	North	Half Section	2
T121N,R48W Section 20	East	146th Street moves to Half Section in T121N,R47W sections 22 and 23	10
T121N,R47W Section 24	North	484th Avenue, continues until the proposed Big Stone South substation	0.5

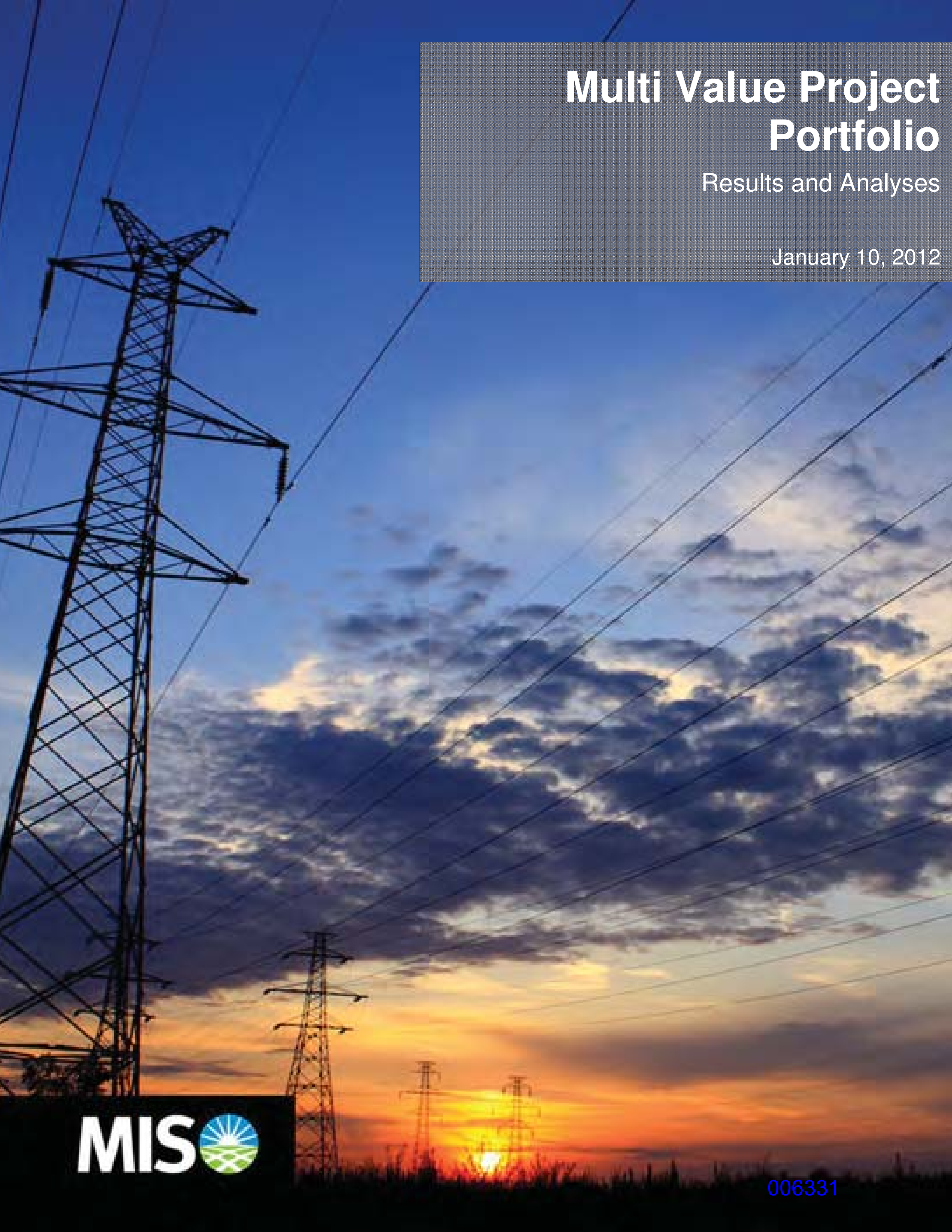
*All route miles are approximate.

APPENDIX B

MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC. (MISO) STUDIES

FILED ELECTRONICALLY ON ATTACHED CD

LIST OF STUDIES
B.1: Multi-Value Project Portfolio, Results and Analyses (Midwest ISO 2012)
B.2: Northwest Exploratory Study completed during MISO Transmission Expansion Plan 2005 (Midwest ISO 2005)
B.3: Regional Generation Outlet Study completed during MISO Transmission Expansion Plan 2009 and 2010 (Midwest ISO 2010)
B.4: "Multi-Value Project Portfolio – Results and Analyses" paraphrased in MISO Transmission Expansion Plan 2011 (Midwest ISO 2011)



Multi Value Project Portfolio

Results and Analyses

January 10, 2012

006331

1 Executive Summary

MISO staff recommends that the Multi Value Project (MVP) portfolio described in this report be approved by the MISO Board of Directors for inclusion into Appendix A of MTEP11. This recommendation is based on the strong reliability, public policy and economic benefits of the portfolio that are distributed across the MISO footprint in a manner that is commensurate with the portfolio's costs. In short, the proposed portfolio will:

- Provide benefits in excess of its costs under all scenarios studied, with its benefit to cost ratio ranging from 1.8 to 3.0.
- Maintain system reliability by resolving reliability violations on approximately 650 elements for more than 6,700 system conditions and mitigating 31 system instability conditions.
- Enable 41 million MWh of wind energy per year to meet renewable energy mandates and goals.
- Provide an average annual value of $1,279 million over the first 40 years of service, at an average annual revenue requirement of $624 million.
- Support a variety of generation policies by using a set of energy zones which support wind, natural gas and other fuel sources.

This report summarizes the key reliability, public policy and economic benefits of the recommended MVP portfolio, as well as the scope of the analyses used to determine these benefits.

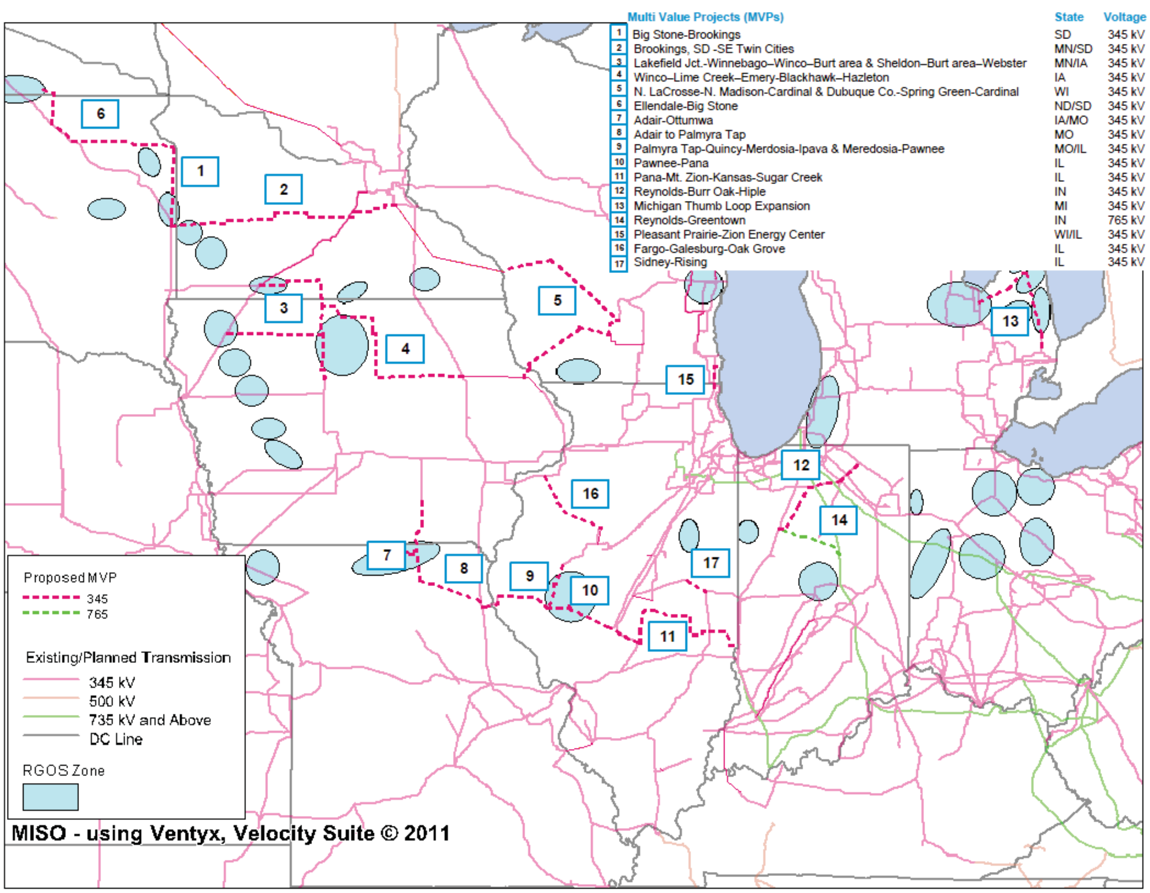


Figure 1.1: MVP portfolio[1]

[1] MVP line routing shown throughout the report is for illustrative purposes only and do not represent the final line routes.

The recommended MVP portfolio includes the Brookings Project, conditionally approved in June 2011, and the Michigan Thumb Loop project, approved in August 2010. It also includes 15 additional projects which, when integrated into the transmission system, provide multiple kinds of benefits under all future scenarios studied[2].

	Project	State	Voltage (kV)	In Service Year	Cost (M, 2011$)[3]
1	Big Stone–Brookings	SD	345	2017	$191
2	Brookings, SD–SE Twin Cities	MN/SD	345	2015	$695
3	Lakefield Jct. –Winnebago–Winco–Burt area & Sheldon–Burt area–Webster	MN/IA	345	2016	$506
4	Winco–Lime Creek–Emery–Black Hawk–Hazleton	IA	345	2015	$480
5	N. LaCrosse–N. Madison–Cardinal & Dubuque Co. –Spring Green–Cardinal	WI	345	2018/2020	$714
6	Ellendale–Big Stone	ND/SD	345	2019	$261
7	Adair–Ottumwa	IA/MO	345	2017	$152
8	Adair–Palmyra Tap	MO/IL	345	2018	$98
9	Palmyra Tap–Quincy–Merdosia–Ipava & Meredosia–Pawnee	IL	345	2016/2017	$392
10	Pawnee–Pana	IL	345	2018	$88
11	Pana–Mt. Zion–Kansas–Sugar Creek	IL/IN	345	2018/2019	$284
12	Reynolds–Burr Oak–Hiple	IN	345	2019	$271
13	Michigan Thumb Loop Expansion	MI	345	2015	$510
14	Reynolds–Greentown	IN	765	2018	$245
15	Pleasant Prairie–Zion Energy Center	WI/IL	345	2014	$26
16	Fargo-Galesburg–Oak Grove	IL	345	2018	$193
17	Sidney–Rising	IL	345	2016	$90
	Total				$5,197

Table 1.1: MVP portfolio[4]

[2] More information on these scenarios may be found in the business case description.
[3] Costs shown are inclusive of transmission underbuild upgrades and upgrades driven by short circuit requirements.
[4] In-service dates represent the best information available at the time of publication. These dates may shift as the projects progress through the state regulatory processes.

Public policy decisions over the last decade have driven changes in how the transmission system is planned. The recent adoption of Renewable Portfolio Standards (RPS) and clean energy goals across the MISO footprint have driven the need for a more regional and robust transmission system to deliver renewable resources from often remote renewable energy generators to load centers.

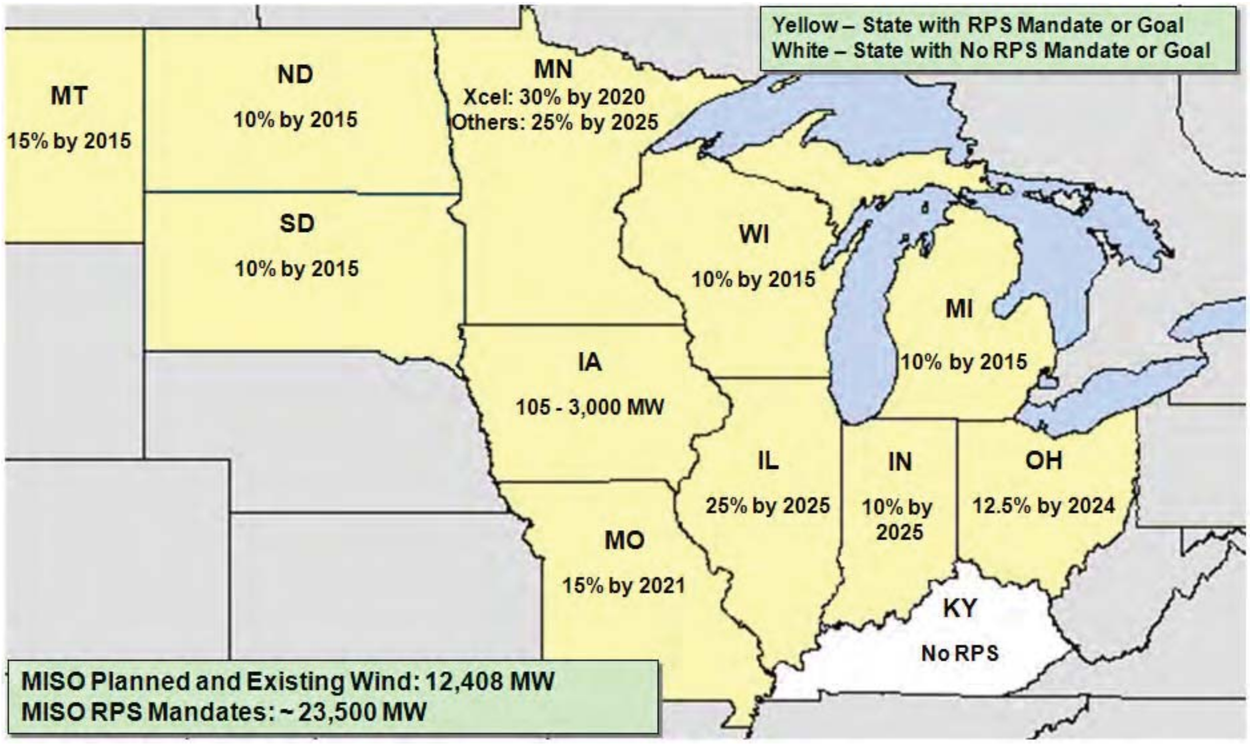


Figure 1.2: Renewable energy mandates and clean energy goals within the MISO footprint[5,6]

Beginning with the MTEP03 Exploratory Studies, MISO and stakeholders began to explore how to best provide a value added regional planning process to complement the local planning of MISO members. These explorations continued in later MTEP cycles and in specific targeted studies. In 2008, MISO, with the assistance of state regulators and industry stakeholders such as the Midwest Governor's Association (MGA), the Upper Midwest Transmission Development Initiative (UMTDI) and the Organization of MISO States (OMS), began the Regional Generation Outlet Study (RGOS) to identify a set of value based transmission projects necessary to enable Load Serving Entities (LSEs) to meet their RPS mandates.

> The recent adoption of Renewable Portfolio Standards (RPS) across the MISO footprint have driven the need for a more regional and robust transmission system to deliver renewable resources from often remote renewable energy generators to load centers.

The goal of the RGOS analysis was to design transmission portfolios that would enable RPS mandates to be met at the lowest delivered wholesale energy cost. The cost calculation combined the expenses of the new transmission portfolios with the capital costs of the new renewable generation, balancing

[5] Existing and planned wind as included in the MVP Portfolio analyses. State RPS mandates and goals include all policies signed into law by June 1, 2011.
[6] The higher number for Iowa's state RPS mandates and goals reflects the wind online rather than a statutory requirement.

the trade offs of a lower transmission investment to deliver wind from low wind availability areas, typically closer to large load centers; against a larger transmission investment to deliver wind from higher wind availability areas, typically located further from load centers.

The zones were chosen with consideration of more factors than wind capacity. Existing infrastructure, such as transmission and natural gas pipelines, also influenced the selection of zones.

While much consideration was given to wind capacity factors when developing the energy zones utilized in the RGOS and MVP portfolio analyses, the zones were chosen with consideration of more factors than wind capacity. Existing infrastructure, such as transmission and natural gas pipelines, also influenced the selection of the zones. As such, although the energy zones were created to serve the renewable generation mandates, they could be used for a variety of different generation types, to serve various future generation policies. Figure 1.3 depicts the correlation between the natural gas pipelines in the MISO footprint and the energy zones.

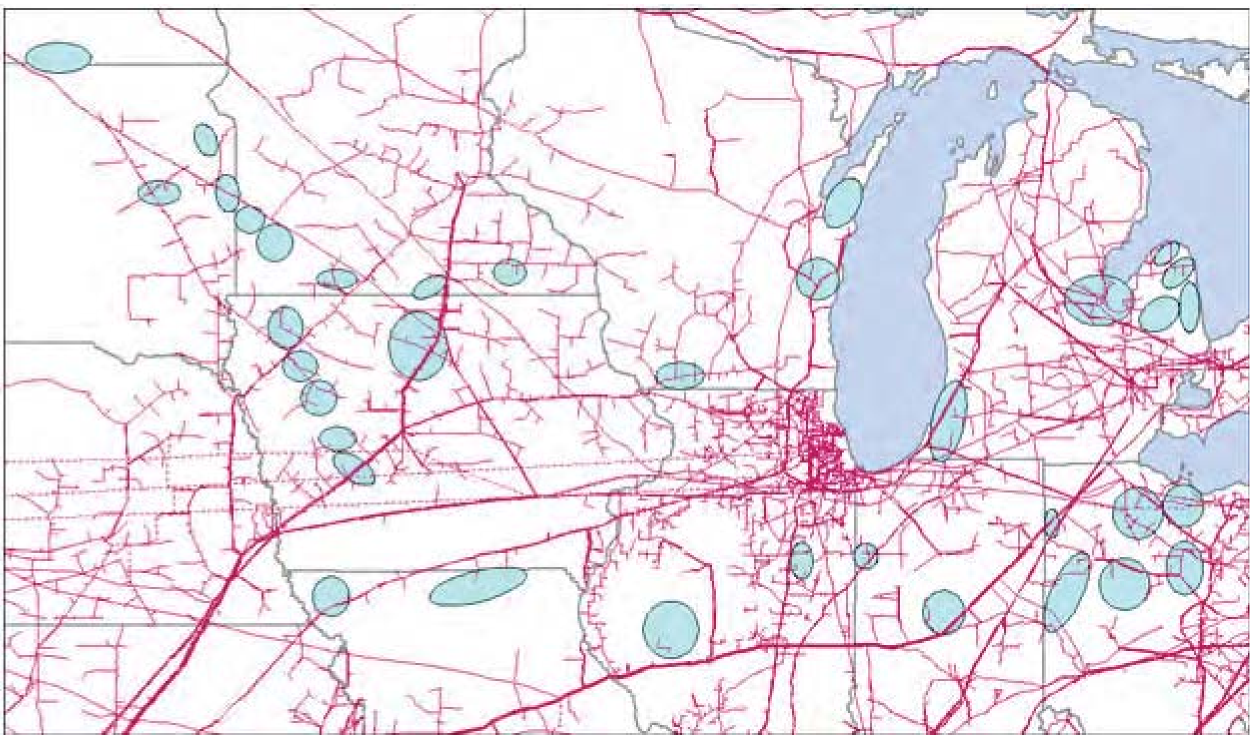


Figure 1.3: RGOS and MVP Analyses Incremental Energy Zones and natural gas pipelines

006337

Common elements between the RGOS results and previous reliability, economic and generation interconnection analyses were identified to create the 2011 candidate MVP portfolio. This portfolio represented a set of “no regrets” projects which were believed to provide multiple kinds of reliability and economic benefits under all alternate futures studied.

The output from the study, a recommended MVP portfolio, will reduce the wholesale cost of energy delivery for the consumer by enabling the delivery of low cost generation to load, reducing congestion costs and increasing system reliability, regardless of the future generation mix.

The 2011 MVP portfolio analysis hypothesized that this set of candidate projects will create a high value transmission portfolio, enabling MISO states to meet their near term RPS mandates. The study evaluated the candidate MVP portfolio against the MVP cost allocation criteria to prove or disprove this hypothesis, as well as to confirm that the benefits of the portfolio would be widely distributed across the footprint. The output from the study, a recommended MVP portfolio, will reduce the wholesale cost of energy delivery for the consumer by enabling the delivery of low cost generation to load, reducing congestion costs and increasing system reliability, regardless of the future generation mix.

Over the course of the MVP portfolio analysis, the candidate MVP portfolio was refined into the portfolio that is now recommended to the MISO Board of Directors for approval. The portfolio was refined to ensure that the portfolio as a group and each project contained within it was justified under the MVP criteria, discussed below, and to ensure that the portfolio benefit to cost ratio was optimized.

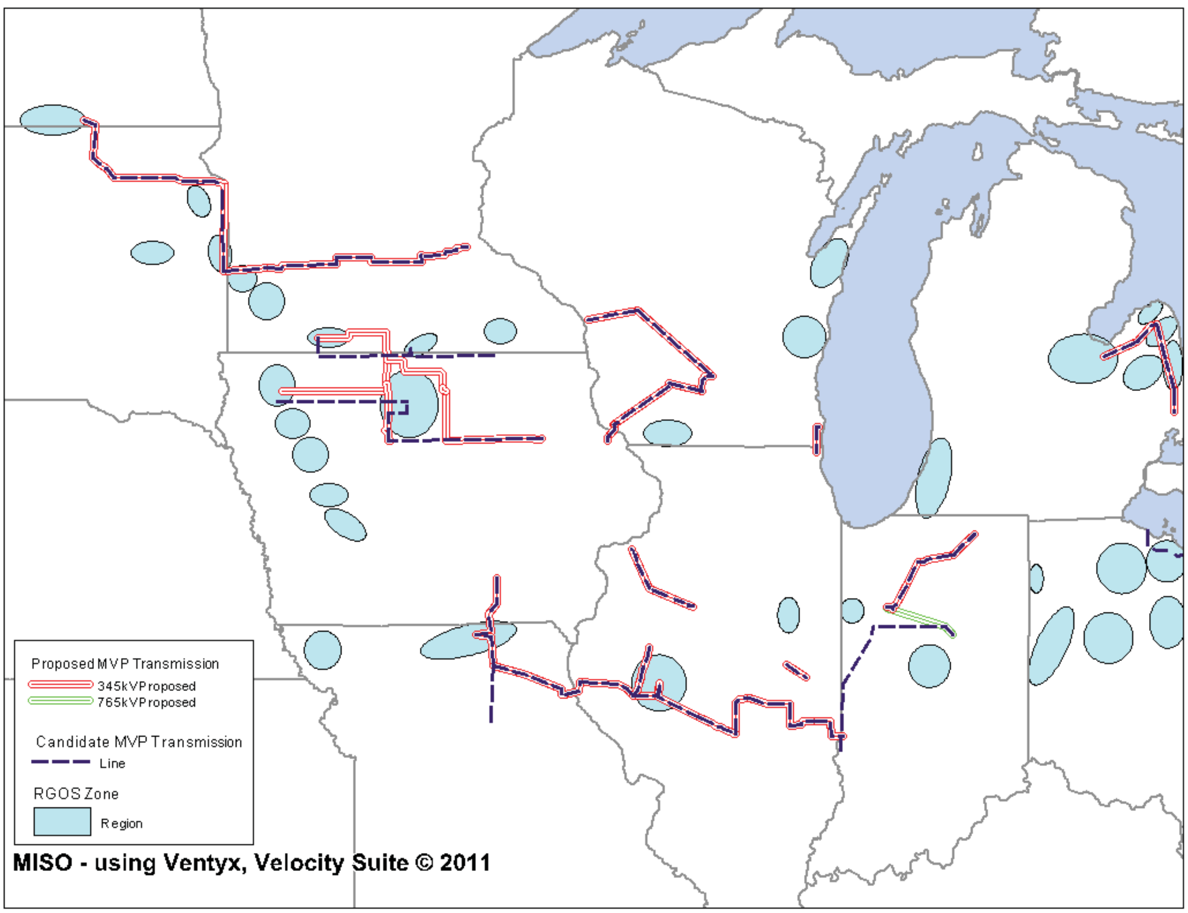


Figure 1.4: Candidate versus Recommended MVP Portfolios

The recommended MVP portfolio will enable the delivery of the renewable energy required by public policy mandates, in a manner more reliable and economic than it would be without the associated transmission upgrades. Specifically, the portfolio mitigates approximately 650 reliability constraints under 6,700 different transmission outage conditions, for steady state and transient conditions under both peak and shoulder load scenarios. Some of these conditions could be severe enough to cause cascading outages on the system. By mitigating these constraints, approximately 41 million MWh per year of renewable generation can be delivered to serve the MISO state renewable portfolio mandates.

> The benefits created by the recommended MVP portfolio are spread across the system, in a manner commensurate with its costs.

Under all future policy scenarios studied, the recommended MVP portfolio delivers widespread regional benefits to the transmission system. For example, based on scenarios that did not consider new energy policies, the benefits of the proposed portfolio were shown to range from 1.8 to 3.0 times its total cost. These benefits are spread across the system, in a manner commensurate with their costs, as demonstrated in Figure 1.5.

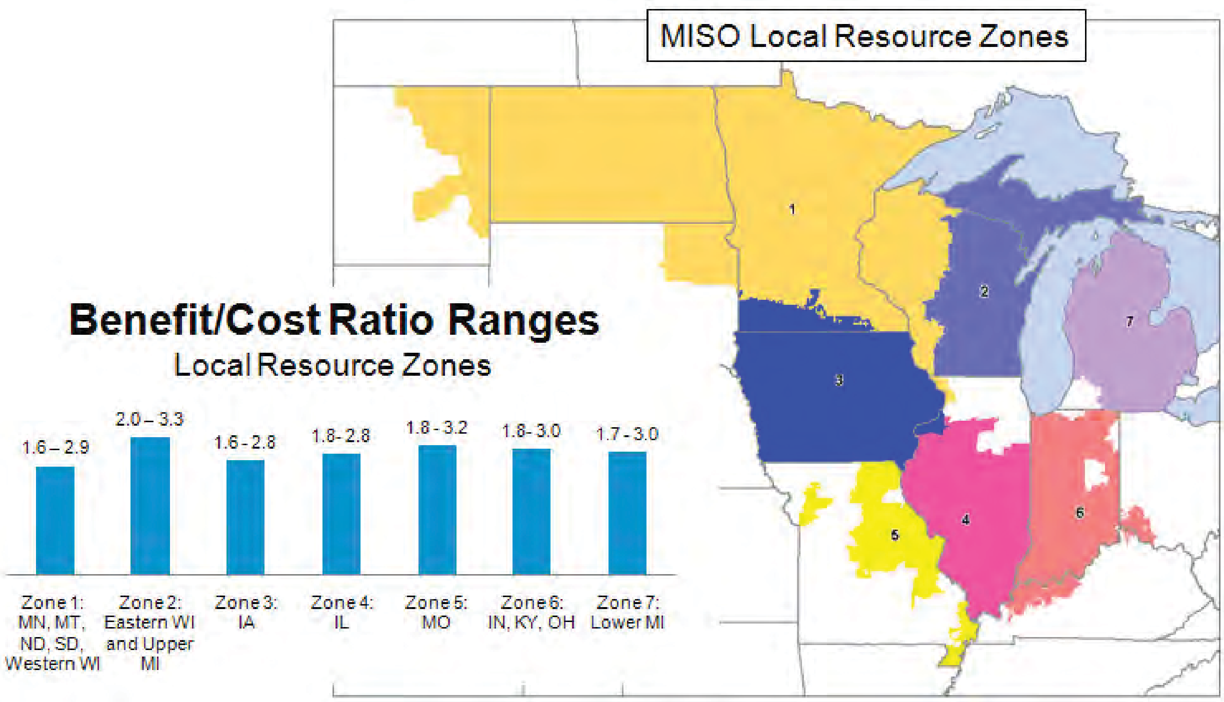


Figure 1.5: Recommended MVP portfolio benefits spread

Taking into account the significant economic value created by the portfolio, the distribution of these value, and the ability of the portfolio to meet MVP criterion 1 through its reliability and public policy benefits, MISO staff recommended the 2011 MVP portfolio to the MISO Board of Directors for their review and approval.

2 MISO Planning Approach

The goal of the MISO planning process is to develop a comprehensive expansion plan that reflects a fully integrated view of project value inclusive of reliability, market efficiency, public policy and other value drivers across all planning horizons. This process is guided by a set of principles established by the MISO Board of Directors, adopted on August 18, 2005. The principles were created in an effort to improve and guide transmission investment in the region and to furnish an element of strategic direction to the MISO transmission planning process. These principles, modified and approved by the MISO Board of Directors System Planning Committee on May 16, 2011, are:

- **Guiding Principle 1:** Make the benefits of an economically efficient energy market available to customers by providing access to the lowest electric energy costs.
- **Guiding Principle 2:** Provide a transmission infrastructure that safeguards local and regional reliability and supports interconnection-wide reliability.
- **Guiding Principle 3:** Support state and federal energy policy objectives by planning for access to a changing resource mix.
- **Guiding Principle 4:** Provide an appropriate cost mechanism that ensures the realization of benefits over time is commensurate with the allocation of costs.
- **Guiding Principle 5:** Develop transmission system scenario models and make them available to state and federal energy policy makers to provide context and inform the choices they face.

A number of conditions must be met to build longer term transmission able to support future generation growth and accommodate new energy policies. These conditions are intertwined with the planning principles put forth by the MISO Board of Directors and supported by an integrated, inclusive transmission planning approach. The conditions that must be met to build transmission include:

- A robust business case that demonstrates value sufficient to support the construction of the transmission project.
- Increased consensus on current and future energy policies.
- A regional tariff that matches who benefits with who pays over time.
- Cost recovery mechanisms that reduce financial risk.

3 Multi Value Project portfolio drivers

The 2011 MVP portfolio analysis was based on the need to economically and reliably help states meet their public policy needs. The study identified a regional transmission portfolio that will enable the MISO Load Serving Entities (LSEs) to meet their Renewable Portfolio Standards (RPS). The analyses and their results describe a robust business case for the portfolio. This business case demonstrates that not only will the recommended MVP portfolio reliably enable Renewable Portfolio Standards to be met, but it will do so in a manner where its economic benefits exceed its costs.

While the study focused upon the RPS requirements, the transmission portfolio will ultimately have widespread benefits beyond the delivery of wind and other renewable energy. It will enhance system reliability and efficiency under a variety of different generation build outs. It will also open markets to competition, reducing congestion and spreading the benefits of low cost generation across the MISO footprint. The MVP portfolio analysis focused on identifying and increasing the benefits of the transmission portfolio, including the reliability, economic and public policy drivers.

3.1 Tariff requirements

The MVP portfolio analysis and the recommendation were premised on the MVP criteria described in Attachment FF of the MISO Tariff and shown below.

> Criterion 1
>
> A Multi Value Project must be developed through the transmission expansion planning process to enable the transmission system to deliver energy reliably and economically in support of documented energy policy mandates or laws enacted or adopted through state or federal legislation or regulatory requirement. These laws must directly or indirectly govern the minimum or maximum amount of energy that can be generated. The MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade.
>
> Criterion 2
>
> A Multi Value Project must provide multiple types of economic value across multiple pricing zones with a Total MVP benefit to cost ratio of 1.0 or higher, where the total MVP benefit to cost ratio is described in Section II.C.7 of Attachment FF to the MISO Tariff. The reduction of production costs and the associated reduction of LMPs from a transmission congestion relief project are not additive and are considered a single type of economic value.
>
> Criterion 3
>
> A Multi Value Project must address at least one transmission issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic based transmission issue that provides economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs based on the definition of financial benefits and Project Costs provided in Section II.C.7 of Attachment FF.

The MVP cost allocation criteria requires evaluation of the portfolio on a reliability, economic and energy delivery basis. The scope of the analysis was designed to demonstrate this value, both on a project and portfolio basis. The projects in the MVP portfolio were evaluated against MVP criteria 1 and their ability to reliably enable the renewable energy mandates of the MISO states was quantified.

In addition, the Tariff identifies specific types of economic value which can be provided by Multi Value Projects. These values are:

- Production cost savings where production costs include generator startup, hourly generator no-load, generator energy and generator Operating Reserve costs. Production cost savings can be realized through reductions in both transmission congestion and transmission energy losses. Productions cost savings can also be realized through reductions in Operating Reserve requirements within Reserve Zones and, in some cases, reductions in overall Operating Reserve requirements for the Transmission Provider.
- Capacity losses savings where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour including associated planning reserve.
- Capacity savings due to reductions in the overall Planning Reserve Margins resulting from transmission expansion.
- Long-term cost savings realized by Transmission Customers by accelerating a long-term project start date in lieu of implementing a short-term project in the interim and/or long-term cost savings realized by Transmission Customers by deferring or eliminating the need to perform one or more projects in the future.
- Any other financially quantifiable benefit to Transmission Customers resulting from an enhancement to the transmission system and related to the provisions of Transmission Service.

The full proposed portfolio was evaluated against the benefits defined in the Tariff for MVPs. In addition to the benefits described above, the operating reserve and wind siting benefits for the portfolio were quantified, as allowed under the last Tariff defined economic value. These benefits are described more fully in the economic benefit section later in the report.

3.2 Transmission strategy

A transmission strategy addressing both local needs and regional drivers allows the MISO system to realize significant economic and reliability benefits. Regional transmission, such as the transmission in the recommended MVP portfolio, increases reliability in the MISO footprint and opens the market to increased competition by providing access to low cost generation, regardless of fuel type. Development of a strong regional transmission backbone is analogous to the development of the U.S. Interstate Highway System. While developed for specific national security justifications, the system has realized significant additional benefits in subsequent years. Similarly, the recommended MVP portfolio will create reliability, economic and public policy benefits reaching beyond the immediate needs exhibited in this analysis.

The overall goal for the MVP portfolio analysis was to design a transmission portfolio which takes advantage of the linkages between local and regional reliability and economic benefits to bring value to the entire MISO system. The portfolio was designed using reliability and economic analyses, applying several futures scenarios to determine the robustness of the designed portfolio under a number of future potential energy policies.

3.3 Public policy needs

Twelve of thirteen states in the MISO footprint have enacted either RPS requirements or renewable energy goals which require or recommend varying amounts of load be served with energy from renewable energy resources. The MVP portfolio analysis focused on the transmission necessary to economically and reliably meet the state RPS mandates. Figure 3.1 provides additional details on these renewable energy requirements and goals.

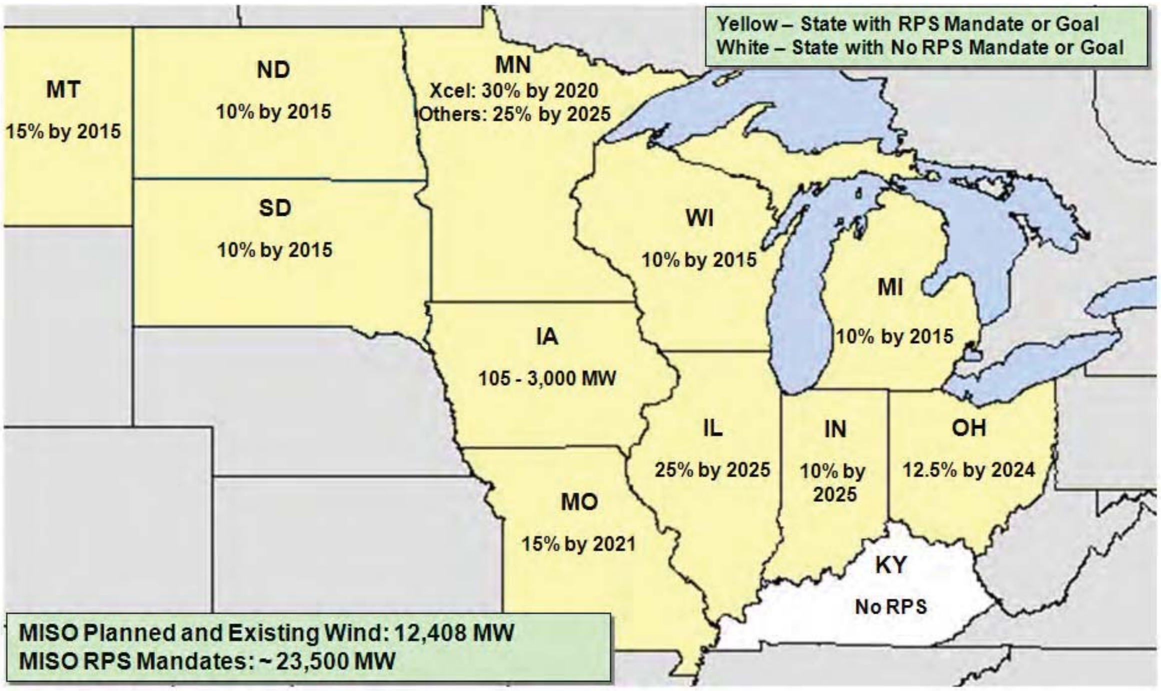


Figure 3.1: RPS mandates and goals within the MISO footprint[7]

RPS mandates vary from state to state in their specific requirement details and implementation timing, but they generally start in about 2010 and are indexed to increase with load growth. While state laws support a number of different types of renewable resources, and multiple types of renewable resources will play a role in meeting state RPS mandates, the majority of renewable energy resources installed in the foreseeable future will likely focus on harnessing the abundant wind resources throughout the MISO footprint.

3.4 Enhanced reliability and economic drivers

The ultimate goal of the MISO planning process is enable the reliable delivery of energy to load at the lowest possible cost. This requires a strategy premised upon a low cost approach to transmission and generation investment. This premise supports the overall constructability of the transmission portfolio, while reducing financial risk associated with overbuilding the system.

> The goal of the MVP portfolio analysis was to design a transmission portfolio which takes advantage of the linkages between local and regional reliability and economic benefits to bring value to the entire MISO system.

[7] The higher number for Iowa's state RPS mandates and goals reflects the wind online rather than a statutory requirement.

4 MVP Portfolio Development and Scope

The MVP portfolio was developed by considering regional system enhancements, from previous MISO analyses, that could potentially provide multiple types of value, including enhanced reliability, reduced congestion, increased market efficiency, reduced real power losses and the deferral of otherwise needed capital investments in transmission.

This portfolio was also based upon a set of energy zones, developed to provide a low-cost approach to wind siting when both generation and transmission capital costs are considered. Incremental wind necessary to meet the 2021 or 2026 renewable mandates for MISO stakeholders was added to these zones, as described in the following sections.

Finally, the MVP portfolio was intensively evaluated to ensure its composite projects, and the portfolio in total, are justified under the MVP cost allocation criterion. This analysis included an evaluation of each individual project justification against MVP criterion 1. It also included an evaluation of the full portfolio, both on a reliability and economic basis.

4.1 Development of the MVP Portfolio

MISO began to investigate the transmission required to integrate wind and provide the best value to consumers in 2002. The analyses continued through subsequent MTEP cycles, with exploratory and energy market analyses. As the demand for renewable energy grew, driven largely by an increasing level of renewable energy mandates or goals, additional regional studies were conducted to determine the transmission necessary to support these policy objectives. These studies included the Joint and Coordinated System Plan (JCSP), the Regional Generation Outlet Studies (RGOS), and analyses by the Organization of MISO States (OMS) Cost Allocation and Regional Planning (CARP) group.

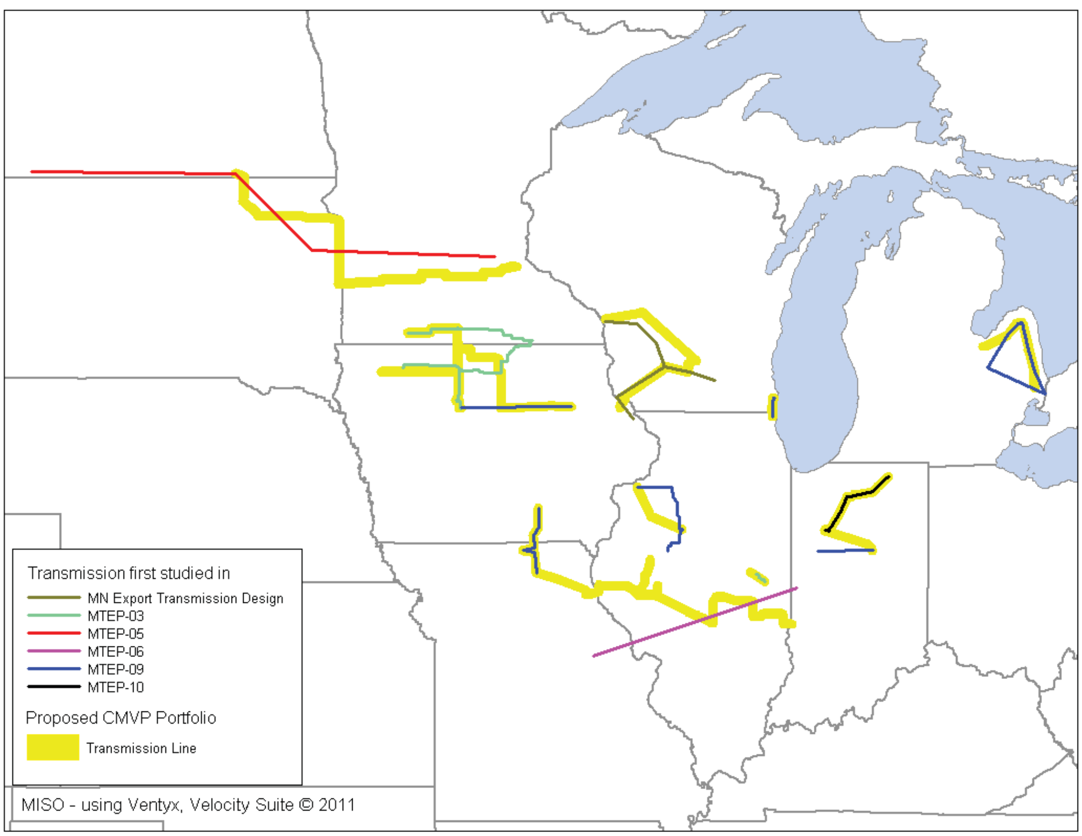


Figure 4.1: Summary of prior study input into recommended MVP portfolio

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As analyses continued, the policy and economic drivers behind a regional transmission plan continued to grow. This growth was partly fueled by the development of the MISO energy and operating reserve market, which allows for regional transmission to provide regional benefits through increasing market efficiency, enabling low cost generation to be delivered to load. Simultaneously, an increase in state energy policy mandates drove the need for a robust regional transmission network, capable of responding to legislated changes in generation requirements.

It is worth noting that, although individual projects were identified beginning in MTEP03, these projects were not studied only in the year they were first identified. Subsequent MTEP analyses built on the analyses of previous years and culminated in the final recommendation of the recommended MVP portfolio.

4.1.1 MTEP03 high wind generation development scenario

In the first MISO Transmission Expansion Plan, MTEP03, the MISO evaluated at a high level the potential economic benefits of large regional transmission projects under various postulated generation development scenarios. MTEP 03 evaluated a dozen such plans based on analysis of the base planned transmission system, and its ability to accommodate substantial new additions of coal, wind and gas generation based on the interconnection queues at the time. The transmission and generation scenario analysis showed generally that there was significant potential for the right regional transmission to result in substantial reductions in marginal energy costs, particularly if that transmission was coupled with introduction of low cost coal and wind energy resources.

More specifically, MTEP03 included a high wind development scenario, which included approximately 8,600 to 10,000 MW of new wind development. This scenario was used to evaluate several transmission scenarios on a conceptual level, including a set of high voltage lines in Iowa, running from Lakefield to Adams in southern Minnesota, then looping back to tap the line from Raun to Lakefield line in Iowa.

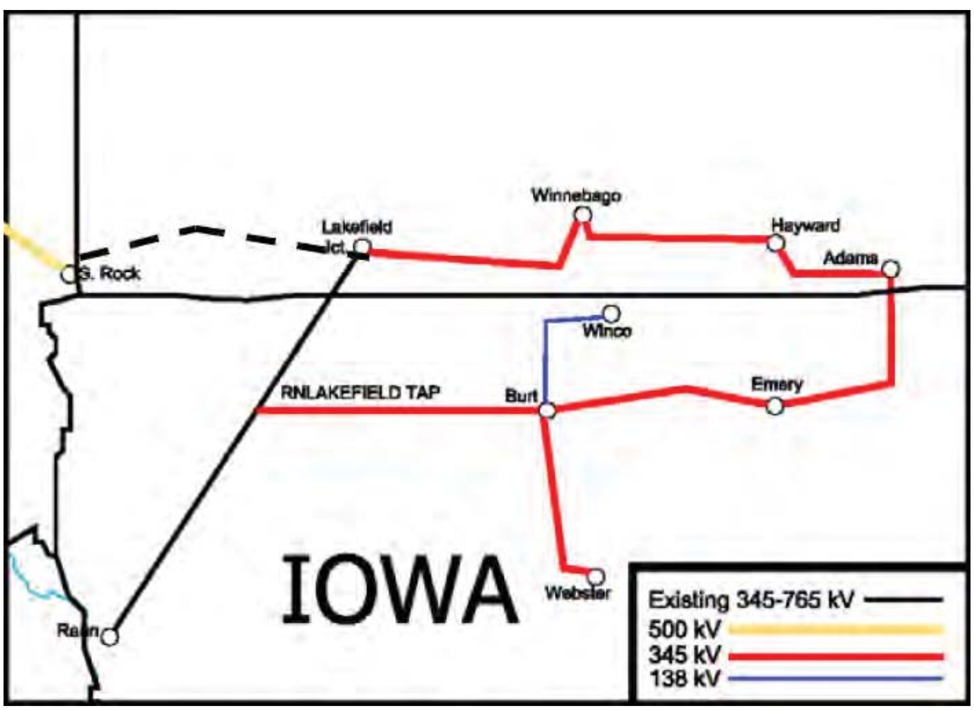

Figure 4.2: Iowa transmission identified in MTEP03

This line was studied in subsequent MTEP cycles, and it eventually led to the identification and incorporation of several Iowa lines into the MVP portfolio. MTEP03 also identified a potential upgrade of the Sidney-Rising line, as a conceptual transmission project.

4.1.2 MTEP05

MTEP05 continued the exploratory transmission analysis began in MTEP03, with two studies which focused in the area around the Dakotas and Northern Minnesota, along with the area around Iowa and Southern Minnesota. It was expected that high voltage transmission projects in these areas would provide additional access to existing base load generation, as well as future wind investment.

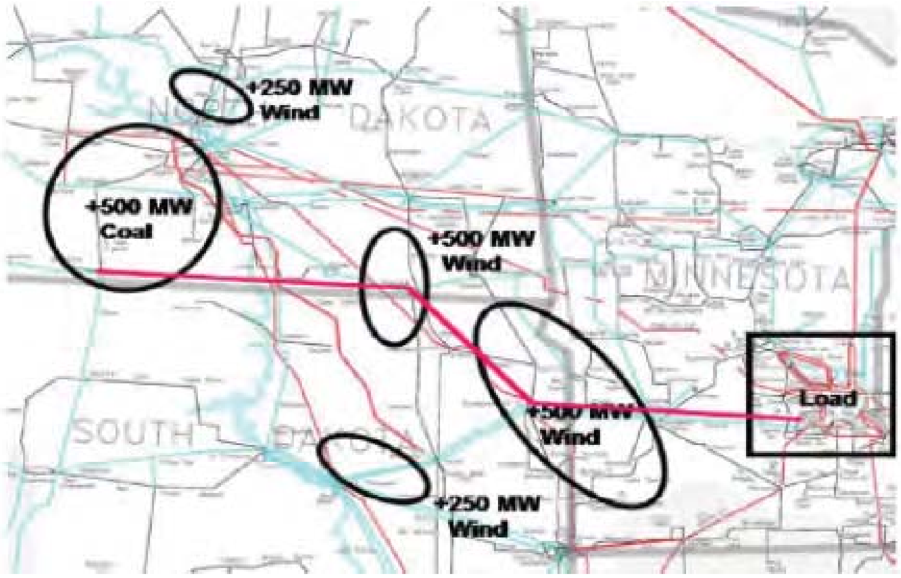

Figure 4.3: Northwest Transmission Option 2

The Northwest study identified the need for at least one, and potentially several, new transmission corridors between the Dakotas and to the Twin Cities of Minnesota. These lines were further studied through the MISO stakeholder CapX 2020 study effort, and they formed the basis of several lines included in the recommended MVP portfolio.

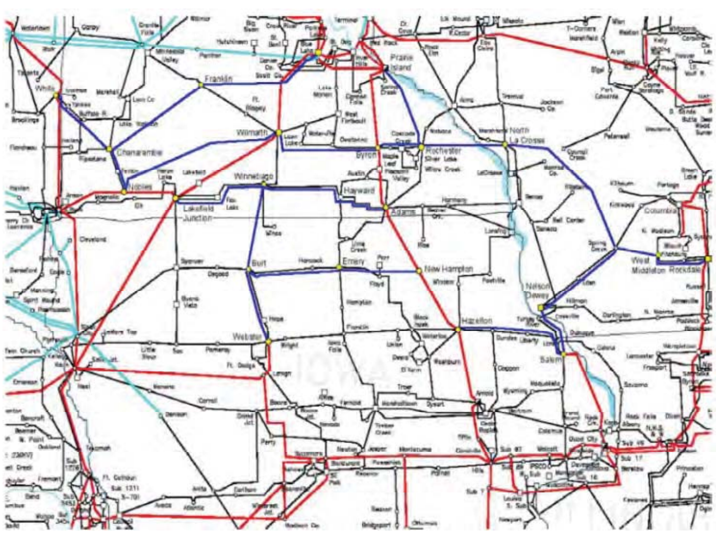

Figure 4.4: Iowa-Minnesota Transmission Scenario 2

The Iowa-Minnesota study further reinforced the need for transmission through southern Minnesota and Iowa. It also identified the need for transmission extending from Minnesota to the Spring Green area in Wisconsin, then from the Spring Green area southwest to the Dubuque area.

4.1.3 MTEP06

In MTEP06, the Vision Exploratory Study modeled scenario which included 20% wind energy for Minnesota and 10% wind energy for the other MISO states, for a total of 16 GW. This hypothetical generation scenario was used to evaluate additional high voltage transmission needs. Although this study focused on a 765 kV solution, it determined that transmission would be needed along many of the corridors identified in prior studies. Additionally, it identified that a transmission path would be required across south-central Illinois to efficiently deliver wind energy to load.

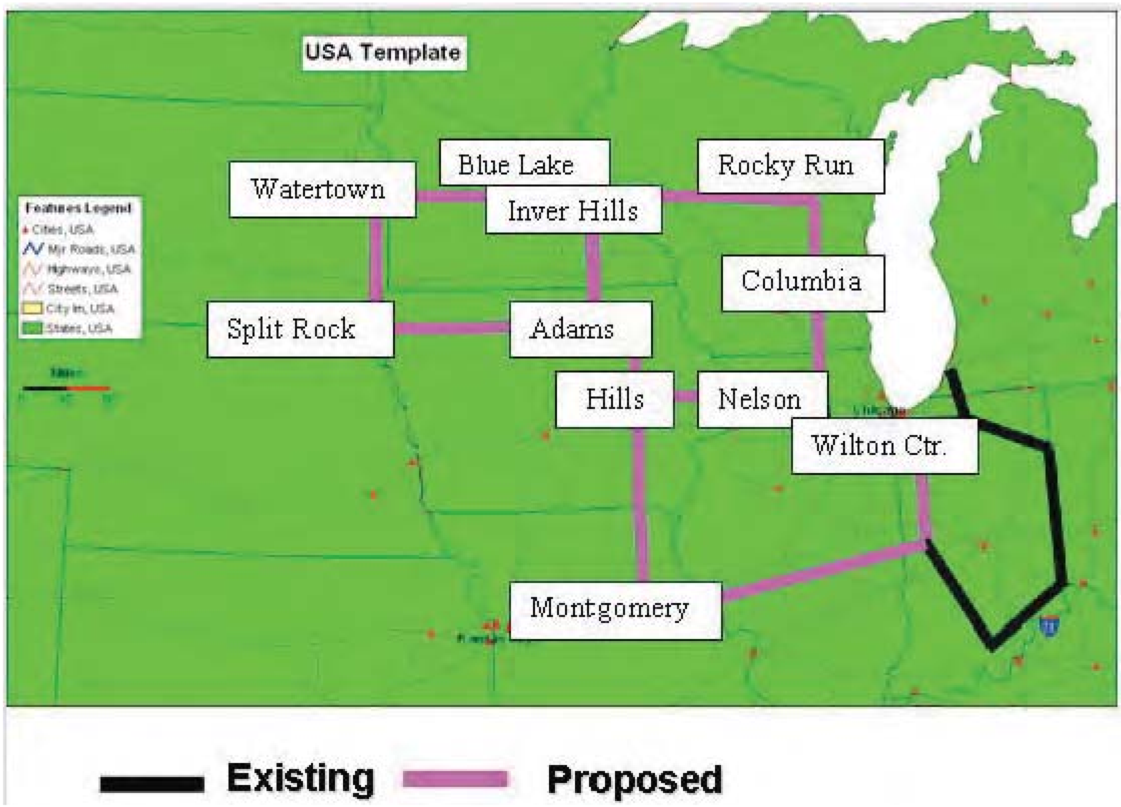

Figure 4.5: Proposed Vision Lines

4.1.4 Regional Generation Outlet Study (RGOS)

Beginning in MTEP09, MISO began the Regional Generation Outlet Study (RGOS). This study was intended, at a high level, to identify the transmission required to support the renewable mandates and goals of the MISO states, while minimizing the cost of energy delivered to the consumers. The study was conducted in two phases: Phase I focused on the western portion of the footprint, while Phase II focused on the full footprint.

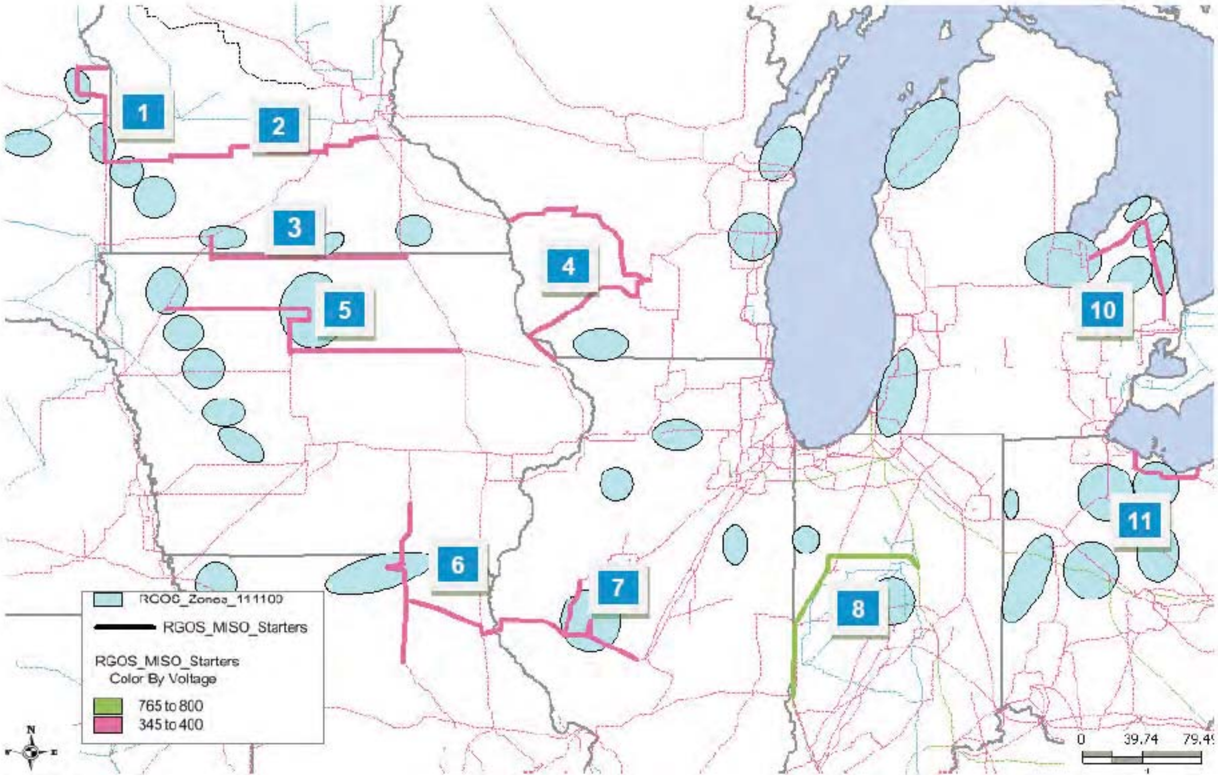

Figure 4.6: Regional Generator Outlet Study Input into MVP Portfolio

At the conclusion of the RGOS analyses, a set of three alternative expansion portfolios were identified. These portfolios, designed to meet the renewable energy mandates and goals of the full load for all the states in the MISO footprint, ranged in cost from $16 to $22 billion. They included transmission identified through the previous MTEP analyses, as highlighted earlier. Common transmission projects or corridors were identified between the three scenarios, and these projects formed transmission recommendations for the initial candidate MVP portfolio.

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4.1.5 Candidate MVP Portfolio

The candidate MVP portfolio was created based on stakeholder feedback, as well as input from the analyses described in section 4.1. The portfolio was designed to meet the renewable energy mandates of all MISO load, and the projects in the portfolio were hypothesized to provide widespread benefits across the footprint. The projects selected as candidates for possible inclusion in the broader portfolio were then intensively evaluated in the MVP portfolio analysis to ensure they were justified and contributed to the portfolio business case.

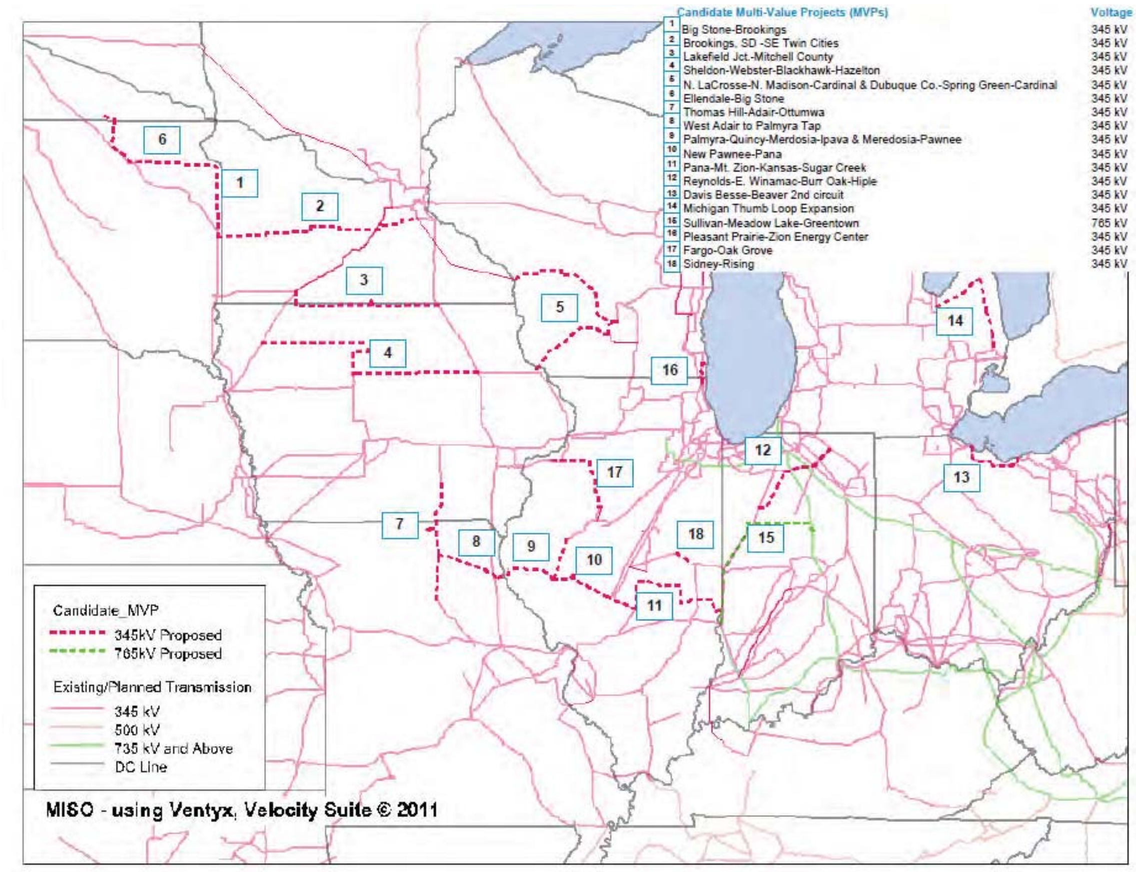

Figure 4.7: Initial Candidate MVP portfolio

4.2 Wind siting strategy

Key assumptions of the MVP portfolio study revolved around the amount and location of wind energy zones modeled within the study footprint. This energy zone development was based on stakeholder surveys focusing on expected renewable energy needs over the next 20 years and how much of that need is expected to be met with wind generation.

During the RGOS energy zone development, MISO staff evaluated multiple energy zone configurations to meet renewable energy requirements. In this process, study participants identified capital costs associated with generation capacity as well as capital costs associated with indicative transmission that would help deliver the energy to the system. It was determined that the most expensive energy delivery options were those options relying: 1) solely on the best regional wind source areas (with higher amounts of transmission needed) or 2) those options relying solely on the best local wind source areas (with higher amounts of generation capital required).

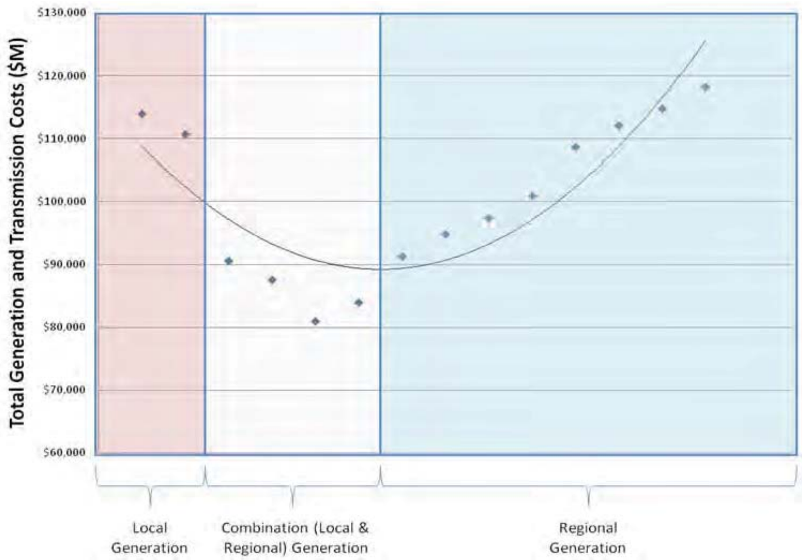

Figure 4.8: Generation and Transmission Capacity, by Energy Zone Location

As a result of RGOS energy zone development efforts as well as interaction with regulatory bodies such as the Upper Midwest Transmission Development Initiative (UMTDI) and various state agencies within the MISO, a set of energy zones was selected. These zones represent the intention of state governments to source some renewable energy locally while also using the higher wind potential areas within the MISO market footprint. Zone selection was based on a number of potential locations developed by MISO utilizing mesoscale wind data supplied by the National Renewable Energy Laboratory (NREL) of the US Department of Energy. The analysis found wind zones distributed across the region resulted in the best method to meet renewable energy requirements at the least overall system cost.

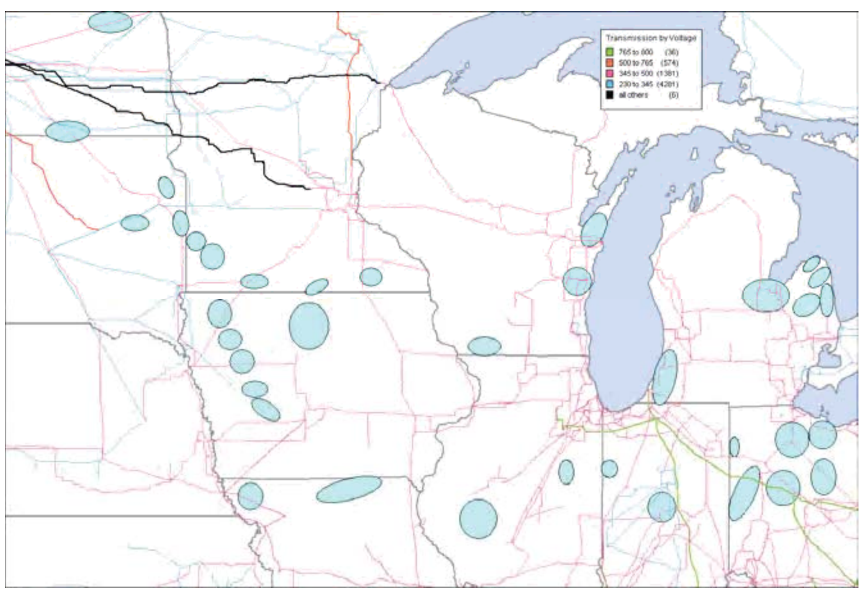

Figure 4.9::Energy Zone Locations

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4.3 Incremental Generation Requirements

Once the location of the incremental wind generation was determined, through the low cost wind siting approach described above, additional analyses were required to determine how much incremental generation will be required to meet the renewable energy mandates of the MISO stakeholders. These analyses are based upon the 2009 retail sales for each area, as provided by the U.S. Energy Information Administration, a growth rate of 1.125% annually, and the specifics of each state's public policy requirements. Details on each state's public policy requirements may be found in Appendix A, while the calculations used to determine the total energy requirements may be found in Appendix B.

	2021 RPS Requirements (MWh)	2026 RPS Requirements (MWh)
IL - Ameren Illinois	3,072,047	4,274,713
IL - Alternative Retail Energy Suppliers in Ameren Illinois	2,016,516	3,046,465
MI - Total State of Michigan less AEP[8]	8,383,843	8,383,843
MN - Xcel Energy	10,535,661	11,141,777
MN - Total State of Minnesota less Xcel Energy	8,050,396	10,641,919
MO - Ameren Missouri	5,825,834	6,160,994
MO - Columbia Water and Light	122,809	194,812
MT - Montana-Dakota Utilities	113,581	120,115
OH - Duke Ohio[9]	2,099,315	2,921,169
WI - Total State of Wisconsin	7,682,829	8,124,821
TOTAL	**47,902,831**	**55,010,629**

Table 4.1: State Renewable Energy Mandates

Incremental wind generation was added to the model to satisfy these mandated needs. The amount of incremental generation for each zone was based on the capacity factor, the planned and proposed generation, and existing wind with power purchase agreements to serve non-MISO load ascribed to each zone. It was also based on a total wind buildout following the distributed, low-cost wind siting approach described in section 4.2.

Wind Zone	2021 Incremental Wind (MW)	2026 Incremental Wind (MW)
IA-B	300	474
IA-F	292	462
IA-G	271	427
IA-H	215	339
IA-I	127	201
IA-J	18	28
IL-F	400	415
IL-K	449	449
IN-E	145	229

Wind Zone	2021 Incremental Wind (MW)	2026 Incremental Wind (MW)
MN-L	0	0
MO-A	356	356
MO-C	500	500
MT-A	136	214
ND-G	199	313
ND-K	164	259
ND-M	59	94
OH-A	30	42
OH-B	30	42

8 RPS requirement must be sourced entirely within Michigan
9 Half of RPS requirement must be sourced from within Ohio.

Wind Zone	2021 Incremental Wind (MW)	2026 Incremental Wind (MW)	Wind Zone	2021 Incremental Wind (MW)	2026 Incremental Wind (MW)
IN-K	194	306	OH-C	30	42
MI-A	0	0	OH-D	30	42
MI-B	601	601	OH-E	30	42
MI-C	549	549	OH-F	30	42
MI-D	442	442	OH-I	30	42
MI-E	601	601	SD-H	300	474
MI-F	601	601	SD-J	292	461
MI-I	303	303	SD-L	300	474
MN-B	75	119	WI-B	234	370
MN-E	0	0	WI-D	257	405
MN-H	0	0	WI-F	0	0
MN-K	175	277			

Table 4.2: Incremental Generation Added to the MVP Portfolio Analysis Model

4.4 Analyses Performed

The MVP portfolio analysis combined the MISO Board of Director planning principles and the conditions precedent to transmission construction to develop a transmission portfolio that meets public policy, economic and reliability requirements. The analysis built a robust business case for the recommended transmission, using the newly created MVP cost allocation methodology approved by FERC. The candidate transmission was tested against a variety of potential policy futures. This maximized the value of the transmission portfolio and reduced potential negative risks associated with its construction due to changes in future demand and energy growth. The output of the study was a justified portfolio of recommended MVPs for inclusion in MTEP11 Appendix A and, if approved by the MISO Board of Directors, subsequent construction.

The MVP cost allocation criteria requires the evaluation of the portfolio on a reliability, economic and energy delivery basis. The analyses were designed to demonstrate this value, both on a project and portfolio basis. To this end, the MVP portfolio analysis included the studies and output shown in Table 4.3.

These analyses focused on three main areas. The project valuation analyses focused on justifying each individual MVP against the MVP criteria. The portfolio valuation analyses determined the benefits of the portfolio in aggregate, quantifying additional reliability and economic benefits. Finally, a series of system performance analyses were performed to ensure that the system reliability will be maintained with the recommended MVP portfolio in service.

Analysis Type	Analysis Output	Purpose
Steady state	List of thermal overloads mitigated by each project in the MVP portfolio	Project valuation
Alternatives	Relative value of each MVP against a stakeholder or MISO identified alternative Can include steady state and production cost analyses	Project valuation
Underbuild requirements	Incremental transmission required to mitigate constraints created by the addition of the recommended MVP portfolio	System performance
Short circuit	Incremental upgrades required to mitigate any short circuit / breaker duty violations	System performance
Stability	List of violations mitigated by the recommended MVP portfolio Includes both transient and voltage stability analysis	System performance Portfolio valuation
Generation enabled	Wind enabled by the MVP portfolio	Portfolio valuation
Production cost	Adjusted Production Cost (APC) benefits of the entire MVP portfolio	Portfolio valuation
Robustness testing	Quantification of MVP portfolio benefits under various policy futures or transmission conditions	Portfolio valuation
Operating reserves Impact	Impact of the MVP portfolio on existing operating reserve zones and quantification of this benefit	Portfolio valuation
Planning Reserve Margin (PRM) benefits	Capacity savings due to reductions in the system-wide Planning Reserve Margin caused by the addition of the MVP portfolio to the transmission system	Portfolio valuation
Transmission loss reductions	Capacity losses savings caused by the addition of the MVP portfolio to the transmission system, where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour	Portfolio valuation
Wind generation capital investment	Quantification of the incremental wind generator capital cost savings enabled by the wind siting methodology supported by the MVP portfolio	Portfolio valuation
Avoided capital investment (transmission)	Future baseline transmission investment that may be avoided due to the installation of the MVP portfolio	Portfolio valuation

Table 4.3: MVP Portfolio Analyses and Output

4.5 Stakeholder involvement

Stakeholders reviewed and contributed to the development of the recommended MVP portfolio throughout the study process. A Technical Study Task Force (TSTF), composed of regulators, transmission owners, renewable energy developers, and market participants, met at least monthly with MISO engineers to provide input, feedback, and guidance throughout the MVP study processes. Also, regular updates were given to the MISO Planning Advisory Committee (PAC) and Planning Subcommittee (PSC). Finally, all study results were available for stakeholder review Feedback or analyses requested throughout the study process were incorporated into the MVP portfolio scope.

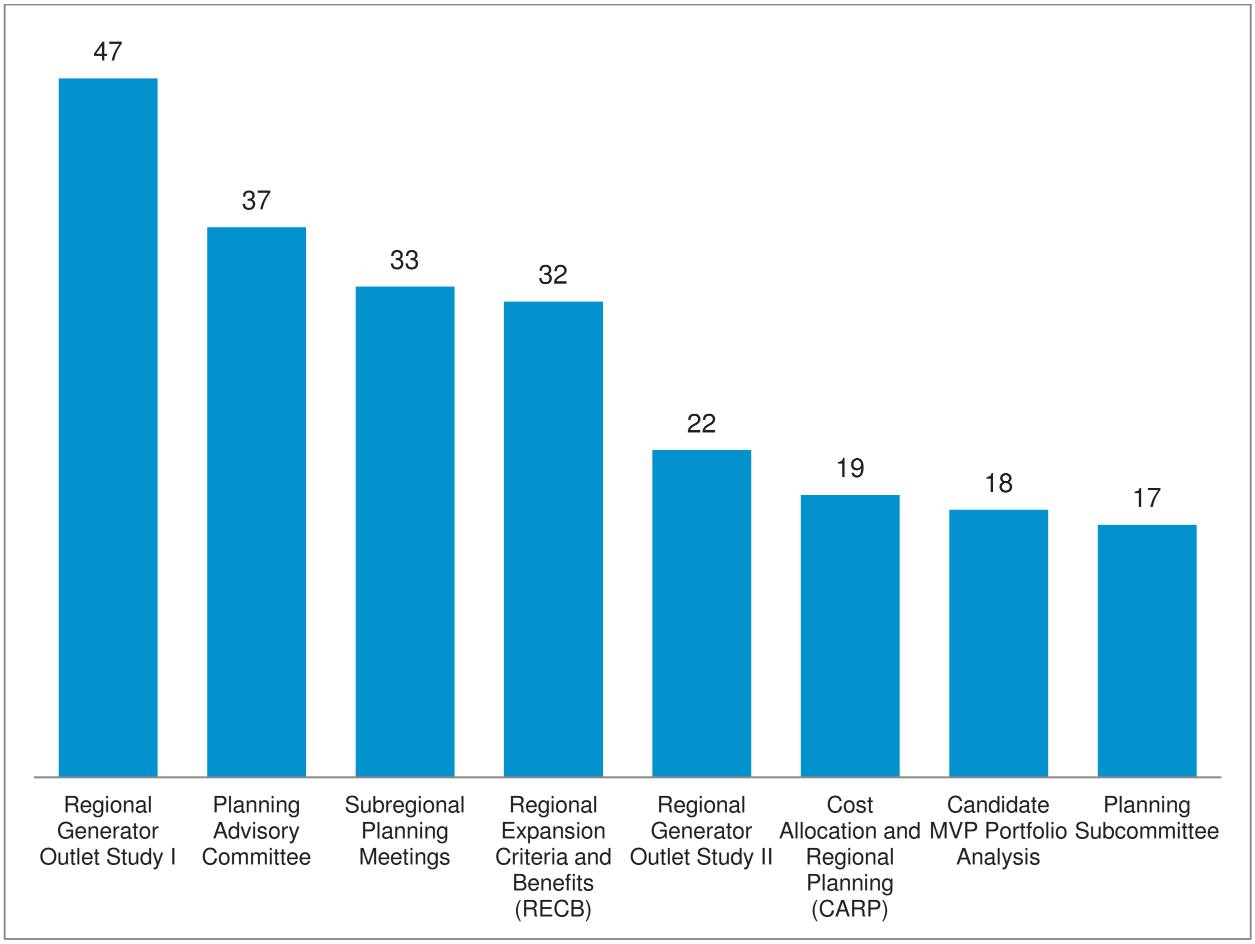

Figure 4.10: Regional Planning Stakeholder Meetings, 2008 - 2011

5 Project justification and alternatives assessment

Each project in the MVP portfolio was analyzed to ensure that the project is justified against MVP cost allocation criterion 1, and to determine if any relevant alternatives exist to the proposed projects. The projects listed below constitute the final projects, which are recommended to the MISO Board of Directors.

5.1 Big Stone to Brookings County 345 kV Line

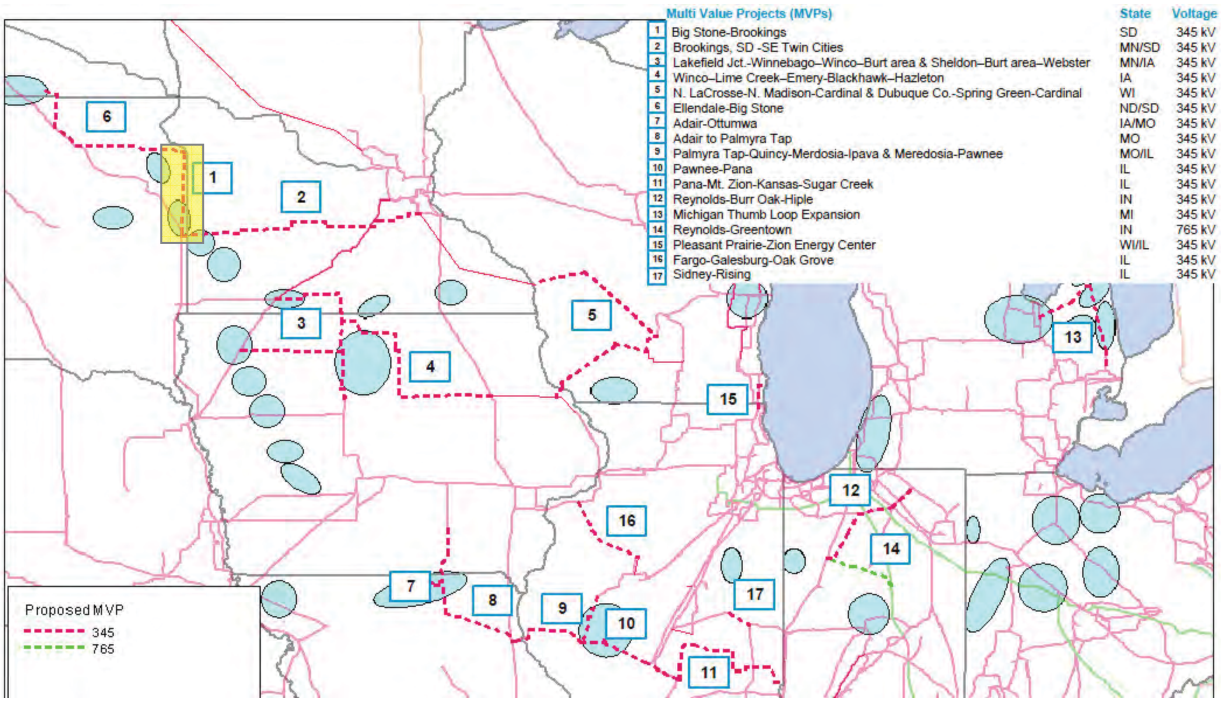

Figure 5.1: Big Stone to Brookings County

Project(s): 2221

Transmission Owner(s): OTP, XEL

Project Description: This project creates a new 345 kV path on the border of South Dakota and Minnesota by connecting XEL's Brookings County and OTP's Big Stone. Approximately 69 miles of new 345 kV transmission will be installed between these two substations along with a new 345 kV terminal at Big Stone and two 345/230 kV, 672 MVA transformers. The total estimated cost of this project is $191 million[10]. The expected in service date for this project is December 2017.

Project Justification: The new 345 kV outlet from Big Stone removes overloads on the 230 kV paths from Big Stone to Blair and Hankinson to Wahpeton along with 115 kV paths from Johnson to Morris , Big Stone to Highway 12 to Ortonville, Pipestone to Buffalo Ridge and Canby to Granite Falls. The overloaded Watertown 345/230 kV is also alleviated. Along with project 2220, this project reliably moves mandated renewable energy from the Dakotas to major 345 kV transmission hubs and load centers.

Alternatives Considered: An alternative to build a new 345 kV from Big Stone to Canby to Granite Falls to Minnesota Valley and rebuild the 230 kV or build a new 345 kV to Morris could provide an

[10] In 2011 dollars.

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alternative outlet for Big Stone wind. The cost of this alternative is higher than the 345 kV path to Brookings County.

5.2 Brookings County to Southeast Twin Cities 345 kV Line

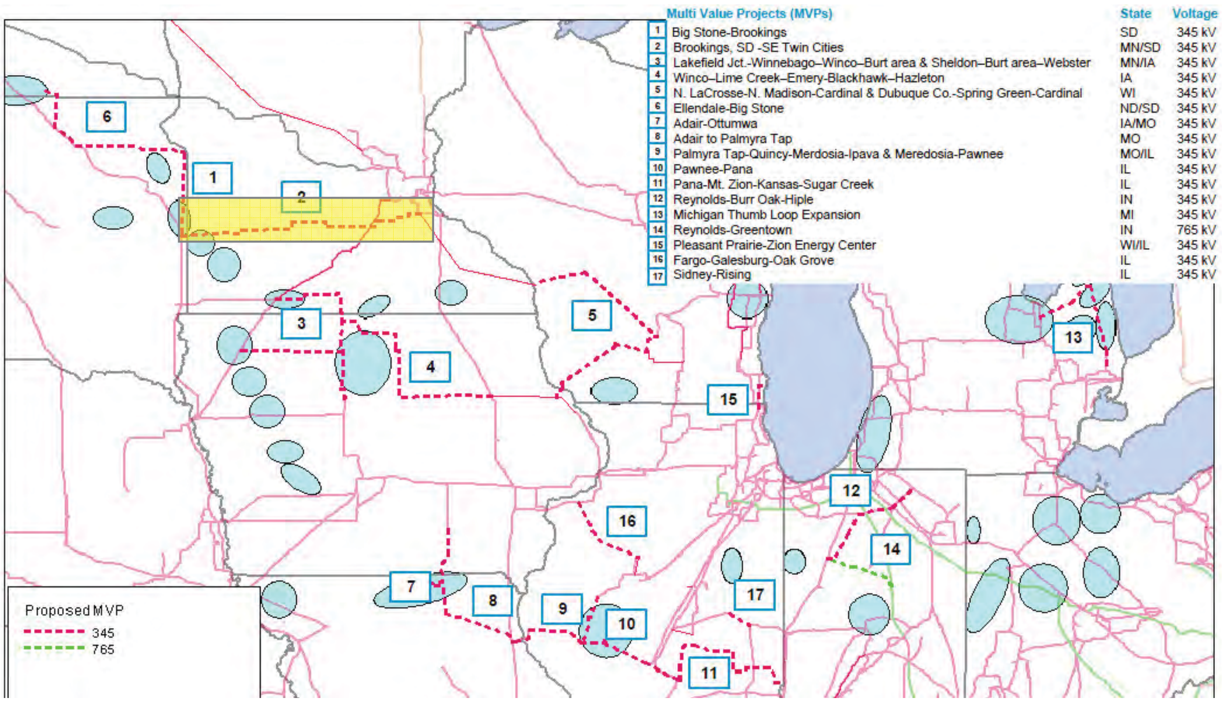

Figure 5.2: Brookings County to Southeast Twin Cities

Project(s): 1203

Transmission Owner(s): XEL, GRE

Project Description:
This project creates a new 345 kV path through southern Minnesota, by connecting XEL's Brookings County substation to the Twin Cities. Single circuit 345 kV transmission will be constructed from Brookings County to Lyon County, from Helena to Lake Marion to Hampton Corner, and from Lyon County to Hazel Creek to Minnesota Valley. The Hazel Creek to Minnesota Valley section will be operated at 230 kV initially. Double circuit 345 kV transmission will be constructed from Lyon Count to Cedar Mountain to Helena. A 115 kV line will be built between the new Cedar Mountain and the existing Franklin substations. The project includes one 345/230 kV, 336 MVA transformer at Hazel Creek, three 345/115 kV, 448 MVA transformers at Lyon County, Lake Marion and Cedar Mountain, one upgraded 115/69 kV, 140 MVA transformer at Lake Marion and two upgraded 115/69 kV, 70 MVA transformers at Franklin. A new breaker and deadend structure is planned at Lake Marion and the Arlington to Green Isle 69 kV line will be upgraded to 477 ACSR. The project adds a total of 351 miles of new 345 kV, 5 miles of new 115 kV and 5.8 miles of rebuilt 69 kV lines. The total estimated cost of this project is $695 million[11]. The expected in service dates for these projects are:

- June 2013 (Cedar Mountain 345/115 kV transformer)
- August 2013 (Cedar Mountain to Helena 345 kV double circuit line and Arlington to Green Isle 69 kV rebuild)

[11] In 2011 dollars

- October 2013 (Lyon County 345/115 kV transformer)
- November 2013 (Lyon County to Cedar Mountain 345 kV double circuit line)
- January 2014 (Franklin 115/69 kV transformers)
- February 2014 (Cedar Mountain to Franklin 115 kV line)
- March 2014 (Lake Marion 345/115 kV and 115/69 kV transformers and station work)
- April 2014 (Helena to Lake Marion 345 kV line)
- June 2014 (Lake Marion to Hampton Corner 345 kV line)
- January 2015 (Brookings to Lyon County 345 kV line and Hazel Creek 345/230 kV transformer)
- February 2015 (Lyon County to Hazel Creek to Minnesota Valley 345 kV line)

Project Justification:
Without the Brookings County to Twin Cities 345 kV line, the loss of Split Rock to White 345 kV leaves only the 230kV system to feed load to the East. This overloads the Watertown 345/230 kV transformer without the parallel 345 kV path from Brookings County. Not having the project also impacts the 115 kV network in southern Minnesota which is connected on both sides by 230 kV. The loss of either 230kV source causes multiple overloads in the surrounding 115 kV network without this project. The loss of any segment of the Wilmarth-Helena-Blue Lake 345 kV line in southeast Minnesota leads to overloads on the underlying 115 kV network. Without this project, the power flowing west to east is forced through the 115 kV system, overloading the underlying 115 kV lines. The Wilmarth to Eastwood and Wilmarth to Swan Lake 115 kV lines are overloaded without the additional 345kV support to the north that is included with project 1203. At the Minnesota/Wisconsin interface, the loss of 345 kV lines at Blue Lake, Prairie Island, Red Rock, Coon Creek and Chisago substations overload the Prairie Island 345/161 kV transformer, particularly for any NERC Category C5 outages involving lines between the aforementioned substations. The Brookings County to Twin Cities project would bring an additional 345 kV source into this area to reduce loading along the path into Wisconsin. There are also 115 kV overloads in this area which are mitigated by this project.

Alternatives Considered:
With the existing 345 kV outlets out of Brookings County thermally constrained and with most of the 230 and 115 kV paths between Brookings County and the Twin Cities overloaded, mitigating all these constraints through underlying line rebuilds would be infeasible and costlier compared to this project.

5.3 Lakefield Junction to Winnebago to Winnco to Burt area; Sheldon to Burt area to Webster 345 kV Lines

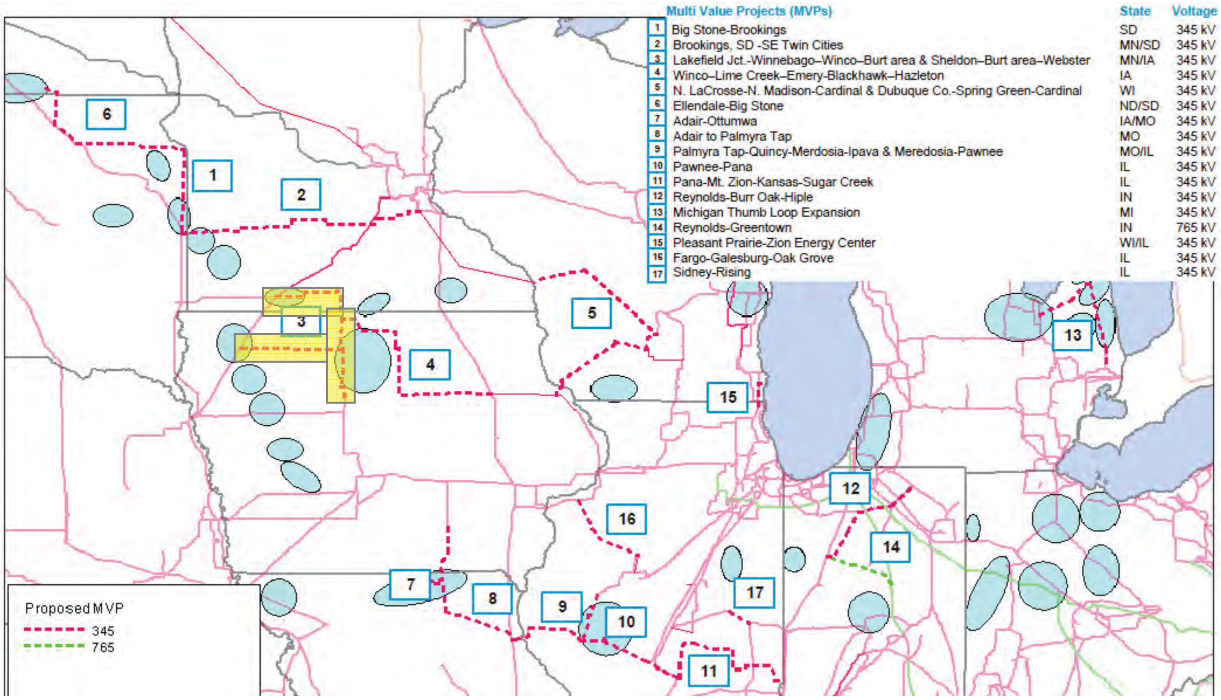

Figure 5.3: Lakefield Jct to Winnebago to Winnco to Burt area; Sheldon to Burt area to Webster

Project(s): 3205

Transmission Owner(s): MEC, ITCM

Project Description:
Designed to connect with project 3213, this project creates a double circuit 345/161 kV path through the border of Minnesota and Iowa. New 345 kV transmission will be built from Lakefield Junction to Winnebago to Winnco to Burt and from Sheldon to Burt to Webster. Rebuilt 161 kV transmission will be on the same towers and go from Lakefield to Fox Lake to Rutland to Winnebago to Winnco and Wisdom to Osgood to Burt to Hope to Webster. Winnebago, Winnco, Sheldon and Burt are all new 345 kV stations. Sheldon will be a tap on the existing Raun to Lakefield 345 kV line. A 345/161 kV, 450 MVA transformer will be installed at Winnebago. This project adds 218 miles of new 345 kV and 92 miles of rebuilt 161 kV transmission. The total estimated cost of this project is $506 million[12]. The expected in service dates for these projects are:

- December 2015 (All Lakefield Junction to Burt work)
- December 2016 (All Sheldon to Webster work)

Project Justification:
The new 345 kV path through southern Minnesota and northern Iowa effectively mitigates the Fox Lake – Rutland – Winnebago 161 kV constraint. Existing wind in the Winnebago and Wisdom areas are benefitted by 345 kV transmission moving generation out of these constrained areas. Working in tandem with project 3213, this project reliably moves mandated renewable energy from western and

[12] In 2011 dollars

northern Iowa along with existing wind at the Winnebago, Wisdom and Lime Creek/Emery areas to major 345 kV transmission hubs.

Alternatives Considered:
An Iowa alternative of Lakefield Junction to Mitchell County and Sheldon to Burt to Webster to Black Hawk to Hazleton 345 kV was analyzed but was not effective in collecting Lime Creek/Emery area wind or lowering congestion on the Mitchell County to Hazleton 345 kV line. It had similar cost to the combined Iowa projects 3205 and 3213.

5.4 Winco to Lime Creek to Emery to Black Hawk to Hazleton 345 kV Line

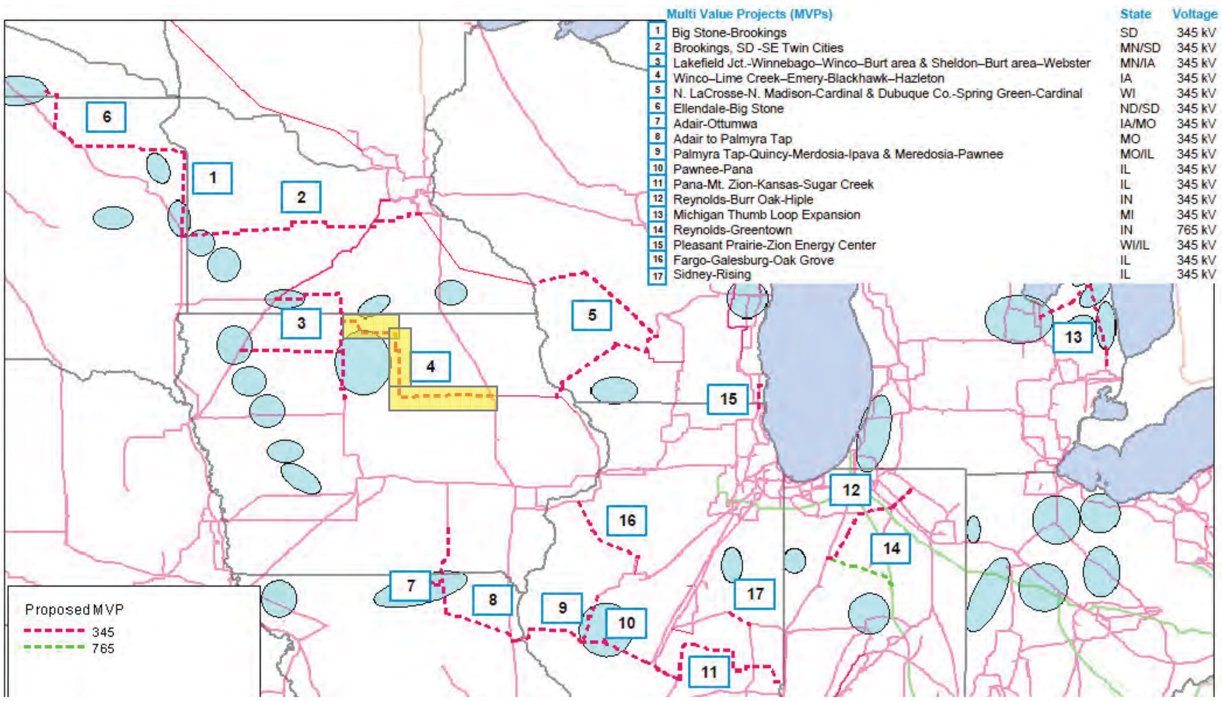

Figure 5.4: Winnco to Lime Creek to Emery to Black Hawk to Hazleton 345 kV line

Project(s): 3213

Transmission Owner(s): MEC, ITCM

Project Description:
Designed to connect with project 3205, this project creates a double circuit 345/161 kV path through northern Iowa. New 345 kV transmission will be built from the new Winnco substation to Lime Creek to Emery to Black Hawk to Hazleton. Rebuilt 161 kV transmission will be on the same towers as the 345 kV and will go from Lime Creek to Emery to Hampton to Franklin to Union Tap to Black Hawk to Hazleton. A 345/161 kV, 450 MVA transformer will be installed at Lime Creek, Emery and Black Hawk. This project adds 206 miles of new 345 kV, 23 miles of new 161 and 149 miles of rebuilt 161 kV transmission. The total estimated cost of this project is $480 million[13]. The expected in service date of the project is December 2015.

Project Justification:

[13] In 2011 dollars

006359

The new 345 kV path through Iowa mitigates constraints seen on the Lime Creek – Emery – Floyd – Bremer – Black Hawk 161 kV line. The 345/161 kV transformers at Lime Creek and Emery are effectively acting as step-up transformers for wind and lowering congestion on the lower voltages. The additional 345 kV path into Hazleton significantly increases the transfer capability of the Mitchell County – Hazleton 345 kV line. Working in tandem with project 3205, this project reliably moves mandated renewable energy from western and northern Iowa along with existing wind at the Winnebago, Wisdom and Lime Creek/Emery areas to major 345 kV transmission hubs.

Alternatives Considered:
An Iowa alternative of Lakefield Junction to Mitchell County and Sheldon to Burt to Webster to Black Hawk to Hazleton 345 kV was analyzed but was not effective in collecting Lime Creek/Emery area wind or lowering congestion on the Mitchell County to Hazleton 345 kV line. It had similar cost to the combined Iowa projects 3205 and 3213.

5.5 North LaCrosse to North Madison to Cardinal 345 kV Line

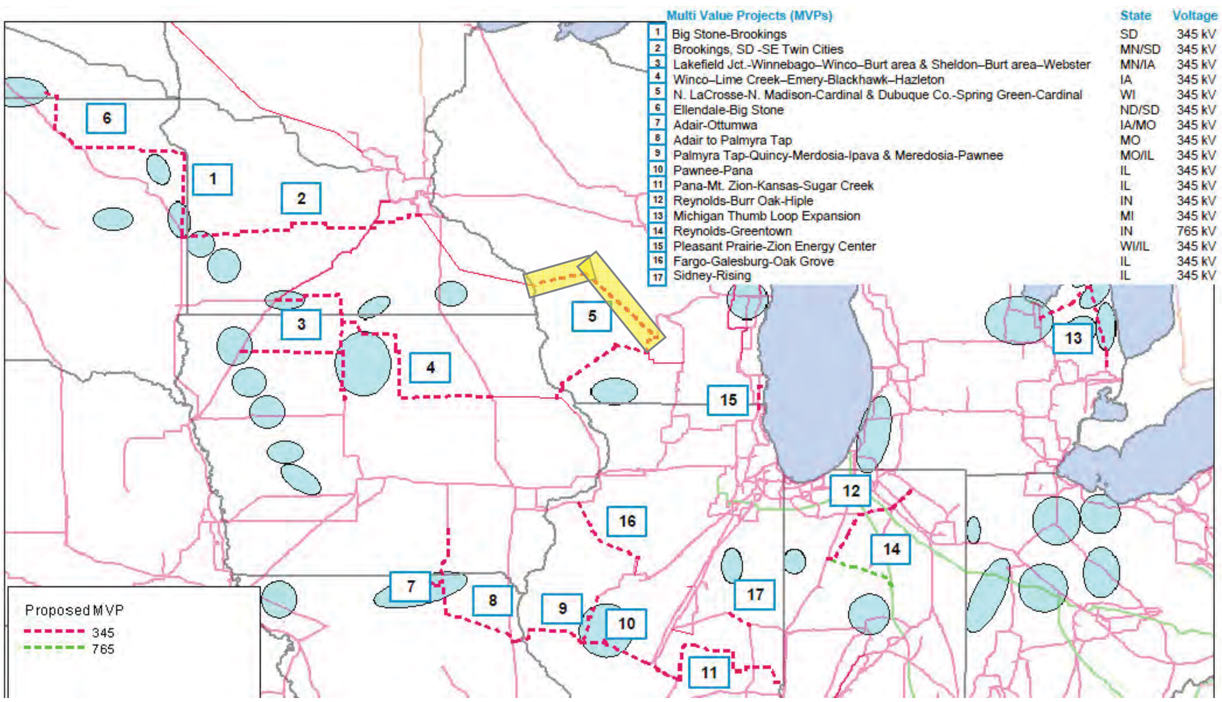

Figure 5.5: North LaCrosse to North Madison to Cardinal

Project(s): 3127

Transmission Owner(s): ATC, XEL

Description: This creates a 345 kV line from the North LaCrosse (Briggs Road) substation, to the North Madison substation, to the Cardinal substation, through southwestern Wisconsin. A 448 MVA, 345/161 kV transformer will be installed at Briggs Road, and approximately 20 miles of 138 kV line between the North Madison and Cardinal substations will be reconductored. The new 345 kV line will be approximately 157 miles long. The estimated cost is $390 million[14]. The expected in service date is December 2018.

[14] In 2011 dollars

Justification: The 345 kV line from North LaCrosse to North Madison creates a tie between the 345kV network in western Wisconsin to the 345 kV network in southeastern Wisconsin. This creates an additional wind outlet path across the state; pushing power into southern Wisconsin, where it can go east into Milwaukee, or south to Illinois, providing access to less expensive wind power in two major load centers. With the Brookings project, the wind coming into North LaCrosse needs an outlet, and the line to North Madison is the best option studied. From a reliability perspective, the addition of the North LaCrosse to North Madison to Cardinal 345 kV path helps relieve constraints on the 345 kV system parallel to the project to the north and south of the new line. The 138 and 161 kV system in southwest Wisconsin and nearby in Iowa are also overloaded during certain contingent events, and the new line relieves those constraints. This project will mitigate twelve bulk electric system (BES) NERC Category B thermal constraints and eight NERC Category C constraints. It will also relieve 30 non-BES NERC Category B and 36 NERC Category C constraints.

Alternatives Considered:
Rebuilding the overloaded 138 and 161 kV lines, along with adding transformers or upgrading the existing units to handle the increased loading, was the only other alternative considered. This was not a viable alternative, because the cost is greater than the proposed project. The proposed project also provides the most benefit to the transmission grid in the future.

5.6 Dubuque to Spring Green to Cardinal 345 kV Line

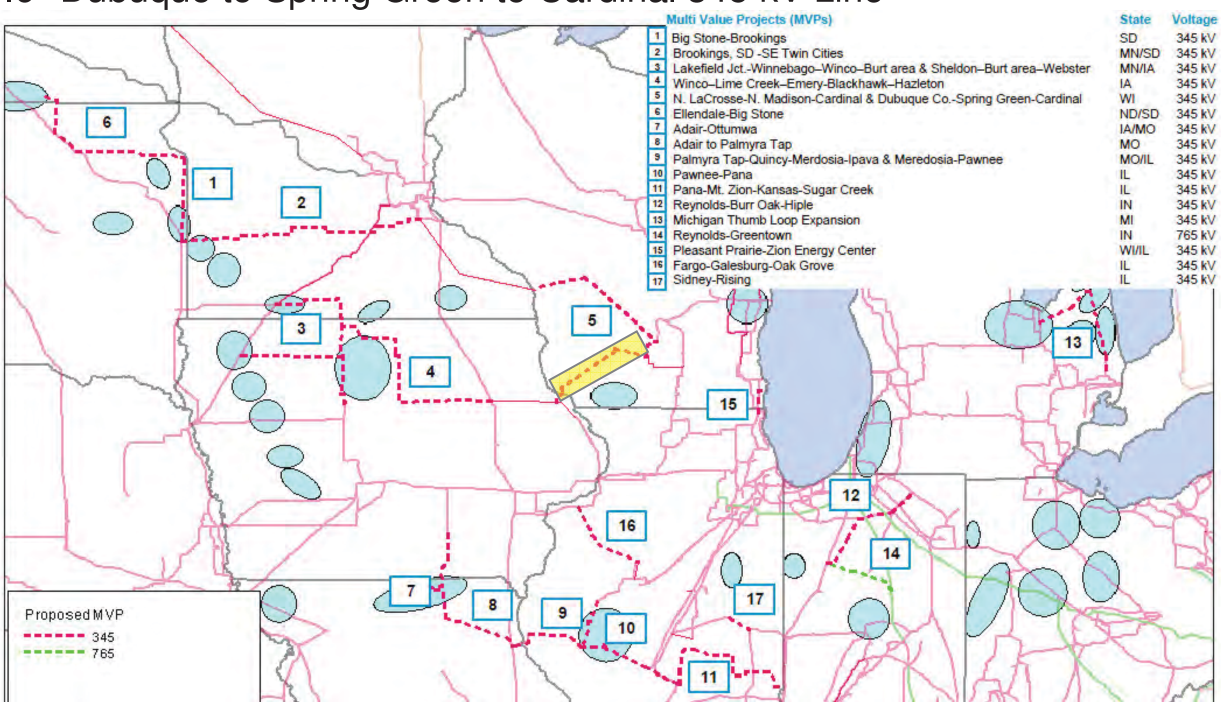

Figure 5.6: Dubuque to Spring Green to Cardinal

Project(s): 3127

Transmission Owner(s): ATC, ITCM

Description: A 345 kV line is created from the Dubuque substation in Iowa, to the Spring Green substation to the Cardinal substation through southwestern Wisconsin. A new Dubuque County 345 kV switching station will be created, and the Spring Green substation will be upgraded to accommodate the new connections. A new 500 MVA, 345/138 kV transformer will be added. To accommodate the new 345 kV connections from Spring Green and North Madison, the Cardinal substation will be upgraded. There are also upgrades to the 69 kV system, which is being converted to operate at 138 kV, in the Mazomanie – Black Earth – Stagecoach area. The new 345 kV line is approximately 136 miles long. The estimated cost is $324 million[15]. The expected in service date is December 2020.

Justification: The 345 kV line from Dubuque to Spring Green to Cardinal creates a tie between the 345kV network in Iowa to the 345 kV network in southcentral Wisconsin. This expansion creates an additional wind outlet path across the state; bringing power from Iowa into southern Wisconsin, where it can then go east into Milwaukee or south toward Chicago providing access to less expensive wind power in two major load centers. In combination with another Multi Value Project, the Oak Grove – Galesburg – Fargo 345 kV line, this project enables 1,100 MW of wind power transfer capability. This new path will help offload the lines that feed the Quad City (Iowa) area by bringing power flow to the north. From a reliability perspective, the addition of the Dubuque – Spring Green – Cardinal 345 kV path helps relieve constraints on the 345 kV system parallel to the project to the north and south of the new line, as well as 138 kV system constraints in the aforementioned areas and to the west of the new line. The 138 kV system in southwest Wisconsin and nearby in Iowa is also overloaded during certain contingent events, and the new line relieves those constraints. Those overloaded facilities that are not relieved by the 345 kV project are relieved by upgrades to the lower voltage transmission system, including converting part of the 69 kV system to operate at 138 kV. This project will mitigate eight bulk electric system (BES) NERC Category B thermal constraints and ten NERC Category C constraints. It will also relieve two non-BES NERC Category B and two NERC Category C constraints.

Alternatives Considered: An alternative to the proposed project would be to rebuild the 138 kV lines that were overloaded. The cost of this alternative would be more than the proposed project, without providing benefits of the proposed project.

[15] In 2011 dollars

5.7 Ellendale to Big Stone 345 kV Line

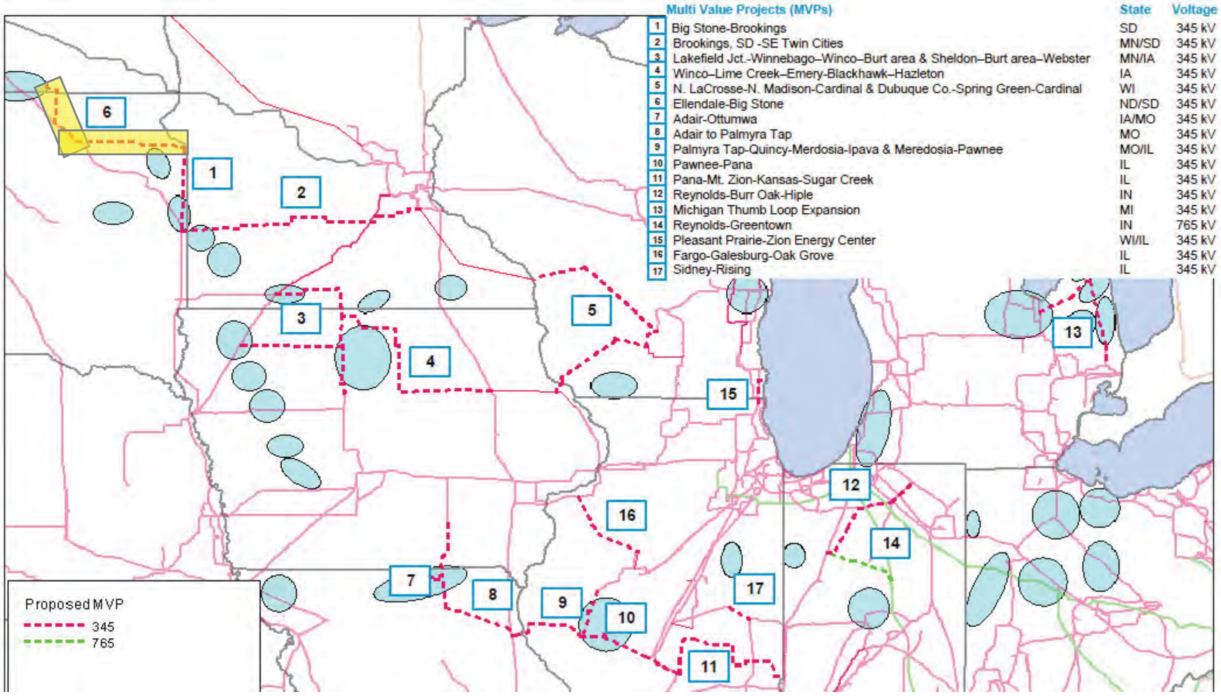

Figure 5.7: Ellendale to Big Stone

Project(s): 2220

Transmission Owner(s): OTP, MDU

Project Description:
This project creates a new 345 kV path through the border of the Dakotas by connecting OTP's Big Stone and MDU's Ellendale substations. Approximately 145 miles of new 345 kV transmission will be installed between these substations along with a new 345kV terminal at Ellendale and a 345/230 kV, 500 MVA transformer. The total estimated cost of this project is $261 million[16]. The expected in service date for this project is December 2019.

Project Justification:
The new 345 kV outlet from Ellendale removes overloads on the 230 kV path from Ellendale to Oakes to Forman and the 115 kV path from Ellendale to Aberdeen. Overloads on the 230/115 kV transformers at Ellendale, Forman and Heskett are also alleviated. Along with project 2221, this project reliably moves mandated renewable energy from the Dakotas to major 345 kV transmission hubs and load centers.

Alternatives Considered:
An alternative to convert the 115 kV path from Ellendale to Huron could alleviate the southern path constraints out of Ellendale but downstream transmission may also need to be rebuilt to accommodate wind injection delivered through a lower impedance line. The eastern 230 kV path out of Ellendale would need to be rebuilt to 345 kV up to Fergus Falls. The cost of this alternative is higher than a 345 kV path to Big Stone.

[16] In 2011 dollars

5.8 Ottumwa to Adair to Palmyra Tap 345 kV Line

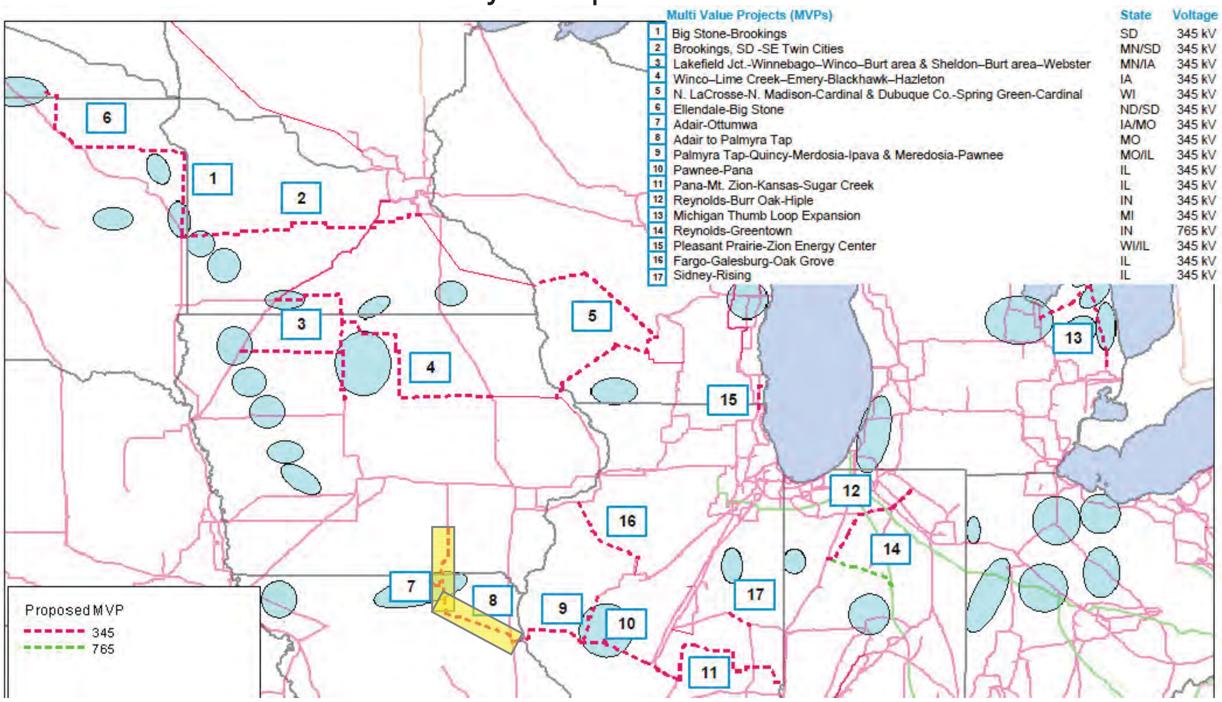

Figure 5.8: Ottumwa to Adair to Palmyra Tap

Project(s): 2248, 3170

Transmission Owner(s): Ameren Missouri, MEC, ITCM

Project Description:
This creates a 345 kV path through central/eastern Missouri by connecting Iowa's Ottumwa substation to Ameren Missouri's West Adair substation (P2248). It then extends 345 kV from West Adair to Ameren Missouri's Palmyra substation Tap (P3370), near the Missouri/Illinois border. Approximately 88 miles of new and rebuilt 345 kV line will be installed between Ottumwa and Adair, along with a 345kV terminal at Adair and a 345/161 kV, 560 MVA step down transformer. Sixty-three miles of new 345 kV line will be built between West Adair and the Palmyra Tap, where a new 345 kV switching station will be established. The estimated cost is $250 million[17]. The New Palmyra Tap substation will be ready by November 2016. The Ottumwa to West Adair 345 kV line and West Adair substation work will be ready by June 2017. The West Adair to Palmyra 345 kV line and West Adair 345/161 kV transformer will be ready by November 2018.

Project Justification:
The new 345 kV lines from Ottumwa to West Adair to Palmyra will provide an outlet for wind generation in the western region to move toward the more densely populated load centers to the east. In addition to providing a wind outlet, the new lines will provide reliability benefits by mitigating a number of contingent outage events during peak and shoulder periods, where the wind generation component is much higher. The addition of the 345 kV lines and step down transformer at West Adair is especially effective in resolving 161 kV line overloads on the lines out of West Adair and preventing the loss of the generation at West Adair during certain NERC Category C events. This project will mitigate two bulk electric system (BES) NERC Category B thermal constraints and five NERC Category C constraints. It will also relieve three non-BES NERC Category B and two NERC Category C constraints.

[17] In 2011 dollars

Alternatives Considered:
An alternative was to incorporate an additional 345 kV line from West Adair to Thomas Hill. While improving reliability in the area, the addition would not improve the distribution of benefits within MISO. Thus the alternative was removed, and the proposed project was recommended.

5.9 Palmyra Tap to Quincy to Meredosia to Pawnee; Meredosia to Ipava 345kV Line

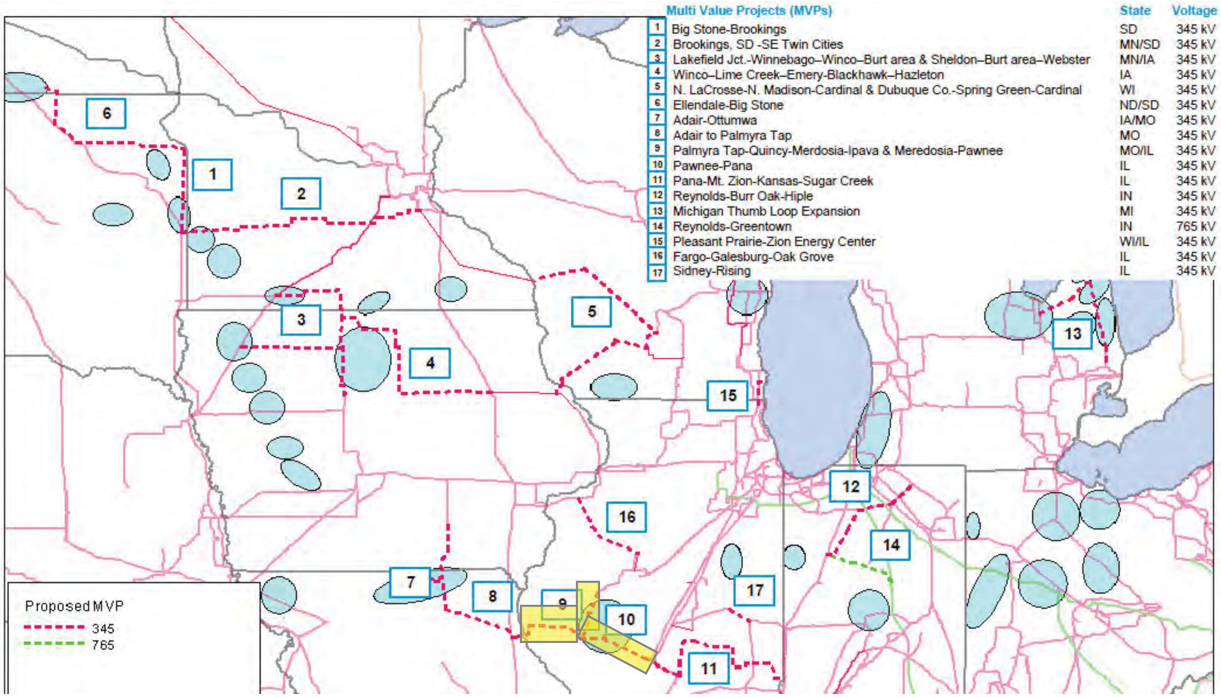

Figure 5.9: Palmyra Tap to Quincy to Meredosia to Pawnee; Meredosia to Ipava

Project(s): 3017

Transmission Owner(s): Ameren

Description: This creates a 345 kV path through western/central Illinois by construction of 345 kV lines between the new Palmyra Tap switching station to Quincy, Meredosia and Pawnee. Another 345 kV line would go from Meredosia north to the Ipava substation. A total of 116 miles of new 345 kV line will be built between the Palmyra switching station and Pawnee, with new 345/138 kV, 560 MVA transformers at Quincy and Pawnee. The new 345 kV line from Meredosia to Ipava would be 41 miles long. The estimated cost is $392 million[18]. The New Palmyra Tap switching station will be ready by June 2016. The Palmyra Tap switching station to Quincy to Meredosia 345 kV line and the Quincy and Pawnee 345/138kV transformers will be ready by November 2016. The Ipava substation upgrades for new 345 kV connection from Meredosia will be ready by June 2017. The Meredosia to Ipava and Meredosia to Pawnee 345 kV lines will be ready by November 2017.

Justification: The 345 kV lines from the Palmyra switching station to Pawnee and from Meredosia to Ipava will provide an outlet for wind generation in the western region to move toward the more densely populated load centers to the east. In addition to providing a wind outlet, the new lines will

[18] In 2011 dollars

provide reliability benefits by mitigating a number of contingent outage events during peak and shoulder periods, where the wind generation component is much higher. The addition of the 345 kV lines and step down transformers in this project will keep the power flow on the 345 kV system. Otherwise, it would be, injected into the lower voltage transmission networks if the 345 kV additions are not made, which causes a number of lower voltage network constraints to be alleviated. This project will mitigate eight bulk electric system (BES) NERC Category B thermal constraints and three NERC Category C constraints.

Alternatives Considered: A 345 kV connection between Palmyra and Sioux would alleviate some constraints, but would not affect constraints in the Tazewell area, which would also need a 345 kV connection to Palmyra. The alternative would not provide regional distribution of benefits with the multi value project, as it would constrain the 345 kV path from St. Louis across southern Illinois and into Indiana. Therefore the proposed project is recommended for the greatest benefit.

5.10 Pawnee to Pana to Mt. Zion to Kansas to Sugar Creek 345kV Line

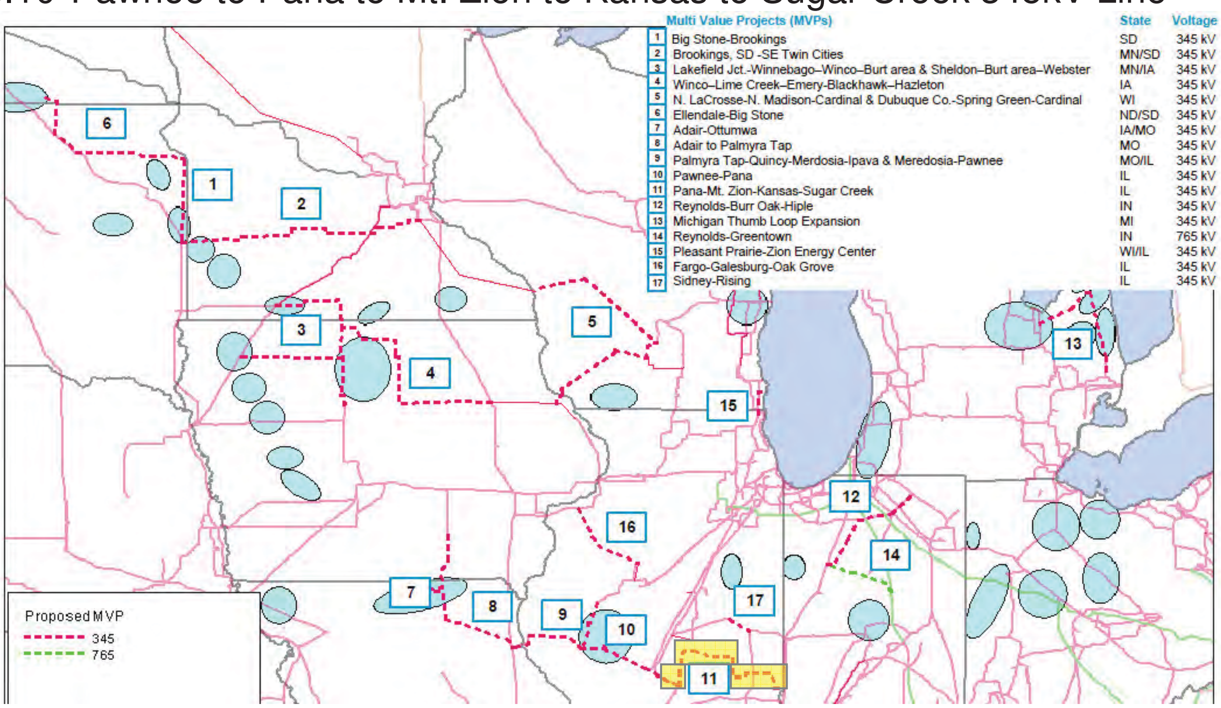

Figure 5.10: Pawnee to Pana to Mt. Zion to Kansas to Sugar Creek

Project(s): 2237, 3169

Transmission Owner(s): Ameren

Description: This creates a 345 kV path through eastern/central Illinois by building 345 kV lines between the Pawnee substation to Pana, Mt. Zion, Kansas and Sugar Creek (Indiana). A total of 146 miles of new 345 kV line will be constructed between the Pawnee substation and Sugar Creek substation on the eastern Illinois/Indiana border, with new 345/138 kV, transformers at Mt. Zion, Pana (both transformers are 560 MVA) and Kansas (448 MVA transformer). The estimated cost is $372 million[19] All components will be in service by November 2018, except the new Kansas to Sugar Creek 345 kV Line, which will be ready by November 2019.

[19] In 2011 dollars

006366

Justification: The 345 kV lines from the Pawnee to Sugar Creek in western Indiana will provide an outlet for wind generation in the western region to move toward the more densely populated load centers to the east. This 345 kV extension creates another 345 kV path across central Illinois to connect to the existing 345 kV network in Indiana at Sugar Creek. This provides access wind generation to all of Indiana, and supplies major load centers such as Indianapolis and the Chicago suburbs in northern Indiana. The new lines will provide a wind outlet and reliability benefits, by mitigating a number of contingent outage events during peak and shoulder periods, where the wind generation component is much higher. The addition of the 345 kV lines and step down transformers in this project will keep the power flow on the 345 kV system. Otherwise, it would be injected into the lower voltage transmission networks in Illinois if the 345kV additions are not made, which causes a number of lower voltage network constraints to be alleviated. This project will mitigate eight bulk electric system (BES) NERC Category B thermal constraints and 12 NERC Category C constraints.

Alternatives Considered: An alternative to the proposed project was a parallel 345 kV path to the north, which would have built a 345 kV line through Bloomington into Brokaw, through Gilman and to the Reynolds Substation in northwest Indiana. Although the benefits of taking this northern path were similar to the southern route, there were fewer benefits gained by going with the northern path. It also cost more than the recommended project.

5.11 Reynolds to Burr Oak to Hiple 345 kV line

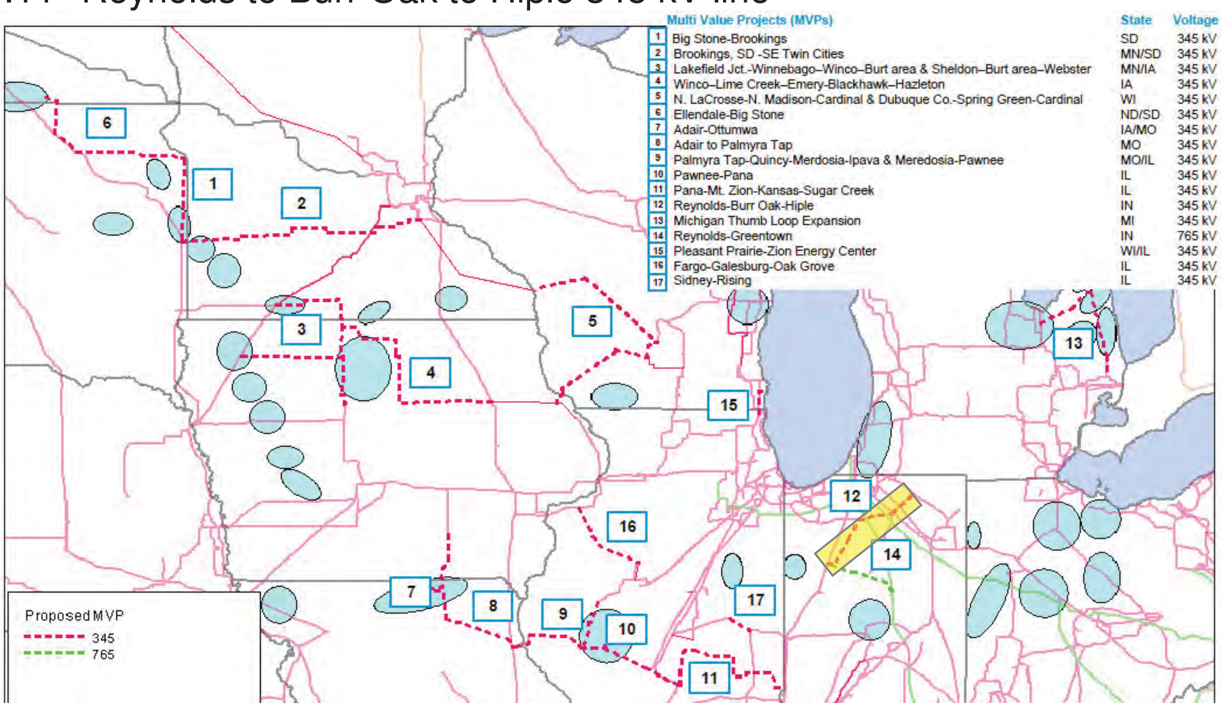

Figure 5.11: Reynolds to Burr Oak to Hiple

Project(s): 3203

Transmission Owner(s): NIPSCo

Description: This creates a 345 kV line from Reynolds substation to Burr Oak to Hiple through northern Indiana. At the Reynolds and Hiple stations, it creates a tie to 345kV lines routed near those two stations but do not connect electrically at those points. The 345 kV line is approximately 100 miles long, along with the substation upgrades at Reynolds and Hiple necessary to accommodate the new 345 kV line connections. The estimated cost of this project is $284 million[20]. The expected in service date is December 2019.

Justification: The project from Reynolds to Burr Oak to Hiple through northern Indiana will create a 345 kV path across the northern portion of Indiana toward Michigan, with the new tie at Hiple connecting an existing 345 kV line to the Argenta Station in southern Michigan. This path will provide an additional 345 kV path to move wind energy across Indiana, and closer to the east coast, bringing less expensive wind generation into areas where the expense to generate power can be considerably greater. The line will relieve overloads on the 138 kV system along a parallel path as well as the 138 kV network in the Lafayette, IN, area. The additional ties at Reynolds and Hiple also reduce loading on the existing 345 kV lines and creates a second path for power flow in this area, enhancing system reliability. This project will mitigate five bulk electric system (BES) NERC Category B thermal constraints and five NERC Category C constraints.

Alternatives Considered: There is no viable alternative to the proposed plan. The proposed project runs parallel to the constraints identified and is the most effective at relieving them.

5.12 MI Thumb Loop Expansion

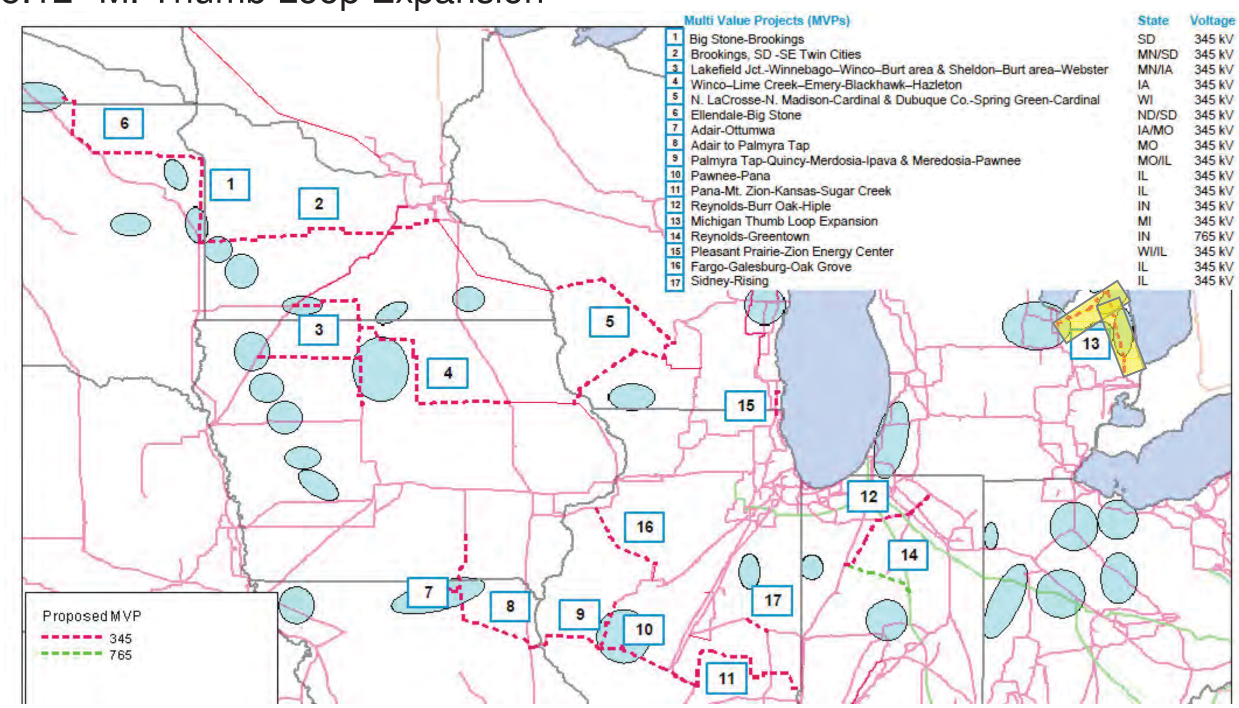

Figure 5.12: Michigan Thumb Loop Expansion

Project(s): 3168

Transmission Owner(s): ITC

Description: The proposed transmission line will connect into a new station to the south and west of the Thumb area that will tap three existing 345 kV circuits; one between the Manning and Thetford 345 kV stations, one between the Hampton and Pontiac 345 kV stations and one between the Hampton and Thetford 345 kV stations. Two new 345 kV circuits will extend from this new station, to be called Baker (formerly Reese), up to a new station, to be called Rapson (formerly Wyatt or Wyatt East) that will be

[20] In 2011 dollars

located to the north and east of the existing 120 kV Wyatt station. In order to support the existing 120 kV system in the northern tip of the Thumb, the two existing 120 kV circuits between the Wyatt and Harbor Beach stations, one that connects directly between Wyatt and Harbor Beach and that connects Wyatt to Harbor Beach through the Seaside station, will be cut into the new Rapson station. From the Rapson station, two 345 kV circuits will extend down the east side of the Thumb to the existing Greenwood 345 kV station and then continue south to the point where the existing three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. To facilitate connection to the existing transmission system a new 345 kV station, to be called Fitz (formerly Saratoga), is included in the plan at a site due south of the existing Greenwood station and just north of where the existing three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. The Fitz station will then tap the existing Pontiac to Belle River to Greenwood 345 kV circuit and the existing Belle River to Blackfoot 345 kV circuit. Transformation from the 345 kV facilities to the 120 kV facilities will be necessary to maintain continuity to the existing system in and around the Sandusky area. The existing 120 kV facilities between the sites that will facilitate the new 345 kV to 120 kV transformation can be utilized to facilitate a connection between the new 345 kV to 120 kV transformation and the existing 120 kV facilities in the Sandusky area. The cost of this project is $510 million[21].

Justification: This project was needed pursuant to the directives of the Michigan Public Service Commission' and the Final Report of the Michigan Wind Energy Resource Zone Board ("Board"). This project is necessary to deliver wind mandate in Region 4, the primary wind zone region in Michigan (the Thumb). Reliability analysis tested 13 different system conditions involving Ludington pumped storage scenarios and Ontario interface transfers. Without mitigations, overloads were up to 155% and instability may happen for some multiple contingencies. With the existing system and alternative designs tested, NERC reliability standards cannot be met when renewable sufficient to deliver the wind mandates are connected.

Alternative 1 Considered: Replace the existing single circuit 120 kV loop from Tuscola up to Wyatt and down to Lee with two new 230 kV circuits on a 230 kV double circuit tower line that will extend from a new 230 kV station at or near the existing 120 kV Wyatt station southwest to a new 345/230 kV station southwest of the existing Atlanta 138/120 kV station and two more 230 kV circuits on a 230 kV double circuit tower line that will extend from the new 230 kV station at or near the Wyatt station down around to the existing Greenwood 345 kV station utilizing high temperature 1431 ACSR conductor (or an equivalently rated conductor) and 230 kV double circuit tower (or steel pole) construction, existing ROW as available and new ROW where necessary. Also, add two new 230 kV circuits (on new ROW) on a 230 kV double circuit tower line that will extend from the new station at or near the Wyatt station down around the west side of the Thumb to the new station south west of the Atlanta 138/120 kV station and two new 230 kV circuits on a 230 kV double circuit tower line that will extend from the Wyatt station down to the Greenwood station along the east side of the Thumb utilizing a similar conductor/tower configuration as the "inner loop". Continue south from the Greenwood 345 kV station with a new 345 kV double circuit tower line containing two new 345 kV circuits toward a new 345 kV station at a site due south of the existing Greenwood station and just north of the point where the three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. The two new 345 kV circuits from Greenwood to this new station south of Greenwood would parallel the existing 345 kV circuit along that same path. These routes would utilize existing ROW to the extent possible.

Total Project Cost Estimate: $740, 000,000

Alternative 2 Considered: Replace the existing single circuit 120 kV loop from Tuscola up to Wyatt and down to Lee with two new 230 kV circuits on a 230 kV double circuit tower line that will extend from a new 230 kV station at or near the existing 120 kV Wyatt station southwest to a new 345/230 kV station southwest of the existing Atlanta 138/120 kV station and two more 230 kV circuits on a 230 kV double circuit tower line that will extend from the new 230 kV station at or near the Wyatt station down around to the existing Greenwood 345 kV station utilizing high temperature 1431 ACSR conductor (or an equivalently rated conductor) and 230 kV double circuit tower (or steel pole) construction, existing ROW

[21] In 2011 dollars

as available and new ROW where necessary. Also, add two new 230 kV circuits (on new ROW) on a 230 kV double circuit tower line that will extend from the new station at or near the Wyatt station down around the west side of the Thumb to the new station south west of the Atlanta 138/120 kV station utilizing a similar conductor/tower configuration as the “inner loop”. Then continue south from the Greenwood 345 kV station with a new 345 kV double circuit tower line containing two new 345 kV circuits toward a new 345 kV station at a site due south of the existing Greenwood station and just north of the point where the three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. The two new 345 kV circuits from Greenwood to this new station south of Greenwood would parallel the existing 345 kV circuit along that same path. These routes would utilize existing ROW to the extent possible.

Total Project Cost Estimate: $560,000,000

5.13 Reynolds to Greentown 765 kV line

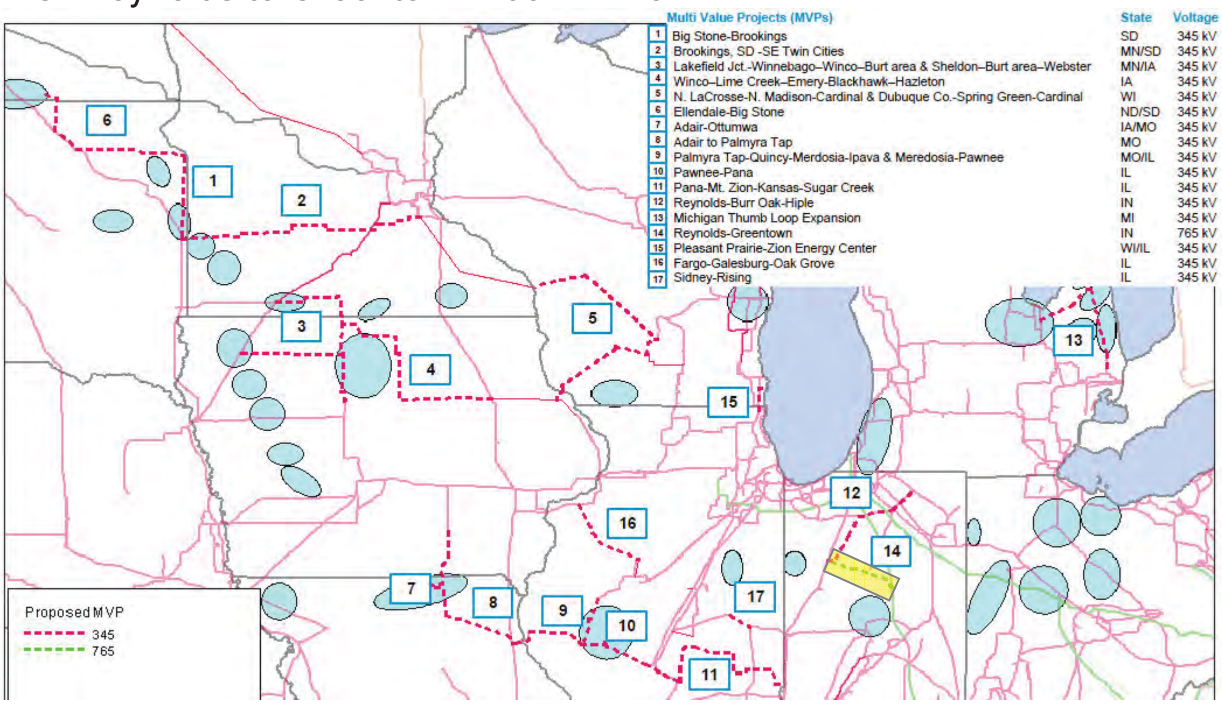

Figure 5.13: Reynolds to Greentown

Project(s): 2202

Transmission Owner(s): NIPSCO, Duke

Description: This project creates a 765 kV line from the Reynolds substation to the Greentown substation through Indiana, north of the Lafayette area. A 765/345 kV transformer/substation will also be installed at the Reynolds substation. The length of 765 kV line is approximately 66 miles, along with the 765 kV substation terminal upgrades at Greentown necessary to accommodate the 765 kV line connection. The estimated cost of this project is $245 million[22]. The 765 kV line project will be ready by June 2018. The 765/345 kV substation upgrade/construction will be ready by August 2018.

Justification: The 765 kV line from Reynolds to Greentown path across central Indiana will create an additional wind outlet path across the state, pushing power closer to the east coast, bringing less expensive wind generation into areas where the generation of power can be considerably more expensive. There are constraints on reliability on the 345 kV system to the north going toward

[22] In 2011 dollars

Chicago and Michigan, and to the south, crossing the Illinois/Indiana border and down into southwestern Indiana. These are mitigated with the new 765 kV line. The system flows attempt to bring power back to the Greentown substation, which cause numerous overloads for contingent scenarios that can be mitigated with the proposed 765 kV line. The line will also relieve constraints on the 138 kV system along a parallel path in the Lafayette, Indiana, area as well as the 138 kV line to the south between Dresser and Bedford. This 765 kV line will provide reliability benefits throughout Indiana. This project will mitigate seven bulk electric system (BES) NERC Category B thermal constraints and 21 NERC Category C constraints. It also relieves four non-BES NERC Category C constraints.

Alternatives Considered: Alternatives to the proposed project would be building lines to bypass the Lafayette area, which would relieve the constraints identified in this analysis, but load up the 230 and 138kV systems beyond the Lafayette area. The 345 kV in the Cayuga area is also heavily loaded, and upgrading would not be recommended. The proposed project is effective in alleviating all these constraints, without creating new ones, and provides a reduction of loadings on the existing lines.

5.14 Pleasant Prairie to Zion Energy Center 345 kV line

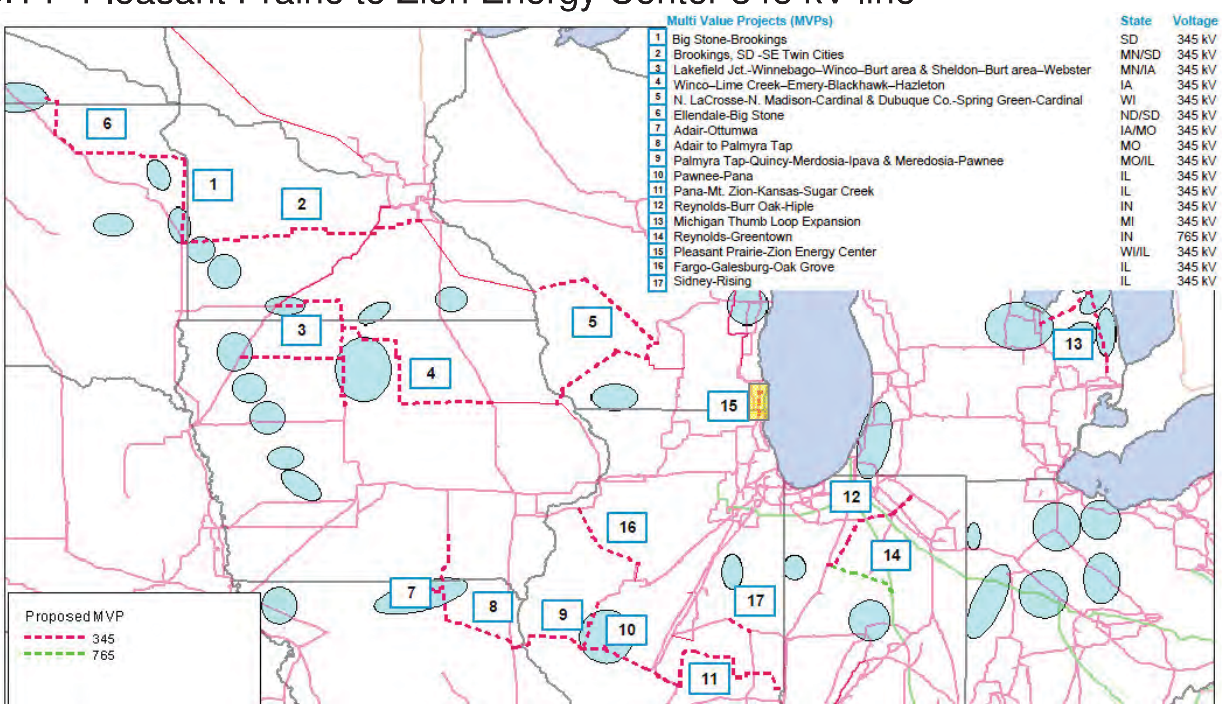

Figure 5.14: Pleasant Prairie to Zion Energy Center

Project(s): 2844

Transmission Owner(s): ATC

Description: A 345 kV line will be created from the Pleasant Prairie substation in Wisconsin to the Zion Energy Center substation in Illinois. The line will be approximately 5.3 miles long. The estimated cost is $26 million[23]. The expected in service date is March 2014.

Justification: The 345 kV line from Pleasant Prairie to Zion Energy Center creates an additional 345kV tie between these two stations, allowing more power to flow from the north down into Illinois.

[23] In 2011 dollars

That will bring wind energy from the north and west into this area. From a reliability perspective, the addition of the path relieves constraints on the 138 kV system adjacent to the project as well as 138 kV system constraints to the west of the new line. This project will mitigate seven bulk electric system (BES) NERC Category B thermal constraints and four NERC Category C constraints.

Alternatives Considered: No viable alternatives to this project were identified. The proposed project, which creates a parallel path to the existing constrained line, is the most effective solution.

5.15 Oak Grove to Galesburg to Fargo 345 kV line

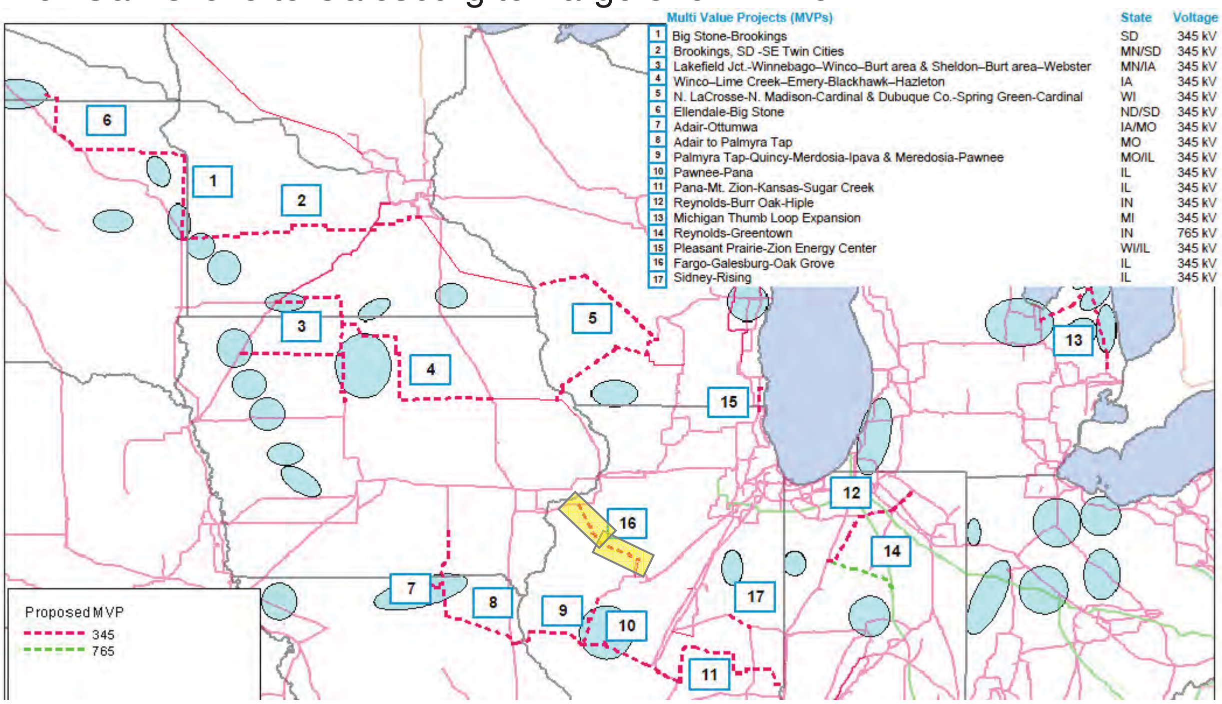

Figure 5.15: Oak Grove to Galesburg to Fargo 345 kV line

Project(s): 3022

Transmission Owner(s): Ameren, MEC

Description: This creates a 345 kV line from the MEC's Oak Grove substation to Ameren's Galesburg substation and to the Fargo substation through central Illinois. A new 560 MVA, 345/138 kV transformer will be installed at the Galesburg substation in addition to terminal additions/upgrades at all three substations. The 345 kV line is approximately 70 miles long, along with 40 miles of reconductor/rebuild at 345 kV and 138 kV to complete the project. The estimated cost is $193 million[24]. The Oak Grove – Galesburg 345 kV line and the Oak Grove 345 kV substation upgrades are expected to be ready by December 2016. The Fargo – Oak Grove 345 kV Line and Galesburg transformer addition are expected to be ready by November 2018. The Fargo substation upgrades are expected to be in service in 2018.

Justification: The new 345 kV line from Oak Grove to Galesburg to Fargo creates a path from western Illinois near the Iowa/Illinois border to central Illinois. This expansion creates an additional wind outlet path across the state, pushing power into central Illinois. In combination with another MVP, Dubuque – Spring Green – Cardinal 345 kV line, this enables 1,100 MW of wind power transfer

[24] In 2011 dollars

capability. From a reliability perspective, the addition of the Oak Grove to Fargo 345 kV path helps relieve constraints on the 345 kV system to the north. The 138kV system in the same area is also overloaded during certain contingent events. With the MVPs proposed in Wisconsin, Oak Grove to Fargo is needed to provide an outlet for the power coming from the west. It will keep that power on the 345 kV transmission system, rather than forcing it through the 138 kV system, requiring significant upgrades to carry the increased power flow.

Analysis also shows that the north ties from ATC to ComEd will remain constrained despite a new MVP from Pleasant Prairie to Zion, if the Oak-Grove Fargo 345 kV line is not built. This is because both outlets, Dubuque-Cardinal and Oak Grove-Fargo, are needed to effectively mitigate constraints on the transmission network supplying the Chicago area. This project will mitigate six bulk electric system (BES) NERC Category B thermal constraints and five NERC Category C constraints.

Alternatives Considered: Alternatives to the proposed project would be upgrading the 345 and 138 kV lines that are overloaded going toward Chicago. Upgrading the overloaded lines would likely lead to more overloads to the east, by injecting the additional power into an already constrained 345 kV path through Com Ed's Silver Lake area. The proposed project provides the greatest benefit to the transmission system.

5.16 Sidney to Rising 345kV Line

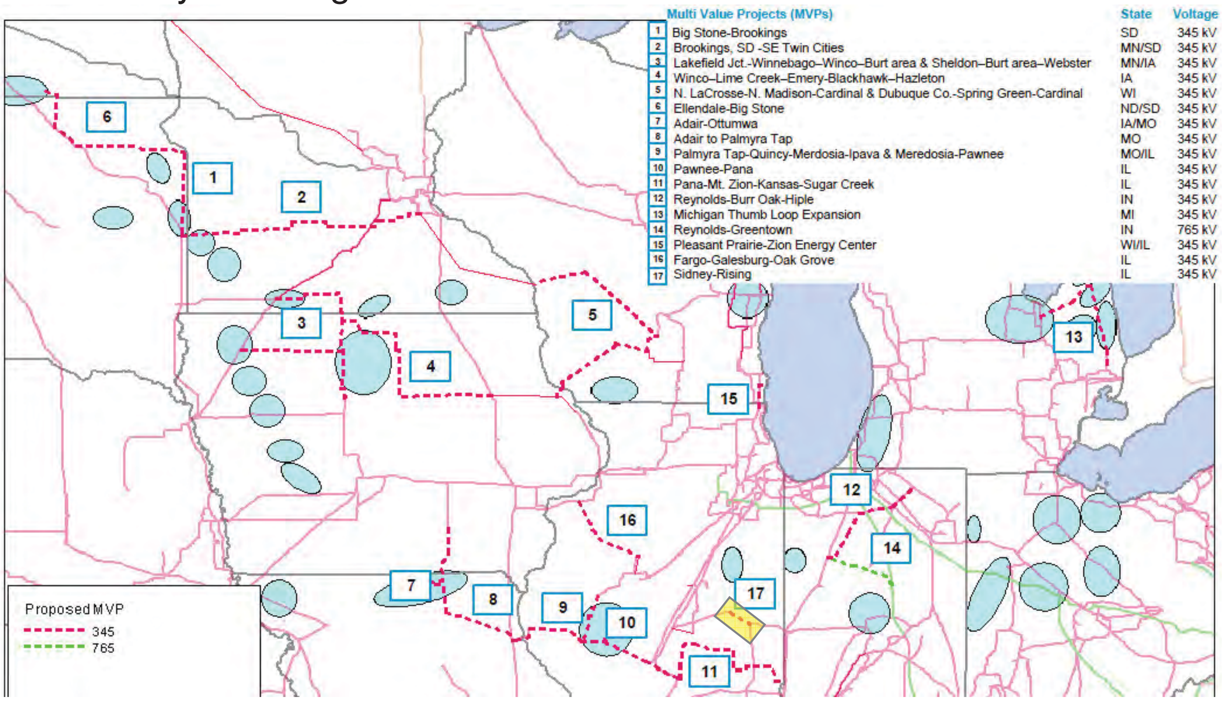

Figure 5.16: Sidney to Rising 345 kV line

Project(s): 2239

Transmission Owner(s): Ameren

Description: This builds a 345 kV line between the Sidney and Rising substation through eastern/central Illinois. That would create approximately 27 miles of 345 kV line, along with the substation upgrades at Sidney and Rising needed to accommodate the new line. The estimated cost of this project is $90 million[25]. The Sidney and Rising substation upgrades are expected to be ready by June 2016, and the 345 kV line should be ready by November 2016.

Justification: The 345 kV line from Rising to Sidney in Illinois will connect a gap in the 345 kV network in the area, promoting wind generation moving from the west to the east into Indiana. It will mitigate constraints by keeping the power on the 345 kV system, rather than pushing it into the 138 kV network at Rising. That causes overloads on the Rising transformer and on nearby 138 kV lines fed from Rising. This project will mitigate one bulk electric system (BES) NERC Category A thermal constraint, one NERC Category B constraint and three NERC Category C constraints.

Alternatives Considered: Upgrading the transformer at Rising and the 138 kV lines are a possible alternative, but that transformer was upgraded recently. Analysis shows that the power flow is being forced into the 138 kV system between Sidney and Rising to step back up to the 345 kV system. Completing the short connection between Sidney and Rising is the most effective recommendation for a long term solution.

[25] In 2011 dollars

6 Portfolio reliability analyses

In addition to the individual project justification, the MVP portfolio analysis also included an evaluation of the complete recommended MVP portfolio to ensure that system reliability is maintained. The recommended MVP portfolio maintains system reliability by resolving violations on approximately 650 transmission elements for more than 6,700 system conditions. It also mitigates 31 system instability conditions. More information on the constraints for each individual project may be found in Section 6 of this report.

6.1 Steady state

6.1.1 Reliability Planning Methodology Overview

The reliability assessment performed for the MVP portfolio analysis tested the transmission system using appropriate North American Electric Reliability Corporation (NERC) Table 1 events to determine if the system, as planned, meets Transmission Planning (TPL) standards. Any violation of these standards was identified, and the components of the portfolio were tested to determine their effectiveness in addressing the identified issues. In addition secondary transmission upgrades were developed to mitigate any unresolved issues. The performance of the mitigation plan was tested to ensure it alleviates the identified issues and does not create additional issues.

6.1.2 Planning Criteria and Monitored Elements

In accordance with the MISO Transmission Owners Agreement, the MISO Transmission System is to be planned to meet local, regional and NERC planning standards. The MVP portfolio analysis, performed by MISO staff, tested the performance of the system against the NERC Standards when applicable Renewable Portfolio Standards (RPS) were applied. Compliance with local requirements, where the local requirements exceed NERC standards, was not evaluated. This analysis will be performed by the responsible Transmission Owners. All system elements that were loaded at 95% or higher were flagged as transmission issues for Category A, B and C events. Elements under Category C3 contingencies were flagged as transmission issues at loadings of 125% and higher.

All system elements, 100 kV and above, within the MISO Planning regions, as well as tie lines to neighboring systems, were monitored. Elements 69 kV and above were monitored in select MISO Planning regions per Transmission Owner planning standards. Some non-MISO member systems were monitored if they were within the MISO Reliability Coordination Area.

6.1.3 Baseline Modeling Methodology

The MVP portfolio analysis powerflow models were developed to represent various system conditions in the planning horizon. 2021 Summer Peak and 2021 Shoulder Peak powerflow models were developed. MISO coordinated with external seam regions, including TVA, SPP, MAPP and PJM, to reflect the latest topology of the corresponding regions. For all other areas, modeling data from the 2020 Eastern Interconnection Planning Collaborative (EIPC) model was applied.

6.1.4 Contingencies Examined

Regional contingency files were developed by MISO staff collaboratively with Transmission Owners and regional study group input. NERC Category A, B and C contingency events on the transmission system under MISO functional control were analyzed. In general, contingencies on the MISO members' transmission system at 100 kV and above were analyzed, although some 69 kV transmission was also analyzed. The MTEP10 MRO contingency files were used with updates from MISO Transmission Owners. Automated single contingencies and bus double contingencies were also performed on the new MVP and surrounding transmission.

6.1.5 Results

A total of 384 thermal overloads were mitigated by the recommended MVP portfolio under shoulder peak conditions, for approximately 4,600 system conditions. In addition, approximately 100 additional thermal overloads and 150 voltage violations were mitigated by the recommended MVP portfolio in the summer peak analysis.

6.2 Transient stability

The purpose of performing transient stability analysis is to identify loss of synchronism, sometimes referred to as 'out of step' conditions for existing and proposed generation under severe fault conditions required by NERC and regional reliability standards. For the MVP portfolio transient stability analysis, two scenarios were studied.

Tasks of the two studies were evaluation of the impact of major fault conditions on the ability of the generators to remain synchronized to the electric system without any voltage or damping criteria violations.

6.2.1 Methodology and base case creation

Transient stability analysis was performed on two cases representing the shoulder peak conditions, in 2021, after the addition of RGOS wind zones and the 17 MVP portfolio lines. The following two cases were created for comparative analysis. These models were based upon the MTEP11 powerflow models utilized for the steady state analysis, as described in the previous section.

1. A base case, or the "No MVP portfolio case," was developed by adding all the incremental wind zones, without the portfolio, to the MTEP11 case.

2. A study case, or the "With MVP portfolio case," was developed by adding all the incremental wind zones, with the portfolio, to the MTEP11 case.

The corresponding dynamic files, for the power flow cases mentioned above, were created by adding the GE 1.5 MW turbines (GEWTG1- Type 3 model) to represent each wind zone. It was assumed that all new wind turbines would have a +/-0.95 power factor range. The machine data for all existing units was unchanged because it had been reviewed by the Transmission Owners during the MTEP10 review process. For all external models where the data was not available, machines were modeled with a classical machine model (GENCLS).

6.2.2 Monitored facilities

For evaluating the transient stability performance under fault conditions, the rotor angle, active power output, terminal voltage and the reactive power output for each machine was monitored. For evaluating the transient voltage violations under fault conditions, 345kV bus voltages in each MISO control area were monitored. The list of monitored bus voltages can be seen in Appendix C of this report.

6.2.3 Fault analysis and assumptions

All faults that were analyzed during the MTEP10 stability analysis review were used as the starting point for the stability analysis. In addition, several three phase faults and single line to ground faults (SLG) were developed to simulate fault conditions on the MVP portfolio lines. All these faults were reviewed by the Technical Study Task Force in the first quarter of 2011.

A two cycle margin was added to the fault clearing times to determine if system reliability would be maintained under more stressed conditions. Generally, when the fault clearing times are increased, the probability of having an unstable condition is also increased. Therefore, it was important to determine whether the existing MTEP10 faults would cause system instability; with a two cycle embedded margin to account for modeling errors that can mask underlying reliability issues if the clearing times are close to the critical clearing times. This analysis was not required to comply with any NERC reliability criteria, but was performed to check the strength of the power system with increased wind generation and transmission under the 2021 conditions.

At the time this fault analysis was conducted, short circuit data was not available to model SLG fault conditions for the CMVP faults. NERC Category C6, C7, C8 and C9 reliability criteria requires the system to be stable under SLG faults cleared under delayed clearing such as a stuck breaker condition. NERC Category D1, D2, D3 and D4 reliability criteria, which is a lot more stringent, requires the system to be stable under three phase fault conditions with delayed clearing. Typically, a three phase fault is a lot more severe than a SLG fault and is a lot easier to simulate due to the absence of zero sequence fault currents. Therefore, SLG faults with delayed clearing on the MVP portfolio lines were simulated as three phase faults with delayed clearing.

The rationale for choosing this approach was simple. If the Three Phase faults were stable under delayed clearing conditions, then it could be reasonably assumed that the same faults would also be stable under SLG with delayed clearing. However, if the analysis revealed that a few faults caused instability, then only those faults would then be re-analyzed with correct fault impedance.

6.2.4 Results

The transient stability analysis revealed that the addition of the MVP portfolio to the transmission system made the system more stable under several fault conditions and 2021 shoulder peak conditions. There were a few fault conditions, which required the addition of minor reactive support devices at a couple of 345kv buses in the western region of the MISO transmission system. The evaluation of optimized reactive support locations under these fault conditions will be studied during the regular MTEP12 reliability analysis, which requires additional stakeholder input and more detailed analysis. The results of the transient stability analysis are under Appendix C of this report.

6.3 Voltage stability

Voltage stability analysis was performed to identify voltage collapse conditions under high energy transfer conditions from major generation resources to major load sinks. For this analysis, high transfer conditions were analyzed, from the wind rich west region of the MISO footprint to major load centers such as Minneapolis-St. Paul, Madison, St Louis and Des Moines. The idea was to evaluate the incremental transfer capability, between the generation resources and the load sinks, that is created by the addition of the MVP portfolio under 2021 summer peak conditions.

6.3.1 Methodology and base case creation

The evaluation of the MVP portfolio's incremental transfer capability benefits can only be quantified when the results are compared to identical system conditions without the MVP lines. Therefore, two different power flow cases were created for 2021 summer peak conditions, shown below.

1. A base case or the "No MVP portfolio case" was developed by adding all the incremental wind zones without the portfolio.

2. A study case or the "With MVP portfolio case" was developed by adding all the incremental wind zones with the portfolio.

For each of the two cases mentioned above, four different transfers were modeled by increasing the generation in the source areas and reducing the generation in the load areas. The idea is to transmit maximum megawatts over the transmission system before a voltage collapse condition occurs due to the contingency loss of a major transmission line. For each simulated transfer, an interface consisting of major import transmission lines into the load centers was created and monitored for each contingency.

The voltage stability transfer analysis was simulated under several contingency conditions to identify the worst contingency and the corresponding maximum megawatt transfer levels over the defined interface. This method was repeated for each transfer and for both the 2021 summer peak load cases as described above.

6.3.2 Results

The comparative analysis summary below shows that the addition of the MVP lines boosted transfer capabilities from wind rich regions to major load centers within the MISO footprint. The details of the voltage stability analysis showing the PV plots and reactive reserve margins for each transfer, under both scenarios, can be viewed in Appendix C of this report.

Voltage Stability Transfer Analyzed	Without Multi Value Project Portfolio (MW)	With Multi Value Project Portfolio (MW)	Incremental Transfer enabled by the MVPs (MW)	Incremental Transfer enabled by the MVPs (percent)
MISO West - Twin Cities	3399	5240	1841	54 percent
MISO West - Madison	1720	3160	1440	84 percent
MISO West - Des Moines	2000	3100	1100	55 percent
MISO West - St Louis	3700	4660	960	26 percent

Table 6.1: Transfer capabilities under high transfer conditions

6.4 Short circuit

The reliability analysis component of the MVP portfolio study included a short-circuit analysis. The goal was to determine whether the installation of the MVP transmission facilities would cause certain existing circuit breakers to exceed their short-circuit fault interrupting capability.

Per the Tariff, should the installation of one or more MVPs cause an electrical issue on a facility, the resolution can be included in the scope of the MVP. The costs can then be shared using the same regional cost allocation mechanism applicable to the base MVPs, as long as the electrical issue is associated with a facility that is owned by a MISO Transmission Owner and classified as a transmission plant. While many electrical issues resulting from MVPs are loading or voltage related, it is also possible for the MVPs to raise the available short-circuit fault current at specific buses.

When the available short-circuit fault current increases beyond the capability of one or more circuit breakers to interrupt the fault current, the situation must be remedied. Typical remedies include replacing the affected circuit breaker with those with higher short circuit fault interrupting capabilities. In some situations, it may be necessary to reconfigure the topology of the system (e.g., splitting buses, etc.) if the available short-circuit fault currents exceed the capabilities of available circuit breakers.

To perform the short-circuit analysis, MISO developed default criteria to govern the short-circuit study. MISO then requested each Transmission Owner to conduct a short-circuit analysis on their own circuit breakers, using either their own internal criteria or MISO's default criteria, to determine if there are fault duty issues with any circuit breakers caused by the installation of one or more MVPs. Most Transmission Owners elected to use the default MISO criteria. The Transmission Owners then submitted results to MISO, including any recommendations to be added to the scope of existing MVPs. The default MISO criteria for the short-circuit analysis follows.

6.4.1 Default criteria for worst case fault current interruption exposure

This default criteria will establish the worst case fault current interruption exposure for each circuit breaker when there is no established criteria for worst case fault current interruption exposure for a specific Transmission Owner:

- Three-phase, phase-to-ground and double phase-to-ground faults will be evaluated. Phase-to-phase faults will not be evaluated.

- Faults will be simulated with zero fault impedance.
- Fault currents will be calculated in accordance with IEEE/ANSI Standard C37.010-1999 using the X/R multiplying factors.
- Faults will be simulated with all generation on-line with the sub transient reactance or equivalent modeled for all generators.
- Faults will be simulated with all network buses and branches in their normal configuration.
- For branch faults, fault locations will be simulated at the branch-side terminals of the circuit breaker in question.
- For branch and bus faults, faults current circuit breaker flows will be determined assuming all other circuit breakers protecting the branch or bus are open. While this results in a lower total fault current, this typically represents the highest fault current exposure for a specific circuit breaker.
- For each circuit breaker, simulations will be made to determine the worst case fault current interruption exposure for primary and backup zones of protection, where backup zones of protection are covered by a specific circuit breaker under the failure of a different circuit breaker.

6.4.2 Default criteria for circuit breaker fault duty calculations

The following default criteria will be used to establish the fault duty for each circuit breaker when there is no established criteria for circuit breaker fault duty calculations for a specific Transmission Owner:

- For each circuit breaker, the interrupting capability of the circuit breaker must be greater than the worst case fault current interrupting exposure of the circuit breaker, plus a safety margin of 2.5 percent
- When specific circuit breakers must be derated for reclosing duty, the Transmission Owner will inform MISO about the specific derates and the associated zones of protection where they apply for each circuit breaker. These derates will be applied in determining the fault duty for the circuit breaker.

6.4.3 Results

The results of the short-circuit analysis indicated the need for only nine circuit breaker replacements, representing an estimated capital cost of about $2.2 million, or less than 0.1 percent of the recommended MVP portfolio. The circuit breaker replacements represented lower voltage circuit breakers exposed to higher fault current levels due the installation of nearby MVP facilities. The recommended circuit breaker replacements are shown in the table below:

Substation	Voltage	Number of Breaker Replacements	Driving MVP
Blount	69 kV	3	N. Lacrosse – Cardinal - Dubuque
Lakefield	161 kV	1	Lakefield - Hazleton
Winnebago	161 kV	3	Lakefield – Hazleton
Lime Creek	161 kV	1	Lakefield – Hazleton
Hazleton	161 kV	1	Lakefield – Hazleton

Table 6.2: Circuit breaker replacements

7 Portfolio Public Policy Assessment

The projects in the proposed Multi Value Project portfolio were evaluated against criterion 1, which require the projects to reliably or economically enable energy policy mandates. To demonstrate the ability of the portfolio to enable the renewable energy mandates of the footprint, a set of analyses were conducted to quantify the renewable energy enabled by the footprint.

This analysis took part in two parts. The first part demonstrated the wind needed to meet the 2026 renewable energy mandates that would be curtailed but for the recommended MVP portfolio. The second part demonstrated the additional renewable energy, above the 2026 mandate, that will be enabled by the portfolio. This energy could be used to serve mandated renewable energy needs beyond 2026, as most of the mandates are indexed to grow with load.

7.1 Wind Curtailment

A wind curtailment analysis was performed to find the percentage of mandated renewable energy which could not be enabled but for the recommended MVP portfolio.

The shift factors for all wind machines were calculated on the worst NERC Category B and C contingency constraints of each monitored element identified as mitigated by the recommended MVP portfolio. The 429 monitored element/contingent element pairs (flowgates) consisted of 205 Category B and 224 Category C contingency events. These constraints were taken from a blend of 2021 and 2026 wind levels with the final calculations based on the 2026 wind levels.

Since the majority of the western region MVP justification was based on 2021 wind levels, it was assumed that any incremental increase to reach the 2026 renewable energy mandated levels would be curtailed. A transfer of the 193 wind units, sourced from both committed wind units and the RGOS energy zones, to the system sink, Browns Ferry in TVA, was used to develop the shift factors on the flowgates.

Linear optimization logic was used to minimize the amount of wind curtailed while reducing loadings to within line capacities. Similar to the Multi Value Project justifications, a target loading of less than or equal to 95% was used. 24 of the 429 flowgates could not achieve the target loading reduction, and their targets were relaxed in order to find a solution.

The algorithm found that 10,885 MW of dispatched wind would be curtailed. As a connected capacity, this equates to 12,095 MW as the wind is modeled at 90% of its nameplate. A MISO-wide per-unit capacity factor was averaged from the 2026 incremental wind zone capacities to 32.8%.

The curtailed energy was calculated to be 34,711,578 MWHr from the connected capacity times the capacity factor times 8,760 hours of the year. Comparatively, the full 2026 RPS energy is 55,010,629 MWHr. As a percentage of the 2026 full RPS energy, 63% would be curtailed in lieu of the MVP portfolio.

7.2 Wind Enabled

Additional analyses were performed to determine any incremental wind energy, in excess of the 2026 requirements, enabled by the recommended MVP portfolio. This energy could be used to meet renewable energy mandates beyond 2026, as most of the state mandates are indexed to grow with load. A set of two First Contingency Incremental Transfer Capability (FCITC) analyses were run on the 2026 model to determine how much the wind in each zone could be ramped up prior to additional reliability constraints occurring.

First, a transfer was sourced from all the wind zones in proportion to their 2026 maximum output. All the Bulk Electric System (BES) elements in the MISO system were monitored, with constraints being flagged at 100% of the applicable ratings. All single contingencies in the MISO footprint were evaluated during the transfer analysis. This transfer was sunk against MISO, PJM, and SPP units, in the proportions below. More specifically, the power was sunk to the smallest units in each region, with the assumption that these small units would be the most expensive system generation.

Region	Sink
MISO	33 percent
PJM	44 percent
SPP	23 percent

Table 7.1: Transfer Sink Distribution

As a result of this analysis, it was determined that an additional 981 MW could be reliably sourced from the energy zones. Because of regional transfer limits, no additional western wind could be increased beyond this level. The output levels of the wind zones were updated in the model and a second transfer analysis was performed to determine any incremental wind that could be sourced from the Central and East wind zones. This analysis was performed with the same methodology and sink as the first analysis, but all the western wind zones were excluded from the transfer source. This analysis determined that 1,249 MW of additional generation could be sourced from the Central and Eastern wind zones.

Wind Zone	Incremental Wind Enabled	Wind Zone	Incremental Wind Enabled	Wind Zone	Incremental Wind Enabled
IA-BF	22.5	IN-E	144.9	MT-A	15.4
IA-GH1	27.4	IN-K	483.0	ND-M	2.4
IA-H2	76.0	MN-B	109.5	SD-HJ	130.1
IA-J	5.1	MN-H	254.7	SD-L	15.4
IL-F	678.6	MN-K	34.8	WI-B	230.4

Table 7.2: Incremental Wind Enabled Above 2026 Mandated Level, by Zone

In total, it was determined that 2,230 MW of additional generation could be sourced from the incremental energy zones to serve future renewable energy mandates. When the results from the curtailment analyses and the wind enabled analyses are combined, the recommended MVP portfolio enables a total of 41 million MWhs of renewable energy to meet the renewable energy mandates.

8 Portfolio economic benefits analyses

Multi Value Projects represent the next step in the evolution of the MISO transmission system: a regional network that, when combined with the existing system, provides value in excess of its costs under a variety of future policy and economic conditions. These benefits are discussed below, as well as the analyses used to determine them.

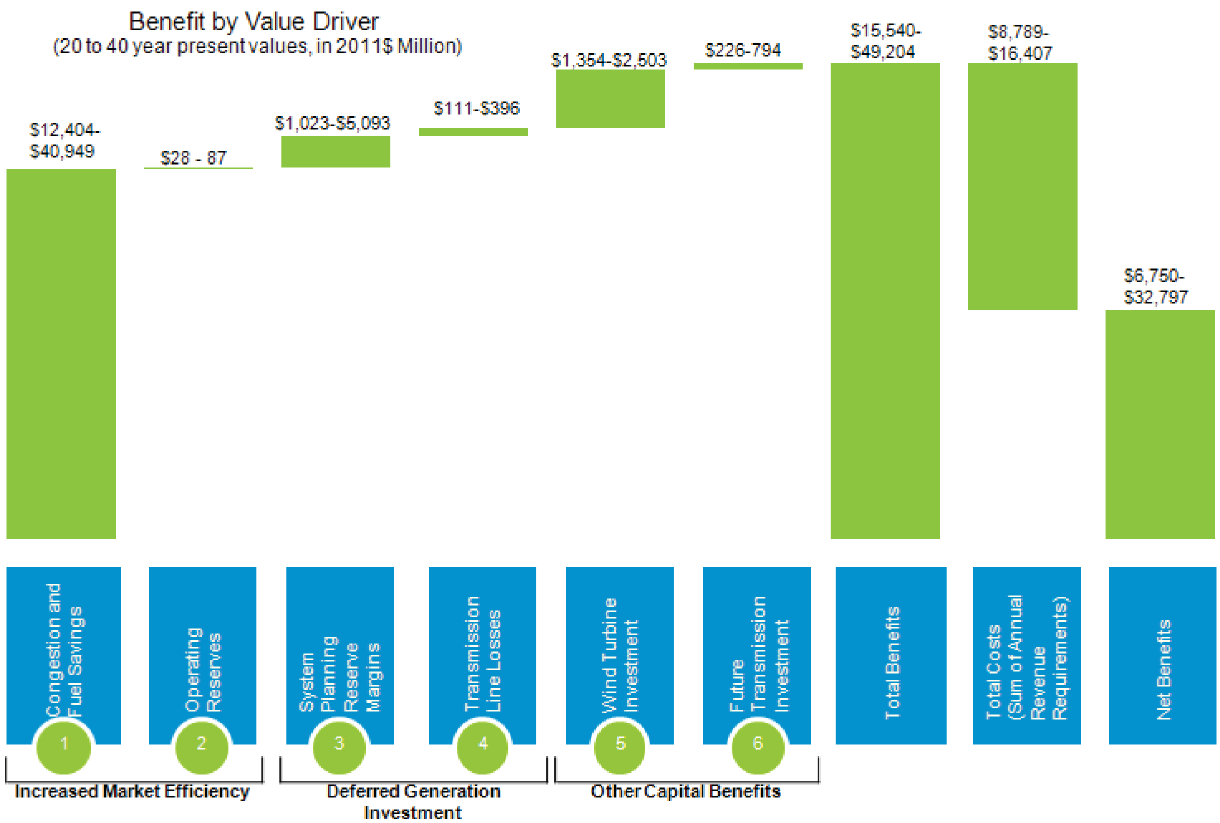

Figure 8.1: Recommended MVP portfolio economic benefits

8.1 Congestion and fuel savings

The recommended MVP portfolio allows for a more efficient dispatch of generation resources, opening markets to competition and spreading the benefits of low cost generation throughout the MISO footprint. These benefits were outlined through a series of production cost analyses, which captured the economic benefits of the recommended MVP transmission and the wind it enables. These benefits reflect the savings achieved through the reduction of transmission congestion costs and through more efficient use of generation resources.

The future scenarios without any new energy policy requirements provide a baseline of the recommended MVP portfolio's benefits under current policy conditions. Additionally, the evaluation of the Carbon Constrained and Combined Policy future scenarios provide "bookends," helping to show the full range of benefits that may be provided by the portfolio. Looking at the "Business as Usual" future scenarios with no new energy policies, the recommended MVP portfolio will produce an estimated $12.4 to $40.9 billion in 20 to 40 year present value adjusted production cost benefits, depending on the timeframe, discounts and growth rates of energy and demand. This benefit increases to a maximum present value of $91.7 billion under the Combined Policy future scenario.

8.1.1 Production cost model development

PROMOD IV® is an integrated electric generation and transmission market simulation system, and was the primary tool used to support economic assessment of the recommended MVP portfolio. It incorporates details of generating unit operating characteristics and constraints, transmission constraints, generation analysis, unit commitment/operating conditions and market system operations. It performs an 8,760-hour centralized security constrained unit commitment and economic dispatch, recognizing generation and transmission impacts at the nodal level. It uses an hourly chronological dispatch algorithm that minimizes cost, while recognizing a variety of operating constraints.

These include generating unit characteristics, transmission limits, fuel and environmental considerations, reserve requirements and customer demand. It provides a wide spectrum of forecasts on hourly energy prices, unit generation, fuel consumption, energy market prices at bus level, regional energy interchanges, transmission flows and congestion prices.

To be able to perform a credible economic assessment on the recommended MVP portfolio, production cost models require detailed model input assumptions on generation, fuel, demand and energy, transmission topology and system configuration, described below.

8.1.2 Models

The primary economic analysis was performed with 2021 and 2026 production cost models, with incremental wind mandates considered for 2021, 2026 and 2031, respectively. Three various levels of wind mandates and loads were modeled: 2021 RPS mandates and load levels, 2026 RPS mandates and load levels and 2026 load levels, plus all generation enabled by the recommended MVP portfolio used to estimate benefits in year 2031.

The transmission topology was taken from the 2021 summer peak power flow model developed through the MTEP11 planning process. The 2026 production cost models used the same transmission topology as 2021. The PROMOD study footprint included the majority of the Eastern Interconnection with ISO-New England, Eastern Canada and Florida excluded. Although these regions have very limited impact on the study results, fixed transactions were modeled to capture the influence of these regions on the rest of the study footprint.

8.1.3 Event file

Production cost models use an “event file” to capture a set of transmission constraints. The constraints ensure system reliability by performing hourly security constrained unit commitment and economic dispatch. The event file was developed based on the latest Book of Flowgates from MISO and NERC, updated to incorporate rating and configuration changes from concurrent studies in the MTEP11 planning cycle. In addition, MUST AC analyses and PROMOD Analysis Tool (PAT) contingency screening analyses were performed to identify a number of additional monitored/contingencies to ensure the most severe limiters of the transmission system are captured in the event file. As an integral part of the study, stakeholders and interested parties were extensively involved in the review of the event file.

8.1.4 Benefit measure

Comprised of 17 projects spread across the MISO footprint, the recommended MVP portfolio enables the renewable energy delivery required by public policy mandates that could not otherwise be realized. To determine the economic benefits of the recommended MVP portfolio, two production cost model simulations were performed with and without the combination of the recommended MVP portfolio and the wind it enables. The difference between these two cases provides measurable benefits associated with the recommended MVP portfolio, focusing on Adjusted Production Cost savings according to the tariff provisions. Adjusted Production Cost is the annual generation fleet production costs, including fuel, variable operations and maintenance, start up cost and emissions, adjusted with off-system purchases and sales. Adjusted Production Cost savings are achieved through reduction of transmission congestion costs and more efficient use of generation resources across the system.

8.1.5 Policy driven future scenarios

To account for out-year public policy and economic uncertainties, MISO collaborated with its stakeholders to refresh available future policy scenarios to better align them with potential policy outcomes taking place. The future scenarios were designed to bookend the potential range of future policy outcomes, ensuring that all of the most likely future policy scenarios and their impacts were within the range bounded by the results. Four futures were refreshed and analyzed:

- Business As Usual with Continued Low Demand and Energy Growth (BAULDE) assumes that current energy policies will be continued, with continuing recession level low demand and energy growth projections.
- Business As Usual with Historic Demand and Energy Growth (BAUHDE) assumes that current energy policies will be continued, with demand and energy returning to pre-recession growth rates.
- Carbon Constrained assumes that current energy policies will be continued, with the addition of a carbon cap modeled on the Waxman-Markey Bill.
- Combined Energy Policy assumes multiple energy policies are enacted, including a 20 percent federal RPS, a carbon cap modeled on the Waxman-Markey Bill, implementation of a smart grid and widespread adoption of electric vehicles.

The various input assumptions and uncertain variables defined for each policy driven future dictate a unique set of generation expansion plans on a least cost basis to meet regional Resource Adequacy Requirements, detailed in Table 8.1.

Future Scenarios	Wind Penetration	Effective Demand Growth Rate	Effective Energy Growth Rate	Gas Price	Carbon Cost / Reduction Target
BAULDE	State RPS	0.78 percent	0.79 percent	$5	None
BAUHDE	State RPS	1.28 percent	1.42 percent	$5	None
Combined Energy Policy	20 percent Federal RPS by 2025	0.52 percent	0.68 percent	$8	$50/ton (42 percent by 2033)
Carbon Constrained	State RPS	0.03 percent	0.05 percent	$8	$50/ton (42 percent by 2033)

Table 8.1: MTEP11 Future Scenario Assumptions

8.1.6 Economic analysis results

A holistic economic assessment for the recommended MVP portfolio was performed against a wide range of future policy driven scenarios. This was done to minimize the risk imposed by the uncertainties around potential policy decisions. The future scenarios without any new energy policy mandates provide a baseline of the recommended MVP portfolio's benefits under current policy conditions. The evaluation of the Carbon Constrained and Combined Energy Policy future scenarios also provide "bookends" which help show the full range of benefits that may be provided by the portfolio.

8.1.7 Adjusted Production Cost savings and benefit spread

With the recommended MVP portfolio providing access to the lowest electric energy costs and relieving transmission congestion across the MISO footprint, the portfolio brought a wide range of adjusted production cost savings, from an estimated $12.4 to $28.3 billion in 20 year present value terms under the four selected future scenarios, as shown in Figure 8.2.

The recommended MVP portfolio also collects renewable energy from a distributed set of wind energy zones, enables the wind delivery and provides widespread regional benefits across the MISO footprint, regardless of future policy outcomes.

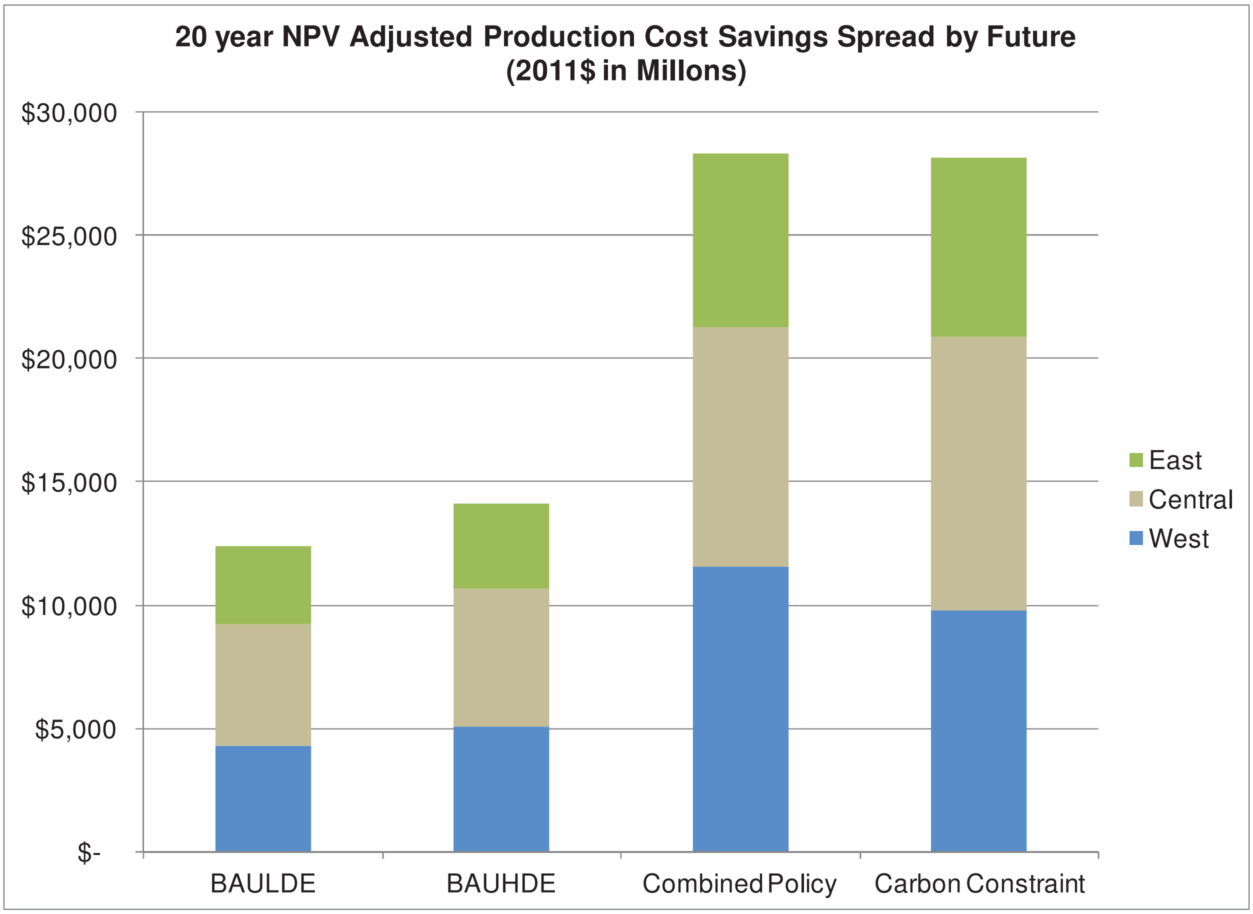

Figure 8.2: Adjusted Production Cost Savings spread by future

8.1.8 Generation displacement

Figure 8.3 summarizes the 2021 annual energy production changes between the base case and the change case. The recommended MVP portfolio enables the delivery of renewable energy to meet the near term RPS mandates of MISO states in a more reliable and economic manner, causing higher cost units to be displaced by the wind resources enabled by the proposed portfolio across the MISO footprint. Moreover, the recommended MVP portfolio allows low cost energy in the western regions to reach a wider footprint. It leads to a more efficient usage of generation resource across the entire study footprint, with some level of generation displacement occurring in external regions, particularly in PJM and SERC.

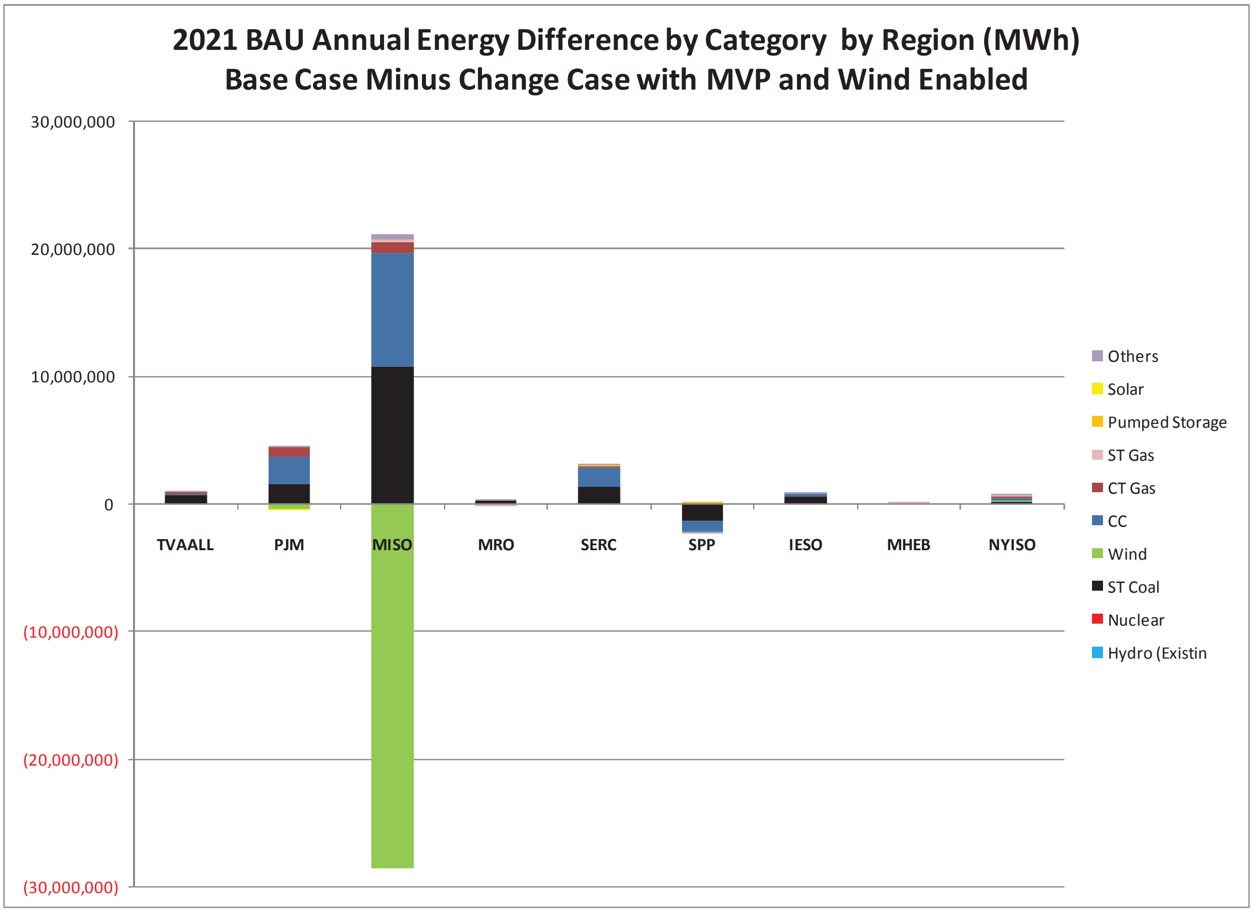

Figure 8.3: Generation displacement by region

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8.1.9 Economic Variable Impact

The projected benefits of the recommended MVP portfolio depend on projections of future policy and economic variables. Figure 8.4 shows the impacts of economic variable assumptions on the projected economic benefits achieved by the recommended MVP portfolio, with the primary focus on the time of present value calculations and discount rate.

Considering solely the ‘Business as Usual’ future scenarios with no new energy policies, the recommended MVP portfolio will produce an estimated $12.4 to $40.9 billion in 20 to 40 year present value adjusted production cost savings, depending on the time, discount rates and rate of energy and demand growth. This benefit would increase to a maximum present value of $91.7 billion under the Combined Energy Policy future scenario.

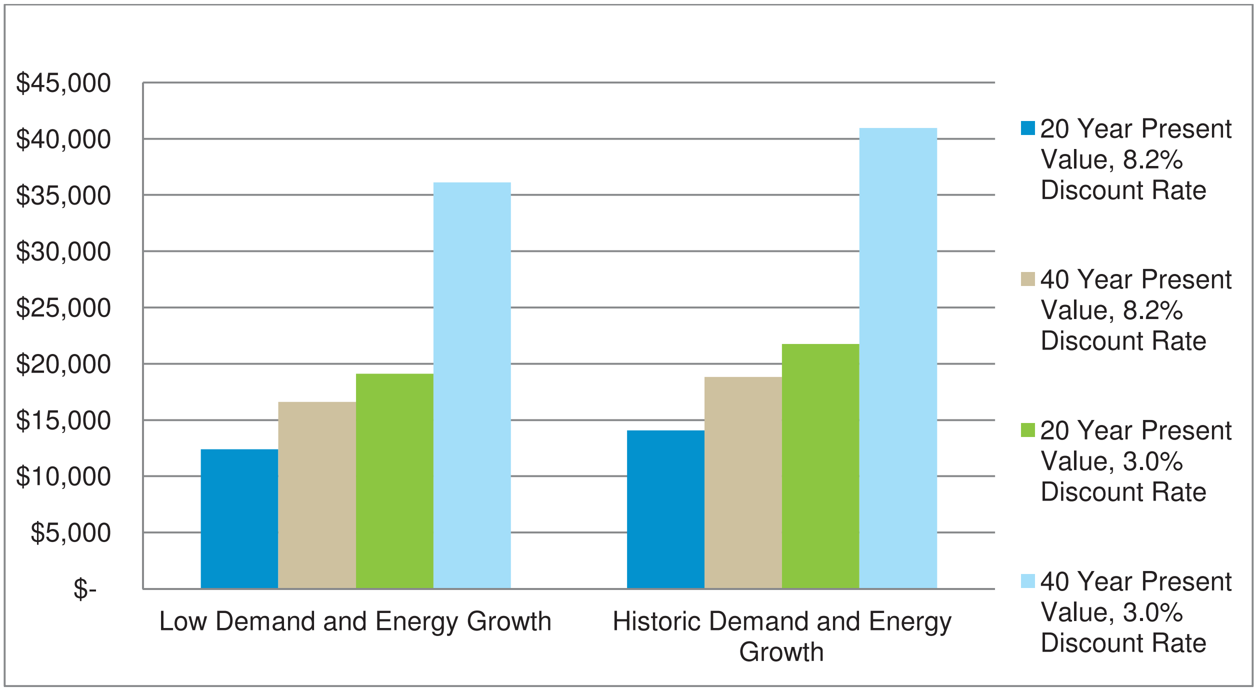


Figure 8.4: Adjusted Production Cost Benefits from recommended MVP portfolio

8.2 Operating reserves

In addition to the energy benefits quantified in the production cost analyses, the recommended MVP portfolio will also reduce operating reserve costs. The recommended MVP portfolio decreases congestion on the system, increasing the transfer capability into several key areas that would otherwise have to hold additional operating reserves under certain system conditions.

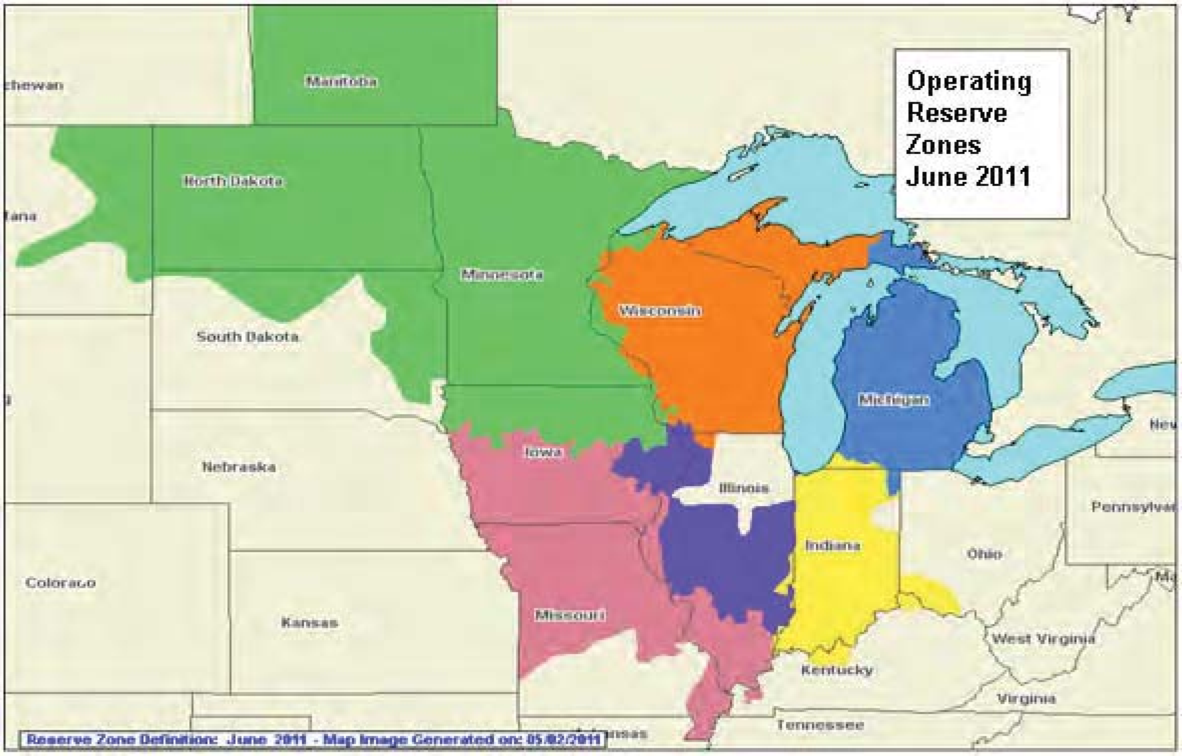


Figure 8.5: Operating reserve zones

MISO determined that the addition of the recommended MVP portfolio will eliminate the need for the Indiana operating reserve zone, as shown in Figure 8.5, and the need for additional system reserves to be held in other zones across the footprint would be reduced by half. This creates the opportunity to locate an average of 690,000 MWh of operating reserves annually where it would be most economical to do so, as opposed to holding these reserves in prescribed zones, creating benefits of $28 to $87 million in 20 to 40 year present value terms.

8.2.1 Analyses

Operating reserve zones are determined, on an ongoing basis, by monitoring the energy flowing through certain flowgates across the system. The zonal operating reserve requirements, based on the actual conditions from June 2010 through May 2011, are shown below in Table 8.2.

Zone	Total Requirement (MW)	Days with Requirement (#)	Average daily requirement (MW)
Missouri	95	1	95.1
Indiana	14966	53	282.4
N-Ohio	9147	15	609.8
Michigan	4915	17	289.1
Wisconsin	227	2	113.4
Minnesota	376	1	376.3

Table 8.2: Historic operating requirements

Transfer analyses were performed to determine the changes in flows due to the addition of the recommended MVP portfolio to the system. These analyses were performed on both the most recent model used to create the operating reserve limitations, as well as on the 2021 MTEP11 power flow model.

Zone	Limiter	Contingency	Operating Model Change in Flows	MTEP11 Model Change in Flows
Missouri	Coffeen - Roxford 345	Newton-Xenia 345	-0.8%	-18.5%
Indiana	Bunsonville-Eugene 345	Casey-Breed 345	-17.5%	-87.2%
Indiana	Crete-St. Johns Tap 345	Dumont-Wilton Center 765	-4.5%	-9.4%
Michigan	Benton Harbor - Palisades 345	Cook - Palisades 345	-10.8%	-4.6%
Wisconsin	MWEX	N/A	-20.2%	-2.3%
Minnesota	Arnold-Hazleton 345	N/A	-60.9%	15.9%

Table 8.3: Change in transfers, pre-MVP minus post-MVP

As a result of these transfer analyses, it was determined that the need for the Indiana operating zone would be eliminated by the addition of the recommended MVP portfolio to the transmission system. Also, it was determined that the need for operating reserve requirements in other zones throughout the MISO footprint would be reduced by half.

The ability to locate reserves at the least-cost location, rather than in a specific zone, will drive a benefit equal to between \$5/MWh and \$7/MWh. These benefits were assumed to grow with load growth, at roughly 1% per year. As a result, the recommended MVP portfolio will create $33 to $116 million in present value benefits.

IN Operating Reserve, no-MVP (MWh)	IN Operating Reserves, with MVP (MWh)	Other Zonal Operating Reserve, no-MVP (MWh)	Other Zonal Operating Reserves, with MVP (MWh)	Total Zonal Operating Reserves, no-MVP	Total Zonal Operating Reserves, with MVP	Nominal Benefits - Low ($M)	Nominal Benefits - High ($M)
359,195	0	354,252	177,126	713,446	177,126	$2.68	$3.75

Table 8.4: 2011 operating reserve reductions and quantification

8.3 System Planning Reserve Margin

The system planning reserve is calculated by determining the amount of generation required to maintain a one day in 10 years Loss of Load Expectation (LOLE). The reserve margin requirement is calculated through summing two components: the unconstrained system Planning Reserve Margin (PRM) and a congestion contribution. The recommended MVP portfolio reduces transmission congestion across MISO, thereby reducing the system PRM and decreasing the amount of generation required to meet the PRM. By reducing the PRM, the recommended MVP portfolio defers new generation, creating present value benefits equal to $1.0 to $5.1 billion in 2011 dollars under business as usual conditions. Results for each set of future scenarios and business case assumptions are shown in Table 8.5.

	20 year NPV		40 year NPV	
	3%	8.20%	3%	8.20%
Business As Usual with Continued Low Demand and Energy Growth	$1,460	$1,023	$1,869	$1,151
Business As Usual with Historic Demand and Energy Growth	$3,811	$1,281	$5,093	$1,496
Combined Energy Policy	$1,610	$971	$2,222	$1,167
Carbon Constraint	$2,145	$1,159	$2,747	$1,309

Table 8.5: Planning Reserve Margin Capacity Reduction

8.3.1 Congestion Impact

Additional transmission investment may ease congestion in the system, reducing the congestion component used to calculate the system PRM and reducing the future capacity required to meet system load. The reduction in system congestion, as calculated through the production cost models as the reduction in congestion costs, was determined to be 21%.

In the 2011 Planning Year LOLE Study Report, it was determined that the system Planning Reserve Margin would begin to increase due to congestion in 2016. Congestion was found to increase by 0.3 percent annually, rising to 1.5 percent by 2020[26] and 4.5 percent by 2030.

The recommended MVP portfolio will decrease this congestion by 21 percent, when the entire portfolio is in-service. The reduction was phased-in to account for the different in-service dates of the various projects in the portfolio, with the congestion reduction starting at 3.5 percent in 2016 and growing linearly to 21 percent by 2021. This congestion reduction was multiplied by the pre-MVP congestion to find the total impact of the recommended MVP portfolio. This resulted in the congestion components shown in Table 8.6.

Year	Pre-MVP Congestion Component [1]	MVP Congestion Reduction Percentage [2]	MVP Congestion Reduction Impact [3]=[1]*[2]	Post-MVP Congestion Component [4]=[1]-[3]
2011	0.0 percent	0.0 percent	0.0 percent	0.0 percent
2012	0.0 percent	0.0 percent	0.0 percent	0.0 percent
2013	0.0 percent	0.0 percent	0.0 percent	0.0 percent
2014	0.0 percent	0.0 percent	0.0 percent	0.0 percent
2015	0.0 percent	0.0 percent	0.0 percent	0.0 percent
2016	0.3 percent	3.5 percent	0.0 percent	0.3 percent
2017	0.6 percent	7.0 percent	0.0 percent	0.6 percent
2018	0.9 percent	10.5 percent	0.1 percent	0.8 percent
2019	1.2 percent	14.0 percent	0.2 percent	1.0 percent
2020	1.5 percent	17.5 percent	0.3 percent	1.2 percent
2021	1.8 percent	21.0 percent	0.4 percent	1.4 percent
2022	2.1 percent	21.0 percent	0.4 percent	1.7 percent
2023	2.4 percent	21.0 percent	0.5 percent	1.9 percent
2024	2.7 percent	21.0 percent	0.6 percent	2.1 percent
2025	3.0 percent	21.0 percent	0.6 percent	2.4 percent
2026	3.3 percent	21.0 percent	0.7 percent	2.6 percent
2027	3.6 percent	21.0 percent	0.8 percent	3.0 percent
2028	3.9 percent	21.0 percent	0.8 percent	3.1 percent
2029	4.2 percent	21.0 percent	0.9 percent	3.3 percent
2030	4.5 percent	21.0 percent	0.9 percent	3.6 percent

Table 8.6: Planning Reserve Margins Congestion Component

[26]For more information, refer to table 5.1 in the Planning Year 2011 LOLE Study Report, at the link below: https://www.misoenergy.org/Library/Repository/Study/LOLE/2011%20LOLE%20Study%20Report.pdf

8.3.2 Planning Reserve Margin Reduction

The uncongested Planning Reserve Margin was set to 17.4 percent for the full study period. This margin was summed with the congestion component, as calculated above, to find the full Planning Reserve Margin Requirement, both with and without the recommended MVP portfolio. Figure 8.6 shows the expected system PRM for 2011 through 2030 accounting for congestion and system PRM relief from the recommended MVP portfolio.

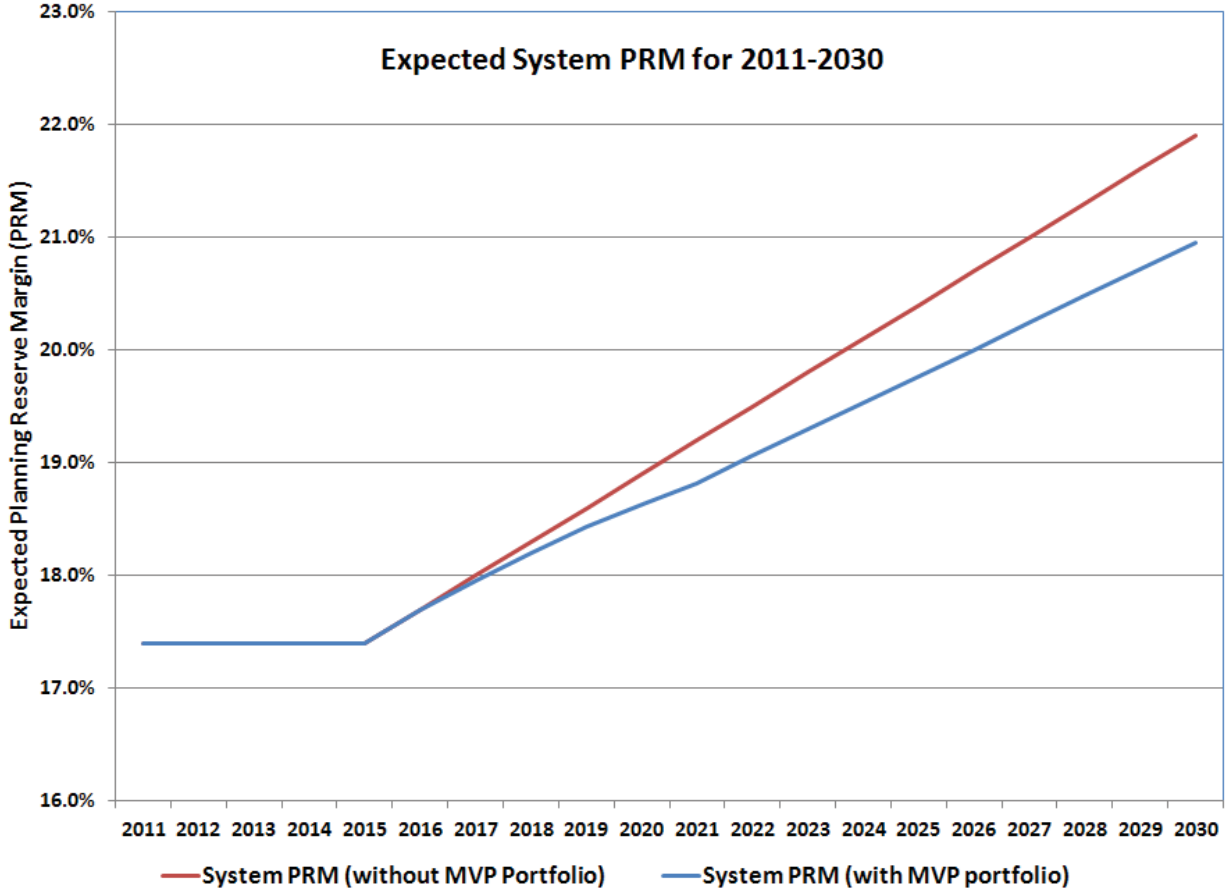


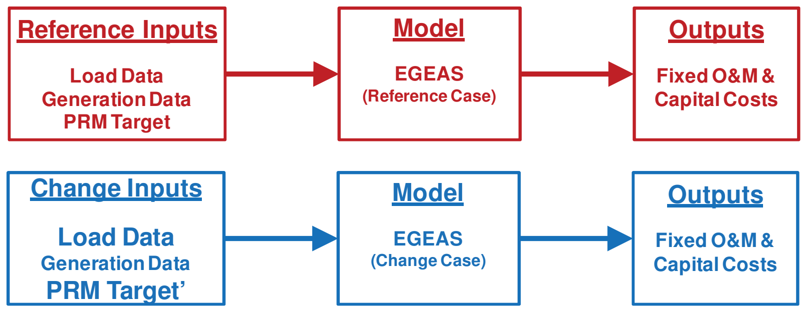
Figure 8.6: Expected System PRM, with and without the recommended MVP portfolio

8.3.3 Deferred Capacity Calculation

Sufficient generation must be built to ensure that, as the system Planning Reserve Margin increases, enough capacity is available to meet the system load and Planning Reserve Margin requirements. A lower PRM will require less future generation investment, resulting in a reduction in required capital outlays.

Electric Power Research Institute (EPRI's) Electric Generation Expansion Analysis System (EGEAS) was used to calculate the capacity benefits from PRM reduction due to transmission investment. The EGEAS model requires load forecast data, existing generation data, planned generation capacity and Planning Reserve Margin target as inputs.

Two series of analyses were run. The first set of analyses, representing the pre-MVP case, contained higher Planning Reserve Margins. The second set of analyses held all the variables constant except for the Planning Reserve Margin, modeling the lower Planning Reserve Margin created by the proposed Multi Value Project portfolio. The difference in the required capacity expansion between the two models is a benefit of the recommended MVP portfolio.



Capacity Cost Savings = $\text{Cost}_{\text{Reference Case}} - \text{Cost}_{\text{Change Case}}$

Figure 8.7: Capacity cost savings will be calculated by running two EGEAS cases.

EGEAS accurately captures the type and timing of resource additions that would occur with and without the Planning Reserve Margin (PRM) congestion relief. EGEAS outputs unit-by-unit capital fixed charge reports for each of these new capacity additions by year from 2011 through 2030. The capital cost of these capacity projections were then calculated as the 20-year or 40-year present values figures. These benefits include the reduction in annual fixed operations and maintenance charges from deferred capacity, as well as the capital charges from the reduced capacity requirements.

As can be seen in Figure 8.8 below, 400 MW of CT would be deferred by the additional of the recommended MVP portfolio in 2020, and 200 MW would be deferred in 2024. These results were documented for the Business as Usual with continued low demand growth rate future. Similar results were documented for the other futures.

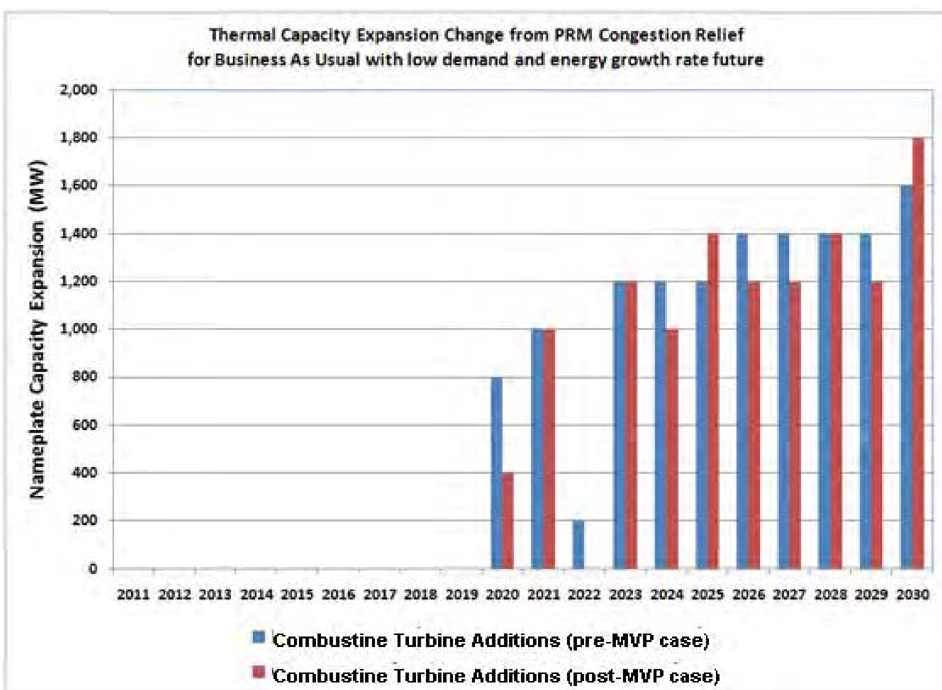


Figure 8.8: Business as Usual capacity expansion results, PRM benefit

8.4 Transmission line losses

The addition of the recommended MVP portfolio to the transmission network reduces overall system losses, which also reduces the generation needed to serve the combined load and transmission line losses. The energy value of these loss reductions is considered in the congestion and fuel savings benefits, but the loss reduction also helps to reduce future generation capacity needs. Specifically, when installed generation capacity is just sufficient to meet peak system load plus the planning reserve margin, a reduction in transmission losses reduces the amount of generation that must be built. This saves $111 million to $396 million in 2011 dollars, excluding the impacts of any potential future policies. Table 8.7 shows the capacity deferral results, depending on the timeline of the present value calculations, the discount rate and future scenarios analyzed.

	20 year NPV		40 year NPV	
	3%	8.20%	3%	8.20%
Business As Usual with Continued Low Demand and Energy Growth	$317	$229	$396	$251
Business As Usual with Historic Demand and Energy Growth	$111	$305	$196	$358
Combined Energy Policy	$655	$525	$834	$532
Carbon Constraint	$737	$229	$749	$248

Table 8.7: Transmission Line Losses Capacity Deferral

8.4.1 Transmission Losses Reduction

The transmission loss reduction was calculated through the PSS/E model. More specifically, the transmission line losses in the MTEP11 2021 summer peak models were compared, both with and without the recommended MVP transmission. This value was then used to extrapolate the transmission line losses for 2016 through 2021, assuming escalation at the normal demand growth rate.

8.4.2 Capacity Deferral Simulations

The change in required system capacity expansion due to the impact of the recommended MVP portfolio was calculated through a series of EGEAS simulations. In these simulations, the total system generation requirement was set to the system Planning Reserve Margin multiplied by the system load plus the system losses (Generation Requirements = (1+PRM)*(Load + Losses)). To isolate the impact of the transmission line loss benefit, all variables in these simulations were held constant, except for the system losses.

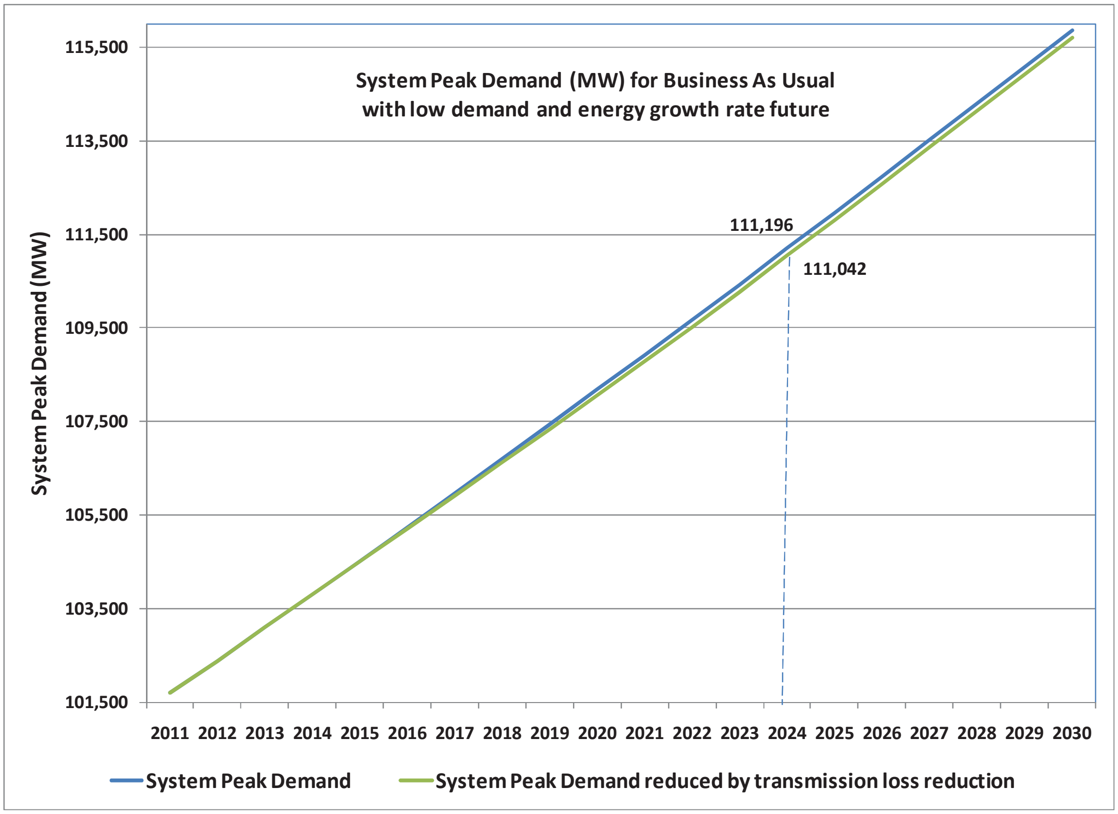


Figure 8.9: System peak demand, with and without the recommended MVP portfolio

The difference in capital fixed charges and fixed operation and maintenance costs in the reference, or pre-MVP case, and the post-MVP case is equal to the capacity benefit from transmission loss reduction, due to the addition of the recommended MVP portfolio to the transmission system. This capacity benefit was studied for the four MTEP11 future scenarios and observed during the study period (2011-2030). The capital impact of the change in capacity was then captured between 2021-2040 for a 20-year benefit value, and 2021-2060 for a 40-year capacity benefit value. As can be seen in Figure 8.10, 200 MW of CT is deferred in 2020 in the Business As Usual with a Low Demand and Energy Future at 8.2 percent discount rate.

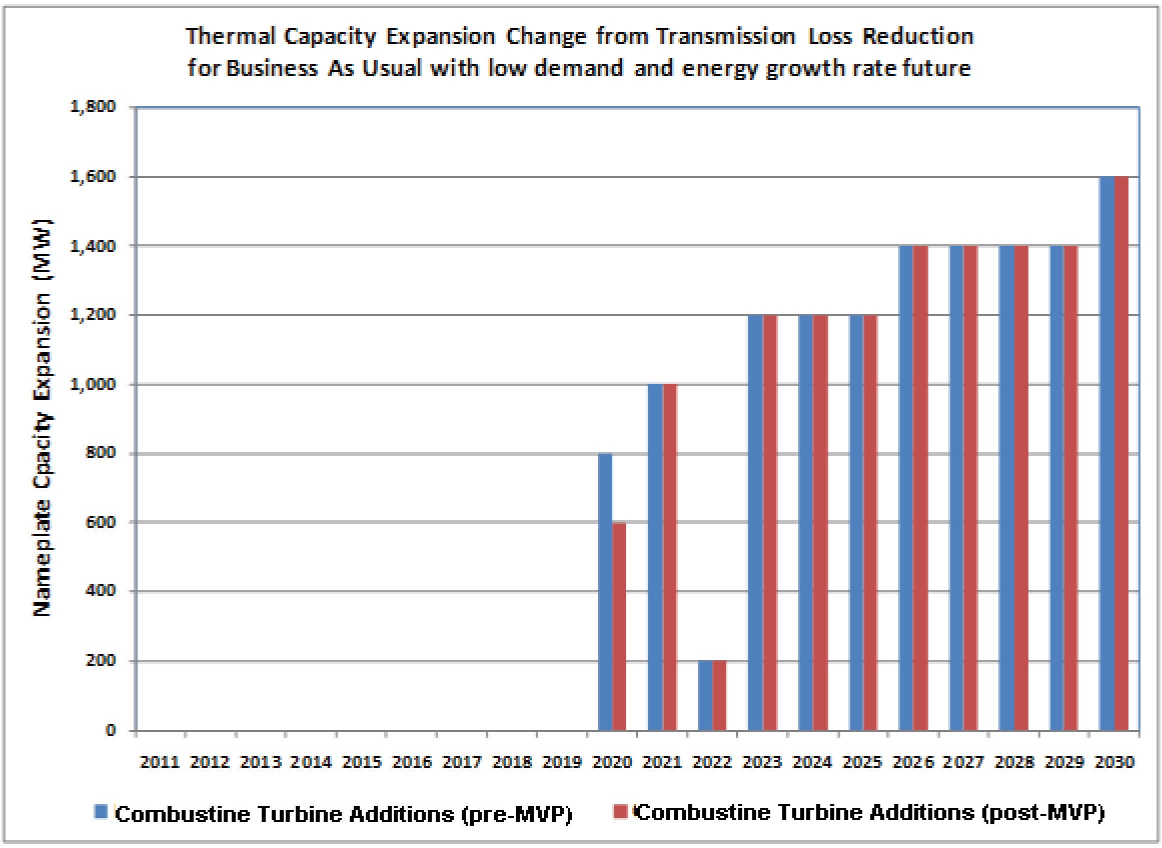


Figure 8.10: Business as Usual with Low Demand and Energy Capacity Additions, pre and post MVP

8.5 Wind turbine investment

As discussed previously, MISO determined a wind siting approach that results in a low cost solution, when transmission and generation capital costs are considered. This approach sources generation in a combination of local and regional locations, placing wind local to load, where less transmission is required; and regionally, where the wind is the strongest. However, this strategy depends on a strong regional transmission system to deliver the wind energy. Without this regional transmission backbone, the wind generation would have to be sited close to load, requiring the construction of significantly larger amounts of wind capacity to produce the renewable energy mandated by public policy.

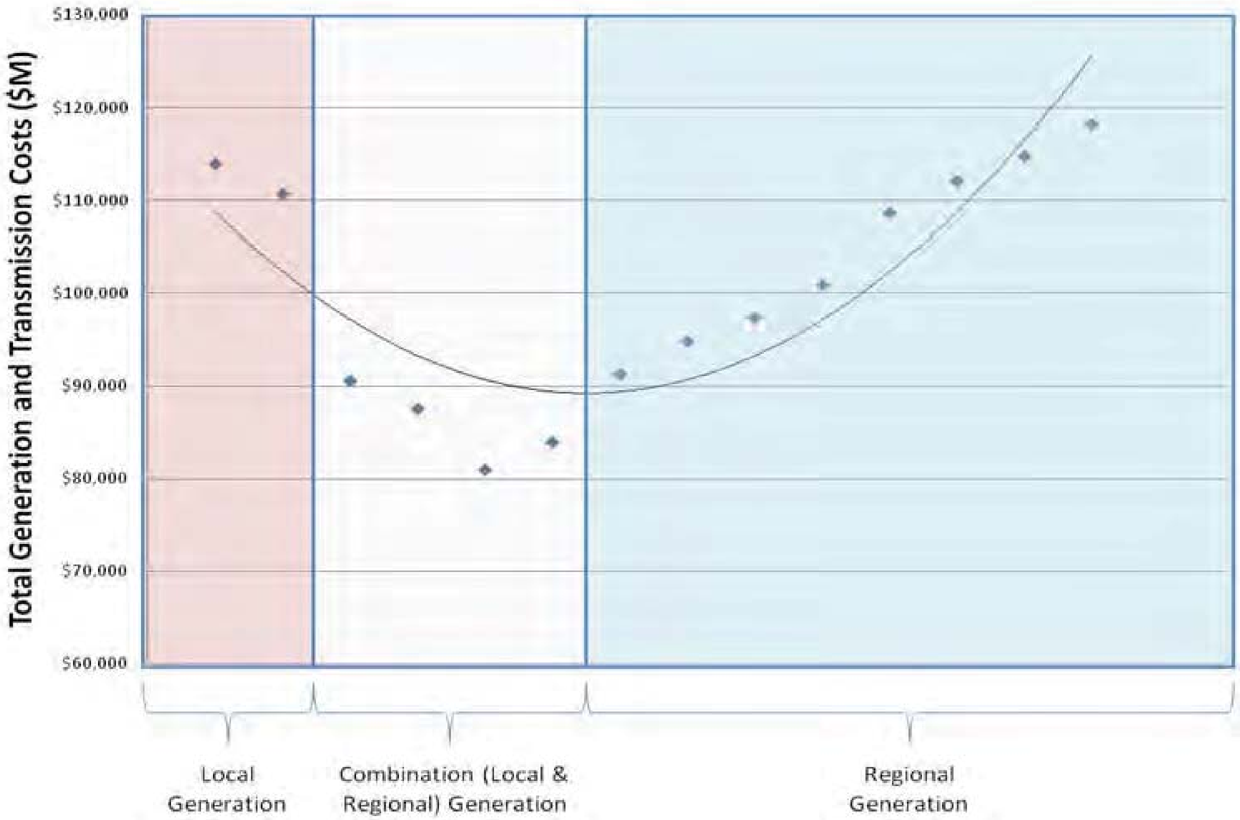


Figure 8.11: Local versus combination wind siting

In the RGOS study, it was determined that 11 percent less wind would need to be built to meet renewable energy mandates in a combination local/regional methodology relative to a local only approach. This change in generation was applied to energy required by the renewable energy mandates, as well as the total wind energy enabled by the recommended MVP portfolio. This resulted in a total of 2.9 GW of avoided wind generation, as shown in Table 8.8

Year	Recommended MVP Portfolio Enabled Wind (MW)	Equivalent Local Wind Generation (MW)	Incremental Wind Benefit (MW)
Pre-2016	12,408	13,802	1,394
2016	17,276	19,217	547
2021	21,173	23,552	438
2026	23,445	26,079	255
Full Wind Enabled	25,675	28,559	251

Table 8.8: Renewable Energy Requirements, Combination versus Local Approach

The incremental wind benefits were monetized by applying a value of $2.0 to $2.9 million/MW, based on the US Energy Information Administration's estimates of the capital costs to build onshore wind, as updated in November 2010. The total wind enabled benefits were then spread between 2015 and 2030, with half of the pre-2021 values lumped into 2021 for the purpose of this analysis. Also, to avoid overstating the benefits of the combination wind siting, a transmission cost differential of approximately $1.5 billion was subtracted from the overall wind turbine capital savings to represent the expected lower transmission costs required by a local-only siting strategy.

The low cost wind siting methodology enabled by the recommended MVP portfolio creates benefits ranging from a present value of $1.4 to $2.5 billion in 2011 dollars, depending on which business case assumptions are applied.

8.6 Transmission investment

In addition to relieving constraints under shoulder peak conditions, the recommended MVP portfolio will eliminate some future baseline reliability upgrades. A model simulating 2031 summer peak load conditions was created by growing the load in the 2021 summer peak model by approximately 8 GW, and this model was run both with and without the recommended MVP portfolio. The investment avoided through the addition of the recommended MVP portfolio into the transmission system, as determined through this analysis, is shown below in Table 8.9.

Avoided Investment	Upgrade Required	Miles
Galesburg to East Galesburg 138 kV	Bus Tie	N/A
Portage to Columbia 1 138 kV	Transmission line, < 345 kV	6
Portage to Columbia 2 138 kV	Transmission line, < 345 kV	6
Arrowhead to Bear Creek 230 kV	Transmission line, < 345 kV	1
Forbes to 44 Line Tap 115 kV	Transmission line, < 345 kV	1
Stone Lake Transformer 345/161 kV	Transformer	N/A
Port Washington to Saukville Bus 6 138 kV	Transmission line, < 345 kV	5
Port Washington to Saukville Bus 5 138 kV	Transmission line, < 345 kV	5
Ipava South to Macomb West 138 kV	Transmission line, < 345 kV	21
Lafayette Cincinnati St. to Purdue 138 kV	Transmission line, < 345 kV	1
Grace VT7 to Ortonville 115 kV	Transmission line, < 345 kV	25
East Kewanee to Kewanee South Street 138 kV	Transmission line, < 345 kV	0
Cloverdale to Stilesville 138 kV	Transmission line, < 345 kV	13
Wilmarth to Field South 345 kV	Transmission line, 345 kV	29
Dundee Transformer 161/115 KV	Transformer	N/A
Stileville to WVC Valley 138 kV	Transmission line, < 345 kV	6
Lafayette South to Lafayette Shadeland 138 kV	Transmission line, < 345 kV	3
Purdue Nw Junction Tap 1 to Westwood 2 138kV	Transmission line, < 345 kV	3
Plainfield South to WVC Valley 138 kV	Transmission line, < 345 kV	5
Antigo to Aurora Street 115 kV	Transmission line, < 345 kV	2
Latham to Kickapoo 138 kV	Transmission line, < 345 kV	5
Bunker Hill to Black Brook 115 kV	Transmission line, < 345 kV	8
Grace VT7 to Morris 115 kV	Transmission line, < 345 kV	14

Table 8.9: Avoided transmission investment

The cost of this avoided investment was estimated using generic transmission costs, as estimated from projects in the MTEP database. The costs of this transmission investment was estimated to be spread between 2027 and 2031. Also, to represent potential production cost benefits that may be missed through avoiding this investment, the value of avoiding the 345 kV transmission line was reduced by half.

Avoided Transmission Investment	Estimated Upgrade Cost
Bus Tie	$1,000,000
Transformer	$5,000,000
Transmission lines (per mile, for voltages under 345 kV)	$1,500,000
Transmission lines (per mile, for 345 kV)	$2,500,000

Table 8.10: Generic transmission costs

The recommended MVP portfolio eliminates the need for baseline reliability upgrades on 23 lines between 2026 and 2031. This creates benefits which have 20 and 40 year present values of $268 and $1,058 million, respectively.

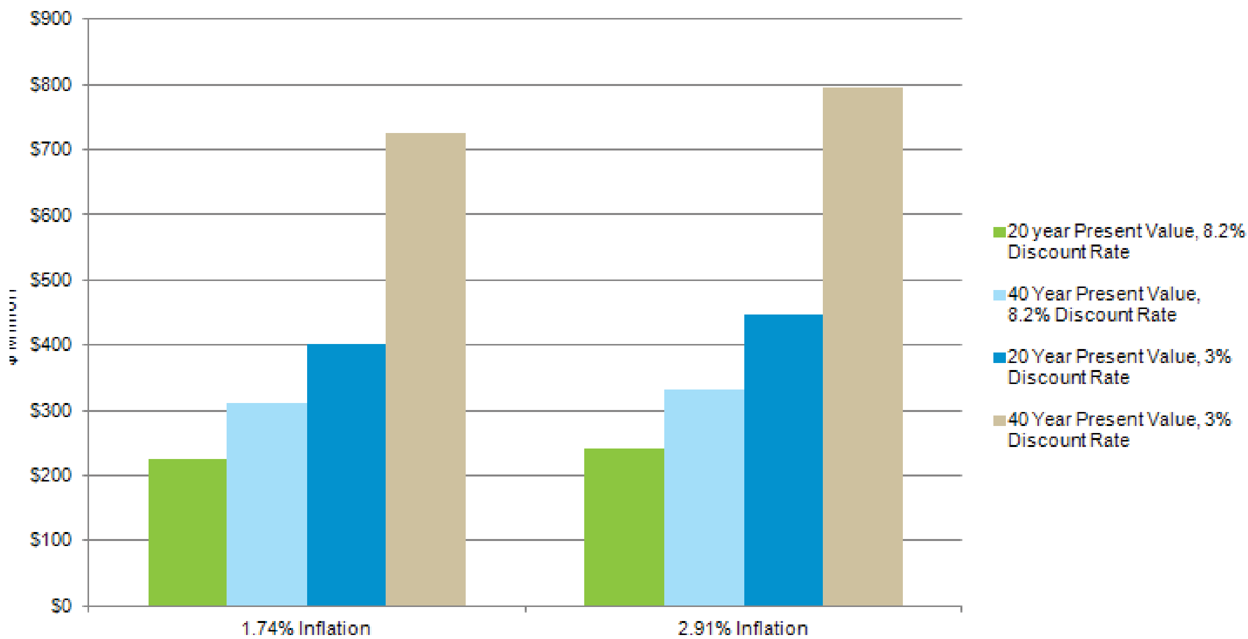


Figure 8.12: Avoided transmission investment

8.7 Business case variables and impacts

The recommended MVP portfolio provides significant benefits under every scenario studied. The base business case was built upon a fixed set of energy policies, with variances in discount rates and time horizons driving the range of benefits. However, additional variables also have the potential to impact the benefits provided by the recommended MVP portfolio.

The most critical variables considered were:

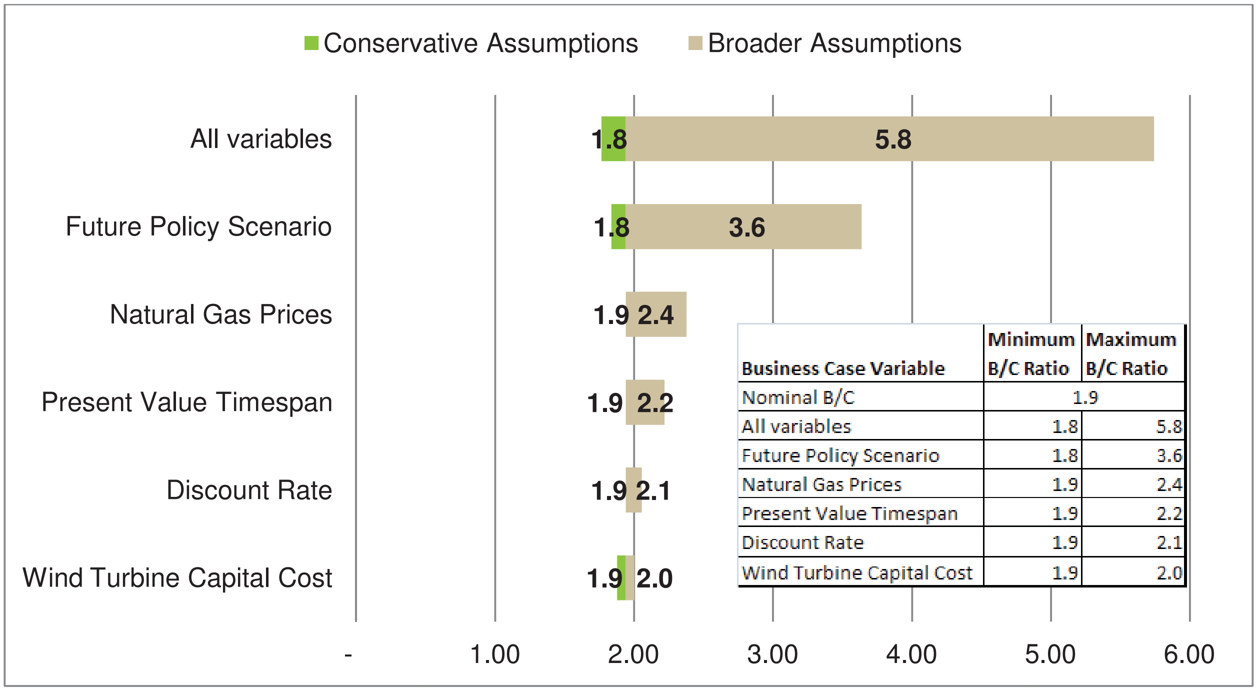
- Future energy policies
    - Includes a range of policy, demand and energy growth assumptions
    - Sensitivities were conducted to determine the impact of a legislated cost of carbon or national renewable energy mandate
- Length of Present Value Calculations: 20 or 40 years from the portfolio's in service date
- Discount Rate: 3 percent or 8.2 percent
- Natural gas prices: $5-$8 (Business as Usual Scenarios)
  $8-$10 (Combination Policy and Carbon Constrained Futures)
- Wind turbine capital cost: 2.0 or 2.9 $M/MW

To calculate the impact of any particular variable on the benefits provided by the recommended MVP portfolio, a series of analyses were performed. These analyses required changing a single variable, then comparing the resulting benefits and costs to a nominal case, which was defined as a 20 year present-value under an 8.2% discount rate. The maximum benefit-cost ratio was determined to be under a 40 year present value, using a 3% discount rate, high natural gas prices, and under the Combination Energy Policy future. The minimum benefit-cost ratio was calculated under a 20-year present value, using an 8.2% discount rate and assuming current economic policies continue under a continued economic recession.

Sensitivity Results ($M)										
	Nominal Benefits	Low Wind Turbine Capital	High Wind Turbine Capital	3% Discount Rate	40 Year Present Values	Future Policy Scenario (Low Demand and Energy Growth)	Future Policy Scenario (Combination Policy)	Natural Gas Price (High)	Maximum Benefit / Cost	Minimum Benefit / Cost
Congestion and Fuel Savings	$16,747	$16,747	$16,747	$25,846	$22,421	$14,740	$37,710	$21,534	$118,011	$14,740
Operating Reserves	$40	$40	$40	$59	$50	$40	$40	$40	$116	$33
Transmission Line Losses	$1,461	$1,461	$1,461	$3,406	$1,680	$272	$699	$1,461	$1,111	$272
System Planning Reserve Margin	$340	$340	$340	$262	$388	$1,216	$1,293	$340	$2,961	$1,216
Wind Turbine Investment	$2,635	$1,936	$3,334	$2,194	$2,635	$2,635	$2,635	$2,635	$2,778	$1,936
Future Transmission Investment	$295	$ 295	$295	$537	$406	$295	$ 295	$ 295	$ 1,058	$268
Total Benefits	$21,518	$ 20,819	$22,217	$32,304	$27,581	$19,198	$42,672	$26,305	$126,035	$18,465
Total Costs	$11,076	$ 11,076	$11,076	$15,699	$12,419	$10,444	$11,709	$11,076	$21,858	$10,444
B/C	1.9	1.9	2.0	2.1	2.2	1.8	3.6	2.4	5.8	1.8

Table 8.11: Recommended MVP portfolio benefits sensitivities

Depending on which variables are assumed, the present value of the benefits created by the entire portfolio can vary between $18.5 and $126.0 billion in 20 to 40 year present value terms. This savings yield benefits ranging from 1.8 to 5.8 times the portfolio cost.



Business Case Variable	Minimum B/C Ratio	Maximum B/C Ratio
Nominal B/C	1.9	
All variables	1.8	5.8
Future Policy Scenario	1.8	3.6
Natural Gas Prices	1.9	2.4
Present Value Timespan	1.9	2.2
Discount Rate	1.9	2.1
Wind Turbine Capital Cost	1.9	2.0

Figure 8.13: Benefit – cost variations due to business case assumptions

It should be noted that the benefits of the portfolio do not depend upon the implementation of any particular future energy policy to exceed the portfolio costs. Under existing energy policies, a conservative discount rate of 8.2 percent and 20 year present value terms, the portfolio produces benefits that are 1.8 times its cost. However, if other energy policies or enacted, or a lower discount rate is used, this benefit has the potential to greatly increase.

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9 Qualitative and social benefits

The previous sections demonstrated that the recommended MVP portfolio provides widespread economic benefits across the MISO system. However, these metrics do not fully quantify the benefits of the portfolio. Other benefits, based on qualitative or social values, are discussed in the next section. These sections suggest that the quantified values from the economic analysis may be conservative because they do not account for the full potential benefits of the portfolio.

9.1 Enhanced generation policy flexibility

Although the recommended MVP portfolio was primarily evaluated on its ability to reliably deliver energy required by the renewable energy mandates, the portfolio will provide value under a variety of different generation policies. The energy zones, which were a key input into the MVP portfolio analysis, were created to support multiple generation fuel types. For example, the correlation of the energy zones to the existing transmission lines and natural gas pipelines were a major factor considered in the design of the zones as shown in Figure 9.1.

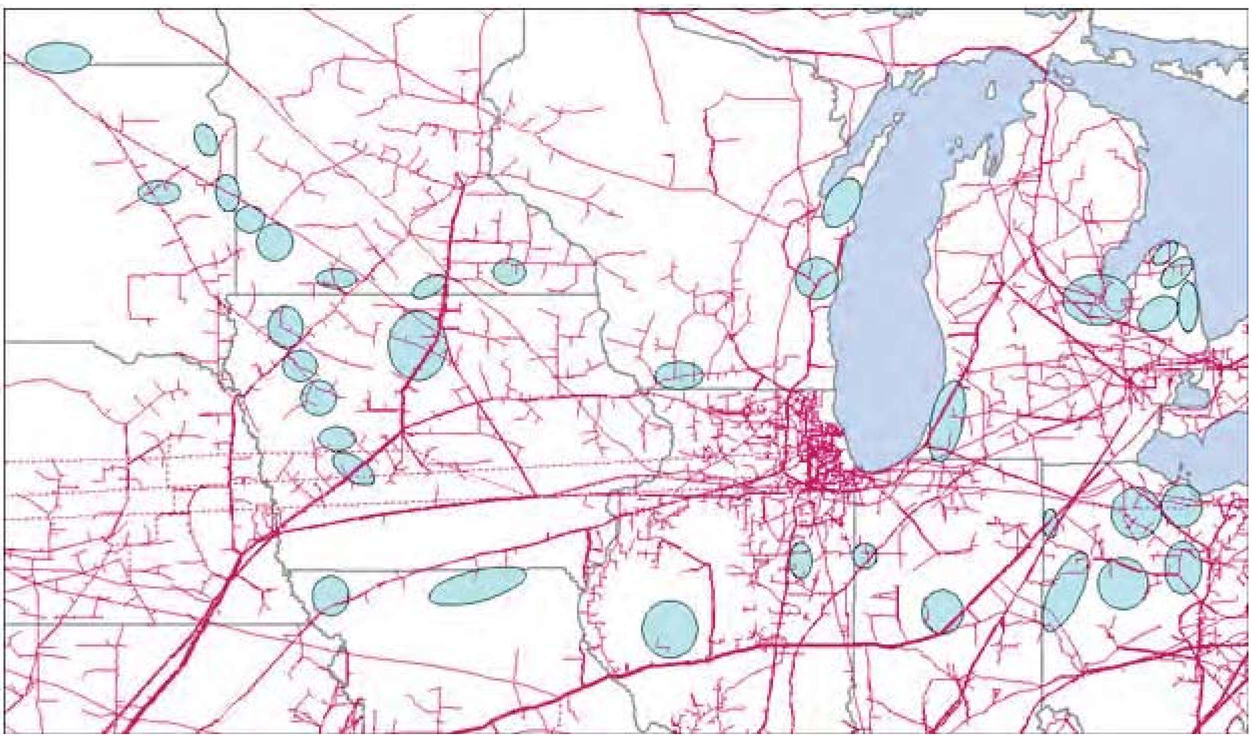

Figure 9.1: Energy zone correlation with natural gas pipelines

9.2 Increased system robustness

A transmission system blackout, or similar event, can have wide spread repercussions, resulting in billions of dollars of damage. The blackout of the Eastern and Midwestern U.S. during August 2003 affected more than 50 million people and had an estimated economic impact of between $4 and $10 billion.[27]

The recommended MVP portfolio creates a more robust regional transmission system which decreases the likelihood of future blackouts by:

- Strengthening the overall transmission system by decreasing the impacts of transmission outages.
- Increasing access to additional generation under contingent events.
- Enabling additional transfers of energy across the system during severe conditions.

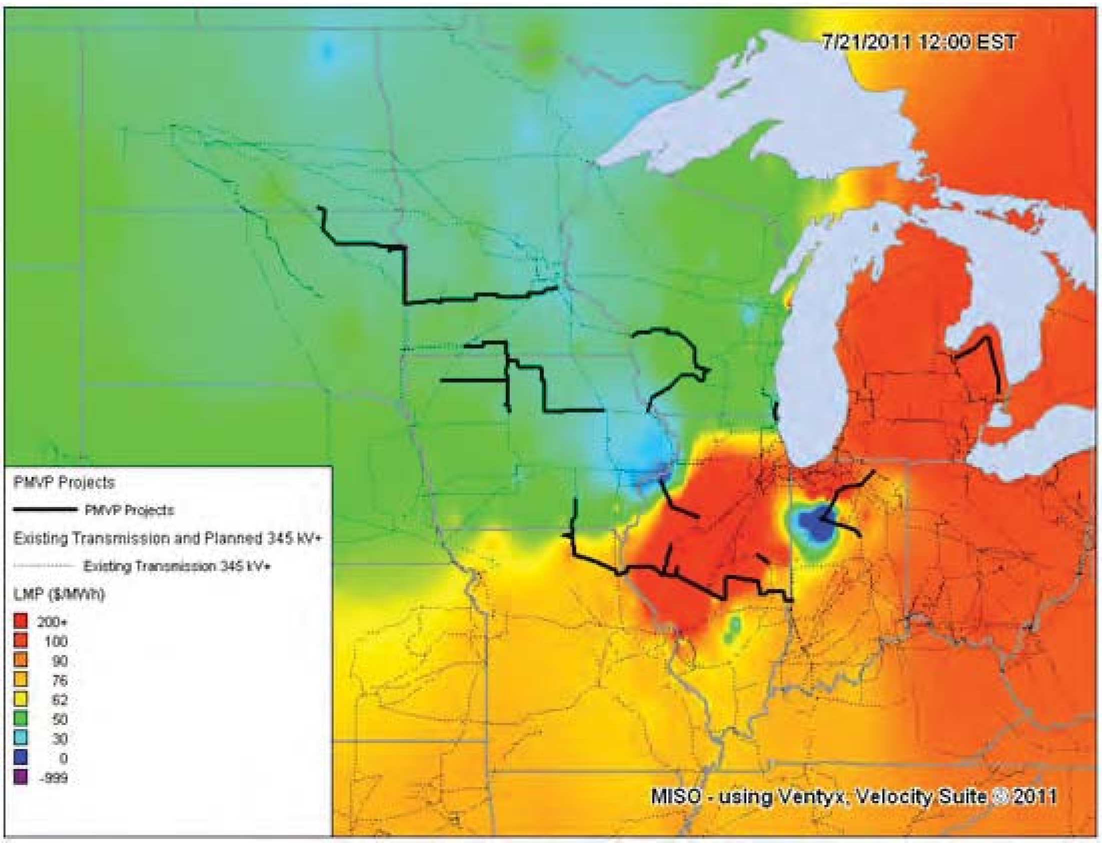

Figure 9.2: June 2011 LMP map with recommended MVP portfolio overlay

For example, the recommended MVP portfolio will allow the system to respond more efficiently during high load periods. During the week of July 17, 2011, high load conditions existed in the eastern portion of the MISO footprint, while the western portion of the footprint experienced lower temperatures and loads. Thermal limitations on west to east transfers across the system limited the ability of low cost generation from the west to serve the high load needs in the east, as shown in Figure 9.2. The recommended MVP portfolio will increase the transfer capability across the system, allowing access to additional generation resources to offset the impact and cost of severe or emergency conditions.

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[27] Data sourced from: *The Economic Impacts of the August 2003 Blackout*, The Electricity Consumers Resource Council (ELCON)

9.3 Decreased natural gas risk

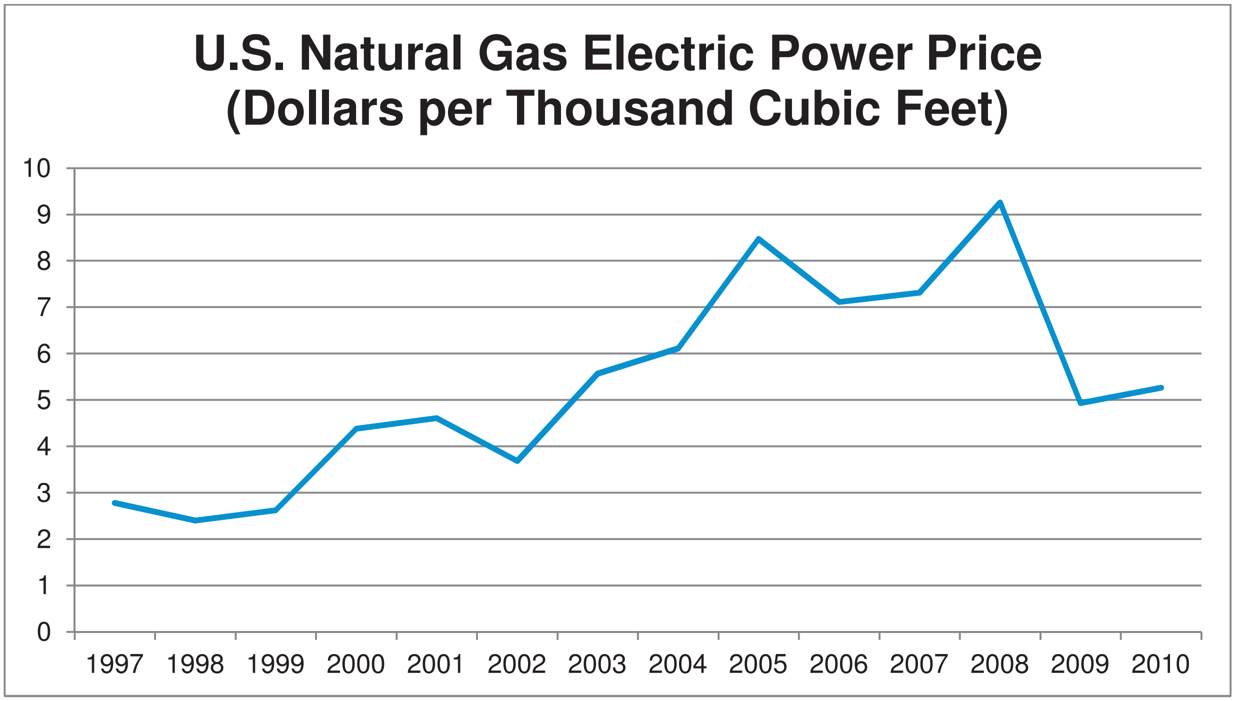

Figure 9.3: Historic U.S. natural gas electric power prices

Natural gas prices vary widely, causing corresponding fluctuations in the cost of energy from natural gas. Also, recent Environmental Protection Agency (EPA) regulations and proposed regulations limiting the emissions permissible from power plants will likely lead to more natural gas generation. This may cause the cost of natural gas to increase as demand increases. The recommended MVP portfolio can partially offset the natural gas price risk by providing additional access to generation that uses fuels other than natural gas (e.g. nuclear, wind, solar and coal) during periods with high natural gas prices. Assuming a natural gas price increase of 25 percent to 60 percent, the recommended MVP portfolio provides approximately a 5 to 40 percent higher adjusted production cost benefits.

9.3.1 Sensitivity Assumptions

A set of sensitivity analyses were performed in PROMOD to quantify the impact of changes in natural gas prices. The sensitivity cases maintained the same production cost modeling assumptions from the base business case analyses, except for the gas prices. The gas prices were increased from $5 to $8/MMBtu under the Business as Usual policy scenarios, and they were increased from $8 to $10/MMBtu under the Carbon Constrained and Combined Energy Policy scenarios. For each future scenario, the gas prices were increased starting in year 2011 and escalated by inflation thereafter.

9.3.2 Production cost benefit impact

The system production cost is driven by many variables, including fuel prices, carbon emission regulations, variable operations, management costs and renewable energy mandates. The increase in natural gas prices imposed additional fuel costs on the system, which in turn produced greater production cost benefits due to the inclusion of the recommended MVP portfolio. These increased benefits were driven by the efficient usage of renewable and low cost generation resources, as shown in

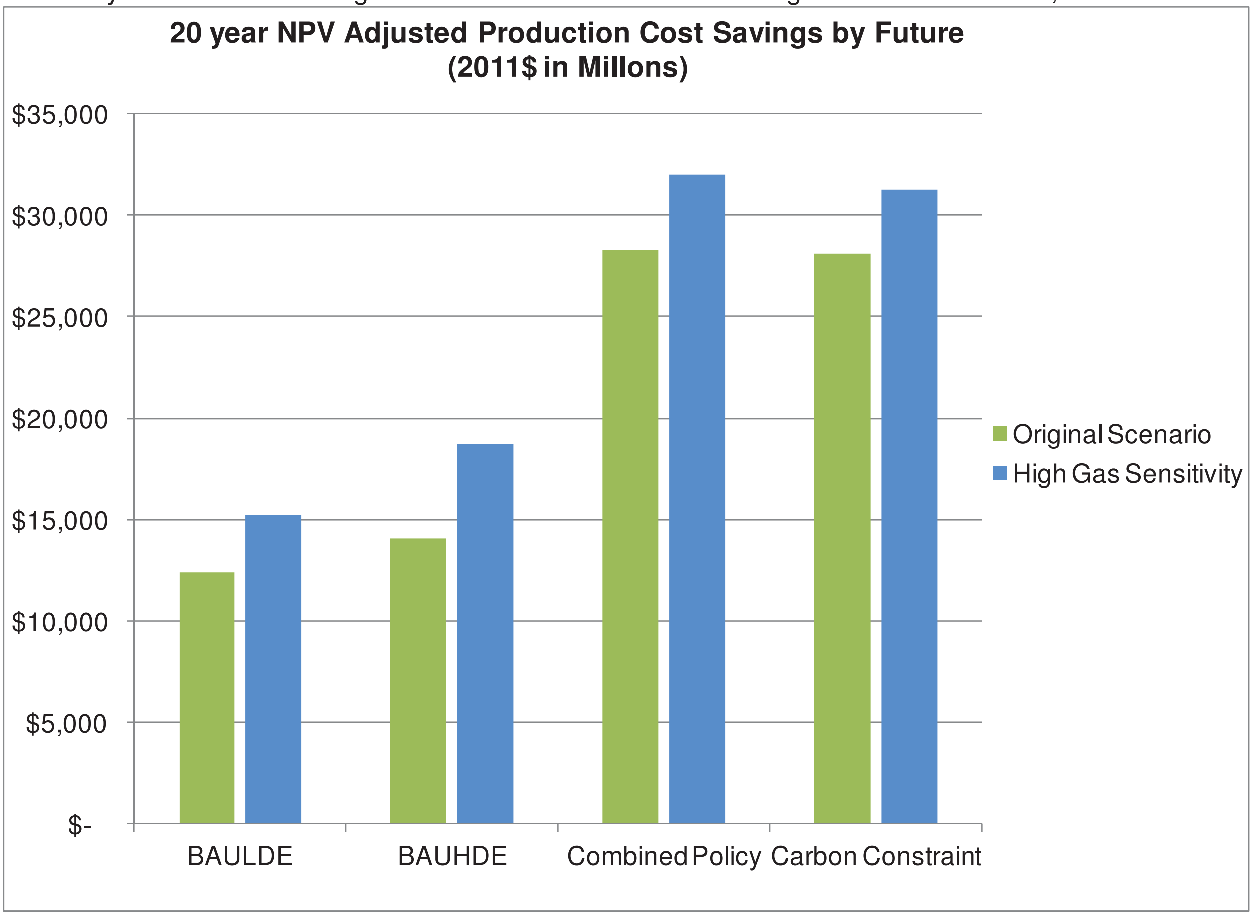

Figure 9.4.

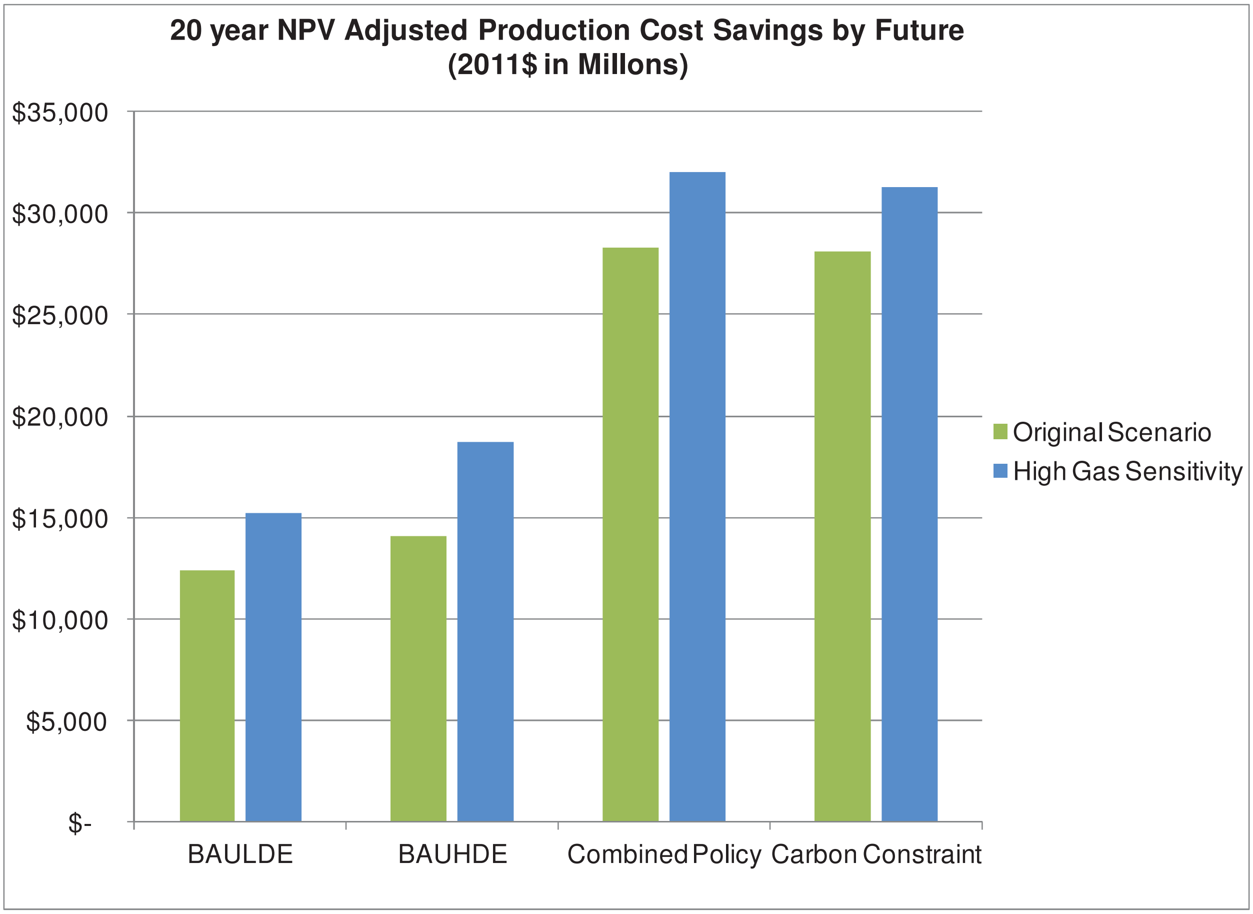

Figure 9.4: Recommended MVP Portfolio Adjusted Production Cost savings by future

9.3.3 Market price impact

The increase in market prices, or Locational Marginal Pricing (LMPs), was also calculated through the PROMOD sensitivities. The LMP is driven by the characteristics of the generation fleet and congestion on the system. With a $2-$3 increase in natural gas prices, the generation weighted average LMP increased by an average value of $7/MWh under a range of policy scenarios.

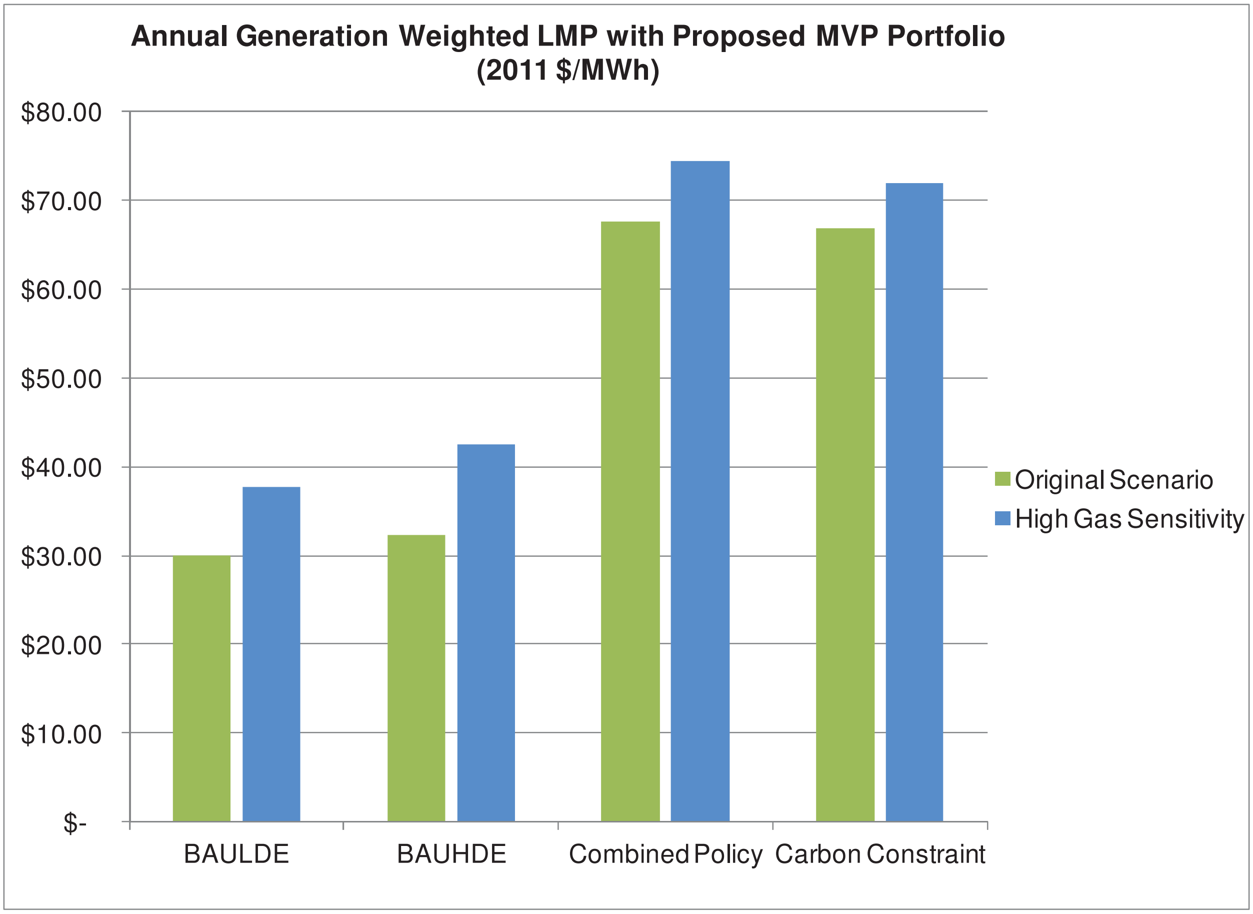

Figure 9.5: Annual generation weighted LMP with recommended MVP portfolio

9.4 Decreased wind generation volatility

As the geographical distance between wind generation increases, the correlation in the wind output decreases. This leads to a higher average output from wind for a geographically diverse set of wind plants, relative to a closely clustered group of wind plants. The recommended MVP portfolio will increase the geographic diversity of wind resources that can be delivered, increasing the average wind output available at any given time.

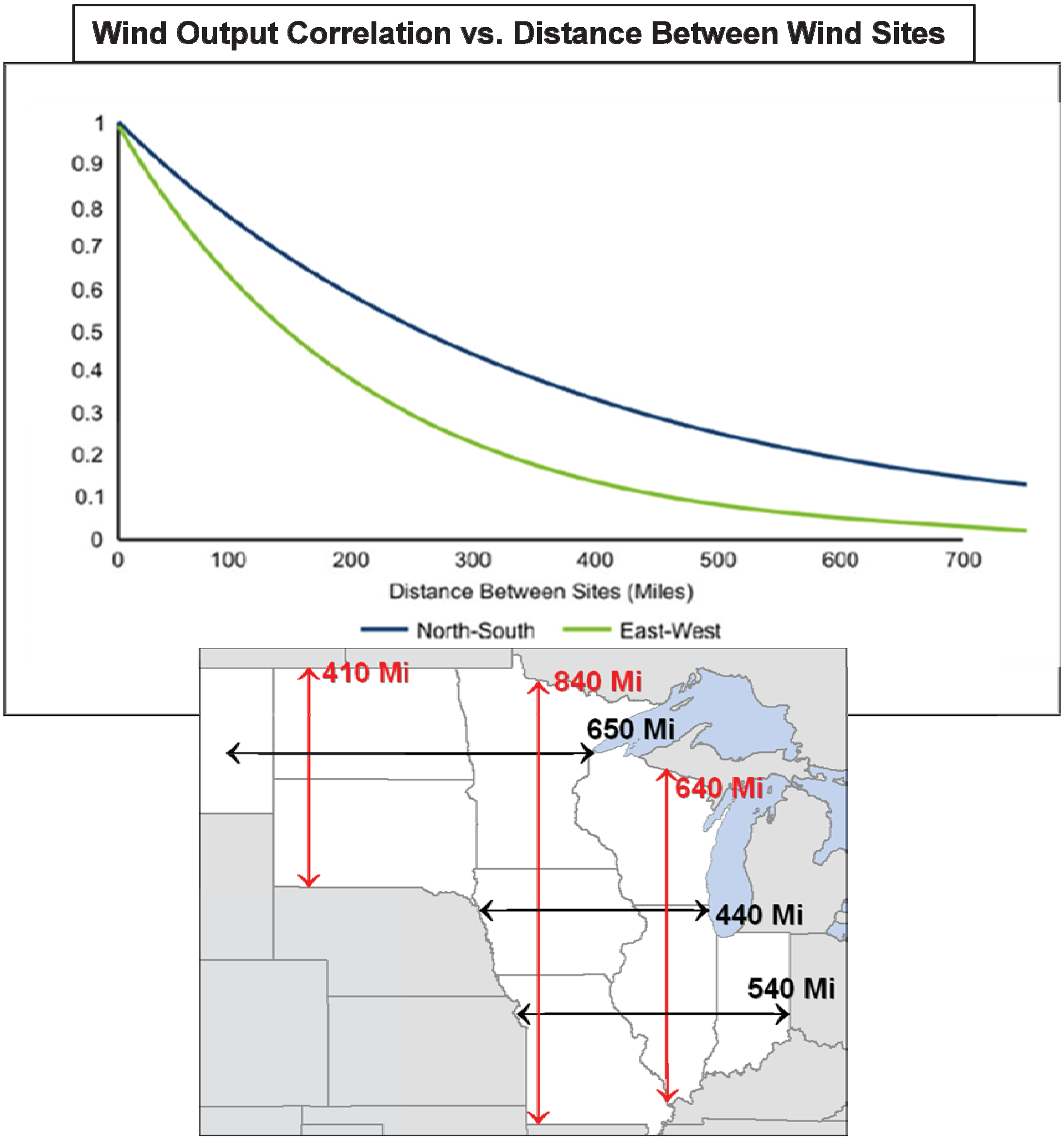

Figure 9.6: Wind Output correlation to distance between wind sites

9.5 Local investment and job creation

In addition to the direct benefits of the recommended MVP portfolio, studies have shown the indirect economic benefits of transmission investment. They estimated that, for each million dollars of transmission investment:

- Between $0.2 and $2.9 million of local investment is created.
- Between 2 and 18 employment years are created.[28]

The wide variations in these numbers are primarily due to the extent to which materials, equipment and workers can be sourced from a 'local' region. For example, each million dollars of local investment supports 11 to 14 employment years of local employment, as compared to 2 to 18 employment years which are created for non-location specific transmission investment.

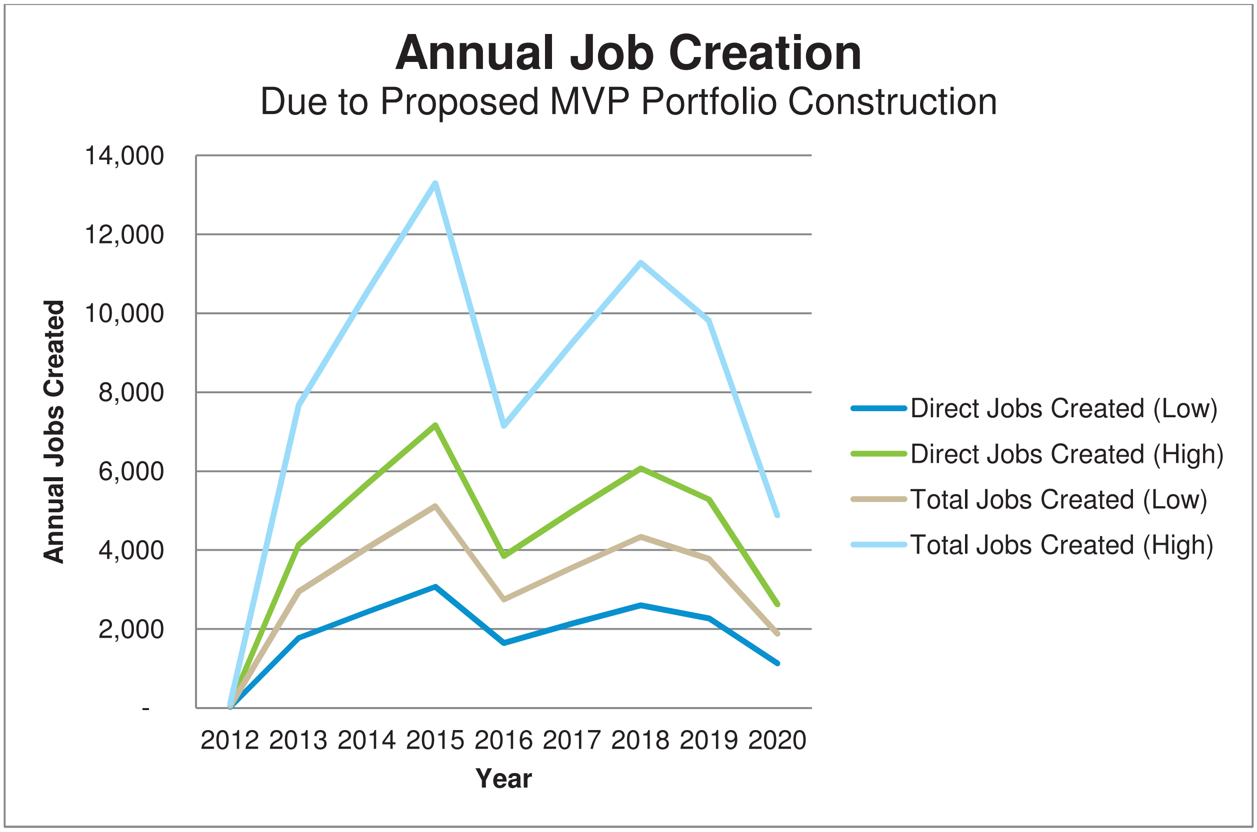

Figure 9.7: Annual Job Creation by Recommended MVP Portfolio

The recommended MVP portfolio supports the creation of between 17,000 and 39,800 local jobs, as well as $1.1 to $9.2 billion in local investment. This calculation is based upon a creation of $0.3 to $1.9 million local investment and 3 to 7 employment years per million of transmission investment. It also assumes that the capital investment for each MVP occurred equally over the 3 years prior to the project's in-service date.

[28] Source: *Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada*, The Brattle Group

9.6 Carbon reduction

With the recommended MVP portfolio delivering significant amounts of wind energy across MISO and the neighboring regions, carbon emissions were reduced because of the more efficient usage of the generation fleet with conventional generation resources displaced by wind. Figure 9.8 summarizes the carbon emission reductions in million tons for each scenario with a range of 8.3 to 17.8 million tons annually.

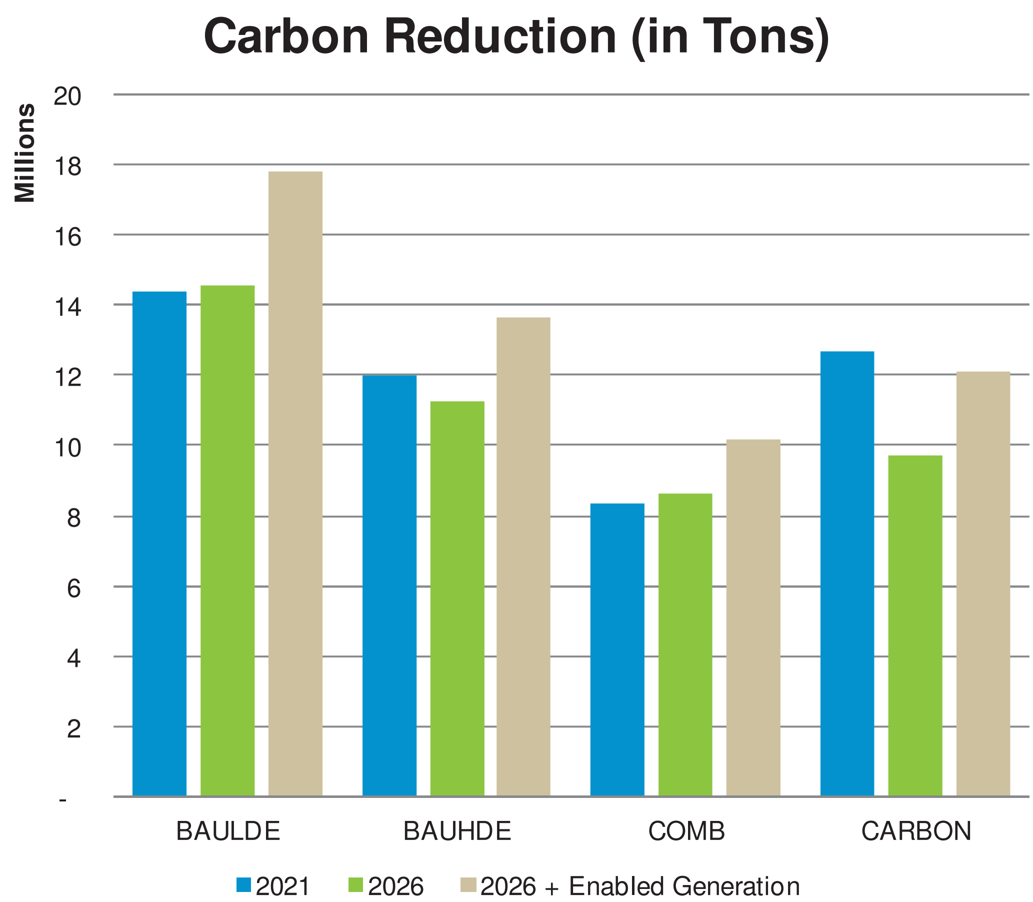

Figure 9.8: Carbon reduction by scenario

For the Combined Energy Policy and Carbon Constrained future scenarios, a $50/ton carbon cost was included to meet aggressive carbon reduction targets, as required by the proposed Waxman-Markey legislation. If policies were enacted that mandate a financial cost of carbon, the benefits provided by the recommended MVP portfolio would increase by between $3.8 and $15.4 billion in 20 and 40 year present value terms respectively, as depicted in Figure 9.9.

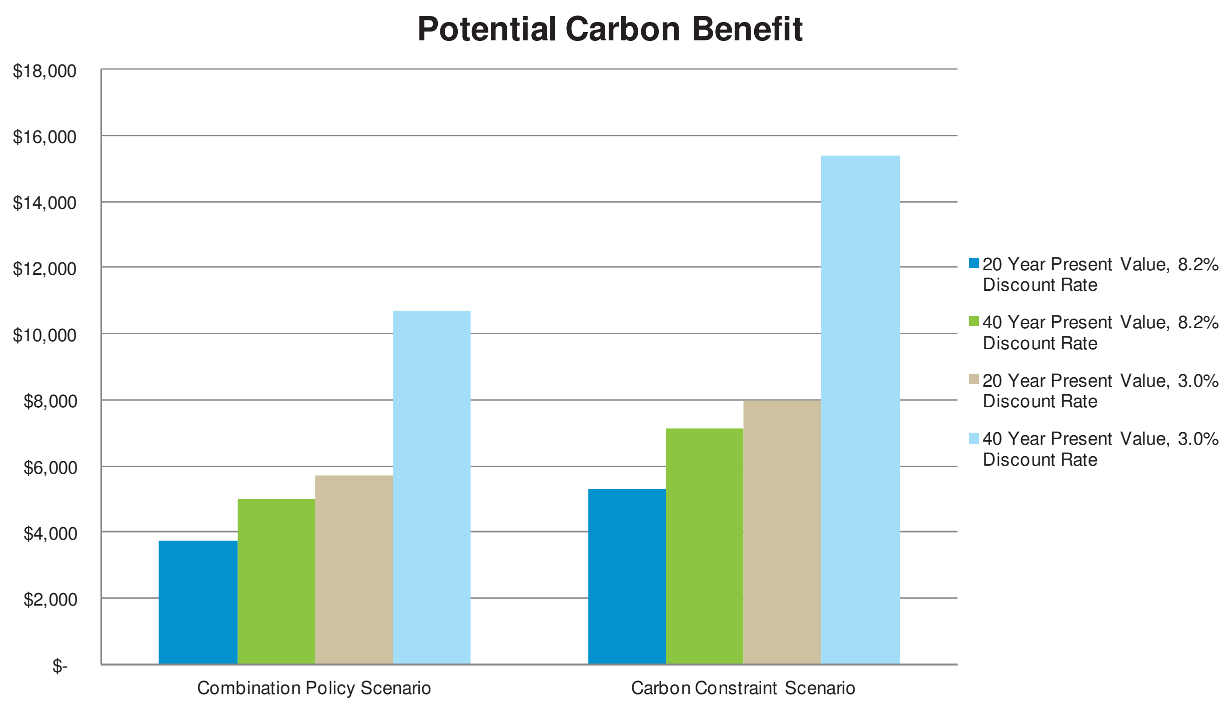

Figure 9.9: Potential carbon benefits

10 Proposed Multi Value Project Portfolio Overview

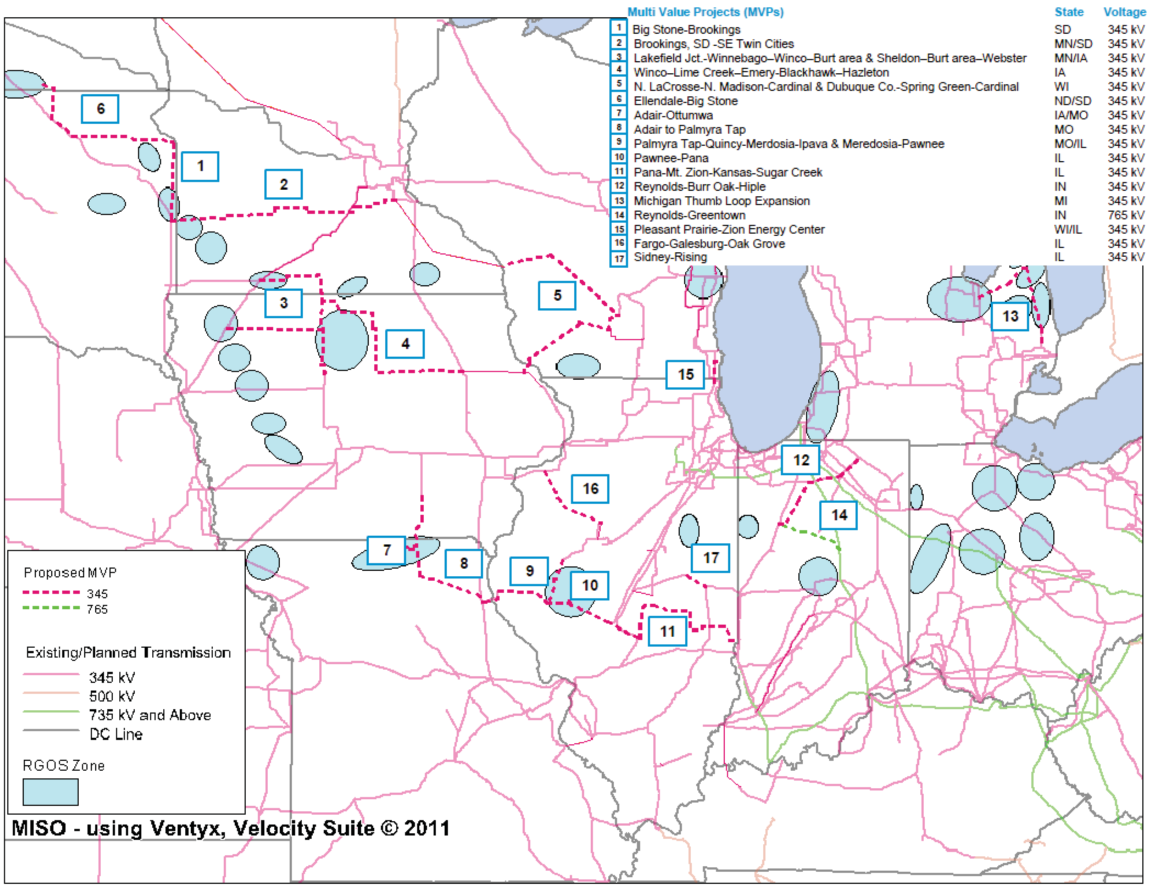

Figure 10.1: 2011 recommended MVP portfolio

The recommended MVP portfolio consists of 17 projects spread across the MISO footprint. These projects work together with the existing transmission network to enhance the reliability of the system, support public policy goals and enable a more efficient dispatch of market resources. Table 10.1 describes the projects that make up the recommended MVP portfolio.

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	Project	State	Voltage (kV)	In Service Year	Cost (M, 2011$)[29]
1	Big Stone–Brookings	SD	345	2017	$191
2	Brookings, SD–SE Twin Cities	MN/SD	345	2015	$695
3	Lakefield Jct. Winnebago–Winco–Burt area & Sheldon–Burt area–Webster	MN/IA	345	2016	$506
4	Winco–Lime Creek–Emery–Black Hawk–Hazleton	IA	345	2015	$480
5	N. LaCrosse–N. Madison–Cardinal & Dubuque Co.–Spring Green–Cardinal	WI	345	2018/2020	$714
6	Ellendale–Big Stone	ND/SD	345	2019	$261
7	Adair–Ottumwa	IA/MO	345	2017	$149
8	Adair–Palmyra Tap	MO/IL	345	2018	$98
9	Palmyra Tap–Quincy–Merdosia–Ipava & Meredosia–Pawnee	IL	345	2016/2017	$392
10	Pawnee–Pana	IL	345	2018	$88
11	Pana–Mt. Zion–Kansas–Sugar Creek	IL/IN	345	2018/2019	$284
12	Reynolds–Burr Oak–Hiple	IN	345	2019	$271
13	Michigan Thumb Loop expansion	MI	345	2015	$510
14	Reynolds–Greentown	IN	765	2018	$245
15	Pleasant Prairie–Zion Energy Center	WI/IL	345	2014	$26
16	Fargo–Galesburg-Oak Grove	IL	345	2018	$193
17	Sidney–Rising	IL	345	2016	$76
Total					$5,180

Table 10.1: Recommended MVP portfolio

[29] Costs shown are inclusive of transmission underbuild upgrades and upgrades driven by short circuit requirements.

10.1 Underbuild requirements

To ensure that the recommended MVP portfolio works well with the existing system to maintain reliability, MISO conducted analyses to determine any constraints that are present with the recommended MVP portfolio and not present without the portfolio. Any new constraints were identified for mitigations, and the appropriate mitigation was determined in coordination with the impacted Transmission Owners.

Below is a full list of the underbuild upgrades. These upgrades were identified through the steady state reliability analyses, using both off peak and peak models. No additional upgrades were identified through the stability analyses. Overall, approximately $70 million of transmission investment is associated with the underbuild upgrades.

Underbuild requirements
Burr Oak to East Winamac 138 kV line uprate[30]
Lake Marian 115/69 kV transformer replacement
Arlington to Green Isle 69 kV line uprate
Columbus 69 kV transformer replacement
Casey to Kansas 345 kV line uprate
Lake Marian to NW Market Tap 69 kV line uprate
Franklin 115/69 kV transformer replacements
Castle Rock to ACEC Quincy 69 kV line uprate
Kokomo Delco to Maple 138 kV line uprate
Wabash to Wabash Container 69 kV line uprate
Spring Green 138/69 kV transformer replacement
Davenport to Sub 85 161 kV line uprate
West Middleton West Towne 69 kV line uprate
Ottumwa Montezuma 345 kV line uprate

Table 10.2: Recommended MVP portfolio underbuild requirements

[30] Burr Oak to East Winamac upgrade also identified as part of the Meadow Lake wind farm upgrades.

10.2 Portfolio benefits and cost spread

A key principle of the MISO planning process is that the benefits from a given transmission project must be spread commensurate with its costs. The MVP cost allocation methodology distributes the costs of the portfolio on a load ratio share across the MISO footprint, so the recommended MVP portfolio must be shown to deliver a similar spread of benefits.

Each economic business case metric calculated for the full recommended MVP portfolio was analyzed to determine how it would accrue to stakeholders across the footprint. These results were then rolled up to a zonal level, based on the proposed Local Resource Zones for Resource Adequacy. This level of detail was chosen to provide stakeholders with an understanding of the benefits spread, without getting into a detail level which may be falsely precise due to the impact of individual stakeholder actions on actual benefit spreads.

The allocation of each of the economic metrics is discussed in more detail below.

10.2.1 Congestion and Fuel Savings

The Production Cost model simulations return results at a granular, generator-specific level. These results were then rolled up from this detailed level to a zonal level.

10.2.2 Operating Reserve Benefits

The costs of Operating Reserves were allocated across the footprint on a load-ratio share basis. This distribution matches the allocation of these costs through the MISO Energy and Ancillary Service markets. As such, although certain areas in the footprint may see reductions in the Operating Reserves they must hold within their area, the benefits of the more economic dispatch of these resources will be shared by the full MISO footprint.

10.2.3 System Planning Reserve Margin Benefits

The benefits accruing from the reduction in the system Planning Reserve Margin (PRM) were distributed across the footprint on a load-ratio share basis. This allocation was selected due to the widespread nature of the system PRM; the reduced planning margin will apply to all load in the MISO system, reducing the capacity needs for the full system.

10.2.4 Transmission Line Loss Benefits

The benefits accruing from the reduction in transmission line losses were allocated across the footprint on a load-ratio share basis. This approach reflects the integrated nature of the transmission system, as the market allows generation to be transported large distances to remote load. This integrated nature is enhanced by the inclusion of the recommended MVP portfolio into the transmission system, as congestion is reduced, and transfer capacity is increased, across the system.

10.2.5 Wind Turbine Investment

The benefits of reducing the required investment in wind turbines are not applicable for areas that do not have either renewable energy mandates or goals that can be sourced from outside the area. This benefit is also enhanced for areas with lower wind capacity factors, as the differential in wind turbine investment is substantially higher for these areas than for those with, on average, higher wind speeds. As a result, this benefit was allocated to the zones through a weighted average of the renewable energy mandates or needs that can be sourced outside of the zone, along with the relative wind capacity factors, when compared to the system's highest wind speed area.

Zone	Average Capacity Factor	Capacity Factor Differential From System Maximum	Average Out-of-State Renewable Mandates or Goals (%)	Out-of-State Renewable Generation Mandates or Goals (MW)	2026 Projected Load (GWh)	Out-of-State Renewable Generation Mandates or Goals (GWh)	Renewable Generation Weighted by Capacity Factor Differential	Zonal Allocation
1	38%	5%	28%		108,371	29,927	1,446	19%
2	28%	16%	10%		80,267	8,027	1,260	16%
3	36%	8%	N/A	3,000	55,648	9,338	716	9%
4	28%	16%	18%		60,063	11,087	1,730	22%
5	33%	10%	14%		55,485	7,788	809	10%
6	29%	14%	9%		143,528	13,013	1,833	24%
7	28%	15%	0%		119,017	-	-	0%

Table 10.3: Wind Turbine Investment Allocation[31]

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[31] All values shown in the table exclude in-state renewable energy goals or mandates.

10.2.6 Future Transmission Investment

Higher voltage Baseline Reliability Projects (BRPs), under Attachment FF of the MISO Tariff, are allocated as a mixture of system wide costs and local costs. More specifically, 20% of the costs of the transmission upgrades are allocated across the system, and 80% of the project costs are allocated to affected pricing zones.

The benefits accruing from the ability of the recommended MVP portfolio to avoid future Baseline Reliability Project investment was allocated using this methodology.

10.2.7 Costs Distribution

The costs of the portfolio were allocated across the footprint on a load-ratio share basis, as required by the Multi Value Project cost allocation methodology. Additional information on the distribution of the costs of the Multi Value Project portfolio may be found in the following section, section 10.3.

10.2.8 Zonal Benefit-Cost Ratio

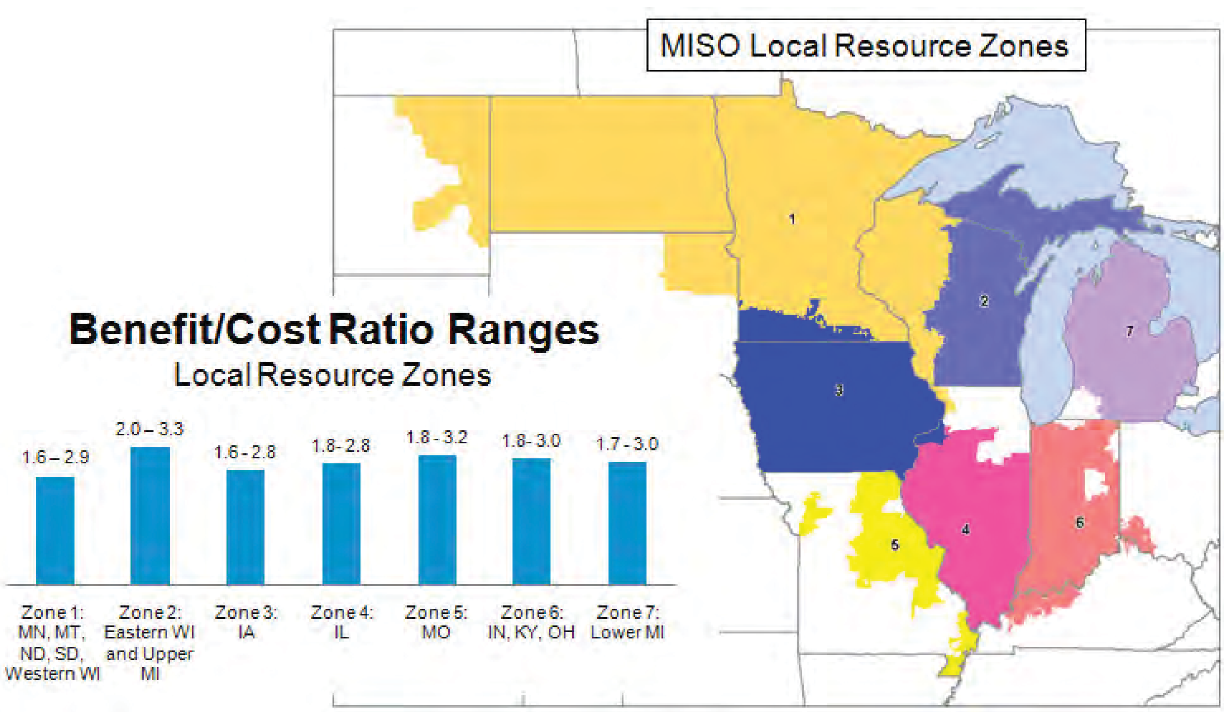

Figure 10.2: Recommended MVP portfolio production cost benefits spread

The recommended MVP portfolio provides benefits across the MISO footprint in a manner that is roughly equivalent to its costs allocation. For each of the local resource zones, as shown in Figure 10.2, the portfolio's benefits are at least 1.6 to 2.9 times the cost allocated to the zone.

10.3 Cost allocation

Multi Value Projects represent a new project type eligible for cost sharing effective since July 16, 2010, and conditionally accepted by the Federal Energy Regulatory Commission on December 16, 2010. Multi Value Projects provide numerous benefits, including, improved reliability, reduced congestion costs, and meeting public policy objectives.

> The costs of Multi Value Projects will have a 100 percent regional allocation and will be recovered from customers through a monthly energy usage charge calculated using the applicable MVP Usage Rate.

The proposed Multi Value Project portfolio described in this report includes the Michigan Thumb Loop project, approved in August 2010; the Brookings to Minneapolis-St. Paul project, conditionally approved in June 2011; and 15 additional projects being proposed to the MISO Board of Directors for approval in December 2011. The cost of the recommended MVP portfolio in 2011 dollars is $5.2 billion, including the $1.2 billion in projects that have previously been approved or conditionally approved by the MISO Board of Directors. See Table 10.1 for individual project costs.

The costs of Multi Value Projects will have a uniform 100 percent regional allocation based on withdrawals and will be recovered from customers through a monthly energy usage charge. This charge will apply to all MISO load, excluding load under Grandfathered Agreements, and also to export and wheel-through transactions not sinking in PJM.

Figure 10.3 shows a 40-year projection of indicative annual MVP Usage Rates based on the recommended MVP portfolio using current year cost estimates and estimated in-service dates. Additional detail on the indicative MVP Usage Rate, including indicative annual MVP charges by Local Balancing Authority, is included in Appendix A-3 of the MTEP11 report.

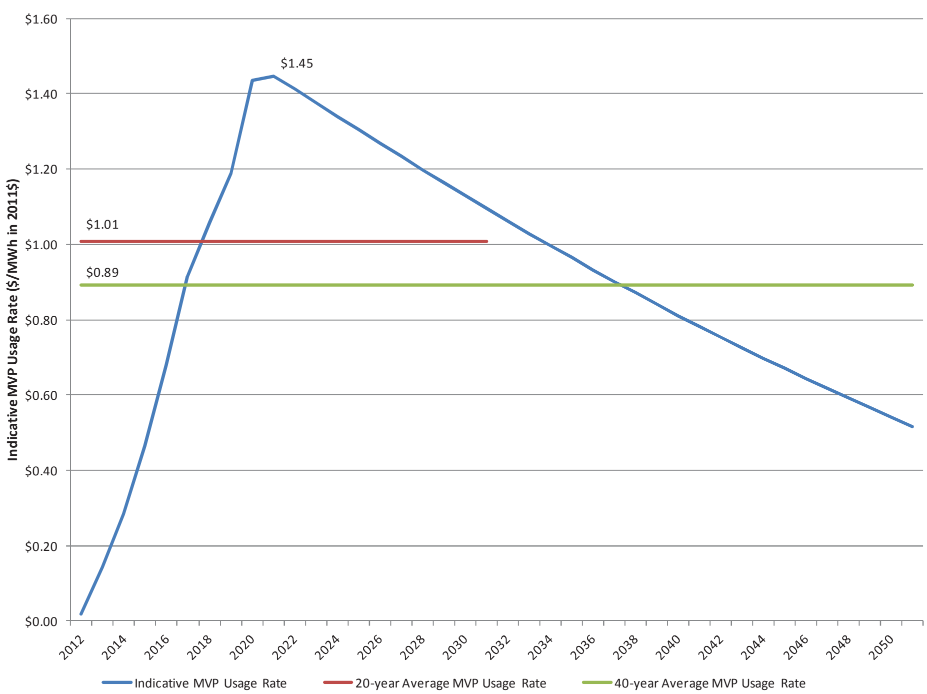

Figure 10.3: Indicative MVP usage rate for recommended MVP portfolio from 2012 to 2051

11 Conclusions and recommendations

MISO staff recommends the recommended MVP portfolio to the MISO Board of Directors for their review and approval. This recommendation is premised on the ability of the portfolio to meet MVP criterion 1, as each project in the portfolio was shown to more reliably enable the delivery of wind generation in support of the renewable energy mandates of the MISO states in a cost effective manner.

The recommendation is also supported by the strong economic benefits of the portfolio, which delivers a large amount of value in excess of costs under all conditions and policy scenarios studied. Furthermore, these benefits are spread across the MISO footprint, in a manner commensurate with the allocation of the portfolio's costs.

Midwest ISO

We manage power.

MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

MTEP 05

Approved by the Midwest ISO Board of Directors
June 2005

MTEP 05 Table of Contents

Figures

Tables

Appendices

Appendix A - MTEP-05 Facilities List

The following appendices are not public information. Please see the Midwest ISO web site for instructions on requesting copies of these appendices. Select Planning & Interconnections, then Expansion Planning from the navigation menus or use the following link http://www.midwestiso.org/plan_inter/expansion.shtml

Appendix A - 2004-2009 MISO Transmission Expansion Planning Map

Appendix D – Analysis Technical Details

D.1 . . . . . . ECAR Regional Study Group
D.2 . . . . . . MAIN Regional Study Group
D.3 . . . . . . MAPP Regional Study Group
D.4 . . . . . . Load Deliverability
D.5 . . . . . . Small-Signal Stability
D.6 . . . . . . Voltage Stability Screening
D.8 . . . . . . Iowa - Southern Minnesota Exploratory Study
D.9 . . . . . . Operational Issues

Section 1: Executive Summary

1.1 Introduction

This Midwest ISO Transmission Expansion Plan 2005 (MTEP 05) report describes the currently recommended transmission needs for the Midwest ISO transmission System. In accordance with the Transmission Owners' Agreement (TOA), approval of the Midwest ISO Plan by the Board certifies it as the Midwest ISO's plan for meeting the transmission needs of all stakeholders subject to any required approvals by federal or state regulatory authorities.

MTEP 05 has identified, through its Baseline Reliability study process, 615 planned or proposed facility additions or enhancements representing an investment of $2.91 billion through 2009, primarily to maintain reliability. In addition to these facilities, the report describes two other large scale "Exploratory" plans that continue to be evaluated by the Midwest ISO and stakeholders for their potential regional benefits. The results of the Baseline Reliability study of MTEP 05 indicate that the Midwest ISO Transmission System as projected for the year 2009 is expected to be able to perform in accordance with NERC Planning Standards for normal system conditions, events involving loss of a single transmission facility, and for most events involving loss of more than one facility. This performance will require that the ***Planned*** projects listed in Appendix A to this report go forward, and that the ***Proposed*** projects or suitable alternatives are in place. The more than 600 Planned or Proposed facility additions needed to enable the Transmission System to meet reliability standards are listed in Appendix A. This Midwest ISO Transmission Expansion Plan 2005 (MTEP 05) report is the second regional expansion plan produced by the Midwest ISO since start of operations in February 2001. The Midwest ISO Board of Directors approved the first regional plan, MTEP 03 in June 2003. The independent system reliability assessment contained in this MTEP 05 should be considered together with the commercial observations drawn in MTEP 03 and in Chapter 7 of MTEP 05. Together, these analyses indicate that the currently planned expansion to the Midwest ISO Transmission System are expected to result in a system that meets reliability requirements, but for which there is opportunity for additional regional expansion to further address congestion and to provide for access to new generation additions. The MTEP 05 work has established that the expansions in Appendix A will provide for a reliable system, but the Midwest ISO has not independently evaluated at this point in the developing expansion planning process whether these expansions are the most efficient solutions to reliability issues identified. The Midwest ISO will continue to work with stakeholders as the planning process evolves to identify and provide for the most efficient solutions to reliability issues, as well as the further identification of broader regional solutions to stakeholder needs.

This MTEP 05 comes at a time of significant transitions for the Midwest ISO. At the time of this writing, the Midwest ISO is at the start of operations of the Midwest Market Implementation, the transmission and energy market for the Midwest ISO region. This region spans 15 states, and 947,000 square miles from the Dakotas to Kentucky, and includes more than 119,000 Mw of demand, 97,000 miles of transmission and diverse generation resources.

This is a time of transition as well for the planning process that will support the implementation of the Midwest Market. Together with stakeholders, the Midwest ISO has been developing a transmission pricing policy and additions to the planning protocol that was established in the Transmission Owners' Agreement. This policy and protocol will enable the Midwest ISO to meet the needs of the market by planning for and promoting the development of system expansion needed to relieve constraints to the efficient delivery of energy from resources to load, and by providing increased certainty to the cost responsibility and recovery for these expansions.

MTEP 05 identifies expansion needed for a planning horizon extending through the peak season of 2009. These expansion plans are listed in Appendix A to this MTEP report, together with information about expected service dates, project owner, estimated project cost and other information. Continuing the project designations initiated with MTEP 03, projects are classified as either "Planned" or "Proposed". Projects in Appendix A that are designated as Planned projects are recommended by the Midwest ISO to be completed by the service dates identified. Other projects listed in Appendix A as Proposed projects are tentative solutions to identified needs, and require additional planning before they are endorsed by the Transmission Owners or the Midwest ISO as the preferred solution. Of the $2.91 billion projected investment, $1.57 billion is for Planned facilities. In many cases, a "project" consists of a number of discrete facilities that are to be developed as a part of a single solution to the identified need. Appendix A includes 369 Planned facilities and 246 Proposed facilities.

This expansion plan report includes sections devoted to the following topics:

- Planning objectives and process of the Midwest ISO
- Midwest ISO system configuration, observations, and issues
- Review and status of the projects identified in MTEP 03
- Analyses of system performance against reliability standards
- Operational issues; constraints related to TLR, AFC, FTR
- Special regional projects with potential benefits
- Summary of transmission investment

1.2 The Midwest ISO Planning Objectives and Process

1.2.1 Objectives

The fundamental objective of the MTEP is to ensure the system can continue to be reliably operated into the future. Day-to-day operations ensure that the current system is reliably operated, but the system must be planned to continue to meet existing obligations into the future including load growth, to respond to changing external system configurations, and changes to the connected generation resources.

As a Transmission Provider, the Midwest ISO has an obligation to continue to provide for the reliable and efficient transmission service to the existing and forecast loads of Network Customers, along with any commitments to Point-to-Point Transmission Customers. Firm Transmission Service Customers expect that in exchange for their transmission service payments that increase over time with necessary additional transmission investment, they will be able to continue to reliably meet their Network Load from their Network Resources at just and reasonable rates. This requires that the planning process identify solutions to reliability issues that arise from the expected dispatch of Network Resources. These solutions should balance the costs of increasing the embedded cost of the grid through transmission expansions with the costs of redispatching the Network Resources (congestion cost) and other operational solutions to managing grid reliability.

The Midwest ISO's transmission owners are expected to make the investments necessary to implement the Planned Projects in this expansion plan, unless alternative funding is provided for under the tariff.

1.2.2 Process

The current planning process at the Midwest ISO integrates the ongoing planning processes that are responsive to new customer requests for system access, and the continuing but cyclic Baseline Reliability studies of the MTEP regional plan development. The graphic below depicts these processes.

Key elements of this process include the following:

- Roll-up of Transmission Owner Plans
- Inclusion of Plans from Interconnection and Delivery Services
- Development of Power Flow Base Case
- Review of System Reliability and Congestion
- Development of any Additional Expansion Needs
- Review of Additional Regionally Beneficial Expansions

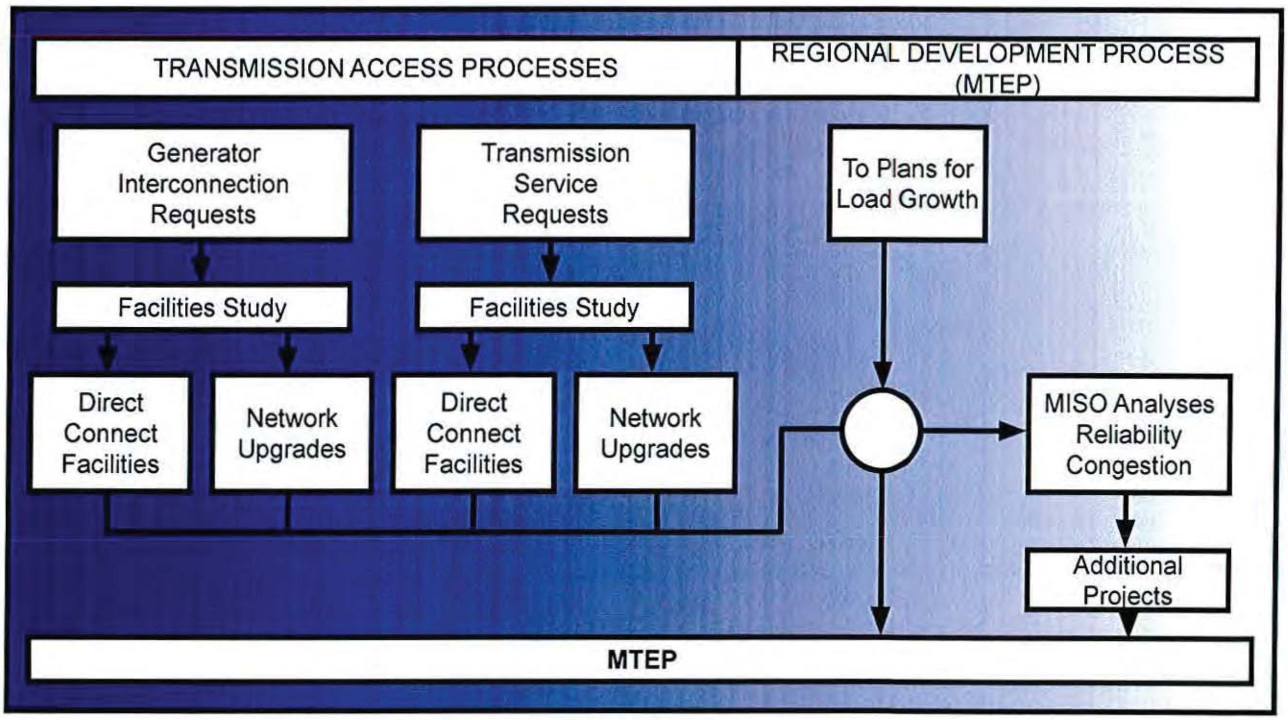

Figure 1.2-1

1.2.2.1 Assignment of Cost Responsibility

As noted above, it is expected that future MTEP will assign cost responsibility for most of the projects contained within the plan. These assignments will be in accordance with to-be-filed tariff provisions governing the cost assignment and recovery for Midwest ISO transmission facilities. At the time of completion of this MTEP 05, cost responsibility for load growth driven projects is in accordance with Attachment N to the tariff and the Transmission Owners Agreement, which, in general assigns the costs for such upgrades to the local Transmission Owner constructing the upgrade. Costs for generator interconnection driven upgrades are in accordance with Attachment X to the tariff and are determined at the time of execution of each individual interconnection agreement.

1.2.2.2 Plan Review

Once the Midwest ISO develops the regional plan in collaboration with the Transmission Owners, the Midwest ISO staff engages in several stages of stakeholder review of the plan. This review is intended to provide input to the staff as to the accuracy of the results of analyses in the plan and comment on the conclusions drawn from those analyses.

The plan is reviewed first by the Expansion Planning Group (EPG), and then by its parent committee the Planning Subcommittee (PS). The MTEP results are then discussed with the OMS and the Advisory Committee before being presented to the Midwest ISO Board of Directors for Approval. The Midwest ISO requests approval by the Board of the Planned projects in the MTEP, recognizing that the more tentative Proposed plans are more likely to undergo further development and modification before becoming Planned projects. Once approved by the Board, the regional plan is implemented in accordance with the Transmission Owners agreement. The Midwest ISO monitors the progress of projects in the plan as future MTEP are developed. It is understood that even Planned projects may be revised as system conditions change or as preferred projects may come to light. The Midwest ISO keeps track of and incorporates any such changes into future system models used to continually assess system performance.

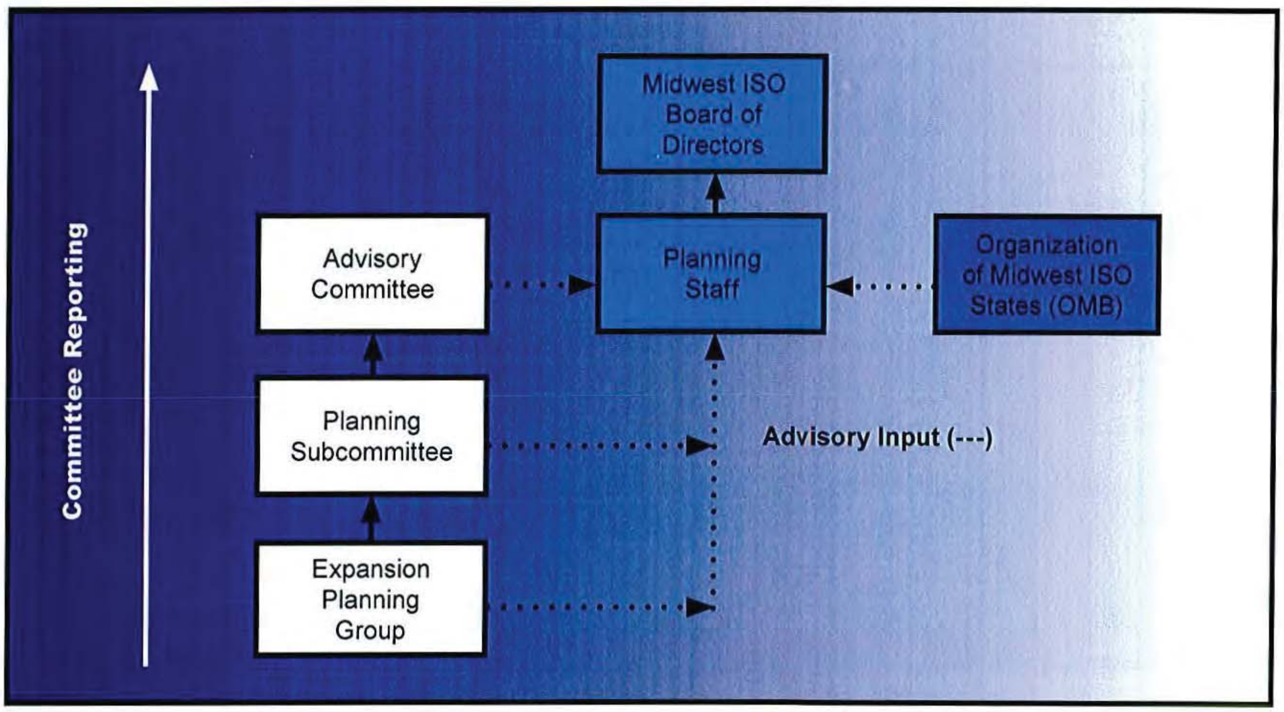

Figure 1.2-2

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1.2.2.3 Organization of Midwest ISO States (OMS)

The Organization of Midwest ISO States (OMS) was formed in mid-2003. Since that time, the role of the OMS in the Midwest ISO planning process has been developing. Midwest ISO staff has discussed the first two regional plans with the OMS. These have been higher-level reviews intended to familiarize the OMS with the basic findings from the analyses and to discuss process issues.

For major projects proposed in the plan, that may need state certification, the Midwest ISO is prepared to support the Transmission Owners in describing the needs and benefits of the projects within the state siting and certification processes.

The OMS has formed a Planning and Siting Work Group, and in subsequent issues of the MTEP the Midwest ISO will seek input from this Work Group as well as from the OMS Board of Directors as to the planning process.

In addition, while the Midwest ISO does not seek nor expect endorsement of any aspect of the plan, it is the hope of the Midwest ISO that by engaging in dialogue with the OMS regarding aspects of the MTEP, particularly the development of regional or multi-state projects, as they may be developed over time, the Midwest ISO and our transmission owning members can gain insights that will help to maximize the value of the transmission grid.

1.3 Update on MTEP 03 Findings

The Transmission Planning responsibilities of the Midwest ISO include monitoring the progress and implementation of necessary system expansions identified in the MTEP. The MISO Board approved the first MISO expansion plan MTEP 03 on June 19, 2003.

MTEP 03 contained 407 Planned and Proposed facilities, of which 229 were Planned. As a whole, nearly all of the 229 Planned facilities included in MTEP 03 are on track

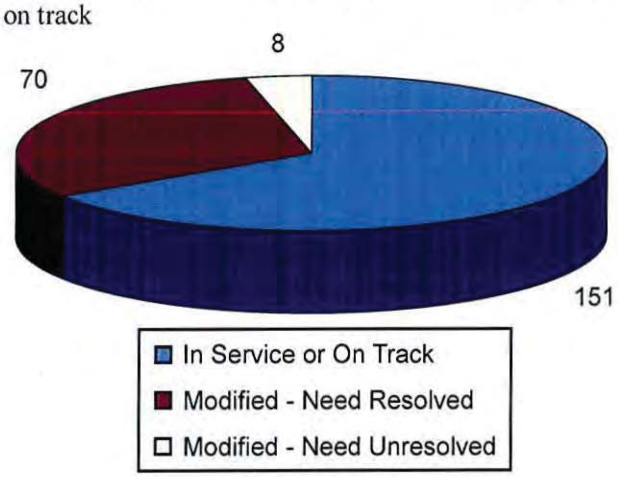

Figure 1.3-1
Status of 229 MTEP 03 Planned Facilities

Planning is a dynamic process and the Midwest ISO expects that as a normal part of developing the most cost effective plans, there should be modifications to plans where appropriate to meet changing system conditions. Review of the projects identified in MTEP 03 has shown that many projects have undergone some modification, delay, substitution, or even cancellation. Typical reasons for these changes involve

- Load growth less than anticipated
- Generation or transmission service plans changing
- Development of alternative solutions such as system operating guides or alternative projects

After considering the circumstances of each project, there remain at this time 21 projects, about 5%, from MTEP 03 for which the need apparently continues to exist and the projects have been delayed beyond the desired service date for reasons predominantly of regulatory delays or construction delays. The Midwest ISO has documented these projects in Section 4 and will incorporate review of the critical conditions driving these projects into seasonal operating reviews of the system to develop operational steps if required to ensure the security of the system until the projects are installed.

1.3.1 New Projects Added in MTEP 05

As noted previously, there where 407 itemized facilities in the 2002-2007 period of MTEP 03. MTEP 05 expands the planning horizon through 2009. There are a total of 542 new facilities now planned or proposed through the 2009 period that have been identified with the MTEP 05 effort (where not identified in MTEP 03). Appendix A contains now a total of 615 planned and proposed facilities.

1.3.2 Impact on Reliability of Changing Project Status

Notwithstanding the natural modifications of the overall plan on a continuing basis, the results of the Baseline Reliability analyses that have been performed for the first time in this MTEP 05 and will be included in subsequent MTEPs, along with other supporting studies performed by the Transmission Owners provided the indication as to whether the currently identified projects in the Appendix A to MTEP 05 form a sufficient set to maintain system reliability. The results of these analyses are described in Section 6 to this MTEP report.

1.4 MTEP 05 - Focus on Reliability

This second Midwest ISO regional plan has a substantial reliability focus. MTEP 03 was issued in June of 2003. MTEP 03 provided foundational information on the scope of expansion planning through the 2007 that was underway by the Transmission Owners at the time of startup of MISO operations and shortly thereafter. This MTEP 05 extends the work of MTEP 03 and provides a comprehensive top-down reliability evaluation of the expected baseline performance of the Transmission System through the 2009 time horizon. This evaluation is referred to as the Baseline Reliability Study.

The Baseline Reliability Study provides an independent assessment of the reliability of the currently planned Midwest ISO Transmission System for the year 2009. This is accomplished through a series of evaluations of the 2009 system with Planned and Proposed transmission system upgrades, as identified in the expansion planning process, to determine if these proposed additions are sufficient to meet NERC planning standards for reliability. This assessment is accomplished through modeling analyses of the transmission system's steady-state power flow, dynamic system performance, small-signal perturbation simulation, load deliverability assessment, and voltage-stability. This analysis was performed by MISO staff and reviewed in an open Stakeholder process.

The purpose of the MTEP Baseline Reliability Study is to determine system expansions that are needed to reliably meet the ongoing needs of existing transmission customers. Projects that are identified in the Baseline Reliability Study are recognized as needed as a part of the base system and are not expected to be the responsibility of new transmission service or interconnection customers that seek access to the transmission system, unless otherwise identified in Appendix A as related to such a request.

The planning horizon studies performed in the MTEP process are coordinated with the seasonal (summer and winter) reliability studies performed by the Midwest ISO. This coordination entails comparison of critical conditions in the near term seasonal assessments and in the further out planning horizon of the MTEP. This comparison ensures that issues identified in the planning horizon will be addressed before they become problems in the operating horizon, and conversely, that planned solutions are being implemented for nearer term issues.

1.5 Key Findings for 2009

The following sections describe key findings from the MTEP 05 Baseline Reliability study.

1.5.1 System Performance with Planned and Proposed Projects

The results of the Baseline Reliability study of MTEP 05 indicate that the Midwest ISO Transmission System as projected for the year 2009 is expected to be able to perform within standards for normal system conditions, events involving loss of a single transmission facility, and for most events involving loss of more than one facility. This performance will require that the Planned projects go forward, and that the Proposed projects or suitable alternatives are in place. The more than 600 Planned or Proposed facility additions needed to enable the Transmission System to meet reliability standards are listed in Appendix A. Projects that are needed to meet the more significant reliability concerns identified by the Midwest ISO are described in section 1.5.2 below.

1.5.2 Key Projects

There are numerous key projects that have been identified as needed to maintain system reliability through the 2009 period. Table 1.5-1 lists projects of member systems for the 2004-2009 planning horizon that have estimated costs of $15 Million or more. These major projects account for $1,093 million, or about 70% of the total cost of all planned projects for the 2004-2009 period. Section 6 of this report contains descriptions of these and other major projects. Appendix A contains a listing of all Planned and Proposed projects.

Table 1.5-1 Planned Projects $15 Million and Above							
Project	Description	Planning Region	Map Grid Location	Driver	Service Date	Project Cost (millions)	Project Status
Arrowhead–Gardner Park 345 kV line	Build 220 miles of 345 kV line, 23 miles of 115 kV line, two 345-115 kV transformers, one 800 phase angle regulating transformer, one 345-230 kV transformer, reactive compensation	Central	I4 - J6	Load & Trans. Service	2008	$422	• Category Planned • Budget Status: Approved • External Approvals: Obtained • Delay Risk: Low • Construction: 10 %
Buffalo Ridge 825 MW of Generation Outlet	Build 94 miles of 345 kV line, 345 / 115 kV transformer, 34 miles of 161 kV, and 26 miles new 115 kV, 15 miles rebuild 115 kV	Northwest	G6 - H7	Generation	2007	$130	• Category Planned • Budget Status: Approved • External Approvals: Final permits pending, IA contracts under negotiation • Delay Risk: Low • Construction: 10 %
Chisago–Apple River	Build 4.5 miles and rebuild 20.6 miles of 161 kV, rebuild 16 miles of 115 kV, and one 161-115 kV transformer	Northwest	I5	Load	2007	$58	• Category Reviewing Alternatives • Budget Status: Pending • External Approvals: Pending • Delay Risk: High • Construction: 0 %
Plains–Amberg–Stiles 138 kV line rebuild	Rebuild 131 miles of 138 kV line	Central	K5 - K6	Load	2006	$45	• Category Planned • Budget Status: Approved • External Approvals: Obtained • Delay Risk: Low • Construction: 15 %
Prairie State Power Plant transmission outlet	Build 35 miles of 345 kV line	Central	J11 - K11	Generation	2009	$39	• Category Planned • Budget Status: Pending • External Approvals: Pending • Delay Risk: Medium • Construction: 0 %
Rosser–Silver 230 kV line	Build 65 miles of 230 kV line	Northwest	F2	Load	2005	$34	• Category Planned • Budget Status: Approved • External Approvals: Obtained • Delay Risk: Low • Construction: 10 %
Callaway–Franks 345 kV line	Build 54 miles of 345 kV line	Central	I10	Load	2006	$29	• Category Planned • Budget Status: Approved • External Approvals: Obtained • Delay Risk: Low • Construction: 20 %
Thumb Loop Rebuild	Rebuild 70 miles of 120 kV line	East	N6	Load & Other	2006	$27	• Category Planned • Budget Status: Approved • External Approvals: Obtained • Delay Risk: Low • Construction: 60 %
Ponton 230 kV	150 / 0 MVAR Static VAR Compensator	Northwest	F2	Generation	2005	$25	• Category Planned • Budget Status: Approved • External Approvals: Obtained • Delay Risk: Low • Construction: 98 % complete, in-service July 2005
Thompson Birchtree	150 / -20 MVAR Static VAR Compensator	Northwest	O3	Generation	2010	$25	• Category Planned • Budget Status: Obtained • External Approvals: Waiting for environmental permits for associated Wuskwatim generator connection project • Delay Risk: Medium • Construction: Not Available

Table 1.5-1 Table 1.5-1 Planned Projects $15 Million and Above (continued)

Project	Description	Planning Region	Map Grid Location	Driver	Service Date	Project Cost (millions)	Project Status
Jefferson City Area Development	Build 15 miles of 345 kV line, build 25 miles of 161 kV line	Central	I11	Load	2007	$25	• Category Planned • Budget Status: Approved • External Approvals: Obtained • Delay Risk: Medium • Construction: 10%
West Marinette–Menominee–Rosebush–Amberg 138 kV line	Rebuild 43 miles of 138 kV line	Central	K5	60% Load 20% TSR 20% Other	2005	$25	• Category Planned • Budget Status: Approved • External Approvals: Obtained • Delay Risk: Low • Construction: 20%
Columbia–North Madison 345 line	Convert 17 miles to 345 kV line, replace two 345/138 kV transformers	Central	K7	Load & Trans. Service	2006	$25	• Category Planned • Budget Status: Approved • External Approvals: Obtained • Delay Risk: Low • Construction: 60%
Buffalo Ridge 425 MW of Generation Outlet	Build 24 miles of 161 kV line, rebuild 63 miles of 115 kV line	Northwest	G6 - H7	Generation	2006	$68	• Category Planned • Budget Status: Approved • External Approvals: Obtained, IA contracts under negotiation • Delay Risk: Low • Construction: 70%
Wagener–NW68th & Holdrege 345	Build 28 miles of 345 kV line	Northwest	F9	Load	2008	$22	• Category Planned • Budget Status: Approved • External Approvals: Obtained • Delay Risk: Medium, some possibility of not being completed in 2008 • Construction: 5% complete
St. Vital–Steinbach 230	Build 35 miles of 230 kV line	Northwest	F1	Load	2010	$21	• Category Deferred by Alternative for 2007 Project is changed from planned to proposed as it was deferred to 2020. Higher load growth in the Steinbach area required a new plan. This plan consists of a second 230-66 kV transformer bank at Richer, which is planned to be in-service in 2007. The second bank provides for immediate load serving needs and defers the need for the 230 kV line. The budget for the alternative transformer bank has been approved and design is underway.
Rock River–Bristol–Elkhorn conversion to 138 kV	Converts 28 miles of 69 kV to 138 kV line, convert five 69 substation to 138 kV	Central	K7	Load	2008	$20	• Category Reviewing • Budget Status: Pending • External Approvals: Pending • Delay Risk: High • Construction: 0%
Lenox Station	Rebuild 28 miles of 345 kV line, rebuild 47 miles of 120 kV line, one 345/120 kV transformer	East	O7	Other	2007	$15	• Category Planned • Budget Status: 2005 portion approved, 2006 portion is pending approval. 2006 budget approval is expected • External Approvals: Pending • Delay Risk: Low • Construction: 0%

In addition to these more significant projects in terms of cost, there are a number of projects of lesser cost that are required to relieve significant loading or low voltage conditions. Some of these include the following and additional detail may be found in Section 6 and the Appendices to this report:

Wisconsin

- Skanawan-Highway 8 rebuild to double circuit 115 kV
- Port Washington–Saukville 138 kV rebuilds
- The second Wempletown–Paddock 345 kV line

North Dakota

- Bismarck Downtown–East Bismarck 115 kV upgrade to 160 MVA
- Maple River–Red River 115 kV line upgrade to 310 MVA

Iowa

- Upgrade Salem 345/161 kV Tr to 550 MVA; replace Hazelton Tr with existing Salem Tr.

Minnesota

- Prairie Island–Red Rock 345 kV # 2 line upgrade to 1198 MVA
- Monticello–Sherco–Salida 115 kV line upgrade to 310 MVA, and Sherco 345/115 ckt 1 to 448 MVA
- Granite City 115 kV 2x40 MVAR capacitor addition
- Aldrich–St. Louis Park 115 kV line upgrade to 310 MVA
- St. Cloud Tap–I94Industrial–Salida 115 kV line upgrade to 310 MVA

Missouri

- Joachim 345/138 kV 560 MVA transformer

Ohio

- Star substation reconfiguration, each 345/138 transformer has independent breaker
- Galion substation reconfiguration, each 345/138 transformer has independent breaker

Indiana

- Westwood 2nd 345/138 kV Transformer & Dequine–Westwood 345 kV line
- Cayuga–Veedersburg 230 kV rebuild
- Hanna–Southeast 138 kV breaker CT changes

Michigan

- Campbell–Hudsonville 138 kV sag limit removed
- Tippy–Hodenpyl 138 ckt 1, reconductor 795 ACSS
- Croton–Felch Rd. 138 kV line reconductor
- North Belding–Sanderson–Eureka reconductor to 795 ACSS and N Beld CT Tap to 1200 A
- Weeds Lake 345/138 substation addition
- Garfield–Hemphill 138 line rebuild
- 36 MVAR Gallagher Capacitor
- 54 MVAR Placid Capacitor addition
- Bismarck–Golf 120 kV project create a 120 kV bus group at Golf and building a new 120 kV line from Bismarck to Golf

1.5.3 Reliability Issues Needing Resolution

The Midwest ISO identified certain conditions for which some facilities could be outside of design limits or for which voltages could be below standards by the year 2009. In all but a few cases these conditions involved multiple elements forced out of service. These multiple contingency events are somewhat rare under peak load conditions, and the current NERC Standards of performance for such events permit such excursions beyond limits provided that system operators can take action to remedy these conditions before they can propagate to an uncontrolled loss of load. For such conditions, it is important that the Midwest ISO as Reliability Coordinator understand the operating steps that can be implemented, including any plans for controlled shedding of load that may be needed to contain the events. For some of these multiple contingency events, not all of the necessary operating steps have been identified by the Midwest ISO to ensure the reliability of the system for these events. These events needing further resolution are tabulated in Section 6 of this report. The Midwest ISO will continue to work with the Transmission Owners to identify all necessary operating steps or other solutions needed to resolve these events.

1.5.4 Operational Issues

The MTEP is a forward looking expansion plan, the objectives of which include ensuring the future system can be operated safely, reliably and efficiently through the planning horizon year. One indication of future system performance are the results of the contingency studies of the planning horizon year, 2009. Another indicator of system performance is the current operational experience, and the relationship between constraints that routinely occur and planned expansions. Many system constraints are revealed as limits to the efficient operation of the system. Transmission customers desiring to make economical transactions request transmission service and are denied service due to the inability of the system to reliably accommodate the desired transactions. This is the result of low Available Flowgate Capability (AFC). Firm transactions are curtailed through the NERC Transmission Loading Relief (TLR) procedure due to unexpected system conditions, or less than perfect coordination amongst transmission providers. Nominations of Financial Transmission Rights (FTR) associated with physical transmission rights (transmission service) may be less than fully feasible. These real-time and near-term issues are referred to in this MTEP as operational issues. Each of these operational issues presents a reliability concern unless a generation redispatch is performed as an operating adjustment to the desired dispatch that would otherwise occur. The planning philosophy of the Midwest ISO is to seek resolution to these reliability issues in the least cost manner, through either a transmission system switching operation, a generation redispatch, or an expansion to the system.

In section 6.4.1 we have reviewed recent incidence of very low AFC, frequent TLR, or constraints to full FTR allocations. That Section draws correlations between Planned and Proposed expansion projects and constraints causing low AFC, high incidents of TLR, or pro-rated FTR allocations. The expansions in this MTEP 05 will address many but not all of these operational issues identified. The Midwest ISO will continue in subsequent expansion plans to review these constraints and identify expansions as appropriate to resolve such reliability concerns in the most efficient manner.

1.5.5 Other Potentially Beneficial Regional Projects

In the first Midwest ISO Transmission Expansion Plan, MTEP 03, the Midwest ISO evaluated at a high level the potential economic benefits of large regional transmission projects under various postulated generation development scenarios. MTEP 03 evaluated a dozen such plans based on analysis of the base planned transmission system, and its ability to accommodate substantial new additions of coal and wind generation, as well as gas generation based the interconnection queues at the time. This study is available on the Midwest ISO web site. The transmission and generation scenario analysis showed generally that there was significant potential for the right regional transmission to result in substantial reductions in marginal energy costs, particularly if that transmission was coupled with introduction of low cost coal and wind energy resources.

Among the dozen potentially regionally beneficial expansion concepts reviewed in MTEP 03, two have been addressed further in this MTEP 05, because of the potential benefits that the preliminary analyses showed, and because of significant stakeholder interest in these two concepts. These two expansion concepts are referred to as 1) the Northwest Exploratory Project, and 2) the Iowa–Southern Minnesota Exploratory Project. Both projects would provide enhanced access by coal and wind resources to load centers in the Midwest ISO.

It is the intention of the Midwest ISO to continue the development of these regional expansion projects through further evaluation of the nature, value, and beneficiaries of these plans. The Midwest ISO intends to recommend such plans as these to the Midwest ISO Board of Directors at such time as the Midwest ISO in collaboration with interested stakeholders can complete these evaluations, and a determination of cost responsibility and recovery can be made, consistent with the Midwest ISO tariff and the Transmission Owners Agreement.

The Northwest Exploratory study involves generation in the Dakotas and transmission upgrades from the Dakotas to Minnesota. The Iowa-Southern Minnesota Exploratory study involves generation in northern Iowa, southern Minnesota, and South Dakota and transmission upgrades from generation to major load centers in Minnesota, Iowa, and Wisconsin. Both studies are in progress and results to date and future work efforts are described in this report.

1.5.6 Total Expected Investment Through 2009

The total estimated direct cost of the Planned and Proposed facilities plus the facilities that went into service since 2003 is $2.91 billion for the six-year period 2004-2009 periods. This is substantially above the **$1.96 billion** that was estimated for the six-year period 2002-2007 in MTEP 03. Of these projects, **$204 million** were In Service by 2004, $1,565 million are considered Planned, and $1,144 million are considered Proposed and will continue to be reviewed.

The cumulative expected spend over the 2004-2009 period is shown in Figure 1.5-1 below.

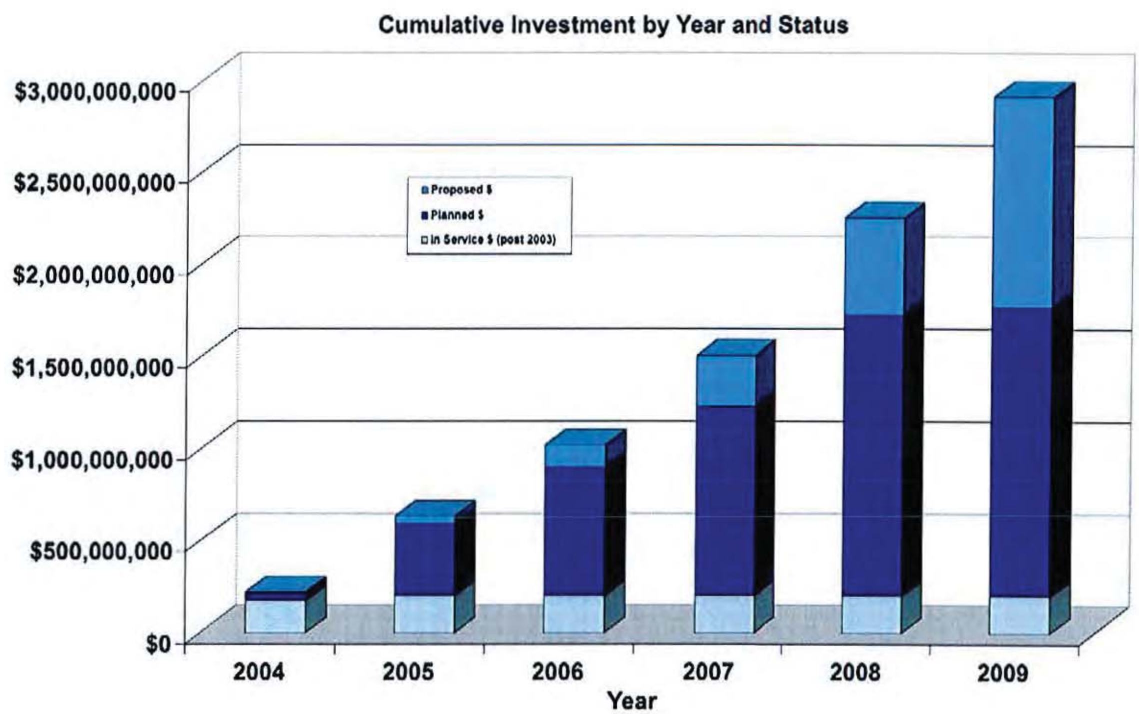

Figure 1.5-1 Cumulative Projected Spending All Projects

About 5,123 miles of transmission line upgrades are projected through 2009 which is about 4.6% of the approximately 112,000 miles of line existing throughout the Midwest ISO area. Less than 2%, however, involve lines on new transmission corridors.

About 59 % of the expected total transmission line and substation enhancements are at 230 kV and above.

Larger projects, with estimated costs of $5,000,000 and higher have been summarized below in Figure 1.5-2. This table shows a comparison of expected spend grouped by NERC region within the Midwest ISO for the out years of 2007 through 2009. For the purposes of this summary, groupings are as follows:

MAPP: Xcel Energy, Otter Tail Power, Montana Dakota Util., Minnesota Power, Manitoba Hydro, Great River Energy, Lincoln Electric Systems, Aquila, Alliant West

MAIN: American Transmission Co., AmerenIP, AmerenCILCO, Southern Illinois Power Coop, City Water Light and Power, City of Columbia

ECAR: Cinergy, International Transmission Co Michigan Electric Transmission Co, Louisville Gas and Electric Corp, Hoosier Energy, Indianapolis Power and Light, Vectren Energy, Northern Indiana Public Service Co., FirstEnergy

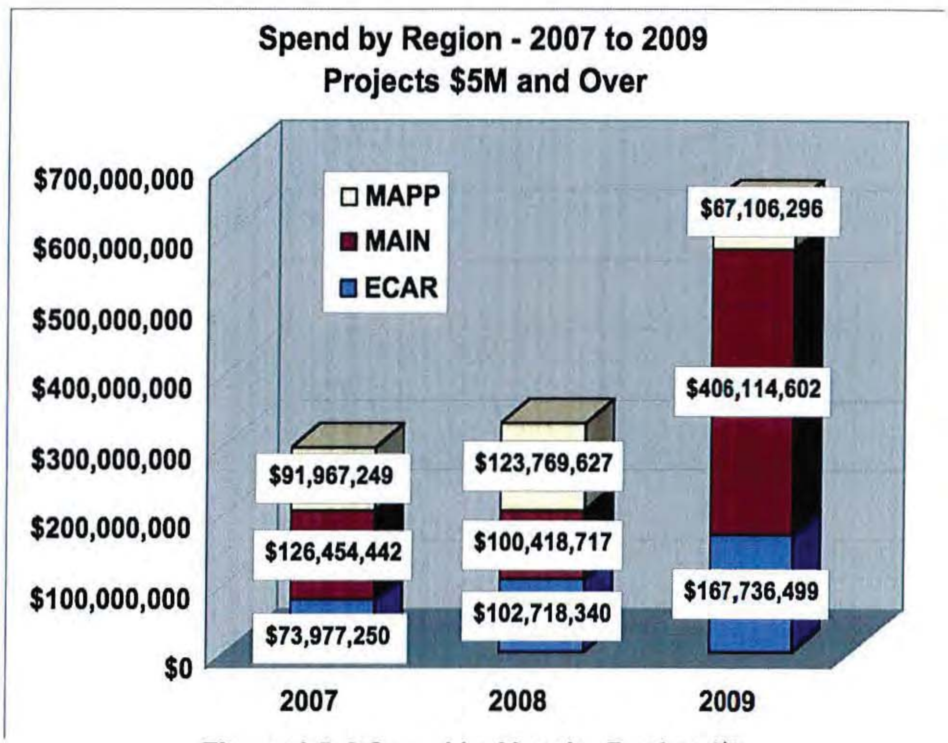

Figure 1.5-2 Spend by Year by Region ($)

This summary shows that of the $1,260,263,022 expected to be spent over the three-year period about 51 % is projected for the year 2009. In addition, projected spending is relatively balanced between the three areas for 2007 and 2008, while in 2009 the MAIN areas entities project spending of about 63 % of the 2009 total with ECAR 26% and MAPP 11%. This summary has excluded two significant projects with a combined cost of $552,000,000: the Arrowhead–Garden Pk Project of ATC LLC and the Buffalo Ridge Area Generation Outlet Project of Xcel Energy. The jurisdictional regulatory authorities already have approved these projects.

1.6 Implementation and Follow-Up

The Midwest ISO will monitor progress on all projects identified in this MTEP 05, and will support the need for and development of projects defined as Planned projects that are part of the approved MTEP.

The MTEP will be subject to change, as system conditions change. Changes in load growth, changes in usage patterns, development of new generation interconnections, changes in projected service dates of interconnection plans, delays in regulatory approvals of transmission projects, or ongoing development of preferred plans, all could cause changes to the overall MISO plan. The MTEP will be updated as needed to incorporate the impacts of such changes on the overall regional plan.

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Section 2: Midwest ISO Planning Objectives and Process – Update

2.1 Overview

The Midwest ISO Transmission Expansion Plan (MTEP) is produced in accordance with the requirements of RTO regional planning as set forth in the FERC Order 2000, and with the Agreement of the Midwest Transmission Owners to Organize the Midwest ISO ("Transmission Owners Agreement", or "TOA"). As part of the ongoing responsibilities delineated in the TOA, the Midwest ISO develops transmission expansion plans to address the reliability of the Transmission System that is under its operational and planning control. In addition, the MTEP is to identify system expansion options that are beneficial in supporting the competitive supply of electric power by this system. The MTEP process is to consider all market perspectives, including demand-side options, generation location, and transmission expansion alternatives.

Together with stakeholders, the Midwest ISO has been developing a transmission pricing policy and additions to the planning protocol that was established in the TOA. This policy and protocol will enable the Midwest ISO to meet the needs of the market by planning for and promoting the development of system expansions needed to relieve constraints to the efficient delivery of energy from resources to load, and by providing certainty to the cost responsibility for these expansions. In this MTEP 05, the cost responsibility for the Planned (expected to go forward as planned) and Proposed (expected to be needed but other solutions under evaluation) projects identified in the regional plan are not yet explicitly described. These plans have been identified under the license-plate pricing policy in place at the start of Midwest ISO operations. Under this policy, projects needed to be constructed by a Transmission Owner in the pricing zone of that Owner are funded by that Owner and costs are recovered from customers taking service in the zone, through the zonal rates established through Attachment O to the tariff, unless a specific Transmission Customer has otherwise been assigned cost responsibility consistent with the policies of the FERC. In future versions of the MTEP, it is expected that projects in the plan will have specific cost responsibility delineated in accordance with the comprehensive pricing policy in development at the time of this MTEP 05.

The MTEP consolidates the transmission needs of the region into a single plan. A bottom-up, top-down approach is used to provide both detail at the local level and wide area analysis and optimization at the RTO-wide level. The Midwest ISO planning process is an open planning process that facilitates communication of ideas and concepts. The collaborative process coordinated through the Midwest ISO provides an opportunity for inputs from all stakeholder groups. This plan has been developed by Regional Study Groups formed from the Expansion Planning Group (EPG), and has been discussed with the parent committee to the EPG the Planning Subcommittee. Finally, it has been discussed with the Organization of Midwest ISO States (OMS) and with the Advisory Committee of the Midwest ISO before being brought before the Midwest ISO Board of Directors.

MTEP 05 is the second issue of a Midwest ISO regional transmission expansion plan. The first, MTEP 03 was issued in June of 2003. MTEP 03 provided foundational information on the scope of expansion planning through the 2007 plan year that was underway at the time of startup of Midwest ISO operations and shortly thereafter. It also provided in-depth analyses of the potential for regional transmission expansions to provide for lower customer energy costs by reducing congestion and by enabling the entry and delivery of new low cost generation.

This MTEP 05 extends the work of MTEP 03 by:

1. Tracking the progress of plans identified in MTEP 03
2. Continuing the development work on several of the most promising "Exploratory" regional projects identified as potentially beneficial in MTEP 03
3. Performing a comprehensive top-down reliability evaluation of the expected baseline performance of the Transmission System through the 2009 horizon
4. Identifying the expansion necessary to maintain system performance within standards, and
5. Updating the expansion plan through the year 2009

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2.2 Baseline Reliability

With MTEP 05, the Midwest ISO prepared the first "Baseline Reliability Study" for the RTO. Such a baseline is important in determining the system expansion needs through the planning horizon that are driven by existing service commitments. These service commitments include the forecast load growth of Network Customers, and firm transmission service commitments, a representation of which has been reflected through the modeled base-case generation dispatch. Expansions driven by these existing commitments form the "baseline" system from which new requests for transmission services, including interconnection service are evaluated.

The Baseline Reliability study performed for MTEP 05 provides an independent assessment of the reliability of the currently planned Midwest ISO Transmission System for the years 2004 through 2009. This is accomplished through a series of evaluations of the 2009 system with Planned and Proposed transmission system upgrades, as identified in the expansion planning process, to determine sufficient and necessary projects to meet NERC and regional planning standards for reliability. This analysis was performed using traditional pre-market dispatch assumptions. The overall assumptions applied to this MTEP development are discussed in Chapter 5. Chapter 6 of this report provides a description of the analyses and results performed, and additional detail is included in Appendix D. In an effort to address recommendations for increased levels of contingency analysis from NERC in the aftermath of the August 2003 blackout, the Midwest ISO has performed an extensive analysis of the reliability of the Transmission System. These analyses are detailed in Chapter 6 and Appendix D and include in addition to first contingency steady state analyses, multiple contingency cascading outage analysis, transient stability simulations, small signal stability analyses, multiple contingency voltage stability screening, and load area loss-of-load expectation also referred to as Load Deliverability studies. This single study, however cannot evaluate all possible contingent conditions that could occur. The planning process is a continual one, and even as this MTEP 05 is distributed the planning staff is preparing a review of the planned 2011 system, and operational studies for the summer and winter 2005 seasons.The Baseline Reliability studies of the MTEP coordinate with the seasonal assessments performed by the Midwest ISO. Summer assessments were performed for the summers of 2003 and 2004. The summer assessment in 2004 expanded on the traditional first-contingency transfer analyses typically performed in NERC regional summer assessments, and explored the ability of the system to withstand additional levels of contingency, with a focus on voltage stability limits. The seasonal analyses provide Midwest ISO system operators with valuable information about proximity to limiting conditions should real-time events exceed usual first or second contingency planning criteria conditions. Information from the seasonal studies can help to target areas of the system for analysis in the planning horizon to ensure that plans are developing in a timely manner to avoid any weaknesses identified. Similarly, areas that are identified to be near or exceeding limits in the planning horizon in the MTEP 05 studies will be reviewed in the current year seasonal assessment for any operational concerns that may exist.

The Midwest ISO also draws information about system performance in both the operating and planning horizons through participation in NERC regional assessments of system performance.

2.3 Load Deliverability Studies

The Midwest ISO performs area import capability versus need studies, also referred to as Load Deliverability studies as a part of the determination of resource reliability for the Midwest ISO market. Resource reliability is maintained by 1) ensuring that market participants with load service responsibility maintain sufficient firm capacity to meet reserve requirements 2) ensuring that Network Resources identified by load serving entities are deliverable without "bottling" each other up if called upon together with other Network Resources to meet load demand, and 3) ensuring that the transmission system has sufficient capacity such that load areas can import needed supplies during times of deficiency of resources within the load area. Import needs are based on Loss of Load Expectation (LOLE) analyses.

At the present time the Midwest ISO requires that its load service entities maintain the reserve requirements prescribed by their respective NERC Regional Councils. Generator deliverability studies are performed on an ongoing basis as new Network Resources connect to the grid or request network resource status. Load Deliverability is evaluated as a part of the annual MTEP Baseline Reliability studies. MTEP 05 contains the first Midwest ISO Load Deliverability Study. The details of this study are contained in Section 6 to this report.

The planned 2009 Transmission System was found to be adequate in terms of its ability to deliver to load areas sufficient capacity to meet loss of load expectations of one day in ten years, with the exception of delivery to the ITC load area. The Midwest ISO, the State of Michigan and International Transmission Company continue to investigate alternatives to meet the target loss of load expectation in that part of the system.

2.4 Operational Concerns

MTEP 05 also looked at the operational issues associated with transmission service requests (TSR) by examining historical transmission line loading relief (TLR) requests and future available transfer capability(AFC) values. There is industry debate as to the extent to which incidence of Transmission Loading Relief and unavailability of transmission capacity for sale are indicative of unreliable grid conditions or are commercial issues. The Midwest ISO planning process monitors flowgates that are associated with the most incidents of TLR and those that are most limiting to sale of transmission service. In many instances, transmission projects designed to relieve identified reliability criteria violations also relieve constraints associated with TLR and low AFC values. This is indicative that although the system may be capable of performing within strict reliability standards in areas of the system near constrained flowgates, high incidence of TLR and persistently low AFC values are often indicative of lower reliability margins. As the Midwest ISO market operation commences, it is expected that congestion management by TLR will be the exception to congestion management via the security constrained economic dispatch of the LMP-based energy market. The Midwest ISO planning philosophy is, in general, to expand the system when it is more economical to do so as compared to redispatching the system, or other operational steps, as resolution to a reliability criteria violation. This must include suitable consideration for the availability of the assumed operational steps, and the extent to which reliance on increasing levels of operating steps can pose an increased reliability risk. These considerations are only a part of the art of planning the system that is applied along with the science of engineering analyses by experienced Midwest ISO planners and operators, working in collaboration with our Transmission Owner planners and operators and other stakeholders.

The planning staff is also monitoring constraints that are binding in the allocation of Financial Transmission Rights. Not surprisingly, these binding constraints are many of the same constraints associated with TLR and low AFC values. Again, many of these constraints have planning solutions in the works as a means of maintaining system reliability. We will be looking at those constraints that are unresolved and developing proposed plans that could resolve them. Additional discussion and results of these analyses are in Chapter 6 of this MTEP 05 report.

2.5 Areas of Heightened Interest

While the Baseline Reliability analysis applied NERC reliability standards comprehensively across the entire Midwest ISO footprint, there are several areas of the system where conditions have caused concern for stakeholders in the recent past. Some of these areas of concern are discussed below.

Michigan West-to-East Interface

Prior to the summer of 2004, a network customer in eastern Michigan requested firm transmission service for the peak months of 2004. The requested service was to source in Michigan Electric Transmission Company (METC). Only about two-thirds of these firm transmission service requests could be accepted on a firm basis.

The network transmission customer expressed concern to the Michigan PUC that these transfer restrictions were impacting reliability of supply to its load responsibilities.

The Midwest ISO performed an analysis of the in-state constraints to west-to-east transfers in Michigan, and reviewed this study with METC and the International Transmission Company (ITC). The report concluded that the transmission interface between METC and ITC systems has become a bottleneck as the result of the increasingly west-to-east intra-state power flows due to a combination of AES [Alternative Energy Suppliers] sourcing preferences, location of merchant generators in Michigan and the attractiveness of the Ontario wholesale power market. The analysis determined that two-thirds of the proposed new generation in Michigan is locating on the METC side of the interface and that required purchases into ITC's territory are expected to increase. ITC moved to address these issues in July of 2004 by approaching Midwest ISO with a plan to increase the Michigan west-to-east intra-state transfer capability as well as the AFC on flowgates impacted by transfers from METC to ITC.Midwest ISO lead a joint study effort of the ITC plan with participation from both METC and ITC. As a result of these analyses, the following set of upgrades have been proposed by ITC, METC & Midwest ISO and are included in Appendix A as a part of the regional plan:

Table 2.5-1: Proposed Upgrades

Upgrade	System	Estimated Cost
Genoa 138 / 120kV Transformer	ITC	$1.2M
Atlanta 138 / 120kV Transformer	ITC	$1.3M
Hemphill to Hunters Creek Line Reactor	ITC end of METC-ITC tie	$1.6M
Pontiac-Hampton 345kV Line Wavetrap	ITC end of METC-ITC tie	$0.1M
Oakland to Dean Road 138 kV Line Relay adjustments and Hemphill Relay Upgrades	METC	$0.2M
Cost Estimate Total:		**$4.4M**

The impact of these upgrades will be to provide an estimated increase of 317 MW in FCITC for METC to ITC transfers. An AFC analysis also indicates that these upgrades would increase AFC on key limiting flowgates from 424 MW to 891 MW. These upgrades will benefit the load centers in the ITC pricing zone by increasing the capacity available for power transfer into this zone and are expected to be in service by summer 2005 (a little over a year from when the issue first arose.).

Michigan Macomb and "Thumb" Area

The Midwest ISO performed a 2004 summer assessment. In that assessment, two areas in the 120 kV transmission system north of the Detroit area showed some weakness to contingencies.

The Macomb 120 kV bus could become critical for select transmission contingencies. Voltage and reactive margin at Macomb was studied under various conditions. V-Q curves were generated for base case and contingency conditions.

The prior outage of one of the St. Clair 120 kV generating units connected to the St Clair 123 bus in addition to the loss of the Stephens–Macomb 120 kV line results in a reactive margin of 10 MVar which is not sufficient to accommodate a possible load forecast variation of 5% and remain stable. Other more severe contingencies such as the loss of both the Stephens line and the double circuit supply to Macomb from St. Clair result in an unstable condition at the Macomb bus at forecast peak load levels.

The unstable conditions found in this area considered is expected to be local in nature in that the critical voltage at Macomb is sufficiently low (.76 pu) at the unstable point such that local motor load would likely trip off-line due to the motor protection devices. ITC has a planned project to bring an additional 120 kV line into the area (Bismarck–Golf 120 kV) that provides a path into the area that acts as a parallel path to the critical Stephens–Macomb path. In addition, Lenox substation (formerly called New Haven) is planned that includes the addition of a 345 / 120 kV transformer that strengthens the 120 kV network in the area. Finally, a 120 kV capacitor is planned to be added at Macomb. The new line, substation and capacitor will provide voltage support during contingency operation and eliminate this area of concern.

A separate area of relative weakness was found to be the Bad Axe area in the Michigan Thumb. There is known weakness in the supply to this area. The loss of the Harbor Beach generator and a single line or transformer supplying the area can result in localized voltage instability.

ITC has a planned project to support this area that includes installing high speed switching dynamic Var devices (Dvars) at two different locations in the Thumb and converting single circuit line construction to double circuit line construction which will enable bringing another 120 kV circuit through the west part of the thumb. In addition, ITC has a proposed project to add a substation at Saratoga. Saratoga, as proposed, will greatly reduce the likelihood that Greenwood generation in the thumb will be forced off due to a transmission event and provide another 345-120 kV transformer that will support the lower portions of the thumb.

These solutions are included in MTEP 05 Appendix A as:

Macomb Area Solutions

- Bismarck–Golf 120 kV , planned project, form 1 project group #518
- Lenox Substation, planned project, form 1 project group #518
- Macomb Capacitor, planned project, form 2 device #87

Thumb Area Solutions

- West Thumb Rebuild, planned project, form 1 branch IDs #529-533
- Bad Axe and Lee Substation DVARs, form 2 device #100 and 101
- Saratoga Substation, proposed project, form 1 project group #ITC9

The Midwest ISO will continue to work with ITC towards resolution to these voltage concerns and will continue to monitor the areas in seasonal assessments so that operating personnel are prepared to take remedial action if necessary.

Michigan–Northern Lower Peninsula

Outage of the 345 kV Ludington–Keystone circuit in the METC northern Michigan area can cause heavy loadings on several underlying 138 kV lines. This condition has worsened over the past few years as area loads have increased. Peaking generation at Gaylord and Livingston has been dispatched during heavy load periods to mitigate potential overloads. MISO has established a flowgate at Tippy to monitor loading and re-dispatch area generation to maintain security. With forecasted growth for 2005, operation of the peakers would no longer be adequate to relieve potential overload conditions. To resolve this condition METC planned several line projects to be completed in the 2005-2009 period. The most critical of these projects are under construction and scheduled to be completed before the summer of 2005. The 13.2 mile Farr Road to Tippy 138 kV line has been rebuilt from 266 ACSR to 795 ACSS conductor this spring. Station terminal upgrades associated with the project are to be completed before June, 2005. A new 20 mile 138 kV line is also being constructed from Pere Marquette to Stronach. The new line is being built along a new route to allow the existing line to remain energized while the new line is being built. This allowed construction of both of these projects to be under construction simultaneously this spring. The new Pere Marquette–Stronach line is also scheduled to be energized before summer 2005. In the fall of 2005 rebuild of the 10.4 mile Tippy to Hodenpyl 138 kV line will begin. This rebuild is scheduled to be completed before summer, 2006. The Stover to Clearwater and Clearwater to Keystone 138 kV lines are also proposed to be rebuilt in 2007 and 2008. Completion of this multiphase 138 kV line rebuild project in the northern lower peninsula of Michigan provides a much needed boost to the capacity and reliability of this growing area.

Michigan–Grand Rapids Area EHV Transformers

The Grand Rapids area is the fastest growing area served by the METC system. This growth has caused increased loading on the 345/138 kV transformers at the three EHV substations that surround the city. The Tallmadge substation serves northern Grand Rapids, the Gaines substation feeds into the rapidly growing area south of the city and Vergennes substation feeds into the developing area east of town. Studies indicated that with growth forecast for 2005, outage of a 345/138 kV transformer at either Gaines or Vergennes would cause the other to overload. Also 138 kV lines in the area were subject to overload for transformer outages. Loss of two of the four transformers serving the area would cause widespread load loss throughout the area. To resolve this condition METC has added a second transformer at both Gaines and Vergennes and located a spare transformer at Tallmadge. The Gaines transformer went in service in 2004 and the Vergennes transformer was energized in March 2005. The Tallmadge spare transformer is also being energized temporarily this spring while one of the existing Tallmadge transformers is undergoing major testing and overhaul. Addition of these transformers has provided the capacity needed to serve this growing area.

Southern and Southeastern Wisconsin

Two areas in southeast Wisconsin area were also identified in the 2004 summer assessment as areas to monitor for potential voltage instability.

One area of concern is the area south of Milwaukee around Racine and Kenosha. The loss of Pleasant Prairie-Racine 345 kV circuit significantly weakens the Racine 345 kV bus. For load increases above forecast of 105%, or for load power factors 1% or more below expected, reactive power margins could become critical. An operating plan to operate the Germantown units as synchronous condensers could add about 30 MVar of reserve to the critical Racine 345 kV bus under the high load scenario.

For normal summer peak load projections, the Racine and Kenosha areas are expected to be stable for single line or single generator contingencies. Multiple outages, or single outages under certain levels of variation in load or load power factor could result in critical reactive margin levels.

ATC LLC has stated that distribution load switching may be available to provide some relief with respect to the Racine 345 kV bus voltage. The mitigation of the Milwaukee area voltage concerns is expected to begin by the summer of 2005 with the planned installation of 54 Mvar of capacitors at Moorland (Appendix A Device ID #2050) and the availability of the expanded capacity of the Port Washington generation facility. An additional 90 Mvar of capacitors are planned to be installed in 2006, with 54 Mvar scheduled to be installed at Burlington (Appendix ID #2059), and 36 MVars at Hartford (Appendix A Device ID # 2082).

The other area to monitor is the Madison area. The Columbia units are important in maintaining voltage stability for Madison area. With one of these units out, the North Madison area is observed to be sensitive to load level changes and power factor changes without local generation redispatch. Normal operation for the prior outage of Columbia Unit 1 at peak load is to bring on other off-line generation in the area. ATC LLC is considering a longer-term solution to provide increased support to the area that involves additional 345 kV supply to the Madison Area. Projects related to this additional support are listed in Appendix A with Branch IDs 139,148,149.

Eastern Iowa

The Alliant Energy transmission system of eastern Iowa is comprised mainly of 69 kV and 161 kV facilities, but also includes 34.5 kV , 115 kV and 345 kV .

Prior to the latter part of the 1990's, the transmission system in this region was primarily used for load serving purposes. With the advent of the open access energy market and significant generation additions in Illinois, this system is under significant additional stress. Alliant Energy has documented line loading difficulties in this area and has presented these results before the NERC standing committees.

Although the MTEP 05 studies have not identified reliability standard violations in this area under expected firm transactions, some multiple contingency conditions identified result in overload conditions.

Table 2.5-2: Multiple Contingency Conditions

System	Limiting Facility	Rating	Contingency	Loading % or P.U	Mitigation Plans
Iowa	Salem 345/161 kV Transformer	336	Rock Creek 345/161 kV Transformer and Beaver Channel 161 kV Beaver Channel Generator	101%	Upgrade Salem Tx. to 550 MVA and replace Hazelton Tx. with old Salem Tx of 336 MVA
	Hazelton 345/161 kV Transformer # 1	223	Salem 345/161 kV and Hazelton 345/161 kV # 2 Transformers	112%	

Further, Midwest ISO TLR information shows that four of the top 22 flowgates in TLR are in this area:

Table 2.5-3: Four of the Top 22 Flowgates in TLR

MTEP-05 TLR Rank	Flowgate (NERC ID Number)	Pending Improvement (As of MTEP-05)	Year
5	Poweshiek–Reasnor 161 for Montezuma–Bondurant 345 (NERC 3704)	Reconductor of Poweshiek–Reasnor 161 kV line to 326 MVA Appendix A Branch ID # 187	2005
10	Arnold–Vinton 161 for D.Arnold–Hazelton 345 (NERC 3724)	None identified at this time	-
14	Montezuma–Bondurant 345 kV (NERC 6086)	None identified at this time	-
21	Arnold-Hazelton 345 for loss of Wemp–Paddock 345 (NERC 3705)	ATCo's Wempleton–Paddock 345 kV cct #2 and long term proposal of Salem–Spring Green 345 kV Appendix A Branch ID # 344, 1266, 1267	2006 & 2014

It is known that the Salem 345/161 kV transformer (ALTW), an existing Midwest ISO flowgate is sensitive to south-to-north and east-to-west transfers. The base case flow on this transformer has increased since the 2003 summer. This is primarily due to an increased south-to-north bias. Changes in local line impedances due to system upgrades and an increased ALTW load since the 2003 summer also contributed to the increase. A Salem Operating Guide (ALTW) has been developed that calls for opening the Salem 161 kV bus tie (ALTW); however, its implementation would overload the Asbury-Lore 161 kV line (ALTW). ALTW plans to re-conductor this line prior to the 2005 summer season. The Salem guide will be available for the 2004/05 winter season.

Alliant Energy and Midwest ISO have been charged by NERC (via the NERC Alliant West TLR Task Force) with ensuring that planning studies are performed to identify transmission facilities needed to be upgraded or added to accommodate known firm uses of the system and to ensure reliability in this area. An Eastern Iowa study group has been formed and is commencing a detailed study of this area that will consider historical levels of parallel path flows in this area. For additional details on this area see Chapter 6 and Appendix D.

South Central Illinois

The Prairie State 1500 MW coal-fired generating plant is planned to interconnect to the AmerenIP system in south central Illinois by 2009. This large base-load plant will tap coal resources in the area and is expected to provide capacity and energy for a number of Midwest ISO Network Customers, once it is established as a deliverable Network Resource. Considerable upgrades are needed to interconnect the plant reliably and provide for adequate delivery service. One of the major upgrades identified so far is the addition of a 26-mile Baldwin–Rush Island 345 kV line. It is possible that a number of transmission system expansions to this area of the Midwest ISO Transmission System could provide for more economical delivery of the output from plants in the area by reducing possible congestion on the system, particularly if other large plants were developed in this area. Analysis performed for MTEP 03 released in June 2003 postulated various expansion options to this system and found some of them effective in relieving congestion that could exist if additional coal plants were added in this area to take advantage of the available coal supplies, or if generation of other fuel sources were added. Several of the postulated expansions in MTEP 03 are included as long-term proposed projects in this MTEP 05 Appendix A and include Newton – Merom 345-kV, St. Francois–Fletcher 345-kV, and Albion–Norris City 345-kV. The Midwest ISO will continue to work with Ameren to evaluate the need for and benefits of these and other projects.

Eastern Kentucky

The Midwest ISO has been advised by Eastern Kentucky Power Cooperative, a non-member of the Midwest ISO, that they are anticipating some significant configuration changes to their system that borders Midwest ISO member system LGEE. These changes are expected to occur by 2008 and involve building a 100 mile 161 kV transmission interconnection between EKPC and BREC to serve the load in WREC and the opening of the tie between TVA and EKPC. The Midwest ISO has been evaluating the impacts of these external system changes. Preliminary findings indicate that with these system changes there could be overloads on the Lake Reba Tap-Union City 138 kV line in the LGEE system under base conditions. Additional limiting facilities for n-1 contingencies were observed in the 2009 model in the LGEE system in the Fawkes/Lake Reba/Delvinta area. This is due to the additional output from the J K Smith power plant in support of service to the 447 MW load at WREC. We will continue to monitor these developing plans and their impact on Midwest ISO system expansion needs, and will report further on these impacts in MTEP 06 which is underway.

South Dakota/ Minnesota

The proposed Big Stone II 600 MW coal-fired generating plant is planned to interconnect to the Otter Tail Power Company system in eastern South Dakota by 2011. This project would be constructed next to the existing 475 MW Big Stone I power plant located near Milbank, South Dakota. Generation capacity and energy from this project is expected to be delivered to both Midwest ISO network customers, as well as non-Midwest ISO network customers located in the MAPP region. Generation Interconnection and Delivery Service studies are underway and have identified two potential transmission alternatives that at a minimum will require construction of new 230 kV transmission facilities in eastern South Dakota and west-central Minnesota.

The next two sections describe exploratory transmission studies which are looking at moving large amounts of energy resources from the Dakotas, Minnesota, and Iowa to markets to the south and east. These studies both have proposed lines in the area of the Big Stone II project. The wider regional planning perspective of the Midwest ISO presents an opportunity to coordinate the development of transmission plans for the area which address both Big Stone II generator outlet requirements and the long-term development of energy resources in this area. The challenge is balancing the value of interconnection upgrades of least cost in the near-term and for current commitments, with the advantages of more expansive upgrades and their potential benefits over a longer term. This is the focus of the Exploratory regional plans discussed briefly below, and further in Chapter 7 of this report.

Northwest Area

Midwest ISO identified in MTEP-03 potential plans for expansion of transmission in the Dakotas and into Minnesota with the goal to eliminate constraints in northwestern MAPP to the development and delivery of additional generation resources in the Dakotas. Since then, the Midwest ISO has been working with an active coalition of generation developers, government entities and utilities, the Upper Great Plains Transmission Coalition (UGPTC), interested in determining best plans to enable this development.

The Midwest ISO is leading studies to address this issue with the goal of selecting preferred projects for increasing the power delivery capability of the transmission system from the Dakota's. This study is ongoing at the time of this MTEP 05 distribution. It is expected that once studies are completed, the Midwest ISO will facilitate the implementation of these projects by identifying impacted and benefiting parties and applying newly developed Midwest ISO transmission pricing policies to recommend fair cost assignment and recovery for the projects.

Please see Charter 7 for further details on the current status and results from these studies.

Southern Minnesota/ Northern Iowa

A study similar in some respects to the Northwest Area study is also being performed by the Midwest ISO in this area. The transmission system in this area has limited capacity to allow for significant development of additional wind generation projects. Because the northern Iowa and southern Minnesota area is a very good wind resource, there are a large number of generator interconnection requests in this area — literally thousands of megawatts of requests. This study will determine how to get 2,700 to 3,500 MW of wind generation to market in addition to existing and committed generation projects. The Rochester, Minnesota area; La Crosse, Wisconsin area; Worthington, Minnesota area and eastern Iowa area all have future load serving reliability concerns. The Minnesota–Wisconsin Stability Interface is a system constraint which can impact the ability of new generation to be sited in Minnesota and Wisconsin. The State of Minnesota also has a Renewable Energy Objective in which utilities in the state should have 10% of energy produced from renewable sources by 2015. This exploratory study will develop a transmission plan, which addresses these concerns at a preliminary level.

Progress on this plan development is contained in Chapter 7.

2.6 Planning Across Midwest ISO Seams

The Midwest ISO continues to develop and improve working arrangements with parties bordering the Midwest ISO region. The Midwest ISO is engaging these border entities in seams discussions and systems integration to permit the orderly conduct of energy transfer and related economic settlements that must occur, and of coordinated system expansion.

The development of these business arrangements is currently done under the collective title of Seams Coordination. The Midwest ISO has a filed Joint Operating Agreement (JOA) with PJM and has recently developed similar agreements with TVA (joint Midwest ISO/TVA/PJM), SPP, and is developing an agreement with the non-Midwest ISO members of MAPP.

Planning coordination with these entities through these JOAs involves close coordination on model development, data exchange, coordinated interconnection and transmission service impact studies, and development of joint regional plans. The Midwest ISO and PJM plan to develop the first joint regional plan by June of 2006. This plan will begin with the individual plans most recently created by each RTO and will develop an integrated view of the future super-regional system. Joint plans will include identification of expansion projects that are subject to cost sharing between the RTOs on the basis of cross-border cause and/or benefits, in accordance with procedures in development and to be filed by each RTO by mid-year 2005.

In addition, the Inter RTO/ISO Council is developing a draft scope and schedule for a combined inter-RTO/ISO expansion plan that will build from the various plans created on a seams interface basis to produce the first ever coordinated plan encompassing a majority of the nation's electrical grid. This activity is tentatively scheduled for release in 2007.

While these coordination agreements and procedures are in initial stages of implementation, this current MTEP 05 has taken advantage of the participation, data exchange, and review of individual transmission owner systems with seams with the Midwest ISO except AECI and SERC.

2.7 Process Overview

As stated above, the Midwest ISO develops the plan with the input and assistance of the following stakeholder groups including:

- The Expansion Planning Group
- The Planning Subcommittee
- The Advisory Committee
- The Organization of Midwest ISO States

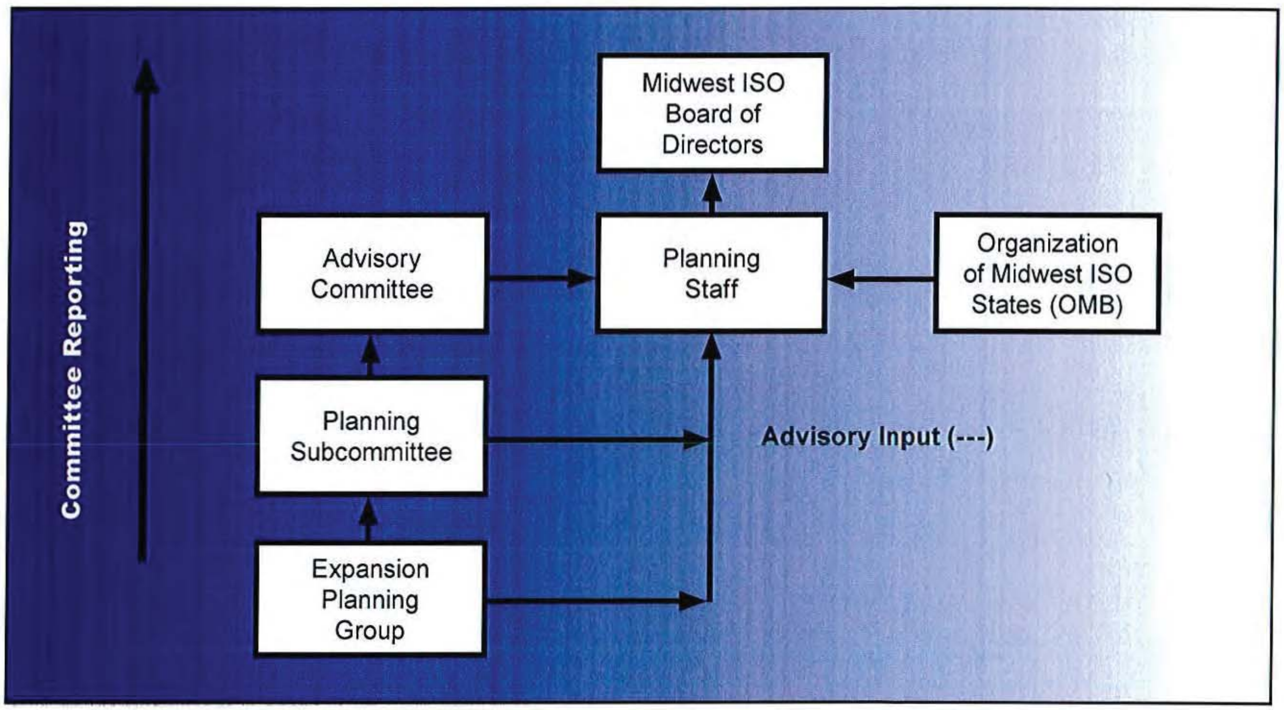


Figure 2.7-1: Process Overview

The current planning process at the Midwest ISO integrates the ongoing planning processes that are responsive to new customer requests for system access, and the continuing but cyclic Baseline Reliability studies of the MTEP regional plan development. The graphic below depicts these processes.

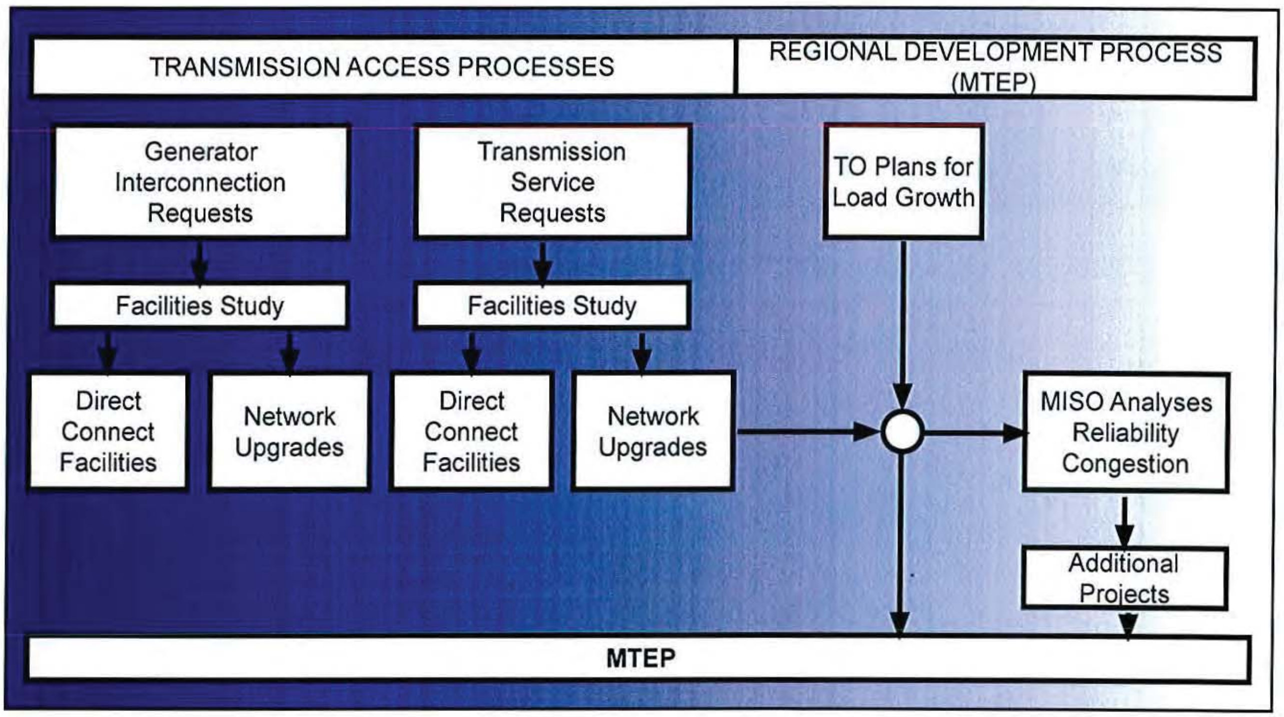


Figure 2.7-2: Planning Process

Key elements of this process include the following:

- Roll-up of Transmission Owner Plans
- Inclusion of Plans from Interconnection and Delivery Services
- Development of Power Flow Base Case
- Review of System Reliability and Congestion
- Development of any Additional Expansion Needs
- Review of Additional Regionally Beneficial Expansions

Roll-up of Transmission Owner Plans

An essential part of the Midwest ISO regional expansion plan is the roll-up of the local area plans of the Transmission Owners. The Midwest ISO Transmission Owners Agreement establishes the ongoing responsibility of the Transmission Owners to plan for the continued reliable operation of their systems. The Midwest ISO and the Transmission Owners collaborate on a daily basis in reliability studies related to requested uses of the system for new delivery service rights, and for new generator interconnections. However, the many Transmission Owners are continually evaluating their systems often independent of each other for their local area needs. The roll-up and testing of the integrated developments from these various processes is essential to ensure the efficient long-term reliable operation of the Midwest ISO system. The roll-up of plans is the integration process, and provides the initial Midwest ISO plan for various study purposes.

Reliability Review of the Planned System

As described above, parallel planning processes coexist within the Midwest ISO region as Transmission Owners continually plan their systems for their local area needs. Some of these localized planning processes are more coordinated than others, depending on the NERC region to which the Transmission Owner is a member. The Midwest ISO must perform comprehensive reliability reviews of the integrated plans of the Transmission Owners. This is in order to ensure that these local processes are sufficient to meet reliability needs, are coordinated and do not result in either inefficient plans or parallel path flow changes that could infringe on the rights of existing transmission customers, or in certain tightly interconnected areas, possibly endanger the reliability of the system.

The reliability review process has several embedded steps as depicted below, the objectives of which are to expand the system where necessary to address reliability needs in the most economical manner.

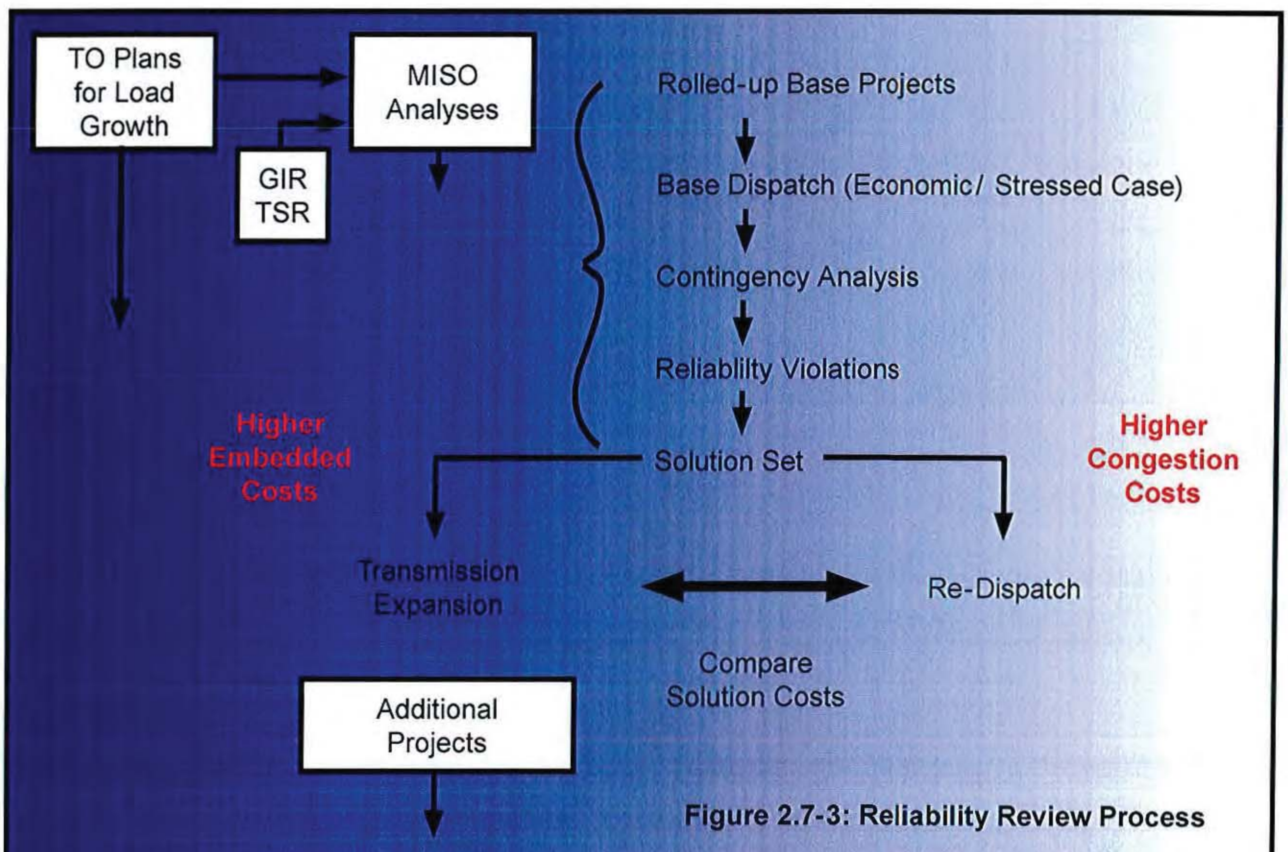


Figure 2.7-3: Reliability Review Process

Review of Additional Regionally Beneficial Expansions

One of the key aspects of the MTEP begun with MTEP 03 is the study of the ability of the planned transmission system to provide low cost electricity to customers into the future. The MTEP process will continue to solicit stakeholder input as to regionally beneficial expansions that while not essential to maintaining reliable supply from currently committed and planned resources, provide benefits that are favorable relative to their costs. Such benefits could involve enabling access to low cost resources, providing for economic development in an area, or furthering energy policy such as achieving renewable energy targets.

2.8 The Importance of Appendix A

Appendix A is a spreadsheet listing of the Planned and Proposed projects that are a part of MTEP 05. The listing includes much information about the nature, location, expected service date, need, driver, estimated cost, and other information about the Baseline projects needed in the region. Appendix A is a living document that is updated twice annually in February and in July and on that basis is a current listing of the expected development of the Midwest ISO Transmission System. Midwest ISO future system models are based on the projects contained in Appendix A.

2.9 Implementation and Follow-Up

The Midwest ISO will support the need for and track the development of projects defined as Planned projects that are part of the approved MTEP.

The MTEP will be subject to change, as system conditions change. Changes in load growth, changes in usage patterns, development of new generation interconnections, changes in projected service dates of interconnection plans, delays in regulatory approvals of transmission projects, or ongoing development of preferred plans, all may cause changes to the overall Midwest ISO plan. The MTEP will be updated as needed to incorporate the impacts of such changes on the overall Plan.

Section 3: About Midwest ISO

3.1 Scope of the Midwest ISO System

On December 20, 2001, the Midwest ISO became the first FERC-approved RTO in the nation and began selling regional transmission service under its FERC-approved tariff on Feb. 1, 2002.

As a Regional Transmission Organization, the Midwest ISO provides non-discriminatory, open access to the transmission system under its operational control. This transmission system spans 15 states.

Midwest ISO statistics:

- 23 Transmission Owners
- 36 Control Areas in three regional reliability organizations
  - MAPP/MRO
  - MAIN
  - ECAR
- 119,000 Mw of peak load
- 131,000 Mw of generating capacity
- 97,000 miles of transmission lines
- 947,000 square miles in the Midwest ISO footprint
- 15.1 million customers
- 1,504 Generating units in the reliability footprint
- 2 Control Centers
  - Carmel, Indiana
  - St. Paul, Minnesota

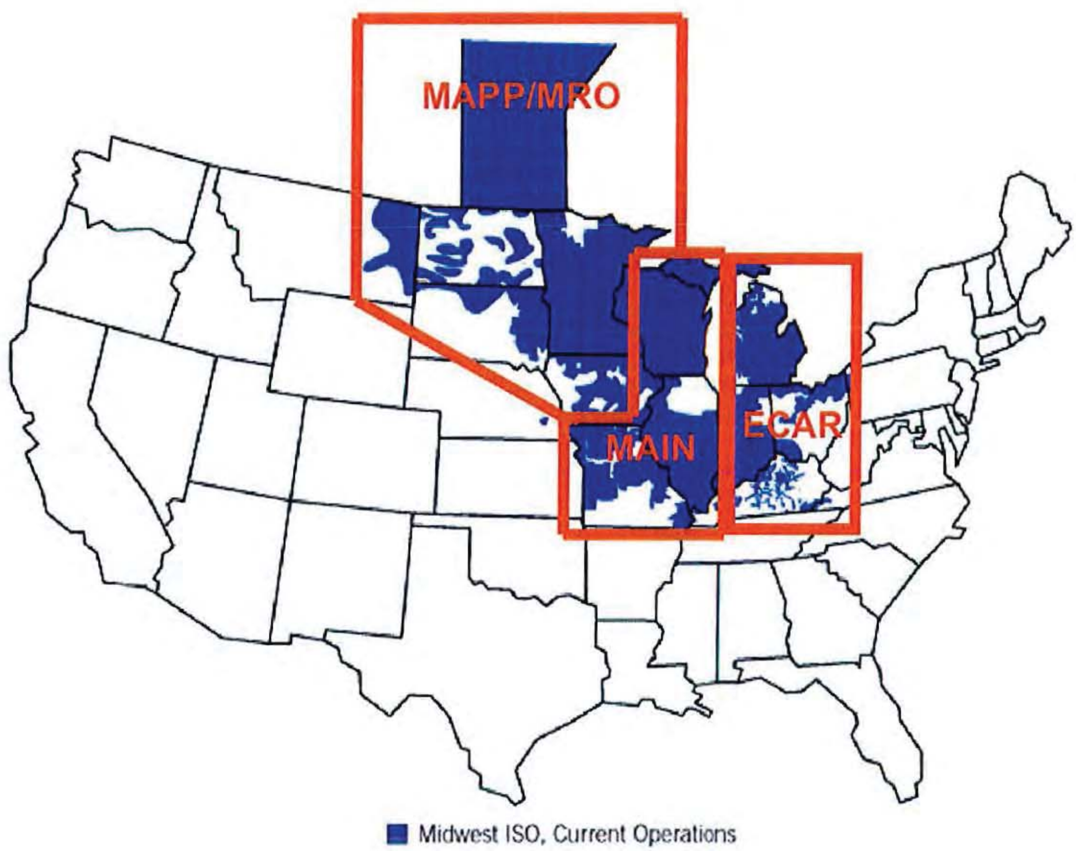


Figure 3.2-1: The General Areas of the Three RSGs.

3.2 Planning Regions

For the MTEP 05 study process, the studies were divided into three regions corresponding closely to the boundaries of the NERC regional reliability organizations MAPP, MAIN and ECAR. Each Regional Study Group (RSG) invited the non-Midwest ISO participants in the NERC region to participate in the Midwest ISO MTEP 05 reliability studies.

ECAR RSG Participants

- CINERGY
- FirstEnergy
- Grid America
- Hoosier Energy
- Indianapolis Power & Light
- International Transmission Company
- LG&E Energy
- Michigan Electric Transmission Company
- Northern Indiana Public Service Company
- VECTREN

MAPP RSG Participants

- Alliant Energy West
- Lincoln Electric System
- MidAmerican Energy Company - Non-Member
- Manitoba Hydro - Coordination Member
- Minnesota Power
- Montana-Dakota Utilities Co.
- Muscatine Power & Water - Non-Member
- Otter Tail Power Company
- Western Area Power Administration - Non-Member
- Xcel Energy North

MAIN RSG Participants

- Allegheny Energy Supply Co., LLC
- Alliant Energy Corporate Services
- Ameren
  (including the operating companies of)
  •AmerenUE
  •AmerenCIPS
  •AmerenCILCO
  •AmerenIP
- American Transmission Company, LLC
- Central Iowa Power Cooperative
- City Water, Light and Power
- Columbia (Missouri) Water & Light
- Commonwealth Edison Company
- Constellation Energy Commodities Group, Inc.
- Coral Power, LLC
- Duke Energy
- North America, LLC
- Edison Mission Marketing and Trading
- Electric Energy, Inc.
- GridAmerica LLC
- Illinois Municipal Electric Agency
- Madison Gas & Electric Company
- Midwest ISO
- Northern Indiana Public Service Co.
- NRG Energy, Inc.
- PJM Interconnection, L.L.C.
- PPL EnergyPlus, LLC
- Southern Illinois Power Co-operative
- Soyland Power Cooperative, Inc.
- Tenaska Power Services
- Wisconsin Electric Power Company
- Wisconsin Public Power Inc.
- Wisconsin Public Service Corporation.

3.3 Load and Generation Trends

The Midwest ISO does not currently prepare a long-term load forecast. Load projections are reported by Network Customers under the tariff, and are represented in planning models developed collaboratively between the Midwest ISO and our transmission-owning members. Members also provide load forecasts through the NERC regional reporting processes. Resource adequacy is established under the tariff by requiring load serving entities to report their Network Resources that will be used to meet State and NERC regional resource adequacy guidelines.

Estimates of load and resource additions through the 2009 period have been made below in Figure 3.3-1 by using the current Midwest ISO peak load measurements, aggregate load growth rate projections reported by members and non-members to NERC, and activity from the Midwest ISO generation interconnection queue.

At an estimated load growth rate of 1.9%, the peak load of Midwest ISO for 2009 would be about 131,000 Mw, which is about equal to the current installed capacity of 131,000 MW. There is about 11,554 Mw of generation in the current queue with executed interconnection agreements and service dates between 2004 and 2009 inclusive. There is an additional 17,521 MW of generation in the queue for service over this period that have not yet executed interconnection agreements.

Additional load and capacity projections for the wider Midwest region are available from the report "2004 Long Term Reliability Assessment, The Reliability of Bulk System in North America" by the North American Electric Reliability Council. This NERC report concluded that overall the three regions are expected to have adequate resources through 2013.

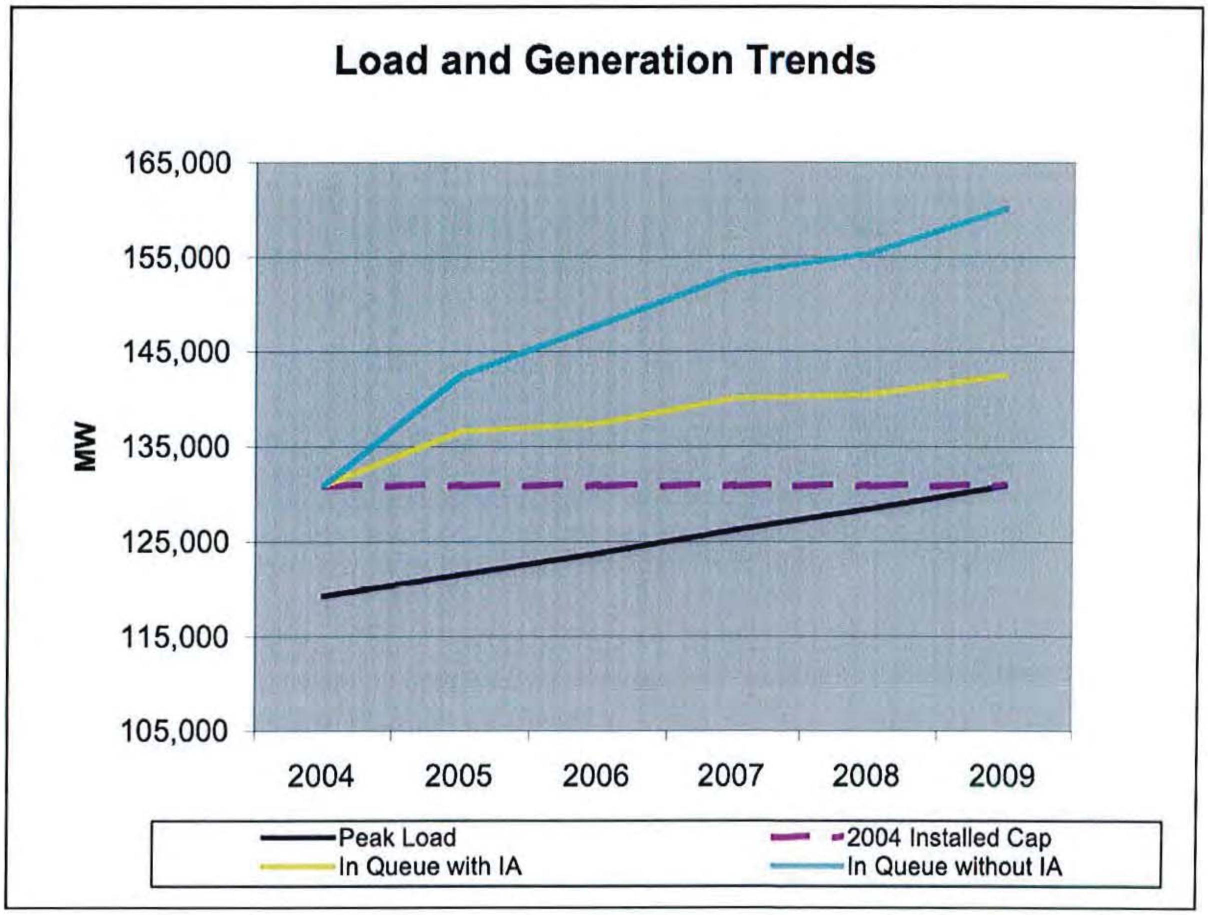
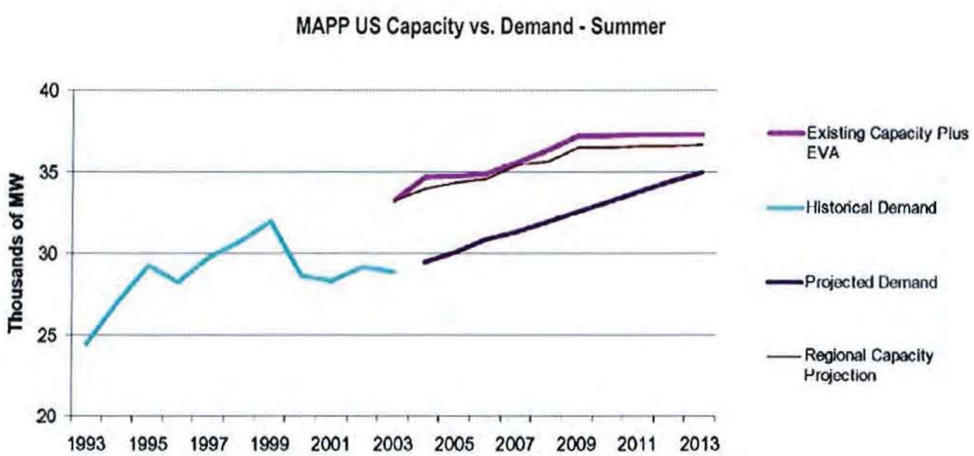
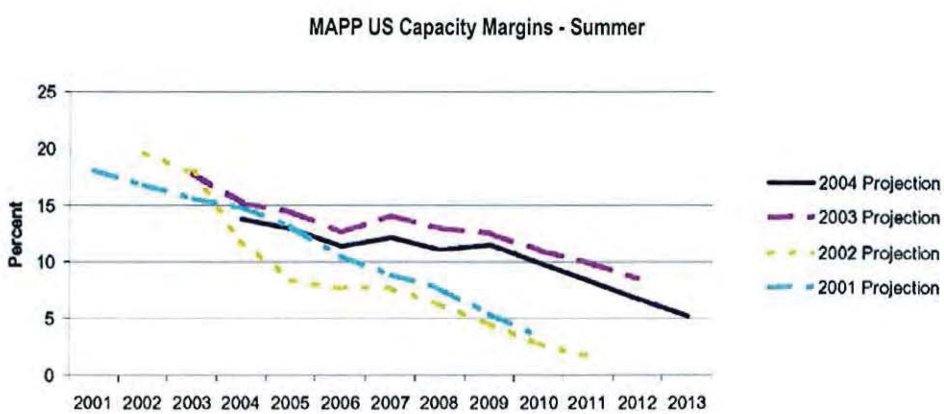


Figure 3.3-1

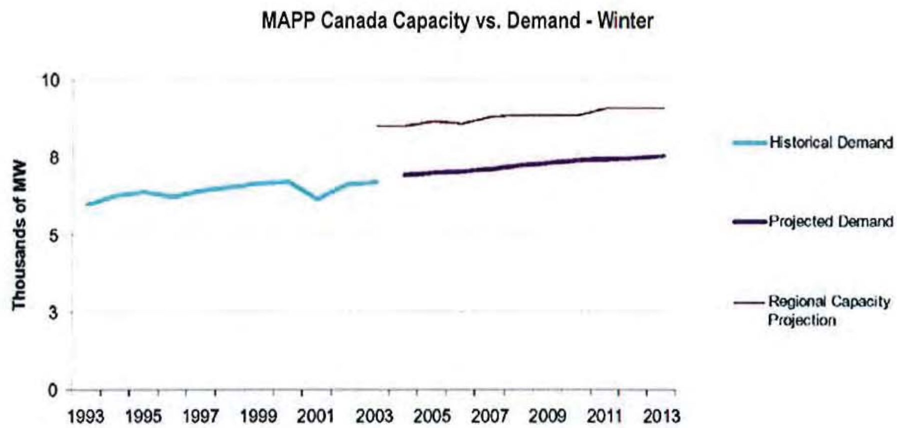
Figures 3.3-2 through 3.3-5 are from this NERC report and show the historical loads, the projected load forecasts under high, normal and low growth assumptions, the existing generation capacity and the projected generation in each region.

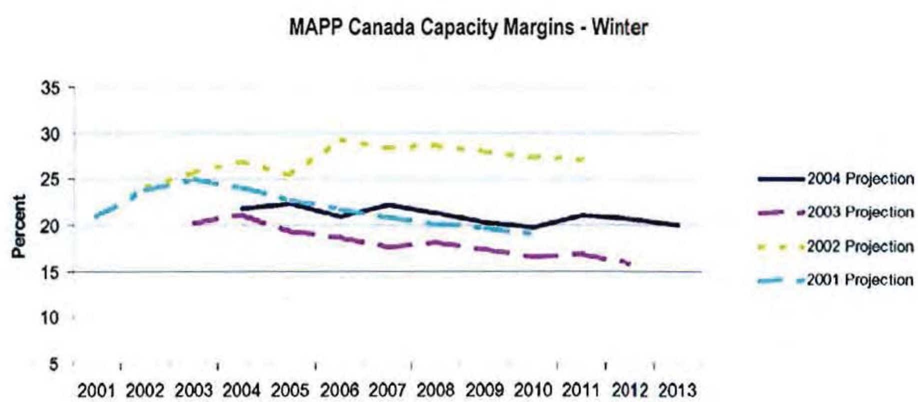




Source: "2004 Long Term Reliability Assessment, The Reliability of Bulk System in North America" by the North American Electric Reliability Council.

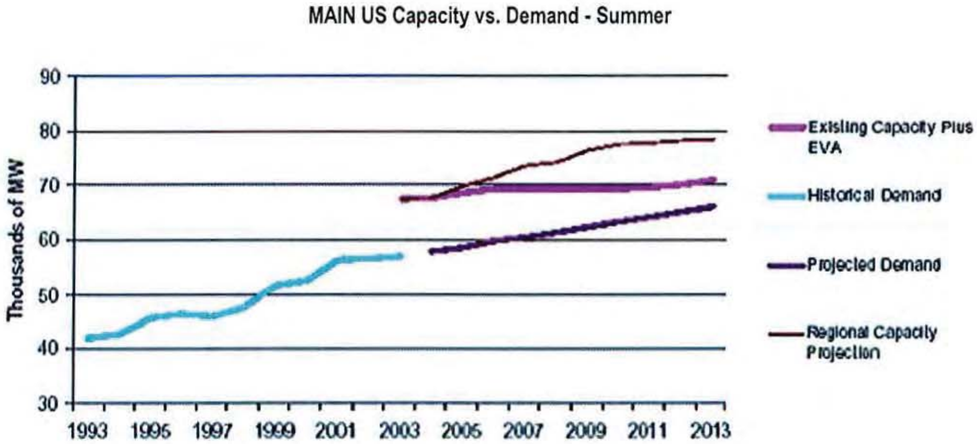
Figure 3.3-2

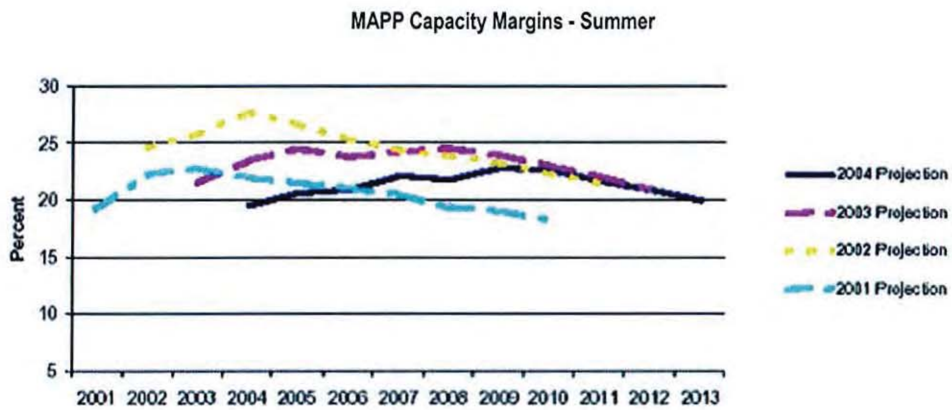




Source: "2004 Long Term Reliability Assessment, The Reliability of Bulk System in North America" by the North American Electric Reliability Council.

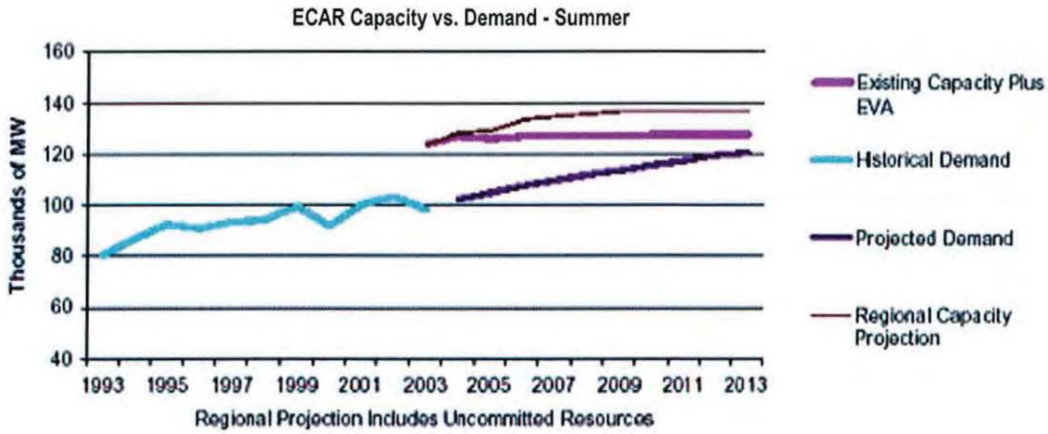
Figure 3.3-3

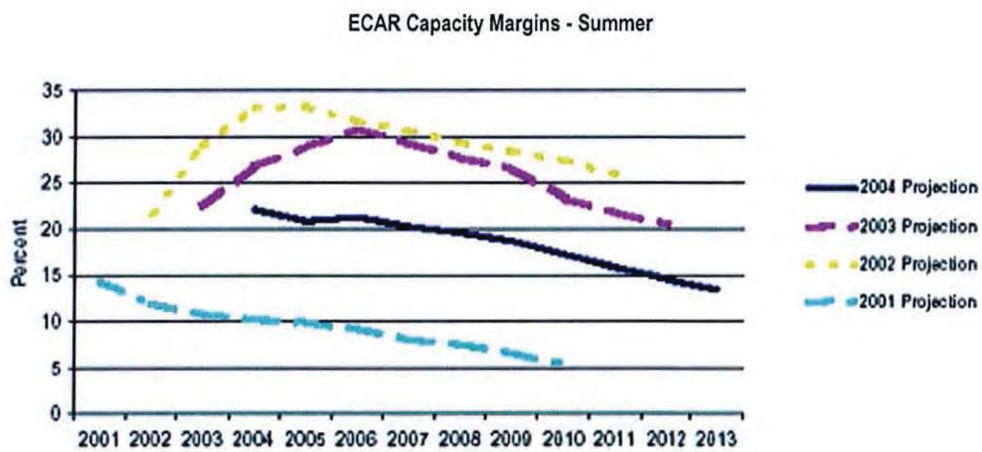




Source: "2004 Long Term Reliability Assessment, The Reliability of Bulk System in North America" by the North American Electric Reliability Council.

Figure 3.3-4





Source: "2004 Long Term Reliability Assessment, The Reliability of Bulk System in North America" by the North American Electric Reliability Council.

Figure 3.3-5

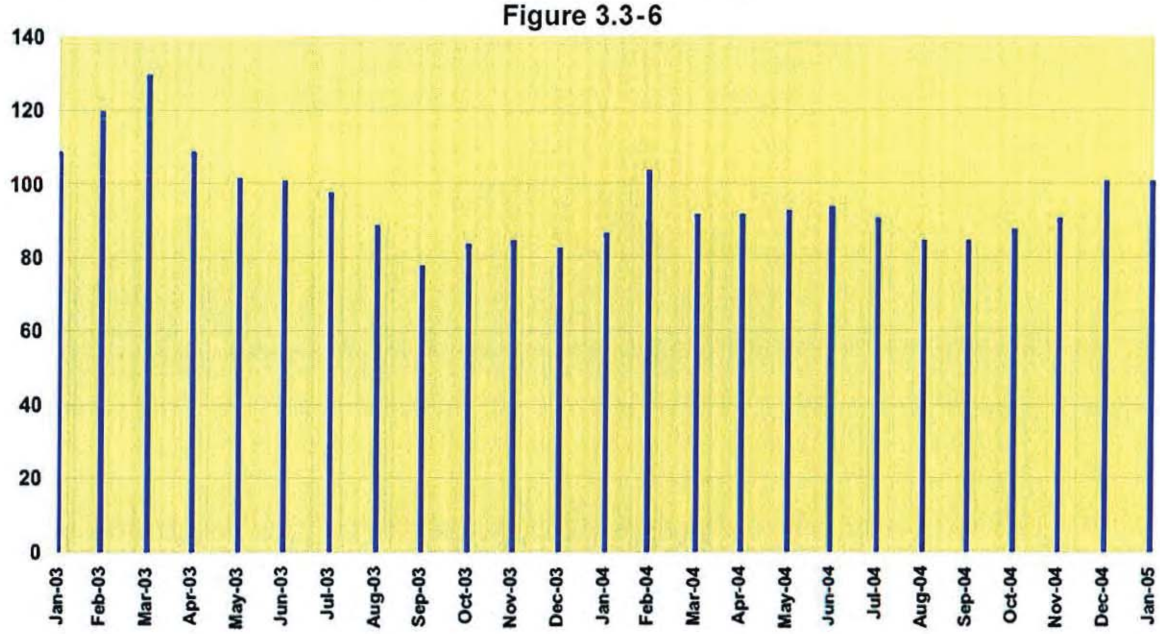
006467

3.3.2 Midwest ISO Generation Interconnection Queue

Figure 3.3-6 below shows the active generation interconnection queue entries for the two-year period January 2003 to January 2005. The number of active entries has remained relatively stable between approximately 80 and 100. During this time, more than 150 new requests have entered the queue.

Number of Active Entries in Queue by Date

Figure 3.3-6



There has been a considerable shift in the type of requests the Midwest ISO is processing. As shown in Figure 3.3-7 below, 65% of current entries are for wind power, 18% for natural gas and 12% coal.

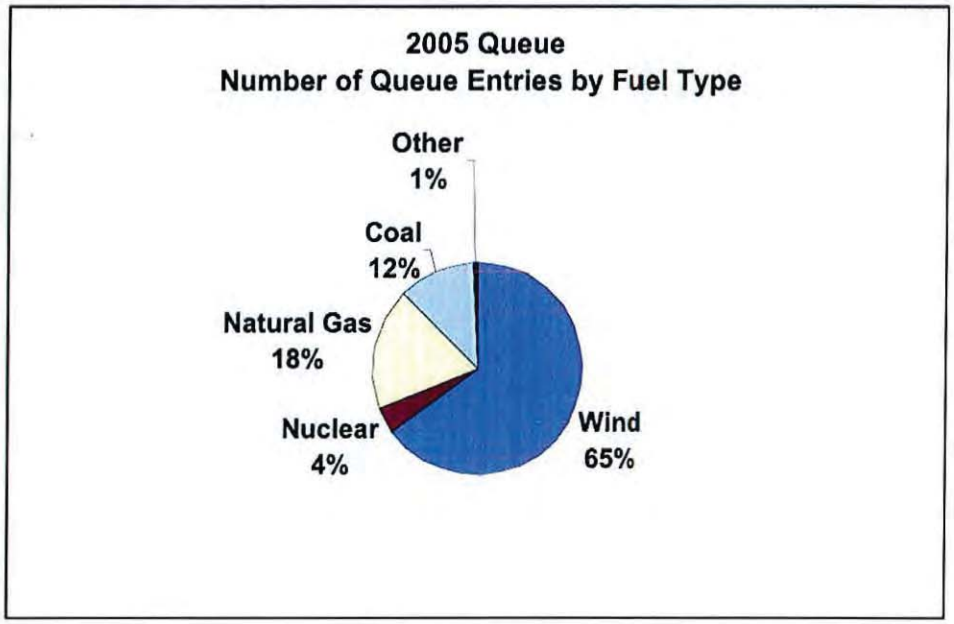


Figure 3.3-7

Compared to the entries in the 2003 queue shown in Figure 3.3-8 below, this is a 30% increase in wind requests, 50% increase in the number of coal requests and a 50% decrease in gas requests.

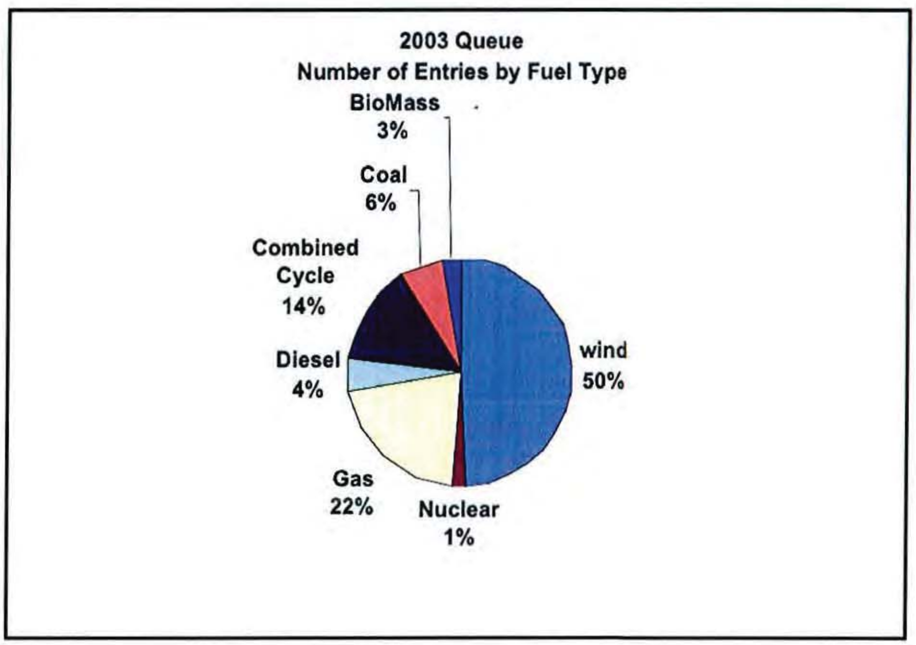


Figure 3.3-8

While the number of wind entries has increased significantly, in terms of capacity, the 2005 queue shows that the predominant fuel type is coal with 6700 MW, followed by wind with 5800 MW and gas with gas with 5000 MW.

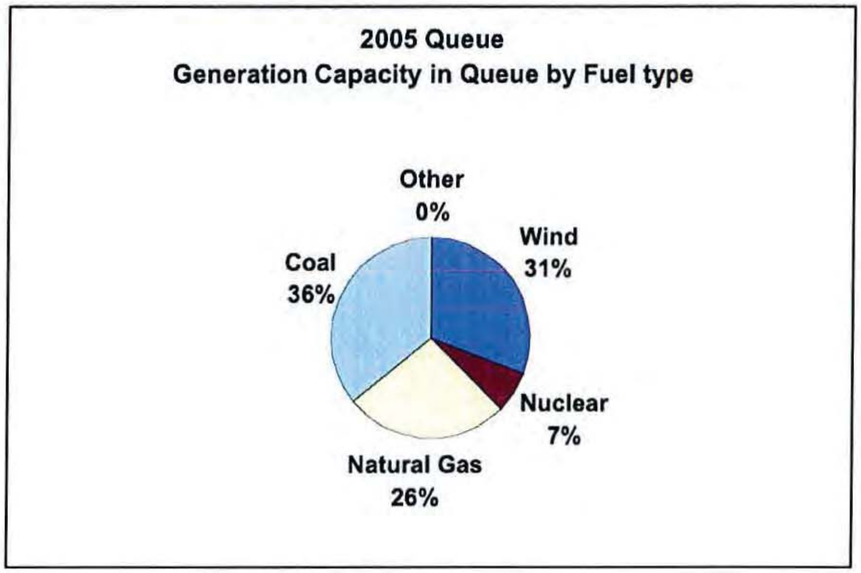


Figure 3.3-9

This compares to the 2003 queue shown in Figure 3.3-10, in which the overwhelming capacity of the queue was in natural gas plants. Most Combined Cycle plants are gas fired also.

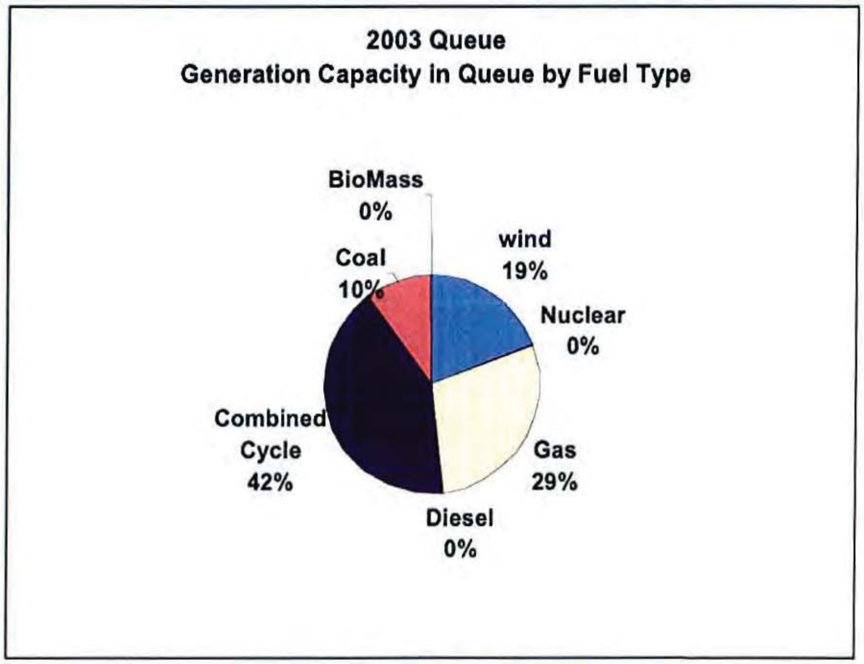


Figure 3.3-10

The higher price of natural gas over the past two years may be a primary factor in more coal and wind being proposed for the future, and for the expectation of reduced energy production from existing gas plants.

The proposed locations of the Queue entries by requests and by fuel type are shown in Figure 3.3-11 below. The bulk of both the entries and the capacity is in Minnesota, and this is largely wind-powered capacity.

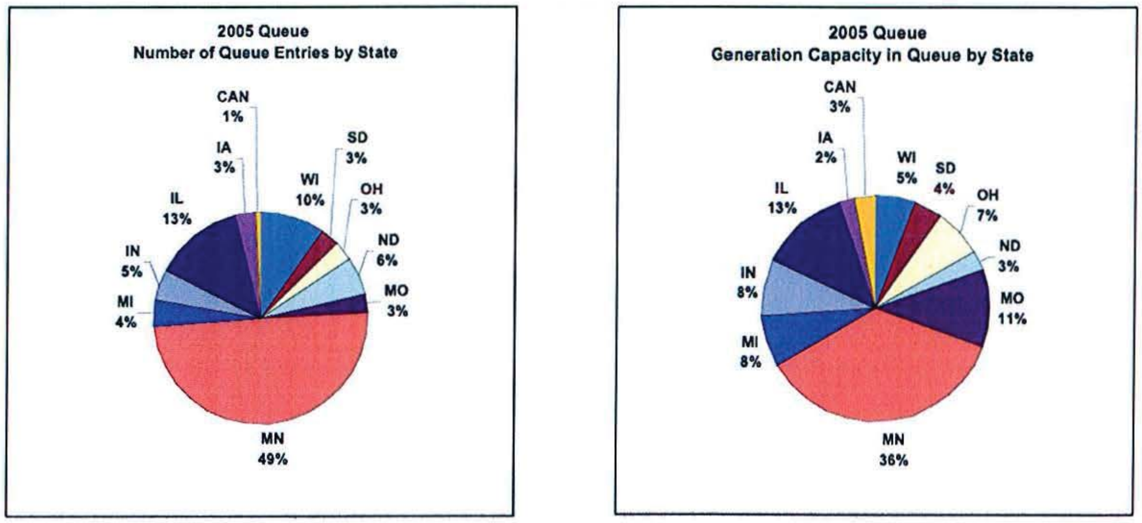


Figure 3.3-11

The plot below shows the geographic distribution of the queue entries.

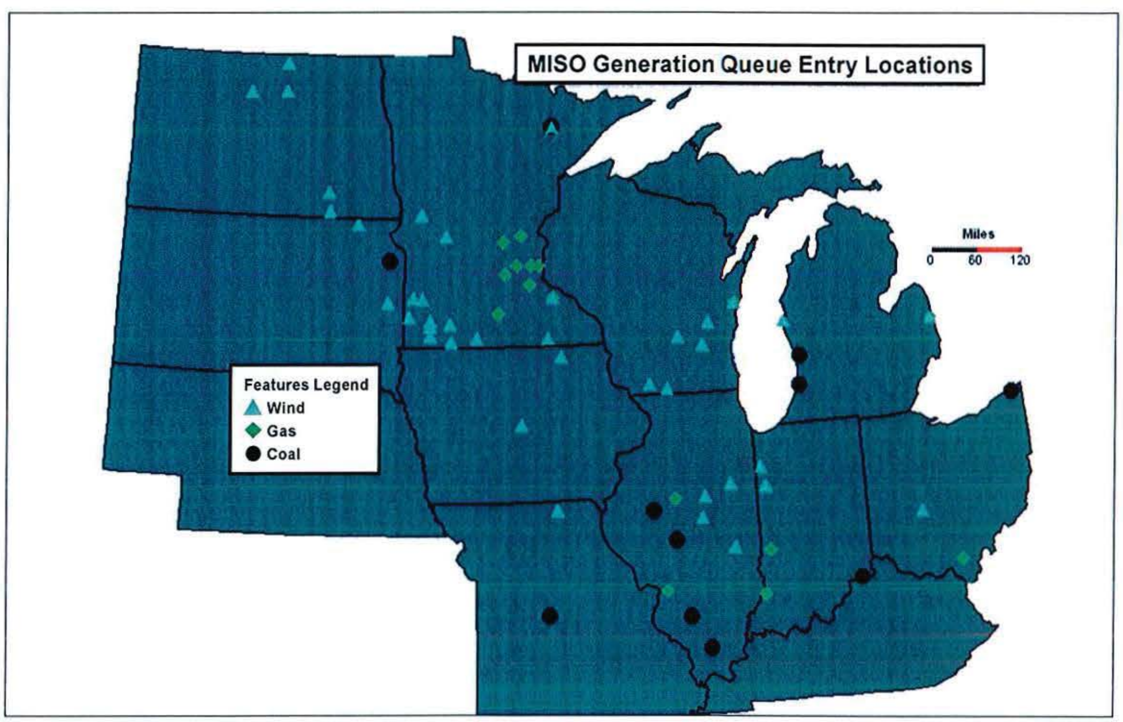


Figure 3.3-12

3.4 Midwest ISO Primary Energy Resource Opportunities

3.4.1 Coal

Midwest ISO has significant coal resources that are being mined in its footprint. North Dakota, Illinois, Indiana, Kentucky and Ohio have concentrations of coal-fired generation near mines. Other states are served by rail from the coalmines and from the Power River Basin mines in Wyoming. Figure 3.4-1 displays the location of sources of coal in the U. S.A. Michigan and Iowa coal beds are not major sources of commercially recoverable coal.

Coal Sources in the United States

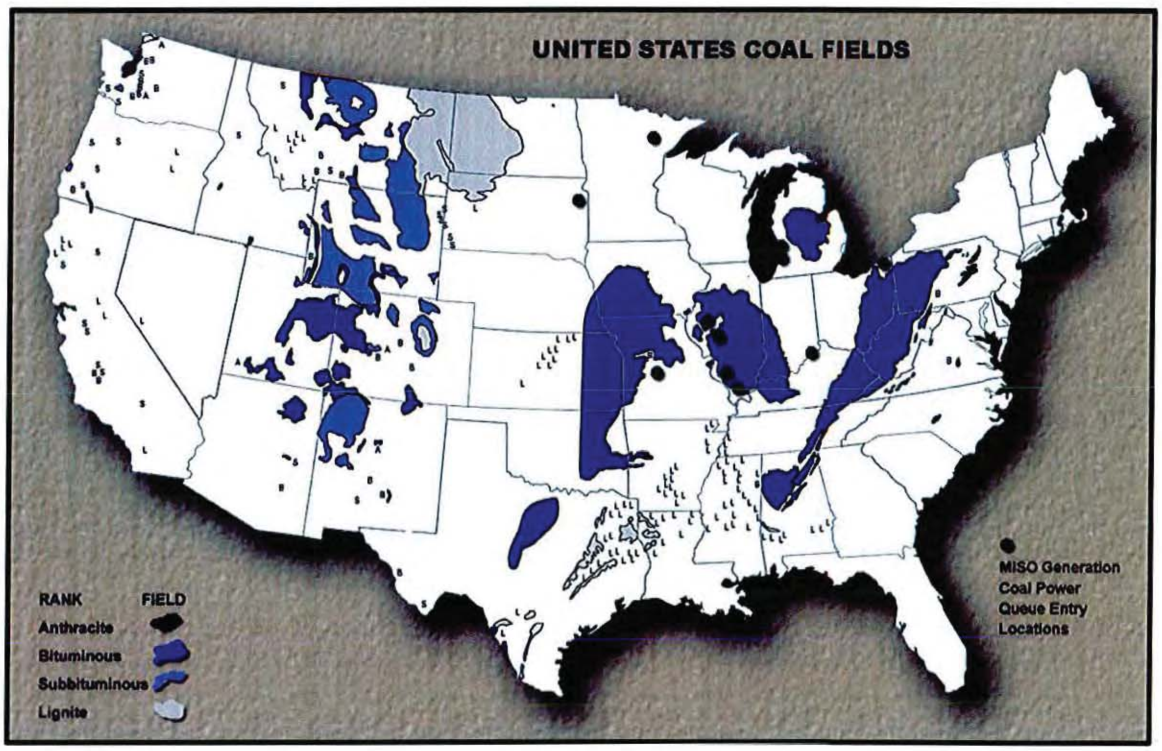
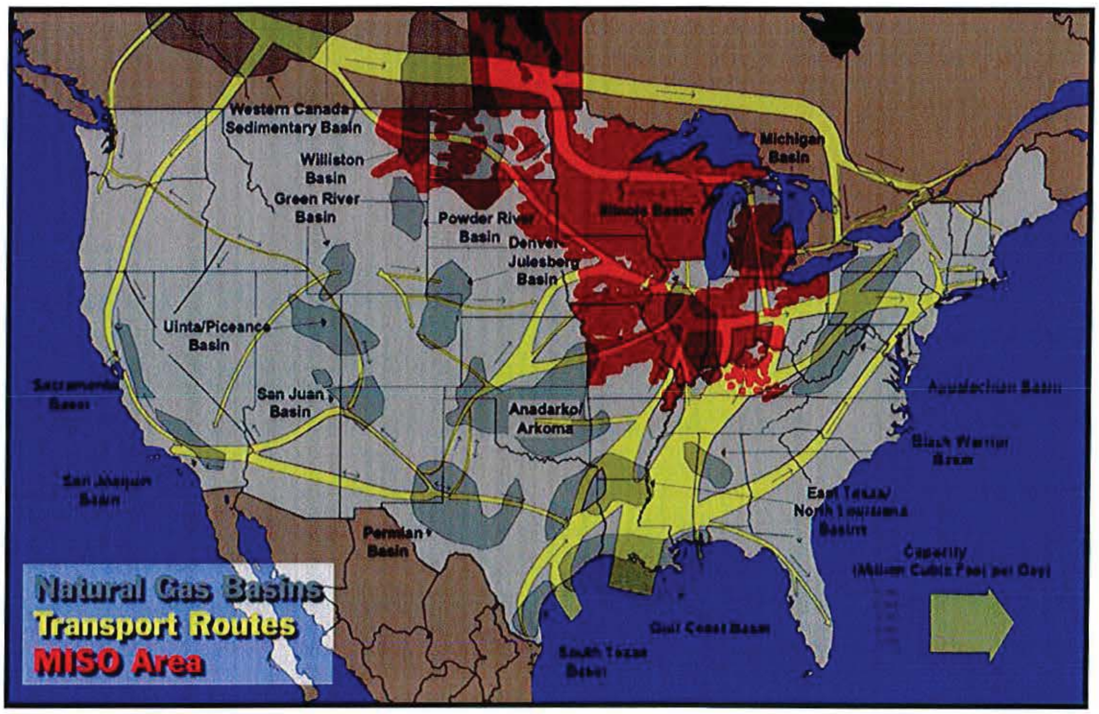


Figure 3.4-1

3.4.2 Gas

The Midwest ISO footprint also has an abundant gas supply available as indicated in the map in Figure 3.4-2. The paths of many of the major pipelines pass through the Midwest ISO footprint.



Natural Gas Basins and Transport Routes
Source (DOE/EIA 0618(98):
Energy Information Administration– Deliverability on the Interstate Natural Gas Pipeline System

Figure 3.4-2

3.4.3 Wind

Wind generation is increasingly a potential source of economic energy. The map in Figure 3.4-3 shows the locations of the major sources of wind energy in the U.S. Class 4 wind areas, with Good wind energy development potential, are shown as blue on the map. The Buffalo Ridge, in southwestern Minnesota, northwestern Iowa and the Dakotas has considerable wind energy development proceeding. A few wind farms have been developed in the Class 3 areas.

The time required to build higher voltage lines of 345-kv or higher is in the range of five to seven years. Wind generation can be developed in two years. Transmission congestion in the Buffalo Ridge area currently limits wind generation output; however, short-term solutions for lower voltage transmission lines are being designed to provide an increase in transmission capacity in the Buffalo Ridge area.

The 5,000 MW of wind generation is a significant amount, but it is small compared to the total potential outlined in Table 3.4-1.

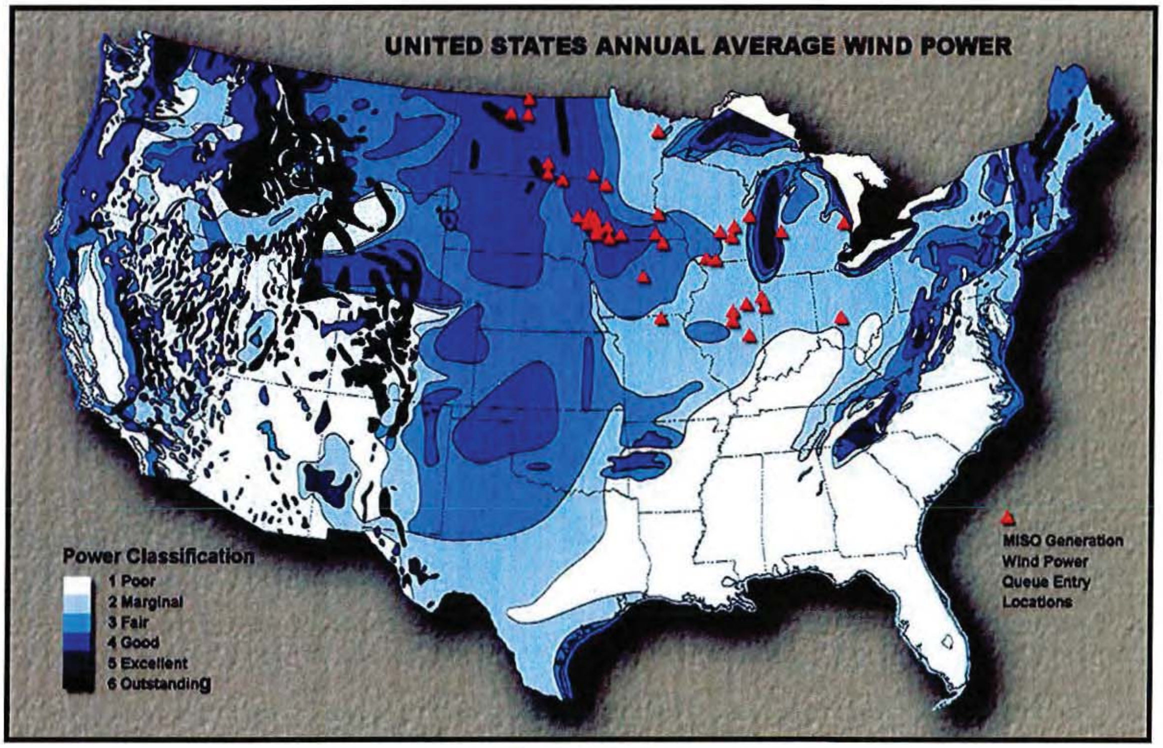


Figure 3.4-3

Table 3.4-1: Wind Power (MW)		
State	Existing [1]	Total Potential [2]
Illinois	50	6980
Iowa	471	62900
Minnesota	563	75000
Nebraska	14	99100
North Dakota	66	138400
South Dakota	44	117200
Wisconsin	53	6440
Total	1261	506020

Notes:

[1] Nameplate MW, American Wind Energy Association, January 2004.

[2] Average MW, circa 33% of nameplate capacity, sourced from "An Assessment of Windy Land Area and Wind Energy Potential", Pacific Northwest Laboratory, 1991.

Source: Wind on the Wires presentation on Net Environmental Impacts of Transmission Systems in the Midwest.

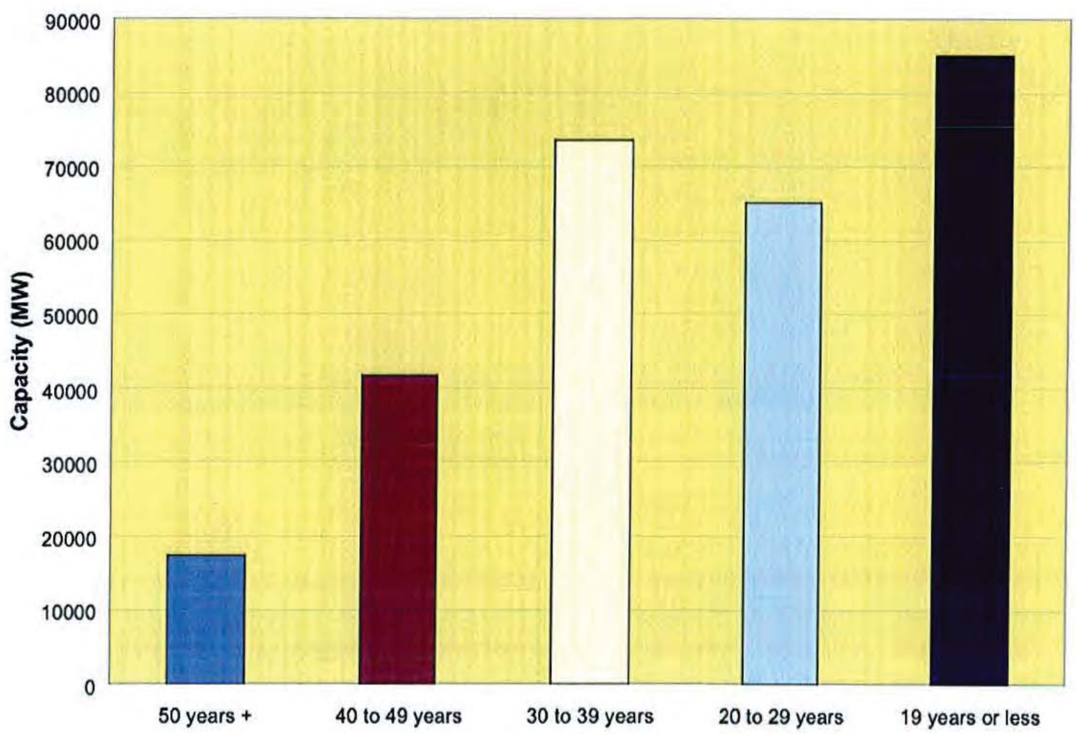
3.5 Regional Transmission to Access Generation Resources

Midwest ISO has engaged in forward transmission studies involving about 5,000 MW of wind generation in the Dakotas, Minnesota and Iowa. These studies are described further in Chapter 7. The Iowa–Southern Minnesota-Wisconsin Exploratory Study has up to 3,500 MW of wind generation included in a study to identify potential transmission that would be required in Southern Minnesota, Northern Iowa and Wisconsin areas. The Northwestern Exploratory Study coordinated with the Upper Great Plains Transmission Coalition determine scenarios for study. The Northwestern Exploratory study includes 500 MW of coal in North Dakota and 1,500 MW of wind generation at various sites in the North and South Dakota.

The Minnesota CAPX study is investigating the generation and the transmission alternatives that would be required to serve the loads in Minnesota for the 2020 study year. The CAPX study is incorporating the Iowa-Southern Minnesota-Wisconsin Exploratory Study and the Northwest Exploratory Study plus scenarios developed by the CAPX group. The CAPX study includes a 10% Renewable Energy Objective in the study scenario.

3.6 Retirement Possibilities of Older Generation

Figure 3.6-1 displays the age of generating plants in the United States. A substantial proportion of the total generation capacity is over forty years old. No indication of retirement of these facilities has been given, but one may expect some decisions as the market matures. In addition, the start of market operations within the Midwest ISO could impact retirement decisions. The amount of generation retirements and the location of new replacement generating resources will have a significant influence on how and where the transmission network may evolve in the longer term.



Source: Energy Information Administration, Existing Electric Generating Units in the United States, 2003.

Figure 3.6-1

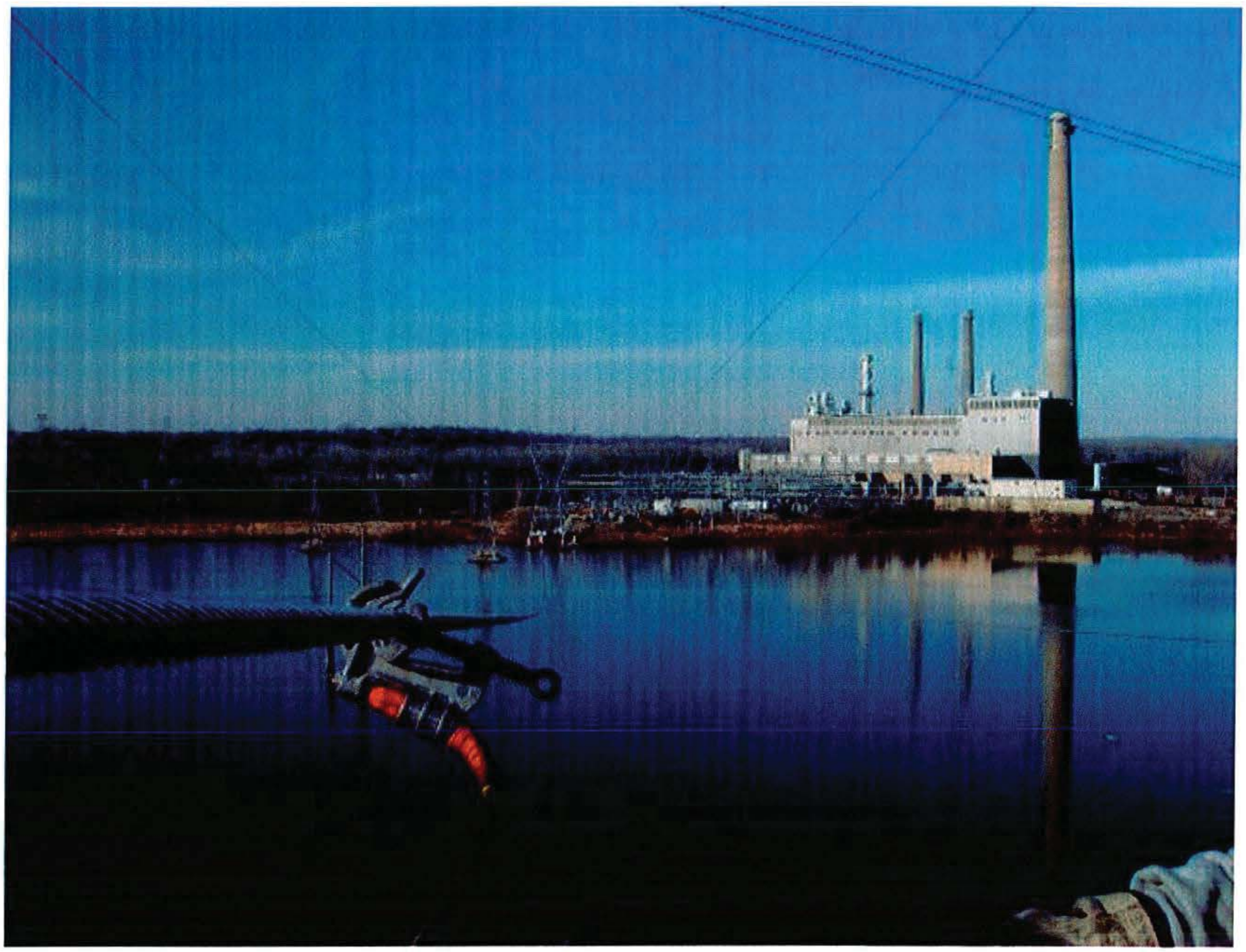
3.7 Transmission Technologies

3.7.1 Conductor Technology

Various transmission conductor technologies have made it possible to increase the thermal loading characteristics of transmission lines on existing right-of-way (ROW). Midwest ISO members have installed some of the higher rated conductors and WAPA has a composite conductor being tested in North Dakota. Such technologies improve the use of existing ROW. Midwest ISO continues to investigate the potential use of these conductors in the planning process.

Xcel Energy has installed a ceramic composite conductor on some 115-kv lines in the Minneapolis area that increases the lines capacity without increasing the size of the transmission structures. 3M is the manufacture of the conductor.

This chart shows the experience in England and Wales in application of new conductor technologies to increase the capacity of a transmission tower line more than twofold.



Ceramic Composite Conductor on 115 kV Line

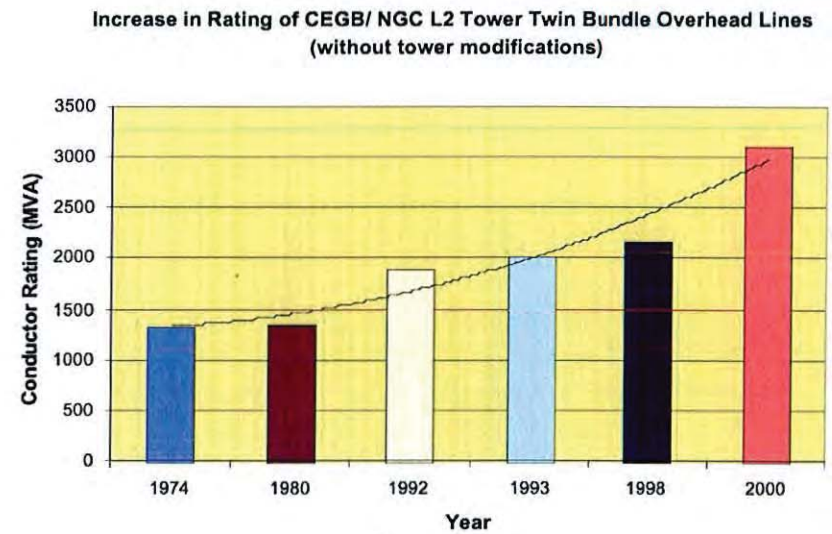


Figure 3.7-1

3.7.2 Long Distance Power Transfer

Midwest ISO held a seminar in St. Paul in 2004 for High Surge Impedance Loading Transmission Line technology. This technology enables the doubling the long distance power transfer capacity of a transmission line with a cost savings for construction of 30% per MW-mile of power transmitted while utilizing forty percent less ROW. The technology has been in use in Russia for about fifteen years. China and Brazil are installing 500-kv lines with the HSIL technology. The design experience and assistance for transmission line design is available to U.S. transmission owners.

Many of the transmission systems in the eastern part of Midwest ISO can be operated to thermal rating limits of the conductor. However, the long distance power transfer capability is very dependent upon the design of the line, or the surge impedance loading. HSIL addresses the impedance aspects of line design for long distance power transfer.

Transferring power from the coalfields, wind farms and to the southern and eastern markets are possible uses for HSIL technology.

3.7.3 FACTS Technology

Midwest ISO members have had HVDC , Static VAR Compensators, Statcoms, Series Capacitors and Phase Angle Regulators (PAR) operating in its transmission systems for some time. Midwest ISO members have experience with FACTS technology. Midwest ISO members consider FACTS technology solutions in their planning processes.

3.7.4 Load Technologies

Link and Sync™ technology is being investigated in the North Dakota area as a means of using a variable electric load to store heat in the floors of buildings for a delayed release as needed to heat a building. The goal is to modify the electric load of the transmission system such that the net energy available from wind generation more closely follows the load pattern required by the other load.

Telecommunications are used to cycle the electric heating elements according to a dispatching order similar to a generator dispatch order.

The load could also be used as a dynamic brake for generator stability considerations following a fault on the transmission system. The heat due to a braking event would be small even in the summer. Using dynamic braking may allow the transmission system to be loaded at higher levels pre-fault.

3.7.5 Eastern Interconnection Phasor Project

Midwest ISO is participating in a demonstration of concept for the Eastern Interconnection Phasor Project(EIPP). The EIPP is sponsored by the Department of Energy. The EIPP is a collection of highly accurate, GPS time synchronized power data monitoring units and computers that concentrate the data. A measurement from EIPP can be combined via digital communication links with other measurements in the Eastern Interconnection to determine the voltage magnitude and angle (phasor) across the geographical distance between the measurement points. Knowing the value of two voltage phasors at the end of a transmission line allows an accurate estimate of the power flow on the line. State Estimators provide the data about the power system that allows the operators to make decisions about the way the transmission system is operated. EIPP receives data inputs up to 60 times faster than the Midwest ISO State Estimator receives inputs. EIPP has the potential to provide nearly a real time state estimate that is much faster than the present State Estimator.

The rate that data is received will allow the Midwest ISO control center to determine if the power system is oscillating and take corrective actions to stop the oscillation. Power oscillations are detrimental to successful operation of a power system

Section 4: Status Update on Plans from MTEP 03

The Transmission Planning responsibilities of the Midwest ISO include monitoring the progress and implementation of necessary system expansions identified in the MTEP. The Midwest ISO Board approved the first Midwest ISO expansion plan MTEP 03 on June 19, 2003. Following is a review of the Midwest ISO expansion facilities listed in the MTEP 03 report Appendix A, and their status. Appendix A is comprised of two tables – Form 1 listing transmission line and transformer facilities, and Form 2 listing device facilities such as capacitors and reactors. A transmission system upgrade project may be comprised of multiple branch and device facilities. Approximately half of the facilities in Appendix A are part of a multiple facility project.

Because the development of data for the pending MTEP 05 began in 2004, original MTEP 03 facilities that had not gone into service before January 1, 2004 are included in the new MTEP 05 Appendix A unless they have been cancelled due to replacement with a preferred project, have been delayed beyond the reporting period of the MTEP 05, or are no longer needed due to changing system conditions. The MTEP 05 Appendix A also includes new expansion facilities that have emerged since MTEP 03 as the planning horizon has been extended through 2009.

Of the 407 facilities in MTEP 03, 229 of them had a Planned status. The chart below shows the present status of the Planned facilities from MTEP 03.

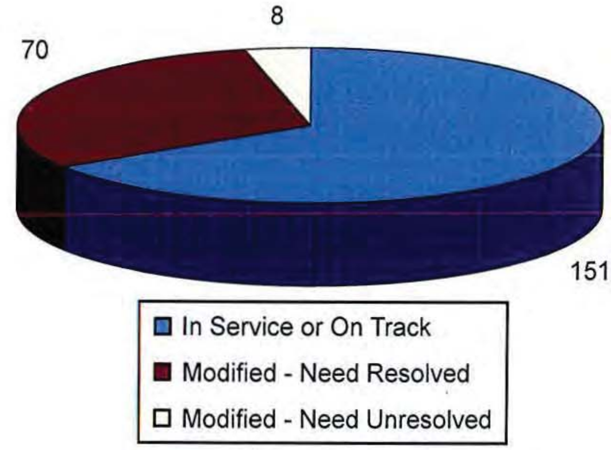


Figure 4-1:
Status of 229 MTEP 03 Planned Facilities

As a whole, nearly all of the 407 facilities included in MTEP 03 are on track or resolved. The chart below shows the present status of all Planned and Proposed facilities from MTEP 03.

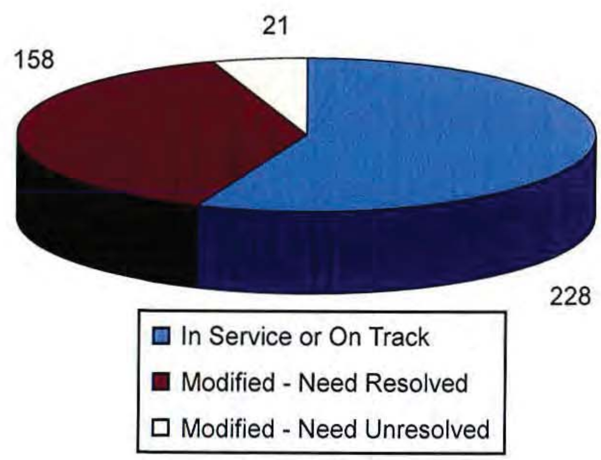


Figure 4-2:
Status of 407 MTEP 03 Facilities
All Planning Status

An initial comparison of planned or proposed facilities between the two plans showed that 179 or 44% of the original plans had been modified from the original plan. Midwest ISO staff inquiry into the reasons for these modifications indicated that for 158 of these facilities the modification is either appropriate due to changing conditions, or the modification is not significant. Appropriate modifications have occurred for a number of reasons such as:

- Load growth less than anticipated, and revised models show delay is appropriate
- Generation or transmission service plans of customers have changed
- Development of alternative solutions such as system operating guides or alternative facilities

Other modifications to the original projects occurred that are not significant to reliability for the following reasons:

- Project was delayed a short period, but is now in service
- Project was, or will be delayed a very short period (months) without significant increase in reliability risk
- Project had some delays but is expected in service by summer 2005

There were some delays in only component parts of a multifaceted project which do not impact overall project schedule

There remain at this time 21 facilities, about 5 %, from MTEP 03 for which the need apparently continues to exist and the facilities have been delayed beyond the desired service date for reasons predominantly of regulatory delays or construction delays. A number of these facilities are part of individual projects, so there are less than 21 projects with delays beyond the desired in-service date. The Midwest ISO has documented these facilities and will incorporate review of the critical conditions driving these facilities into seasonal operating reviews of the system to develop operational steps if required to secure the system until the facilities are installed. The 21 facilities are listed in the table on the following page.

New Facilities Added in MTEP 05

As noted previously, there were 407 itemized facilities in the 2002-2007 period of MTEP 03. MTEP 05 expands the planning horizon through 2009. There are a total of 518 new facilities now planned or proposed through the 2009 period that have been newly identified with the MTEP 05 effort (where not identified in MTEP 03).

Impact on Reliability of Changing Project Status

The Midwest ISO is committed to monitoring the implementation of facilities identified as necessary in the MTEP process. A part of this planning process involves the continuing assessment of project status. Changing conditions of the current and projected system will cause appropriate modifications to plans, and status changes as we have seen between MTEP 03 and MTEP 05 are expected.

The results of the Baseline Reliability analyses that have been performed for the first time in this MTEP 05 and that will be a part of subsequent MTEP, along with other supporting studies performed by the Transmission Owners are the indication as to whether the currently identified facilities in the Appendix A to MTEP 05 are sufficient to maintain system reliability. The results of these analyses are described in Section 6 to this MTEP report.

Table 4-1: Projects With Delays Beyond the Desired In Service Date

MTEP 03 Expected In Service Date	MTEP 05 Expected In Service Date	From	To	Ckt	Voltage (kV)	MTEP 03 Status	Updated Status	Delay in Months	Reason For Change
5/1/04	5/1/05	19th & Alvo	NW 12th & Arbor	1	115	Planned	Planned	12	One year delay in scheduled construction
6/1/04	6/1/05	Falls	Pioneer		138	Proposed	Planned	12	Project changed from simple reconductor to line rebuild to allow for higher capacity and future uncertainties.
6/1/04	6/1/05	Morgan	Falls		138	Proposed	Planned	12	Project changed from simple reconductor to line rebuild to allow for higher capacity and future uncertainties.
6/1/04	6/1/05	Pioneer	Stiles		138	Proposed	Planned	12	Project changed from simple reconductor to line rebuild to allow for higher capacity and future uncertainties.
6/1/04	Dropped	Daytons Bluff	Battle Creek	1	115	Proposed	Dropped	n.a.	no longer planned
6/1/04	Dropped	Red Rock	Battle Creek	2	115	Proposed	Dropped	n.a.	no longer planned
6/1/04	Dropped	Red Rock	transformer	1	345-115	Proposed	Dropped	n.a.	no longer planned
6/1/04	Dropped	Red Rock	transformer	2	345-115	Proposed	Dropped	n.a.	no longer planned
11/1/05	11/1/06	Herblet Lake	Sherridon	1	115	Proposed	Planned	12	Budget constraints have resulted in a deferral as new lower cost alternatives are being evaluated.
5/1/06	12/31/07	Chisago	Lindstrom	1	115	Planned	Planned	20	Addressing local opposition concerns and change in state regulations. Also, after further review the 2nd Lawrence Creek 161-115 transformer (Row ID 305) can be cancelled
5/1/06	12/31/07	Lawrence Creek	St Croix Falls	1	161	Planned	Planned	20	Addressing local opposition concerns and change in state regulations. Also, after further review the 2nd Lawrence Creek 161-115 transformer (Row ID 305) can be cancelled
5/1/06	12/31/07	Lawrence Creek	transformer	1	161-115	Planned	Planned	20	Addressing local opposition concerns and change in state regulations.
5/1/06	12/31/07	Lindstrom	Shafer	1	115	Planned	Planned	20	Addressing local opposition concerns and change in state regulations.
5/1/06	6/30/08	Kelly	Whitcomb		115	Proposed	Planned	26	Revised in-service date due to the need to re-apply for regulatory approval. Reapplication was primarily based on increased costs due to restrictions included in original application to the Public Service Commission of Wisconsin.
9/1/06	7/1/07	Fenton	Chanarambie	1	115	Planned	Planned	10	Part of wind outlet project. Total project has late 2007 in-service date. Shift due to construction scheduling.
5/1/04	Dropped	Elm Creek	Capacitor upgrade	80>120 MVAR	115	Proposed	Dropped	n.a.	Additional study needed
5/1/04	Dropped	St. Louis Park	Capacitor	60 MVAR	115	Proposed	Dropped	n.a.	Additional study needed
5/1/05	Cancelled	Wilson	Capacitor #2	120 MVAR	115	Planned	Cancelled	n.a.	Additional study needed
5/1/05	Dropped	Elm Creek	Capacitor #2	120 MVAR	115	Proposed	Dropped	n.a.	Additional study needed
5/1/06	Dropped	W River Road	Capacitor	80 MVAR	115	Proposed	Dropped	n.a.	Additional study needed
5/1/07	Cancelled	Wilson	Capacitor #3	120 MVAR	115	Planned	Cancelled	n.a.	Additional study needed

Section 5: Overview of the MTEP 05 Study

5.1 Scope and Objectives

MTEP 05 is the second issue of a Midwest ISO regional transmission expansion plan. The first, MTEP 03, was issued in June of 2003. MTEP 03 provided foundational information on the scope of expansion planning through the 2007 plan year that was underway at the time of startup of Midwest ISO operations and shortly thereafter. It also provided in-depth analyses of the potential for regional transmission expansions to provide for lower customer energy costs by reducing congestion and by enabling the entry and delivery of new low cost generation.

MTEP 05 extends the work of MTEP 03 by updating the expansion plan through the year 2009, tracking the progress of plans identified in MTEP 03, continuing the development work on several of the most promising "Exploratory" regional projects identified as potentially beneficial in MTEP 03, performing a comprehensive top-down reliability evaluation of the expected baseline performance of the Transmission System through the 2009 horizon, and identifying the expansion necessary to maintain system performance within standards.

The Baseline Reliability Study provides an independent assessment of the reliability of the currently planned Midwest ISO Transmission System for the year 2009. This is accomplished through a series of evaluations of the 2009 system with Planned and Proposed transmission system upgrades, as identified in the expansion planning process, to ensure that they are sufficient and necessary to meet NERC and regional planning standards for reliability. This assessment is accomplished through steady-state powerflow, dynamic stability, small-signal stability, load deliverability, and voltage-stability analysis of the transmission system performed by Midwest ISO staff and reviewed in an open Stakeholder process. The current assessment of the 2009 system focused on performance of the system for summer peak operating conditions.

The Baseline Study was performed in two phases. Phase 1 of the Baseline Reliability Study determined if the Planned projects in the current transmission expansion plan provide adequate system reliability. NERC category A, B, and C events were analyzed with steady-state and dynamic stability analysis. Planning criteria violations (thermal overloads and low or high voltage) were flagged using local limit criteria, as Midwest ISO member's systems have been designed to different standards. Load deliverability was determined for control areas in Midwest ISO by calculation of Loss of Load Probability (LOLP) value. Category C events were evaluated for cascading by using a tripping proxy to gauge the severity of the event and if cascading may occur.

Phase 2 of the Baseline Reliability Study added to the Phase 1 model projects that the Transmission Owners have proposed to meet reliability needs through the period. The critical analyses were repeated to determine if the Planned and Proposed projects in the current transmission expansion plan provide adequate system reliability. The projects in the current transmission plan, which are the result of the transmission studies, are listed in Appendix A.

When Phase 2 of the Baseline Reliability Study was nearing completion, the RSG's reviewed operational issues associated with transmission service requests (TSR) by examining historical transmission line loading relief (TLR) requests and future available flowgate capacity (AFC) values. Financial Transmission Rights (FTR) allocation binding constraints were also reviewed. Operational issues that will be addressed by the expansion plan were documented. A voltage stability screening of expected 2009 summer peak conditions was performed to determine areas that may have voltage stability issues and which are being further evaluated in continuing studies.

The Baseline Reliability Study determined how the system is expected to perform under peak load conditions with completion of present transmission plans. Any gaps in the transmission plans were identified and solutions proposed and tested. The end result is a Midwest ISO transmission expansion plan that is expected to meet reliability criteria once all identified solutions are implemented, unless changes to the plan are warranted. This expansion plan will undergo continuous review and will be formally reassessed in subsequent releases of MTEP. Near-term issues are also communicated to those within Midwest ISO performing seasonal assessments, establishing a feedback loop between Planning and Operating areas.

5.2 Baseline Reliability Study Inputs and Assumptions

The primary inputs and assumptions for the Baseline Reliability Study are:

1) The transmission system condition to be modeled and analyzed with associated load, generation and base interchange values

2) The contingencies and system events to be analyzed

3) The facilities monitored with respect to the Planning Criteria

4) The current transmission expansion plans from the planning process

5.2.1 Baseline Models

This Midwest ISO Transmission Expansion Plan study started in Fall of 2003. A 2004 year was selected for the near-term model that would be used to determine existing system deficiencies as a reference point. The 2009 model was selected to determine 5-year out transmission system performance with Planned transmission system improvements. The Midwest ISO Baseline study models for 2004 summer peak and 2009 summer peak were developed from NERC MMWG 2002 Series models. MAPP member data from the MAPP 2003 Series model was inserted and SPP member data from the most recent SPP Series model was inserted. Forecast network resources (generation) and loads were validated. The steady-state powerflow analysis examined the system performance for summer peak conditions with firm transfers modeled.

An assumption in the MTEP Baseline Reliability study was the inclusion of Planned transmission system upgrade projects in the Baseline models for Phase 1 of the analysis. Past planning studies have demonstrated the need for these projects; therefore, the inclusion of Planned projects would demonstrate how the current transmission plan performed in 2009. For Phase 2 of the analysis, the Proposed projects from Appendix A were also included in the model and any new proposals to address outstanding issues identified in Phase 1 which were identified prior to Phase 2 model development. The projects that comprise the current transmission plan are listed in Appendix A. As Appendix A is updated biennially, the projects which were Proposed when the models were developed, may now have a planning status of Planned. Therefore, Appendix A has two columns that indicate if a project was included in the Phase 1 or Phase 2 models.

MAIN Study Region Modeling Notes

At the start of the Study, many transmission owners requested model updates. In the MAIN region, the ATC and SIPC models were updated with complete inserts of their systems. AMEREN supplied updates to reflect changes in the information that was supplied in the MTEP Appendix A dated January 29, 2004. AMEREN also updated net load, and shunt data. CE, CILCO, IP, MEC, and CWLP also provided updates to the models.

MAPP Study Region Modeling Notes

Load levels for the entire MAPP area were modeled at 100% peak summer load for the 2004 and 2009 base cases. No additional generation or load adjustments were made in the MAPP region. The table below shows the exports levels in the system intact base case models MAPP.

Table 5.2-1: Base Case Area Export Levels

Case	MH-US	NDEX	MWSI	MNEX	SPC-BEPC (B10T)	MH-SPC	OH-MP (F3M)	MH-OH	OH E-W Ties	Quad City West	Cooper South
2009 Summer Peak	1346	634	170	212	150 S	205	0	0	50	820	98

The above table shows that the real power flows across monitored interfaces are from the north to south and west to east.In recognition of the complexity of the integrated system that must be studied, the models must be as realistic as possible. Particular attention was given to the following features in the dynamic models:

- The machine and control system models were suitable for the duration of the real time period being examined in each case.
- Where load representation is critical, suitable detailed load models were used.
- Where large amounts of wind power are located, appropriate detail of interconnecting substations and maximum system outputs were modeled.
- HVdc system behavior was modeled in appropriate detail.
- Reactive control devices such as Static VAr Systems and fast switched shunt capacitors were modeled using standard models where possible, but with custom models where required.
- Out-of-step relays on the MH / SP / IMO ties to the U.S. were modeled to determine not only whether these relays will operate, but also the steady state and dynamic relay margins.

5.2.2 Planning Criteria - Contingencies and Limits

In accordance with the Midwest ISO Transmission Owners Agreement, the Midwest ISO Transmission System is to be planned to meet local, regional and NERC planning standards. The Baseline Reliability Study performed by the Midwest ISO staff in this plan tested the performance of the system against the NERC Standards, leaving the compliance to local requirements to the Transmission Owners where those standards may exceed NERC standards. The specific branch loading and bus voltage thresholds of our member's criteria (local flagging criteria) were applied to accurately reflect the different system design standards of our members in this assessment.

Regional contingency files were developed by Midwest ISO Staff collaboratively with Transmission Owner with TO and regional study group inputs. NERC Category B and C contingency events at 100-kV and above were specified and analyzed. Over 10,000 NERC Category B (single line, transformer, or generator outage) contingency events and approximately 2,700 NERC Category C (double circuit tower, breaker fault / failure, bus fault and double element outage) contingency events were in the regional contingency files used for steady-state powerflow analysis. Where Midwest ISO and non-Midwest ISO systems were highly integrated, contingencies on non-Midwest ISO systems were also analyzed for impacts on the Midwest ISO member's systems. There is a huge number of possible NERC Category C events and it is not practical to analyze them all in any single study. NERC Planning Standards allow Category C analysis to focus on the most severe events. Midwest ISO requested that its members draw on their past studies and system knowledge to provide the severe Category C events. Those events were analyzed in this study. Midwest ISO expects that the selection of contingencies to be studied in any one MTEP will vary, so that over several MTEP studies, all areas of the system will be thoroughly tested. Midwest ISO also expects to add additional contingencies as we move forward based on our own operating and planning experience. In addition, Midwest ISO staff performed independent screening analyses of multiple element outage events to help identify areas potentially vulnerable to voltage instability. Approximately 140 NERC Category B and C events were specified and studied with dynamic stability simulations. The contingencies studied by each RSG are summarized below.

ECAR Region Contingencies

The ECAR RSG analyzed NERC category B events (single element) and the following types of NERC Category C events: double circuit tower outages (C5, ECAR Type 4), two independent single contingencies involving multiple terminal lines (C3, ECAR Type 5), automated double contingencies 200-kV and above (C3), and double contingencies which share a common bus at 138-kV level on METC system. Automated single contingencies (Category B) 100-kV and above were analyzed. ECAR region non-Midwest ISO member contingencies were included in automated contingency analysis. Dynamics simulations for 49 disturbances were performed.

MAIN Region Contingencies

The MAIN RSG analyzed NERC category B events (single element) and the following types of NERC Category C events: double circuit tower outages (C5) and selected breaker failures. The category B contingencies supplied by the RSG members were mostly those involving the outage of multi-terminal lines and multi-segment line outages. Automated single contingencies (Category B) 100-kV and above were analyzed. Non-Midwest ISO members, ComEd and MidAmerican, provided contingencies. Dynamics simulations of 15 disturbances were analyzed.

MAPP Region Contingencies

The MAPP RSG analyzed NERC category B events (single element) and the following types of NERC Category C events: double circuit tower outages (C5) and selected two independent single contingencies (C3), circuit breaker failures, bus faults for SGL and 3-phase with normal clearing or delayed clearing (stuck breakers), and bipolar block for DC lines. Automated single contingencies (Category B) 100-kV and above were analyzed. MAPP region non-Midwest ISO member contingencies were included in automated contingency analysis. Dynamics simulations of 63 disturbances were analyzed.

NERC Planning Standards allow for manual system adjustment and load shedding if necessary for Category C events. Because the contingency files typically contain the Category C forced outage event only, and not the allowable associated manual adjustments and / or load shedding, it may not be appropriate to say the Category C event is a criteria violation when flagged in this analysis. Therefore, in this report the results of Category C events that are outside the limit boundaries that were set are flagged as criteria exceptions, until the event can be analyzed according to NERC Planning Standards considering all input parameters. For example, a NERC Category C3 event is a single contingency, followed by operator adjustments, followed by another single contingency. The event is not modeled with operator actions in the contingency files and an overload is flagged in the analysis. However, with appropriate operator action after the first event, the overload would not occur after the second contingency occurs. That is why initial Category C event results were called criteria exceptions.

5.2.3 Monitored Elements

All system elements 100-kV and above within the Midwest ISO study regions as well as tie lines to neighboring systems were monitored. Some non-Midwest ISO member systems were monitored if they were within the Midwest ISO study region.

5.3 Baseline Reliability Study Process

5.3.1 Study Working Groups

To facilitate the Baseline Reliability Study, the Midwest ISO was divided into three Regional Study Groups (RSG). The regions selected used existing NERC regional reliability councils of Mid-Continent Area Power Pool (MAPP), Mid-America Interconnected Network (MAIN), and East Central Area Reliability Council (ECAR) to take advantage of existing working relationships and familiarity with regional criteria. A Midwest ISO Staff member was assigned to be the Lead for each RSG.

The RSG's were the primary work group which facilitated the technical studies. The RSG's documented the study criteria and defined study methodologies; reviewed and updated models; produced contingency and monitored element files; and were the first to review the results produced by Midwest ISO Staff. Note that transmission planning studies were conducted using an iterative process. If there was an issue with some of the results, the appropriate study input was corrected and analysis rerun.

The Expansion Planning Working Group (EPWG) facilitated the study process by providing input on the scope of work and methodology. If the RSG's had concerns they were brought to the EPWG for feedback and recommendations. The EPWG was also given periodic status reports on the study.

The flowchart below shows the iterative nature of transmission planning studies and how the RSG is a key part of the Baseline Reliability Study process.

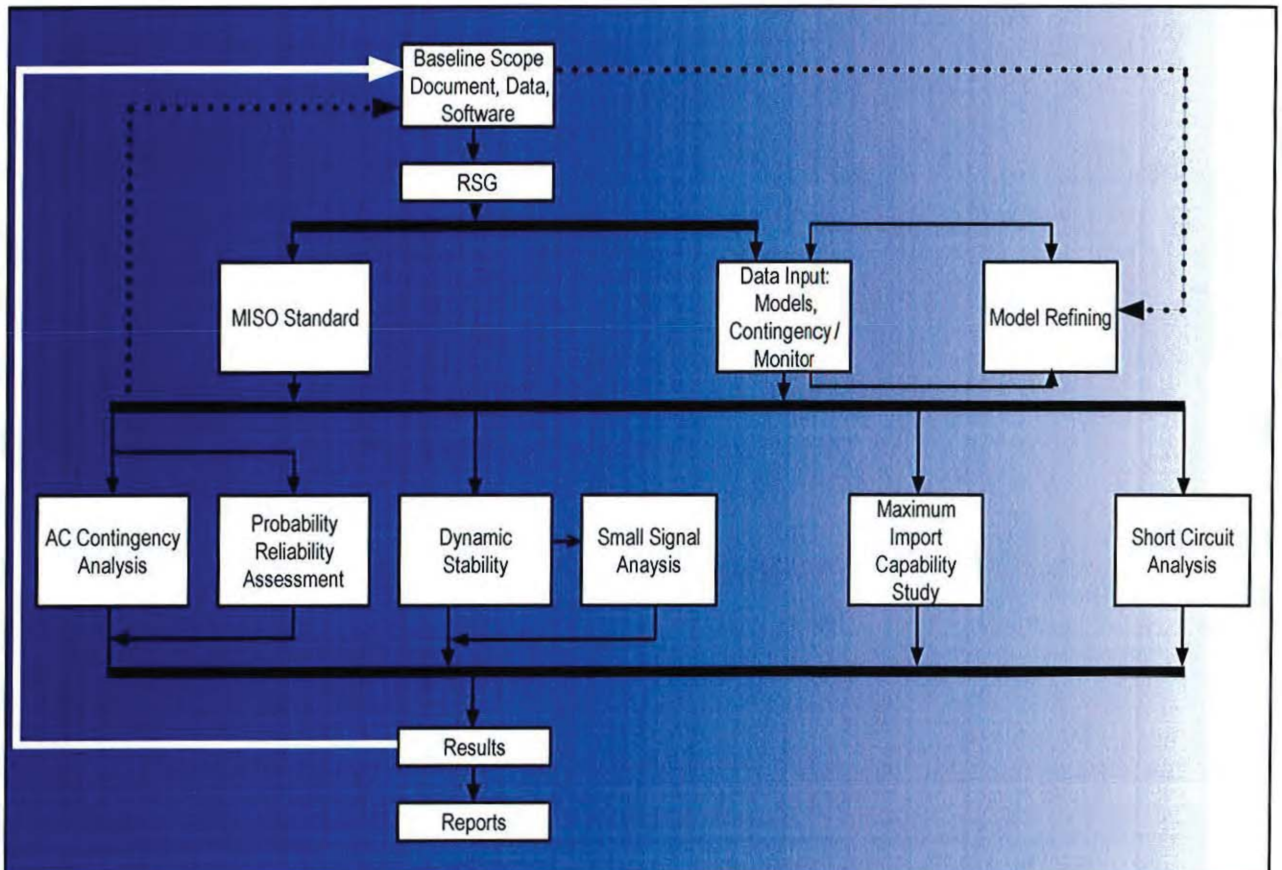


Figure 5.3-1: Baseline Reliability Study Process Flowchart

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5.3.2 Baseline Study Process and Methodology

This section describes how the various tasks in this study were accomplished.

5.3.2.1 Steady-State Powerflow Analysis

The Study evaluated the thermal loadings of lines and transformers and bus voltages for the system above the 100 kV voltage level in the Midwest ISO including tie lines under both pre-contingency and post-contingency system conditions. The Study was conducted on 2009 summer peak cases using ShawPTI's PSS / E and MUST digital simulation programs. Although the primary focus of the study was on the future 2009 system performance, the 2004 summer peak condition was analyzed in Phase 1 as a reference point. The steady-state power analysis included the following tasks:

Phase 1

- Evaluate and document system intact (Category A) branch thermal loading and bus voltage limitations according to the local Transmission Owner (TO) flagging criteria.
- Evaluate and document contingent (Categories B and C) branch thermal loading and bus voltage limitations according to the local Transmission Owner (TO) flagging criteria.

Phase 2

- Map all system issues identified in Phase 1 to the Planned and Proposed facilities in Appendix A.
- Develop proposals (system upgrades) as necessary for Phase 1 issues without an identified Planned or Proposed solution in Appendix A or operating procedure.
- After all required proposals are developed, prepare a comprehensive list of all planned and proposed facilities (previous Appendix A plus any new projects).
- Create a Phase 2 powerflow base case with all Planned and Proposed facilities.
- Run contingency analysis to verify that all Planned and Proposed transmission system upgrades satisfy planning criteria. The end result of Phase 2 should be without planning criteria violations.
- If issues persist or Reliability Plan results in new issues, develop additional proposed upgrades or operating procedures as necessary.
- Analyze NERC Category C event exceptions to determine if event is a violation after allowed operator action has been taken. A system upgrade may be proposed if desirable to address the Category C issue. Document how Category C events will be addressed.
- Document all system upgrades and operating procedures which are necessary for reliable system performance.

In the past, review of operating procedures used to mitigate Category C events was not done in long-term planning study, but was done in short-term operating studies. However, it is beneficial to consider whether Category C events may merit transmission system upgrades by examining the effectiveness of the operating guides in the long-term. The next section discusses the Category C event cascade screening which is another part of reviewing of Category C events in the planning process.

5.3.2.2 Category C Event Cascade Screening

NERC Planning Standards require that Category C events do not exceed applicable ratings or result in uncontrolled cascading outages. Therefore, this Study screened the Category C events which resulted in criteria exceptions to determine if the event may be a criteria violation and warrant additional analysis. NERC Planning Standards do not provide an objective definition for cascading. Therefore, the desired outcome of the screening was to identify the approximate amount of MW of load which would be shed and / or the number of additional lines which would trip because of the event, to indicate cascading potential. The following screening procedure / guidelines were used:

i. Run Category C contingencies with all planned and proposed facilities modeled. Determine if issues remain and if voltages are below under-voltage load shed (UVLS) relay set points.

ii. Individually run contingencies with appropriate UVLS substation loads removed (status 0) from case. If branch loadings exceed Post-contingent Branch Tripping Guidelines (see section vii below), remove them from service and rerun the case. Repeat as necessary. Document the branches tripped (in addition to the Category C event) and the amount of load that is shed because of these trips.

iii. If initial load shedding does not address the issue or if the event appears to be cascading, develop an operating procedure or system upgrade.

iv. Run contingency with proposed operating procedure (generation re-dispatch, system reconfiguration, planned load shedding). Local re-dispatch or system swing re-dispatch may be used as appropriate.

v. Determine if the post-operating voltages and branch loadings are within applicable ratings. Divergent case solutions may indicate cascading potential.

vi. If criteria violations persist, modify procedure and try again.

vii. Post-Contingent Branch Tripping Guidelines: These tripping guidelines were to be used as a proxy for determining cascading outages. As Midwest ISO's members' systems were developed using different design standards, a common tripping proxy was not recommended. TO's were asked to provide input to determine if a wider area tripping proxy for transmission lines and transformers could be developed. A consensus was not reached by the EPWG participants. Consequently, Midwest ISO used TO provided tripping proxy to analyze possible cascading for that TO. If the TO did not respond to the tripping proxy survey, a default tripping proxy was used.

- The default transmission line tripping proxy was 100 % of emergency rating.
- Large Power Transformers tripping proxy. The default large power transformer tripping proxy is 100 % of emergency rating.
- Overhead transmission lines respond in a predictable manner to a contingent increase in current, assuming the line is conductor limited and not equipment limited. Pre-contingent and post-contingent flows can be used to determine a response time to reach the TO specified applicable rating. If the response time to reach the TO specified applicable rating is less than the time required for manual operator intervention, it is assumed that the line will trip. The table below gives a sample of response times for DRAKE conductor to reach its emergency rating (assumed to be 110 percent normal) from a given pre-contingent initial flow to the specified post-contingent flow on a 104F degree summer day. An overhead response time may be used. The default is no overhead conductor response time is used.

Table 5.3-1: Overhead Conductor Response Times to Percent of Normal

Initial Flow Percent Normal	Post-Con. Percent Normal	Time Minutes
50	110	18
60	110	17
70	110	15
80	110	11
90	110	6
50	130	9
60	130	8
70	130	6
80	130	5
90	130	2

If an event appears to result in cascading outages or exceeds applicable ratings, then a special protection scheme (SPS) may need to be implemented or a system upgrade proposed. Because this was a fast screening of cascading potential, any event which appears to be cascading should be reviewed using line specific tripping values which require a thorough review of design parameters and rights-of-way.

5.3.2.3 Dynamic Stability Analysis

The Study evaluated numerous system disturbances using ShawPTI's PSS / E Dynamics program. The dynamic simulations were performed on the Phase 1 summer peak models which contained Planned system upgrades. The dynamic stability analysis included the following activities:

- Create or modify channel definition, monitoring specification and fault definition files as necessary.
- Convert stability powerflow model to MAPP NMORWG User Interface Package compatibility (MAPP study region only).
- Create dynamic snapshots; compile user models and dynamic files for 2004, and 2009 summer peak base cases.
- Perform a steady state simulation analysis for 20 seconds with no disturbance and analyze voltage and transient voltage limitations according to the local Transmission Owner (TO) criteria for pre-disturbance.
- Perform fault scenarios including disturbances that conform to the NERC Planning Standards Table 1A Category B, C and D (monitor only) fault definitions. Evaluate voltage instability and transient limitations according to the local Transmission Owner (TO) criteria for post-disturbance.

5.3.2.4 Load Deliverability

Midwest ISO performed a Load Deliverability study for the 2004 and 2009 years. This study analyzed whether Midwest ISO areas have sufficient import capabilities to meet the industry criteria of 1 day in 10 year (0.1 day per year Loss Of Load Probability). Both the import capability needed to meet the reliability criteria and the actual import levels in 2004 and 2009 for all LOLE zones in this study were identified. Please see Section 6.4.2 Load Deliverability for complete discussion of how this analysis was performed and the results.

5.3.2.5 Small-Signal Stability

Midwest ISO performed a Small Signal Study Analysis (SSSA) study for the whole Midwest ISO footprint which included non-Midwest ISO MAPP members. The small signal analysis included the following activities:

- Development of a small signal stability (SSAT) case, including the whole Midwest ISO footprint, for the small signal study.
- Investigation of the 0.25Hz inter-area oscillation mode of MAPP region and participation factors.
- Evaluation of the settings of the SVCs and PSSs of the generators that contribute to the 0.25 Hertz inter-area mode.
- Identification of potential problem modes of oscillation in system intact 2004 and 2009 conditions.

Please see Section 6.4.3 Small Signal Stability for study assumptions and results.

5.3.2.6 Voltage Stability Screen 2009

The purpose of the voltage stability *screening* was to identify portions of the transmission system which may have reactive power resource limitations after loss of multiple system facilities, so that additional analyses can be focused on areas which have needs and not on areas which have adequate reactive supplies. The screening was performed on the MTEP 2009 Summer Peak cases (Phase 1 with Planned facilities and Phase 2 with Planned and Proposed facilities). The output of the screening was a list of buses whose controlling generators have depleted their reactive power supplies. Only buses whose voltages are controlled by generators (V_{remote} buses) were monitored. Control area generator and switched shunt reactive reserves in the base case were documented. The Midwest ISO staff and the RSG's reviewed the raw output and recommended areas and contingencies which merit additional study. Continuing study tasks include determining the nature of the system response and, if necessary, obtaining a resolution to the reactive supply issue.

Detailed voltage stability analysis is computationally intensive. Therefore, a *screening* study was performed to identify portions of the transmission system which merit future study. The challenge for this voltage stability screening was determining a study technique which would be efficient and yet point us in the right direction. Midwest ISO determined that generators which are at their reactive output limits could be gleaned from monitoring the V buses of active generators with available reactive capability. If the V_{remote} bus was below $V_{scheduled}$, then the generator had reached its reactive limit.

Specific analytical technique is described in Appendix D6. Specific study recommendations are located in Appendix D6. The raw output is available in Appendix D6 Voltage Stability Screen 2009.

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5.3.2.7 Operational Issues

The Baseline Reliability Study also reviewed the operational issues associated with transmission service requests (TSR) by examining historical transmission line loading relief (TLR) requests, future available flowgate capacity (AFC) values, and financial transmission rights (FTR) allocation binding constraints. This review was done after the majority of baseline study analysis had been completed. The FTR allocation binding constraints information was not available until early in February, 2005. Therefore, the expansion plans were already developed to address related known reliability issues and were not developed in MTEP05 to address these constraints.

Historical flowgate TLR data for January 2001 through December 2004 was documented. Expansion plans in place to address known TLR issues were subsequently documented.

Forward looking available flowgate capacity (AFC) for December 2004 through October 2007 was reviewed. Flowgates with negative AFC during the period were listed and compared against a security constrained economic dispatch (SCED) model to determine if the limitations may still exist under a market based dispatch. Flowgates with negative AFC and which were constrained in SCED were documented and existing expansion plans which may address potential future AFC issues were noted.

FTR allocation binding constraints from allocation process which occurred in January, 2005, were reviewed and facilities in the expansion plan which may address the constraint were noted.

Section 6: Baseline Reliability Study Findings

6.1 Midwest ISO System - ECAR Region

6.1.1 System Description

The ECAR Regional Reliability Organization (RRO) includes several member systems that are also members of the Midwest ISO RTO. The ECAR RRO includes systems in Michigan, Indiana, Ohio, and Kentucky.

Midwest ISO member systems in ECAR are:

- First Energy (FE)
- Cinergy (CIN)
- Louisville Gas & Electric (LGEE)
- Northern Indiana Public Service Company (NIPSCO)
- Michigan Electric Transmission Company (METC)
- International Transmission Company (ITC)
- Hoosier Energy (HE)
- Indianapolis Power & Light (IPL)
- Vectren

Non-Midwest ISO systems include:

- American Electric Power (AEP)
- Dayton Power & Light (DPL)
- East Kentucky Power Cooperative (EKPC)
- Big Rivers Electric Cooperative (BREC)
- Ohio Valley Electric Corp. (OVEC)

In northern ECAR, two 138 kV transmission lines connect the METC transmission system in the Michigan lower peninsula to the transmission network in the Michigan upper peninsula operated by WUMS. ITC in southeastern Michigan interconnects with Hydro One (Ontario) by phase shifters. To the west, NIPSCO connects with the Commonwealth Edison and Ameren systems and Cinergy connects with the Ameren System. To the south, LGEE interconnects with the TVA system at 161 kV at several locations and at 500 kV at one location. FE, NIPSCO, METC, Cinergy and LGEE all connect with AEP system. AEP also has an extensive 765 kV system across the area.The Midwest ISO member systems in ECAR were modeled with the projected control area load and dispatched generation for 2009 summer as shown below.

The generation figures in table 6.1-1 are not indicative of available capacity to meet load, but rather the dispatch levels anticipated at peak load for generation in the control areas, as consistent with the interchange levels projected by the Transmission Owners in 2003 when the 2009 model for this study was developed. Note that positive area interchange means the system is exporting power; negative area interchange is importing power. Contingencies came from ECAR database, TO provided lists, global single unit outage, global single transmission element outage which has both terminal voltages greater than 100 kV, global double transmission element outage which has both terminal voltages greater than 200 kV. Contingencies of ECAR Type 1-5 were tested for this study. ECAR Type 1-3 contingencies are single contingencies. ECAR Type 4 contingencies are double circuit tower outages. ECAR Type 5 contingencies are combination of any two single circuit outage. ITC system was also tested for double circuit tower outage of 100 kV and above system. METC system was tested for double outages which share a common bus at 138 kV level. All facilities within Midwest ISO ECAR footprint rated 100 kV and above were monitored for voltage and thermal violations for the above contingencies. The criteria used for determining violations are in Table 6.1-2.

Table 6.1-1: ECAR 2009 Program

System	Modeled Load (MW)	Modeled Generation (MW)	Modeled Area Interchange (MW)
First Energy	14,877	13,872	-1,358
Cinergy	14,164	13,557	-1,075
Hoosier Energy	680	1,654	935
Vectren	2,009	2,004	-30
LGEE	8,356	8,019	-530
IP&L	3,391	3,471	0
NIPSCO	3,497	2,651	-892
METC	10,970	11,751	538
ITC	13,262	12,426	-1,174
Total	**71,205**	**69,405**	**-3,586**

Table 6.1-2: Thermal Violation Criteria

System	Thermal	Voltage	Voltage drop
No outages	100% normal	0.95-1.05 0.97-1.05 (METC) 0.94-1.05 (LGEE)	n/a
Single outages	100% emergency	0.90-1.05 0.92-1.05 (METC) 0.87-1.05 (ITC) 0.95-1.05 (IPL) 0.95-1.05 (Vectren)	0.05 (345-kV and above) 0.10(100-kV–345-kV)
Multiple contingencies	100% emergency	0.90-1.05	0.10

6.1.2 Summary of Baseline Study Results for ECAR Region Systems in Midwest ISO

Continuing the project designations initiated with MTEP 03, projects are classified as either "Planned" or "Proposed". Projects in Appendix A that are designated as Planned projects are recommended by the Midwest ISO to be completed by the service dates identified. Other projects listed in Appendix A as Proposed projects are tentative solutions to identified needs, and require additional planning before they are endorsed by the Transmission Owners or the Midwest ISO as the preferred solution. As described in Section 5 of this report, the Baseline study was performed in two phases. Phase 1 tested the system against reliability criteria with a set of "Planned" upgrades included in the model. It was anticipated that there might be certain conditions for which additional upgrades would be shown to be required. Phase 2 of testing included all expansions and enhancements "Planned" and "Proposed" by the Transmission Owners. Critical tests were then repeated for the system with this more complete set of upgrades.

The results of Phase 2 should show no violations of tested reliability criteria, or where violations remain additional solutions must be developed before 2009 if modeled conditions prevail.

First Energy

The following tables summarize system performance issues that remained after submitted Planned and Proposed projects were inserted into the study model. Possible mitigation steps are indicated, and will be monitored by Midwest ISO for resolution.

Table 6.1-3: First Energy Phase 1 Results

Area	Model Year	Limiter Element	Rating	Contingent Level (%, PU)	Con. Type	Contingency	Plan Status	Project to Address Limiter
FE	2009	Crissinger–Tangy 138 kV	182	107.40 %	B	Galion 345-138 #3 & #4	PR2	Crissinger–Tangy 138 kV circuit upgrade planned in 2006, BR_ID 1284
		Galion, Marion area 138 kV system		23 bus <0.9 pu				Galion substation reconfiguration. BR_ID 1283
FE	2009	Star 345-138 #1	151.3	102.30 %	B	Star 345-138 #2 & #3		Op procedure (switch back one transformer). Project to provide independent bus positions for each of the three transformers is scheduled for 2005 BR_ID 1282
FE	2009	Division–CPP CL 138 Division–CPP LS 138 Lakeshore–CPP LS 138	165 165 287	143 % 154 % 118 %	C	Fox–Harding 345 #1 & Fox–Harding 345 #2	n.a.	Op guide: trip CPP to Division ties.
FE	2009	Galion 345 kV , Galion, Cardington 138 kV		24 buses <0.90 pu, lowest of 0.867 pu	C	South Berwick–Galion 345 kV & Ohio CT–Galion 345 kV		

PL	–	Planned Projects	PR	–	Proposed Projects
PL2	–	New Planned Project in Phase 2	PR2	–	New Proposed Project in Phase 2 study
CP2	–	Conceptual Projects	N.A.	–	Not Avalable

Table 6.1-4: First Energy - Phase 2 Results

Area	Model Year	Limiter Element	Rating	Contingent Level (%, PU)	Con. Type	Contingency	Plan Status	Project to Address Limiter
FE	2009	Crissinger–Tangy 138	182	106.80%	B	Galion 345-138 #3 & #4	PR2	Crissinger–Tangy 138 kV circuit upgrade planned in 2006, BR_ID 1284 Galion substation reconfiguration to eliminate the contingency, BR_ID 1283
		Brookside–Beaver 138	135	98.50%				
		Crissinger/Tangy area		24 buses <0.9 pu				
FE	2009	Star 345-138 #1	300	102.40%	B	Star 345-138 #2 & #3	PR2	Operating step is to switch back one transformer. Project to provide independent bus positions for each of the three transformers is scheduled for 2005 BR_ID: 1282
FE	2009	Sammis–Highland 345 kV	997	106%	C	Mansfield–Highland 345 kV & Mansfield–Hoytdale 345 kV	PR2	A project to increase rating of this line is scheduled for completion by summer 2005.
FE	2009	Lakeshore–CPP LS 138	287	118%	C	Fox–Harding 345 #1 & Fox–Harding 345 #2		Operating guide, trip CPP to Division ties.
		Division–CPP CL 138	165	143%				
		Division–CPP LS 138	165	154%				
FE	2009	Crissinger–Tangy 138	182	108%	C	South Berwick–Galion 345 kV & Ohio CT–Galion 345 kV	PR2	A project to increase the rating of this line is scheduled for completion prior to summer 2006. BR_ID 1284
FE	2009	Star 345-138 #1	300	115%	C	Breaker failure: Star–Juniper 345 & Star 345-138 #2 & #3	PR2	Operating step is to switch back one transformer. Project to provide independent bus positions for each of the three transformers is scheduled for 2005. BR_ID 1282
FE	2009	Galion 345, Galion Cardington 138 kV		24 buses <0.90 pu, lowest at 0.867 pu	C	South Berwick–Galion 345 kV & Ohio CT–Galion 345 kV		

Table 6.1-5: First Energy - Phase 2 Outstanding Issues

Area	Model Year	Limiter Element	Rating	Contingent Level (%, PU)	Con. Type	Contingency	Plan Status	Project to Address Limiter
FE	2009	Galion 345, Galion Cardington 138 kV		24 buses < 0.90 pu, lowest of 0.867 pu	C	South Berwick–Galion 345 kV & Ohio CT–Galion 345 kV		

First Energy has two outstanding issues. One is simultaneous outages of two lines which may be potentially cascading. Additional information is provided in the ECAR Region study details appendix. Prior to summer 2005, FirstEnergy will be installing a system-wide UVLS scheme that will mitigate both the thermal and voltage impacts of this category C3 contingency. FirstEnergy is also investigating a project to get additional power source in the area, however this project is too preliminary to be defined as proposed. This area is to be monitored in 2005 Coordinated Summer Assessment.

The other outstanding issue is double 345 kV line outage South Berwick–Galion 345 kV & Ohio CT–Galion 345 kV which could cause low voltage at Galion area. The mitigation is under investigation.

Hoosier Energy

The following tables summarize system performance issues that remained after submitted Planned and Proposed projects were inserted into the study model. Possible mitigation steps are indicated, and will be monitored by Midwest ISO for resolution.

Table 6.1-6: Hoosier Energy - Phase I Results

Area	Model Year	Limiter Element	Rating	Contingent Level (%, PU)	Con. Type	Contingency	Plan Status	Project to Address Limiter
HE-CIN	2009	Georgetown, Mill town 138 kV		0.86 pu	B	Georgetown–Gallagher 138		Change Georgetown transformers tap ratio
HE		Owensburg–Worthington 138 kV	129	109 %		Worthington–Bloomington 345		Op procedure
HE-CIN		Georgetown–Gallagher 138 kV	133	104 %		Whitefield–Edwardsport 138	PR2	Reconductor project BR_ID: 1311

For the Worthington–Bloomington 345 kV outage, there is an operating procedure. When the CTs at Worthington are in operation the breaker on the Worthington 345/138 kV transformer is opened. This policy was adopted as protection against line overloads on the 138 kV system out of Worthington in the event that a fault occurs on the Hoosier Energy Worthington–Bloomington 345 kV line. In Phase 2 analysis, the Worthington 345/138 kV transformer is set off, hence Owensburg–Worthington 138 kV is no longer overloaded.

Table 6.1-7: Hoosier Energy - Phase 2 Results

Area	Model Year	Limiter Element	Rating	Contingent Level (%, PU)	Con. Type	Contingency	Plan Status	Project to Address Limiter
HE-CIN	2009	Georgetown–Gallagher 138	133	103.9 %	B	Whitfield–Edwardsport 138 kV	PR2	Reconductor project. BR_ID: 1311
		Georgetown / Mill Town 138 kV		0.8637		Goergetown–Gallagher 138 kV		Change Georgetown transformer tap ratio

After inclusion of proposed projects, there is no outstanding issue.

Cinergy

The following tables summarize system performance issues that remained after submitted Planned and Proposed projects were inserted into the study model. Possible mitigation steps are indicated, and will be monitored by Midwest ISO for resolution.

Table 6.1-8: Cinergy - Phase 1 Results

Area	Model Year	Limiter Element	Rating	Contingent Level (%, PU)	Con. Type	Contingency	Plan Status	Project to Address Limiter
CIN	2009	Five Points 230 kV		0.90 pu	B	Noblesville–Geist 230		Change LTC tap
CIN	2009	Geist 230 kV		0.87 pu	B	Noblesville–Geist 230		Change LTC tap
CIN	2009	Westwood 345-138 kV	382.4	103%	B	Dequine–Reynolds–Olive 345 kV / Reynold 345-138	PR	Westwood–Dequine 345 kV line and Westwood 345/138 TX 2 BR_ID: 357,367.
			382.4	100%	B	Cayuga–Veedersburg 230 kV		
CIN	2009	Georgetown–Gallagher 138 kV	133	104%	B	Whitefield–Edwardsport 138		
CIN	2009	Port Union–Hall 138 kV	206	104%	B	Hamilton–Port Union 138 kV	PL	Port Union– Hall 138 ckt 1, Sum rate 300 BR_ID: 594
CIN	2009	Staunton–Greencastle–Lone Star–Greencastle	95.6	103%	B	Staunton–Greencastle Jct. 2–Cloverdale		69 kV configure change
CIN	2009	Beckjord–Tobasco 138 kV	344	102%	B	Beckjord–Clermont–Summerside–Port Union 138 kV	PL	Addition of Beckjord–Silver Grove 138 kV line BR_ID: 365
CIN	2009	Ashland–Redbank 138 kV	300	99.5%	B	Red Bank–Terminal 345& Redbank 345/138		
CIN	2009	Crescent 138 bus tie	382	101%	B	Red Bank–Silver Grove-Zimmer 345	In Service	5% reactor at Buffington–Florence 138 kV line DV_ID: 80
		Crescent 138 bus tie	382	104%	B	Pierce–Foster 345 kV	In Service	5% reactor at Buffington–Florence 138 kV line DV_ID: 80
		Crescent–W. End 138	273	99.5%	B			
CIN	2009	Kokomo HP 230-138 kV	75	98%	B	Greentown–Jefferson 765 kV	PR	2nd Kokomo 230/138 kV transformer BR_ID: 356
CIN	2009	Todhunter 345/138 kV transformer and 138 kV lines	478	106%	C	Foster–Todhunter 345 & Todhunter 345/138 kV transformer	PL	Beckjord–Feldman 138 ckt 1, Sum rate 308 BR_ID: 363; Beckjord–Silver Grove 138 ckt 1, Sum rate 304 BR_ID: 365
CIN	2009	Terminal 345/138 kV transformer and Terminal 138 kV lines	478	111%	C	Red Rank–Terminal 345 kV & Red Bank–Silver Grove-Zimmer 345/Red Rank transformers and Silver Grove transformer	PL	Beckjord–Silver Grove 138 ckt 1, Sum rate 304 BR_ID: 365; Beckjord–Feldman 138 ckt 1, Sum rate 308 BR_ID: 363
CIN	2009	Kokomo 230/138 transformer and 138 kV circuits	75	144%	C	Double circuit outages involving Greentown–Jefferson 765 kV circuit	PR	Kokomo–230/138 ckt 1, Sum rate 200 BR_ID: 356"

Table 6.1-8 (cont.): Cinergy - Phase 1 Results								
Area	Model Year	Limiter Element	Rating	Contingent Level (%, PU)	Con. Type	Contingency	Plan Status	Project to Address Limiter
		Crawfordsville, CrawMU 138 kV		0.87	C	Dequine–Westwood 345 kV / Westwood 345-138 & Lafayette–New London 138 kV		
		Crawfordsville138 kV		0.9	C	Dequine–Westwood 345 kV / Westwood 345-138 & Reynolds 345 / 138 transformer		
CIN	2009	Westwood 345-138 kV	382.4	126%	C	Dequine–Olive & Dequine–Reynolds–Olive 345 kV & Reynold 345-138	PR	Westwood–Dequine 345 kV line and Westwood 345 / 138 TX 2 BR_ID: 357,367
		Westwood 345-138 kV	382.4	126%	C	Dequine–Olive & Dequine–Reynolds 345 kV		
		Dequine–Westwood 345 kV	409	118%	C	Dequine–Olive & Dequine–Reynolds–Olive 345 kV & Reynold 345-138		
		Dequine–Westwood 345 kV	409	117%	C	Dequine–Olive & Dequine–Reynolds 345 kV		
CIN	2009	Northwest Tap–W. Lafayette 138	143	107%	C	Dequine–Olive & Dequine–Reynolds 345 kV	PR	West Lafayette Purdue–Purdue NW Tap 138 ckt 1, Sum rate 179 BR_ID: 618
			143	105%	C	Dequine–Olive & Dequine–Reynolds–Olive 345 kV & Reynold 345-138		
CIN	2009	Cayuga–Veedersburg-Attica–Lafayette 230 kV	478	118%			PR2	2006 proposed project to uprate the line to 496 MVA. BR_ID: 1296
CIN	2009	Cloverdale–Stilesville–Plain 138 kV	240	118%	C	Eugene–Cayuga 345 kV & Cayuga–Nucor 345 kV	PR2	Cloverdale–Plainfield South 138 kV is planned to be rebuilt in 2006. Rate 307 MVA. BR_ID: 1300
CIN	2009	Cayuga–Frankfort 230 kV	637	118%				
CIN	2009	Dresser 345-138 #2	478	113%	C	Worthington–Bloomington 345 kV & Dresser 345-138 #1		
CIN	2009	Crescent 138 kV bus tie	382	107%	C	Foster–Pierce & Port Union–Zimmer		Buffington–Florence 138, 337 MVA Reactor (change Impedance from 5% to 3%) DV_ID: 81
CIN	2009	Crescent-W. End 138 kV	273	103%	C		PL	Buffington–Florence 138, 337 MVA Reactor (change Impedance from 5% to 3%) DV_ID: 81
CIN	2009	Crescent-W. End 138 kV	273	101%	C	E. Bend–Terminal & Miami Fort–Terminal		Buffington–Florence 138, 337 MVA Reactor (change Impedance from 5% to 3%) DV_ID: 81
CIN	2009	Miami Fort 345 / 138 transformer	486	102%	C	E. Bend–Terminal & Miami Fort–Terminal	PR	Miami Fort–345 / 138 ckt 2, Sum rate 450 BR_ID: 360
CIN	2009	Bloomington 230-138 kV	162.4	109.2%	C	Gibson–Bedford & Bedford–Lost River 345	n.a.	Operating guide and / or generation redispatch

Table 6.1-9: Cinergy - Phase 2 Results								
Area	Model Year	Limiter Element	Rating	Contingent Level (%, PU)	Con. Type	Contingency	Plan Status	Project to Address Limiter
HE-CIN	2009	Georgetown–Gallagher 138	133	103.90 %	B	Whitfield–Edwardsport 138 kV		Reconductor the line BR_ID: 1311
CIN	2009	Ashland–Red Bank 138	300	102.20 %	B	Red Bank–Terminal 345 / Red Bank 345-138		
CIN	2009	Geist 230 kV		0.8709	B	Geist–Noblesville 230 kV		Lock LTC and add 35 MVAR capacitors at Geist 69 kV
HE-CIN	2009	Georgetown / Mill Town 138 kV		0.8637	B	Goergetown–Gallagher 138 kV		change Georgetown transformer tap ratio
CIN	2009	W. Lafayette–Cumberland 138	143	113.80 %	C	Dequine–Olive 345 & Dequine–Eugene 345	PR2	Replace 600 A switches, rate to 179 MVA, proposed project of 2007 BR_ID: 1307
				103.10 %		Cayuga–Nucor 345 & Lafayette–Attica–Veedersburg–Cayuga 230		
				100.90 %		Nucor–Whitestown 345 & Lafayette–Attica–Veedersburg–Cayuga 230		
CIN	2009	Kokomo 230 / 138 transformer and 138 kV circuits	75	135 %	C	Dumont–Greentown 765 & Greentown–Jefferson 765		
		Carmel JT–Noblesville 230	319	112.20 %				
CIN	2009	Kokomo Highland Park–Kokomo Delco 138 kV	146	114.70 %	C	Clifty Creek–Pierce 345 #1 & #2	PR2	Proposed project of 2007; uprate line to 179 MVA. BR_ID: 1306
CIN	2009	Kokomo Highland Park–Kokomo Chrysler 138 kV	146	127.30 %	C	Clifty Creek–Pierce 345 #1 & #2	PR2	Proposed project of 2007; uprate to 179 MVA. R_ID: 1305
CIN	2009	Carmel Jct.–Noblesville 230 kV	319	112 %	C	Dumont–Greentown 765 kV & Greentown–Jefferson 765 kV		
				115 %	C	Noblesville 345-230 kV & Noblesville–Geist 230 kV		
CIN	2009	Noblesville–Geist 230 kV	319	116 %	C	Noblesville 345-230 kV & Noblesville–Carmel Jct. 230 kV		
				101 %	C	Whitestown–Guion 345 & Petersburg–Thompson 345 kV		
				103 %	C	Clark-Columbus N 230 kV & Franklin–Columbus 230 kV		
CIN	2009	Veedersburg–Attica 230 kV	478	110 %	C	Eugene–Cayuga Sub 345 kV & Cayuga–Nucor 345 kV		
				103 %	C	Eugene–Cayuga Sub 345 & Nucor–Whitestown 345 kV		
CIN	2009	Veedersburg–Cayuga 230 kV	478	98 %	C	DCT of Breed–Cassid 345 & Dequine–Eugene 345	PR2	2006 proposed project to uprate the line to 496 MVA. BR_ID: 1296
				119 %	C	Eugene–Cayuga Sub 345 & Cayuga–Nucor 345		
				112 %	C	Eugene–Cayuga Sub 345 & Nucor–Whitestown 345		
				101 %	C	Nucor–Cayuga 345 kV & Cayuga–Cayuga Sub 345 kV		

Table 6.1-9 (cont.): Cinergy - Phase 2 Results

Area	Model Year	Limiter Element	Rating	Contingent Level (%, PU)	Con. Type	Contingency	Plan Status	Project to Address Limiter
CIN	2009	Lafayette–Attica 230	478	102.70%	C	Eugene–Cayuga 345 kV & Cayuga–Nucor 345 kV	PL2	Cloverdale–Plainfield South 138 kV is planned to be rebuilt in 2006. Rate 307 MVA. BR_ID: 1300
		Cayuga–Frankfort 230	637	104.80%				
		Cloverdale–Stilesville 138	240	117.60%				
		Stilesville-Plain 138	240	103.70%				
CIN	2009	Cloverdale–Stilesville 138 kV	240	100%	C	Eugene–Cayuga 345 & Nucor–Whitestown 345 kV		
CIN	2009	Dresser–Terre Haute S 138 kV	246	113%	C	Merom–Worthington–Bloomington 345 kV & Cayuga-Cayuga CT 345 kV		
				107%	C	Merom–Worthington–Bloomington 345 kV & Cayuga CT-Sugar Creek 345 kV		
CIN	2009	Dresser–Allendale–Amaxch–Stauton 138 kV	304	111%	C	Merom-Worthington–Bloomington 345 kV & Cayuga–Cayuga CT 345 kV		
				105%	C	Merom-Worthington–Bloomington 345 kV & Cayuga CT–Sugar Creek 345 kV		
				113%	C	Merom–Worthington–Bloomington 345 kV & Wabash River-Stauton 230 kV		
CIN	2009	Allendale–Margaret Ave. 138 kV	240	103%	C	Merom–Worthington 345 kV & Cayuga–Cayuga CT 345 kV		
CIN	2009	Worthington–Owen 138	135	119.80%	C	Gibson–Bedford & Bedford–Lost River 345		
		Bloomington 230-138	162	107.90%				
		Bedford–HE Owen 138	135	116.40%				
		Bloomington NW-Bloomington 138 kV	143	123%				
CIN	2009	Dresser 345-138 #1	478	116.00%	C	Merom–Worthington–Bloomington 345 kV & Cayuga–Cayuga CT 345 kV		
				109.90%	C	Merom–Worthington–Bloomington 345 kV & Cayuga–Sugar Creek 345 kV		
CIN	2009	Dresser 345-138 #2	478	126%	C	Merom–Worthington–Bloomington 345 kV & Dresser 345-138 #1		
				116%	C	Merom–Worthington–Bloomington 345 kV & Cayuga–Cayuga CT 345 kV		
				110%	C	Merom–Worthington–Bloomington 345 kV & Cayuga CT–Sugar Creek 345 kV		

Table 6.1-9 (cont.): Cinergy - Phase 2 Results								
Area	Model Year	Limiter Element	Rating	Contingent Level (%, PU)	Con. Type	Contingency	Plan Status	Project to Address Limiter
CIN	2009	Wabash River-Stauton 230 kV	401	100%	C	Worthington–Bloomington 345 kV & Lost River–Petersburg 345 kV		
				100%	C	Worthington–Bloomington 345 kV & Noblesville–Geist 230		
				101%	C	Merom–Worthington 345 kV & Clinton–Wabash River 230 kV		
				102%	C	Merom–Worthington 345 kV & Kokomo–Thorntown 230 kV		
				105%	C	Merom–Worthington 345 kV & Bedford–Gibson 345 kV		
				107%	C	Merom–Worthington 345 kV & Nucor–Whitestown 345 kV		
				108%	C	Clinton–Wabash River 230 kV & Wabash River–Whitestown 230 kV		
				109%	C	Merom–Worthington–Bloomington 345 kV & Thorntown–Whitesville 230 kV		
				112%	C	Merom–Worthington-Bloomington 345 kV & Nucor–Cayuga 345 kV		
				115%	C	Merom–Worthington–Bloomington 345 kV & Wabash River–Whitesville 230 kV		
CIN	2009	Gibson–Petersburg 345	1200	100%	C	Bedford–Gibson 345 kV & Gibson–Duff 345 kV		
CIN	2009	Pierce 345-138 kV	302	102.80%	C	East Bend–Terminal 345 & Pierce–Foster 345		
CIN	2009	Bloomington West–Whitehall 138 kV	143	100.50%	C	Merom–Worthington 345 kV & Columbus–Bedford 345 kV		
CIN	2009	Ashland–Red Bank 138 kV	300	115.40%	C	Port Union–Zimmer 345 kV & Red Bank 345 kV bus tie		
				102.20%	C	Red Bank 345 kV bus tie & Red Bank–Terminal 345 kV		
CIN	2009	Augustine–Wilder 138 kV	314	101.10%	C	Clifty–Dearborn 345 kV & Red Bank–Silver Grove 345 kV		
				104.00%	C	Pierce–Foster 345 kV & Red Bank–Silver Grove 345 kV		
				101.50%	C	E Bend–Terminal 345 kV & Red Bank–Silver Grove 345 kV		
				101.40%	C	Foster–Hilcrest 345 kV & Red Bank–Silver Grove 345 kV		
				102.50%	C	Miami For–Terminal 345 kV & Red Bank–Silver Grove 345 kV		

Table 6.1-9 (cont.): Cinergy - Phase 2 Results								
Area	Model Year	Limiter Element	Rating	Contingent Level (%, PU)	Con. Type	Contingency	Plan Status	Project to Address Limiter
CIN	2009	Augustine–Wilder 138 kV	314	100.70 %	C	Port Union–Terminal 345 kV & Red Bank–Silver Grove 345 kV		
				104.50 %	C	Port Union–Zimmer 345 kV & Red Bank 345 kV bus tie		
				100.70 %	C	Red Bank–S. Grove 345 kV & Woodsdale–Madison 345 kV		
CIN	2009	Beckjord–Tabasco 138 kV	344	102.40 %	C	Red Bank–Terminal 345 kV & Red Bank–Silver Grove 345 kV		
CIN	2009	Buffington–Hands 138 kV	201	102.20 %	C	Port Union–Zimmer 345 & Red Bank-S. Grove–Zimmer 345 kV	PR2	Uprate the line to 309 MVA in 2007. BR_ID: 1303
			201	99.10 %	C	Red Bank–Terminal 345 & Red Bank–S. Grove–Zimmer 345 kV		
			201	105.50 %	C	Red Bank–Terminal 345 & S.Grove–Zimmer 345 kV		
CIN	2009	Red Bank 345-138	440	125.50 %	C	Port Union–Zimmer 345 kV & Red Bank 345 kV bus tie		
CIN	2009	Terminal 345-138 #1	478	110.60 %	C	Red Bank–Terminal 345 kV & Red Bank-S. Grove–Zimmer 345 kV		
CIN	2009	Terminal 138 kV bus tie	478	107.80 %	C	Red Bank–Terminal 345 & Red Bank-S. Grove-Zimmer 345		
				106.30 %	C	Red Bank-Terminal 345 & S. Grove–Zimmer 345		
CIN	2009	Terminal 345-138 #2	478	101.00 %	C	Red Bank–Terminal 345 & Red Bank-S. Grove-Zimmer 345		
				100.40 %	C	Red Bank–Terminal 345 & S. Grove-Zimmer 345		
CIN	2009	Todhunter 345-138 transformer and 138 kV bus tie	478	105.80 %	C	Foster–Todhunter 345 & Todhunter 345-138		
CIN	2009	Todhunter–Woodsdale 345 kV #2	1315	110.90 %	C	Miami Fort–Terminal 345 kV & Todhunter–Woodsdale 345 kV #1		
CIN	2009	Five Points 230 kV		0.8868	C	Eugene–Cayuga Sub 345 & Cayuga–Nucor 345 kV		Change LTC tap
CIN	2009	Five Points 230 kV		0.8899	C	Hanna–Francis–Petersburg 345 & Petersburg–Thompson 345		Change LTC tap

006502

With the Proposed projects or operating procedures implemented, most of the NERC Category B thermal violations were gone in the Indiana and Cincinnati area, except Ashland-Red Bank 138 kV facility. This facility is an underground cable so increasing capacity is a very expensive option. Cinergy is aware of this contingency overload and is currently evaluating solution alternatives with Midwest ISO.

For NERC Category C events, Phase 2 study not only included the events that were studied in Phase 1, but also included double contingencies that have terminal voltage 200 kV and above.

The outstanding issues in Cinergy include a NERC Category B violation and several NERC Category C violations.

Several NERC Category C events result in lines with contingeny loading over the cascading trip proxy. Tripping the overloaded line will result in no other loadings over the cascading trip proxy. These constraints will be reviewed in future studies by Midwest ISO and Cinergy. Additional information on these events is provided in the ECAR Region study details appendix.

Dresser 345-138 kV transformer - Project to replace limiting equipment (breakers and switches) to achieve full transformer rating will be included in next revision of Appendix A.

VECTREN

The following table summarizes system performance issues that remained after submitted Planned and Proposed projects were inserted into the study model. Possible mitigation steps are indicated, and will be monitored by Midwest ISO for resolution.

VECTREN - Phase 1 Results

There are no limiting facilities identified in Phase 1 study.

Table 6.1-10: VECTREN - Phase 2 Results

Area	Model Year	Limiter Element	Rating	Contingent Level (%, PU)	Con. Type	Contingency	Plan Status	Project to Address Limiter
Vectren	2009	Northwest-AB Brown 138	275	103.2%	B	Northeast-AB Brown 138		Loading reduced to 98% by bypassing AB Brown-Henderson reactor

There is no outstanding issue after including Planned/Proposed facilities and operating procedure.

LGEE

LGEE area includes Louisville metro area and Lexington area. Major new projects in LGEE area is the Trimble County #2 750 MW generator outlet which requires the construction of 43 miles of 345 kV line from the Mill Creek substation to the Hardin County substation, constructing three 138 kV lines Elizabethtown-Hardin, W. Frankfort-Tyron, and W. Lexington-Higby Mill.

The following tables summarize system performance issues that remained after submitted Planned and Proposed projects were inserted into the study model. Possible mitigation steps are indicated, and will be monitored by Midwest ISO for resolution.

Table 6.1-11: LGEE - Phase 1 Results

Area	Model Year	Limiter Element	Rating	Contingent Level (%, PU)	Con. Type	Contingency	Plan Status	Project to Address Limiter
LGEE	2009	Trimble County 345-138 kV	258	109 %	C	Middletown–Bluelick 345 kV / Bluelick 345-138 kV & Middletown–Mill Creek 345 kV		did not show in Phase 2

Table 6.1-12: LGEE - Phase 2 Results

Area	Model Year	Limiter Element	Rating	Contingent Level (%, PU)	Con. Type	Contingency	Plan Status	Project to Address Limiter
LGEE	2009	Middletown–3842 Tap 138	287	105.90 %	B	Blue Lick–Middletown 345 / Blue Lick 345-138		
				101.20 %	B	Ashbottom–Grade 138	PR2	upgrade the terminal device
				106.30 %	B	Blue Lick 345-138 kV		
LGEE	2009	Hardin 345-138 #1	344	104.50 %	B	Hardin 345-138 #2	PR2	upgrade the terminal device
LGEE	2009	Knob Creek / Pond Creek 138 kV		0.893 pu	B	Knob Creek–Mill Creek 138 kV	PR2	add capacitors
LGEE	2009	Middletown-3842 Tap 138	287	102.50 %	C	Blue Lick–Middletown 345 & Blue Lick–Mill Creek 345 kV	PR2	Upgrade the terminal device
LGEE	2009	Carrollton–Dow Corning 138	173	125.10 %	C	Ghent–W Lexington–Brown N 345 & Ghent-W Frankfort 345 / Frankfort 345-138		
		Dow Corning–Dayton Walther 138	195	123.70 %				
		Dayton Walther–Nas 138	204	121.40 %				
		Carrollton–Lockport 138	172	106.80 %				
		Ghent–Nas 138	277	98.30 %				
		Owen County Tap–Scott Co. 138	194	112.20 %				
LGEE	2009	Adams–Tyrone 138	139	101.50 %	C	Ghent-W Lexington–Brown N 345 & Ghent–Midway-W. Lexington 138		
		OC Tap–Scott 138	194	98.90 %				

LGEE - Outstanding Issues

LGEE proposed three projects in Phase 2 study, including: upgrading Middletown–3842 Tap 138 kV line terminal devices, upgrading Hardin transformer terminal devices and adding capacitors at Knob Creek/Pond Creek area. However these projects have not been submitted to MTEP Appendix A. Outage of multiple system elements may result in potential local area cascading and loss of load. Additional information is provided in the ECAR Region study details appendix.

For outage of Ghent–W. Lexington–Brown N 345 kV & Ghent–W. Frankfort 345/W. Frankfort 345-138, there is no cascading after level 1 tripping. Dispatch Brown CT could alleviate overloading.

IPL

IPL - Phase 1 Results

IPL system was not documented in Phase 1 due to the lack of IPL participant in Midwest ISO RSG. The system was studied in Phase 2.

Table 6.1-13: IPL - Phase 2 Results

Area	Model Year	Limiter Element	Rating	Contingent Level (%, PU)	Con. Type	Contingency	Plan Status	Project to Address Limiter
IPL	2009	South–Stouts 138	245	103.50 %	A	Base Case		IPL manages internal 138 kV loads through internal area 216 switching
				100.30 %	B	Hanna–Francis–Petersburg 345		
				111 %	B	Hanna–Stout 345 / Hanna 345-138		
				99 %	B	Hortonville–Whitestown 345		
				101.10 %	B	Hanna–Stout 345		
				109 %	B	Hanna 345-138		
				106 %	B	Airco–Southeast 138		
				107.60 %	B	Airco–Stouts 138		
				104.10 %	B	Prospect–Center 138		
				104.60 %	B	Stouts–Center 138		
				109.20 %	B	Hanna–Franklin Township 138		
				98.30 %	B	Gardner Lane–Sheffield 138		
				98.30 %	B	Guion–Tremont 138		
IPL	2009	Guion–Tremont 138	276	101.60 %	B	Gwynneville–Sunnyside 345 / Sunnyside 345-138		IPL manages internal 138 kV loads through internal area 216 switching
				98.90 %	B	Hanna–Stout South-Thompson 345 / Stout South 345-138		
				98.40 %	B	Hortonville–Noblesville 345		
				100.80 %	B	Hortonville–Whitestown 345		
				99.40 %	B	Stout–Thompson 345		
				101.70 %	B	Sunnyside 345-138		
				107.20 %	B	Castleton–River Road 138		
				102 %	B	Guion–Crestview 138		
				109.20 %	B	East–Parker 138		
				103.90 %	B	Geist–Sunnyside 138		
IPL	2009	Pritchard–Centerton 138 kV		100.80 %	A	Base Case		This facility is overloaded due to a fictitious generation at Centerton.
			245 / 286	116 %	C	Bloomington–Worthington 345 & Merom–Dresser 345		
IPL	2009	Petersburg–Thompson 345	956	106.20 %	C	Petersburg–Hanna 345 & Breed–Wheatland 345		MISO curtail system transactions to relieve overloads
IPL	2009	Petersburg 345-138 E	150	99.80 %	C	Hanna–Francis–Petersburg 345 & Petersburg–Thompson 345		MISO curtail system transactions to relieve overloads
IPL	2009	Guion-Tremont 138	245	105.50 %	C	DCT of Hanna–Fransis–Petersburg 345 & Hanna–Stouts 345		IPL manages internal 138 kV loads through internal area 216 switching
				99.80 %	C	Fall Creek-Sunny side 345 & Gwynville–Sunnyside 345-Hanna 345 / Sunnyside 345-138		

Table 6.1-13 (cont.): IPL - Phase 2 Results

Area	Model Year	Limiter Element	Rating	Contingent Level (%, PU)	Con. Type	Contingency	Plan Status	Project to Address Limiter
IPL	2009	Guion–Tremont 138	245	98.20%	C	Hanna–Francis Creek–Petersburg 345 & Hanna 345-138 #E & #W		IPL manages internal 138 kV loads through internal area 216 switching
				106%	C	Hanna–Francis–Petersburg 345 & Noblesville–Hortonville–Whitestown 345		
				110.80%	C	Hanna–Francis–Petersburg 345 & Hanna-Stout–Thompson 345, Hanna 345-138, Stout 345-138		
				109%	C	Hanna–Stout 345 & Noblesville–Hortonville–Whitestown 345		
IPL	2009	Hanna–SE 138	286	116.00%	C	Guion–Rock Ville–Thompson 345 & Hanna–Sunny Side 345		Solutions for this overload include breaker CT changes scheduled before 2010 depending on construction forecast and budgetary concerns.
IPL	2009	South–Stouts 138	276	121.00%	C	DCT of Hanna–Francis–Petersburg 345 & Hanna–Stouts 345		IPL manages internal 138 kV loads through internal area 216 switching
				98.20%	C	Petersburg–Hanna 345 & Breed–Wheatland 345		
				98.00%	C	Bedford–Gibson 345 & Bedford–Lost River 345		
				101.00%	C	Hanna–Francis Creek–Petersburg 345 & Hanna 345-138 #E & #W		
				107.30%	C	Hanna–Francis–Petersburg 345 & Noblesville–Hortonville–Whitestown 345		
				99.40%	C	Hanna–Francis–Petersburg 345 & RockVille–Thompson 345 / Hanna 345-138		
				102.50%	C	Hanna–Francis–Petersburg 345 & Hanna-Stout–Thompson 345, Hanna 345-138, Stout 345-138		
				123.90%	C	Hanna–Stout 345 & Noblesville–Hortonville–whitestown 345		

IPL - Outstanding Issues

South–Stouts 138 kV line and Guion–Tremont 138 kV lines are frequently overloaded for NERC Category B and Category C events. The overloading is due to the fact IPL area has 18% load increase from 2004 summer to 2009 summer.

Petersburg–Thompson is overloaded to 106% for NERC Category C contingency Petersburg–Hanna 345 kV & Breed–Wheatland 345 kV. Operating procedure should be adopted to relieve the overloading. Hanna–Southeast 138 kV is overloaded to 116% for NERC Category C contingency Guion–RockVille–Thompson 345 kV & Hanna–Sunny Side 345 kV. Solutions for this overload include breaker CT ratio changes and is scheduled before the 2010 year depending on construction forecast timing and budgetary concerns.

NIPSCO

The following table is a list of violations identified in Phase 1 of the 2009 summer study. Prior to the 2004 operating season NIPSCO reviewed circuits that were identified in the MTEP study to operate at a higher temperature. The new circuit ratings mitigate those thermal violations. The proposed project to re-conductor Leesburg to Northeast 138 kV still remains. Midwest ISO will be monitoring this circuit for resolution.

Table 6.1-14: NIPSCO - Phase 1 Results

Area	Model Year	Limiter Element	Rating	Contingent Level (%, PU)	Con. Type	Contingency	Plan Status	Project to Address Limiter
NIPS	2009	Schahfer Tap–Starke 138 kV	156	102%	B	Flint Lake-Tower Road 138-kV	PR2	Rating upgrade – reviewed circuit to operate at a higher temperature.
		Liberty Park–St. John 138 kV	156	105%	B	Hartsdale–St. John 138 kV	PR2	Rating upgrade – reviewed circuit to operate at a higher temperature.
			156	103%	B	Green Acres–St. John 138 kV		
		Northeast–Goshen Jct. 138 kV	253	114%	B	Hiple–Collinwood 345 kV & Hiple 345-138 kV XFR	PR2	Rating upgrade – reviewed circuit to operate at a higher temperature.
		Leesburg–Northeast 138 kV	222	100%	B	Hiple–Collinwood 345 kV & Hiple 345-138 kV XFR	PR2	Proposed project to re-conductor in 2007 summer.
		Northeast–Goshen Jct. 138 kV	253	112%	B	Hiple–Leesburg 345 kV & Hiple 345-138 kV XFR	PR2	Rating upgrade – reviewed circuit to operate at a higher temperature
		Leesburg–Northeast 138 kV	222	101%	B	Hiple–Leesburg 345 kV & Hiple 345-138 kV XFR	PR2	Proposed project to re-conductor in 2007
		Reynolds 345-138 kV	224	116%	C	Olive–Dequine–Westwood 345 kV & Westwood 345-138	PR	Westwood–Dequine 345 kV line and Westwood 345/138 TX 2

NIPSCO - Phase 2 Results

With the planned and proposed projects, there are no limiting facilities identified in NIPSCO system.

METC

As indicated in Appendix A, planned and proposed projects in the METC system from 2004 to 2009 include:

- Three new 345/138 kV transformers and associated switching
- Over 200 miles of new, rebuilt or reconductored 138 kV lines
- Over 900 Mvar of capacitor additions
- Numerous circuit up-rates resulting from improving sag clearance and terminal upgrades.

In the Midwest ISO Baseline 2009 summer peak model, the 46 kV and 69 kV systems connected to the METC system were not modeled. This is typical for models prepared for regional transmission system assessments used to identify regional limitations and constraints. However, the looped sub-transmission system provides significant support to the transmission system. Therefore, this Baseline model did not contain sufficient detail in portions of the METC area to provide accurate results when modeling facility outages at the 138 kV transmission level. The consequence of this modeling assumption is that some post-contingency conditions show more voltage violations when studies on the Midwest ISO Baseline case than those indicated in the more detailed METC planning model. Therefore, the METC detailed powerflow model was used by Midwest ISO in Phase I to determine the system support provided by the sub-transmission system for certain contingencies.

Only NERC Category B contingencies were studied in Phase I.

Table 6.1-15: METC - Phase 1 Results

Area	Model Year	Limiter Element	Rating	Contingent Level (%, PU)	Con. Type	Contingency	Plan Status	Project to Address Limiter
METC	2009	Amber 138		0.92 pu	B	Pere Marquette–Amber 138	PR2	Gallagher Cap (36 MVAR) DV_ID: 1078
		Bagley 138		0.866 pu		Gaylord–Livingston 138		
		Bard Road 138		0.91 pu		Gallagher–Bard Road 138 kV		
		Clare 138		0.72 pu		Bullock–Edenville-Warren 138		
		Begole 138		0.917 pu		Begole–Tittabawassee 138		
		Evart Products 138		0.91 pu		Cobb–Brickyard J.–Felch Road 138		
		Evart Products 138		0.9167 pu		Croton–Nineteen Mile–Mecosta 138 kV		
		McGulpin 138, Straints 138		0.916 pu		Livingston–Riggsville 138 or Riggsville–McGulpin 138		
		Iosco 138		0.89 pu		Karn–Iosco 138		
METC	2009	Battle Creek–Verona 138 #1	309.3	99 %	B	Battle Creek-Verona 138 #2	PR2	Battle Creek–Verona 138 kV #1 Line, Remove Sag Limit BR_ID: 1317
METC	2009	Battle Creek–Verona 138 #2	309.3	106 %	B	Battle Creek-Verona 138 #1	PR2	Battle Creek–Verona 138 kV #2 Line, Remove Sag Limit BR_ID: 1317
METC	2009	Piston Ring, Cedar Spring 138		0.88 pu	B	Four Mile–Piston Ring 138	PL	Four Mile–Algoma 138 ckt 1 BR_ID: 515
METC	2009	Brickyard–Felch Road 138	139.3	101 %	B	Four Mile–Piston Ring 138	PR2	Brickyard–Felch Rd 138 kV reconductor to 795 ACSS and CT Tap change BR_ID: 1336
METC	2009	Brickyard-Felch Road 138	139.3	101 %	B	Hull Street-Englishville-Piston Ring 138	PR2	Brickyard - Felch Rd 138 kV reconductor to 795 ACSS and CT Tap change BR_ID: 1336

Table 6.1-15 (cont.): METC - Phase 1 Results

Area	Model Year	Limiter Element	Rating	Contingent Level (%, PU)	Con. Type	Contingency	Plan Status	Project to Address Limiter
METC	2009	Campbell–Hudsonville 138	309.3	117 %	B	Plaster Creek–Kentwood 138	PR2	Campbell–Hudsonville 138 kV line, Remove Sag limit BR_ID: 1342"
METC	2009	Cobb–Sternberg 138	189.5	114 %	B	Campbell–Black River 138		
METC	2009	Savidge–Sternberg 138	189.5	112 %	B	Campbell–Black River 138		
METC	2009	Croton–Felch Road 138	86.1	120 %	B	Four Mile–Piston Ring 138	PL2	Croton–Felch Rd. 138 kV line reconductor BR_ID: 1318
METC	2009	Croton–Felch Road 138	86.1	125 %	B	Hull Street–Englishville–Piston Ring 138	PL2	Croton–Felch Rd. 138 kV line reconductor BR_ID: 1318
METC	2009	Croton B–Croton W 138	86.1	102 %	B	Four Mile–Piston Ring 138	PR2	Croton 138 kV breaker
METC	2009	Tippy–Hodenpyl 138 kV	219	114 %	B	Keystone–Ludington 345 kV line	PR	Tippy–Hodenpyl 138 ckt 1, reconductor 795 ACSS BR_ID: 535
METC	2009	Hudsonville–Jamestown 138	309.3	101 %	B	Plaster Creek–Kentwood 138	PR2	Hundersonville–Jamestown 138 kV line
METC	2009	James 138 Substation (City of Holland)		0.88 pu	B	Campbell–Black River 138	PR2	Black River Cap addition DV_ID: 46
METC	2009	Kenwood 138		0.9155 pu	B	Plaster Creek–Kenwood 138 kV	PR2	Add Distribution Capacitors Bank (at Bayberry or Kenwood or Buck Creek)
METC	2009	Lowell–Marquette 138	268.9	99 %	B	North Belding–Vergennes 138	PR2	Lowell–Marguette, Change open-leg ratings at Marquette
METC	2009	Michigan Ave 138		0.91 pu	B	Coldwater–Project 138	PR2	Batavia Capacitor Additions DV_ID: 1077
METC	2009	North Belding–Sanderson–Eureka 138 kV	209.9	110 %	B	Tittabawassee 345-138 #1 or #2	PR2	North Belding–Sanderson–Eureka reconductor to 795 ACSS and N Beld CT Tap to 1200 A BR_ID: 1331
METC	2009	North Belding–Vergennes 138	239	124 %	B	Vergennes–Lowell-Marquette 138	PR2	Vergennes–North Belding 138 kV terminal upgrade
METC	2009	Rifle River, Simmons, Ogemaw 138		0.90 pu	B	Gallagher 345-138 #2	PR2	Gallagher Cap (36 MVAR) DV_ID: 1078
METC	2009	Summerton 138, Bluegrass 138		0.91 pu	B	Bullock–Summerton 138	PR2	Alma Capacitor Additions DV_ID: 1076
METC	2009	Tallmadge–Wealthy Street #2	358.5	101 %	B	Tallmadge–Wealthy Street #1	PR2	Wealthy Street sub Replace CT's BR_ID: 1322
METC	2009	Thetford–Delaney 138	286.7	108 %	B	Hemphill–Thetford 138	PR2	Thetford–Delaney line, change CT Tap at Delaney and Remove Sag Limit BR_ID: 1352
METC	2009	Tittabawassee 345-138 #1	610	110 %	B	Tittabawassee 345-138 #2	PR2	Tittabawassee 5 Ohm Reactors (add) BR_ID: 1315
METC	2009	Tittabawassee 345-138 #2	601	106 %	B	Tittabawassee 345-138 #1	PR2	Tittabawassee 5 Ohm Reactors (add) BR_ID: 1315
METC	2009	Tittabawassee-Dow Corning 138	358.5	103.50 %	B	Bullock-Tittabawassee 138	PR2	Tittabawassee–Dow Corning–Change Open Leg Rating at Tittabawassee

In Phase 2 study, both NERC category B and NERC category C contingencies were analyzed, including double contingencies which have terminal bus voltage 345 kV and double contingencies that share same buses at 138 kV level.

Table 6.1-16: METC - Phase 2 Results

Area	Model Year	Limiter Element	Rating	Contingent Level (%, PU)	Con. Type	Contingency	Plan Status	Project to Address Limiter
METC	2009	Cobb-Sternberg 138	181	115.7%	B	Campbell-Northern Fibre -Black River 138		87.5% loading in the new model
		Savidge-Sternberg 138		114.9%				
		Plaster-Kent-Buck Creek	360	106.2%	B	Campbell-Hudsonville 138		93.3% loading in the new model
		Cole Creek-Dort 138	192	121.2%	B	Goss-Beveridge 138		
		James 138 kV substation		0.9272 pu	B	Campbell-Northern Fiber 138		0.9929 pu in the new model

The above table summarizes system performance issues that remained after submitted Planned and Proposed projects were inserted into this Midwest ISO study Baseline model.

METC also tested (and Midwest ISO verified) these single contingencies on the newly developed regional model with the Consumers Energy and Wolverine 46 kV and 69 kV systems equivalized in the case. Including these equivalized models in the case eliminated the remaining loading concerns.

The major load centers in the METC system are: Kalamazoo/Battle Creek area, Grand Rapids area, Midland/Bay City/Saginaw area and Flint area. Its Northern area is predominately rural with sparsely distributed loads.

The following study results for METC Double Contingencies reported here were based on the Midwest ISO 2009 Baseline model which did not include the 46/69 kV system equivalent. The severity of the reported problems should be reduced with equivalent looped sub-transmission system modeled as was shown in the single contingency test. Time did not permit rerunning all double contingency studies on the revised case with the improved model.

Table 6.1-17: METC- Double Contingencies Results

Area	Model Year	Limiter Element	Rating	Contingent Level (%, PU)	Con. Type	Contingency	Plan Status	Project to Address Limiter
Kalamazoo / Battle Creek Area								
METC	2009	Argenta 345/138 #3	549.8	137.90%	C	Argenta 345/138 #1 & #2	PL2	The Weeds Lake 345-138 kV Substation
METC	2009	Argenta 345/138 #2	602	126.70%	C	Argenta 345/138 #1 & #3	PL2	The Weeds Lake 345-138 kV Substation
METC	2009	Agenta 345/138 #1	602	126.50%	C	Argenta 345/138 #2 & #3	PL2	The Weeds Lake 345-138 kV Substation
METC	2009	Aubil Lake Jct–Gaines 138 kV	195	107.10%	C	Argenta–Morrow 138 & Argenta–Riverview 138	PL2	The Weeds Lake 345-138 kV Substation
METC	2009	Morrow–ParkVille Jct 138 kV	320.5	105.30%	C	DCT Argenta–Drake Rd 138 & Argenta–Lindbergh 138	PL2	The Weeds Lake 345-138 kV Substation
METC	2009	Upjohn 138 kV bus tie	256.5	120.60%	C	DCT Argenta–Drake Rd 138 & Argenta–Lindbergh 138	PL2	The Weeds Lake 345-138 kV Substation
METC	2009	Upjohn 138 kV bus tie	280.2	131.70%	C	DCT Argenta–Drake Rd 138 & Argenta–Lindbergh 138	PL2	The Weeds Lake 345-138 kV Substation
METC	2009	Battle Creek–Verona 138 kV #1	361.4	106.80%	C	Verona–Argenta 138 & Verona–Battle Creek 138 #2		The Weeds Lake 345-138 kV Substation
METC	2009	Milham 138 kV bus tie	115.2	100.30%	C	Up John–Milham 138 kV & Up John 138 kV bus tie		
Grand Rapids Area								
METC	2009	Alpine–Cannon 138 kV	209.9	124.50%	C	Vergennes–Lowell–Marquette 138 & Vergennes–North Belding 138		Load tripping
METC	2009	Alpine–Four Mile 138 kV	263	105.80%	C	Vergennes–Lowell–Marquette 138 & Vergennes–North Belding 138		Load tripping
METC	2009	Cannon–Cowan Lake 138 kV	209.9	104.40%	C	Vergennes–Lowell-Marquette 138 & Vergennes–North Belding 138		Load tripping
METC	2009	Campbell 345/138 kV transformer	629	130.50%	C	DCT of Campbell–Tallmadge 345 & Campbell–Roosevelt 345 (operating procedure)		
METC	2009	Four Mile 138 kV bus tie	329.9	112.30%	C	Tallmadge–Wealth St. #1 & #2		
METC	2009	Four Mile–Tallmadge 138 kV	468.4	104.20%	C	Tallmadge–Wealth St. #1 & #2		
METC	2009	Gaines–Meadowbrook 138 kV	521	100.70%	C	Campbell–Hudsonville 138 & Campbell–Port Sheldon 138		
METC	2009	Gaines–Meadowbrook 138 kV	521	106.50%	C	Vergennes 345/138 kV #1 & #2		
METC	2009	Lowell–Marquette 138 kV	312.1	104.80%	C	North Belding–Vergennes 138 & North Belding–Cowan Lake 138		
METC	2009	Mullins–Wealthy St. 138 kV	289.7	100.70%	C	Four Mile–Tallmadge 138 & Four Mile–White Road 138	PR2	Mullins–Wealthy 138 kV rebuild in 2007 BR_ID: 1330
METC	2009	Tallmadge–Wealthy St. 138 kV #1	518.7	102.40%	C	Tallmadge–Wealthy St. #2 & Tallmadge–Four Mile 138		
METC	2009	Tallmadge–Wealthy St. 138 kV #2	518.7	101.90%	C	Tallmadge–Wealthy St. #1 & Tallmadge–Four Mile 138	PR2	BR_ID: 1322

Table 6.1-17 (cont.): METC- Double Contingencies Results

Area	Model Year	Limiter Element	Rating	Contingent Level (%, PU)	Con. Type	Contingency	Plan Status	Project to Address Limiter
Grand Rapids Area (cont.)								
METC	2009	Croton–Nineteen Mile 138 kV	111	121.90 %	C	DCT of Keystone–Ludington-Pere Marquette 345 & Pere Marquette 345-138 #2		
		Alba–Stover 138 kV	180.5	103.40 %	C	Keystone 345 / 138 #1 & #2	PR2	Stover–Livingston 138 kV reconductored
		Alba–Livingston 138 kV		133.10 %				
		Clearwater–Keystone 138 kV	180.5	101.90 %	C	Livingston 345 / 138 #1 & #2	PR2	Clearwater–Keystone 138 kV rebuild in 2009 BR_ID: 1347
		Livingston–OTSE 138 kV	130	103.10 %	C	Livingston 345 / 138 #1 & #2		
		Emmet county		Oden 138 kV (0.8696)	C	Livingston–Emmet 138 & Livingston peak off		Under-voltage relaying at Oden would be expected to trip the Oden load if the voltage got this low.
		Iosco, E. Tawas, Cottage Grove		Cottage Grove 138 kV (0.9014)	C	Karn–Cottage Grove 138 kV with another source		
Midland / Bay City / Saginaw area								
METC	2009	Bullock–Dow Corning 138 kV	329.9	101.40 %	C	Breaker failure: Tittabawassee–Bullock 138 & Tittabawassee–Begole		
		Claremont–Manning 138 kV	309.3	149.40 %	C	Tittabawassee 345 / 138 #1 &#2		
		Hackett–Saginaw River 138 kV	192.2	145.50 %				
		Hackett–Saginaw River 138 kV	192.2	101.40 %	C	Tittabawasee-Bullock 138 & Tittabawassee-Dow Corning 138		
Flint Area								
METC	2009	Garfield Ave.–Hemphill 138	216.8	145.20 %	C	DCT of Thetford–Delaney 138 & Thetford–Hemphill 138	PL2	Garfield–Hemphill 138 rebuild in 2008 BR_ID:_336
		Duffield–Goss 138 kV	260.1	102.20 %	C	Dort bus tie & Dort–Thetford 138		
		Cole Creek–Dort 138 kV	192.1	128.30 %	C	Goss–Duffield–Stacey-Beveridge 138 kV		
		Cole Creek–Dort 138 kV	192.1	129 %	C	Goss–Beveridge 138 & Goss–Cornell 138		
		Cole Creek–Dort 138 kV	192.1	128.40 %	C	Goss–Beveridge 138 & Goss 345 / 138 kV		
		Cole Creek–Dort 138 kV	192.1	128.40 %	C	Breaker failure: Goss–Beveridge 138 & Goss–Pasadena-Dort 138		
		Hemphill 138 kV bus tie	192.2	101.50 %	C	Hemphill–Thetford 138 & Hemphill–Neff Rd 138	PR2	BR_ID:_1320
		Goss 345 / 138 #1	595	109 %	C	Thetford 345 / 138 #3 & #4		

Kalamazoo/Battle Creek Area

The load of this area is mainly supported by Argenta 345 kV substation and Battle Creek 345 kV substation while power comes through 345 kV circuits from power plants at west: Palisades, Covert, and Benton Harbor IPP. Loss of Argenta substation is the most severe fault in this area. Loss of either two Argenta 345/138 kV transformers causes the remaining Argenta 345/138 transformer to be severely overloaded. Loss of double circuit tower Argenta-Drake Rd 138 kV & Argenta–Lindbergh 138 kV leaves the loads in Lindbergh/Bronco/Milham area fully dependant on the only 138 kV source from Morrow–Pavilion–Upjohn and overloads Morrow–Pavilion section and Upjohn 138 kV bus ties. The new Weeds Lake 345/138 kV Substation and transformer should take care of the overloads showed here.

The Verona area is supported mainly by power from two 138 kV lines from Battle Creek substation and one 138 kV line from Argenta substation. Loss of Battle Creek–Verona #2 line and Verona–Argenta line leaves Battle Creek-Verona #1 line overloaded to 107%.

Loss of Verona–Battle Creek 138 kV #1 circuit and Verona 138 kV bus tie left Elm St./Hughes Rd loads solely dependant on the only 138 kV source from Blackstone to Marshall to Hughes Rd. Blackstone–Marshall 138 kV circuit severely overloads to 169%. Tripping Blackstone–Marshall 138 kV line isolates Hughes Rd and Elm St. loads. No overloading was observed after the tripping.

Grand Rapids Area

The Grand Rapids metro area is surrounded by a ring of double circuit 345 kV lines. Major 345 switching stations and 345/138 kV substations in this area include Kenowa, Tallmadge, Roosevelt, Gaines and Vergennes.

Four Mile 138 kV bus tie and Four Mile–Tallmadge 138 kV were observed to be overloaded for Tallmadge–Wealthy St. #1 & #2. Tallmadge–Wealthy St. 138 kV could be overloaded by the outage of Tallmadge–Four Mile and the other Tallmadge–Wealthy St. 138 kV line.

Vergennes–Lowell–Marquette could be overloaded up to 111% due to outage of North Belding–Vergennes 138 kV and North Belding–Cowan Lake and be overloaded to 102% due to outage of North Belding–Vergennes 138 kV & Vergennes–Spaulding 138 kV.

Loss of Vergennes–Lowell–Marquette 138 kV line and the Vergennes–North Belding 138 kV line results in the load east from Vergennes substation being fed by Four Mile 138 kV substation. The line from Four Mile–Alpine J.–Cannon J. could be overloaded. Consumer Energy has proposed to build a new 138/46 kV substation (Five Mile), new Four Mile substation, and redistribute their load in year 2006-2007 time frame. This project along with other area plans will be evaluated as METC gets closer to year 2009 to determine the most economic way to relieve this overload.

DCT outage of Campbell–Roosevelt 345 kV and Campbell–Tallmadge 345 kV caused the Campbell 345/138 kV transformer to be overloaded to 130% of the LTE rating. An STE rating and operating procedure have been established to protect for this condition. For trip of the bus tie, no overload over 125% was observed.

Northern Area

Keystone is the major 345/138 kV station in the northwest METC area. Loss of two Keystone 345/138 kV transformer banks will lose all power transformation from large generation source connected to the 345 kV transmission grid. Should the first contingency occur operators will prepare for the next contingency. Dispatch local generation, turn on distribution capacitors and drop some local load may be needed. Additional capacitors at specific site locations will be planned and installed as METC gets closer to year 2009 to relieve the local low voltage condition.

Midland/Bay City/Saginaw area

Tittabawassee is the major 345/138 kV station in the METC northeast area. It is the major station to step down MCV's generation to the 138 kV system. Loss of two Tittabawassee 345/138 kV transformer banks are severe N-2 contingency. Should the first contingency occur, operators will prepare for the next contingency. Re-dispatch MCV generation and other local generation, turn on distribution and bulk capacitors, reduce exports and drop some local load may be needed. METC continues to identify and propose specific projects to address the issue.

Flint Area

Cole Crek–Dort 138 kV was found to be overloaded for several N-2 contingencies. With the underlying 46 kV system modeled, the overloading could be reduced. Note that all substations tapped from the outaged lines would be effectively load shed with automatic breaker action which would normally occur for METC 138 kV line outages.

The double circuit tower outage of the Thetford–Delaney and Thetford–Hemphill 138 kV circuits left Garfield Ave.–Hemphill 138 kV circuit severely overloaded. Tripping Garfield Ave.–Hemphill 138 kV circuit will overload Neff Road-Hemphill 138 kV. If this line is again tripped, Goss–Cornell–Tihart-Latson path will be overloaded. Tripping this path will isolate loads in the Oakland/Halsey area; thus the load shedding is limited only to this area.

ITC

The following tables summarizes system performance issues that remained after submitted Planned and Proposed projects were inserted into the study model. Possible mitigation steps are indicated, and will be monitored by Midwest ISO for resolution.

Table 6.1-18: ITC - Phase 1 Results

Area	Model Year	Limiter Element	Rating	Contingent Level (%, PU)	Con. Type	Contingency	Plan Status	Project to Address Limiter
ITC	2009	Placid, Proud, Prizm 120		0.82 pu	B	Placid 345/120	PL	PL: Placid 120 kV capacitor DV_ID: 88
ITC	2009	Proud–Tamarack	312	0.997	B	Pontiac–Placid–Wixom 345 kV	CP2	CP2: Placid–Walton 120 kV line 9.0 mile (new) (conceptual) BR_ID: 756
		Coventry–Tamarack	343	0.988	B	Pontiac–Placid–Wixom 345 kV		
		Proud end of Coventry–Proud-Wixom 120 kV	343	100 %	C	Pontiac–Wixom 345 kV, Pontiac–Placid–Wixom 345 kV & Placid 345-120 kV		
ITC	2009	Quaker 345-120 kV	700	104 %	B	Wixom 345-120 kV	PL2	Quaker project BR_ID: 757, 758, 759
		Wixom 345-120 kV	624	109 %	B	Quaker 345-120 kV		
		Hines 230-120 kV	405	102 %	A	Base Case		
ITC	2009	Hancock–Southfield 120 kV, Hancock–Quaker 120 kV, Hancock–Wixom 120 kV	222, 223, 445	118.90 %	C	Akron–Wixom & Quaker Tap to Quaker, Wixom and Wayne 345 kV		
ITC	2009	Hancock–Southfield 120 kV, Hancock–Quaker 120 kV, Hancock–Wixom 120 kV	222, 223, 445	114.00 %	C	Akron–Sunset& Quaker Tap to Quaker, Wixom and Wayne 345 kV		
ITC	2009	Evergreen–Northwest 120 kV	250	100.90 %	C	Wixom–Wayne & Quaker Tap to Quaker, Wixom and Wayne 345 kV		
ITC	2009	Stephens 345-120 kV #301	624	111 %	B	Stephens 345-120 kV #303	PL	Bismark–Golf 120 kV line. Project_ID: 518 Lenox Station. Project_ID: 509
		Stephens 345-120 kV #303	678	103 %	B	Stephens 345-120 kV #301		
		Grayling, Malta, Victor, Augusta 120 kV		0.79 pu	B	Victor–Foundry–Jacob 120		
		St. Clair–Jacob 120 kV	249	125 %	C	St. Clair–Macomb 120 kV & St. Clair–Boyne 120 kV		
		Stephens–Benson–Macomb 120 kV	312	149 %	C	St. Clair–Macomb 120 kV & St. Clair–Boyne 120 kV		
		St. Clair–Macomb 120 kV	229	116 %	C	Beck–Stephens & Stephens-Benson-Macomb 120 kV		
		Golf/Boyne 120 kV		0.87 pu	C	St. Clair–Macomb 120 kV & St. Clair–Boyne 120 kV		
		Golf, Macomb, Boyne, Houston 120 kV buses		0.81 pu	C	Beck–Stephens & Stephens-Benson-Macomb 120 kV		
ITC	2009	Macomb 120 area (Golf, Macomb, Boyne, Houston)		0.81 pu	B	Stephens–Macomb 120	PL	Macomb 120 kV capacitor DV_ID: 87
ITC	2009	Latson–Genoa 138 kV METC-ITC	129	101 %	B	Madrid–Majestic 345 kV & Madrid 345-120 kV	PL	ITC–METC Interface Upgrade: BR_ID: 701
ITC	2009	Lincoln–Northeast–Northwest 120 kV (Lincoln end)	222.4	104 %	C	Bloomfield–Wheeler 120 kV & Bloomfield–Troy 120 kV		
ITC	2009	Pontiac–Joslyn 120 kV	416	106 %	C	Pontiac–Bloomfield 230 kV & Pontiac–Sunbird 120 kV		
ITC	2009	Apache–Seneca 120 kV	216	101 %	C	Troy–Wheeler 120 kV & Bloomfield-Troy 120 kV		
				113 %	C	Bloomfield–Wheeler 120 kV & Bloomfield-Troy 120 kV		

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Table 6.1-18 (cont.): ITC - Phase 1 Results								
Area	Model Year	Limiter Element	Rating	Contingent Level (%, PU)	Con. Type	Contingency	Plan Status	Project to Address Limiter
ITC	2009	Beck–Stephens 120 kV	290	148 %	C	Erin–Stephens 120 kV #1 & #2	CP2	Stephens–Medina 120 kV new line 8.5 mile, Erie area in 2006 (conceptual)
		Beck–Medina 120 kV	244	154 %				
ITC	2009	Spokane–Seneca 120 kV	216	125 %	C	Troy–Wheeler 120 kV & Bloomfield–Troy 120 kV	PR2	Spokane–Seneca - the limit on this circuit was a portion of underground cable. It was recently determined that the rating on this cable should be higher than the 216 MVA rating being used.
				138 %	C	Bloomfield–Wheeler 120 kV & Bloomfield–Troy 120 kV		

ITC projects in Phase 2 include the following:

- Placid–Walton: proposed project to create a 120 kV circuit from Placid to Walton.
- Quaker project is currently planned – it involves a 345/230 kV transformer at Wixom converting some 120 kV lines to 230 kV and creating Wixom–Quaker 230 kV and a 230/120 kV transformer at Quaker.
- Lenox (formerly called New Haven) project is planned. It involves building a new station west of the existing Victor site and creating a 120 kV bus group that ties together several 120 kV lines in the area. A 345/120 kV transformer will also be added.
- Bismarck–Golf project is planned. It involves creating a three ended Bismarck–Boyne–Macomb120 kV line by building a new 120 kV line from Bismarck to Golf. The proposal studied in this analysis involved building a switching station at Golf to avoid creating a three-ended line. The creation of the three-ended line is an interim step until the switching station can be constructed.
- ITC upgrades near it's METC interface include upgrading the Genoa 138-120 kV transformer, adding a reactor in Hunters Creek–Hemphill 138 kV, and upgrading the Atlanta 138-120 kV transformer.
- Add 54 MVAR capacitors at Placid 120 kV and Macomb 120 kV buses.
- Erin area: proposal to add 8.5 mile 120 kV new line from Stephens–Medina.

Table 6.1-19: ITC - Phase 2 Results								
Area	Model Year	Limiter Element	Rating	Contingent Level (%, PU)	Con. Type	Contingency	Plan Status	Project to Address Limiter
ITC	2009	Madrid 345-120 #1	313	100.40 %	B	Cody-Nolan 120 kV	CP2	Majestic 345-120 kV transformer and Majestic-Madrid, Majestic-Lark and Majestic-Phoenix 120 kV circuits BR_ID: 1377, 1378
ITC	2009	Sterling 120 kV		0.89 pu	B	Jewell-Sterling 230 kV	CP2	Add capacitors
				0.896 pu	B	Jewell 345-230 #3		
ITC	2009	Apache-Seneca 120 kV	216	100.70 %	C	DCT Bloomfield-Troy 120 kV & Wheeler-Troy 120 kV		
				113.10 %	C	DCT Bloomfield-Wheeler 120 kV & Bloomfield-Troy 120 kV		
ITC	2009	Spokane-Seneca 120 kV	290	102.80 %	C	DCT Bloomfield-Wheeler 120 kV & Bloomfield-Troy 120 kV		
ITC	2009	Lincoln end of Lincoln-Northeast-Northwest 120 kV	222	104.70 %	C	DCT Bloomfield-Wheeler 120 kV & Bloomfiled-Troy 120 kV		
ITC	2009	Lincoln-Troy 120 kV	196	102.40 %	C	DCT Bloomfield-Wheeler 120 kV & Bloomfiled-Troy 120 kV		
ITC	2009	Bloomfield-Walton 120 kV	312	101.50 %	C	DCT Bloomfield-Pontiac 230 kV & Pontiac-Sunbird-Colorado-Tienken 120 kV		

Table 6.1-19 (cont.): ITC - Phase 2 Results								
Area	Model Year	Limiter Element	Rating	Contingent Level (%, PU)	Con. Type	Contingency	Plan Status	Project to Address Limiter
ITC	2009	Caniff–Northeast 120 kV	250	106.10 %	C	Double: Northeast–Stephens 230 kV & Jewel–Sterling 230 kV		
				115.90 %	C	Double: Northeast–Stephens 230 kV & Bismark 345-230 #3		
ITC	2009	Northeast–Red Run 120 kV	313	100.40 %	C	Double: Jewel 345-230 #1 & Bismark–Red Run 230 kV		
				102.70 %	C	Double: Bismark–Red Run 230 kV & Jewel–Sterling 230 kV		
ITC	2009	Monroe–Bayshore 345 kV	1536	100.40 %	C	Double: Monroe–Wayne 345 kV & Monroe–Brownstown 345 kV		
ITC	2009	Monroe 345-120 #4	323	100.20 %	C	Double: Lulu–Monroe 345 kV & Monroe–Coventry 345 kV		
				114.70 %	C	Double: Lulu–Monroe 345 kV & Monroe–Brownstown 345 kV		
ITC	2009	Warren 230-120 #1	636	100.10 %	C	Double: DigTp–Navarre–Waterman 230 kV & Wayne–Hines 230 kV		
ITC	2009	Wixom 345-120 #1	624	103.40 %	C	Double: Wayne–Wixom–Quaker 345 kV (with Quaker 345-120 kV transformer) & Wixom–Quaker 230 kV		
ITC	2009	Newburgh–Peru 120 kV	222	104.80 %	C	DCT Brownstown–Elm-Rotunda 230 kV & Elm–Taylor 130 kV		
				100.20 %	C	Double: Baxter–Warren 230 kV & Brownstown–Elm Tap 230 kV		
ITC	2009	Brownstown–Rotunda 230 kV	850	101 %	C	Double: Fermi–Brownstown 345 kV & Wayne–Brownstown 345 kV		
ITC	2009	Adams 120 kV		0.88 pu	C	DCT Jewell–Sterling 230 kV & Jewell–Spokane–Carbnet–St. Clair 120		
ITC	2009	Jewell / Sterling		0.87 pu	C	Double: Jewell 345-230 #3 & Bismark 345-230 #3		
ITC	2009	Sterling		0.87 pu	C	Double: Jewell 345-230 #3 & Bismark–Red Run 230 kV		
				0.8665 pu	C	Double: Jewell–Sterling 230 kV & Bismark 345-230 #3		
				0.8661pu	C	Double: Bismark–Red Run 230 kV & Jewell–Sterling 230 kV		
ITC	2009	Malta 120 kV		0.8988 pu	C	DCT Bismark–Red Run 230 kV & Northeast–Red Run 120 kV		
ITC	2009	Red Run 230 kV		0.8866 pu	C	DCT Bismark–Red Run 230 kV & Northeast–Red Run 120 kV		

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Midwest ISO 2004 Coordinated Summer Assessment identified ITC's Thumb areas as reactive reserve deficit areas. Macomb area does not have sufficient reactive reserve when subjected to loss of one line Stephens–Macomb 120 kV and one generator unit at St. Clair 120 kV bus. 54 MVAR capacitor is planned to be installed at Macomb 120 kV substation before 2009 summer. Meanwhile, Macomb area is planned to have another power source from Bismarck besides Stephens 345 kV substation and St. Clair generators. Bismarck–Golf project will create a three-ended Bismarck–Boyne–Macomb 120 kV line by building a new 120 kV line from Bismarck. Loss of Arrowhead–Tuscola 120 kV leads to voltage collapse at Bad Axe with Harbor Beach generation offline. Loss of Belle River–Greenwood–Pontiac 345 kV & Greenwood units forced outage leads to low voltage at Lee 120 kV bus with Harbor Beach generation offline. 30 MVAR dynamic VAR devices will be installed at Bad Axe 120 kV substation and Lee 120 kV substation. Placid 120 kV voltage drops down to 87% post contingency (Pontiac–Placid–Wayne 345 kV line). 54 MVAR capacitors will be installed at Placid 120 kV substation before 2005 summer. In addition to the capacitor, a 120 kV line from Pontiac–Walton is proposed to be built to increase the source to Pontiac.

DTE complained to the Michigan PUC in 2004 summer that there was insufficient AFC into DTE to allow them to import what they needed to meet their required reserve levels (15% firm reserve). METC and ITC have agreed to certain upgrades that will improve West-East transfers in Michigan. ITC upgrades near its METC interface include the following projects:

- Replace the Genoa transformer and upgrade the relays and current transformers to meet or exceed the limit of the transformer. The Madrid 345-120 kV transformer outage has a significant impact on the loading on the Genoa 138-120 kV transformer.
- Replace the Atlanta transformer and upgrade the relays and current transformer to meet or exceed the limit of the transformer. Also upgrade a relay, trainer, and current transformers in the Atlanta–Tuscola 120 kV circuit to meet or exceed the limit of the conductor. The Atlanta 130-120 kV limit can be reached for the outage of Belle River–Greenwood–Pontiac 345 kV (which includes outage of the Greenwood 345-120 kV and all Greenwood generation) for transfers from METC to ITC.
- Add a new bus and breaker along with the appropriate disconnects at the Hunters Creek substation to accommodate the reactor which will be placed in series with the Hemphill–Hunters Creek 120 kV circuit. The Hemphill–Hunters Creek 120 kV limits for the outage of Greenwood unit #1 could be significantly impacted by west-east flows.

The upgrades could improve transfer capability up to 1000 MW considering single contingencies. The project is planned to be completed before 2005 summer. Without the upgrades, Genoa 138/120 kV transformer was identified in baseline reliability Phase 1 study as limiting facility under single contingency. With the upgrades, it is no longer shown as a limiting facility.

As currently configured, the ITC system has approximately 1000 MW of generation at the Greenwood site that cannot operate unless the approximate 73-mile three-ended Belle River-Greenwood-Pontiac 345 kV circuit is in-service. A generation rejection scheme is in place that will reject the entire output from the Greenwood generating site for the contingent loss of the Belle River-Greenwood-Pontiac 345 kV circuit.

Subsequent to this analysis, ITC has identified three additional project concepts –

1) Bismarck-Troy 345 kV cable with a 345-120 kV transformer at Troy – this project mitigates overloads in the Northeast, Red Run, Troy, Bloomfield, Lincoln, Walton and Pontiac areas and reduces losses. ITC is in the process of studying other potential projects in this area that may be implemented in place of this cable.

2) Majestic 345-120 kV transformer and Majestic-Madrid, Majestic-Lark and Majestic–Phoenix 120 kV circuits – addresses thermal loading of the Madrid 345-120 kV and Coventry 345-120 kV and low voltages in the Genoa area and reduces losses.

3) Saratoga North–Additional 345 kV circuitry in Greenwood area and 345-120 kV transformer. Allows Greenwood generation to operate under all single transmission contingency/shutdown events. Supports voltage at Adams and throughout the "Thumb" area and reduces losses. Had these three conceptual projects been included, many of the limitations identified above would have been mitigated.

Outage of multiple system elements may result in potential local area cascading and loss of load. Additional information is provided in the ECAR Region study details appendix.

The thermal constraints due to NERC category C contingencies mainly are located at the Lincoln/Northeast area, Atlanta area, Madrid area, Wixom/Quaker area, Monroe/Elm area.

6.1.3 Operational Issues (AFC/TLR) TLR Issues

One NIPSCO flowgate and three LGEE flowgates are among Midwest ISO's top 25 called for TLR. They are:

- Dune Acres–Michigan City 138 1&2 (flo) Wilton Center–Dumont 765-kV
- Blue Lick–Bullitt County 161 kV/Clifty–Trimble 345 kV
- Blue Lick 345/161 kV transformer/Baker–Broadford 765 kV
- Paddy–Summershade 161 kV

Large west to east power transfers caused loading problem on the two Dune Acres to Michigan City 138 kV circuits. These two circuits as well as Wilton Center-Dumont 765 kV circuit are both west to east power transfer path. With the 765 kV outage, these two 138 kV circuits could overload. Because in the 2009 summer peak model, Wilton Center–Dumont 765 kV only carries about 200 MW power, the outage of the 765 kV circuit will not cause Dune Acres–Michigan City 138 1 & 2 overloading.

The Blue Lick–Bullit County 161 kV (LGEE/EKPC) and Paddy–Summershade 161 kV (LGEE/TVA) circuits are historically common north-south transfer limitations and highly correlated in response to similar conditions. Hence, they are treated with a common operating guide. These facilities are subject to high loadings during heavy North-South transfers and/or following the loss of AEP's Baker–Broadford 765 kV circuit.

The new Mill Creek–Hardin County 345 kV line, a part of Trimble County Outlet #2 project, provides an alternative north-south path. Hence in 2009 summer, the loading at Blue Lick–Bullitt County 161 kV, Blue Lick 345/161 kV transformer, Paddy–Summershade kV is expected to be reduced.MECS-IMO interface is also among the top 20 TLR calling list. The Michigan–Ontario interface was a significant limitation to transfers, particularly transfers involving Ontario. ITC is developing some conceptual plan, e.g., HVDC, to address this issue.

6.1.4 Analysis Details

The outstanding issues of the Baseline Reliability Study are summarized above. If you would like to see the technical details of the Phase 1 analysis and Phase 2 analysis for the Midwest ISO system in the ECAR study region, please see Appendix D1.

6.2 Midwest ISO - MAIN Region

6.2.1 System Description

The MAIN region of Midwest ISO includes investor-owned utilities, cooperative systems, municipal power agencies, independent power producers, power marketers, and municipal systems. This region provides electricity to 21 million people living in the 145,000 square miles the Region encompasses. This study region includes all of Illinois and portions of Missouri, Wisconsin, Iowa, Minnesota and Michigan. The 8 million customers in this region represent a cross section of Mid-America: commerce, industry, agriculture, education, research, recreation, and residences in cities, suburbs, small towns, and rural areas.

The MAIN region is served by a grid of transmission lines consisting of 90 miles of 765 kV, 5,879 miles of 345 kV, and 226 miles of 230 kV transmission lines. Another 374 miles of 345 kV transmission is planned to be in service over the next five years.

In 2009 there was 64,611 MW of generation modeled in the MAIN region; 38,920 MW is owned by Midwest ISO members. The generation figures in table 6.2-1 are not indicative of available capacity to meet MAIN load, but rather the dispatch levels anticipated at peak load for generation in the control areas, as consistent with the interchange levels projected by the Transmission Owners in 2003 when the 2009 model for this study was developed. The projected peak load for 2009 was 62,272 MW (Midwest ISO load only) representing a little more than 1.5% per year load growth across the MAIN study region from the present time. Table 6.2-1 shows the breakdown of load and generation across the MAIN area.

Note that Alliant West is not included in the MAIN area even though the company is officially part of the MAIN area. It is included with the MAPP area appraisal for purposes of clarity because operationally they align with the MAPP utilities more closely than with the MAIN utilities. It was their wish to have the study results of their area included with the MAPP appraisal.

Table 6.2-1: MAIN Load, Generation, and Interchange in the Summer 2009 Peak Model

System	Modeled Load (MW)	Modeled Generation (MW)	Modeled Area Interchange (MW)
Duke Energy: Lee County		322	320
ENRON/Lincoln Center	1	665	664
Columbia (Missouri) Water & Light	331	198	-135
Ameren	12,523	11,869	-876
AmerenIP	4,338	4,080	-354
AmerenCILCO	1,287	1,299	0
City Water, Light and Power	515	518	0
Southern Illinois Power Co-operative	285	403	111
Electric Energy, Inc	90	1,331	1,235
Northern Illinois (ComEd)	24,196	25,689	962
Alliant Energy East	2,835	3,624	712
Wisconsin Electric Power Company	7,578	6,934	-791
Wisconsin Public Service Corporation	2,762	2,657	-175
Madison Gas & Electric Company	862	514	-361
Upper Peninsula Power Co	170	146	-30
TOTAL	57,773	60,249	1,282

The following are the members of MAIN regional reliability organization:

- Allegheny Energy Supply Co., LLC
- Alliant Energy Corporate Services
- Ameren
  (including the operating companies of)
  - AmerenUE
  - AmerenCIPS
  - AmerenCILCO
  - AmerenIP
- American Transmission Company, LLC
- Central Iowa Power Cooperative
- City Water, Light and Power
- Columbia (Missouri) Water & Light
- Commonwealth Edison Company
- Constellation Energy Commodities Group, Inc.
- Coral Power, LLC
- Duke Energy
- North America, LLC
- Edison Mission Marketing and Trading
- Electric Energy, Inc.
- GridAmerica LLC
- Illinois Municipal Electric Agency
- Madison Gas & Electric Company
- Midwest ISO
- Northern Indiana Public Service Co.
- NRG Energy, Inc.
- PJM Interconnection, L.L.C.
- PPL EnergyPlus, LLC
- Southern Illinois Power Co-operative
- Soyland Power Cooperative, Inc.
- Tenaska Power Services
- Wisconsin Electric Power Company
- Wisconsin Public Power Inc.
- Wisconsin Public Service Corporation.

6.2.2 Summary of Baseline Study Results for MAIN Region Systems in Midwest ISO

Table 6.2-2 shows the results from the phase 1 studies together with projects that would address the limiting conditions. The plan status, as shown, is the current status of the plan that would address the limiting condition.

Table 6.2-2: Phase 1 Study Results and Projects That Address Limiting Conditions

Control Area	Year	Limiter / System Need	Contingent Level (%, PU)	Rating	Cont. Type	Contingency	Plan Status	Project to Address Limiter
Ameren	2009	PT.PRAIR 161 kV	0.899 pu		B	31542 PT.PRAIR 161 96059 5BIG CK 161 1	PR2	Point Prairie 28.8 MVAR cap at the 161 / 34 kV sub
ATCLLC	2009	CORNEL 1-FEBRNT5 138 kV	1.015 pu	225	B	39255 ARCADN5 138 39356 MORLND4 138 1	n.a.	Existing Operating guide and / or generation redispatch
Ameren	2009	31723 SELMA 138-31782 STFT 138 1	1.275 %	253	C	31669 RUSH 345 31858 TYSON 1 345 1 31669 RUSH 345 31859 TYSON 2 345 1	PL	Operating guide until 2007, and then, installation of a new 345 / 138 kV sub at Joachim.-App A ID 401
Ameren	2009	31392 ORGD 2 138-31860 TYSON 138 1	1.003 %	270	C	30079 WILDWD 345 30886 LABADIE 345 1 30079 WILDWD 345 31051 MASON 13 345 1 30886 LABADIE 345 31051 MASON 13 345 1	PL PR	Joachim 345 / 138-345 / 138 ckt 1, Sum rate 560-App A ID 401 Wildwood 345 kV PCBs App A ID 1412
Ameren	2009	31391 ORGD 1 138-31860 TYSON 138 1	1.022 %	270	C	30079 WILDWD 345 30886 LABADIE 345 1 30079 WILDWD 345 31051 MASON 13 345 1 30886 LABADIE 345 31051 MASON 13 345 1	PL PR	Joachim 345 / 138-345 / 138 ckt 1, Sum rate 560-App A ID 401 Wildwood 345 kV PCBs App A ID 1412
Ameren	2009	30648 GRAYSUM1 345-30650 GRAY SUM 138 1	1.133 %	560	C	30079 WILDWD 345 30886 LABADIE 345 1 30079 WILDWD 345 31051 MASON 13 345 1 30886 LABADIE 345 31051 MASON 13 345 1	PL PR	Joachim 345 / 138-345 / 138 ckt 1, Sum rate 560-App A ID 401 Wildwood 345 kV PCBs App A ID 1412
Ameren	2009	30421 CONWAY 1 138-31392 ORGD 2 138 1	1.177 %	205	C	30079 WILDWD 345 30886 LABADIE 345 1 30079 WILDWD 345 31051 MASON 13 345 1 30886 LABADIE 345 31051 MASON 13 345 1	PL PR	Joachim 345 / 138-345 / 138 ckt 1, Sum rate 560-App A ID 401 Wildwood 345 kV PCBs App A ID 1412
Ameren	2009	30197 BUCKNOB 138-31870 VALMTAP 138 1	1.001 %	253	C	31669 RUSH 345 31858 TYSON 1 345 1 31669 RUSH 345 31859 TYSON 2 345 1	PL	Operating guide until 2007, and then, installation of a new 345 / 138 kV sub at Joachim.
Ameren	2009	30197 BUCKNOB 138-31723 SELMA 138 1	1.014 %	253	C	31669 RUSH 345 31858 TYSON 1 345 1 31669 RUSH 345 31859 TYSON 2 345 1	PL	Operating guide until 2007, and then, installation of a new 345 / 138 kV sub at Joachim.
Ameren	2009	30090 BAILEY 2 138-31774 ST FRANC 138 1	1.151 %	210	C	31669 RUSH 345 31858 TYSON 1 345 1 31669 RUSH 345 31859 TYSON 2 345 1	PL	Operating guide until 2007, and then, installation of a new 345 / 138 kV sub at Joachim.
AMRN	2009	30089 BAILEY 1 138-31774 ST FRANC 138 1	1.107 %	229	C	31669 RUSH 345 31858 TYSON 1 345 1 31669 RUSH 345 31859 TYSON 2 345 1	PLn.a.	Operating guide until 2007, and then, installation of a new 345 / 138 kV sub at Joachim.

Table 6.2-2 (cont.): Phase 1 Study Results and Projects That Address Limiting Conditions

Control Area	Year	Limiter/System Need	Contingent Level (%, PU)	Rating	Cont. Type	Contingency	Plan Status	Project to Address Limiter
Ameren	2009	30422 CONWAY 3 138-31391 ORGD 1 138 1	1.20 8	205	C	30079 WILDWD 345 30886 LABADIE 345 1 30079 WILDWD 345 31051 MASON 13 345 1 30886 LABADIE 345 31051 MASON 13 345 1	PL PR	Joachim 345/138-345/138 ckt 1, Sum rate 560-App A ID 401 Wildwood 345 kV PCBs App A ID 1412
Ameren IP	2009	N DEC W 138 kV	0.8976 PU		C	Dbl. Cont. 4571 and 4545 opens 6 lines: CLINTON 345-MAROA W 345 1 MAROA W 345-OREANA E 345 1 MAROA W 345-LATHAM 345 1 CLINTON 345-MAROA E 345 1 MAROA E 345-OREANA E 345 1 MAROA E 345-GOS_CK_W 345 1 GOOS_CRK 345-GOS_CK_W 345 1	n.a.	Low voltages to be re-evaluated with detailed modeling of the large customer generating facilities in the Decatur area, along with evaluation of system changes to ensure adequate voltage
Ameren IP	2009	CATERPIL 138 kV	0.8746 PU		C	Dbl. Cont. 4571 and 4545 opens 6 lines: CLINTON 345-MAROA W 345 1 MAROA W 345-OREANA E 345 1 MAROA W 345-LATHAM 345 1 CLINTON 345-MAROA E 345 1 MAROA E 345-OREANA E 345 1 MAROA E 345-GOS_CK_W 345 1 GOOS_CRK 345-GOS_CK_W 345 1	n.a.	Low voltages to be re-evaluated with detailed modeling of the large customer generating facilities in the Decatur area, along with evaluation of system changes to ensure adequate voltage
Ameren IP	2009	RT 51 138 kV	0.8922 PU		C	Dbl. Cont. 4571 and 4545 opens 6 lines: CLINTON 345-MAROA W 345 1 MAROA W 345-OREANA E 345 1 MAROA W 345-LATHAM 345 1 CLINTON 345-MAROA E 345 1 MAROA E 345-OREANA E 345 1 MAROA E 345-GOS_CK_W 345 1 GOOS_CRK 345-GOS_CK_W 345 1	n.a.	Low voltages to be re-evaluated with detailed modeling of the large customer generating facilities in the Decatur area, along with evaluation of system changes to ensure adequate voltage.

Table 6.2-2 (cont.): Phase 1 Study Results and Projects That Address Limiting Conditions								
Control Area	Year	Limiter/System Need	Contingent Level (%, PU)	Rating	Cont. Type	Contingency	Plan Status	Project to Address Limiter
Ameren IP	2009	MT ZION 138 kV	0.8789 PU		C	Dbl. Cont. 4571 and 4545 opens 6 lines: CLINTON 345-MAROA W 345 1 MAROA W 345-OREANA E 345 1 MAROA W 345-LATHAM 345 1 CLINTON 345-MAROA E 345 1 MAROA E 345-OREANA E 345 1 MAROA E 345-GOS_CK_W 345 1 GOOS_CRK 345-GOS_CK_W 345 1	n.a.	Low voltages to be re-evaluated with detailed modeling of the large customer generating facilities in the Decatur area, along with evaluation of system changes to ensure adequate voltage.
Ameren IP	2009	ADM N AM 138 kV	0.8703 PU		C	Dbl. Cont. 4571 and 4545 opens 6 lines: CLINTON 345-MAROA W 345 1 MAROA W 345-OREANA E 345 1 MAROA W 345-LATHAM 345 1 CLINTON 345-MAROA E 345 1 MAROA E 345-OREANA E 345 1 MAROA E 345-GOS_CK_W 345 1 GOOS_CRK 345-GOS_CK_W 345 1	n.a.	Low voltages to be re-evaluated with detailed modeling of the large customer generating facilities in the Decatur area, along with evaluation of system changes to ensure adequate voltage.
Ameren IP	2009	ADM F AM 138 kV	0.8703 PU		C	Dbl. Cont. 4571 and 4545 opens 6 lines: CLINTON 345-MAROA W 345 1 MAROA W 345-OREANA E 345 1 MAROA W 345-LATHAM 345 1 CLINTON 345-MAROA E 345 1 MAROA E 345-OREANA E 345 1 MAROA E 345-GOS_CK_W 345 1 GOOS_CRK 345-GOS_CK_W 345 1	n.a.	Low voltages to be re-evaluated with detailed modeling of the large customer generating facilities in the Decatur area, along with evaluation of system changes to ensure adequate voltage.

Table 6.2-2 (cont.): Phase 1 Study Results and Projects That Address Limiting Conditions

Control Area	Year	Limiter / System Need	Contingent Level (%, PU)	Rating	Cont. Type	Contingency	Plan Status	Project to Address Limiter
Ameren IP	2009	BLMGTN E 138 kV	0.8884 PU		C	Dbl. Cont. 1562 and 1596 opens 5 lines: 32348 BROKAW 138 32392 ST FARM2 138 1 32268 BLMGTN 7 138 32392 ST FARM2 138 1 32268 BLMGTN 7 138 32389 BLMGTN W 138 1 32348 BROKAW 138 32391 ST FARM1 138 1 32374 BLMGTN E 138 32391 ST FARM1 138 1	n.a.	Further study needed to ensure adequate distribution voltages are being maintained in the Bloomington area and to evaluate possible system upgrades and / or generation re-dispatch
Ameren IP	2009	32348 BROKAW 138-32378 NORMAL E 138 1	1.208 %	165	C	Dbl. Cont. 1562 and 1596 opens 5 lines: 32348 BROKAW 138 32392 ST FARM2 138 1 32268 BLMGTN 7 138 32392 ST FARM2 138 1 32268 BLMGTN 7 138 32389 BLMGTN W 138 1 32348 BROKAW 138 32391 ST FARM1 138 1 32374 BLMGTN E 138 32391 ST FARM1 138 1	n.a.	Further study needed to ensure adequate distribution voltages are being maintained in the Bloomington area and to evaluate possible system upgrades and / or generation re-dispatch.
Ameren IP	2009	PPG 138 kV	0.8829 PU		C	Dbl. Cont. 4571 and 4545 opens 6 lines: CLINTON 345-MAROA W 345 1 MAROA W 345-OREANA E 345 1 MAROA W 345-LATHAM 345 1 CLINTON 345-MAROA E 345 1 MAROA E 345-OREANA E 345 1 MAROA E 345-GOS_CK_W 345 1 GOOS_CRK 345-GOS_CK_W 345	n.a.	Low voltages to be re-evaluated with detailed modeling of the large customer generating facilities in the Decatur area, along with evaluation of system changes to ensure adequate voltage.
Ameren IP	2009	RAAB RD 138 kV	0.8922 PU		C	Dbl. Cont. 1562 and 1596 opens 5 lines: 32348 BROKAW 138 32392 ST FARM2 138 1 32268 BLMGTN 7 138 32392 ST FARM2 138 1 32268 BLMGTN 7 138 32389 BLMGTN W 138 1 32348 BROKAW 138 32391 ST FARM1 138 1 32374 BLMGTN E 138 32391 ST FARM1 138 1	n.a.	Further study needed to ensure adequate distribution voltages are being maintained in the Bloomington area and to evaluate possible system upgrades and / or generation re-dispatch

Table 6.2-3 shows the results from the phase 2 studies together with projects that would address the limiting conditions. The plan status, as shown, is the current status of the plan that would address the limiting condition.

Table 6.2-3: Phase 2 Study Results and Projects That Address Limiting Conditions

Control Area	Year	Limiter / System Need	Contingent Level (%, PU)	Rating	Cont. Type	Contingency	Plan Status	Project to Address Limiter
Ameren	2009	BAILEY ST FRANC 138 1	104.70%	229	C	RUSH ISLAND-TYSON-1&2 345	PR	Operating guide until 2007, and then, instalation of a new 345 / 138 kV sub at Joachim. - App A ID 401
Ameren	2009	BAILEY ST FRANC 138 2	108.40%	210	C	RUSH ISLAND-TYSON-1&2 345	PL	Operating guide until 2007, and then, installation of a new 345 / 138 kV sub at Joachim.
Ameren	2009	SELMA St. Francois Tap 138 1	123.60%	253	C	RUSH ISLAND-TYSON-1&2 345	PL	Operating guide until 2007, and then, installation of a new 345 / 138 kV sub at Joachim.
Ameren	2009	GRAY SUMMIT GRAY SUM 138 1	115.10%	560	C	LABADIE-MASON-3&4 345	PL PR	Operating guide until 2007, and then, instalation of a new 345 / 138 kV sub at Joachim. - App A ID 401 Also 345 kV PCBs proposed at Wildwood in 2009
Ameren	2009	ORGD TYSON 138 1	102.10%	270	C	LABADIE-MASON-3&4 345	PL PR	Operating guide until 2007, and then, instalation of a new 345 / 138 kV sub at Joachim. - App A ID 401 Also 345 kV PCBs proposed at Wildwood in 2009
Ameren	2009	ORGD TYSON 138 2	100.30%	270	C	LABADIE-MASON-3&4 345	PL PR	Operating guide until 2007, and then, instalation of a new 345 / 138 kV sub at Joachim. - App A ID 401 Also 345 kV PCBs proposed at Wildwood in 2009
Ameren	2009	TYSON TYSON 138 1	102%	560	C	LABADIE-MASON-3&4 345	PL PR	Operating guide until 2007, and then, instalation of a new 345 / 138 kV sub at Joachim. - App A ID 401 Also 345 kV PCBs proposed at Wildwood in 2009
Ameren	2009	TYSON TYSON 138 2	101.6 PU	560	C	LABADIE-MASON-3&4 345	PL PR	Operating guide until 2007, and then, instalation of a new 345 / 138 kV sub at Joachim. - App A ID 401 Also 345 kV PCBs proposed at Wildwood in 2009
Ameren	2009	PARIS AM	0.8933 PU		C	KANSAS 345 KANSAS 138 AND SIDNEY 345 SIDNEY 138	na	Operating Guide
Ameren	2009	PARIS AM	0.8933 PU		C	KANSAS 345 KANSAS 138 AND SIDNEY 345 SIDNEY 138	na	Operating Guide
Ameren	2009	PARIS AM	0.891 PU		C	KANSAS SIDNEY 345, KANSAS CASEY 345, KANSAS 345 KANSAS 138 AND SIDNEY 345 SIDNEY 138	PL	A breaker installation is planned for June of 2005 at the Sidney bus that will remove the multi-terminal outage.

Table 6.2-3 (cont.): Phase 2 Study Results and Projects That Address Limiting Conditions								
Control Area	Year	Limiter/System Need	Contingent Level (%, PU)	Rating	Cont. Type	Contingency	Plan Status	Project to Address Limiter
Ameren IP	2009	BROKAW NORMAL E 138 1	119.90%	165	C	Dbl. Cont. 1562 and 1596 opens 5 lines: BLOOMINGTON-ST FARM1-BROKAW and ST FARM 1-ST FARM 2, and BLOOMINGTON-BLOOMINGTON W. OR BROKAW-ST. FARM-BLOOMINGTON E. and ST FARM 1-ST FARM 2	na	Further study needed to ensure adequate distribution voltages are being maintained in the Bloomington area and to evaluate possible system upgrades and/or generation re-dispatch
Ameren IP	2009	RAAB RD	0.898 PU					
Ameren IP	2009	BLOOMINGTON EAST	0.8931 PU					
Ameren IP	2009	ADM F AM	0.8713 PU		C	Dbl. Cont. 4571 and 4545 opens 6 lines: MOROA 345 TO CLINTON, OREANA E., AND LATHAM OR MOROA 345 TO CLINTON, ORANA E., AND GOOSE CREEK WEST	n.a.	Low voltages to be re-evaluated with detailed modeling of the large customer generating facilities in the Decatur area, along with evaluation of system changes to ensure adequate voltage.
Ameren IP	2009	ADM N AM	0.8713 PU					
Ameren IP	2009	N DEC W	0.8981 PU					
Ameren IP	2009	RT 51	0.8925 PU					
Ameren IP	2009	CATERPIL	0.8757 PU					
Ameren IP	2009	MT ZION	0.8796 PU					
Ameren IP	2009	PPG	0.8835 PU					

Illinois Missouri Area

This area is located in the southern part of the MAIN region and is bounded by the service territories of the Ameren (including the operating companies of AmerenUE, AmerenCIPS, AmerenCILCO, and AmerenIP), City Water, Light and Power, Columbia (Missouri) Water & Light, and Southern Illinois Power Co-operative. There are several areas where there are known loading problems and low voltage issues. There are planned projects to mitigate those constraints. In Phase 2 analysis, Midwest ISO added known planned and proposed projects to the 2009 summer peak model to test the performance of those projects. All NERC category B loading violations were resolved. However, there are some NERC category C issues that remain. Because NERC planning standards allow significant operator adjustments for category C events, load shedding is allowed, and because of the many possible avenues that can be taken to deal with those issues, Midwest ISO will continue to work with the Transmission Owners to determine the best way to address the Category C issues. Some overload levels observed in 2009 are significant enough to warrant review by 2005 the Summer Assessment team to see if they are also issues in the near term. As was done in the northern part of MAIN, transfer levels were tested to ensure that load-serving reserves could be maintained at satisfactory levels, and Midwest ISO continues to work to ensure the ability of the region's transmission system to perform its function in a cost effective way.

Wisconsin Minnesota Iowa Area of MAIN

The area is situated between the large load and generation centers in MAPP and Southern MAIN and includes the service territories of American Transmission Company, LLC; Central Iowa Power Cooperative, Madison Gas & Electric Company, Wisconsin Electric Power Company, Wisconsin Public Power Inc., and Wisconsin Public Service Corporation. Because of it's geographic and electrical location it is subject to through flows of electrical energy. The transmission system is in the process of being upgraded to handle local load serving issues, as well as, long term transmission needs. Several transmission projects are being built and/or considered for the future to improve voltage and the ability to move power across the region.

In Phase 2 of the Baseline Reliability Study, Midwest ISO added the Planned and Proposed projects to the 2009 summer peak model and determined the ability of those expansions plans to provide adequate system reliability. Phase 2 contingency analyses resulted in no planning criteria violations, indicating that the implementation of these expansion plans in the MAIN study region will provide adequate system performance. Transfer levels were tested to ensure that load-serving reserves could be maintained at satisfactory levels. Midwest ISO continues to work to ensure the ability of the region's transmission system to perform its function in a cost effective way.

Again, timely implementation of the planned and proposed facilities which comprise the expansion plan for the MAIN region of Midwest ISO, will result is a system that will meet planning reliability standards.

6.2.3 Operational Issues (AFC/TLR)

Of the top 23 flow gates in Midwest ISO; MAIN has 18 of them based on historical data. Five of the 18 are in the ALTW system and are addressed in the MAPP section of this report. Thirteen are left, and all thirteen are addressed by system additions that are included in Appendix A. Some system improvements will be completed by the time this report is published. Others are scheduled for completion as noted in Appendix A. Please see Section 6.4.1 addition discussion on operational issues.

6.2.4 Analysis Details

The outstanding issues of the Baseline Reliability Study are summarized above. If you would like to see the technical details of the Phase 1 analysis and Phase 2 analysis for the Midwest ISO system in the MAIN study region, please see Appendix D2.

6.3 Midwest ISO-MAPP Region

6.3.1 System Description

Midwest ISO System-MAPP Region membership now totals 6 transmission-owning members, including the newest member, Great River Energy (GRE). The MAPP region covers all or portions of Iowa, Illinois, Minnesota, Nebraska area, North and South Dakota, Wisconsin and the Canadian province of Manitoba and Saskatchewan.

The MAPP study region has several large load centers served by both local and remote generation. Thermal and hydro resources in the Dakotas, Wyoming, western Nebraska, and Canada deliver power across long EHV transmission lines to load centers in Minnesota, Nebraska, and Iowa. Because of the location of load and generation, several important flow patterns can be used to evaluate the MAPP transmission system. The assessment of transmission system was done on a MAPP sub-region area basis, which comprised of Canada, Dakotas, Iowa, Minnesota, and Nebraska. Key interfaces between Canada and the United States, the Dakotas and Minnesota, Minnesota and Wisconsin, and West-East Nebraska is studied.

Figure 6.3-1: The Midwest ISO-MAPP Region

The Canadian area of MAPP study region consists of the Manitoba Hydro (MH) and Saskatchewan Power (SPC) system. The area is synchronously interconnected to Saskatchewan Power (SPC) system to the west via three 230 kV and two 115 kV lines and to the Ontario Hydro Networks Company (OHNC) system to the east with two phase-shifted 230 kV lines. Saskatchewan system has a back-to-back HVDC link with the province of Alberta to the west. To the south, the Canadian area system is tied with the US part of the MAPP region system through a 500 kV line and three 230 kV lines in MH system, a phase-shifted 230 kV line in SPC system, and a phase-shifted 115 kV line from the northwest OHNC system. The MAPP RSG study participant from Canada is Manitoba Hydro (MH).

The Minnesota area covers the state of Minnesota and the portion of western Wisconsin that is within the MAPP region. The traditional powerflow pattern in Minnesota is from the northwest to the southeast and central areas of the state. A major portion of the electric load in Minnesota is concentrated around the Twin Cities metropolitan area of Minneapolis-St. Paul, the principal load center of the Xcel Energy North Control Area. The MAPP RSG study participants from Minnesota and Wisconsin are Alliant Energy–IPL (ALTW), Minnesota Power (MP), Otter Tail Power Company (OTP), and Xcel Energy North (XEL).

The Iowa area generally covers the transmission facilities located within the State of Iowa. The MAPP RSG participants from Iowa are Alliant Energy–IPL (ALTW), MidAmerican Energy Company (MEC), and Muscatine Power and Water (MPW). Besides facilities in Iowa, Alliant Energy has some transmission facilities in Illinois and Minnesota. MidAmerican Energy Company also has some facilities in Illinois and South Dakota. A relatively small portion of the Western Area Power Administration facilities are located in Iowa, with the majority of WAPA's facilities located in areas northwest of Iowa. The Iowa electric system consists mainly of 345, 161, and 115 kV transmission facilities.

The Dakotas area generally covers the transmission facilities in portions of Eastern Montana / Western North Dakota, Central North Dakota, Eastern North Dakota, Western South Dakota and Eastern South Dakota. The MAPP RSG participants from the Dakotas are Montana-Dakota Utilities (MDU), Otter Tail Power Company (OTP), Western Area Power Administration (WAPA), and Xcel Energy North (XEL). Nebraska generally covers the transmission facilities located within the State of Nebraska, portion of western Wyoming and South Dakota. The MAPP RSG participant from Nebraska is Lincoln Electric System (LES).

Table 6.3-1 shows the system intact base case model for 2009 summer peak case with area load and generation levels.

The generation figures in the table are not indicative of available capacity to meet MAPP load, but rather the dispatch levels anticipated at peak load for generation in the control areas, as consistent with the interchange levels projected by the Transmission Owners in 2003 when the 2009 model for this study was developed. Note that positive area interchange means the system is exporting power; negative area interchange is importing power.

The load growth in the 2009 summer case for the MAPP (including Alliant Energy-IPL) region is approximately 8%.

Table 6.3-1: Base Case Area Load and Generation Levels

System	Modeled Load (MW)	Modeled Generation (MW)	Modeled Area Interchange (MW)
Alliant Energy–IPL	4522.6	4388.2	-206.2
Xcel Energy North	10334.5	8506.3	-2156.0
Minnesota Power	1700.1	1380.2	-7.7
Southern MN Municipal Power Association	325.4	181.1	-145.0
Great River Energy	1611.7	2487.9	791.0
Otter Tail Power Company	1662.9	1204.6	-504.5
Muscatine Power and Light	175.9	175.7	-1.0
MidAmerican Energy	5154.5	5146.2	-105.0
Nebraska Public Power District	2994.0	2778.1	-327.0
Omaha Public Power District	2676.8	2603.1	-104.0
Lincoln Electric System	814.5	139.8	-687.0
Western Area Power Administration	3278.1	4758.9	1274.0
Manitoba Hydro	2784.2	4560.0	1494.0
Saskatchewan Power Company	3025.9	3118.9	0.0
Dairyland Power Cooperative	952.1	1198.3	164.0
Total	**42013.2**	**42653.0**	**-520.4**

6.3.2 Summary of Baseline Study Results for MAPP Region Systems in Midwest ISO

This section provides a long-term assessment of the reliability of the Midwest ISO System in the MAPP Study Region. The study was conducted in a joint collaborative effort between Midwest ISO Reliability Study Group (RSG) and the MAPP Transmission Reliability Assessment Working Group (TRAWG) members. In an effort to identify a reliability plan, this assessment discusses the facility upgrades needed as a result of the thermal, voltage and dynamic stability analysis performed. Depending on the results of the assessment study, further studies on more specific alternatives to improve system performance may follow.

Planned projects are the preferred solution to an identified issue and Proposed projects are a tentative solution to an identified issue. Additional facilities address system issues identified in Phase 2 of this study, which were not addressed by the Planned and Proposed facilities in Appendix A. Additional facilities are those in addition to the expansion facilities listed as Planned or Proposed in Midwest ISO Appendix A.

In general, the MAPP Region of the Midwest ISO transmission system is judged to be adequate to meet firm obligations of the member systems provided that the local facility improvements identified in the Appendix A, in addition to what the Midwest ISO have identified below, are implemented.

Phase 1 Steady-State Analysis

Table 6.3-2 summarizes the Phase 1 reliability issues the Midwest ISO has identified in the 2009 summer peak study cases. It discusses the results; planned solutions to the reliability issues summarized at the MAPP sub-regional level. Phase 1 analysis consists of only planned (PL) facilities.

In the Phase 1 analysis, the Midwest ISO has identified several new reliability issues in the 2009 summer peak case. These reliability issues do not have a corresponding Appendix A planned (PL) or proposed (PR) projects identified (see branch ID column–N.A). It is also important to note that some planned projects were not listed in Appendix A during the Phase 1 analysis or had a proposed plan status that later changed to a planned status in Phase 2 analysis. This is noted in the plan status column. Projects that have the planned (PL) status will be monitored closely by Midwest ISO for development and construction of these facilities. Projects with a proposed (PR) plan status are expected to become planned status facilities in Appendix A and closely monitored in next MTEP 06 analysis. The detail of Phase 2 analysis is discussed in the next paragraph.

Table 6.3-2: Phase 1 Steady-State Analysis Summary Table

Area	Model Year	Limiter / System Need	Contingent Level (%, PU)	Rating	Con. Type	Contingency	Plan Status	Branch or Device ID	Project to Address Limiter
Dakotas	2009	Bismarck Downtown–East Bismarck 115 kV	171%	67.7	B	Heskett–Mandan 115 kV	PR2	N.A	Bismarck Downtown–East Bismarck 115 kV upgrade to at least 160 MVA
Dakotas	2009	Jamestown 115 kV buses	< 1.12 p.u		B	Buffalo–Maple River 345 kV	PR2	N.A	Jamestown 115 kV 25 MVAR capacitor
Dakotas	2009	Maple River–Red River 115 kV	112%	79.1	C	Sheyenne–Cass County–Moderow 115 kV loop & Sheyenne 230/115 Transformer	PL	1354	Maple River–Red River115 kV upgrade to 310 MVA in 6/1/05
Iowa	2009	Hazelton 345/161 kV Transformer # 1	112%	223	C	Salem 345/161 kV and Hazelton 345/161 kV # 2 Transformers	PR2	N.A	Upgrade Salem transformer to 550 MVA and replace Hazelton transformer with old Salem Tr. 336 MVA
Iowa	2009	Salem 345/161 kV Transformer	101%	335	C	Rock Creek 345/161 kV Transformer and Beaver Channel 161 kV–Beaver Channel Generator	LT or PR2	1266 or N.A	Salem-Spring Green–West Middleton 345 kV line. Total project $310 million in 1/1/14 or Upgrade Salem transformer to 550 MVA
Minnesota	2009	Prairie Island–Red Rock 345 kV # 2	116%	625	C	Prairie Island–Blue Lake 345 kV and Prairie Island–Red Rock 345 kV	PR changed to PL	1137	Prairie Island–Red Rock 345 kV # 2 line upgrade to 1198 MVA in 6/1/06
Minnesota	2009	Cromwell and McGregor 115 kV	0.88 p.u		B	Mahtowa–Wrenshall 115 kV	N.A	N.A	MP is currently looking into building a new 115 kV source into the Cromwell area
Minnesota	2009	Mahtowa, Cromwell and McGregor 115 kV	0.87 p.u		B	Wrenshall–Thompson 115 kV	N.A	N.A	MP is currently looking into building a new 115 kV source into the Cromwell area
Minnesota	2009	Alexandria 115 kV	0.89 p.u		B	Alexandria Switching St.–Alexandria SW 115 kV	PR	1032	Alexandria 115, 2 x 25 MVAR Capacitors in 3/1/07
Minnesota	2009	Hibbard–Winter St. 115 kV	102%	200	B	Arrowhead–Gary 115 kV	N.A changed to PL	1242	Stone Lake 345/161 tap of Arrowhead–Gardner Park 345 kV line
Minnesota	2009	Wheaton–Presto 161 kV	102%	300	B	Elk Mound–Barron 161 kV	PR2	N.A	Elk Mound 161 kV Tap on Red Cedar–Hydro Lane 161 kV
Minnesota	2009	River Wood–Johnny Cake–Inver Grove-Black Dog 115 kV	106%	210 & 263	B	River Wood–Black Dog 115 kV or River Wood–Burnsville 115 kV	PR changed to PL	277	Air Lake–Vermillion River 115 ckt 1, Sum rate 200 in 6/1/07
Minnesota	2009	Eau Claire–Presto tap 161 kV	102%	300	B	Elk Mound–Barron 161 kV	PR2	N.A	Elk Mound 161 kV Tap on Red Cedar–Hydro Lane 161 kV
Minnesota	2009	Barron–Washco 161 kV overload	108%	132	B	Stinson MN–Stinson WI 115 kV Phase Shifter	N.A changed to PL	1242	Stone Lake 345/161 tap of Arrowhead–Gardner Park 345 kV line in 6/1/06
Minnesota	2009	Monticello–Salida 115 kV	118%	154	C	Blue Lake–Inver Hills–Red Rock 345 kV	PR changed to PL	571 572 573	Monticello–Sherco-Salida 115 kV , Sum rate 310, Sherco 345/115 ckt 1, Sum rate 448 in 6/1/06

Table 6.3-2 (cont.): Phase 1 Steady-State Analysis Summary Table

Area	Model Year	Limiter / System Need	Contingent Level (%, PU)	Rating	Con. Type	Contingency	Plan Status	Branch or Device ID	Project to Address Limiter
Minnesota	2009	River Wood–Johnny Cake–Inver Grove-Black Dog 115 kV	106%	210 & 263	C	Prairie Island–Blue Lake 345 kV and Blue Lake–Inver Hills-Red Rock 345 kV outage or Blue Lake–Inver Hills–Red Rock 345 kV	PR changed to PL	277	Air Lake–Vermillion River 115 ckt 1, Sum rate 200 in 6/1/07
Minnesota	2009	Monticello–Salida 115 kV	117%	154	C	Blue Lake-Inver Hills–Red Rock 345 kV	PR changed to PL	571 572 573	Monticello–Sherco–Salida 115 kV , Sum rate 310, Sherco 345 / 115 ckt 1, Sum rate 448 in 6 / 1 / 06
Minnesota	2009	Aldrich–St. Louis Park 115 kV	111%	156	C	Parkers–Basst Creek 115 kV and Parkers–St. Louis Park 115 kV	PR changed to PL	249	Aldrich–St. Louis Park 115 kV line upgrade to 310 in 6 / 1 / 06
Minnesota	2009	Champlin–Champlin Tap 115 kV	108%	154	C	Sherco-Maple Grove-Coon Creek 345 kV and Coon Creek 345 / 115 / 34.5 kV transformers	PR	1138	Champlin–Champlin Tap 115 kV line upgrade to 310 in 6 / 1 / 06
Minnesota	2009	St. Cloud Tap–Salida 115 kV	117%	152	C	Blue Lake–Inver Hills–Red Rock 345 kV	PR changed to PL	569 574	St. Cloud Tap–I94 Industrial-Salida 115 kV , Sum rate 310 in 6 / 1 / 06

PL–Planned Projects

PR–Proposed Projects

PR2–New Proposed Project not in Appendix A

N.A–Not Available

LT–Long Term Projects

Phase 2 Steady-State Analysis

Table 6.3-3 summarizes the Phase 2 reliability issues the Midwest ISO has identified in the 2009 summer peak study case. It discusses the results; planned solutions to the reliability issues summarized at the MAPP sub-regional level. Phase 2 analysis consists of planned (PL) facilities from Phase 1, proposed (PR) facilities listed in Appendix A and new proposed (PR2) facilities not listed in Appendix A.

In the Phase 2 analysis, the new proposed (PR2) facilities not listed in Appendix A have shown to eliminate all of the reliability issues found in Phase 1 analysis. In this analysis, the Midwest ISO also has identified two new additional reliability issues in the 2009 summer peak case, which was not found in Phase 1 analysis. The following summarizes the new two limiting elements.

Stone Lake 345 kV Bus

Loss of the planned Arrowhead 345/230 kV Transformer (ATCLLC) or Arrowhead 230 kV Phase Shifter (ATCLLC) has been shown to cause high voltage on the planned Stone Lake 345 kV bus (ATCLLC). The Stone Lake 345 kV bus facility was not modeled in the Phase 1 analysis. For these contingencies, the Arrowhead-Stone Lake Tap 345 kV line and cap banks at the Stone Lake Tap 345 kV substation will be cross-tripped. This new proposed remedial action would eliminate the high voltage issue on this bus. ATCLLC will study this facility in depth and propose a remedial action or operating guide that would cross trip the planned capacitor banks at the Stone Lake 345/230 kV substation. The facility is expected to be in service in 2006.

Johnny Cake–Apple Valley West–Williams Pipeline–Fischer 115 kV Lines

The Johnny Cake–Apple Valley West–Williams Pipeline–Fischer 115 kV lines is overloaded approximately 106 percent for loss of single contingency; River Wood–Black Dog 115 kV or River Wood–Burnsville 115 kV branch and for the double contingency; Prairie Island–Blue Lake 345 kV and Blue Lake–Inver Hills–Red Rock 345 kV outage or Blue Lake–Inver Hills–Red Rock 345 kV. This new limit is due to the addition of the planned Air Lake–Vermillion, Koch Refinery–Inver Hills 115 kV lines and the proposed Dakota County generations. A separate Dakota County generation interconnection study is underway between GRE and Midwest ISO that would increase the line rating of these lines as part of the generation outlet upgrade.

For projects that have new proposed (PR2) status will be monitored closely by Midwest ISO in next MTEP 2006 analysis. These facilities are expected to be included in the next Appendix A development or update for MTEP 2006 with a Planned or Proposed status. It is the expectation of the Midwest ISO that these facilities will be addressed with a project cost, in-service date and analysis performed of these facilities. The following describes the new proposed (PR2) facilities summarized at the MAPP sub-regional level.

Dakotas

The Bismarck Downtown–East Bismarck 115 kV line (MDU) was overloaded at approximately 71 percent above its emergency line rating for the loss of Heskett–Mandan West 115 kV line (MDU). The Midwest ISO's proposal to upgrade the Bismarck Downtown–East Bismarck 115 kV line to at least 160 MVA has shown significant improvement for this contingency. The Bismarck area 115 kV transmission loop is being studied to determine the solution to implement.

The loss of Buffalo–Maple River 345 kV line may result in high voltages in the Jamestown area (OTP) of the Eastern North Dakota sub-region. These high voltage problems are due to charging current from the lightly loaded 345 kV line. The proposal to install a 25 MVAR shunt at Jamestown substation has shown significant voltage improvement for the loss of Buffalo–Maple River 345 kV line. An analysis to determine the appropriate shunt size will be performed.

Iowa

The outage of Rock Creek 345/161 kV transformer and Beaver Channel 161 kV –Beaver Channel Generator (ALTW) results in overload of the Salem 345/161 kV transformer (ALTW). The Midwest ISO and the Eastern Iowa study group will review this contingency and recommend a solution. It is possible that a 550 MVA Salem 345/161 kV transformer may be recommended.

The loss of Salem 345/161 kV and Hazelton 345/161 kV # 2 Transformers (ALTW) may result in overload of the Hazelton 345/161 kV transformer #1 (ALTW) of approximately 12 percent above its emergency rating. The Midwest ISO and the Eastern Iowa study group will review this contingency and recommend a solution. It is possible that moving the Salem 336 MVA transformer from Salem to Hazelton maybe be recommended to eliminate the thermal overload on the existing transformer.

Minnesota

Loss of Elk Mound–Barron 161 kV line (DPC) has shown to overload the Eau Claire–Presto tap 161 kV and Wheaton–Presto tap 161 kV lines to approximately 106 percent of its emergency rating. The proposed Elk Mound 161 Tap on Red Cedar–Hydro Lane 161 kV would relieve the flow on these lines. The Elk Mound unit generates approximately 72 MW of generation for loads in Northwest Wisconsin via the Elk Mound–Barron 161 kV line. This new proposed line would serve as an outlet to the Elk Mound generations for this contingency. XEL and DPC will perform a joint analysis.

The possibility of a breaker failure at Mahtowa–Wrenshall 115 kV (MP) or Wrenshall–Thompson 115 kV (MP), could result in low voltage occurring in the area immediately south of the Duluth/Cloquet load center. These limitations are confined to local area. To improve the reliability in this area, Midwest ISO and Minnesota Power is currently looking into building a new 115 kV source into the Cromwell area.

In the Phase 2 analysis, the construction of the ATCLLC Arrowhead–Stone Lake–Weston 345 kV line and Stone Lake 345/161 substation has shown to improve the overall performance and operational flexibility of the Northwestern Wisconsin transmission system.

Nebraska

No significant branch overloads or voltage limitations occur on the LES system.

Table 6.3-3: Phase 2 Steady-State Analysis Summary Table

Area	Model Year	Limiter/System Need	Contingent Level (%, PU)	Rating	Con. Type	Contingency	Plan Status	Branch or Device ID	Project to Address Limiter
Dakotas	2009	Bismarck Downtown–East Bismarck 115 kV	171%	67.7	B	Heskett–Mandan 115 kV	PR2	N.A	Bismarck Downtown–East Bismarck 115 kV upgrade to at least 160 MVA
Dakotas	2009	Jamestown 115 kV buses	< 1.12 p.u		B	Buffalo–Maple River 345 kV	PR2	N.A	Jamestown 115 kV 25 MVAR capacitor
Iowa	2009	Hazelton 345/161 kV Transformer # 1	112%	223	C	Salem 345/161 kV and Hazelton 345/161 kV # 2 Transformers	PR2	N.A	Upgrade Salem transformer to 550 MVA and replace Hazelton transformer with old Salem Tr. 336 MVA
Iowa	2009	Salem 345/161 kV Transformer	101%	335	C	Rock Creek 345/161 kV Transformer and Beaver Channel 161 kV -Beaver Channel Generator	PR2	N.A	Upgrade Salem transformer to 550 MVA
Minnesota	2009	Wheaton–Presto tap 161 kV	102%	300	B	Elk Mound–Barron 161 kV	PR2	N.A	Elk Mound 161 kV Tap on Red Cedar–Hydro Lane 161 kV
Minnesota	2009	Eau Claire–Presto tap 161 kV	102%	300	B	Elk Mound–Barron 161 kV	PR2	N.A	Elk Mound 161 kV Tap on Red Cedar–Hydro Lane 161 kV
Minnesota	2009	Stone Lake 345 kV	1.16 p.u		B	Arrowhead 345/230 kV Transformer or Arrowhead 230 kV Phase shifter	PR2	N.A	The Arrowhead–Stone Lake Tap 345 kV and cap banks at Stone Lake Tap s/s will be cross-tripped.
Minnesota	2009	Johnny Cake-Apple Valley West-Williams Pipeline–Fischer 115 kV	> 106%	211	B	River Wood–Black Dog 115 kV or River Wood–Burnsville 115 kV	PR2	N.A	Equipment upgrades to 310 MVA on William Pipeline–Fischer 115 kV William Pipeline–Apple Valley West 115 kV, Johnny Cake–Apple Valley West 115 kV lines
Minnesota	2009	Johnny Cake-Apple Valley West-Williams Pipeline–Fischer 115 kV	> 106%	211	C	Prairie Island–Blue Lake 345 kV and Blue Lake–Inver Hills-Red Rock 345 kV outage or Blue Lake–Inver Hills-Red Rock 345 kV	PR2	N.A	Equipment upgrades to 310 MVA on William Pipeline–Fischer 115 kV William Pipeline–Apple Valley West 115 kV, Johnny Cake–Apple Valley West 115 kV lines

New Limiter in Phase 2 Analysis

PL–Planned Projects
PR–Proposed Projects
PR2–New Proposed Project not in Appendix A
N.A–Not Available
LT–Long Term Project

Outstanding Issues

Table 6.3-4 summarizes the outstanding reliability issues the Midwest ISO has identified in the 2009 summer peak study case. In the Phase 2 analysis, no new proposed facilities were provided to eliminate the outstanding limiting elements. The following summarizes the limiting elements.

Mahtowa, Cromwell and McGregor 115 kV Bus

The possibility of a breaker failure at Mahtowa–Wrenshall 115 kV (MP) or Wrenshall–Thompson 115 kV (MP), could result in low voltage occurring in the area immediately south of the Duluth/Cloquet load center. These limitations are confined to local area and not wide spread. To improve the reliability in this area, Midwest ISO and Minnesota Power is currently looking into building a new 115 kV source into the Cromwell area

The Midwest ISO will monitor the reliability issue shown above closely for a proposed facility and to be addressed with a project cost, in-service date and analysis performed on these facilities.

Dynamic Stability Analysis

During the Phase 1 analysis, the dynamic stability analysis was also performed in parallel in an effort to identify any reliability issues. For dynamic stability analysis, post-disturbance thermal overloads are based on the component's *emergency rating.* The report discusses the facility upgrades needed as a result of the dynamic stability analysis. Post disturbance power flow analysis was performed on the 2009 power flow case using the disturbances shown in Appendix D3 (see section 6.3.4). Approximately sixty-two disturbances from NERC Category A, B and C were applied.

The analysis showed there was no significant branch, voltage or transient voltage limitations occurred in the 2009 summer peak case of the Midwest ISO System in the MAPP Study Region.

Table 6.3-4: Outstanding Issue Summary Table

Area	Model Year	Limiter/System Need	Contingent Level (%, PU)	Rating	Con. Type	Contingency	Plan Status	Branch or Device ID	Resolution Status
Minnesota	2009	Cromwell and McGregor 115 kV	0.88 p.u		B	Mahtowa-Wrenshall 115 kV	N.A	N.A	MP will perform a separate study to determine a new 115 kV source into the Cromwell area
Minnesota	2009	Mahtowa, Cromwell and McGregor 115 kV	0.87 p.u		B	Wrenshall-Thompson 115 kV	N.A	N.A	MP will perform a separate study to determine a new 115 kV source into the Cromwell area

N.A – Not Available

6.3.3 Operational Issues (AFC/TLR)

Midwest ISO Reliability Authority continues to monitor approximately 32 constrained flowgates within the MAPP region. These constraints can limit MAPP imports and exports under various conditions, and require continuous monitoring. Reliability problems are not expected as long as limits are identified in real time and respected.

The Salem 345/161 kV transformer (ALTW), an existing Midwest ISO flowgate is sensitive to south-to-north and east-to-west transfers. The base case flow on this transformer has increased since the 2003 summer. This is primarily due to an increased south-to-north bias. Updates to local line impedances and an increased ALTW load since the 2003 summer also contributed to the increase. A Salem Transformer Emergency Operating Guide (ALTW) applicable for post-contingency has been developed that calls for opening the Salem 161 kV bus tie (ALTW); however, its implementation would overload the Asbury-Lore 161 kV line (ALTW) under certain system conditions. ALTW plans to re-conductor the Asbury-Lore 161 kV line prior to the 2005 summer season. The reconductoring of this line allows the implementation of the Salem Transformer Emergency Operating Guide. The Midwest ISO and the Eastern Iowa study group will review this contingency and recommend a solution. It is possible that a 550 MVA Salem 345/161 kV transformer may be recommended.

Alliant Energy–IPL and Dairyland Power Cooperative presently is upgrading its 161 kV system, which includes the Asbury–Lore 161 kV , Salem–Maquoketa 161 kV , and Galena 161/69 transformer in the Dubuque, IA area for increased capacity for issues caused by loss of the Wempletown–Paddock 345 kV line connecting Illinois and Wisconsin. ATCLLC and ComEd are constructing the second Wempletown-Paddock 345 kV circuit; it is expected to be in-service by 6/1/2005 and long term proposal to construct an additional 345 kV circuit from south-central Wisconsin to either north-central Illinois or northeast Iowa in the 2012-2014 timeframe would strengthen the south-to-north and east-to-west flows and mitigate AFC/TLR issues on the Iowa system. Alliant Energy is also rebuilding the Poweshiek–Reasnor 161 kV line to mitigate overloading due to loss of the Montezuma–Bondurant 345 kV line. A joint effort by ALTW and XEL to build a second Lakefield–Fox Lake 161 kV line prior to the 2006 summer season would also mitigate the AFC/TLR issue for loss of Lakefield–Wilmarth 345 kV line. In addition, the Midwest ISO and ALTW will perform a comprehensive planning study of eastern Iowa that will include evaluating options to relieve loading on the Hills_IE 345/161 kV transformer for loss of Tiffin–D. Arnold 345 kV line, Wisdom–Triboji 161 kV line for loss of Raun–Lakefield 345 kV line and Arnold–Vinton 161 kV line (ALTW) for loss of Duane Arnold–Hazelton 345 kV line (ALTW). The Eastern Iowa study is currently under way and expected to be completed by early this year.

The MAPP Montezuma West flowgate ATC components were changed in 2004 because the Montezuma West (or Montezuma–Bondurant 345 kV line) flowgate is no longer a proxy OTDF flowgate for the Midwest ISO Poweshiek–Reasnor 161 kV line/flowgate. The MAPP Montezuma West flowgate ATC components are now defined to limit flows on the Montezuma–Bondurant 345 kV line so that the circuit breaker closing phase angle limits are not exceeded to protect nearby MidAmerican peaking and combined cycle plants from potential shaft torque damage. MEC will continue to have two MAPP 345 kV constrained interfaces (Quad Cities West and Montezuma West). Standing operating guides are in place for both interfaces to mitigate any AFC/TLR issues on these lines.

No significant operational issues are expected for northern MAPP sub-region. The existing standing operating guides, and temporary operating guides that are developed as needed, have proven to effectively deal with the system conditions throughout the year. The Manitoba–United States configuration was enhanced so that the scheduling limits were increased by 200 MW system-intact prior to last winter. Increased southward transfer flows from Manitoba may be experienced this summer, but they have not occurred yet.

No significant operational issues are expected in Nebraska during 2005. Lincoln Electric System (LES) experienced a bulk transmission transformer failure on January 27, 2004. This 345/115 kV transformer is a critical interconnection to the bulk transmission system. The transformer repair or replacement is estimated to take 12-18 months. LES and NPPD are developing operating procedures necessary to maintain system reliability in the Lincoln area. Currently undergoing diagnostic testing, however, ongoing test issues make it less than certain that the transformer will be in-service prior to midsummer 2005.

6.3.4 Analysis Details

The outstanding issues of the Baseline Reliability Study are summarized above. Technical details of the Phase 1 and Phase 2 steady-state analysis and Dynamic stability analysis of the 2009 summer peak case for the Midwest ISO system in the MAPP study region are available in Appendix D3.

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6.4 System-Wide Studies

6.4.1 Operational Issues Overview - AFC/TLR

Transmission system constraints that limit the availability of service reservations or that limit the flow of scheduled transmission service reservations, generally represent limitations to the commercial use of the system, rather than limitations to the reliability of the system. This is because mechanisms exist for the curtailment of scheduled transactions when system conditions are other than planned and are designed to prevent system security violations. These commercial limitations give rise, however, to congestion costs that may or may not exceed the costs of relieving the constraints. Much of the congestion realized simply reflects proper management of the system within reliable bounds, and is not reflective of other eminent problems or expansion needs. Given adequate generation reserves, the transmission system becomes the "ultimate sentinel" for reliability. Any subsequently realized transmission congestion has two faces. When transmission limits are reached and there are adequate generation resources to shift supply the reliability risk is very low. This is the situation for an extreme majority of the time. Alternatively, when a transmission limit is reached and generation resources are fully utilized, the situation is very critical. The following discussion provides information about constraints that have been most frequently involved in limiting transactions and measures being taken to ensure reliability is maintained.

The primary value in summarizing this information is that the TLR history is pure historical data of one measure of system performance. This summary does not include tracking the individual impacts upon flowgates (FG's) of new FG's being introduced or the dynamics as the system itself changes over time. While no particular attempt has been made in MTEP to dissect specific historical data or merge commonly impacted FG's, this summary (particularly the individual FG charts in Appendix D9) provide a basis for such detailed investigations. This type of information is commonly utilized along with further local knowledge incorporated into more detailed discussions for specific project needs or in addressing stakeholder questions about the transmission system. This MTEP report does correlate where planned expansions are expected to mitigate the need for future TLR. Similarly, expansions have been identified that may mitigate negative AFC. Therefore, this section attempts to report the overall congestion metrics, and known related expansion activity. More substantive congestion planning may be realized from post March 31, 2005 market data, and expansion studies that are base on simulating future market loadings of the system.

Historically the transmission reservation process has attempted to measure the available flowgate capacity (AFC) and used that as a basis on which to grant or refuse additional service requests. Subsequent to the granting of transmission service, transmission loading relief (TLR) is a procedure to control flows and prevent system security violations. Beginning March 31, 2005 the Midwest ISO intends to implement a centrally controlled security constrained dispatched as a part of the LMP based market, and this dispatch will become the primary process for controlling security constraints on an operational basis. The central dispatch process is directed at economically dispatching the system while honoring constraints and avoiding security violations. MTEP reports after 2005 may contain a review of system limits based on central dispatch history. Such central dispatch history may provide information to better resolve if the cost of relieving constraints would warrant network expansion solutions. Meanwhile this report associates known expansions that will mitigate TLR at certain locations. It should be recognized that the historical TLR has often only been needed to serve as a security operating mechanism where expansion solutions were not necessary. Therefore, historically predominant TLR locations may or may not be associated with need for transmission facility expansion. The following is the historical information from a transmission service perspective and any subsequently required TLR.

To characterize this massive amount of history, the TLR summaries in the MTEP text focus heavily on average statistics over the past 48 months. This aggregated (or averaged) approach can be misleading in that it does not reflect modifications to the network over time or the impact of rare patterns due to weather or other unusual generation availability patterns. Unusual events can cause a FG to have high average values but not represent an issue going forward. Therefore, the reader is urged to reflect upon the detailed monthly TLR patterns for the top 24 FG's as illustrated in Appendix D9. This MTEP does not expand on the multitude of individual factors for each FG over the 48-month period. It is intended that the charts in Appendix D9 will provide a basis for further insight. On occasions Midwest ISO and its members have provided more intensive analysis and explanations for specific FG's of interest, and will continue to contribute to such forums beyond an MTEP report

6.4.1.1 Transmission Service AFC Conditions

With the start of open access transmission service the Available Flowgate Capacity (AFC) process of the Midwest ISO or similar business processes of other OASIS providers was the first type of tool that evolved to manage the open access reservation and use of the transmission system. This approach was implemented out of necessity and has been the primary "before-the-fact" congestion management tool for most of the eastern interconnection. The term "before-the-fact" meaning the months, days, or hours ahead of actual schedules between control areas. While the business practices have been designed to be technical in the sense that the impacts upon flowgates are calculated with realistic network knowledge by applying power flow distribution factors, the result is subject to further distortion due to inaccuracies caused by coordination (or lack of coordination) with adjacent transmission providers and truncating or ignoring very small impacts. While diligent efforts have been made by transmission providers to be consistent and coordinated in evaluation of TSR's the end results are a mix of art and science due to the complexities inherent in providing fair and reliable access to available system capacity. For example, the cumulative effect of small impacts (typically less than 5%), the multitude of coordination policies, and the requirement to implement rules in non-discriminatory fashion results in a system that can either oversell or undersell transmission service.

Midwest ISO Expansion Planning Staff reviewed Available Flowgate Capacity values as of November 25, 2004. Midwest ISO TSR's are evaluated for impacts on 616 flowgates throughout the Midwest ISO tariff footprint[1]. About 40% or 251 of the 616 Midwest ISO TSR flowgates have a zero or negative monthly AFC for the period December, 2004 through October, 2007. This means that any request for service that would add flow above accepted cutoff values for distribution factors to any of these 251 would be refused. This presents a situation where many reservations cannot be approved, but it does not indicate that where there is negative AFC on a flowgate there is a reliability violation. Negative AFC's can occur when despite efforts, there is mis-coordination in selling, inaccurate data or assumptions, or when small impacts below cutoff levels for denying service requests accumulate to exceed flowgate capability. Often, more than one transmission path is reserved for use by a single source. Efforts are made by transmission providers to consider, when evaluating requests for service, that not all such reservations can be scheduled simultaneously. However, the AFC values reflect some measure of reservations that may exceed actual schedule potential at any one time. As a result of these factors, although there may be negative AFC on a flowgate that precludes the equitable sale of additional service impacting the flowgate, there are usually redispatch options that can maintain system reliability, as evidenced by the successful implementation of TLR for many of these flowgates. In rare situations the "redispatch" can manifest itself as dropping load and backing down generation rather than simply shifting generation among sources.

The universal back up, in non-market environments, to assure reliability in managing flowgate capacity is NERC's Transmission Loading Relief (TLR) procedure. Table 6.4-1 is a summary of Midwest ISO AFC versus TLR. The table illustrates that the 40% or 251 of 616 Midwest ISO TSR flowgates that have a zero or negative AFC, account for 84% of the TLR Hours on Midwest ISO TSR flowgates. Including all 616 Midwest ISO TSR flowgates with negative or positive AFC values, 131 have been associated with TLR over a 48-month period from 1/1/2001 to 12/31/2004. Section 6.4.1.2 covers a more detailed discussion of the 316 flowgates (Midwest ISO TSR flowgates plus other Midwest ISO RA responsibility flowgates) that have experienced TLR. For another perspective, Figure 6.4-1 is an illustration the AFC values sorted for all 616 Midwest ISO TSR flowgates and the TLR Hours associated with 131 of them. Of the 131 flowgates, 88 flowgates have a zero or negative AFC value and have been in TLR over the 48-month period from 1/1/2004 to 12/31/2004. Bottom line is that 84% of the historical TLR Hours on Midwest ISO TSR flowgates are associated with flowgates that have a forward-looking zero or negative AFC value. Of those zero or negative AFC values, 24 of the 88 Midwest ISO flowgates accounted for 67% of flowgate hours in TLR and the remaining 64 Midwest ISO flowgates accounted for 17% of the flowgate hours in TLR.

Table 6.4-1 Transmission Service Flowgates
Positive and Negative AFC and Associated TLR Activity

	Positive AFC/FG's	Zero or Negative AFC/FG's	Total
Number with TLR	43	88	131
Number without TLR	208	277	485
Total AFC FG's	251	365	616
TLR Hours	4,640	24,700	29,340
% TLR Hours	16%	84%	100%

(future AFC's from December 2004 through October 2007)
(historical TLR from January 2001 through December 2004)

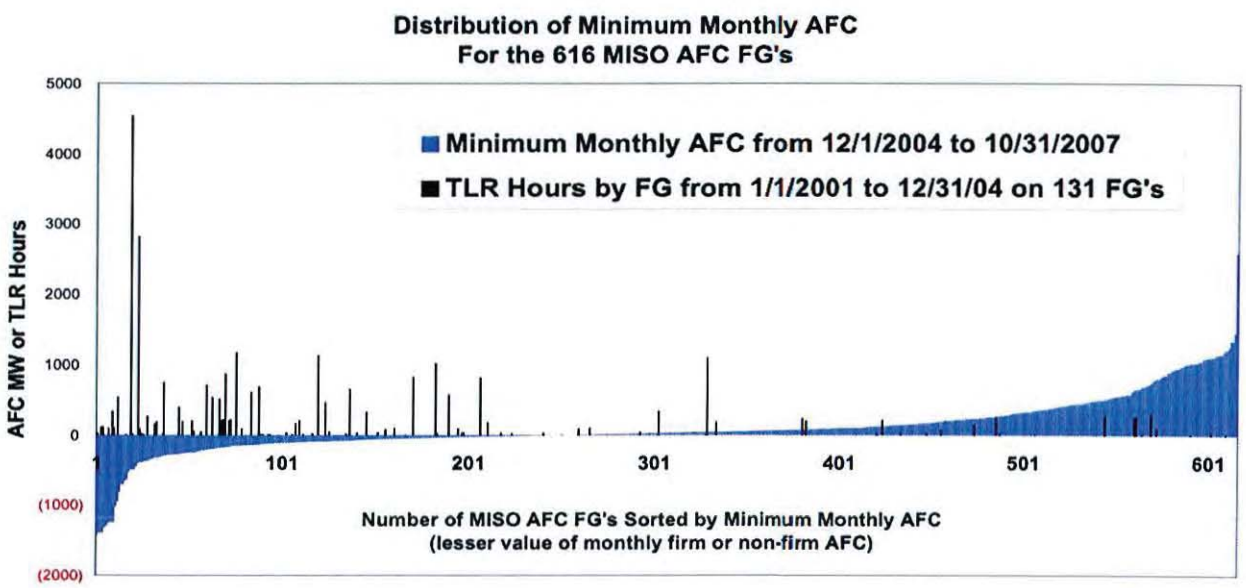

Figure 6.4-1 Minimum Monthly AFC Flowgate Distribution And Correlation to TLR Activity

6.4.1.2 Resolution of Negative AFC Flowgates

While it is clear from the correlation with TLR events that flowgates with negative AFC do not require mitigation in order to ensure reliability, these flowgates, as with others in frequent TLR do result in congestion costs and need to be reviewed to see whether their resolution is economically justified. The Midwest ISO will be in a better position to be able to make these determinations when we begin monitoring actual congestion costs associated with binding constraints under market operations. Until that time, Midwest ISO has reviewed both flowgates with negative AFC values and those with positive AFC but that have significant TLR hours associated with them and whether or not plans are in place to address these issues. The FG with negative AFC are discussed here and any others that are associated with significant TLR hours are addressed in the TLR discussion in section 6.4.1.4 below.

Of the 251 FG with negative AFC, reviews of plans contained in MTEP 05 indicate that 84 of these will be addressed by these plans . Of the remaining 167 FG with no specific plans in place in MTEP that will likely relieve the loading levels on these FG, 118 are not associated with a TLR call. That leaves 49 of greater interest that were negative, had a TLR, and have no related expansion solution.

Looking forward, a 2009 review was done by running a security constrained dispatch (SCD) model that is indicative of the market dispatch that may be expected for 2009 with planned and proposed projects from MTEP 05 included. The SCD model indicates that of the 251 flowgates that now show negative AFC, 15 of these appear to be significant drivers of congestion costs under the market dispatch, as indicated by the high shadow prices and large number of binding hours associated with these Flowgates. Consequently, a majority of the flowgates with negative AFC do not have a significant impact on Day 2 market operations.

Three of the 15 flowgates in Midwest ISO with higher constraint costs and hours have projects identified to mitigate them. That leaves 12 of the 251 FG that currently show negative AFC values and that therefore limit commercial transactions, for which there are no planned solutions in place and that continue to show the potential under the market dispatch to cause congestion. These flowgates are tabulated in Table 6.4-2 along with the market model congestion parameters: Sum of Flowgate Price at Max (annual value), Average Price at Max (shadow price), Hours at Max (binding hours).

Table 6.4-2
Flowgates with Negative AFC and Congestion in 2009 SCD Model

Flowgate Name	Min. AFC	TLR Hours by FG from 1/1/2001 to 12/31/04	Hours at Max	Sum of Flowgate Price at Max $	Average Price at Max $	Project from Appendix A
Moberly–Overton 161 (flo) Thomas Hill–McCredie–Kingdom City 345	-158		4360	$257,240	$59	
Genoa–Coulee 161 (flo) Genoa–LaCrosse 161	-179	219	1907	$150,920	$79	Proposed Genoa–Coulee 161 kV line upgrade to 304 MVA - 12/31/08 (Branch 313)
Cassville–Nelson Dewey 161 (flo) Wempletown–Paddock 345	-73	36	6465	$129,710	$20	Wempletown–Paddock 345 kV line #2 project in 2005 (Branch 344)
Renshaw–Livingston 161 (flo) E. W. Frankfort-Shawnee 345	-58	86	2461	$112,870	$46	
Northside–Jeffersonville Jct. 138 (flo) Northside–Beargrass 138	-49		112	$74,700	$667	
MH_SPC_W	-110	45	4509	$61,070	$14	
Rivermines–Fredricktown 138 (flo) St. Francis–Lutesville 345	-114		467	$31,320	$67	
N. Coulterville–Cahokia 230 (flo) Pinckneyville–St. John 230	-98		134	$13,170	$98	Upgrade planned for 2007 to increase rating to 400/475 SN/SE.
MH_IMO_E	-28		4671	$11,180	$2	
Columbia–Portage 138 #1 (flo) Columbia–Portage 138 #2	(84)		56	$7,940	$142	Uprate Portage–Columbia double ckt 138 kV line terminal equipment in 2005 (BR 422, 423)
Kenton–Wedonia 138 (flo) Spurlock–Maysville Junction 138	(14)		56	$5,940	$106	
Hills 345/161 Xfm (flo) Duane Arnold Unit	(119)		46	$4,010	$87	
Hills 345/161 Xfm (flo) Tiffin–Arnold 345	(88)	55	46	$4,010	$87	
Murdock–Sidney 138 (flo) Sidney 345/138 Xfm	(54)		15	$1,360	$91	
Kansas–Murdock 138 (flo) Sidney 345/138 Xfm	(19)		2	$220	$109	

6.4.1.3 History of TLR Curtailments

This historical review is based on including a flowgate (FG) as a Midwest ISO flowgate if the facility is under the Midwest ISO Reliability Authority (RA). For example, this includes flowgates owned by Midwest ISO TO's, and includes flowgates of non-member systems in the MAPP region that have their RA functions contracted to Midwest ISO. On this basis, there are 841 Midwest ISO flowgates listed in the September, 2004, NERC book of flowgates. TLR was called on 316 of these flowgates during the 48-month period from January 1, 2001, through December 31, 2004. Over this period, 24 Midwest ISO flowgates accounted for 67% of flowgate hours in TLR (each of these 24 flowgates were in TLR for 1% of the time or more). The January 1, 2001 start was selected because at that time curtailment practices became uniform over the entire Eastern Interconnection. NERC began saving data directly from TLR events and placed it in a database. The following review is based on hourly information from the NERC database.

Figure 6.4-2 is a time of day illustration of the total hours that flowgates were required to be under TLR in the Eastern Interconnection, and the portion of TLRs called by the Midwest ISO RA. TLR is more predominant during the active hours of the day. The late PM and early AM hours experience about half the TLR hours as during the mid day hours.

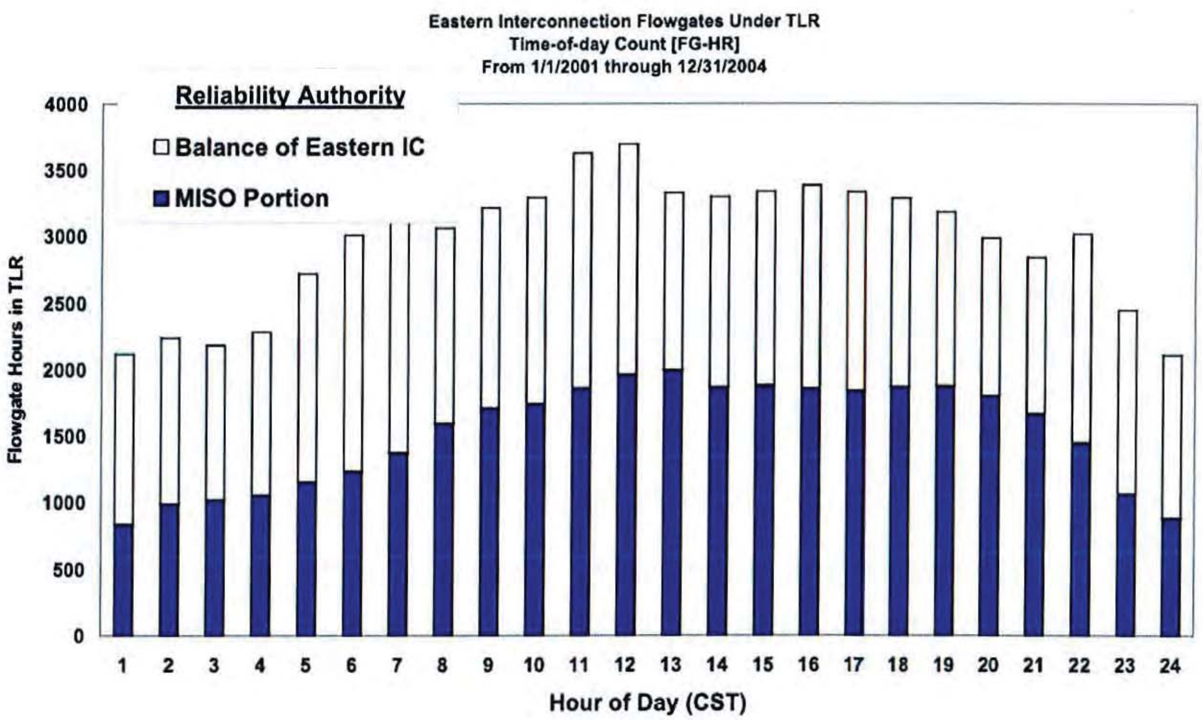

Figure 6.4-2. Midwest ISO Flowgate TLR Hours by Time of Day Relative Eastern Interconnection

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Nine levels of TLR are listed below. Figure 6.4-2 and other summaries in this report are inclusive of the TLR levels ranging from curtailing transactions (Level 3a) to taking Emergency action (Level 6).

Level 0: Level 0 refers to normal operation. This accounts for transactions that were defaulted to zero MW due to improper Tag information.

Level 1: Notify Reliability Coordinators of potential operating security limit violations

Level 2: Hold interchange transactions at current levels to prevent operating security limit violations

Level 3a: Curtail transactions using Non-firm Point-to-Point transmission service to allow transactions using higher priority Point-to-Point transmission service

Level 3b: Curtail transactions using Non-firm Point-to-Point transmission service to mitigate operating security limit violations

Level 4: Reconfigure transmission system to allow transactions using Firm Point-to-Point transmission service to continue

Level 5a: Curtail transactions (pro rata) using Firm Point-to-Point Transmission Service to allow new transactions using Firm Point-to-Point Transmission Service to begin (pro rata)

Level 5b: Curtail transactions using Firm Point-to-Point transmission service to mitigate operating security limit violations

Level 6: Emergency action.

Figure 6.4-3 illustrates grouping Midwest ISO curtailments by time of day and TLR Level. The totals are the same as the Midwest ISO portion in Figure 6.4-2, but in addition Figure 6.4-3 shows how the contribution from each priority level varies throughout the day. Levels 3 and 4 are the most significant contributors to causing the daily pattern. Figure 6.4-4 illustrates grouping Midwest ISO curtailments by month and TLR Level. This reflects a general increasing trend, but can experience both high and low periods of activity. The lowest periods are during late winter and early spring.

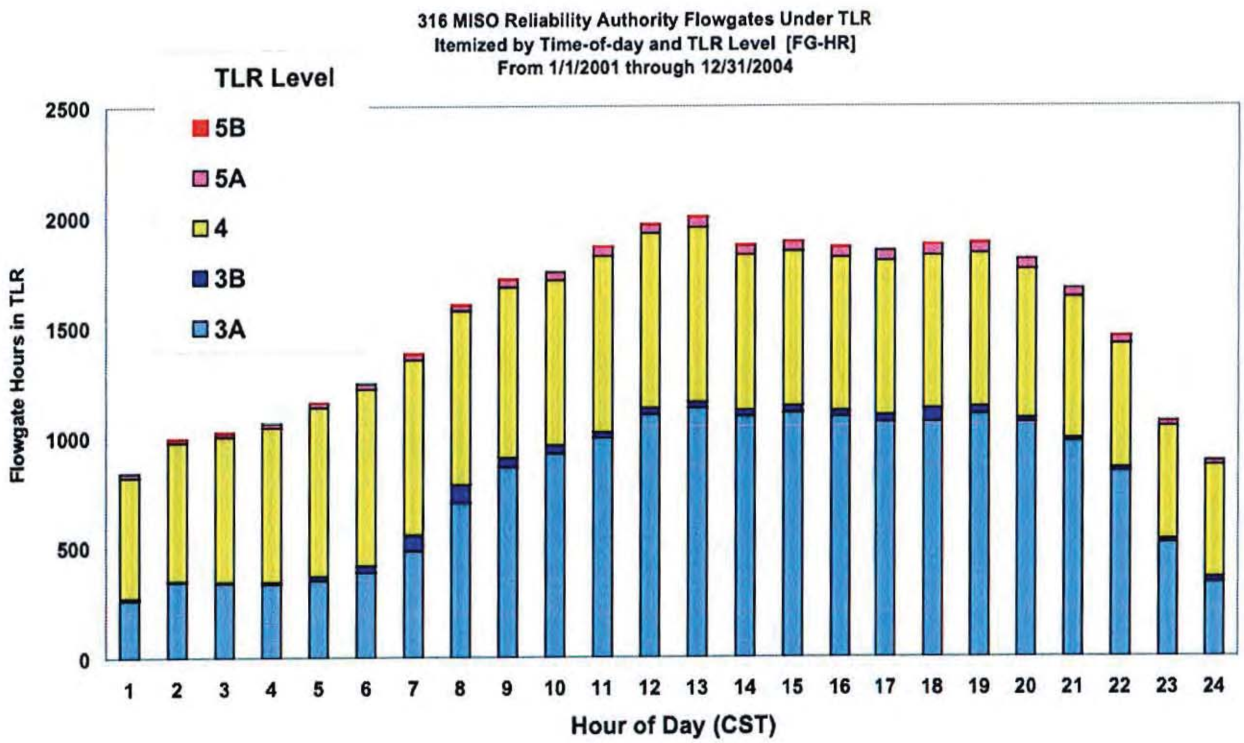

Figure 6.4-3. Midwest ISO Flowgate Hours by Time of Day

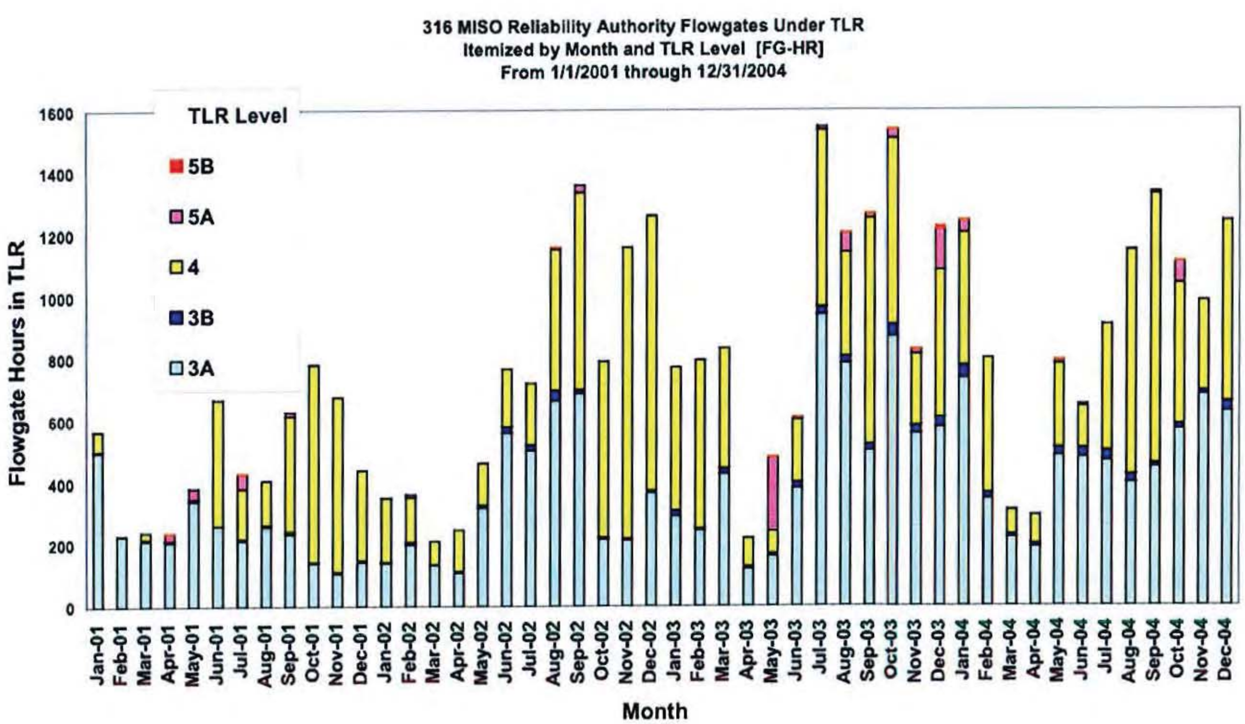

Figure 6.4-4 Midwest ISO Flowgate Hours by Month

Figure 6.4-5 shows the TLR hours distributed over the predominant 24 Midwest ISO flowgates involved during the same 48-month period. The 24 FG shown in Figure 6.3-5 accounted for two thirds or 67% of all Midwest ISO TLR hours. Similarly, the top eleven flowgates included in Figure 6.3-4 accounted for half of all Midwest ISO TLR hours.

There has been a flattening effect compared to the analysis in MTEP 03. In MTEP 03 just 19 FG's accounted for 80% of the TLR hours where as currently it would take the aggregate history of 44 FG's to account for 80% of the Midwest ISO TLR hours. This flattening effect is in part due to the previous 24 months of history having involved TLR on only 110 FG's versus the present 48-month history base where TLR was called on 316 FG's. The increased time frame increases the likelihood of TLR having been called on a larger diverse collection of FG's across the system.

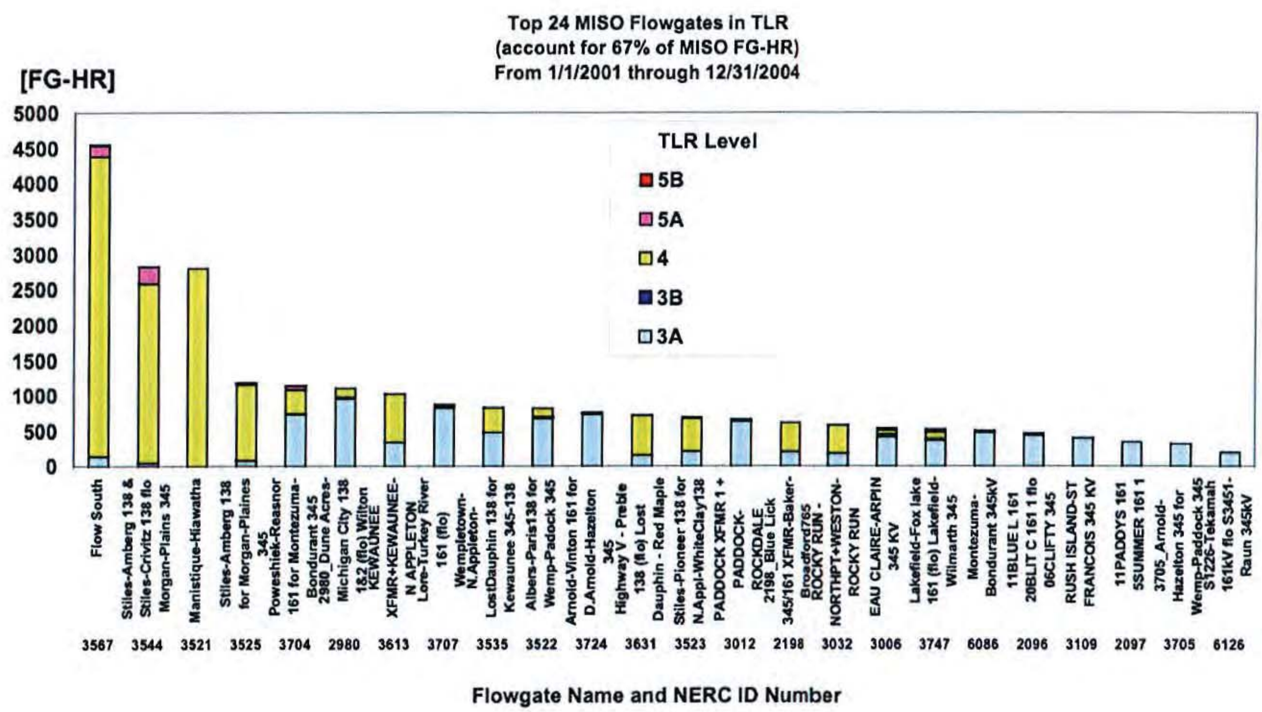

Figure 6.4-5 Top 24 Midwest ISO Flowgates in TLR Accounting for 67% of Midwest ISO FG-HR from 1/1/2001 through 12/31/2004 Midwest ISO TLR

The flattening effect is most clear when the TLR activity is itemized by FG and by month. Figure 6.4-6 shows the monthly TLR hours for the leading ten Midwest ISO flowgates individually and the balance of 306 FG combined, over the 48-month period. This demonstrates how curtailments on specific flowgates vary over time since they are dependent upon load levels, generation outage patterns, and transmission outage schedules. Clearly some FG's were active early in the 48-month period and different FG's contribute more heavily later on. Such variables affect the type and location of the competing generation that comprises the market at any moment. The detailed monthly TLR patterns for the top 24 FG's are illustrated in Appendix D9.

The transmission system imposes constraints on the market by being the reason for refusing transmission service, need for TLR calls, or (in the near future) driving LMP prices higher. Absent any constraints or loss effects, only the generation or market prices determine the cost of energy. In the past generation costs plus a margin defined a sell or buy price across the system. After April 1, 2005 the part within the MISO Market is the market cleared price in DA or RT, which is the same in the whole market. After April 1, 2005 the reason why we have different LMP's at different CPNodes is we have different congestion (sometimes zero) and loss cost at different CPNodes

Most of the time the transmission system has adequate capability to maintain reliability while not constraining the generation dispatch. The most frequently curtailed Midwest ISO flowgate in Figure 6.4-5 represents a constraint to generation dispatch or market preferences about 12.9% of the time. In the 48-month period, curtailments affected Firm transmission service (those at TLR Level 5a or 5b) totaled 806 Flowgate Hours. This represents 2.3% of the time in the 48-month period. Of the 806 Flowgate Hours at Level 5 one incident in the northern WI and Upper MI area alone, accounted for 240 Flowgate Hours.

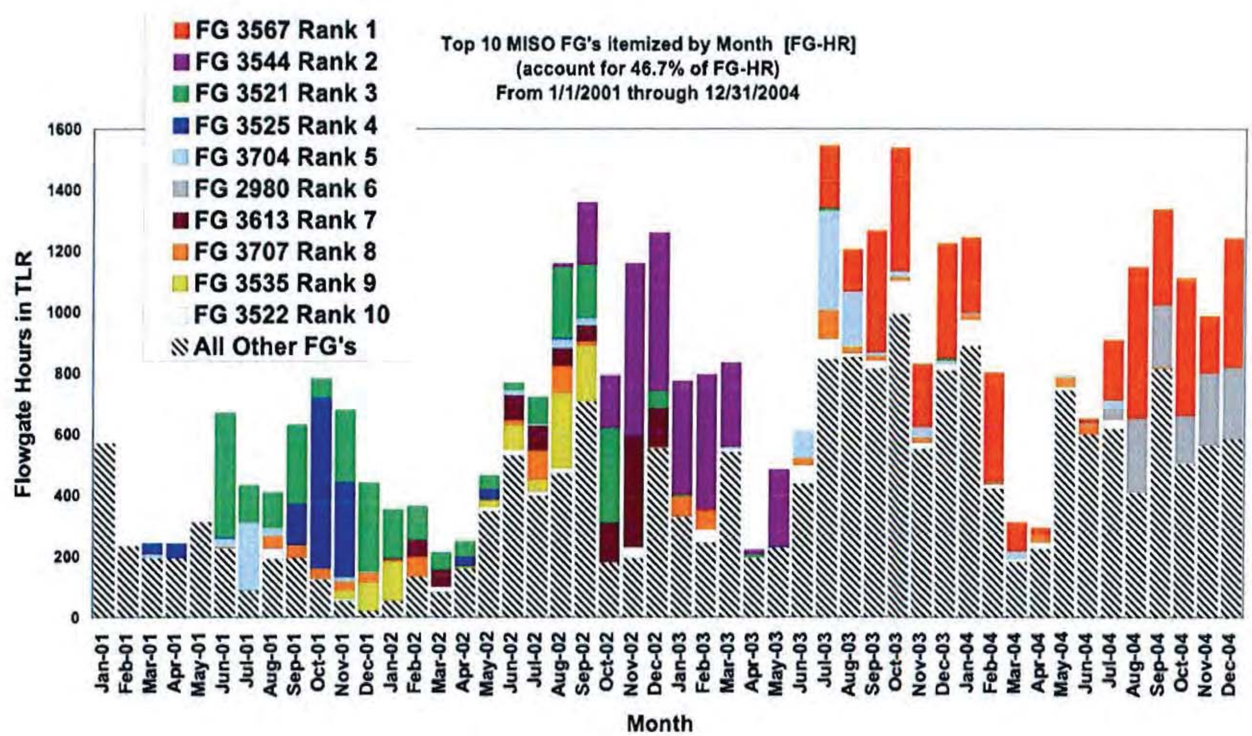

Figure 6.4-6. Monthly TLR Itemized for 10 Predominant Midwest ISO Flowgates (See Figure 6.4-5 X-Axis Labels for FG Name Associated with NERC FG Number)

Figure 6.4-7 displays the relative contribution of all 316 FG's. The 80% of TLR accumulation from the top most 44 FG is noted, along with the 350-hour mark which represents one percent of the time in the 48 month period.

The 80% of TLR accumulation from the topmost 44 FG is noted, along with the 350-hour mark which represents one percent of the time in the 48 month period. The 350-hour mark is the cutoff level that defines the top 24 Midwest ISO flowgates.

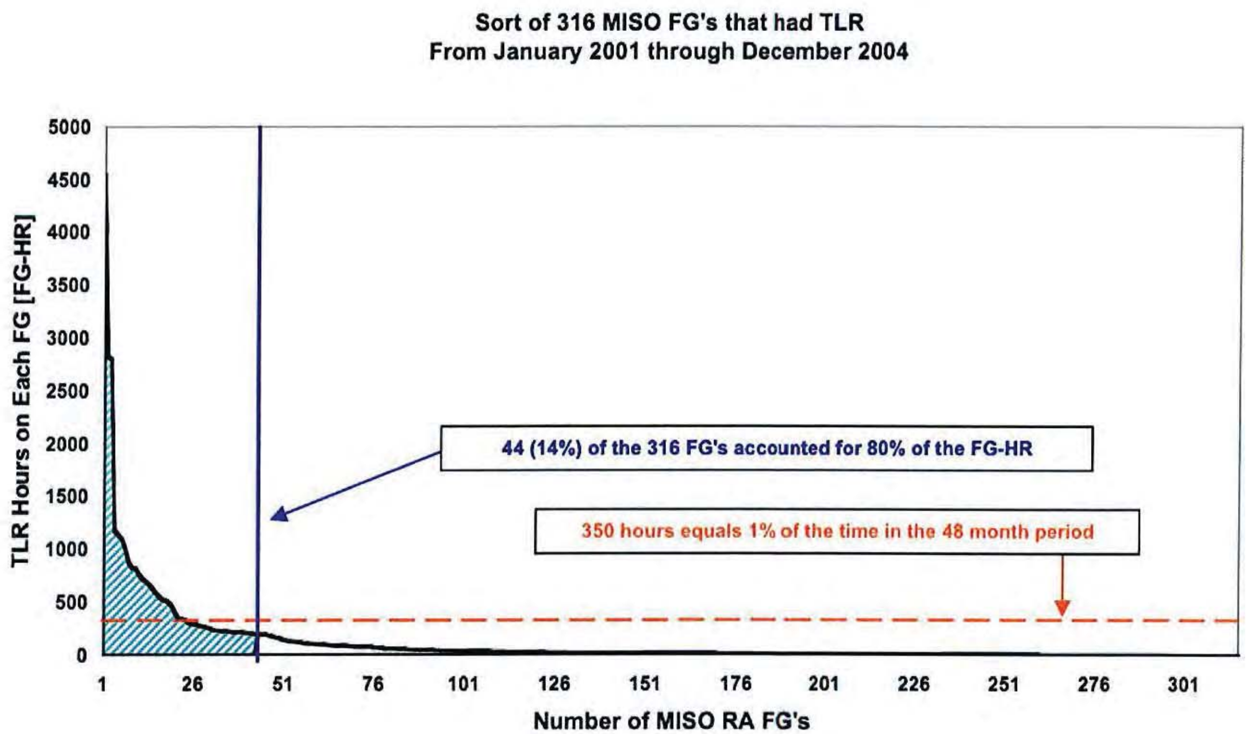

Figure 6.4-7 Sort of 316 Midwest ISO Reliability Authority Flowgates that had TLR From Jan 2001 through December 2004

6.4.1.4 Resolution of Flowgates that are Constraints to Commercial Operation

Plans identified in this Midwest ISO Transmission Expansion Plan address many of these constraints that fall within the Midwest ISO footprint. The following chart in Figure 6.4-8 shows the specific flowgates that have most frequently involved TLR and that are addressed by projects in this plan, highlighted in white circles.

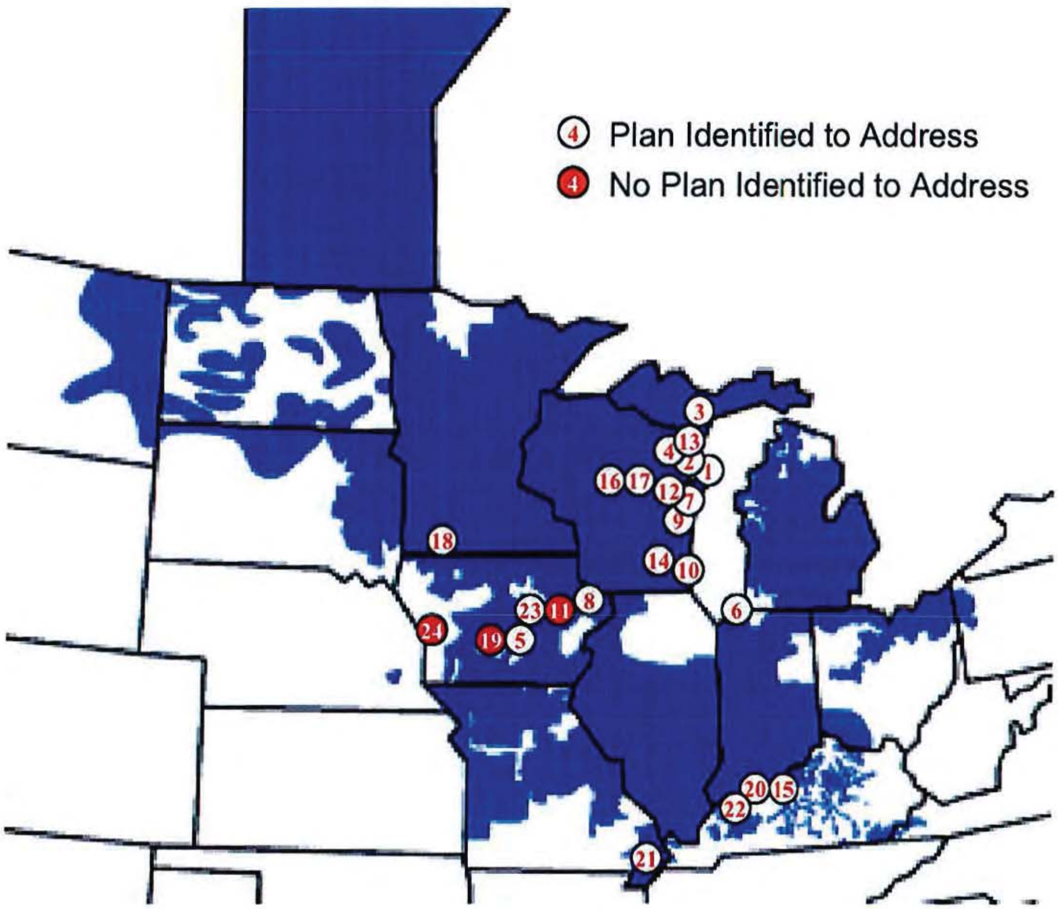

Figure 6.4-8. Specific Flowgates That Have Most Frequently Involved TLR

The following Table 6.4-3 lists the member improvements that will contribute to mitigating TLR on 21 of the 24 top Midwest ISO flowgates.

Table 6.4-3: Top 24 Active Flowgates, 21 With Pending or Completed Improvements

MTEP 05 TLR Rank	Flowgate (NERC ID Number)	Pending Improvement or Completed Project (As of MTEP 05)	Year
1	Flow South (NERC 3567)	1) Rebuilding double circuit Plains–Amberg 138 kV line, construct, rebuild and convert the 69 kV & 138 kV line from West Marinett to Amberg as a 138 kV line with portions double circuited with a 69 kV line. 2) Uprate Morgan–White Clay 138 kV. 3) Rebuild Morgan–Stiles 138 kV. 4) Uprate North Appleton–White Clay 138 kV. 5) Considering adding a series reactor to the Highway V–Preble 138 kV line. 6) Construct a 345 kV line from a new Werner West SS to Morgan.	1) 2005 2) 2005 3) 2005 4) 2005 5) 2005 6) 2009
2	Stiles–Amberg 138 & Stiles–Crivitz 138 flo Morgan–Plains 345 (NERC ID 3544)	1) Rebuilding double circuit Plains–Amberg 138 kV line, construct, rebuild and convert the 69 kV & 138 kV line from West Marinett to Amberg as a 138 kV line with portions double circuited with a 69 kV line. 2) Rebuild the Stiles–Amberg double circuit 138 kV line	1) 2005 2) 2006
3	Manistique–Hiawatha 69 kV Circuit (NERC ID 3521)	1) Rebuilding single circuit 69 kV line to double circuit 138 kV 2) Operate rebuilt line at 69 kV until Morgan–Werner West 345 kV line is in-service	1) 2005 2) 2009
4	Stiles–Amberg 138 kV Circuit flo Morgan–Plains 345 kV Circuit (NERC ID 3525)	1) Rebuilding double circuit Plains–Amberg 138 kV line, construct, rebuild and convert the 69 kV & 138 kV line from West Marinett to Amberg as a 138 kV line with portions double circuited with a 69 kV line. 2) Rebuild the Stiles–Amberg double circuit 138 kV line	1) 2005 2) 2006
5	Poweshiek–Reasnor 161 for Montezuma–Bondurant 345 (NERC 3704)	Reconductor of Poweshiek–Reasnor 161 kV line to 326 MVA	2005
6	Dune Acres–Michigan City 138 1&2 (flo) Wilton Center–Dumont 765 (NERC 2980)	Both 138 kV circuits from Dune Acres to Michigan City are planned for reconductor to 186 MVA capacity.	2005
7	KEWAUNEE XFMR+KEWAUNEE–N APPLETON (NERC 3613)	Should be resolved with the installation of the Forest Junction transformer in 2003. In addition, Kewaunee redispatch is still an option	2003
8	Lore–Turkey River 161 (flo) Wempletown–Paddock 34 (NERC 3707)	1) ATCLLC's Wempleton–Paddock 345 kV circuit #2 2) Long term proposal of a new 345 kV line to north-central Illinois or northeast Iowa	1) 2006 2) 2014
9	N.Appleton–LostDauphin 138 flo Kewaunee 345-138 TR (NERC ID 3535)	Relief is provided by the Forest Jct. Project which loops the Point Beach–Arcadian 345 line into a new 138 kV substation with 345-138 kV TX's	2003
10	Albers–Paris138 for Wemp–Padock 345 (NERC 3522)	Construct Wempletown–Paddock 345 kV circuit #2.	2005
11	Arnold–Vinton 161 for loss of D. Arnold–Hazelton 345 (NERC 3724)	None. (Not significantly constrained in 2009 SCD model.)	
12	Highway V - Preble 138 (flo) Lost Dauphin - Red Maple 138 (NERC 3631)	Install a series reactor on the Highway V - Preble 138 kV line	2005

Table 6.4-3 Twelve of Top 24 Flowgates With Pending or Completed Improvements (cont.)

MTEP 05 TLR Rank	Flowgate (NERC ID Number)	Pending Improvement or Completed Project (As of MTEP 05)	Year
13	Stiles–Pioneer 138 flo N.Appl–WhiteClay138 (NERC ID 3523)	Rebuild the Morgan–Falls–Pioneer-Stiles 138 kV line to double circuit 138 kV and operate as a single circuit initially	2006
14	Paddock XFMR 1 + Paddock Rockdale (NERC 3012)	Construct Wempleton–Paddock 345 kV circuit #2	2005
15	Blue Lick 345/161 XFMR–Baker–Broadford765 (NERC 2198)	Proposed Mill Creek–Hardin County 345 kV line, a part of Trimble County Outlet #2 project	2009
16	Rocky Run–NorthPT+ Weston–Rocky Run (NERC 3032)	Rocky Run-Northpoint has had switches replaced. Northpoint–Weston will be rebuilt in 2006. Weston–Rocky Run will see relief with the new Gardner Park ss planned for 2006.	2006
17	Eau Claire–Arpin 345 kV Circuit (NERC ID 3006)	Arrowhead-Weston 345 kV line	2008
18	Lakefield–Fox lake 161 (flo) Lakefield-Wilmarth 345 (NERC 3747)	Circuit # 2 from Lakefield-Fox Lake 161 kV	2006
19	Montezuma–Bondurant 345 kV (NERC 6086)	None (Not constrained in 2009 SCD model)	
20	11BLUE L 161 20BLIT C 161 1 flo 06CLIFTY 345 11TRIMBL 345 (NERC 2096)	Proposed Mill Creek–Hardin County 345 kV line, a part of Trimble County Outlet #2 project	2009
21	Rush Island–St. Francois 345 kV (NERC 3109)	A second Rush Island–St. Francois 345 kV line was completed in 2003, eliminating this line as a limit to system transfers.	2003
22	11PADDYS 161 5SUMMER 161 1 (NERC 2097)	Proposed Mill Creek–Hardin County 345 kV line, a part of Trimble County Outlet #2 project	2009
23	Arnold–Hazelton 345 for loss of Wempleton–Paddock 345 (NERC 3705)	1) ATCLLC's Wempleton–Paddock 345 kV circuit #2 2) Long term proposal of a new 345 kV line to north-central Illinois or northeast Iowa	1) 2006 2) 2014
24	S1226–Tekamah 161 kV flo S3451–Raun 345 kV (NERC 6126)	None (Not significantly constrained in 2009 SCD model.)	

Legend: flo means "for loss of"

As can be seen, there are three Flowgates with substantial TLR hours for which there is no specific plan in place to resolve these constraints. As with the AFC analyses above, a review was made of a 2009 security constrained dispatch model that is indicative of the market dispatch that may be expected for 2009 with planned and proposed projects from MTEP 05 included. The SCD model indicates that of these three high TLR flowgates without an associated expansion plan solution, none of these are expected, based on the SCD model to be significant drivers of congestion costs under the market dispatch, as indicated by the low shadow prices and binding hours associated with these Flowgates.

6.4.1.5 Financial Transmission Rights Allocations with Binding Constraints

With the start of the Midwest ISO Midwest Energy Market in March of 2005, addressing Financial Transmission Rights (FTR) will now become part of the MTEP transmission expansion planning process. The first FTR allocation was completed by Midwest ISO in January 2005, which produced a list of binding transmission constraints. This list of binding constraints was reviewed in light of the expansion plan developed in MTEP 05(see table 6.4-4 below).

Table 6.4-4: FTR Allocation Binding Constraints with System Upgrade Project

Binding Constraint Name	Contingency	System Upgrade or Comment	App A Branch
Richland–Ridgeville 138	Midway–Naomi–Wauseon 138, Naomi–Richland 138	Proposed upgrade to 193MVA - 6/1/2005 (FE)	
Power JctB–Power; 138	Duck Creek–Tazewell 345	None	
Bluemnd6–Butler 138	Arcadian–Granville 345	Lannon Jct. Substation in 2007.	103
Genoa–Coulee 161	Genoa–LaCrosse 161	Proposed line upgrade to 304 MVA - 12/31/2008 (DPC)	313
Mason Cy–1346A TP 138	Duck Creek–Tazewell 345	None	
Newton–Effinghm 138	Newton–Casey 345	Planned line reconductor to 382 MVA - 6/2006	390
Fawkes Tap–Fawkes 138	Fawkes EKPC–Fawkes 138	Proposed line upgrade to 277 MVA - 11/30/2007	485
Farr RDJ–Tippy 138	Ludington–Keystone 345	Planned line upgrade to 286.8/329.9 MVA - 5/1/2005 and Tippy–Hodenpy 138 rebuild - 6/1/2006	534, 535
Gibson C–GibsonCP 138	Base Case	Gibson City Plant generation can be designated for a maximum of 174 MW unless Gibson City S–Brokaw and Gibson City S–Paxton 138 kV lines are upgraded.	
Green River Steel–Cloverport 138	Smith–Hardin County 345	None	
Havana–Ipava 138	Havana–Monmouth 138	Planned line reconductor to 243 MVA - 6/2006	393
Clinton RT54– SClinton 138	Brokaw–Statefarm–SBloom 138	None	
Clinton Tap–SBloomington 138	Brokaw–Statefarm - SBloom 138	None	
Lakefield Jct–Fox Lake 161	Lakefield –Wilmarth 345	Lakefield–Fox Lake 161 kV line #2 434MVA - 4/1/2006	266
Lyon Co–Marshall 115	Base Case	Upgrades for wind outlet or Marshall area load serving.	537
Lyon Co–Marshall 115	Big Stone gen #1	Upgrades for wind outlet or Marshall area load serving.	537
Monroe–Wayne 345	Monroe–Brownstown S 345	None	
Moranvl4 230/115 transformer	Base Case	None	

Table 6.4-4: FTR Allocation Binding Constraints with System Upgrade Project (cont.)

Binding Constraint Name	Contingency	System Upgrade or Comment	App A Branch
Maries 138/161 transformer	Bland-Franks 345, Maries-Lakeside 138	Planned Callaway-Franks 345 kV line -12/2006. The Maries 138/161 kV Xfmr should not be the limit after implementation of the Maries operating guide.	46
Palmyra 345/161 Xfm	Palmyra Tap-Sub T 345	None. Emergency rating of Palmyra 345/161 kV Xfmr is 370 MVA for the outage of the Louisa-Sub T-Hills 345 kV line in Iowa. (Palmyra Tap-Sub T outage is used as a proxy to model this contingency).	
Pruntytown-Mt. Storm 500	Black Oak-Bedington 500	PJM constraint	
Reasnor-Des Moines 161	Montezuma-Bondurant 345	Planned line upgrade to 326 MVA - 6/1/2007	1020
Richer-Roseau 230	Dorsey-Roseau 500	SPS implemented after Tier 1. No constraint with Special Protection Scheme.	n.a.
Spokane-Tinken 120	Base Case	A radial line.	
Weston 345/115 tx	Weston gen	Gardner Park substation in 6/2006	136, 137
Weston-Rocky Run 345	Weston gen	Gardner Park substation in 6/2006	136, 137

Twenty five binding constraints were identified. Fourteen of the constraints have solutions identified from the existing transmission expansion plan developed in MTEP 05. The remaining constraints don't have a solution identified at this time. As the constraints were just identified in January of 2005, when the MTEP 05 report was being written, additional analysis and plan development will be performed in future MTEP studies to address the long-term binding constraints from the FTR allocation process.

(Footnotes)

[1] Because the Midwest ISO is the Reliability Authority (RA) for an area larger than its Transmission Provider footprint, Midwest ISO calls TLR on up to 841 NERC flowgates.

6.4.2 Deliverability to Load

The Midwest ISO Reliability Authority (RA) area was subdivided into 14 LOLE zones for testing the ability of a load zone to meet its reliability requirements through internal generation plus the use of transmission system for import of external resources. Each of these zones were either consistent with an existing Control Area (CA) or were an aggregate of more than one CA.

In 2009, for 5 of the 14 zones the internal generation mix alone was sufficient to meet the reliability criteria of 1 day in 10 years or an Loss of Load Probability (LOLP) value of 0.1, without depending on support from transmission ties. For the remaining 9 zones, the amount of transmission support needed to sustain reliability criteria was within the import transfer capability of the transmission. Tables 6.4-5 and 6.4-6 list the findings for each zone, with the following discussion providing some background on the table content. In 2004, for 6 of the 14 zones the internal generation was sufficient to meet the criteria.

Two stages of calculations were done. First the Loss Of Load Probability was calculated on the basis that the only resource was the generation internal to a zone. This first stage interim value is referred to as the LOLP without transmission support. Without support meaning without support of transmission tie lines that could be considered as a resource to complement the internal generation supply.

Where an area's stand-alone or without tie line support LOLE value was below the 1 day in 10 year criteria, the amount of additional proxy generation that would achieve the 1 day in 10 year level was calculated.

The amount of the proxy generation was equated to a level of transmission capacity into the area that would be needed to sustain the 1-day in 10-year level. In the last step the ability of the transmission system to provide import capacity was determined, and this import transfer capability was compared to the amount needed to sustain the reliability criteria for each area.

The ability of the transmission system to provide import capacity was quantified by calculating the First Contingency Total Transfer Capability (FCTTC) in to each Sink Zone. The FCTTC was accomplished by using a MUST run of each area to calculate the First Contingency Incremental Transfer Capability (FCITC) and adding the base case import. Tables 6.4-5 and 6.4-6 summarize the generation and transmission capability findings for each of the 14 LOLE areas or Sink Zones.

Table 6.4-5: Imports needed for meeting Reliability criteria in 2004

LOLE Zone	FCTTC (MW)	Imports Needed (MW)	Import Capability Margin (MW)	Comments
MAPP1 (1)	6947	2432	4515	
MAPP2 (2)	-761	0	n/a	Self Sufficient, Normally Exporting in Summer and Importing in Winter
MAPP3 (3)	2919	0	2919	Self Sufficient, LOLP = 0.00169 without support
ATC (4)	2546	1000	1546	
SMAIN (5)	6973	0	6973	Self Sufficient, LOLP = 0.00038 without support
METC (6)	2325	0	2325	Self Sufficient, LOLP = 0.0027 without support
ITC (7)	3318	2862	456	
FE (8)	4504	0	4504	Self Sufficient, LOLP = 0.005 without support
CIN (9)	5682[2]	1275	4407	
HE (10)	1279	525	754	
IPL (11)	1243	625	618	
LGEE (12)	1037	0	1034	Self Sufficient, LOLP = 0.002 without support
NIPS (13)	2508	850	1658	
SIGE (14)	393	130	263	

Table 6.4-6: Imports needed for meeting Reliability criteria in 2009

LOLE Zone	FCTTC (MW)	Imports Needed (MW)	Import Capability Margin (MW)	Comments
MAPP1 (1)	8082	1200	6882	
MAPP2 (2)	-602	0	1050[3]	Self Sufficient, Normally Exporting in Summer and Importing in Winter
MAPP3 (3)	2191	0	2191	Self Sufficient, LOLP = 0.0004 without support
ATC (4)	2408	700	1708	
SMAIN (5)	6802	0	6802	Self Sufficient, LOLP = 0 without support
METC (6)	4900	0	4900	Self Sufficient, LOLP = 0.03 without support
ITC (7)	4520	4910	-390	ITC needs additional 390 MW to meet the criteria
FE (8)	3773	300	3473	
CIN (9)	11649	7000	4649	
HE (10)	1054	650	404	
IPL (11)	977	900	77	
LGEE (12)	1425	0	1425	Self Sufficient, LOLP = 0.0004 without support
NIPS (13)	2874	1555	1319	
SIGE (14)	281	341	-60	SIGE needs an additonal 60 MW to meet criteria.

In 2004, all 14 LOLE zones meet the reliability criteria of 1 day in 10 year. This translates into all zones having sufficient import capability to meet the load obligations in 2004. When load was increased by 5% in all 14 LOLE zones within Midwest ISO footprint, all zones meet the criteria also. (Table 6.4-7)

In 2009, generators from the interconnection queue were added to the 2004 case. Adding generators of Interconnection Agreement Executed (IAE) and Filed (IAF) status from the queue, International Transmission Company (ITC) and Southern Indiana Gas and Electric (SIGE) do not have enough import capability to satisfy the criteria. ITC had an LOLP of 0.262 and SIGE had 0.221 LOLP. (Table 6.4-8) Adding additional generators from the queue of Interconnection Agreement Pending (IAP) status and other "active" status generators didn't help ITC and SIGE since those generators were from LGEE, NSP (MAPP1 LOLE zone), WPS (ATC zone), and SIPC (South MAIN zone) areas. From imports needed in 2009 Table 6.4-6, ITC needs 390 MW of additional imports or new generation in the zone to meet the reliability criteria. Efforts are underway for more detailed analysis to determine imports needed for ITC using PROMOD software. This study will focus on import and export capabilities of companies in Michigan area. Similarly SIGE needs 60 MW of additional import capability or new internal generation to meet reliability criteria in 2009.

Detailed report is given in the appendix.

(Footnotes)

[1] Imports Needed represents the firm capacity a zone needs, to meet the 1 day in 10 reliability criteria. This value was found from "Annual Remaining Load Curve" in MARELI. Each zone's LOLP was based on that zone's peak load hour for that year instead of the system peak. This note applies to both 2004 and 2009.

[2] Cinergy's FCITC value in 2004 is less than what Cinergy found in its internal analysis.

[3] Considering sufficient capacitors turning ON in northern MAPP and minimal load growth and network changes, the import capability margin is expected to remain near 1050 MW in 2009.

Table 6.4-7: 2004 LOLP Results - Base Case and Load Sensitivity Case

Target LOLP (Loss of Load Probability) = 0.1 day per year (1 day in 10 year)

	01MAPP1	02MAPP2	03MAPP3	04ATCLLC	05MAINS	06METC	07ITC
Base Case	–	–	–	–	–	–	–
Load Sensitivity	–	–		–	–	–	–
	08FEE	09CIN	10HEREC	11IPL	12LGEE	13NIPSCO	14SIGEE
Base Case	–	–	–	–	–	–	–
Load Sensitivity	–	–		–	–	–	–

Note: Load Sensitivity Increased load by 5% in all 14 areas.

Table 6.4-8: 2009 LOLP Results - Base Case and Sensitivity Cases

Target LOLP (Loss of Load Probability) = 0.1 day per year (1 day in 10 year)

	01MAPP1	02MAPP2	03MAPP3	04ATCLLC	05MAINS	06METC	07ITC
With IAs E&F	-	-	-	-	-	-	0.262
With IAP	-	-	-	-	-	-	0.262
With IAs E&F - Coal	-	0.310	-	-	-	-	0.423
With IAs E&F - FOR	-	0.460	-	-	-	-	0.567
	08FEE	09CIN	10HEREC	11IPL	12LGEE	13NIPSCO	14SIGEE
With IAs E&F	-	-	-	-	-	-	0.221
With IAP	-	-	-	-	-	-	0.221
With IAs E&F - Coal	-	-	-	0.261	-	-	0.455
With IAs E&F - FOR	-	-	-	0.191	-	-	0.504

Note:

IAs E&F	Agreements Executed (Signed) and Filed
IAP	Agreements Pending
IAs E&F - Coal	Coal Units less than 75 MW are retired in all 14 Midwest ISO Areas
IAs E&F - FOR	Forced Outage Rates were increased by 25% in all 14 Midwest ISO Areas

6.4.3 Small Signal Stability Analysis

As part of the MTEP 05 Baseline Reliability Study, Midwest ISO performed a Small Signal Study Analysis (SSSA) study for the whole Midwest ISO footprint and non-Midwest ISO MAPP members.

The full-size Eastern Interconnection light load model was selected to run the study. The case was studied and reported in this report.

The study work consist of:

- Developed SSAT model
- Power transfers and inter-area modes: three critical modes were identified
- Impacts of Forbes SVC on inter-area mode
- Impacts of loads model

There are multiple inter-area modes existing in the system. Increasing the power transfer from MAPP region to southeast regions causes the damping of one critical inter-area mode decreasing. The power transfers can move both frequency and damping of the related inter-area modes. Three critical inter-area modes were identified.

A few conclusions can been drawn from the study:

i. The electrical distance (impedance) between the generation center and the load center is the fundamental factor to cause inter-area oscillations

ii. The longer distance could cause lower damping of the inter-area modes

iii. The heavier power transfer could cause lower damping of the inter-area modes

The studies showed that the inter-area modes were well damped in the summer peak conditions (e.g. baseline 04 & 09 cases).

The low damping or undamping oscillation could happen under certain heavy long distance power transfer conditions. In the future power market circumstance, more and more power will be long-distance transferred from low price generation area to the high price load centers. We need pay more attention to the inter-area modes. More dynamic/small signal studies are necessary for the various operation conditions.

Possible solutions to improve the damping of the inter-area modes (idea only):

1) Identify several critical inter-area stability interfaces through further small signal/dynamic stability studies under various conditions – generations, loads and power transfers

2) Set up the stability interface limits, which are normally less than the thermal limits. The inter-area modes damping can be maintained to a safe level by limiting the power flows on these interfaces

3) Transmission line expansion plans can directly increase damping of some inter-area modes by decreasing the electrical distance (impedance) between the generators and the loads

4) Set up the supplementary controllers through existed PSS, SVC or HVDC is an efficient way to improve the damping of one (one group of) inter-area mode

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Section 7: Exploratory Projects

7.1 General Objectives of Exploratory Studies

In the first Midwest ISO Transmission Expansion Plan, MTEP 03, the Midwest ISO evaluated at a high level the potential economic benefits of large regional transmission projects under various postulated generation development scenarios. MTEP 03 evaluated a dozen such plans based on analysis of the base planned transmission system, and its ability to accommodate substantial new additions of coal and wind generation, as well as gas generation based the interconnection queues at the time. This study is available on the Midwest ISO web site. The transmission and generation scenario analysis showed generally that there was significant potential for the right regional transmission to result in substantial reductions in marginal energy costs, particularly if that transmission was coupled with introduction of low cost coal and wind energy resources.

Among the dozen potentially regionally beneficial expansion concepts reviewed in MTEP 03, two have been addressed further in this MTEP 05, because of the potential benefits that the preliminary analyses showed, and because of significant stakeholder interest in these two concepts. These two expansion concepts are referred to as 1) the Northwest Exploratory Project, and 2) the Iowa–Southern Minnesota Exploratory Project. Both projects would provide enhanced access by coal and wind resources to load centers in the Midwest ISO.

It is the intention of the Midwest ISO to continue the development of these regional expansion projects through further evaluation of the nature, value, and beneficiaries of these plans. The Midwest ISO intends to recommend such plans as these to the Midwest ISO Board of Directors at such time as the Midwest ISO in collaboration with interested stakeholders can complete these evaluations, and a determination of cost responsibility and recovery can be made, consistent with the Midwest ISO tariff and the Transmission Owners Agreement. Additional regional projects of this type may be evaluated by the Midwest ISO in subsequent MTEP based on stakeholder expressed interest and staff resources.

The Northwest Exploratory study involves generation in the Dakotas and transmission upgrades from the Dakotas to Minnesota. The Iowa–Southern Minnesota Exploratory study involves generation in northern Iowa, southern Minnesota, and South Dakota and transmission upgrades from generation to major load centers in Minnesota, Iowa, and Wisconsin. Both studies are in progress and results to date and future work efforts are described in this section.

7.2 Northwest Exploratory Study

Purpose and Introduction

Midwest ISO identified in MTEP 03 a plan to study the expansion of transmission in the Dakotas and into Minnesota with the goal to eliminate existing market constraints in northwestern MAPP. In addition there is a coalition of generation developers, government entities and utilities interested in expanding generation in the Dakota's that will require similar transmission expansion.

The goal of this study is to continue the study effort in the region begun in MTEP 03 for increasing the power delivery capability of the transmission system from the Dakota's and coordinate with the best information available on potential generation expansion to develop a reliability based technical analysis of transmission developments that can enhance the market and meet the regional reliability needs in northwest MAPP region. This study will be the next step in the Midwest ISO evaluation for the MTEP 05 plan. It will provide the transmission information needed for the interested advocacy groups such as the Upper Great Plains Transmission Coalition (UGPTC) and the local utilities in this region to provide the foundation for the final detailed studies required for commitment and regulatory approval for transmission expansion.

To date, only preliminary results have been developed.

Scope

The purpose of this study is to evaluate the incremental delivery capability from potential generation development regions in North Dakota and southeast South Dakota that might be achieved with various transmission development scenarios. This evaluation is to determine the transmission capability added to the system with single 345 and 500 kV transmission additions along with various multiple combinations of these transmission additions. Each transmission option will be evaluated for it's increase in transmission delivery from the potential generation expansion regions to the Twin Cities, it's impact on recognized constrained interfaces, and it's flexibility to accommodate various generation development scenarios.

Issues Under Investigation

- Determine most efficient method of collecting generation from five different geographic sites.
- Determine most beneficial way to deliver power from new potential wind and coal generation locations to load centers.
- Use this information to piece together a full transmission plan that will enable flexibility in implementation.

This evaluation will be based on the increase of transmission capability above the presently recognized limits of the North Dakota Export (NDEX), Manitoba Hydro Export (MHEX) and the Minnesota-Wisconsin Stability Interface (MWSI). The evaluation will be made to encompass a minimum of 2000 MW's of new generation.

The final product is to be a series of projects evaluated for providing the best capability from each site plus for the overall region. It will identify what is accomplished with the best single 345 kV plan, the best single 500 kV plan and the best two, three or any multiple circuit plan required to increase the export capability to the Twin Cities up to a 2000 MW minimum.

The results of this evaluation will provide the necessary information required by Midwest ISO and the utilities to base decisions on the best transmission development concepts for expanding generation in North Dakota and south east South Dakota. This can also provide important information for initiating a Certificate of Need study of any development chosen for further consideration.

Model Development

The Northwest Exploratory Study used the 2009 summer peak model from the MAPP Regional Study Group (RSG). This model was used in performing the Midwest ISO Baseline Reliability Study as part of MTEP 05. All known generation and transmission projects that are expected to be completed and in-service by 2009 were added to the models. This includes the bulk transmission facilities in the Buffalo Ridge area, the Xcel Energy SW Minnesota 825 MW transmission upgrades. Members of the MAPP RSG have reviewed all of these models and have submitted numerous corrections. Alliant West (ALTW), who is a participant on the MAPP RSG, is a MAIN member and has submitted extensive modeling changes after reviewing these cases.

Summer off-peak models will also be available from the latest stability package developed by the Northern MAPP Operating Review Working Group (NMORWG). These cases will include stressed conditions with maximum simultaneous exports over the three previously mentioned constrained interfaces of NDEX, MHEX, and MWSI. Since the presently allowed power flow limit across the NDEX interface results from stability violations at high simultaneous transfer limits, the need for accurate summer off-peak cases will be critical.

The following interface limits were used for the stressed models.

- NDEX = 2080 MW
- MHEX = 2175 MW
- MWSI = 1480 MW

The 2009 summer off peak is a MAPP 2003 series model and the interface limits were changed in the model using the idevs from the UIP package.

Generation Options Examined

The following generation options are used in the study for the transfer study analysis:

Option 1 - Coal Site

500 MW of base load generation level at Belfield, ND connected at Belfield 345 kV bus.

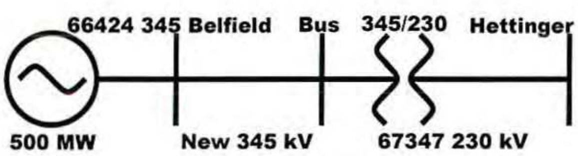


Figure 7.2-1

In order to connect the new generator at Belfield, a new 345 kV line was modeled from Belfield to Hettinger with a new 345/230 kV transformer installed at Hettinger. In addition, a new 345 kV line was also modeled from Hettinger to Oahe and to Watertown to bypass some of the known system constraints on the 230 kV system south of Hettinger towards New Underwood and Rapid City.

Option 2 - Wind Site 1

250 MW of base load generation southwest of Minot, ND, connected to a tap between Leland Olds and Logan.

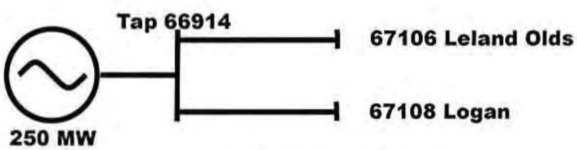


Figure 7.2-2

Option 3 - Wind Site 2

500 MW of base load generation northwest of Ellendale, ND, connected at intersection of Ellendale – Wishek 230 kV line and Leland Olds-Groton 345 kV line.

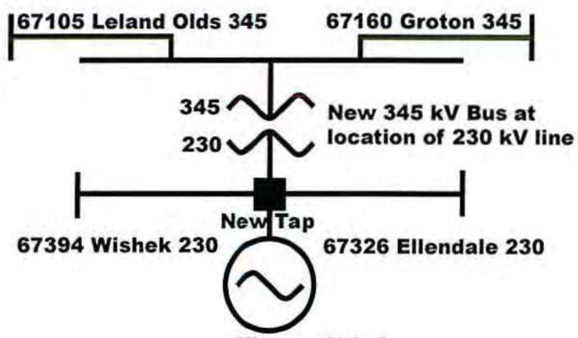


Figure 7.2-3

Option 4 - Wind Site 3

250 MW of base load generation northeast of Fort Thompson, SD connected at the Fort Thompson 230 kV bus.

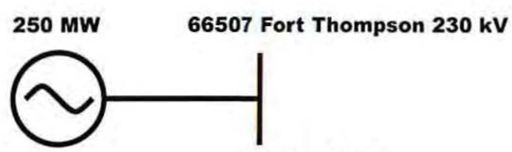


Figure 7.2-4

Option 5 - Wind Site 4

500 MW base load generation in the Buffalo Ridge area connected at Watertown 230 kV bus.

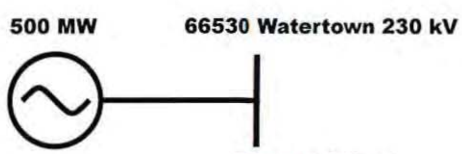


Figure 7.2-5

Transmission Options in The NW Exploratory Study

Seven initial transmission projects were studied as part of NW Exploratory Study. These are explained below. All of the below options are new construction options.

Table 7.2-1: Transmission Option 1

From	To	kV
Antelope Valley	Jamestown	345
Jamestown	Maple River	345
Maple River	Audubon	345
Audubon	Badoura	345
Badoura	Riverton	345
Riverton	Benton County	345

Table 7.2-2: Transmission Option 2

From	To	kV
Belfield	Hettinger	345
Hettinger	Ellendale	345
Ellendale	Watertown	345
Watertown	MN Valley	345
MN Valley	Blue Lake	345

Table 7.2-3: Transmission Option 3

From	To	kV
Belfield	Hettinger	345
Antelope Valley	Huron	500

Table 7.2-4: Transmission Option 4

From	To	kV
Belfield	Hettinger	345
Watertown	MN Valley	345
MN Valley	Blue Lake	345

Table 7.2-5: Transmission Option 5

From	To	kV
Belfield	Hettinger	345
Ellendale	Alex Switch Station	345
Alex Switch Station	Benton County	345

Table 7.2-6: Transmission Option 6

From	To	kV
Belfield	Hettinger	345
Maple River	Alex Switch Station	345
Alex Switch Station	Benton County	345

Table 7.2-7: Transmission Option 7

From	To	kV
Belfield	Hettinger	345
Antelope Valley	Center	345
Center	Jamestown	345
Jamestown	Maple River	345
Maple River	Audubon	345
Audubon	Badoura	345
Badoura	Riverton	345
Riverton	Benton County	345

Methodology

Transfer analysis was performed on the 2009 summer peak model by evaluating each generation site individually up to two times its base generation level. The primary steady state screening tool will be the PTI MUST program with verification of key results via full AC powerflow. For each generation site, MUST will be used to perform a transfer analysis by delivering generation from each site to the Twin Cities while simulating contingencies in the northern MAPP region. Each transmission option will be tested individually for each of the generation sites. Once all of the generation sites are individually tested, a comprehensive investigation will be performed on all generation sites together with the transmission options tested separately up to a total generation level of 3000 MW's.

Contingencies of 230 kV and above from the MAPP RSG contingency file were performed during this analysis. During the transfer analysis elements with a voltage of 115 kV and higher in North Dakota, South Dakota and Minnesota will be monitored.

Twin Cities area generation was selected for sinking the new generation with an attempt to avoid, to the extent possible, reducing the Sherco, Monticello, Prairie Island and King units since these are the primary base load units and will cause the highest load impacts in the 345 kV.

After the first benchmark run, the team evaluated the initial proposed interconnections to address local issues and possibly identify better interconnections, if needed. These potential new interconnections would then be re-run to establish the base benchmarks. In addition, each transmission project will be reviewed and modified for better performance, if so indicated based on the results of the first run, to take advantage of the information learned from the first run. Those options that are revised will be re-run with the modifications.

The study team used the results of the steady state evaluation to select the alternatives to evaluate for system stability. The same analysis was done on summer off-peak models to understand how the new transmission options behaved under summer off-peak stressed system conditions. The final transmission options would be selected on the results of both summer peak and summer off-peak transfer study results.

Discussion Of Results with Initial Transmission Options

FCITC analysis was performed with each generation site as the source and Xcel Energy generation acting as the sink. The results are explained below. Summer Peak models were used for the screening transfer studies. Each generation option was dispatched up to twice its output for the transfer study. All the above seven transmission options were tested to determine the transfer capability each option provided for each of the five-generation options.

Generator Option 1

The following results were observed for a transfer of 1000 MW from Generator 1 into the Twin Cities.

- Constraints around Maple River (OTP).
- Constraints around the generator location.
- Constraints around Leland Olds.
- Constraints in WAPA's 230 kV and 115 kV systems in the southern direction.
- Constraints around Bison, Maurine, and New Underwood.

The transfer capability provided by the transmission options for Generator Option 1 is as follows:

Transmission Option 1
The 1st valid limit is 621 MW with BELFELDT 345 66424 BELFELD3 345 limiter for the outage of BELFELD3 345 67183 CHAR.CK3 345 line.

Transmission Option 2
The 1st valid limit is 283 MW with HOOT LK7 115 63231 FERGSFL7 115 limiter for the outage of HENNING4 230 63331 FERGSFL4 230 line. If we upgrade this line, the next valid limiter is 464 MW.

Transmission Option 3
The 1st valid limit is 231 MW with HOOT LK7 115 63231 FERGSFL7 115 limiter for the outage of HENNING4 230 63331 FERGSFL4 230 line. If we upgrade this line, the next valid limiter is 306 MW.

Transmission Option 4
The 1st valid limit is 279 MW with STANLEY7 115 67385 TIOGA4 7 115 limiter for the outage of LOGAN 4 230 67208 LOGAN TY 230 line.

Transmission Option 5
The 1st valid limit is 242 MW with STANLEY7 115 67385 TIOGA4 7 115 limiter for the outage of LOGAN 4 230 67208 LOGAN TY 230 line.

Transmission Option 6
The 1st valid limit is 219 MW with STANLEY7 115 67385 TIOGA4 7 115 limiter for the outage of LOGAN 4 230 67208 LOGAN TY 230 line.

Transmission Option 7
The 1st valid limit is 601 MW(DC) with BISON 4 230 66497 MAURINE4 230 limiter for the outage of STEGALL3 345 67207 STEGALTY 345 line.

Generator Option 2

The following results were observed for a transfer of 500 MW from Generator 2 into the Twin Cities.

- Local 115 kV and 230 kV system violations.
- Overloads in Maple River OTP system.

The transfer capability provided by the transmission options for Generator Option 2 is as follows:

Transmission Option 1
The 1st valid limit is 480 MW with HOOT LK7 115 63231 FERGSFL7 115 limiter for the outage of HENNING4 230 63331 FERGSFL4 230 line.

Transmission Option 2
The 1st valid limit is 278 MW with HOOT LK7 115 63231 FERGSFL7 115 limiter for the outage of HENNING4 230 63331 FERGSFL4 230 line. If we upgrade this line, the next valid limiter is 608 MW.

Transmission Option 3
The 1st valid limit is 74 MW with HOOT LK7 115 63231 FERGSFL7 115 limiter for the outage of HENNING4 230 63331 FERGSFL4 230 line. If we upgrade this line, the next valid limiter is 452 MW.

Transmission Option 4
The 1st valid limit is 203 MW with HOOT LK7 115 63231 FERGSFL7 115 limiter for the outage of HENNING4 230 63331 FERGSFL4 230 line. If we upgrade this line, the next valid limiter is 537 MW.

Transmission Option 5
The 1st valid limit is 568 MW with COULEE 5 161 69523 GENOA 5 161 limiter for the contingency of GENOA 5 161 69535 LAC TAP5 161 line.

Transmission Option 6
The 1st valid limit is 416 MW with COULEE 5 161 69523 GENOA 5 161 limiter for the contingency of GENOA 5 161 69535 LAC TAP5 161 line.

Transmission Option 7
The 1st valid limit is 507 MW with HOOT LK7 115 63231 FERGSFL7 115 limiter for the outage of HENNING4 230 63331 FERGSFL4 230 line

Generator Option 3

The following results were observed for a transfer of 1000 MW from Generator 3 into the Twin Cities.

- Overloads in OTP Maple River System.
- Violations in OTP and WAPA systems in the southeast and northeast of the generator.
- OTP 230 kV system constraints.
- The 230 kV systems out of Ellendale does not have sufficient capacity.

The transfer capability provided by the transmission options for Generator Option 3 is as follows:

Transmission option 1
The 1st valid limit is 458 MW with GARRISN7 115 67308 BEULAH 7 115 limiter for the contingency Dak001B 4707.

Transmission option 2
The 1st valid limit is 430 MW with GARRISN7 115 67308 BEULAH 7 115 limiter for the contingency of GARRISN4 230 66442 GARRISN7 115 Transformer.

Transmission option 3
The 1st valid limit is 259 MW with HOOT LK7 115 63231 FERGSFL7 115 limiter for the outage of HENNING4 230 63331 FERGSFL4 230 line.

Transmission option 4
The 1st valid limit is 439 MW with GARRISN7 115 67308 BEULAH 7 115 limiter for the contingency of GARRISN4 230 66442 GARRISN7 115 Transformer.

Transmission Option 5
The 1st valid limit is 438 MW with GARRISN7 115 67308 BEULAH 7 115 limiter for the contingency of GARRISN4 230 66442 GARRISN7 115 Transformer.

Transmission Option 6
The 1st valid limit is 430 MW with GARRISN7 115 67308 BEULAH 7 115 limiter for the contingency of GARRISN4 230 66442 GARRISN7 115 Transformer.

Transmission Option 7
The 1st valid limit is 480 MW with GARRISN7 115 67308 BEULAH 7 115 limiter for the contingency of GARRISN4 230 66442 GARRISN7 115 Transformer.

Generator Option 4

The following results were observed for a transfer of 1000 MW from Generator 4 into the Twin Cities.

- Flows into northwest Area towards Leland Olds constraint.
- Constraints around Fort Thompson 230 kV system.

The transfer capability provided by the transmission options for Generator 4 is as follows:

Transmission Option 1
There are no valid limiters found for the transfer of 500 MW from Generator option 4.

Transmission Option 2
There are no valid limiters found for the transfer of 500 MW from Generator option 4.

Transmission Option 3
The transfer capability was negative which means this option cannot provide any transfer capability for Generator Option 4.

Transmission Option 4
There are no valid limiters found for the Transfer of 500 MW from the Generator Option 4.

Transmission Option 5
The 1st valid limit is 297 MW with COULEE 5 161 69523 GENOA 5 161 limiter for the contingency of GENOA 5 161 69535 LAC TAP5 161 line.

Transmission Option 6
The 1st valid limit is 352 MW with COULEE 5 161 69523 GENOA 5 161 limiter for the contingency of GENOA 5 161 69535 LAC TAP5 161 line.

Transmission Option 7
The 1st valid limit is 394 MW with COULEE 5 161 69523 GENOA 5 161 limiter for the contingency of GENOA 5 161 69535 LAC TAP5 161 line.

Generator Option 5

The following results were observed for a transfer of 1000 MW from Generator 5 into the Twin Cities.

- Constraints around Leland Olds.
- Local 230 kV systems around Watertown (WAPA).

The transfer capability provided by the transmission options is as follows:

Transmission Option 1
The 1st valid limit is 562(DC) MW with JOHNJCT7 115 63216 ORTONVL7 115 limiter for the contingency Dak002B 4708.

Transmission Option 2
The 1st valid limit is 38 MW with GRANTCO7 115 66555 MORRIS 7 115 limiter for the contingency of WAHPETN4 230 63331 FERGSFL4 230 line. If we upgrade this line, the next valid limiter is 586 MW.

Transmission Option 3
The 1st valid limit is -34 MW with GRANTCO7 115 66555 MORRIS 7 115 limiter for the contingency of WAHPETN4 230 63331 FERGSFL4 230 line. Therefore, this option cannot provide any transfer capability for Generator Option 5. If we upgrade the Grant County - Morris 115 kV line, the next valid limiter is 270 MW.

Transmission Option 4
The 1st valid limit is 86 MW with GRANTCO7 115 66555 MORRIS 7 115 limiter for the contingency of WAHPETN4 230 63331 FERGSFL4 230 line. If we upgrade this line, the next valid limiter is 526 MW.

Transmission Option 5
The 1st valid limit is 421 MW with COULEE 5 161 69523 GENOA 5 161 limiter for the contingency of GENOA 5 161 69535 LAC TAP5 161 line.

Transmission Option 6
The 1st valid limit is 403 MW with COULEE 5 161 69523 GENOA 5 161 limiter for the contingency of GENOA 5 161 69535 LAC TAP5 161 line.

Transmission Option 7
The 1st valid limit is 254 MW with GRANTCO7 115 66555 MORRIS 7 115 limiter for the contingency of WAHPETN4 230 63331 FERGSFL4 230 line. If we upgrade this line, the next valid limiter is 416 MW.

Conclusions

Based on the results above, the group decided to concentrate on the Transmission Option 1, 2 and 7 for further study. These three transmission options were selected because the incremental transfer capability provided by each of them was acceptable, as per the study requirements, for each of the five generation options and they do not have negative impacts on the transmission system.

Also, the group decided to make the following modifications to generation options 1 and 3:

- For Generation Option 1 the group decided to add a 345 kV line going from Hettinger to Oahe to Watertown to bypass some of the system constraints on the 230 kV system south of Hettinger towards New Underwood and Rapid City.
- For Generation Option 3 the group decided to add a 345 kV line going from Ellendale to Maple River to bypass some of the system constraints identified on the 230 kV system east of Ellendale towards Hankinson.

With these modifications, another set of the FCITC runs were made for both summer peak and summer off-peak cases and based on those results the following combinations of three lines were agreed upon for further studies.

Final Three Transmission Options

- Transmission Option 1: Antelope Valley–Jamestown–Maple River 345 kV line with a Maple River–Alexandria–Benton County 345 kV line.
- Transmission Option 2: Hettinger–Ellendale–Watertown–Granite Falls–Blue Lake 345 kV line.
- Transmission Option 2K: Hettinger–Ellendale–Watertown–Granite Falls with a Maple Rive–Alexandria–Benton County 345 kV line.

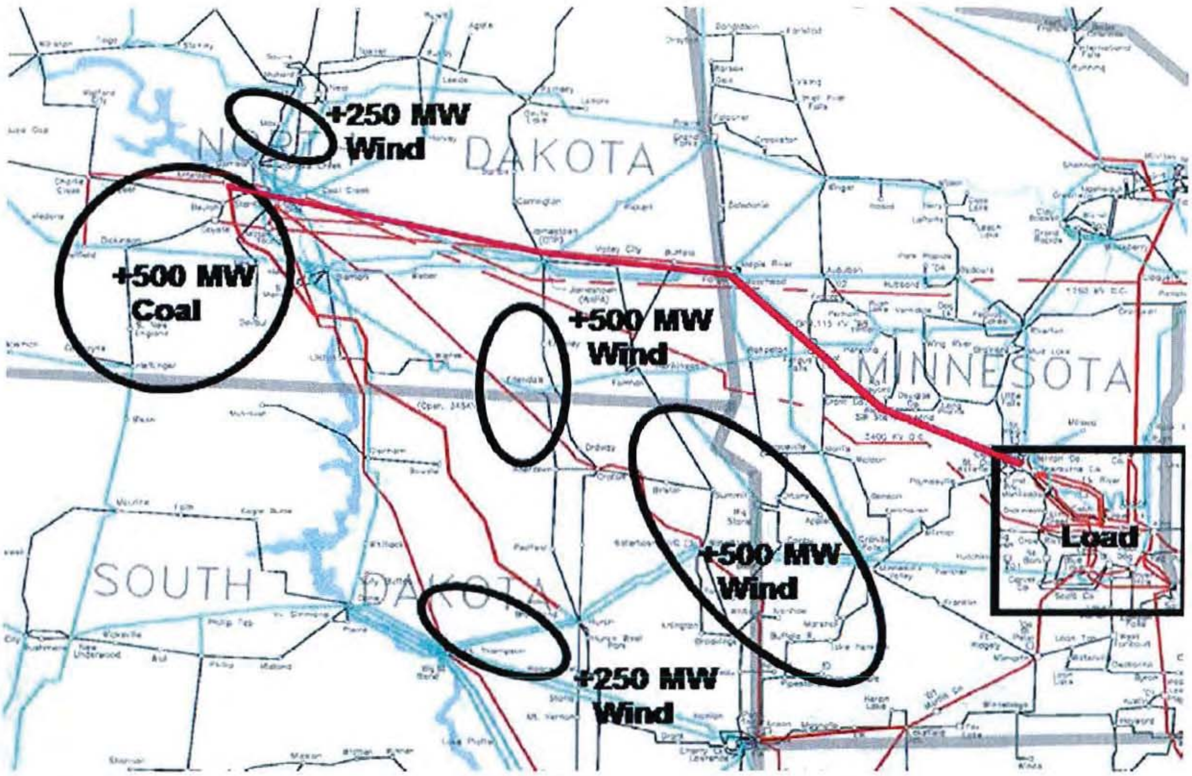


Figure 7.2-6: NW Transmission Option

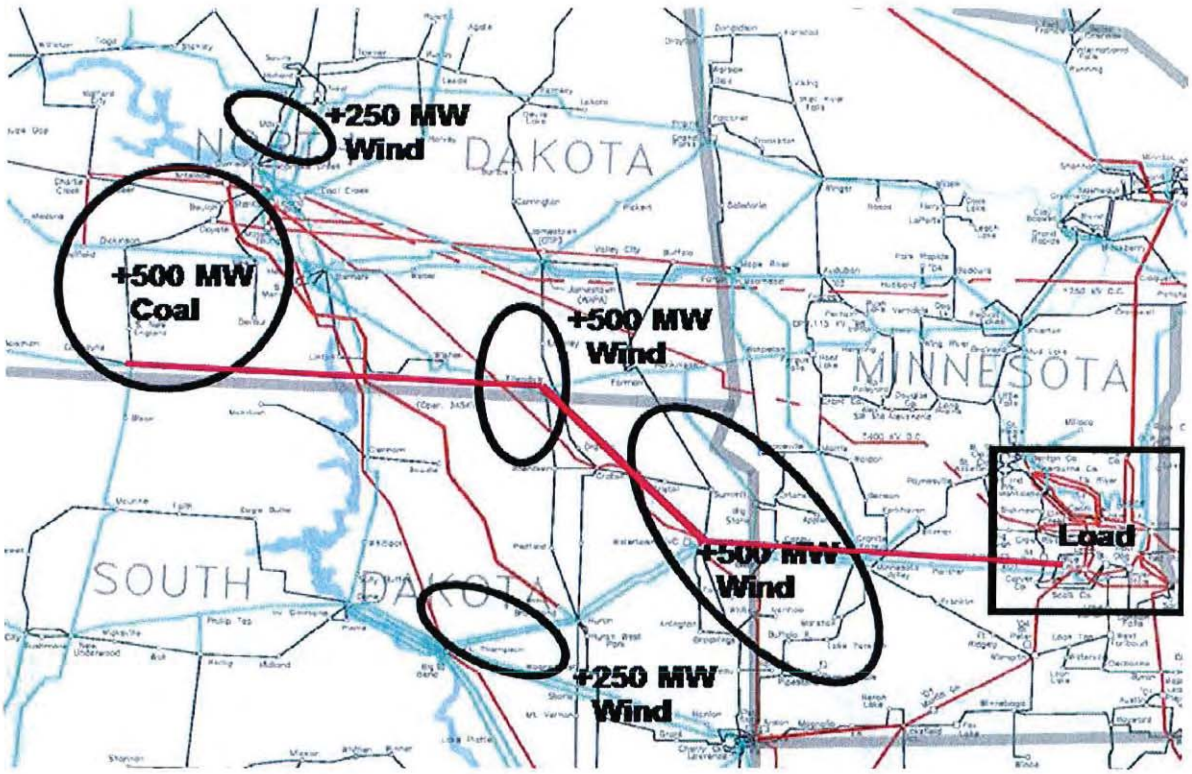


Figure 7.2-7: NW Transmission Option 2

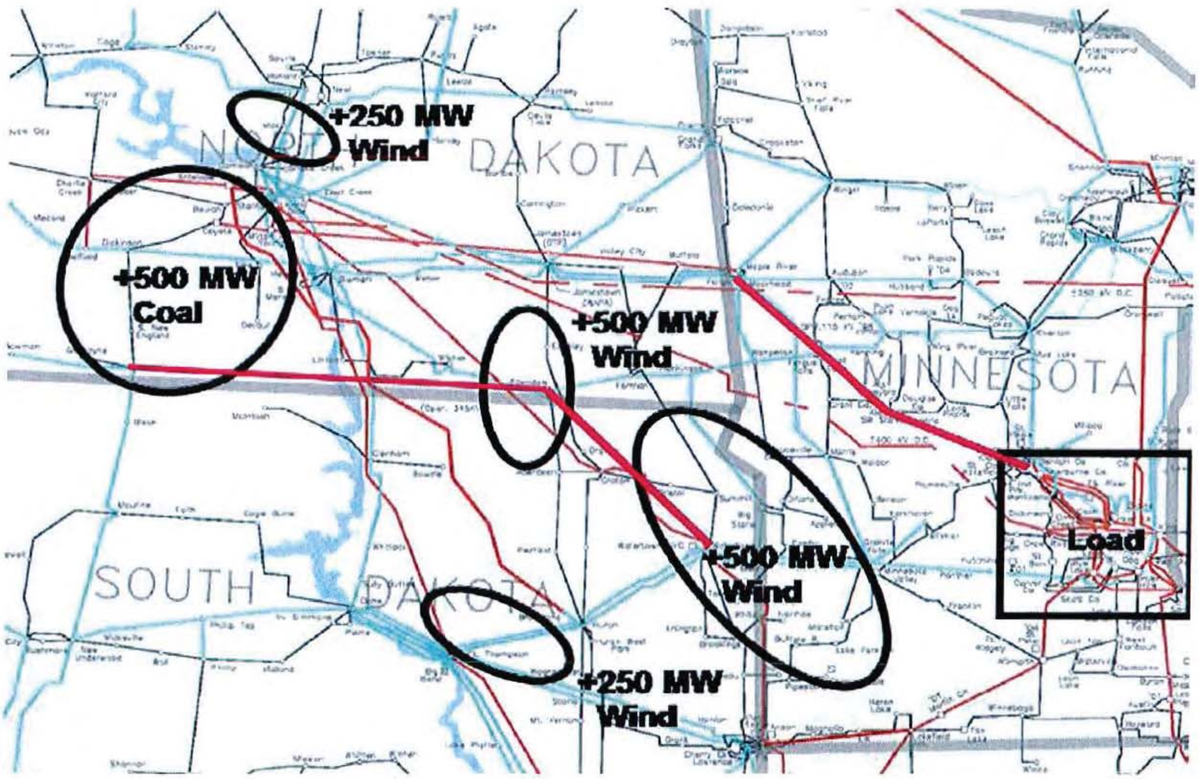


Figure 7.2-8: NW Transmission Option 2K

Tabulation Of FCITC Results

Table 7.2-8: MUST FCITC Table for 2009 Summer Off-Peak Case						
	Site 1 (Belfield) generation + Hettinger-Oahe-Watertown 345 kV capability / MW		Site 2 (Leland Olds-Logan 230 kV line) generation capability / MW		Site 3 (Ellendale 345) generation + Ellendale-Maple River 345 kV capability / MW	
Option	first limiter	second limiter	first limiter	second limiter	first limiter	second limiter
existing system	253	356	293	562	-1511	244
limiter	Bemidji–Nary 115	Bison–Hettinger 230	Brainerd–Riverton 115	Hubbard–Palmer Lake 115	Kerkhoven–Kerkhoven Tap 115	Brainerd–Riverton 115
outage	Hubbard–Audubon 230 & Hubbard 230 / 115	Hettinger–Oahe 345	Riverton–Mud Lake 230	Hubbard–Badoura 230	Granite Falls–Morris 230	Riverton–Mud Lake 230
1	505	No Limit	No Limit	No Limit	191	1272
limiter	Bison–Hettinger 230	none	none	none	Ellendale–Gen3 230	Brainerd–Riverton 115
outage	Hettinger–Oahe 345	none	none	none	Groton–Gen3 345	Riverton–Mud Lake 230
2	551	710	692	718	64	740
limiter	Brainerd–Riverton 115	Bison–Hettinger 230	Brainerd–Riverton 115	Huron-Broadland 230	Ellendale–Gen3 230	Brainerd–Riverton 115
outage	Riverton–Mud Lake 230	Hettinger–Oahe 345	Riverton–Mud Lake 230	Leland Olds–Ft Thompson 345	Groton–Gen3 345	Riverton–Mud Lake 230
2k	769	841	No Limit	No Limit	65	1146
limiter	Bison–Hettinger 230	Granite Falls–Minn Valley Tap 230	none	none	Ellendale–Gen3 230	Granite Falls–Minn Valley Tap 230
outage	Hettinger–Oahe 345	Brookings–Watertown 115 & Watertown-White 345	none	none	Groton–Gen3 345	Brookings–Watertown 115 & Watertown–White 345
	Site 4 (Ft Thompson) generation capability / MW		Site 5 (Watertown) generation capability / MW		All Sites generation capability / MW	
Option	first limiter	second limiter	first limiter	second limiter	first limiter	second limiter
existing system	399	527	368	516	262	338
limiter	Brainerd–Riverton 115	Mt Vernon–Storla 115	Brainerd–Riverton 115	Granite Falls–Minn Valley Tap 230	Nary–LaPorte 115	Brainerd–Riverton 115
outage	Riverton–Mud Lake 230	Ft Thomp–Ft Randall 230 & Ft Thomp-Lakplat 230	Riverton–Mud Lake 230	Willmar–Granite Falls 230 & Willmar 230 / 69	Hubbard–Audubon 230 & Hubbard 230 / 115	Riverton–Mud Lake 230
1	No Limit	No Limit	891	976	960	970
limiter	none	none	Johnson Jct–Ortonville 115	Johnson Jct–Morris 115	Bison–Hettinger 230	Ellendale–Gen3 230
outage	none	none	Watertown–Granite Falls 230 & Blair–Granite Falls 230	Watertown–Granite Falls 230 & Blair–Granite Falls 230	Leland Olds–Ft Thompson 345	Groton–Gen3 345
2	No Limit	No Limit	689	760	-1	244
limiter	none	none	Brainerd–Riverton 115	Granite Falls–Minn Valley Tap 230	Ellendale–Gen3 230	Huron–Broadland 230
outage	none	none	Riverton–Mud Lake 230	Granite Falls–Blue Lake 345	Gen3–Groton 345	Antelope Valley–Leland Olds 345 1 & 2
2k	No Limit	No Limit	757	983	273	946
limiter	none	none	Granite Falls–Minn Valley Tap 229	Panther–Minn Valley Tap 230	Ellendale–Gen3 230	Granite Falls–Minn Valley Tap 230
outage	none	none	Brookings–Watertown 115 & Watertown–White 345	Split Rock–White 345 & Split Rock–Sioux City 345	Gen3–Groton 345	none

Table 7.2-9: MUST FCITC Table for 2009 Summer Peak Case

	Site 1 (Belfield) generation + Hettinger-Oahe-Watertown 345 kV capability / MW		Site 2 (Leland Olds-Logan 230 kV line) generation capability / MW		Site 3 (Ellendale 345) generation + Ellendale-Maple River 345 kV capability / MW	
Option	first limiter	second limiter	first limiter	second limiter	first limiter	second limiter
existing system	302	659	-113	340	102	154
limiter	BELFELDT 345 66424 BELFELD3 345	BENTON 7 115 60146 GRANCTY7 115	HOOT LK7 115 63231 FERGSFL7 115	LELANDO4 230 66914 OPT_2 230	JOHNJCT7 115 63216 ORTONVL7	OAKES 4 230 67326 ELLENDL4
outage	BELFELD3 345 67175 N_HETTI 345	BENTON 7 115 60348 BENCTP7 115	HENNING4 230 63331 FERGSFL4 230	LOGAN 4 230 66914 OPT_2 230	Dak002B 4704	GROTON 3 345 67172 TAP_345
1	438	662	338	none found	376	669
limiter	BELFELDT 345 66424 BELFELD3 345	BUFFALO3 345 66792 MAPLE R3 345	LELANDO4 230 66914 OPT_2 230		SHEYNNE4 230 66754 MAPLE R4 230	GOOSELK7 115 62091 VADNSTP7 115
outage	BELFELD3 345 67175 N_HETT 345	JAMESTN3 345 66792 MAPLE R3 345	LOGAN 4 230 66914 OPT_2 230		MAPLE R3 345 61742 N_ALEXA 345	
2	325	493	338	none found	684	754
limiter	BELFELDT 345 66424 BELFELD3 345	BENTON 7 115 60146 GRANCTY7 115	LELANDO4 230 66914 OPT_2 230		GOOSELK7 115 62091 VADNSTP7 115	OAKES 4 230 67326 ELLENDL4
outage	BELFELD3 345 67175 N_HETT 345	BENTON 7 115 60348 BENCTP7 115	LOGAN 4 230 66914 OPT_2 230			GROTON 3 345 67172 TAP_345
2k	296	683	338	none found	690	1146
limiter	BELFELDT 345 66424 BELFELD3 345	GOOSELK7 115 62091 VADNSTP7 115	LELANDO4 230 66914 OPT_2 230		GOOSELK7 115 62091 VADNSTP7 115	
outage	BELFELD3 345 67175 N_HETT 345	KOLMNLK3 345 60251 TERMINL3 345	LOGAN 4 230 66914 OPT_2 230			

	Site 4 (Ft Thompson) generation capability / MW		Site 5 (Watertown) generation capability / MW		All Sites generation capability / MW	
Option	first limiter	second limiter	first limiter	second limiter	first limiter	second limiter
existing system	-174	149	-157	69	-237	112
limiter	HOOT LK7 115 63231 FERGSFL7 115	JOHNJCT7 115 63216 ORTONVL7 115	HOOT LK7 115 63231 FERGSFL7 115	JOHNJCT7 115 63216 ORTONVL7 115	HOOT LK7 115 63231 FERGSFL7 115	JOHNJCT7 115 63216 ORTONVL7 115
outage	HENNING4 230 63331 FERGSFL4 230	Dak002B	HENNING4 230 63331 FERGSFL4 230	Dak002B	HENNING4 230 63331 FERGSFL4 230	Dak002B
1	none found	none found	593	710	530	1054
limiter			BIGSTONY 230 63314 BIGSTON4 230	JOHNJCT7 115 63216 ORTONVL7 115	SHEYNNE4 230 66754 MAPLE R4 230	LXNGTON7 115 62091 VADNSTP7 115
outage			Dak002B	Dak002B	3982STK	022 5
2	480	none found	420	896	615	1013
limiter	SIOUXF1T 230 66523 SIOUXFL4 230		WATERT1T 345 66529 WATERTN3 345	MNVLTAP4 230 66550 GRANITF4 230	COULEE 5 161 69523 GENOA 5 161	HIBRDGE7 115 60239 ROGRSLK7 115
outage	SPLT RK4 230 66523 SIOUXFL4 230		Dak002B	BLUE LK3 345 61743 N_GRANI 345	GENOA 5 161 69535 LAC TAP5 161	022 5
2k	none found		533	596	566	1076
limiter			WATERT1T 345 66529 WATERTN3 345	MNVLTAP4 230 66550 GRANITF4 230	COULEE 5 161 69523 GENOA 5 161	HIBRDGE7 115 60239 ROGRSLK7 115
outage			Dak002B	WILLMAR4 230 66550 GRANITF4 230	GENOA 5 161 69535 LAC TAP5 161	022 5

Stability Studies

Initial stability analysis was done using the NMORWG Study Package. All present operating guides and special protection systems will continue for the duration of this study. This evaluation is not investigating improving plant operation of the existing generation. The main goal of the stability study is to get a bare minimum plan where each generation addition and transmission addition still maintain system's stability.

Dynamic study work was done using faults in the UIP package and the faults on the new lines. Dynamic simulations were run on 15 models. These 15 cases were developed from the base case and adding the five generators and three transmission options of the study.

Findings

Stability studies showed that Generation Option 3 and Generation Option 5 have dynamic voltage violations around the point of interconnection.

Stability analysis did not show any potential problems with the addition of new transmission options.

Next Steps

The Northwest Exploratory Study Group has decided that it would be better to determine if any conversion options perform similar to the new construction options. The group came up with 13 new conversion and new construction options for further study along with the finalized three new construction options. Further transfer studies were done on the 16 total transmission options and the results are being evaluated among the study group and will be presented to the Steering Committee of the Northwest Exploratory Study. The next steps of the study will be decided upon after the Steering Committee evaluates the results. These are the 16 new transmission options.

Transmission Option A

This is a conversion option with the Maple River-Sheyenne-Audubon-Hubbard-Badoura-Riverton-Mud Lake-Benton County 230 kV transmission lines being converted to 345 kV.

Transmission Option B

This is a conversion option with the Watertown-Granite Falls-Minnesota Valley-Panther-McLeod-Blue Lake 230 kV transmission lines being converted to 345 kV.

Transmission Option C

This is a new 345 kV construction option. It is a single line option from Maple River to the Alexandria Switching Station to Benton County.

Transmission Option D

This is a single line conversion option. This option includes converting 230 kV lines from Maple River-Sheyenne-Fargo-Moorhead-Morris-Granite Falls-Minnesota Valley-Panther-McLeod-Blue Lake to 345 kV.

Transmission Option E

This is new single line 345 kV options. This option includes building a Watertown to Blue Lake 345 kV lines.

Transmission Option F

This is a new single line 345 kV option. This option includes building a new Antelope Valley-Jamestown-Maple River-Alexandria-Benton County 345 kV line. This is Transmission Option 1 from the initial study group's recommendation.

Transmission Option G

This is a combination of both new construction and a conversion of existing line options. This option includes building a new Antelope Valley-Jamestown-Maple River 345 kV line and converting Maple River-Sheyenne-Audubon-Hubbard-Badoura-Riverton-Mud Lake-Benton County 230 kV line to 345 kV.

Transmission Option H

This is a combination of both new construction and a conversion of existing line options. This option includes building a new Hettinger-Ellendale-Watertown 345 kV line and converting the existing Watertown-Granite Falls-Minnesota Valley-Panther-McLeod-Blue Lake 230 kV line to 345 kV.

Transmission Option I

This is new single line 345 kV build option. This option includes building a new Hettinger-Ellendale-Watertown-Granite Falls-Blue Lake 345 kV line. This is the Transmission Option 2 from the study group's initial recommendations.

Transmission Option J

This is a new double line 345 kV option. This option includes building a Hettinger-Ellendale-Watertown-Granite Falls 345 kV line and building a new Maple River-Alexandria-Benton County 345 kV line. This is the Transmission Option 2k from the study group's initial recommendations.

Transmission Option K

This is a new single line 500 kV option. This option includes building a new Antelope Valley-Maple River-Benton County 500 kV line.

Transmission Option L

This is a new single line 500 kV option. This option includes building a new Hettinger-Ellendale-Watertown-Blue Lake 500 kV line.

Transmission Option M

This is a conversion option, which converts two segments of the transmission system to 500 kV. This option includes converting the Antelope Valley—Huron 345 kV line to 500 kV and converting the Huron-Watertown-Granite Falls-Minnesota Valley-Panther-McLeod-Blue Lake 230 kV line to 500 kV.

Transmission Option N

This is a new double line 345 kV option. This option includes building a new Antelope Valley-Maple River-Alex-Benton County 345 kV line and building a new Hettinger-Ellendale-Blue Lake 345 kV line.

Transmission Option O

This is a new double line 500 kV option. This option builds a new Antelope Valley-Maple River-Benton County 500 kV line segment and a new Hettinger-Ellendale-Blue Lake 500 kV line.

Transmission Option P

This is a combination of both new construction and conversion of the existing line options. This option includes building a new Antelope Valley-Maple River-Benton County 500 kV line and converting the existing Antelope Valley-Huron 345 kV line to 500 kV and building a new Watertown-Blue Lake to 500 kV line.

7.3 Iowa-Southern Minnesota Exploratory Study

Objectives

The objective of the Iowa-Southern Minnesota Exploratory Study (ISMNEX) is to develop a high-level exploratory transmission plan which provides increased transmission capability to facilitate the development and integration of wind generation resources in this area and addresses regional reliability issues. The study results will provide direction to Midwest ISO and transmission providers in the region on how to best develop the transmission system in this region. This exploratory study will not attempt to resolve underlying system issues, but develop an understanding of what bulk transmission improvements would be required to delivery significant amounts of generation. This study is a continuation of the MTEP 03 exploratory study. This study is an open and collaborative planning process with Midwest ISO staff, wind developers, wind advocates, utility planners, and state regulatory staff members in the stakeholder/study group.

System Issues

The following system issues are drivers for this study. The transmission system in this area has limited capacity to allow for significant development of additional wind generation projects. Because the northern Iowa and southern Minnesota area is a very good wind resource, there are a large number of generator interconnection requests in this area — literally thousands of megawatts of requests. This study will determine how to get 2,700 to 3,500 MW of wind generation to market in addition to existing and committed generation projects. The Rochester, Minnesota area; La Crosse, Wisconsin area; Worthington, Minnesota area and eastern Iowa area all have future load serving reliability concerns. The Minnesota-Wisconsin Stability Interface is a system constraint which can impact the ability of new generation to be sited in Minnesota and Wisconsin. The State of Minnesota also has a Renewable Energy Objective in which utilities in the state should have 10% of energy come from renewables by 2015. This exploratory study will develop a transmission plan which addresses these concerns at a high-level.

Scope and Methodology

The scope and methodology for Iowa - Southern Minnesota Exploratory Study is described in this section. First, generation scenarios were developed with Midwest ISO Generation Interconnection Queue and stakeholder input to capture realistic wind development in the area. Considering the proposed generation scenarios and regional reliability needs, exploratory transmission options were developed. Next the generation and transmission scenario combinations were screened for thermal limitations using ShawPTI's MUST program. MUST performs linear (DC) First Contingency Incremental Transfer Capability (FCITC) analysis. The MUST screening results were then reviewed and the transmission options were modified, if necessary. When the transmission scenarios are reasonable from a thermal performance standpoint, the study will proceed with the AC powerflow analysis to determine the voltage and thermal performance of the generation and transmission scenarios. The transmission options may be modified at this stage in the study. The final transmission scenarios will be analyzed in using PROMOD to determine the market benefits of the transmission upgrades.

All thermal issues and the associated generation output level when the thermal issues occur will be documented. It is the desire of the stakeholders to develop a transmission plan which delivers a specified amount of generation, instead of developing a transmission plan and determining how much generation the plan could deliver. However, because of the exploratory nature of the transmission, issues on the underlying system will only be documented, but not be addressed by the plan. For example, a 161 kV line may overload at a generation output of 1800 MW. This limitation will be noted. Investment costs to achieve a given level of generation output will be calculated, assuming underlying system overloads can be addressed by rebuilding the transmission line or upgrading transformers.

Generation Scenarios

The following two generation scenarios (G1 and G2) were developed with stakeholder input at the 8/24/04 study group meeting. A majority of these locations reflect generation interconnection queue projects. However, some generation locations were requested by wind developers. Note that a majority of the generation is located on 345 kV buses for this study, because of the high-level nature and focus of this study.

Table 7.3-1: ISMNEX Generation Scenarios

State	Substation	kV	G1 MW	G2 MW
IA	Spencer	161	200	200
IA	Webster	345		300
IA	Eagle	230	120	
IA	Winnebago	345	190	300
IA	Top of Iowa	161	200	200
MN	Lakefield Jct.	345	200	200
MN	Yankee	115	200	300
MN	Lakefield	345	300	300
MN	Adams	345	500	500
MN	Chanarambie	345	200	200
MN	Nobles	345	200	400
MN	Fenton	115		200
MN	Byron	345	200	200
MN	Rochester–LaCrosse	345		200
SD	White	345	200	
SD	Big Stone	345		600
	Total Generation		2710	4100

Two delivery scenarios (D1 and D2) were developed with stakeholder input at the 8/24/2004 study group meeting. Delivery Scenario D2 was later modified. We assumed delivery of the study generation to utility load in the MUST screening, because this would reflect future deliveries to meet the Minnesota renewable energy objective. Note that approximately 2,200 MW of Delivery Scenario D1 is delivered to Minnesota utilities to meet the renewable energy objective requirements. A similar amount is delivered to Minnesota utilities in Delivery Scenario D2 for this purpose. Delivery Scenario D1 goes with Generation Scenario G1 and Delivery Scenario D2 goes with Generation Scenario G2. The Delivery Scenarios used for MUST Screening are described below, with the utilities' MW share of the delivery specified.

Table 7.3-2: ISMNEX MUST Delivery Scenarios

Utility Load to Scale	Scenario D1 MW	Scenario D2 MW
Minnesota Deliveries		
ALTW (MN)	30	30
MP	335	335
OTP	68	68
XEL	1110	1310
DPC (MN)	21	21
GRE	325	425
MPC	54	54
SMP	99	99
Municipals		
XEL-municipal	103	103
RPU municipal	69	69
DPC municipal	10	10
GRE-municipal	33	33
Iowa Deliveries		
ALTW	226.5	250
MEC	226.5	250
Wisconsin Deliveries		
ALTE		1
WPL		232
WEC		551
WEC		4
WPS		175
MGE		72
UPPCo		14
Total MW	2710	4107

Transmission Scenarios

The following two transmission scenarios (T1 and T2) were developed with stakeholder input at the 8/24/2004 study group meeting. Note the scenarios have many lines in common. The differences between them are in how the lines are brought into the Twin Cities and southeastern Wisconsin. Transmission Scenario T1 has 1190 miles of 345 kV transmission lines and Transmission Scenario T2 has 1300 miles of 345 kV lines. Note the Big Stone-Benton County 345 kV line is only modeled with Generation Scenario G2 and is not included in the previous mileage totals for T1 and T2. The table also shows the reduced options (T1b and T2b) which resulted from the first round of MUST screening analysis.

Table 7.3-3: ISMNEX Transmission Scenarios

Line Section Description	Miles	Conductor	Voltage	T1	T2	T1b	T2b	State
Salem-Wempleton	60	T2-556	345 kV	T1	n.a.	T1b	n.a.	IL
Wilmarth-Blue Lake #2	65	2-1192A	345 kV	T1	n.a.	T1b	n.a.	MN
Lakefield-Winnebago	52	T2-556	345 kV	T1	T2	T1b	T2b	MN
Winnebago-Hayward	50	T2-556	345 kV	T1	T2	T1b	T2b	MN
Hayward-Adams	30	T2-556	345 kV	T1	T2	T1b	T2b	MN
Winnebago-Burt	40	T2-556	345 kV	T1	T2	T1b	T2b	IA
Burt-Webster	50	T2-556	345 kV	T1	T2	T1b	T2b	IA
Burt-Emery	50	T2-556	345 kV	T1	T2	n.a.	n.a.	IA
Emery-New Hampton	50	T2-556	345 kV	T1	T2	n.a.	n.a.	IA
Hazelton-Salem	70	T2-556	345 kV	T1	T2	T1b	T2b	IA
White-Chanarambie	55	2-1192A	345 kV	T1	T2	T1b	T2b	MN
Chanarambie-Franklin	95	2-1192A	345 kV	T1	T2	T1b	T2b	MN
Nobles Co-Chanarambie	41	2-1192A	345 kV	T1	T2	n.a.	n.a.	MN
Franklin-Blue Lake	88	2-1192A	345 kV	T1	T2	T1b	T2b	MN
Nobles Co-Wilmarth	120	2-1192A	345 kV	T1	T2	T1b	T2b	MN
Prairie Island-Rochester	56	2-1192A	345 kV	T1	T2	T1b	T2b	MN
Rochester-Fremont	32	2-1192A	345 kV	T1	T2	T1b	T2b	MN
Fremont-N La Crosse	44	2-1192A	345 kV	T1	T2	T1b	T2b	MN
N La Crosse-Spring Green	116	2156A	345 kV	T1	T2	T1b	T2b	WI
Spring Green-W Middleton	29	2156A	345 kV	T1	T2	T1b	T2b	WI
Salem-Nelson Dewey	41	2156A	345 kV	n.a.	T2	n.a.	T2b	IA
Nelson Dewey-Spring Green	60	2156A	345 kV	n.a.	T2	n.a.	T2b	IA
Spring Green-W Middleton	29	2156A	345 kV	n.a.	T2	n.a.	T2b	WI
Wilmarth-Byron	80	2-1192A	345 kV	n.a.	T2	n.a.	T2b	MN
Byron-Rochester	20	2-1192A	345 kV	n.a.	T2	n.a.	T2b	MN
Big Stone-Benton Co	159	2-1192A	345 kV	G2	G2	G2	G2	MN

n.a. = not applicable to the transmission scenario

Figure 7.3-1: ISMNEX Transmission Scenario T1 Diagram

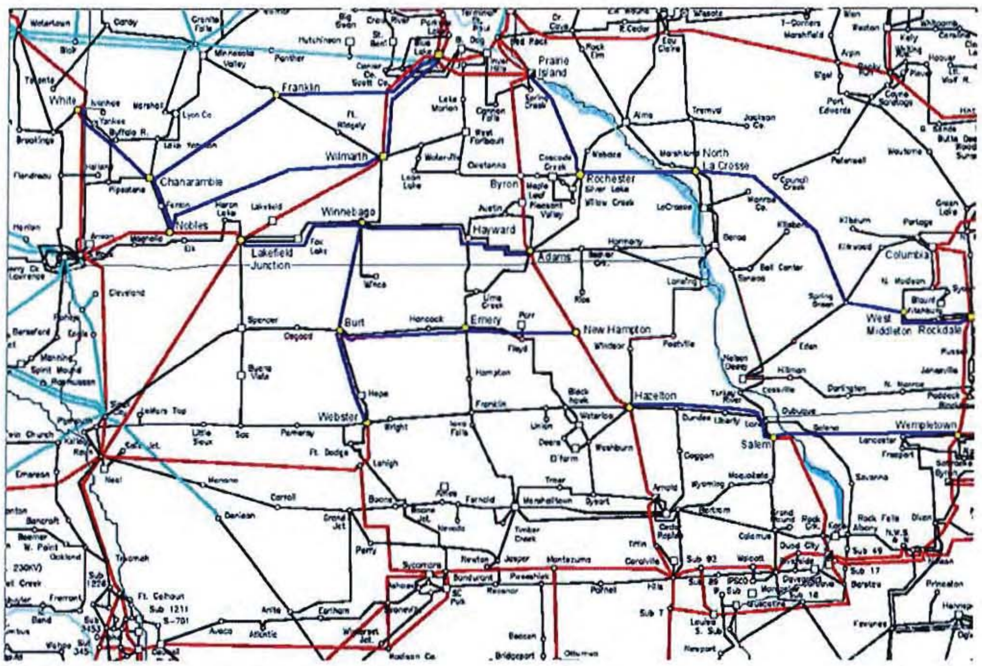
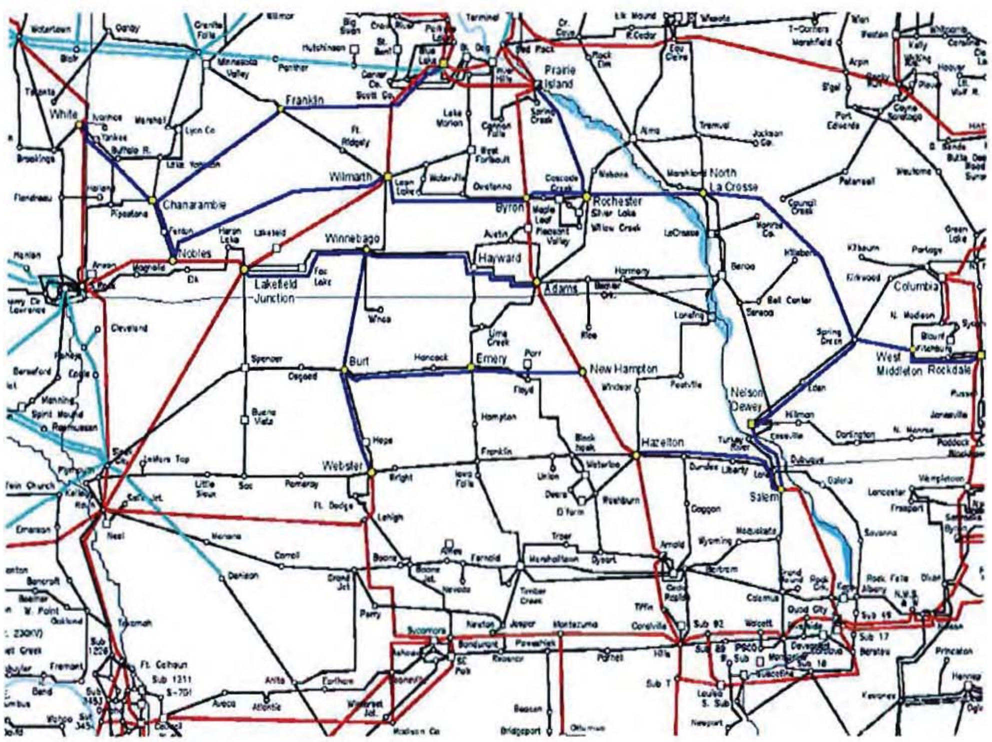


Figure 7.3-2: ISMNEX Transmission Scenario T2 Diagram



The transmission scenarios also have transformers at the following locations.

Table 7.3-4 Transmission Scenarios

Transformer Description	Rating	HV-LV	T1	T2	T1b	T2b	State
White 345/115 TX	448MVA	345/115	T1	T2	T1b	T2b	SD
Chanarambie 345/115 TX	448MVA	345/115	T1	T2	T1b	T2b	MN
Franklin 345/115 TX	448MVA	345/115	T1	T2	T1b	T2b	MN
Winnebago 345/161 TX	560MVA	345/161	T1	T2	T1b	T2b	MN
Burt 345/161 TX	560MVA	345/161	T1	T2	T1b	T2b	IA
Emery 345/161 TX	560MVA	345/161	T1	T2	n.a.	n.a.	IA
Rochester 345/161 TX	560MVA	345/161	T1	T2	T1b	T2b	MN
North La Crosse 345/161 TX	560MVA	345/161	T1	T2	T1b	T2b	WI
Spring Green 345/138 TX	500 MVA	345/138	T1	T2	T1b	T2b	WI
Nelson Dewey 345/138 TX	500 MVA	345/138	n.a.	T2	n.a.	T2b	WI
Big Stone 345/230 TX	500 MVA	345/230	G2	G2	G2	G2	SD

Model Development for MUST Analysis

The MTEP Baseline summer 2009 peak case (Base09S_Jun0104_v03.sav) was used to develop the cases for MUST FCITC screening. Existing wind generation and other significant new generation projects in the study area were turned on at maximum output. Planned transmission upgrades from Appendix A were modeled. The generators in the generation scenarios were modeled on-line with output of 0 MW and no load was scaled, because the MUST program will increase generation and loads to simulate the delivery of the generation to the specified loads. The MUST powerflow models contained transmission scenario facilities. The following powerflow base cases were developed for MUST FCITC screening.

Transmission Scenario T1 and Generation Scenario G1
sp09_t1_g1_must.sav

Transmission Scenario T1 and Generation Scenario G2
sp09_t1_g2_must.sav

Transmission Scenario T2 and Generation Scenario G1
sp09_t2_g1_must.sav

Transmission Scenario T2 and Generation Scenario G2
sp09_t2_g2_must.sav

Note that no Northwest Exploratory transmission option facilities were included in the Iowa–Southern Minnesota Exploratory study base cases. Integration of the exploratory plans may occur in future studies.

MUST Analysis

The MUST FCITC analysis used the following inputs and assumptions. Analyze all single contingencies for facilities, including tie lines, greater than 100 kV in MAPP and MAIN regions. Monitor all facilities greater than 100 kV , including ties lines, in the MAPP and MAIN regions. Contingent overloads were flagged at 100% of normal rating (rate A). This is more stringent than standard planning criteria, but the study group wanted to capture all elements which may limit delivery of the generation to load. MUST output was filtered with a distribution factor cutoff of 1% and contingency case flow change cutoff of 1 MW.

Results of MUST FCITC Analysis

All the transmission and generation scenario combinations have thermal limitations on the underlying transmission system. The only exploratory facility which is thermally limited is the Chanarambie 345/115 transformer at 1300 MW of new generation being transferred. Thermal limits were flagged at 100% of normal facility rating, therefore, not all the limiters identified at this level will need to be addressed to enable the transfers to occur. Some limiters are common to all plans. Many limiters appear to be related to increasing Xcel Energy load 1100 MW on 115 kV which is mostly in Twin Cities, and is a result of the generation-to-load delivery assumption.

MUST screening result summaries can be found in Appendix D8.

Exploratory Facility Loading

There are 35 exploratory lines and transformers between the two transmission scenarios. Each facility was monitored with MUST and maximum flows during system intact and contingent conditions were estimated. Nine of exploratory facilities are over 400 MW (the approximate Surge Impedance Loading (SIL) of a 345 kV line) during system intact, post-transfer condition. Twenty one are over 400 MW during contingencies. A few facilities don't load significantly. However, they would likely be beneficial for load serving during low wind periods.

Estimated exploratory facility flows can be found in Appendix D8.

Reduced Transmission Scenarios

Midwest ISO staff identified several facilities which were not loading significantly and proposed to the study group that a sensitivity should be performed. The ISMNEX study group agreed to remove the Burt–Emery–New Hampton 345 kV line and Chanarambie–Nobles 345 kV line from the transmission scenarios. The Burt 345/161 kV transformer was going to be removed, but the Burt transformer would likely have reliability benefits for the Webster 345/161 transformer outage. Therefore, the Burt transformer was left in the reduced transmission scenario cases. The Emery transformer was removed as the associated 345 kV was removed.

The powerflow models were created for the reduced transmission scenarios and MUST FCITC analysis was performed. Overall, the reduced scenarios performed similar to the original transmission scenarios, with 140 miles of transmission removed from the scenarios. There were a few new 161 kV overloads in the area where the transmission was removed, but the overloads did not occur until generation transfer levels were around 3400 MW.

Market Screening

In order to determine the ability of the generation to be delivered to a specific market, MUST FCITIC analysis was performed on the transmission and generation scenarios. A separate transfer of 2500 MW to each of the MN, IA, and WI markets was assumed. Generation-to-Generation dispatch was assumed. Large, low cost base load plants were excluded from the market delivery areas to make the generation dispatch more realistic. That is, the generation being delivered to market should be used to displace high cost generation.

This analysis showed that most limiters were market specific. Only limiters near the generation were common to multiple markets. The Iowa market had a noticeably lower number of limiters at the 2500 MW transfer level.

MUST result summaries for the market analysis can be found in Appendix D8.

Next Steps

The Iowa–Southern Minnesota Exploratory Study is still in progress. There are several work items remaining before the study will be completed. The parts of the study to be performed are an AC powerflow analysis and a PROMOD economic analysis.

7.4 CapX 2020: Identifying Minnesota's Electric Transmission Infrastructure Needs

Minnesota's electric transmission infrastructure—a network of high voltage transmission

Lines of 230 kilovolts and higher—requires major upgrades and expansion over the next 15 years to support customers' growing demand for electricity. To ensure the backbone transmission system is developed and available to serve these growing needs, the six largest Minnesota transmission-owning utilities initiated the CapX 2020 project. CapX 2020 is short for Capital Expenditures by the year 2020.

CapX 2020's mission is to:

- Create a joint vision of required transmission infrastructure investments needed to meet growing demand for electricity in Minnesota and the region; and
- Work to create an environment that allows these projects to be developed in a timely, efficient manner, consistent with the public interest.

Great River Energy, Minnesota Power, Otter Tail Power Company and Xcel Energy jointly formed CapX 2020 in the summer of 2004; Missouri River Energy Services and Southern Minnesota Municipal Power Agency subsequently joined this effort, and other investor-owned utilities, cooperatives, and municipal utilities have been following the initiative.

This Interim Report presents our work to date. Its purpose is to create awareness of the significant need for new transmission investment, to inform stakeholders of our study efforts underway, and to begin a public dialogue on transmission issues. We present this report in the following sections:

- *Our future needs,* presenting forecasts of customer demand over the next 15 years.
- *Our current system,* outlining the characteristics and capacity of our current backbone transmission system.
- *A changed market,* describing how management of the transmission network operates under federal reforms.
- *The CapX 2020 planning effort,* providing an overview of our CapX 2020 study.
- *Our preliminary results,* presenting our findings to date.
- *Next steps,* discussing the continued planning effort and inviting stakeholder dialogue.

A final CapX 2020 report is scheduled to be completed in the second quarter 2005.

7.5 Other Exploratory Expansion Plans

This section provides an overview of exploratory plans from previous studies and other reliability regions. After tariff additions to address sharing of large interstate projects has been implemented and necessary technical analysis have been performed, some of these exploratory projects may become part of future MTEP recommended expansion plans.

MTEP 03 report[1] outlined transmission plans for Western Nebraska-Western Kansas (SPP 345 kV) and from Indiana to Kentucky (Rockport-Paradise) that would provide transmission to allow coal derived electric energy to flow toward areas of higher concentrations of gas derived electric energy. This exploratory plan had economic merit in MTEP 03 analysis. Transmission reliability studies would need to be performed to determine how this exploratory plan integrates with the transmission system.

SPP has an exploratory plan, called Plan A that addresses the Western Nebraska-SPP potential transmission expansion.

Peabody Energy Corporation has pursued interconnection studies for the Thoroughbred coal fired plant in Kentucky requiring a TVA to AEP interconnection. The Rockport to Paradise line identified in MTEP 03 proposed a similar interconnection.

The Michigan 765 kV Exploratory Expansion study included a 765 kV line traversing Michigan and connecting to Ontario and the Cleveland area. This exploratory proposal produced little economic benefit for the Midwest ISO footprint in MTEP 03 and was not pursued.

As the energy markets mature, costly transmission constraints will be identified. New exploratory transmission studies will be performed to determine if transmission system upgrades can be made in a cost effective manner to improve market performance.

Footnotes

1 - The MTEP 0 3 report is available on the Midwest ISO web site under Planning and Interconnections and Expansion Planning.

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Section 8: Summary Transmission Investment Needs

The present Midwest ISO Transmission System consists of 112,000 miles of existing transmission lines. This section provides an overview of the expansion plans identified in the regional expansion planning process. The MTEP documents planned facilities above 100 kV . Of the reported 6,940 mile total for expansion facilities as far out as the year 2017, about 2,852 miles are Planned lines in the 2004 through 2009 timeframe. Together with some planned lower voltage facilities of Midwest SO Transmission Owners, these future expansion facilities become a predictor of additional revenue requirements that must be provided for via the Midwest ISO Tariff.

Most of the plans in development by the Transmission Owners are reliability-driven plans. Projects in the MTEP are designated as either Planned, or Proposed. Planned plans are those for which a system condition has been found to violate applicable planning standards, and the Planned plan has been determined to be the recommended plan from among alternatives. Planned plans are in various stages of corporate internal and external approval processes. Proposed plans are those for which a system condition has been found to violate applicable planning standards, and the proposed plan is the best-known alternative at this time. Proposed projects will continue to be evaluated and, unless system conditions change from projected, the Proposed plan will either become a Planned plan, or will be replaced by a preferred alternative Planned plan in subsequent issues of the MTEP.

Although Midwest ISO has knowledge of planned facilities that are adjacent to the Midwest ISO system, those facilities are not quantified in this section. Such facilities are considered in ongoing model building, coordinating planning studies, and operating responsibilities of the MISO Reliability Authority (RA). The most significant of these adjacent facilities are included on the MISO Expansion Planning map (Form 3 in Appendix A). Appendix A contains a detailed list of the locally planned facilities. Appendix A includes the following forms:

Form 1	A transmission line list
Form 2	A device list, which are mostly capacitor banks
Form 3	An expansion planning map

For the purposes of organizing system upgrade information in Appendix A, MISO has grouped the transmission expansion facilities into four planning areas as described below.

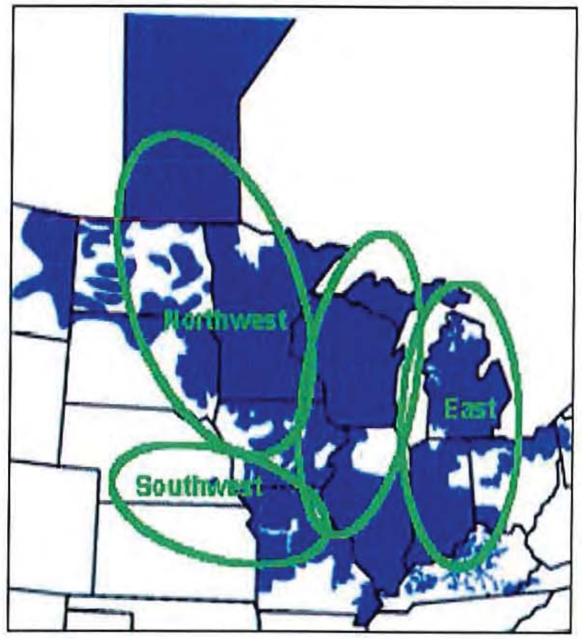


Figure 8.1-1: Planning Regions in MISO

Table 8.1-1: Planning Regions and Sub-Regions

Tree Structure "Bottom Up" Planning Activity

	Planning Regions									
	Central			East		Northwest				Southwest
Existing and Potential Sub Regional Planning Groups	Central and Southern Illinois (C-CSILL)	Northern Illinois (C-NILL)	Wisconsin, Upper Michigan (C-WUM)	S. Indiana, S. Ohio, Kentucky (E-IOK)	Michigan, N. Indiana, N. Ohio (E-MIOO)	Iowa Transmission Working Group (N-ITWG)	Missouri Basin (N-MB)	Nebraska (N-Nebraska)	Northern MAPP** (N-NM)	Southwest (SW)
Midwest ISO Member, Pending, and MOU Systems	CWLP Grid Am (AMRN & CILCO) SIPC	*	ATCo	LGEE VECTREN	CIN ITC Grid Am (FE & NIPS) HE IPL METC	ALT	*	LES	OTP MDU MH*** MP XEL GRE	Aquila****

* Seams Coordination Only

** Subsequent to MTEP 03 the N-RRV and N-UMV have been combined into the "Northern MAPP" Subregional Planning Group (N-NM)

*** MH is not a Midwest ISO member but coordinates via a Memorandum of Understanding

**** Aquila has a practice of reporting their facilities and coordinating plans through the Nebraska SPG (N-Nebraska)

The total estimated direct cost of the Planned and Proposed facilities plus the facilities that went into service since 2003 is **$2.91 billion** for the six-year period 2004-2009 periods. This is substantially above the **$1.96 billion** that was estimated for the six-year period 2002-2007 in MTEP 03. Of these projects, $204 million were In Service by 2004, $1,565 million are considered Planned, and $1,144 million are considered Proposed and will continue to be reviewed.

The cumulative expected spend over the 2004-2009 period is shown in Figure 8.1-2 below.

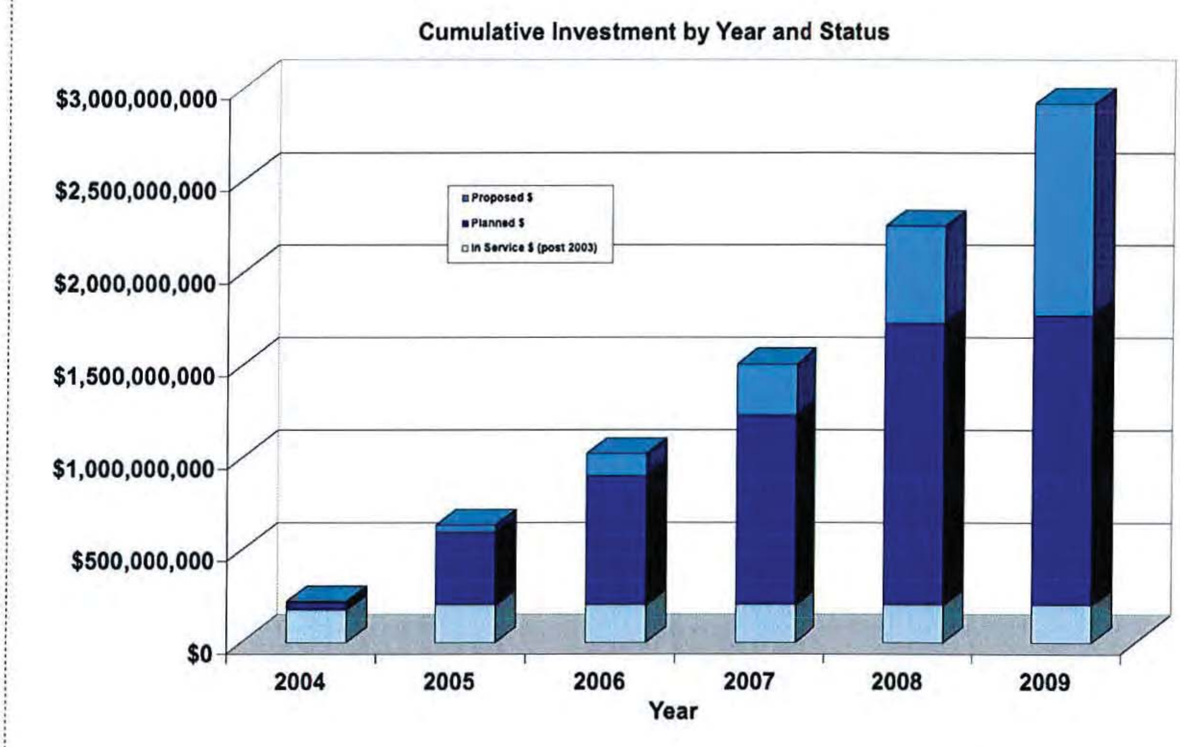


Figure 8.1-2: Cumulative Projected Spending All Projects

When totaled, the TO reported transmission lines planned for new construction and enhancement amount to 5,123 miles by 2009. This includes lines that went in service in 2004, as well as lines Planned or Proposed through 2009. In contrast to the approximate 112,000 miles of line existing throughout the MISO area, only about 1,836 miles of the 5,123 miles by 2009 represent an increase as new corridor usage over the six-year period 2004-2009. The cumulative miles of line by voltage class are shown in Figure 8.1-3. The cumulative line additions by planning status (In service in 2004, Planned, or Proposed) are shown in Figure 8.1-4 as cumulative miles, and the impact by corridor types is shown in Figure 8.1-5.

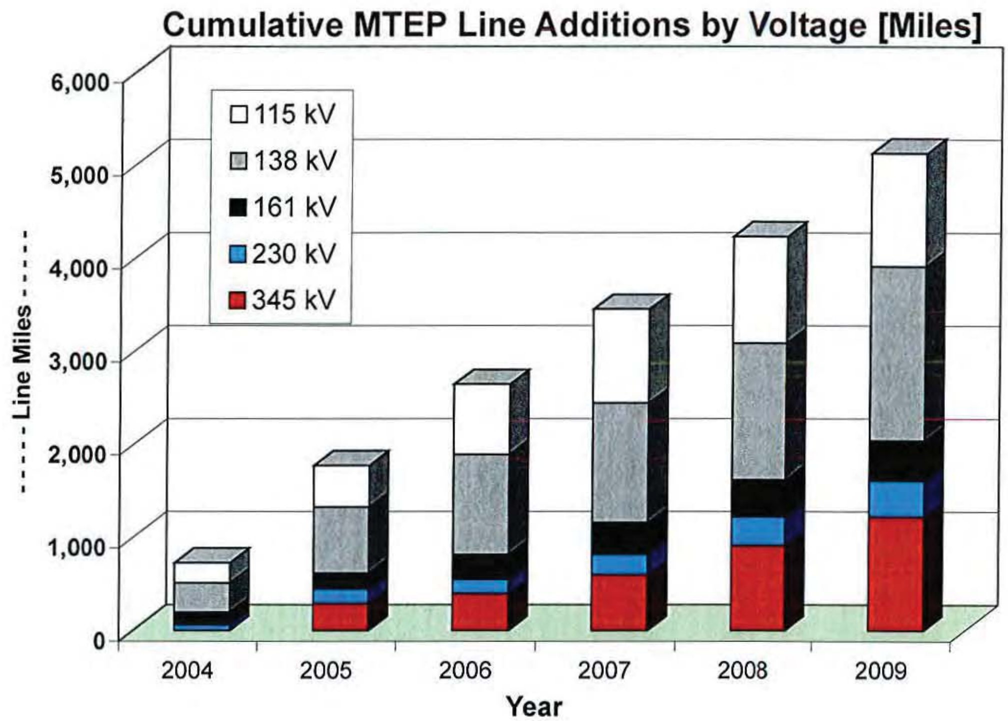


Figure 8.1-3: Cumulative Line Additions/Enhancements by Voltage Class / Miles

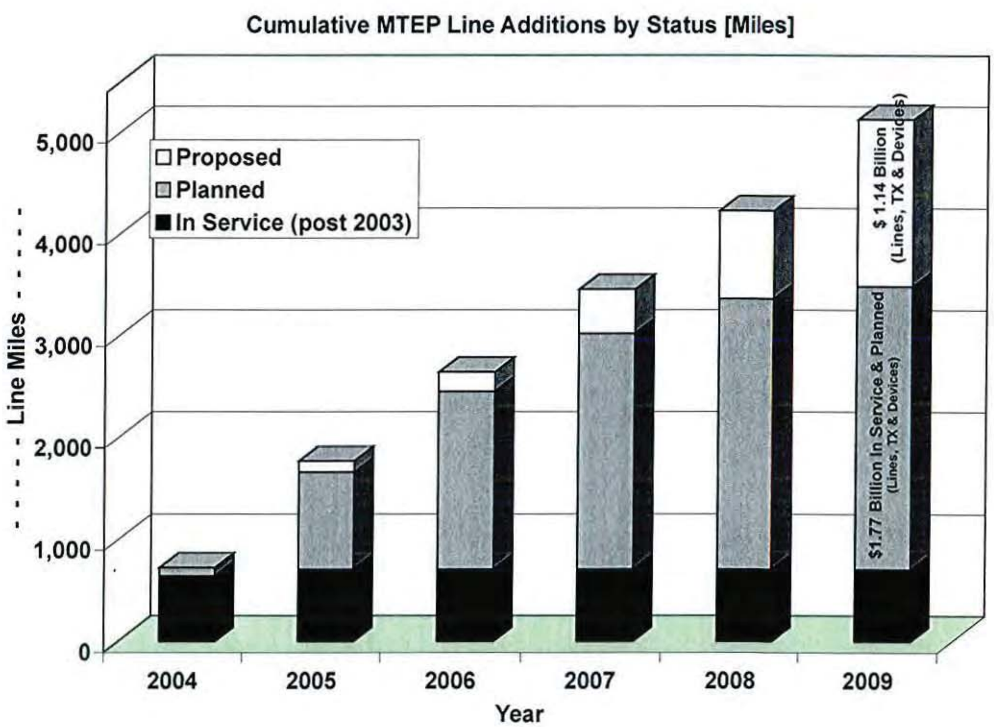


Figure 8.1-4: Cumulative Line Additions/Enhancements by Planning Status (Miles)

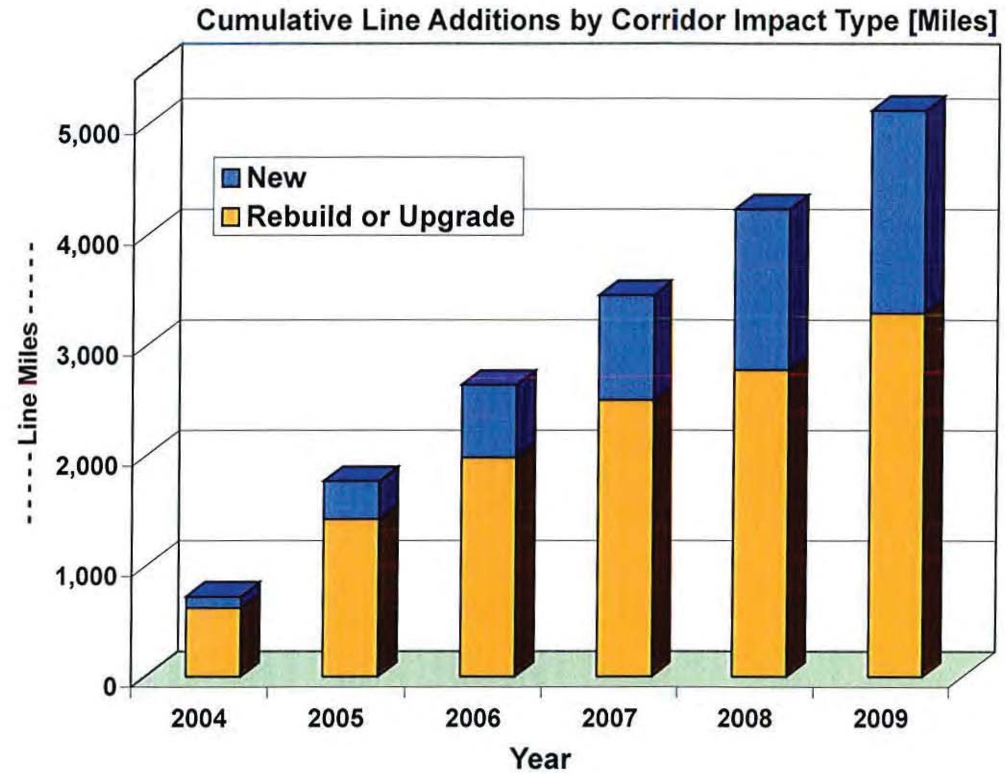


Figure 8.1-5: Cumulative Line Additions/Enhancements by Corridor Impact Type (Miles)

The anticipated 5,123 miles of new or enhanced line and the associated termination facilities at substations are estimated to cost about $2.91 billion. The allocation to specific planning regions is shown in Table 8.1-2.

Table 8.1-2: Cost Allocations to Functional Use Categories

Planning Region	Lines and Terminals	Devices	Total	Percent of Total
Northwest	$1,108,667,079	$47,672,083	$1,156,339,161	39.7%
Central	$1,025,590,492	$30,749,009	$1,056,339,501	36.3%
East	$630,538,612	$48,354,380	$678,892,992	23.3%
Southwest	$19,615,975	$2,011,235	$21,627,210	0.7%
TOTAL	$2,784,412,158	$1,287,786,706	$2,913,198,864	100.0%

Local system plans have been driven by a number of factors including Native Network Load, Generation Interconnection, Transmission Service, etc. Table 8.1-3 is an estimate of the transmission investment by functional use categories. This includes $128,787 for devices (capacitor banks, reactors and reactive power compensators) that has been prorated on a percentage basis across the Functional Use Categories.

Table 8.1-3: Cost Allocations to Functional Use Categories

Native Network Load	Gen Interconnection	Transmission Service	Misc. Other	Total
$1,573,883,432	$544,600,376	$319,957,031	$474,758,025	$2,913,198,864
54.0%	18.7%	11.0%	16.3%	100.0%

Larger projects, with estimated costs of $5,000,000 and higher have been summarized below in Figure 8.1-6. This figure shows a comparison of expected spend grouped by NERC region within the Midwest ISO for the out years of 2007 through 2009. For the purpose of this summary, companies having projects that exceed $ 5,000,000 are in groupings as follows:

MAPP	MAIN	ECAR
XEL	ATC	CIN
OTP	AMRN	ITC
MDU	CILCO	METC
MP	IP	LGEE
MH	SIPC	HE
GRE	CWLP	IPL
LES	CWLD	VECTREN
AQN		
ALTW		

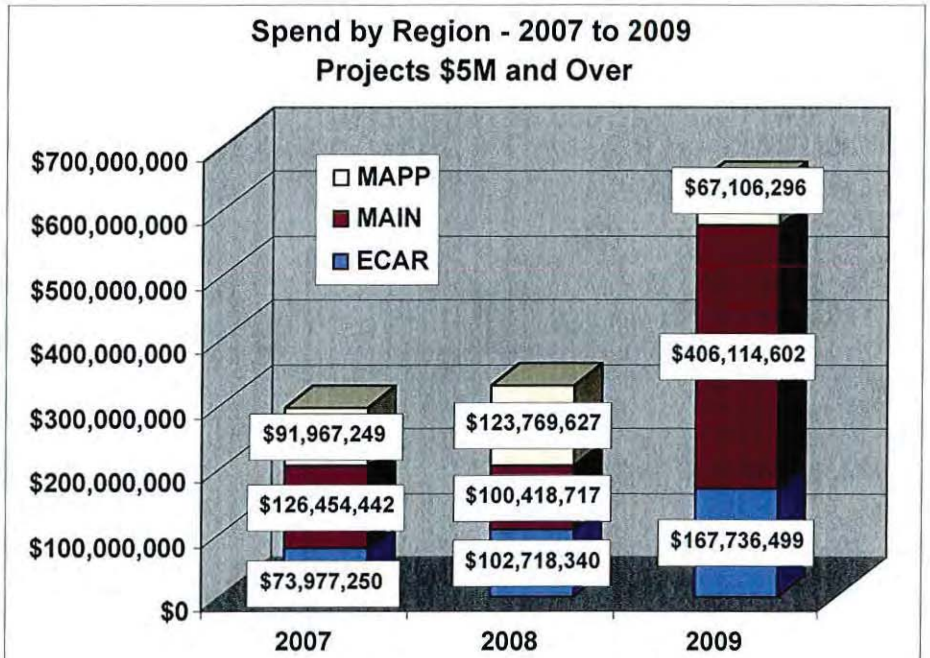
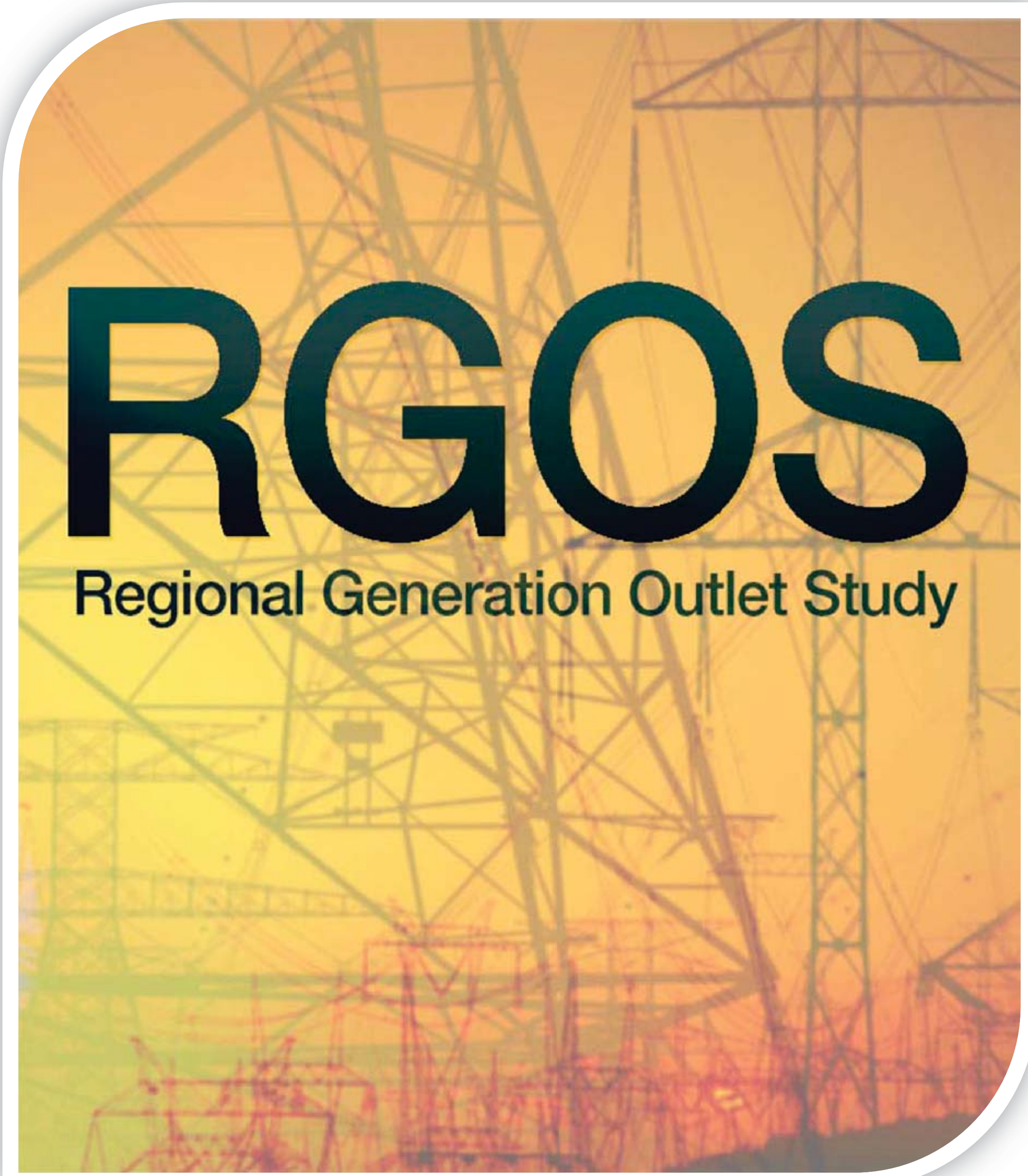


Figure 8.1-6 Spend by Year by Region ($)

This summary shows that of the $1,260,263,022 expected to be spent over the three-year period about 51% is projected for the year 2009. In addition, projected spending is relatively balanced between the three areas for 2007 and 2008, while in 2009 the MAIN areas entities project spending of about 63% of the 2009 total with ECAR 26% and MAPP 11%. This summary has excluded two significant projects with a combined cost of $552,000,000 the Arrowhead–Weston Project of ATC LLC and the Buffalo Ridge Area Generation Outlet Project of XEL. The jurisdictional regulatory authorities already have approved these projects.

Midwest ISO



November 19, 2010

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Contents

Tables & Figures

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1 Study Overview

Renewable Portfolio Standards (RPS) passed by most Midwest ISO member states mandate meeting significant percentages of total electrical energy with renewable energy resources. To develop transmission portfolios fulfilling these requirements and meeting the objective function of achieving the lowest delivered dollar per MWh cost, Midwest ISO, with the assistance of state regulators and industry stakeholders, conducted the Regional Generator Outlet Study (RGOS).

1.1 RGOS Results Summary

During initial RGOS phases, analysis showed locating wind zones in a distributed manner throughout the system—as opposed to only locating the wind local to load or regionally where the best wind resources are located—results in a set of least-cost wind zones that help to reduce the delivered dollar per MWh cost needed to meet renewable energy requirements. From this earlier work, a combination of local and regional wind zones were identified and approved by the Upper Midwest Transmission Development Initiative (UMTDI). Further solidifying the validity of this methodology, the Midwest Governors' Association affirmed the method employed selecting these wind zones as the best approach to wind zone selection.

- RGOS determined the best fit solution to be a transmission overlay encompassing all Midwest ISO states, premised on a distributed set of wind zones, each with varying capacity factors and distances from load.

RGOS narrowed its focus to the development of three (3) transmission expansion scenarios to integrate wind from the designated zones: (1) a **Native Voltage** overlay that does *not* introduce new voltages such as 765kV in areas where they do not currently exist; (2) a **765 kV** overlay allowing the introduction of 765 kV transmission throughout the study footprint; and (3) **Native Voltage with DC** transmission that allows for the expansion of DC technology within the study footprint.

- All three (3) transmission expansion scenarios meet respective state Renewable Portfolio Standards (RPS) requirements within the Midwest ISO footprint.
- The addition of renewable energy zones with the transmission overlays reduced the Midwest ISO load-weighted LMP between $4.30 to $4.90/MWh (2010 USD).
- The three (3) transmission overlay plans represent potential investment of $16B to $22B in 2010 USD in transmission over the next 20 years and consist of new transmission mileage of 6,400–8,000 miles.
- Total cost for the transmission overlays range from $19/MWh to $25/MWh. The cost of the wind generation is an additional $72/MWh. However, the overlays and generation also produce Adjusted Production Cost (APC) savings of $41/MWh to $43/MWh within the Midwest ISO footprint, creating a net cost of $49/MWh to $54/MWh. This cost does not include the value associated with an additional $20/MWh to $22/MWh of APC savings which would accrue to the rest of the Eastern Interconnect as the result of the RGOS transmission overlays and generation.
- Analyses of these three (3) transmission plan alternatives through the RGOS study, along with additional analytics performed within Midwest ISO planning processes, have identified a sub-set qualifying as inputs into the Candidate Mutli-Value Project (MVP) portfolio analysis.

Because of RGOS, Midwest ISO has identified the next, most immediate step to transmission investment: a set of robust Candidate MVPs designed to address current renewable energy mandates and the regional reliability needs of its members. Viable for near-term development, these projects represent $5.8B (2010 USD) of capital investment, approximately $4.4 billion in the Midwest ISO footprint with the remainder in PJM. These Candidate MVPs will serve as inputs into the 2011 Candidate MVP Portfolio analysis, the first of a cyclical set of MVP Portfolio analyses which will propose and evaluate transmission to meet a changing policy landscape. While none of the overlay scenarios—Native Voltage, 765 kV, Native Voltage with DC—has emerged as the definitive renewable energy transmission solution, it is important to note all selected Candidate MVPs are compatible with all three (3) transmission plans.

1.2 Long-term Transmission Strategies

All three (3) transmission plans were developed to provide reliable delivery of the RPS-identified levels of renewable energy. Reliable delivery assumptions are discussed within Section 5 and focus on transmission system constraints 200 kV and higher. Refer to Figure 1.2-1. The study region consists of Midwest ISO and neighboring facilities including MAPP, Commonwealth Edison, and American Electric Power.

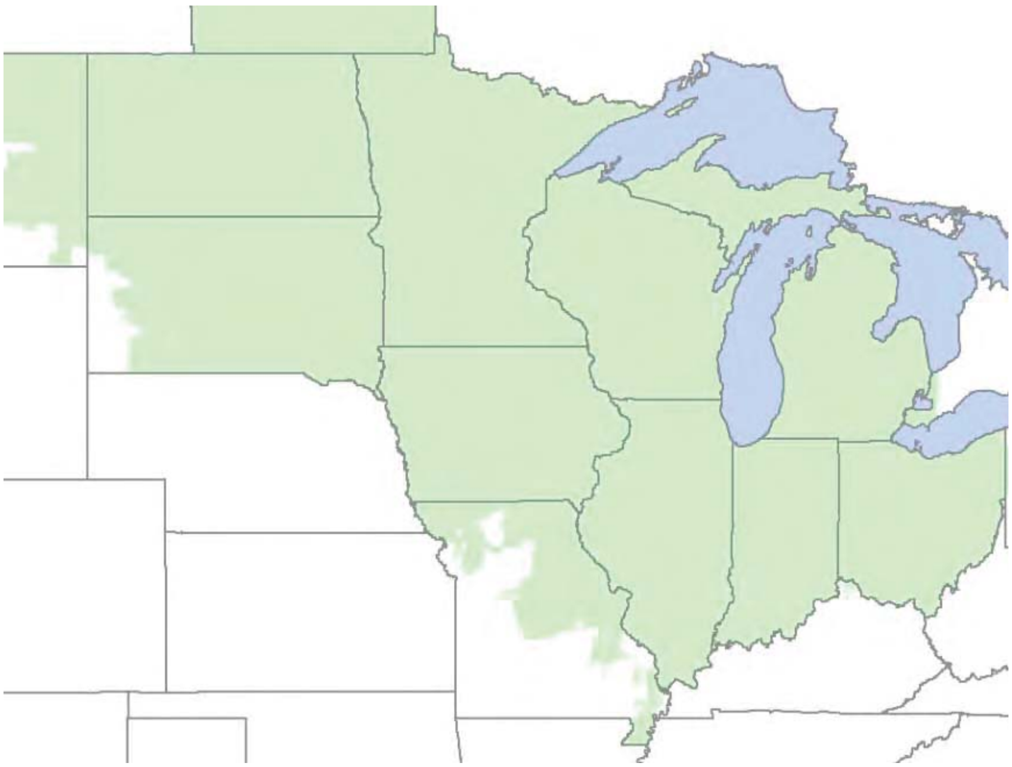

Figure 1.2-1: RGOS Study Footprint

Because RGOS transmission plans impact MAPP and PJM systems, references to these neighboring systems are made whenever RGOS is discussed, the result of necessary assumptions regarding planning practices and strategic assessment. For example, a 765 kV grid logically connects into an already existing 765 backbone on the PJM system, but PJM references are not yet indicative of any projects in the PJM Regional Transmission Expansion Plan. Evaluation of overlays moving forward will continue to require coordination between impacted neighboring entities, including PJM, MAPP, SPP, and TVA.

1.2.1 Transmission Expansion Drivers

The Midwest ISO region observed two significant drivers for transmission expansion: (1) state RPS mandates; and (2) associated generation in the Midwest ISO Generation Interconnection Queue (GIQ). For more detailed information regarding state RPS mandates and goals, refer to section 3 and Appendix 2 of this document. The second major driver for transmission expansion is the Midwest ISO Generation Interconnection Queue (GIQ), which—as of the end of July 2010—held approximately 64,500 MWs of wind requests. After careful examination of the inherently complex issues involved, Midwest ISO staff and stakeholders determined the GIQ process would not be an efficient means for building a cost-effective transmission system either immediately, over the next 5–10 year period or in the foreseeable future beyond that time-frame.

1.2.2 Indicative Zone Selection Rationale

Several different generation siting options were analyzed during previous phases of RGOS. This analysis focused on the relative benefits of local generation, which typically requires less transmission to be delivered to major load centers, and regional generation, which can be located where wind energy is the strongest. A total of fourteen (14) generation siting options were developed, with options ranging from purely local generation siting, purely regional generation siting, or a combination of local and regional generation siting. Transmission overlays were then developed with Transmission Owners (TOs) on a high-level, indicative basis for each generation siting option. Capital costs for each generation siting option and its associated high-level transmission overlay were calculated and plotted against each other to determine the relative cost of each generation siting approach. Refer to Figure 1.2-2.

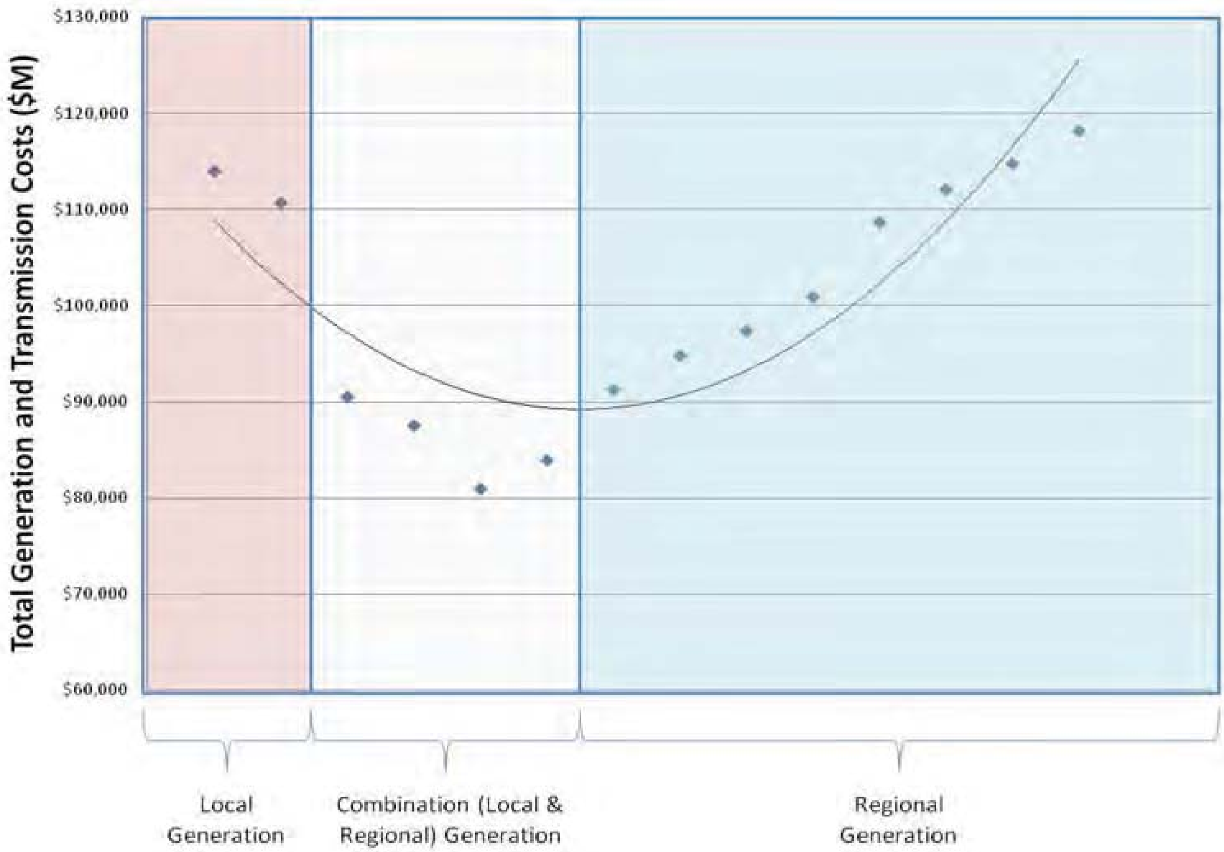

Figure 1.2-2: Zone Scenario Generation and Transmission Cost Comparison

It was determined the least cost approach to generation siting is a methodology containing a combination of local and regional wind generation locations, as shown by the white area on Figure 1.2-2. This was the approach affirmed by the Midwest Governors' Association as the best approach to wind zone selection.

For greater detail regarding the indicative transmission results, design, and optimization, refer to sections 4.1,1, 5.1, and Appendix 3 of this document. Also refer to section 9.1 of the Midwest ISO Transmission Expansion Plan (MTEP) 2009, which more fully describes the rationale driving zone scenario generation.

1.2.3 Comparative Analysis

During the study process, the RGOS group focused on the development of three (3) transmission expansion scenarios mentioned in the previous section: (1) a **Native Voltage** overlay that does *not* introduce new technology or voltages in the area; (2) a **765 kV** overlay allowing the introduction of 765 kV transmission throughout the study footprint; and (3) **Native Voltage with DC** transmission that allows for the expansion of DC technology within the study footprint. Refer to Table 1.2-1, which describes the physical characteristics of the three (3) overlay scenarios. It shows how the number of new lines, total line miles, acres of right-of-way, river crossings, and substations differ between scenarios. It also breaks down each scenario geographically between Midwest ISO, PJM, and Total study footprint. Joint/DC represents AC and DC transmission projects that may constitute shared costs between Midwest ISO and PJM.

The data reveals, for example, that the Native Voltage scenario requires more new lines, more line miles, and more substations than the 765 kV overlay for the total study footprint but does, however, require less acres of right-of-way.

Table 1.2-1: Summary of RGOS Overlay Physical Infrastructure

Overlay	Purview	# of New Lines	Line Miles	Acres of Right-of-way	River Crossings	Substations
Native	**Total**	**122**	**6,795**	**126,637**	**7**	**139**
	Midwest ISO	107	5,938	109,248	7	119
	PJM	13	685	13,197	0	20
	Joint/DC	2	173	4,192	0	0
765	**Total**	**90**	**6,412**	**136,612**	**7**	**124**
	Midwest ISO	69	5,029	104582	7	94
	PJM	17	1,047	23,891	0	30
	Joint/DC	4	336	8,139	0	0
Native DC	**Total**	**113**	**8,033**	**150,094**	**7**	**132**
	Midwest ISO	95	5,340	100,917	7	101
	PJM	17	836	16,289	0	21
	Joint/DC	1	1,857	32,887	0	10
*** Right-of-way widths used in Calculation: 230 kV–100ft ; 345 kV–150ft; Dbl Ckt 345 kV–160ft; 765 kV–200 ft**						

Refer to Table 1.2-2, which describes the costs to build new transmission and generation for the three (3) overlay scenarios. Transmission costs were calculated by multiplying line mileage by cost per mile, with cost per mile differentiated by state. These calculations also included substations, transformers, and related infrastructure. Construction cost estimates also attempted to include the regulatory permitting process. The table categorizes these factors by Native Voltage, 765 kV, and Native Voltage with DC scenarios, as well as Midwest ISO, PJM, and Joint/DC geographies.

Based on these factors, RGOS produced total overlay estimates of $16.3 billion (2010 USD) for the Native Voltage system, $20.2 billion for 765 kV, and $21.9 billion for the Native Voltage with DC scenario for the RGOS study footprint.

Generation costs were calculated by multiplying the total amount of RPS required MW by construction cost estimates of $2 million per MW. This cost, at $58.1 billion (2010 USD), does not vary between scenarios.

Table 1.2-2: 2010 Cost Summary - Construction (2010 USD in Millions)

Category	Geographic Purview	Native Voltage	765 kV	Native DC
Transmission	**Total**	$16,301	$20,249	$21,544
	Midwest ISO	$13,865	$15,099	$12,662
	PJM	$1,952	$4,196	$2,138
	Joint/DC*	$484	$955	6,744
Generation	**Total**	$58,100	$58,100	$58,100
	Midwest ISO	$44,737	$44,737	$44,737
	PJM	$13,363	$13,363	$13,363
	Joint/DC*	$ -	$ -	$ -
Total	**Total**	$74,401	$78,349	$79,644
	Midwest ISO	$58,602	$59,836	$57,399
	PJM	$15,315	$17,559	$15,501
	Joint/DC*	$484	$955	$6,744

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Refer to Table 1.2-3, which describes 2010 Levelized Annual Costs, which are the total revenue requirements (2010 USD) for the three (3) scenarios. Revenue requirements refer to the total annualized costs for the new transmission and generation. These levelized annual costs are determined through application of proxy Attachment O of the Midwest ISO FERC tariff. Table 1.2-3 breaks these factors down by Native Voltage, 765 kV, and Native Voltage with DC (Native DC) scenarios, and Midwest ISO, PJM, and Joint/DC geographies.

RGOS found total study footprint annual levelized costs vary between $1.7 billion per year for Native Voltage, to $2.1 for 765 kV, to $2.2 for Native Voltage with DC (Native DC), with generation annual costs at $4.9 billion.

Table 1.2-3: Cost Summary - 2010 Levelized Annual Costs***

Category	Geographic Purview	Native Voltage	765 kV	Native DC
Transmission	**Total**	**$1,686**	**$2,064**	**$2,188**
	Midwest ISO	$1,419	$1,537	$1,304
	PJM	$209	$424	$227
	Joint/DC*	$57	$102	$656
Generation	**Total**	**$6,334**	**$6,334**	**$6,334**
	Midwest ISO	$4,931	$4,931	$4,931
	PJM	$1,402	$1,402	$1,402
	Joint/DC*	$ -	$ -	$ -
Total	**Total**	**$8,019**	**$8,397**	**$8,521**
	Midwest ISO	$6,351	$6,469	$6,236
	PJM	$1,612	$1,826	$1,630
	Joint/DC*	$57	$102	$656

Table 1.2-4 describes 2010 Annual Costs $/MWh, which takes total costs from Table 1.2-3 and presents total costs as a per MWh value. This calculation is based on 88.6 TWh of energy delivered from renewable energy zones. Table 1.2-4 describes transmission and generation costs for the modeled RGOS renewable wind zone energy.

These are not incremental costs; rather, these are a comparative measure of total MWh cost if wind served as the only energy source relative to RGOS wind and transmission. This table indicates transmission costs for the modeled RGOS renewable energy wind zone delivered would be $19, $23, or $25 per MWh based on the addition of the various RGOS transmission overlays in the Midwest ISO footprint. On the generation side, MWh cost would increase to $72/MWh for all scenarios. It should be understood that the wind and the subsequent transmission have impacts on the entire system being served. This includes providing additional potential reliability benefits to the system for the transmission additions, as well as providing reductions in the production costs on the system. Within this study, only adjusted production costs were given a value to compare to the costs. Because costs are added to the system infrastructure as a direct result to the renewable energy zones to meet RPS requirements, the energy delivered from those zones was used as a common denominator for the per unit comparsion.

Table 1.2-4: Cost Summary – 2010 Annual Costs ($/MW*)**

Category	Geographic Purview	Native Voltage	765 kV	Native DC
Transmission	**Total**	**$19**	**$23**	**$25**
	Midwest ISO	$16	$17	$15
	PJM	$2	$5	$3
	Joint/DC*	$1	$1	$7
Generation	**Total**	**$72**	**$72**	**$72**
	Midwest ISO	$56	$56	$56
	PJM	$16	$16	$16
	Joint/DC*	$0	$0	$0
Total	**Total**	**$91**	**$95**	**$96**
	Midwest ISO	$72	$73	$70
	PJM	$18	$21	$18
	Joint/DC*	$1	$1	$7

* Joint/DC represents AC and DC transmission projects that may constitute shared costs between Midwest ISO and PJM. Note, too, there is one AC project: the Pioneer 765 kV project in Indiana. The rest represent DC projects.

** Transmission costs include line and substation cost estimates

*** Levelized annual costs determined through application of proxy Attachment O calculation to determine annual revenue requirements

**** Calculation based on energy delivered from renewable energy zones: 88.6 TWh (each overlay effectively delivered the same amount of energy)

Adding wind to the system reduces energy costs. This benefit is captured through the adjusted production cost calculated by dividing total production cost savings by total MWh. Refer to Table 1.2-5, which describes regional per MWh adjusted production savings based on 88.6 TWh of RGOS wind zone delivered energy. Adjusted cost savings within the Midwest ISO footprint for Native Voltage, 765 kV, and Native Voltage with DC (Native DC) scenarios would be \$41/MWh, \$43/MWh, and \$43/MWh (2010 USD), respectively.

Table 1.2-5: 2010 Adjusted Production Cost (APC) Savings (\$/MWh)

Entity	Native Voltage	765 kV	Native DC
Midwest ISO	\$41	\$43	\$42
Midwest ISO/MAPP	\$56	\$57	\$57
Midwest ISO/MAPP/PJM	\$62	\$63	\$63
Eastern Interconnect	\$62	\$63	\$63

Table 1.2-6 summarizes net cost. Subtracting 2010 MWh Adjusted Production Cost (APC) benefits from 2010 installed costs results in the following net costs per MWh of delivered RGOS wind zone energy.

Table 1.2-6: 2010 Net Total Cost Summary (\$/MWh)

Entity	Native Voltage	765 kV	Native DC
Midwest ISO	\$49	\$52	\$54
Midwest ISO/MAPP	\$35	\$37	\$39
Midwest ISO/MAPP/PJM	\$29	\$32	\$33
Eastern Interconnect	\$29	\$32	\$33

When analyzing the information presented in Tables 1.2-1–1.2-4, it is important to note while overall metrics show some disparity among plans, the Native Voltage and 765 kV overlays are very similar when looking solely at Midwest ISO-only impacts. It is more problematic, however, when comparing either of these two (2) overlays to the Native Voltage with DC option since DC transmission costs are not categorized as solely Midwest ISO or solely PJM because the lines start in one system and terminate in the other.

1.2.4 Native Voltage Overlay

The Native Voltage solution focuses on transmission development that does **not** introduce a new voltage class within areas. This means areas with 345 kV transmission as the native Extra High Voltage (EHV) transmission must be limited to a maximum of 345 kV transmission for new infrastructure expansion. However, those areas with existing 765 kV transmission would be allowed to expand 765 kV infrastructure. Refer to Figure 1.2-3, which depicts the Native Voltage transmission solution meeting the RGOS design criteria. For a large (42 in. x 36 in.), detailed version of the Native Voltage overlay, refer to Appendix 10, attached.

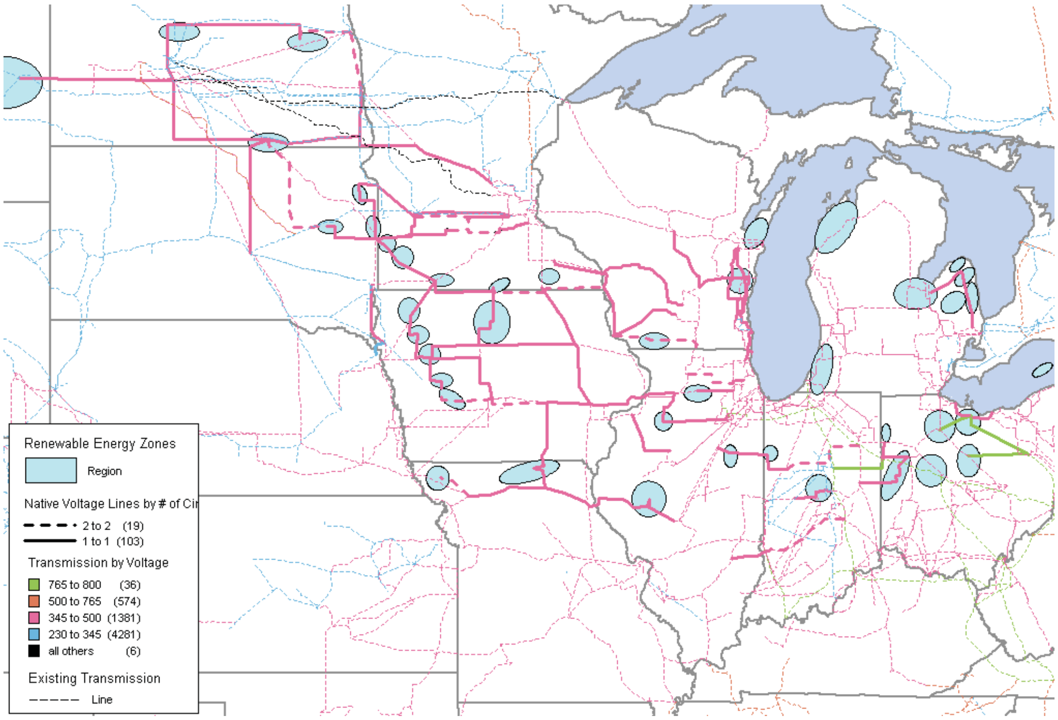

Figure 1.2-3: Native Voltage Transmission Overlay Strategy

As currently designed, the Native Voltage transmission overlay has the lowest construction cost. Although Native Voltage has more line miles than the 765 kV overlay, it requires fewer acres of right-of-way. When considering Midwest ISO alone, although the economic metrics of the Native Voltage overlay may not be as attractive as the metrics for the 765 kV overlay, Native Voltage requires about $1,200M less in capital investment to construct. The Native Voltage plan, like the two other transmission overlays, achieves the reliability objectives of the study. However, this plan does not extend as far south as the other two plans. This is part of the reason the other plans have higher construction/capital costs.

The Native Voltage strategy does have some risks and benefits. If renewable energy mandates are increased within the study footprint, or if there is an increased need for exports, additional transmission may need to be constructed. This would likely require additional right-of-way and more miles of transmission line when compared to the 765 kV and Native Voltage with DC overlays. In the long-term, this may result in escalating costs and environmental impacts that are not accounted for in this study. However, the Native Voltage Overlay has less dependence on the future transmission expansion plans of neighbors. By not introducing new voltages, the Native Voltage strategy readily integrates into the existing Midwest ISO system and may allow for quicker construction and better sequencing with other overlay components compared with the 765 kV overlays. Additionally, this strategy possibly puts less cost at risk if actual wind requirements of the Midwest ISO states are determined to be lower than the amount of wind included in the RGOS study—a determination not yet made. This risk will be minimized by carefully sequencing the construction of whichever overlay is chosen.

1.2.5 765 kV Overlay

The 765 kV solution emphasizes the development of transmission that introduces a new voltage class to much of the RGOS footprint. Figure 1.2-4 depicts the 765 kV transmission solution meeting RGOS design criteria. For a large (42 in. x 36 in.), detailed version of the 765 kV overlay, refer to Appendix 10, attached.

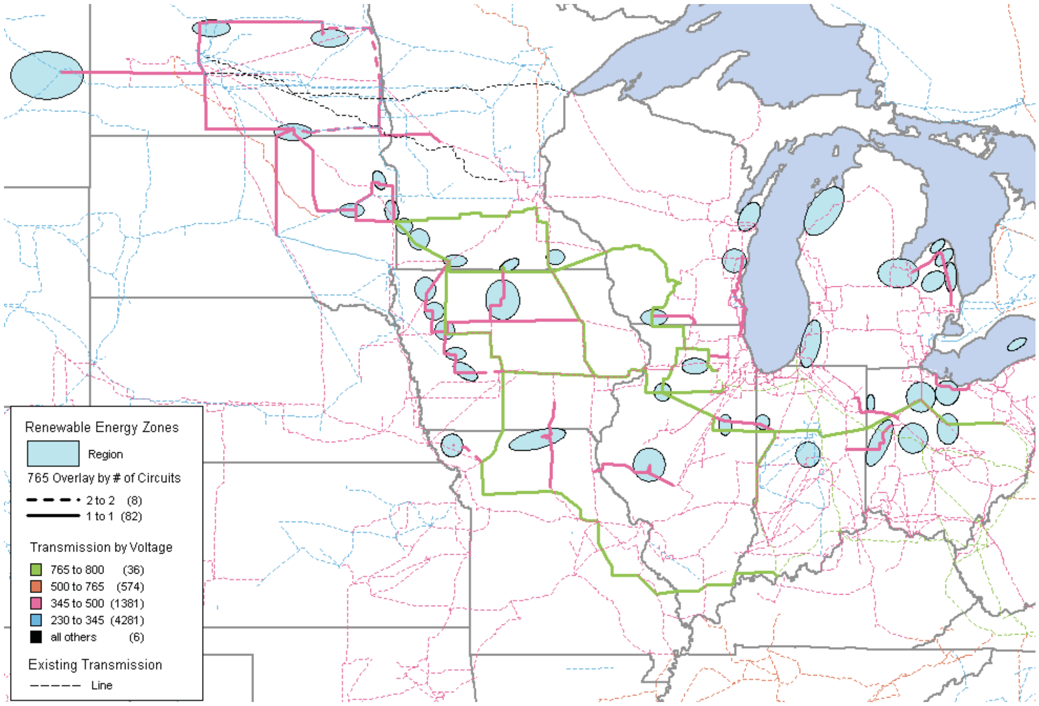

Figure 1.2-4: 765 kV Transmission Overlay Strategy

The 765 kV overlay results in Adjusted Production Cost (APC) savings greater than the Native Voltage overlay. The 765 kV overlay also uses less line miles of transmission lines than the Native Voltage overlay, although the 765 kV overlay does require more acres of right-of-way due to the wider right-of-way needed for 765 kV transmission. However, in the Midwest ISO portion of the overlay, the comparison of transmission costs, mileage, and acreage may favor the 765 kV plan.

Selecting 765 kV as an overall strategy also holds risks. For example, system development may not be achievable without cooperation among the transmission expansion strategies of two RTO regions; e.g., investment in 765 kV construction within Midwest ISO may be more heavily dependent upon the investment of the 765 kV grid within the western PJM region than the Native Voltage overlay. Proper coordination of development within Midwest ISO is also an important consideration. Transmission built in the western portion of the footprint to 765 kV standards may default to 345 kV transmission operation if eastern portions of the Midwest ISO footprint do not commit to the same 765 kV development in the same time-frame, resulting in potential cost risk. Finally, introducing 765 kV into new portions of the footprint will require costs associated with the learning curve required for the development and management necessitated by a new voltage type in the system.

Adopting a 765 kV strategy does, however, offer a number of benefits. For example, the 765 kV overlay demonstrates the need for less miles of transmission than the miles of transmission required by Native Voltage to deliver the same amount of renewable energy. If wind development in the region continues to increase over the future—and it is reasonable to expect this would be a continuing trend—the 765 kV overlay will reduce the amount of environmental impact caused by transmission construction. Although the current 765 kV plan has the potential to create better interconnection access to areas to the south and Southeast of Midwest ISO, additional refinement of the 765 kV plan that results in the same geographical footprint access as the current Native Voltage design could further reduce the line mileage of the strategy while also reducing total costs.

1.2.6 Native Voltage with DC Overlay

The Native Voltage with DC solution focuses on the development of transmission that introduces a new voltage class to much of the RGOS study footprint. Figure 1.2-5 shows the Native Voltage with DC transmission solution that meets RGOS design criteria. For a large (42 in. x 36 in.), detailed version of the Native Voltage with DC overlay, refer to Appendix 10, attached.

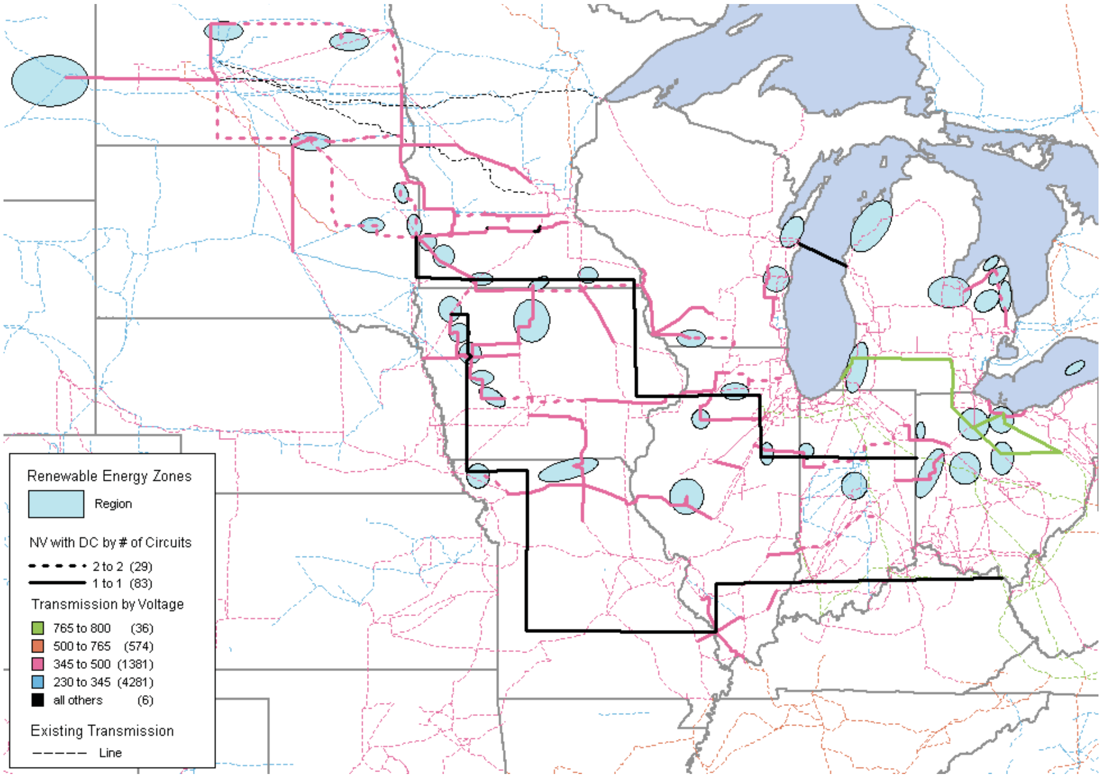

Figure 1.2-5: Native Voltage with DC Transmission Overlay Strategy

The Native Voltage with DC overlay provides benefits to the system—reducing, for example, the amount of AC transmission needed by allowing energy to be gathered in the western region of the study footprint and delivered to points to the east while avoiding potential impacts on the underlying systems. This scenario demonstrates that the crossing under Lake Michigan has the potential to reduce land-based transmission within Wisconsin and along the southern shores of Lake Michigan. Like 765 kV, Native Voltage with DC accesses part of the footprint that the Native Voltage strategy would not.

Land-based High Voltage Direct Current (HVDC) transmission was modeled as conventional HVDC. However, there are other options for the DC design available for future analysis that may provide for operational benefit that could not be captured through this study. For example, HVDC–Voltage Source Control (VSC) provides real power flow control beyond generator dispatch at full range of capability where conventional has limitations at lightly loaded schedules. In addition, HVDC–VSC has voltage control capability independent of the real power flow on the line, whereas conventional design reactive support is dependent on the real power flow. Finally, it is more functional in being able to interconnect at more intermediate locations compared to conventional HVDC which limits intermediate interconnection points.

Unfortunately the costs of adding DC to the system are rather high compared to the AC alternatives at shorter distance needs, and the entries to tap the lines are much more expensive and less integrated than providing AC paths across the system. However, it is difficult to eliminate DC transmission as an option for bulk energy delivery from renewable energy areas across long distances because of not-yet-evaluated option values. Proper evaluation of these other metrics along with improved design of what type of HVDC as well as interconnection locations could improve the case for long-distance DC energy delivery.

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1.3 RGOS Candidate Multi-Value Projects

Although RGOS focused on the development of holistic system solutions meeting long-term needs for the integration of renewable resources into the transmission system, it is important to identify an initial group of projects that are compatible with the three overlays that provide a practical first step towards meeting the renewable resource requirements. Midwest ISO staff has developed an analytical framework to identify the best potential transmission projects. These RGOS-identified projects will require more detailed analysis. Because a Midwest ISO long-range transmission expansion strategy has not yet been determined and was not within the scope of RGOS analysis, it is important Candidate Multi-Value Projects (MVPs) not pre-determine Midwest ISO long-range strategic aims and equally important Candidate MVPs prove compatible with all potential strategies.

Refer to the Venn diagram in Figure 1.3-1 conceptualizing RGOS Candidate Multi-Value Project (MVP) selection.

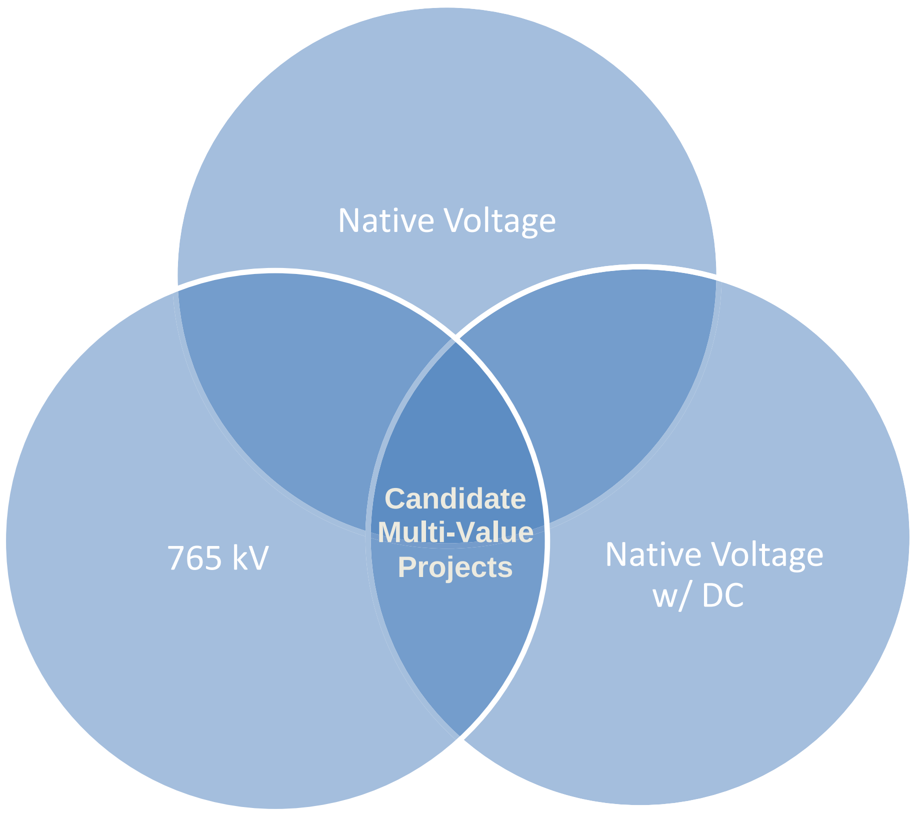

Figure 1.3-1: Candidate MVP Strategy Development Venn Diagram

1.3.1 Identifying RGOS Candidate Multi-Value Projects

The RGOS inputs into the Candidate Multi-Value Projects (MVPs) portfolio were identified by means of the steps outlined below. Please note other studies were considered in collecting the final Candidate MVP portfolio; not all projects in that portfolio are derived from the RGOS study effort. For greater detail regarding the steps comprising the Candidate MVP identification process, refer to section 7 of this document. For a summary of the future ramifications of Candidate MVP portfolio identification, refer to section 8.

- **Step 1:** Identify useful corridors common to multiple Midwest ISO studies.
- **Step 2:** Identify RPS timing needs and synchronize with generation interconnection queue locations.
- **Step 3:** Evaluate constructability of transmission.

An initial set of transmission projects was identified using the inspection steps listed above. These transmission projects served as an input into the overall Candidate MVP portfolio described in section 7.1. The selected Candidate MVPs are compatible with RGOS-developed overlays and provide potential value for other needs identified within the transmission system. Refer to Figure 1.3-2, which depicts Candidate MVPs from the RGOS analysis. Estimated cost for this RGOS Candidate MVP set is approximately $5.8 Billion, with $4.4 billion of that amount within Midwest ISO borders.

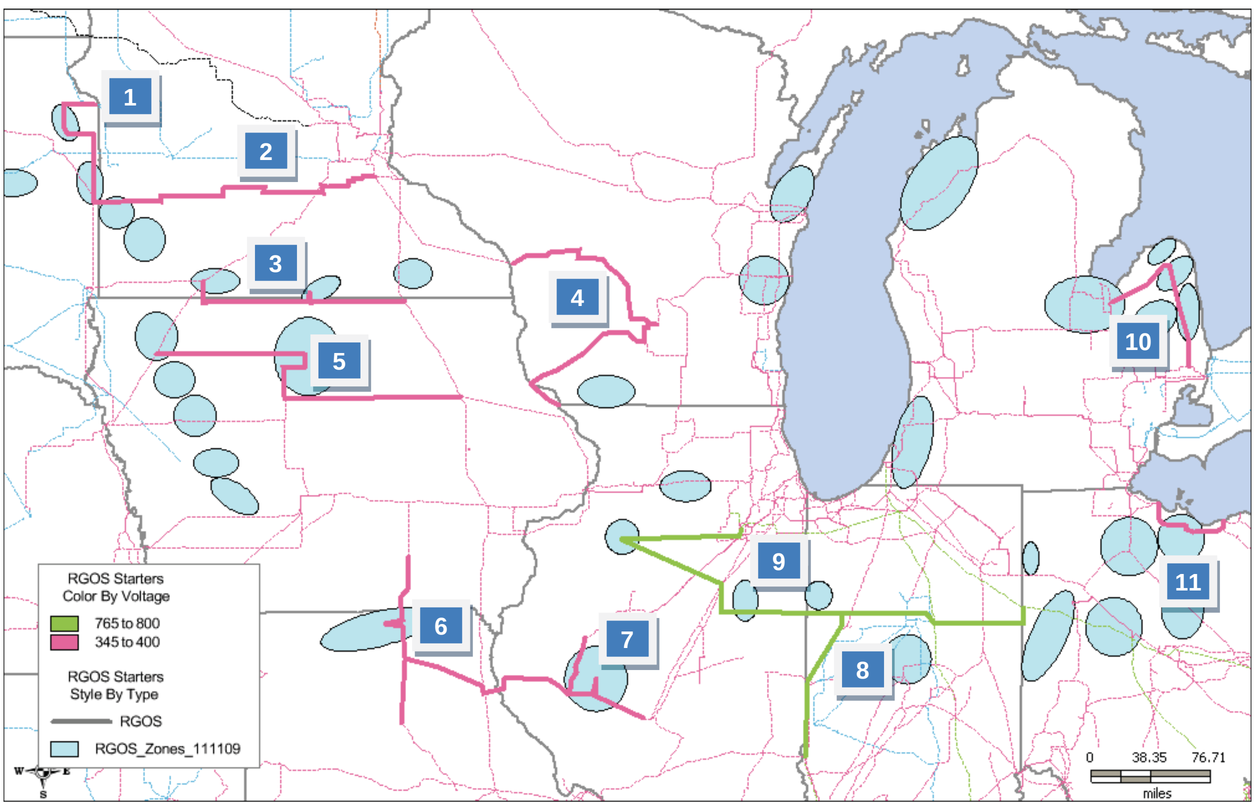

Figure 1.3-2: RGOS-identified Candidate Multi-Value Projects (Midwest ISO and PJM Lines Shown)

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The numbered list shown in Table 1.3-1, below, corresponds to the Candidate MVP identifiers depicted in Figure 1.3-2 on the previous page.

Table 1.3-2: Candidate Multi-Value Projects

ID	Candidate MVP	Estimated Installed Cost (2010 USD in millions)
1	Big Stone to Brookings 345 kV line	150
2	Brookings to Twin Cities 345 kV line	700
3	Lakefield Junction to Mitchell County 345 kV line constructed at 765 kV specifications	600
4	North LaCrosse to North Madison to Cardinal, Dubuque to Spring Green to Cardinal 345 kV lines	811
5	Sheldon to Webster to Hazleton 345 kV line	458
6	Ottumwa to Adair to Thomas Hill, Adair to Palmyra 345 kV lines	295
7	Palmyra to Meredosia to Pawnee, Ipava to Meredosia 345 kV lines	345
8	Sullivan to Meadow Lake to Greentown to Blue Creek 765 kV line	908
9	Collins to Kewanee to Pontiac to Meadow Lake 765 kV line	964
10	Michigan Thumb 345 kV transmission loop	510
11	Davis Besse to Beaver 345 kV line	71

The RGOS effort encompassed not only Midwest ISO but also immediate neighbors within PJM. This broadening of the study footprint resulted in development of transmission overlays that also include transmission within the PJM footprint. However, for purposes of Candidate Multi Value Project (MVP) evaluation, only Midwest ISO projects are included.

1.4 RGOS Results Summary

RGOS provides industry stakeholders and policy makers with a regional planning perspective identifying potential investment opportunities and demonstrating the integration of renewable energy policies into electrical system development. The purpose of RGOS has been to explore long-term transmission strategies ensuring study defined reliability objectives in delivery of renewable energy as well as RPS compliance. Aside from developmental considerations and regulatory concerns, determining a long-term transmission expansion strategy also serves to frame and define near-term needs. With these factors in mind, RGOS contributors considered the following when formulating viable long-term transmission strategies:

- **Performance:** Does the proposed strategy perform well under a variety of future scenarios?
- **Developmental Considerations:** Noting many of the more reliable wind resources reside far from large electrical load centers and lack adequate long-distance transmission lines, what is the expectation for further long-term development of wind resources within Midwest ISO?
- **Time Constraints:** Can finalizing a single, long-term strategy decision be deferred long enough to allow continued testing of important assumptions without jeopardizing legal requirements and renewable investment or risking the potential for stranded investment?

The best fit solution is a transmission overlay encompassing all Midwest ISO states, premised on a distributed set of wind zones, each with varying capacity factors and distances from load.

The best fit solution is a transmission overlay encompassing all Midwest ISO states, premised on a distributed set of wind zones, each with varying capacity factors and distances from load.

Midwest ISO cannot currently recommend a long-term transmission development strategy employing Native Voltage, 765 kV, or Native Voltage with DC. All three plans meet study objectives. Costs and benefits vary between scenarios, but not significantly. Methodologies for analyzing performance under a variety of possible futures require continued development along with determining ‘options value’ for each strategy. Detailed construction design analysis is still required.

No consensus exists regarding the amount of renewable generation ultimately needed to comply with current and future RPS mandates. Predictions vary. Some assert a much higher level of wind generation will be required than those included in RGOS analyses while others, equally confident, claim a lower amount. Regardless of the long-term uncertainty engendered by expansion or reduction of renewable energy standards, states within the Midwest ISO system will need new transmission to meet current and near-term renewable energy requirements, to ensure reliable operation of the transmission grid, and to facilitate the generation interconnection queue process. Midwest ISO will continue to work with policy makers and industry stakeholders to determine a strategy for transmission development within the footprint.

Because of RGOS, Midwest ISO has identified the next, most immediate step to transmission investment: a set of robust Candidate Multi-Value Projects (MVPs) meeting current renewable energy mandates and the regional reliability needs of its members.

2 Scope

2.1 Stakeholder Study Participation

Stakeholders reviewed and contributed to RGOS throughout the study process. A Technical Review Group (TRG), composed of regulators, transmission owners, renewable energy developers, and market participants, met monthly with Midwest ISO engineers to provide input, feedback, and guidance. Composed of a smaller group of experienced transmission engineers, a Design Subteam (DST) met bi-weekly to review detailed results. RGOS reported regularly to the Midwest ISO Planning Advisory Committee (PAC) and Planning Subcommittee (PSC). RGOS transmission planners also conferred with the Upper Midwest Transmission Development Initiative (UMTDI), a group of Governor-appointed representatives from Wisconsin, Iowa, Minnesota, South Dakota, and North Dakota.

2.2 Stakeholder Survey Results

In 2008, at the onset of Phase I of the RGOS study, a stakeholder survey was completed for the states of Illinois, Iowa, Minnesota, and Wisconsin. The purpose of the survey was to determine the renewable energy requirements; i.e., the Renewable Portfolio Standards (RPS), of the various Load Serving Entities (LSEs) in those states. The results were published in the RGOS Phase I Executive Summary Report[1]. Likewise, another survey was performed during the summer 2009 to update RGOS Phase I information and to gather LSE renewable requirements from the remaining Midwest ISO states. The surveys also included the PJM members Commonwealth Edison (CE) and American Electric Power (AEP).

This inquiry sought detailed information regarding the plan of each company to meet the requirements of their particular RPS or goal. Each State also received a survey for their perspective. The survey results provided specific and current information on the RPS and wind assumptions within the RGOS study area, such as the following:

- Identifying the RPS mandates and respective plans by each LSE, by state
- Determining how and to what extent each LSE intends to utilize wind generation to meet its RPS obligations
- Calculating the energy projections of each LSE for each year under its RPS

The information obtained from these surveys was vital in determining the amount of renewable energy and capacity to study. Not all the LSE's responded to the survey resulting in some data being determined through a similar survey by the Organization of Midwest States (OMS) Cost Allocation and Regional Planning (CARP) Working Group.

[1] RGOS Phase I Executive Summary Report

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Table 3.2-1 below summarizes the results of the RGOS survey, identifying total and net renewable energy requirements, existing and planned renewable energy, and the net renewable capacity for 2027. Table 3.2-1 also identifies the amount (in percent) of each states RPS expected to be served by wind energy. The 'Total Energy Required' column is the net requirement after applying the "% of RPS by Wind" percentages. As can be seen in Table 3.2-1, some states have more existing renewable energy than required by their respective mandates or goals. Existing renewables were only counted towards the requirements of the respective state in which these renewables originate; thus, an excess of existing wind in one state was not counted towards the requirements in another state. In Iowa, for example, it was not fully known where an excess of that state's existing renewable energy is being supplied. Confining source to state also reduced the risk of double counting if an LSE is fulfilling part of its requirements by deriving some of its renewable energy from another state.

Table 2.2-1: RGOS Survey Results

State	% of RPS by Wind	Total Energy Required (GWh)	Existing & Planned (GWh)	Net Needs (GWh)	Wind Zone Capacity (MW)
IA	100%	348	10,272	-	4,650
IL	75%	17,905	5,608	12,297	2,200
IN	-	-	2,263	-	1,000
MI	92%	7,884	365	7,519	3,150
MN	95%	22,786	6,929	15,857	3,875
MO	90%	6,591	439	6,152	1,000
MT	-	-	-	-	400
OH	100%	26,244	3	26,241	5,075
WI	63%	14,630	1,959	12,671	2,325
ND	-	1,453	4,752	-	2,325
SD	-	1,294	626	668	2,325
Total	**-**	**99,135**	**33,215**	**81,406**	**28,325**
RTO					
Midwest ISO	-	78,707	32,165	62,028	21,582
PJM	**-**	20,428	1,050	19,378	6,743

Note the following:

- "Existing & Planned" refers to wind farms or other qualifying renewable energy source currently in operation or holding a signed Generator Interconnection Agreement.
- The Wisconsin RPS is 10% of energy served from renewable; however, it has been adjusted to 25% per direction from the State of Wisconsin.
- Several sources were considered in order to determine the most up-to-date levels of Existing and Planned renewable energy within the study footprint. Those sources included LSE surveys, Midwest ISO Operations data, and data compiled from the SMARTransmission[2] study.

[2] SMARTransmission

2.3 Wind Zone Development

A key assumption of the RGOS study has been the amount and location of wind energy zones modeled within the study footprint. Wind energy zone development was based on stakeholder surveys focusing on expected renewable energy needs over the next 20 years and how much of that need is expected to be met with wind generation.

During RGOS I and RGOS II wind zone development, Midwest ISO staff provided for consideration multiple energy zone configurations that met renewable energy requirements. In this process, study participants identified capital costs associated with generation capacity as well as capital costs associated with indicative transmission that would help deliver the energy to the system. In both RGOS I and II efforts, the most expensive energy delivery options were those options relying solely on the best regional wind source areas (with higher amounts of transmission needed) or those options relying solely on the best local wind source areas (with higher amounts of generation capital required).

As a result of RGOS I and RGOS II zone development efforts as well as interaction with regulatory bodies such as the Upper Midwest Transmission Development Initiative (UMTDI) and various state agencies within Midwest ISO, a set of renewable energy zones was selected. These zones represent the intention of state governments to source some renewable energy locally while also using the higher wind potential areas within the Midwest ISO market footprint. Zone selection was based on a number of potential locations developed by the Midwest ISO utilizing mesoscale wind data supplied by the National Renewable Energy Laboratory (NREL) of the US Department of Energy. Wind zones distributed across the region (1) reflecting local development trends and requirements; or (2) occupying the best regional wind locations, results in a set of distributed wind zones best balancing renewable energy requirements and overall system costs.

Refer to Figure 2.3-1, which depicts this selected set of renewable energy zones, and to Table 2.3-1 and Table 2.3-2, which furnish zone-by-zone UMTDI and non-UMTDI selections, respectively.

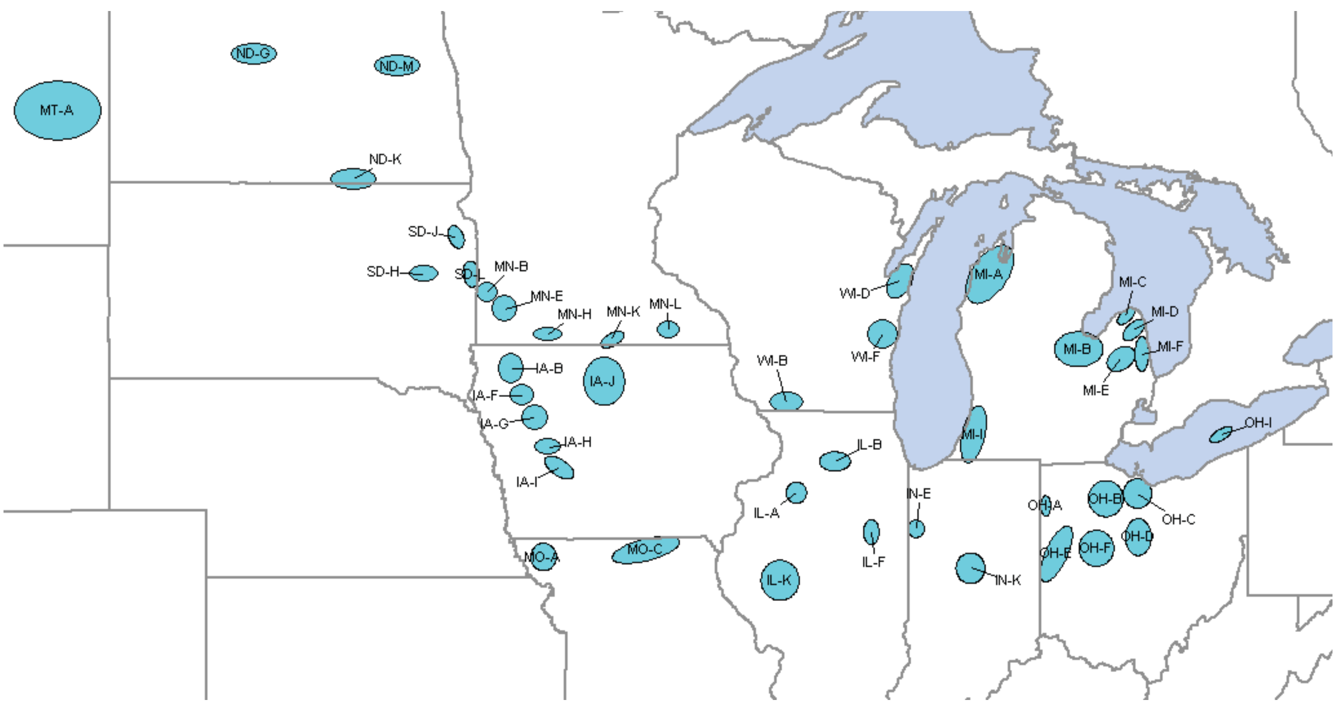

Figure 2.3-1: Renewable Energy Zone Locations

Table 2.3-1: Renewable Energy Zone Information (UMTDI Zone Selection B)

Zone	State	CF	Nameplate (MW)	Energy Output (GWh)	Zone	State	CF	Nameplate(MW)	Energy Output (GWh)
IA-B	IA	0.366	775	2485	MN-L	MN	0.349	775	2369
IA-F	IA	0.362	775	2458	ND-G	ND	0.424	775	2879
IA-G	IA	0.354	775	2403	ND-K	ND	0.373	775	2532
IA-H	IA	0.367	775	2492	ND-M	ND	0.359	775	2437
IA-I	IA	0.356	775	2417	SD-H	SD	0.384	775	2607
IA-J	IA	0.327	775	2220	SD-J	SD	0.407	775	2763
MN-B	MN	0.393	775	2668	SD-L	SD	0.399	775	2709
MN-E	MN	0.382	775	2593	WI-B	WI	0.266	775	1806
MN-H	MN	0.368	775	2498	WI-D	WI	0.283	775	1921
MN-K	MN	0.334	775	2268	WI-F	WI	0.276	775	1874

Table 2.3-2: Renewable Energy Zone Information (non-UMTDI Zone Selections)

Zone	State	CF	Nameplate (MW)	Energy Output (GWh)	Zone	State	CF	Nameplate(MW)	Energy Output (GWh)
IL-A	IL	0.310	550	1494	MI-I	MI	0.259	350	794
IL-B	IL	0.298	550	1436	MO-A	MO	0.358	500	1568
IL-F	IL	0.300	550	1445	MO-C	MO	0.330	500	1445
IL-K	IL	0.252	550	1214	MT-A	MT	0.432	400	1514
IN-E	IN	0.311	500	1362	OH-A	OH	0.272	725	1727
IN-K	IN	0.291	500	1275	OH-B	OH	0.271	725	1721
MI-A	MI	0.264	300	694	OH-C	OH	0.280	725	1778
MI-B	MI	0.274	500	1200	OH-D	OH	0.252	725	1600
MI-C	MI	0.298	500	1305	OH-E	OH	0.255	725	1620
MI-D	MI	0.281	500	1231	OH-F	OH	0.281	725	1785
MI-E	MI	0.272	500	1191	OH-I	OH	0.407	725	2585
MI-F	MI	0.270	500	1183					

The capacity factors used in Table 2.3-1 and Table 2.3-2 are weighted capacity factors (CFs) developed as part of RGOS Phase I analysis. For further information regarding CF calculations, refer to section 9 of MTEP09 and the RGOS Phase I Executive Summary Report. In selecting renewable energy zones, a general methodology was used:

1. UMTDI B zones from the RGOS Phase I were used for the western footprint to meet local needs.
2. Michigan would meet all of its energy needs within the state of Michigan in accordance with state legislation.
3. Ohio, Missouri, and Illinois would meet 50% of their needs with respective in-state resources to reflect state legislation and the desire for local development.
4. UMTDI group B zones, Montana, and Indiana were used to meet the remaining renewable energy needs of Ohio, Missouri, and Illinois.
5. Target energy from renewable energy zones was 81,406 GWh.

2.4 Study Methodology

There were three (3) primary steps utilized in the development of the transmission overlays. These steps include both production cost and Power Flow analysis, with each technique providing its own value to the process. The starting point of this analysis was the indicative transmission developed during RGOS Phase I and Phase II studies in 2008 and 2009. For more information regarding this development process, again refer to MTEP09 report, Section 9.

2.4.1 Production Cost Analysis

Power Flow reliability analysis was conducted using a production cost model as a starting point. This starting point analyzed the energy flow on the system and reduced the indicative transmission to a limited level of transmission to achieve economic energy flow. Production cost modeling uses a limited list of reliability constraints for analysis, and therefore should not be considered an optimal solution without reliability model analysis.

The production cost model included the transmission infrastructure contained within the RGOS peer-reviewed 2019 Power Flow model. The initial production cost analysis was based on the Organization of Midwest ISO States (OMS) Cost Allocation and Regional Planning (CARP) developed Business as Usual with High Demand and Energy Case. Refer to Table 2.4-1, which posits the primary assumptions associated with the development of this case.

Table 2.4-1: Key Assumptions for Economic Model Development

Uncertainty	Value
Demand Source	Module E 2009 Submittal
Demand Growth	1.6% Annual Escalation
Energy Growth	2.19% Annual Escalation
Natural Gas Cost (2010 Henry Hub)	$6.22/MBtu
Carbon Cost/Cap	No Cap nor Cost applied
Reserve Target	15% of Midwest ISO Coincident Peak Demand

Note each overlay was compared to a base run that included new wind zone generation without additional transmission beyond 2019 base case assumptions. The base run included typical flowgates, and was not screened for additional flowgates that might have the potential to severely restrict RPS wind injections resulting in ‘dump’ energy.

The production cost model uses an event file to perform contingencies and system monitoring. This event file was updated with ‘local’ contingencies to capture wind effects, and contains Midwest ISO and NERC flowgates. These flowgates will not show the outlet issues associated with the zones. To add relevant constraints to the modeling, Midwest ISO staff utilized the Power Flow Analysis Tool (PAT).

2.4.2 Linear Power Flow Analysis

The reduced amount of transmission developed through the production cost analysis of the indicative transmission designs was then added to the off-peak (70% of peak load), shoulder Power Flow model. Linear analysis on the off-peak shoulder model identified additional reliability constraints that were addressed. The bulk of the reliability analysis fell within the off-peak shoulder case work effort.

Once all selected criteria violations were identified and solutions proposed, plans were analyzed using an on-peak model as well as a light load (40% of peak load) model.

MTEP09 Power Flow models were used in the development of the 2019 peak and off-peak models. These models were created within the Midwest ISO Model On Demand database and include 2019 summer peak load cases, which were then modified to produce the 2019 off-peak model used in the analysis. The MTEP10 Power Flow model was used to create the light load model employed in analysis. The external representation used for the MTEP models are the NERC ERAG MMWG models. The latest MRO models were used to update non-Midwest ISO Midwest Reliability Organization (MRO) data. Midwest ISO system updates were added through the stakeholder process. Neighboring utility updates were provided by SPP, TVA, and PJM.

The 2019 model contains all projects moving to MTEP Appendix A or Appendix B as well as those MTEP Appendix B projects identified with a “Planned” status designation. Given the uncertainty of their respective status, those projects in MTEP Appendices B and C **not** moving to MTEP Appendix A in the current planning cycle will be removed or not incorporated in RGOS models. Designing RGOS (or any) transmission system dependent on projects not confirmed for development or potentially destined for replacement by an alternative project would adversely impact the final set of transmission projects.

NERC Category A, B and C events were used in Power Flow analysis. A comprehensive Category C evaluation was not performed. Category C events were limited to select events greater than 230 kV supplied by stakeholders, and double branch contingencies within a bus of each zone’s outlet facilities were used. Category C events were tested for energy zone outlet restriction and for potential cascading events. These cascading events were defined as situations in which transmission facilities experience a maximum loading of 125% or higher, as compared to the facility's emergency ratings. All elements greater than 100 kV were monitored during analysis. However, only elements greater than 200 kV in violation were addressed for solutions. All other elements were identified and included within the evaluation of the overlays.

It is understood that evaluating the system reliability for violations on the 230 kV system and above misses constraints on the lower voltage system. This may result in the understatement of the wind curtailment within the economic models as well as the amount of transmission that must be considered for full reliability modeling impact. However, it is a functional screen of the impacts caused by the injection of new resources on the system. Future evaluation of an overall strategy may need to assess the lower voltage concerns in its final decision on the proper transmission expansion strategy for the Midwest ISO footprint.

2.4.3 AC Power Flow Analysis

AC Power Flow analysis was performed on the same peak, off-peak, and light load models used in the linear flow analysis by employing an AC Power Flow solution with the same contingency files used in linear Power Flow work. This analysis helped identify an approximation for reactive and capacitive support on the system, improving the accuracy of cost estimates and providing a more holistic solution to stated RGOS objectives.

2.4.4 Study Objective Change

Initially, the RGOS study was commissioned to develop and analyze multiple transmission overlay solutions that would meet the desire to deliver the RPS requirements in a reliable and economically conscientious way. It was expected that the study would identify a single strategy that would guide transmission investment for the next 20 years. However, during the development and analytics of the overlays, it was determined by Midwest ISO staff and management that none of the overlays stood out as the proper strategy to push forward for all future EHV transmission development.

Because an overall strategy for future transmission development was deemed inappropriate at this time, the RGOS study focused on transmission projects identified within the study that facilitate RPS requirements throughout the study footprint while not predetermining a long-term transmission investment strategy.

3 Renewable Energy Requirements

The bulk of the generation expansion within the RGOS study footprint will consist of resources that will be required to meet legislated renewable energy requirements and goals. Based on RGOS survey results and the current construct of the Midwest ISO Generation Interconnection Queue (GIQ), wind will be relied upon to meet the majority of the requirements. Therefore, the RGOS study focused on the development of a transmission system that would help facilitate the wind contribution to the renewable energy requirements.

3.1 Renewable Portfolio Standards

The Midwest ISO region observed two significant drivers for transmission expansion: (1) state RPS mandates; and (2) associated generation in the Midwest ISO Generation Interconnection Queue (GIQ).

Some states within the Midwest ISO purview; i.e., Montana, Minnesota, Wisconsin, Iowa, Missouri, Illinois, Michigan, Ohio, and Pennsylvania, currently have RPS mandates that require varying percentages of electrical energy be met from renewable energy resources. North Dakota and South Dakota do not have an RPS but do have renewable goals. Kentucky and Indiana currently have neither RPS mandates nor goals. RPS mandates vary from state to state in specific requirements and implementation timing but generally start at or around 2010 and continue into the next decade. Refer to Figure 3.1-1.

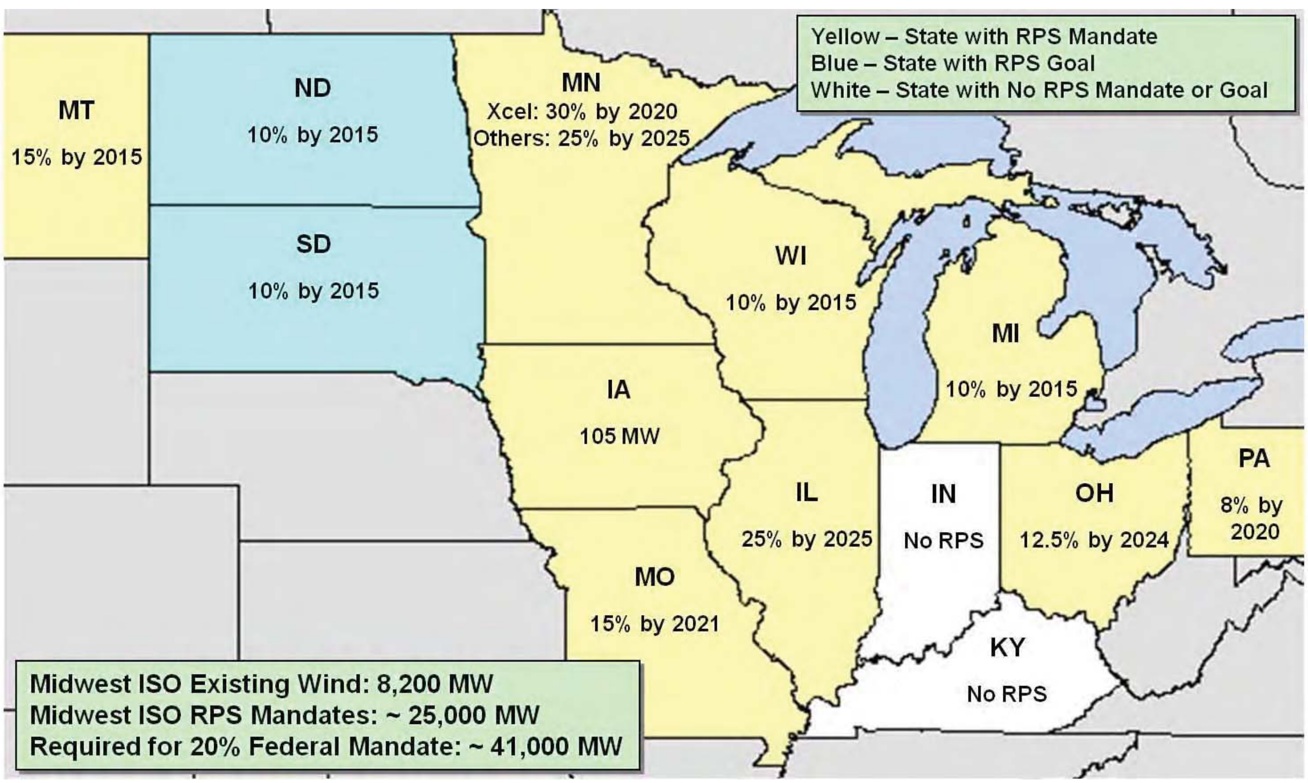

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Figure 3.1-1: RPS Requirements within Midwest ISO Footprint

The second major driver for transmission expansion is the Midwest ISO Generation Interconnection Queue (GIQ), which—as of the end of July 2010—held approximately 64,500 MWs of wind requests. After careful examination of the inherently complex issues involved, Midwest ISO staff and stakeholders determined the GIQ process would not be an efficient means for building a cost-effective transmission system over the next 5–10 year period or in the foreseeable future beyond that time-frame.

Each state has specific requirements associated with RPS mandates and goals. Most of the legislated mandates within the study footprint come to maturity between 2015 and 2025. Refer to Table 3.1-1 for a summary of the percentages of energy to be served over time, by year.

Table 3.1-1: 2015–2025 RPS Targets

Year	WI (% of Energy)	MN (w/o Xcel) (% of Energy)	MN (w/Xcel) (% of Energy)	IL (% of Energy)	MI (% of Energy)	OH (% of Energy)	MO (% of Energy)	MT (% of Energy)	PA (% of Energy)	SD (% of Energy)	ND (% of Energy)	IA (MW)
2015	10.00%	12.00%	18.00%	10.00%	10.00%	3.50%	5.00%	15.00%	5.50%	10.00%	10.00%	105
2016	10.00%	17.00%	25.00%	11.50%	10.00%	4.50%	5.00%	15.00%	6.00%	10.00%	10.00%	105
2017	10.00%	17.00%	25.00%	13.00%	10.00%	5.50%	5.00%	15.00%	6.50%	10.00%	10.00%	105
2018	10.00%	17.00%	25.00%	14.50%	10.00%	6.50%	10.00%	15.00%	7.00%	10.00%	10.00%	105
2019	10.00%	17.00%	25.00%	16.00%	10.00%	7.50%	10.00%	15.00%	7.50%	10.00%	10.00%	105
2020	10.00%	20.00%	30.00%	17.50%	10.00%	8.50%	10.00%	15.00%	8.00%	10.00%	10.00%	105
2021	10.00%	20.00%	30.00%	19.00%	10.00%	9.50%	15.00%	15.00%	8.00%	10.00%	10.00%	105
2022	10.00%	20.00%	30.00%	20.50%	10.00%	10.50%	15.00%	15.00%	8.00%	10.00%	10.00%	105
2023	10.00%	20.00%	30.00%	22.00%	10.00%	11.50%	15.00%	15.00%	8.00%	10.00%	10.00%	105
2024	10.00%	20.00%	30.00%	23.50%	10.00%	12.50%	15.00%	15.00%	8.00%	10.00%	10.00%	105
2025	10.00%	25.00%	30.00%	25.00%	10.00%	12.50%	15.00%	15.00%	8.00%	10.00%	10.00%	105

For a tabular breakdown of respective state RPS requirements, refer to Appendix 2 of this document.

4 Renewable Energy Zones Development

4.1 Wind Analysis

Significant work was performed in 2008 and 2009 relating to wind data development and analysis for the RGOS Phase I study, completed in 2009. This work was essential to the RGOS Phase I effort and carried over into further development of renewable resources for current RGOS study work. No consistent source for geographically disparate wind data existed within the RGOS study region at the start of the study. Although basic wind speed information has been available for many years, factors such as wind speed, for example, leave too many unanswered assumptions for the purposes of a detailed statistical and economic study. Other factors include—but are not limited to—wind power output, time correlation with load, turbine class used, terrain, weather, and available capacity. Although data from existing wind farms in the Midwest ISO region could have been used, there were limitations to this data, such as size and quantity, geographic diversity, output history, and future technology or turbine classes.

As identified in the RGOS Phase I Executive Summary Report[3], the Generation Interconnection Queue (GIQ) was not, of itself, an appropriate identifier for wind resources to perform this study. As reported in the RGOS Phase I report in July 2008, the Midwest ISO Queue had 350 wind interconnection requests totaling 67,000 MW, and the PJM Queue had 42,400 MW of wind, of which 27,000 MW was in the RGOS study region. This totaled over 94,000 MW of wind generation which could have been used during the RGOS study. Impartially selecting a subset of queued projects to meet identified state renewable energy requirements without detailed wind data would have been difficult.

Several additional issues made using GIQ data problematic, to include:

- Queue requests for wind had increased in locations with an RPS, which could potentially bias zones towards states with RPS and against potentially higher capacity factor sites in states that do not have such mandates, such as North and South Dakota, and Indiana.
- The location of generation interconnection requests were potentially biased by other criteria not related to the wind capacity factor, such as the generators' location in relation to available transmission, wind turbine transportation, and financing. However, it was recognized that most of the wind interconnection requests do occur in the high wind areas, and that this would be accounted for in any statistical analysis of wind potential in the region.

Midwest ISO worked with the National Renewable Energy Laboratory (NREL) throughout 2007 and early 2008 in a collaborative effort with the Joint Coordinated System Plan (JCSP) and was aware NREL would be performing the Eastern Wind Integration and Transmission Study (EWITS), a comprehensive study of wind in the Eastern Interconnect. In March 2008, NREL engaged AWS Truewind to develop a set of wind resource and plant output data for the eastern United States for EWITS. The statement of work identified five (5) technical tasks to developing high resolution wind power output data in 10-minute increments for years 2004, 2005, and 2006. The methods used and results achieved are described in the following sections. The final results and a study report are available on the NREL website at http://wind.nrel.gov/public/EWITS.

[3] RGOS Phase I Executive Summary Report

4.1.1 Renewable Energy Zone Scenario Development

The information gathered in performing the metrics work discussed in Section 4.1 was used to identify an appropriate weighting system for developing the renewable energy zones. The renewable energy zones were developed on a state-by-state basis taking advantage of the highest eleven (11) year average capacity factor sites in each state. Selected sites were lumped together to achieve an energy zone that had an approximate capacity of 2,400 MW, while maximizing the overall capacity factor of the energy zone. Many energy zones were developed for each state in this manner. Based on the metrics, weighted values were created and used to rank the zones. The four (4) weighted measures and their weighting are as follows, where on-peak hours are 6AM–10PM, afternoon on-peak hours are 3PM–6PM, and summer months are June, July, and August:

- **Weighted Capacity Factor (CF)**
  - 11-Year average CF 50%
  - 3-Year average CF 10%
  - On-peak CF 10%
  - Afternoon On-peak CF 10%
  - Summer On-peak CF 10%
  - Summer Afternoon On-peak CF 10%
- **Distance to Load Center**
- **Weighted Variability**
  - Variance of hourly wind output 25%
  - Standard Deviation 25%
  - Average hourly ramp-up 25%
  - Average hourly ramp-down 25%
- **Distance to Infrastructure**
  - Distance to existing transmission (>300 kV) 33.3%
  - Distance to Railroads 33.3%
  - Distance to major highways 33.3%

For each renewable energy zone developed, weighted metrics were calculated as a composite of the selected sites in that zone. The weighted capacity factor was converted to a $/MWh value based on a capacity of 750MW from each zone and a cost of $2M/MW for wind turbines. Distance-to-load center values were calculated by taking the distance from each selected site to the nearest large load center. Distance to infrastructure was used to help select zones that may otherwise have a similar metrics score to another zone, by giving preference to a zone close to existing infrastructure. Proximity to major railroads and highways aids in the delivery and construction of necessary substations and wind farms.

Wind zones were created in each state once a process methodology was established. Even though North Dakota, South Dakota, and Indiana do not have RPS mandates in accordance with RGOS scope, they do have extensive wind resources and thus were used to provide possible renewable energy to the study. In order to establish local versus regional energy sources—again per study scope—energy zone scenarios were created, each concentrating on local to load center wind (with most of the renewable energy zones located within each state, respectively), remote to load center wind (utilizing higher capacity factors and transporting the wind as needed) and a local and remote combination. A ranking was applied to the four (4) measures described in the last section to create a score from 0-100 for each energy zone. Appropriate renewable energy zones were selected for each scenario based on those rankings. For renewable energy zones in the western part of the footprint, the Upper Midwest Transmission Development Initiative (UMTDI) Zone Scenario B was used.

For each scenario, the top ranking zones were selected as sites for renewable generation until the needed amount of MWh's was sufficient to meet the RPS requirements. Since higher capacity factor areas produce more energy, the regional scenarios had fewer zones than the local scenarios.

The results of this work are shown in Figures 4.1-1–4.1-3, which depict the three (3) scenarios: local, regional, and combination, including the UMTDI Zone Scenario B.

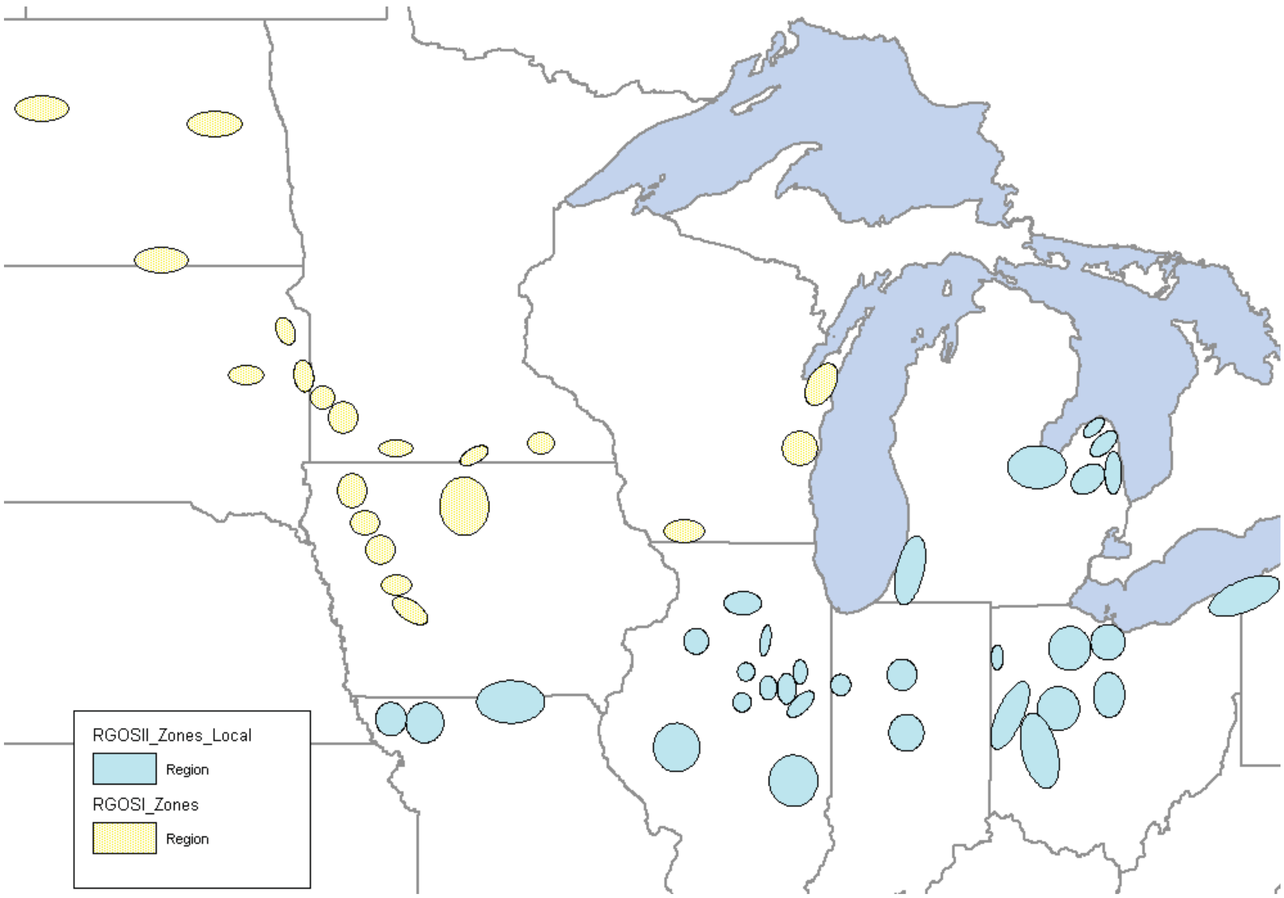

Figure 4.1-1: Local Wind Zone Identification

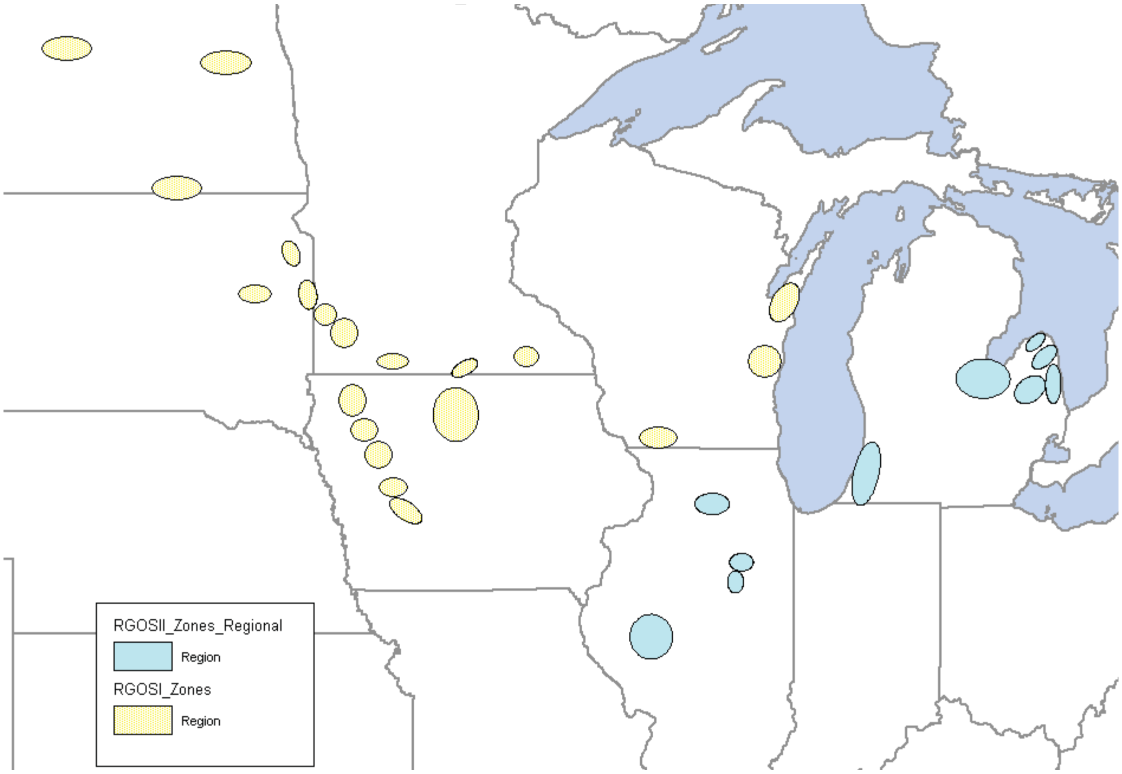

Figure 4.1-2: Regional Wind Zone Identification

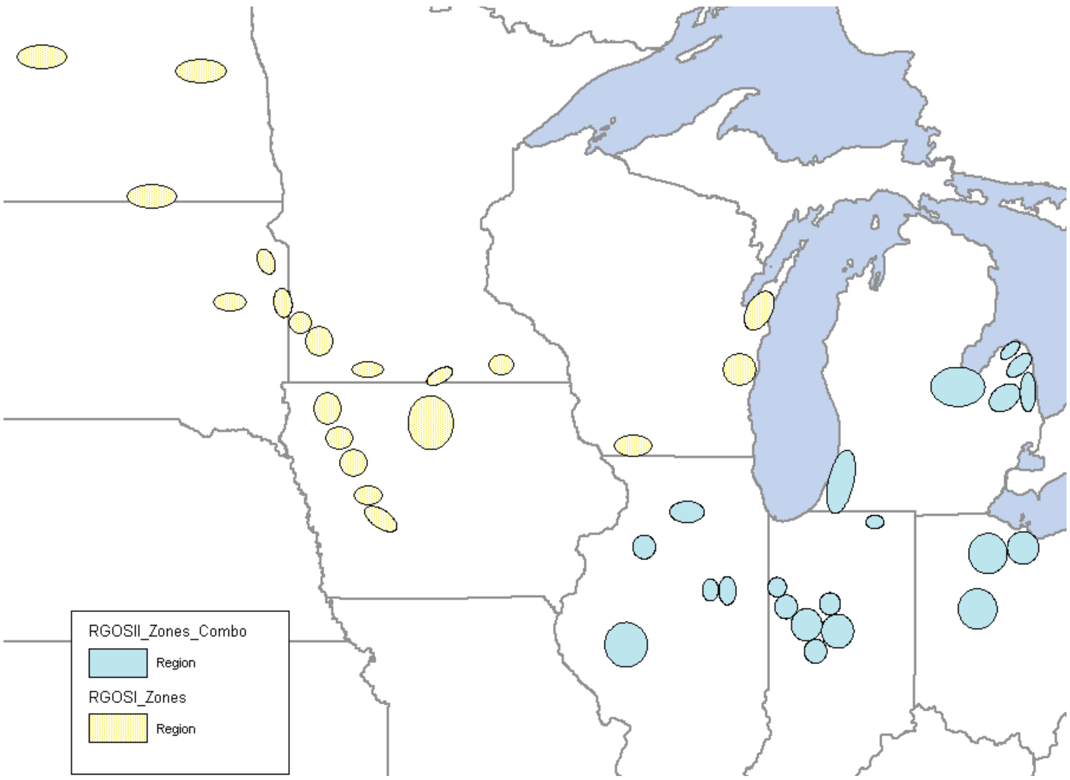

Figure 4.1-3: Combination Wind Zone Identification

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To provide for a full range of opportunities in meeting various RPS and goal requirements, these three (3) renewable energy zone scenarios were adjusted to create two (2) additional scenarios. These five (5) scenarios include the following:

- **Local:** In the Local scenario, renewable energy requirements and goals will be met with resources located within the same state as the load.
- **Regional:** In the Regional scenario, renewable energy requirements and goals will be met with resources located in the highest ranking renewable energy zones regardless of respective zone location relative to the RGOS II load. This scenario will utilize the high capacity factor zones recommended by UMTDI from RGOS I.
- **Regional Optimized:** The Regional scenario results in capacity in excess of what is needed to at least cover the renewable requirements/goals. In the optimized case, the capacity in some zones is reduced to the extent there are just enough resources to cover renewable energy requirements/goals.
- **Combination:** In the Combination scenario, renewable energy requirements and goals will be met with a combination of resources located within the RGOS II states and those outside RGOS II states with the highest ranking. Emphasis will be given to state requirements to locate part or all of their resources used to meet renewable energy requirements and goals within those states. Also, distance to load centers will be given more emphasis when determining zones than in the Regional scenario.
- **Combination 75/25:** In this scenario, 75% of RGOS requirements are met with resources in the UMTDI zones and 25% of RGOS requirements are met within the remaining states.

5 Regional Transmission Designs

The goal of the Regional Generation Outlet Study (RGOS) is to develop transmission projects that will facilitate the state renewable energy mandates in the Midwest ISO footprint. The process used to meet this goal consists of detailed transmission design analysis to determine a transmission system that meets RGOS reliability objectives while delivering energy from the generation zones. Refer to Figure 5-1.

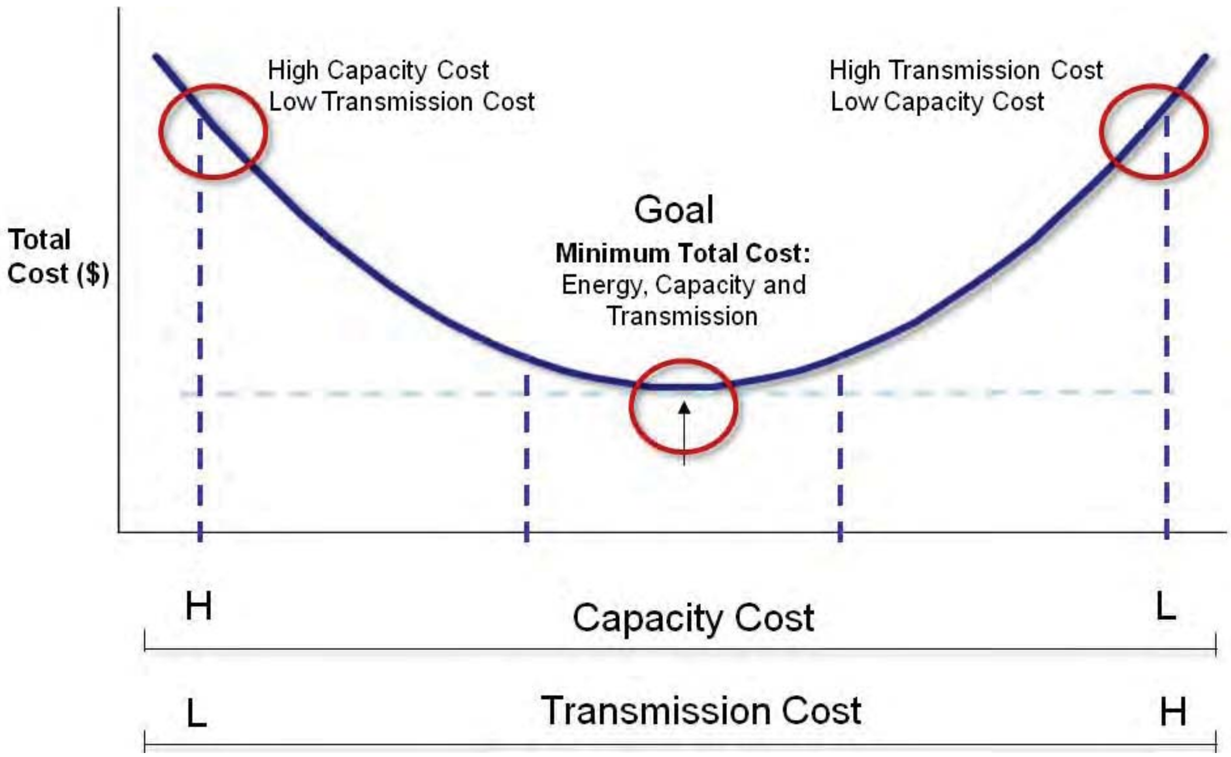

Figure 5-1: Balancing Generation and Transmission Investment

5.1 Indicative Transmission Designs

As in the RGOS Phase I, once candidate renewable energy zone scenarios were established for study, the next step was to design an indicative transmission system for those zones to connect to the grid and deliver energy to load. There were many different transmission designs that could be utilized to achieve this goal, all of which had different costs and benefits associated with them. The purpose of the Indicative Transmission Design phase of the study was to analyze these different alternatives and to quantify costs and benefits of these alternatives. These costs and benefits would then be used to provide information to select a final set of energy zones.

Indicative transmission designs were created with stakeholders by means of a design workshop. Stakeholders, specifically experienced transmission planners from the region, and Midwest ISO staff developed the different transmission alternatives for economic analysis. The process consisted of developing an assumption set to guide the indicative development process, understanding the various renewable energy zone scenarios, and finally developing an indicative set of transmission that could potentially supply the renewable energy. The indicative transmission was developed without the use of system modeling or analysis; rather, the task was achieved by harnessing the collective knowledge of workshop participants, all experienced transmission planners. Again, the point of the exercise was to develop transmission that could “indicatively” provide a solution.

5.1.1 Assumption Set

An assumption set was established by the stakeholders to develop the indicative transmission portfolios and apply costs to them. The indicative transmission portfolios were developed without the benefit of transmission simulations; i.e. Power Flow, so a consistent assumption set had to be employed to compare the transmission portfolio of one energy zone scenario against another.

The primary assumption for the indicative transmission development was that the system would be considered self-healing. It would not depend on the underlying system in the indicative design phase. For this work, Surge Impedance Loading (SIL) ratings were used for new transmission lines. This eliminated the need for Power Flow analysis in the indicative stage since a 'self-healing' plan minimized the impact of new transmission on the existing system. Actual analysis of Power Flow was planned for the conceptual transmission design phase to evaluate the underlying system impacts and would use normal and emergency line ratings. 750 MW of capacity would be exploited from each zone. Other assumptions included the approximate range of capacity for 345 kV and 765 kV transmission using SIL as a limiter. Note economic parameters were also developed for calculating the cost of the transmission. Refer to Table 5.1-1, which shows the capital costs applied to the transmission.

Table 5.1-1: Transmission Line Cost Assumptions used within Indicative Work Efforts (2010 USD in Millions)

kV	MN/Dak	IA	WI	IL	MO	IN	MI	OH/PA
345	2	1.5	2.5	2	1	1.8	1.8	2
2-345	2.5	2.1	3	2.6	1.5	2.3	2.3	2.5
500	3.5							
765	4.8	4.2	4.8	4.2	4.2	4.4	3.6	4
400	0	0	0	0	0	0	0	0
800	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2

Note wind generation at $2M/MW was used for the wind turbine capital costs.

5.1.2 Indicative Transmission Results

Given the five (5) renewable energy zone scenarios, several indicative transmission overlays were created using 345 kV, 765 kV, and DC transmission options. For additional details regarding Indicative Transmission Design, refer to Appendix 3, which shows the transmission and renewable energy zone maps for the various overlays. Financial results are shown in Table 5.1-2.

Table 5.1-2: Indicative Transmission Costs (2010 USD in Millions Sorted by Total Cost)

Voltage (kV)	Zone Scenario	Generation	Transmission	Total
345	Combination 75/25	$62,300	$18,601	$80,901
345	Combination	$65,300	$18,601	$83,901
765	Combination 75/25	$62,300	$25,193	$87,493
765	Combination	$65,300	$25,192	$90,492
765	Regional Optimized	$60,800	$30,428	$91,228
765/DC	Regional Optimized	$60,800	$33,981	$94,781
765	Regional	$66,900	$30,428	$97,328
765/DC	Regional	$66,900	$33,981	$100,881
765/DC	Regional Optimized	$60,800	$47,855	$108,655
345	Local	$91,400	$19,291	$110,691
345	Regional Optimized	$60,800	$51,260	$112,060
765	Local	$91,400	$22,553	$113,953
765/DC	Regional	$66,900	$47,855	$114,755
345	Regional	$66,900	$51,260	$118,160

As can be seen from Table 5.1-2, all four (4) Combination scenarios demonstrated the lowest overall cost alternative. The "Bathtub Curve" for these scenarios can be seen in Figure 5.1-1 (also refer to section 5 of this document). Hence, a Combination set of zones was selected as the basis for moving forward to select a final set of renewable energy zones. Feeding into the final zone selection for each scenario were other state requirements in addition to energy. For example, the State of Michigan requires the state RPS be served 100% internally to the state. In Ohio, the requirement is 50%, and Illinois has a preference defined in its requirements for local wind. As a result, Missouri, Illinois, and Ohio renewable energy zones were selected based on at least 50% of the wind requirements being served within that respective state. Input on the final zones was gathered from Midwest Governors Association (MGA), the Upper Midwest Transmission Development Initiative (UMTDI), and from stakeholders—including non-Midwest ISO, PJM members Commonwealth and American Electric Power.

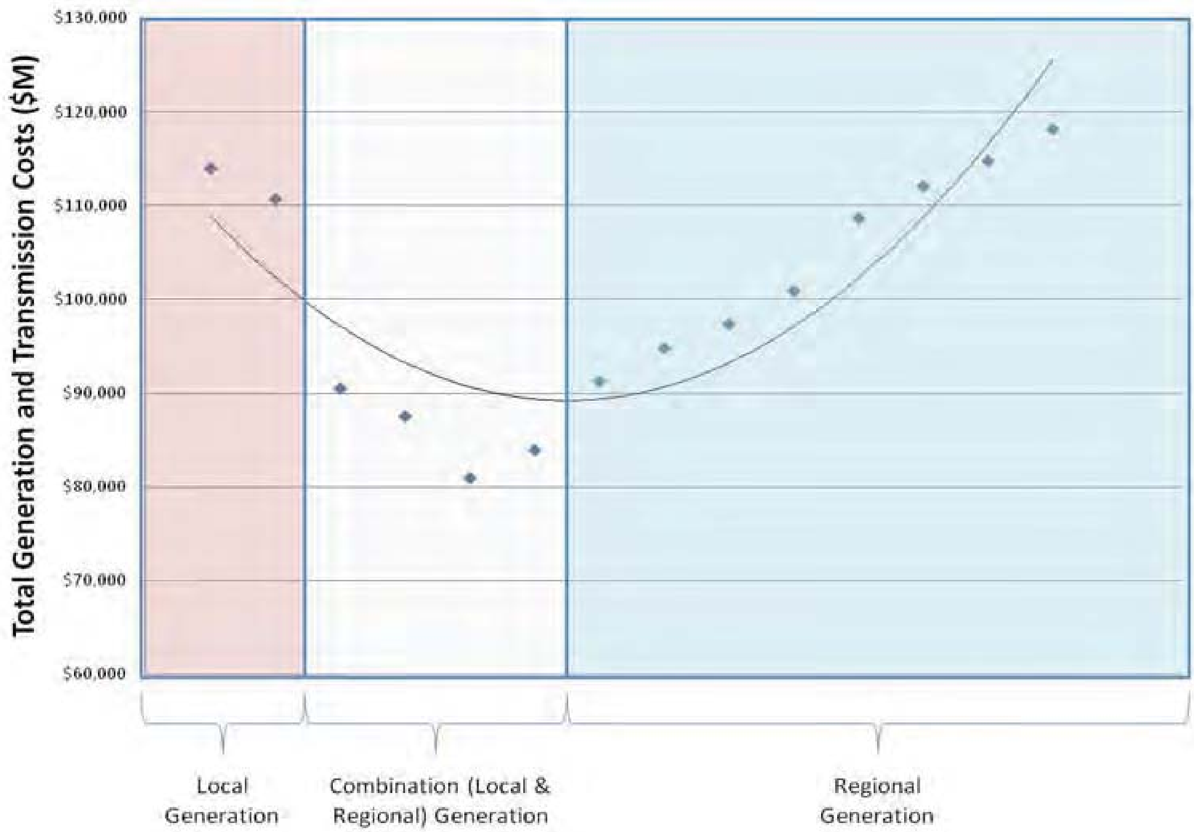

Figure 5.1-1: Zone Scenario Generation and Transmission Cost Comparison

For greater detail regarding indicative transmission results, design, and optimization, refer to Appendix 3 of this document. Also refer to Midwest ISO Transmission Expansion Plan (MTEP) 2009, which more fully describes the rationale driving zone scenario origination.

5.2 Model Development

5.2.1 Power Flow Model Creation

The majority of the transmission design analysis was conducted on a MTEP09 series 2019 summer peak model. This model was developed via the MTEP09 model building effort with considerable stakeholder review. It was used for two sets of analyses: a summer off-peak analysis and a summer peak analysis. For the summer off-peak analysis, the base transmission model was modified to create a shoulder-peak (70% load level) Power Flow model for the RGOS I system analysis in mid-2009 and sent to the stakeholders for additional review. Both the summer peak and summer off-peak models were updated for

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the full RGOS analysis effort in early 2010 and sent to the stakeholders for a final review. A list of the major transmission upgrades made to this model since the RGOS I study effort is included in the public folder located at:

ftp://mtep.midwestiso.org/mtep10/RGOS/report/Appendices4-6.zip

And includes the following MS Excel .xlsx spreadsheet files:

- A4_1_Native Voltage.xlsx
- A4_2_Native Voltage with DC.xlsx
- A4_3_765 kV.xlsx

A secondary set of analyses were performed on a light load model. This model was converted from a MTEP10 series 2015 light load scenario to a 2019 light load scenario. The model, in addition to being developed and reviewed through the MTEP model building effort, was also provided to the stakeholders for additional review. A list of the major modeling corrections made to this model is also included in the public folder identified above and includes the following MS Excel .xlsx spreadsheet files:

- Modeling Corrections - 765 Modeling Documentation.xlsx
- Modeling Corrections - NV with DC Modeling Documentation.xlsx
- Modeling Corrections - NV wo DC Modeling Documentation.xlsx

External transmission system representation in the MTEP series models was provided by the Eastern Interconnection Reliability Assessment Group (ERAG) Multi-Regional Modeling Working Group (MMWG) North American Electric Reliability Corporation (NERC) models, except for the non-Midwest ISO MRO members, where the latest Midwest Reliability Organization (MRO) models were used. Commonwealth Edison and American Electric Power (AEP) supplied system updates directly to the RGOS study effort for their respective transmission systems.The base MTEP models included all transmission projects moving to MTEP Appendix A or B as well as Appendix B and C projects with a status of Planned. Prior to the start of the RGOS work, any projects in Appendix B or C that were not moving to Appendix A in the MTEP10 planning cycle and have a voltage class greater than 300 kV were removed from the model. These projects could have a significant impact on the transmission network. As such, given the level of uncertainty on whether the projects will be constructed or not, it was determined that designing the RGOS transmission system dependent on these projects adds additional uncertainty to the final RGOS transmission portfolio.

5.2.2 Generation

As part of the MTEP10 model building process, a Regional Merit Dispatch (RMD) was created to aid in dispatching the Midwest ISO generation fleet for the various MTEP10 Power Flow models. This RMD was used to dispatch the wind zones into all the models used for the RGOS analysis. Commonwealth Edison supplied a generation dispatch for its system to enable the wind zones in its control area, and the generation in American Electric Power (AEP) was scaled down to enable the dispatch of the wind zones in its control area. Further information on RMD may be found in the MTEP10 report Appendix E1. Additionally, only existing generators and generators with an executed generator interconnection agreement were included in the Power Flow model.

Consistent with Midwest ISO Planning Subcommittee practices, generation from the energy zones was dispatched to the system at 90% and 20% of capacity for all zones in the shoulder-peak and peak models, respectively. No wind was dispatched in the light load model. Existing and planned wind generation already in the model was dispatched at this same level, respectively, for each model. Data analysis shows load levels between 40% and 80% of peak load, wind output can randomly vary from 0%–90%. The wind levels chosen for analysis represent a majority of the worst case conditions for each scenario—although it could be argued a light load, 90% wind output model should be considered to capture all the worst case scenarios. This light load, high-wind analysis, while initially part of the RGOS effort, was deferred due to time constraints.

Refer to Tables 5.2-1 and 5.2-2, which show the modeled capacity of each wind zone. It is important to note each zone was designed for a potential capacity of up to 2400 MWs even though transmission was not designed for that level of injection. Wind generation in the Midwest ISO footprint was delivered (sunk) to the Midwest ISO market. Generators in the Illinois Commonwealth Edison area are delivered to Commonwealth Edison (PJM), and the wind zones located in American Electric Power (AEP) were sunk to other AEP generation.

Table 5.2-1: Renewable Energy Zone Information (UMTDI Zone Selections)

Zone	State	Nameplate (MW)	Modeled Capacity		
			Off-peak (MW)	Peak (MW)	Light Load (MW)
IA-B	IA	775	698	155	0
IA-F	IA	775	698	155	0
IA-G	IA	775	698	155	0
IA-H	IA	775	698	155	0
IA-I	IA	775	698	155	0
IA-J	IA	775	698	155	0
MN-B	MN	775	698	155	0
MN-E	MN	775	698	155	0
MN-H	MN	775	698	155	0
MN-K	MN	775	698	155	0
MN-L	MN	775	698	155	0
ND-G	ND	775	698	155	0
ND-K	ND	775	698	155	0
ND-M	ND	775	698	155	0
SD-H	SD	775	698	155	0
SD-J	SD	775	698	155	0
SD-L	SD	775	698	155	0
WI-B	WI	775	698	155	0
WI-D	WI	775	698	155	0

Table 5.2-2: Renewable Energy Zone Information (non-UMTDI Zone Selections)

Zone	State	Nameplate (MW)	Modeled Capacity		
			Off-peak (MW)	Peak (MW)	Light Load (MW)
IL-A	IL	550	495	110	0
IL-B	IL	550	495	110	0
IL-F	IL	550	495	110	0
IL-K	IL	550	495	110	0
IN-E	IN	500	450	100	0
IN-K	IN	500	450	100	0
MI-A	MI	300	270	60	0
MI-B	MI	500	450	100	0
MI-C	MI	500	450	100	0
MI-D	MI	500	450	100	0
MI-E	MI	500	450	100	0
MI-F	MI	500	450	100	0
MI-I	MI	350	315	70	0
MO-A	MO	500	450	100	0
MO-C	MO	500	450	100	0
MT-A	MT	400	360	80	0
OH-A	OH	725	652.5	145	0
OH-B	OH	725	652.5	145	0
OH-C	OH	725	652.5	145	0
OH-D	OH	725	652.5	145	0
OH-E	OH	725	652.5	145	0
OH-F	OH	725	652.5	145	0
OH-I	OH	725	652.5	145	0

5.3 Analyses

5.3.1 Initial Energy Model Results

The first transmission analytical step of the RGOS process was the evaluation of the combination ('Combo') indicative overlays with the selected RGOS zones in a production cost model. The analysis consisted of four (4) iterations of PROMOD runs that reduced the indicative overlays that delivered energy and showed utilization of the transmission lines identified in the overlays. Through this process, the RGOS study was able to reduce the inherent overbuild of the indicative work to a set of transmission that provided energy flow based on modeled flowgates, delivered the renewable energy zones, and provided a starting point for the more detailed Power Flow work.

The primary metric to reduce overlay transmission was line utilization. Within the first iteration, all transmission segments with peak line flow less than 20% of the rated limit were removed from the overlay. Iterations 2 and 3 removed all transmission loaded less than 30% of the rated limit was also removed. Iteration 4 removed additional under-utilized transmission while using engineering judgment to ensure overlay circuits were not radial and made general sense in system configuration.

5.3.1.1 Native Voltage Overlay

The Native Voltage overlay saw significant reduction in the process of eliminating under-utilized transmission. Between Iteration 1 and Iteration 4, 128 line segments and autotransformers were removed from the overlay, reducing the high-level generic cost of the overlay used in this stage of the analysis from $18 billion to $10.3 billion. With better engineering judgment on the interconnection of the renewable energy zones, wind curtailment improved with the refinement. However, adjusted production cost savings also decreased—but not at the same rate as the cost to add the transmission to the system. Refer to Table 5.3-1, which provides more detail on the outputs of the energy model iterations.

Table 5.3-1: Native Voltage Overlay Information from Initial Energy Model Analysis

Iteration	Rough Costs (2009 - $M)*	20% ARR (2009 - $M)	APC Savings (annual) 2019 - $M			Wind Curtailment**
			Midwest ISO	RGOS	Eastern Interconnect	
1	18,024	3,605	609	749	716	0.84%
2	16,677	3,335	614	758	718	0.85%
3	9,697	1,939	459	567	547	2.42%
4	10,269	2,054	487	602	558	0.71%
* Costs represent 345 @$1.5/M, 345-2@$2.0/M, 765 @$3.0/M and a 25% adder for station costs ** 10.44% Wind Curtailment prior to indicative transmission additions						

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Refer to Figures 5.3-1 and 5.3-2, which show the overlay at the beginning and end of the energy model refinement.

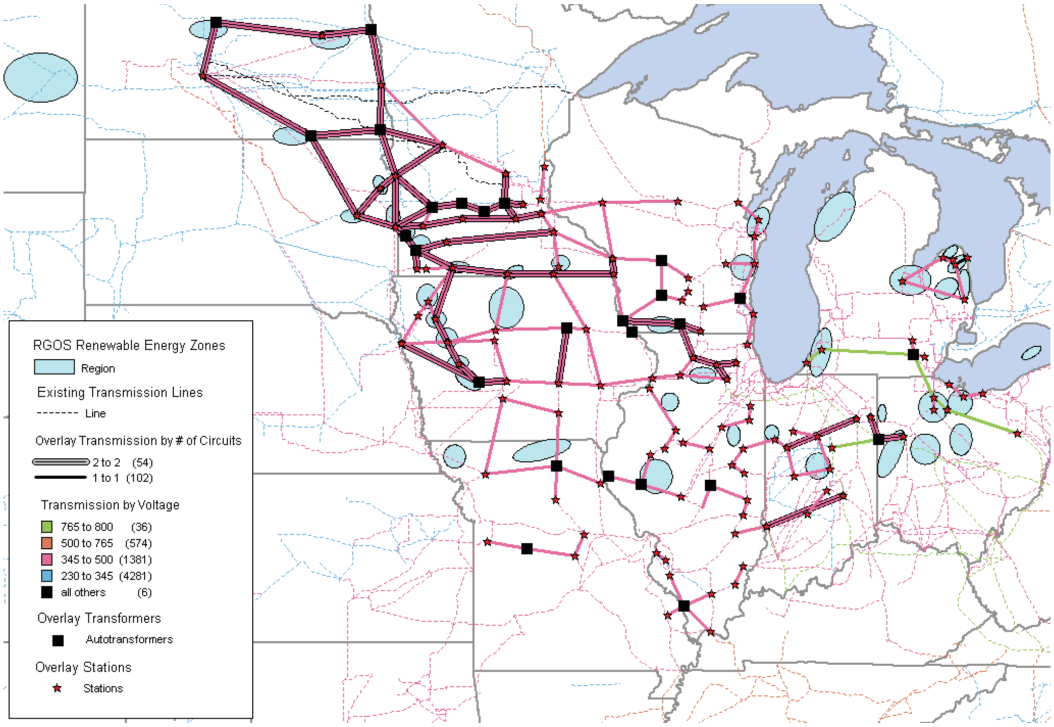

Figure 5.3-1: Native Voltage Indicative Overlay (Iteration 1)

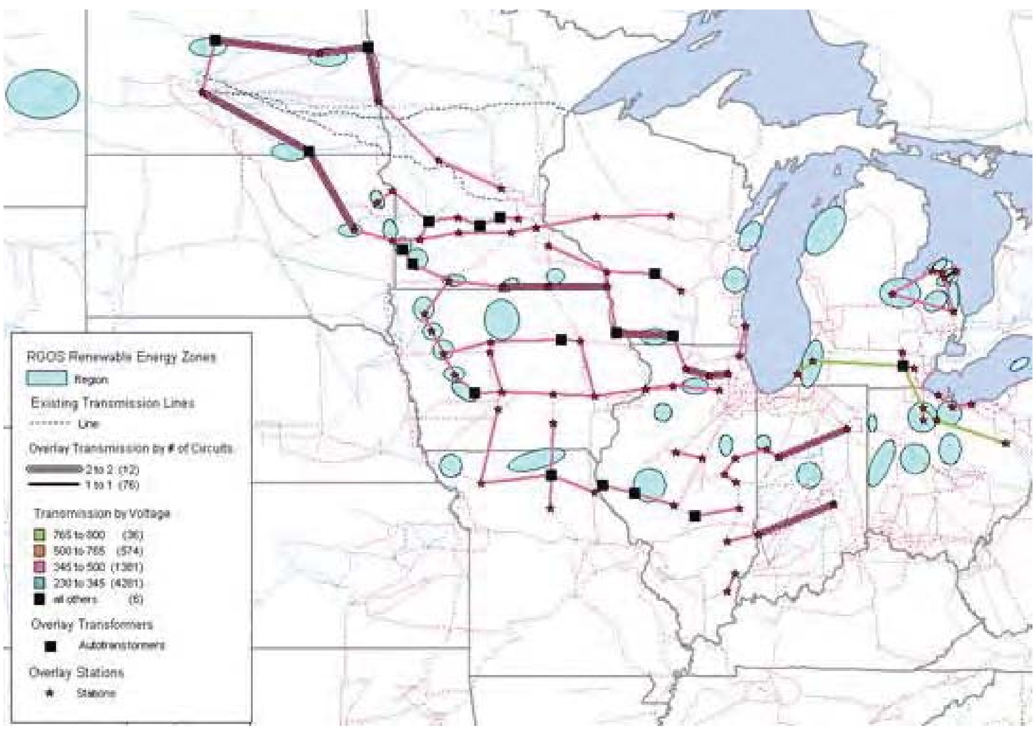

Figure 5.3-2: Native Voltage after Production Cost Modeling Optimization (Iteration 4)

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5.3.1.2 765 kV Overlay

The 765 kV overlay saw significant reduction in the process of eliminating under-utilized transmission. Between Iteration 1 and Iteration 4, 124 line segments and autotransformers were removed from the overlay. This reduced the high-level generic cost, used in this stage of the analysis, of the overlay from $23.8 billion to $15.6 billion. With better engineering judgment on the interconnection of the renewable energy zones, the wind curtailment improved with the refinement. However, adjusted production cost savings also decreased but not at the same rate as the cost required to add the transmission to the system. Refer to Table 5.3-2, which furnishes more detail on the outputs of the energy model iterations.

Table 5.3-2: Native Voltage Overlay Information from Initial Energy Model Analysis Annual APC Savings (2019 USD in Millions)

Iteration	Rough Costs (2009 - $M)*	20% ARR (2009 - $M)	Midwest ISO	RGOS	Eastern Interconnect	Wind Curtailment**
1	23,752	4,750	702	926	887	0.89%
2	21,781	4,356	701	922	884	0.90%
3	16,960	3,392	689	924	883	0.14%***
4	15,564	3,113	558	785	737	0.10%

* Costs represent 345 @$1.5/M, 345-2@$2.0/M, 765 @$3.0/M and a 25% adder for station costs

** 10.44% Wind Curtailment prior to indicative transmission additions

*** Primary reduction result of moving some of the wind zones to an indicative overlay station

Refer to Figures 5.3-3 and 5.3-4, which depict the overlay at the beginning and end of the energy model refinement.

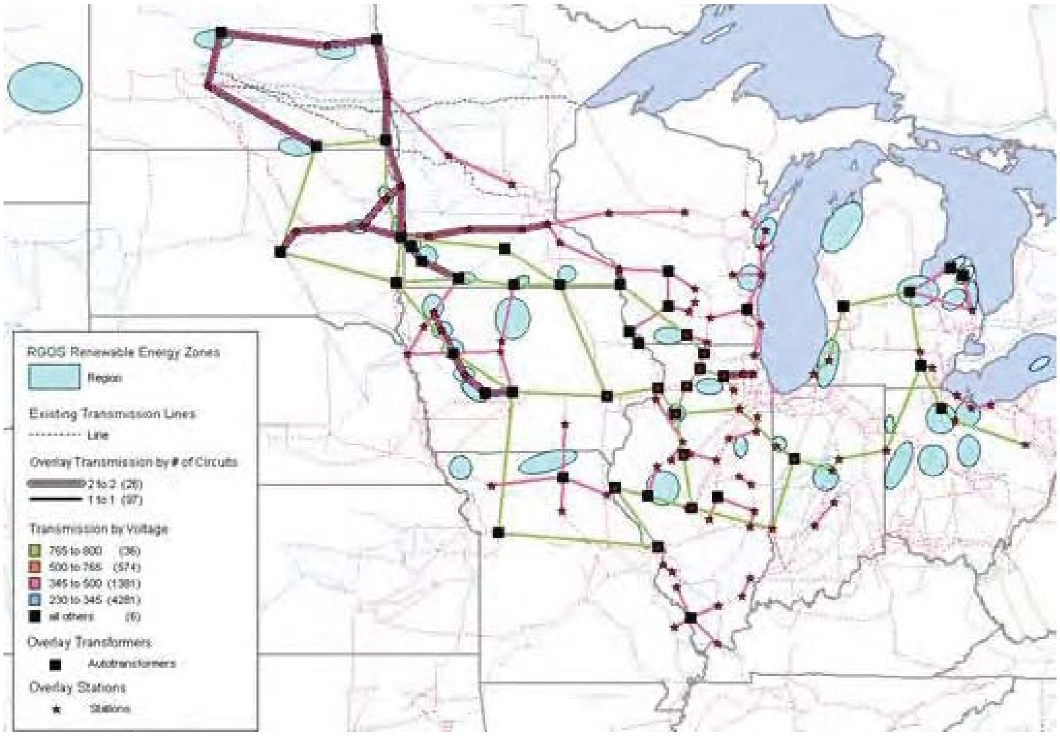

Figure 5.3-3: 765 kV Indicative Overlay (Iteration 1)

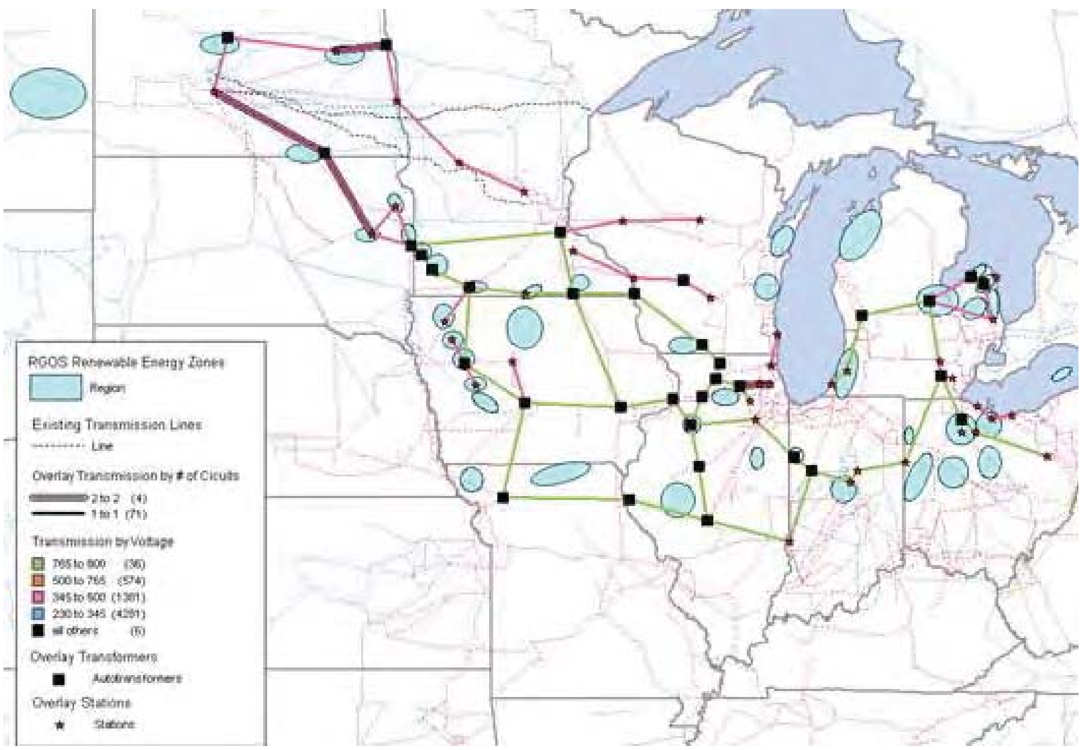

Figure 5.3-4: 765 kV Overlay after Production Cost Modeling Optimization (Iteration 4)

5.3.1.3 Native Voltage with DC Overlay

The Native Voltage with DC overlay saw significant reduction in the process of eliminating under-utilized transmission. Between Iteration 1 and Iteration 4, 123 line segments and autotransformers were removed from the overlay, reducing the high-level generic cost of the overlay used in this stage of the analysis from $23.5 billion to $16.1 billion. With better engineering judgment on the interconnection of the renewable energy zones, the wind curtailment improved with refinement. However, adjusted production cost savings also decreased but not at the same rate as the cost required to add the transmission to the system. Refer to Table 5.3-3, which offers more detail on the outputs of the energy model iterations.

Table 5.3-3: Native Voltage Overlay Information from Initial Energy Model Analysis

Iteration	Rough Costs (2009 - $M)*	20% ARR (2009 - $M)	APC Savings (annual) 2019 - $M			Wind Curtailment**
			Midwest ISO	RGOS	Eastern Interconnect	
1	23,524	4,705	734	986	995	0.85%
2	22,457	4,491	734	989	998	0.85%
3	14,654	2,931	673	925	927	0.32%
4	16,109	3,222	734	1023	1035	0.04%

* Costs represent 345 @$1.5/M, 345-2@$2.0/M, 765 @$3.0/M and a 25% adder for station costs and a cost of $5.5B for the DC transmission

** 10.44% Wind Curtailment prior to indicative transmission additions

Refer to Figures 5.3-5 and 5.3-6, which show the overlay at the beginning and end of the energy model refinement process.

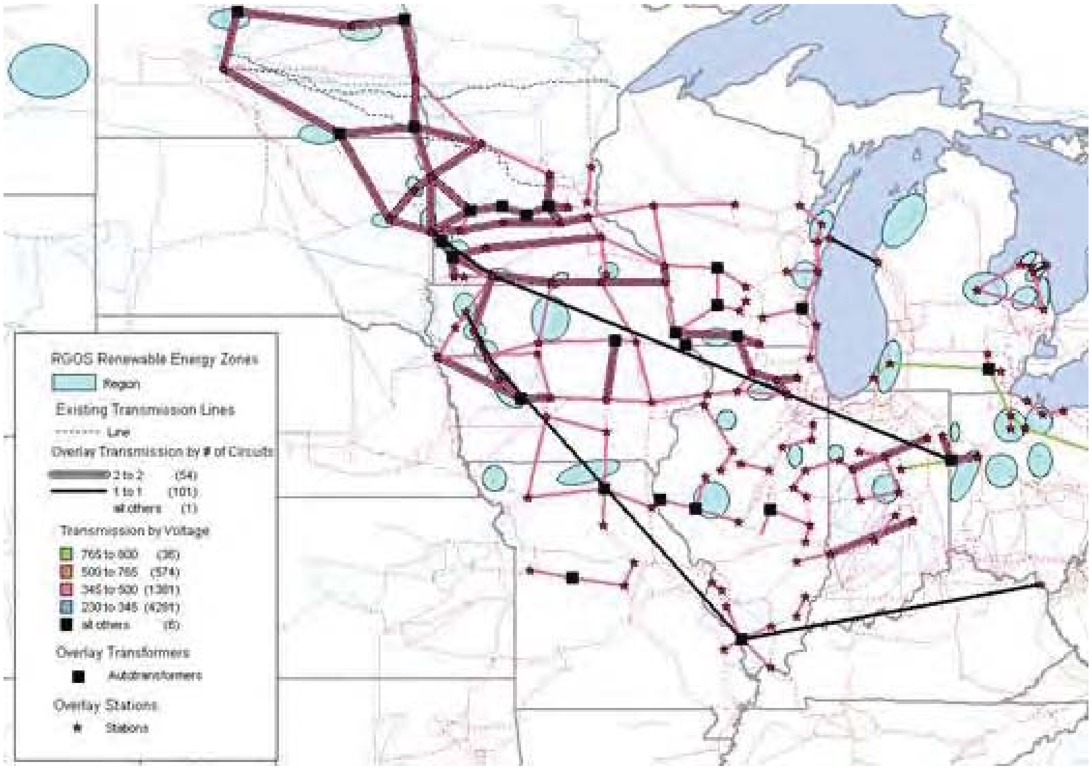

Figure 5.3-5: Native Voltage with DC Indicative Overlay

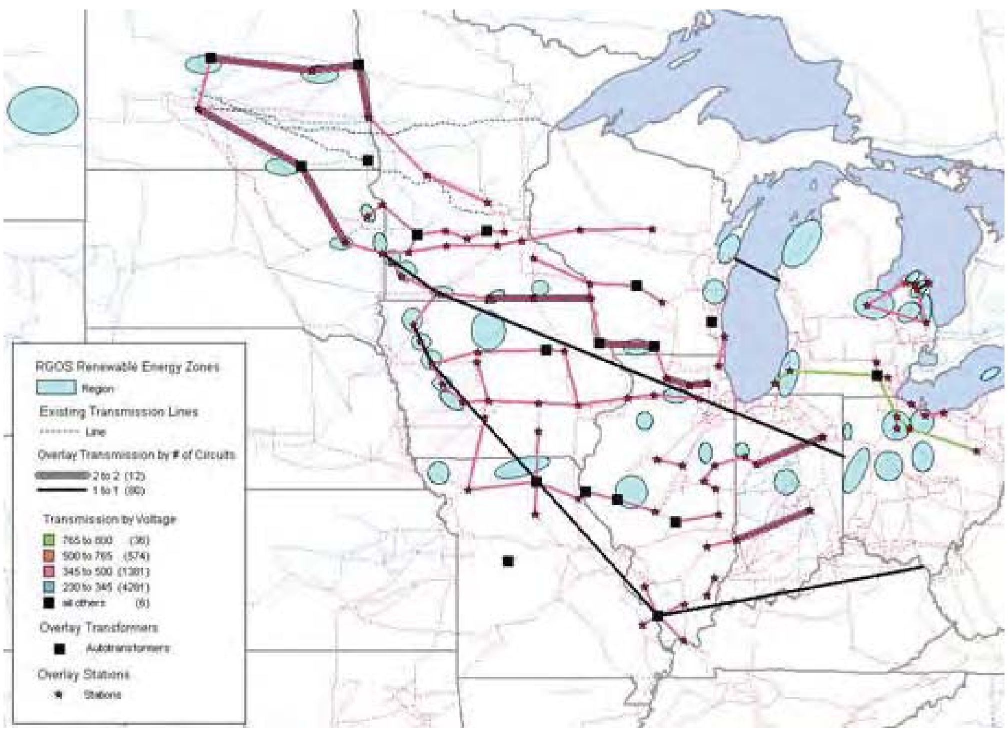

Figure 5.3-6: Native Voltage with DC Overlay after Production Cost Modeling Optimization

5.3.2 Power Flow Analysis Set-up

A set of monitored and contingent elements was created and constraints were defined prior to beginning Power Flow analysis. Voltage and thermal design criteria from each Transmission Owner were applied during the analysis. Voltage limitations were set through the monitored element file and thermal ratings of elements were taken from the Power Flow case. More details on the monitored, contingent elements, and constraint parameters are discussed below.

5.3.2.1 Monitored Elements

The study footprint included the entire Midwest ISO footprint, along with the footprints of American Electric Power, Commonweath Edison, and MAPP. Overloads identified outside of the study footprint were evaluated for their impact; all constraints outside the footprint with a meaningful cause and material impact on the RGOS footprint were mitigated. All elements greater than 100 kV were monitored during analysis, but the primary focus of the study was overloads on transmission elements with a voltage of 230 kV or higher. More details on the monitored elements are shown in Table 5.3-4, below.

Table 5.3-4: Monitored Elements Metrics and Criteria

Metric	Criteria
Thermal Monitoring	1. System Intact 2. All transmission with thermal loadings over 90% of the normal rating (Rate A) was monitored during the analysis. 3. Category B Contingencies: a. All transmission with thermal loadings over 90% of the emergency rating (Rate B) was monitored during the analysis. 4. Category C Contingencies: a. All transmission with thermal loadings over 125% of the emergency rating (Rate B) was monitored during the analysis.
Voltages	1. System Intact 2. All voltages greater than or less than the TO thresholds were monitored during the analysis.

5.3.2.2 Contingency Set-Up

NERC Category A and B events were used for the primary RGOS analysis, including the blanket outage of any 200 kV or higher facilities as well as the implementation of the contingency files provided throughout the MTEP study process. Selected Category C events were also analyzed in the analysis. These events include the double outage of lines surrounding each wind zone, and they also included the ‘critical few’ double outage contingencies provided by stakeholders. The contingency files used were from the MTEP10 reliability study and consistent with NERC, regional, state, and local planning criteria. These contingency files were screened for compatibility with each model, any discrepancies resolved.

5.3.2.3 Constraint Criteria

All 200 kV or higher transmission with overloads was identified as a constraint and appropriate mitigation was taken. More details on the specific constraint mitigation for each portion of the analysis are shown in Table 5.3-5, below.

Table 5.3-5: Constraint Metrics and Criteria

Metric	Criteria
Thermal Monitoring	1. System Intact: 2. All 200 kV+ transmission with thermal loadings over 100% of the normal rating (Rate A) was considered a constraint. 3. Category B Contingencies: a. All 200 kV+ transmission with thermal loadings over 100% of the emergency rating (Rate B) was considered a constraint. 4. Category C Contingencies: a. All 200 kV+ transmission with thermal loadings over 125% of the emergency rating (Rate B) was considered a constraint.
Voltages	All voltages on a 200 kV+ buses that were greater than or less than the TO thresholds were considered constraints.

5.3.3 NERC Transmission Planning Standards

North American Reliability Corporation (NERC) Transmission Planning standards TPL-001-0, TPL-002-0, and TPL-003-0 specify system performance requirements for the Bulk Electric System (>100 kV) under system intact (Category A), single element events (Category B), and multiple element events (Category C) for a variety of system conditions. Transmission planners must analyze and design the system to meet these system performance requirements or face monetary penalties. The standards specify the type of events to be analyzed and the system performance required for the different categories of events. System intact performance has the most restrictive performance requirements for voltage levels and thermal loadings on equipment. Single element events, loss of any single line or transformer or generator or shunt, must result in system performance within applicable voltage limits and thermal ratings. There should be no loss of load on the system not directly involved in the event. The system must also be stable, with no cascading outages. For multiple element outages, the system must be within limits, stable, and with no cascading outages. However, system adjustments including controlled loss of load or firm transfers are allowed to mitigate contingent performance issues associated with Category C events.

The intent of the RGOS effort was to examine system performance, with NERC TPL standards as a reliability guideline, to determine transmission upgrades to provide system intact and contingent performance standards. The focus of reliability study efforts was fixed on providing adequate capacity to deliver power and energy from wind energy zones.

Refer to Table 5.3-6. NERC Category A, B, and select C events were used in Power Flow analysis. The category C events applied to greater than 230 kV events as supplied by stakeholders, and bus double branch contingencies within a bus of each zone's outlet facilities was used. Category C events tested for energy zone outlet restriction and for potential cascading events. These cascading events were defined as situations in which transmission facilities experience a maximum loading of 125% or higher, as compared to the facility's emergency ratings. All elements greater than 100 kV were monitored during analysis while only elements greater than 200 kV in violation were addressed for solutions. All other elements were identified. NERC and regional entity (RE) planning criteria were applied. Transmission Owners' voltage and thermal design criteria were applied.

Table 5.3-6: Power Flow Solution Criteria

Metric	Criteria
Thermal Monitoring	1. System Intact: 2. Thermal loadings over normal rating (Rate A). All transmission with thermal loadings between 90% and 100% of normal rating will be identified and noted and considered when comparing portfolios. 3. Contingent: 4. Thermal overloads over emergency (Rate B). All transmission with thermal loadings between 90% and 100% of emergency rating will be identified and noted and considered when comparing portfolios.
Thermal Overload	1. System Intact: 2. All transmission greater than 200 kV with thermal loadings greater than 100% of normal rating will be addressed for solution. 3. All transmission less than 200 kV with thermal loadings greater that 100% of normal rating will be identified and noted and considered when comparing portfolios. 4. Contingent: 5. All transmission greater than 200 kV with thermal loadings greater than 100% of emergency rating will be addressed for solution. 6. All transmission less than 200 kV with thermal loadings greater that 100% of emergency rating will be identified and noted and considered when comparing portfolios.
High Voltage	1. System Intact 2. Voltages greater than TO thresholds will be addressed for solution on buses greater than 200 kV. All other buses will be identified and noted. 3. Contingent 4. Voltages greater than TO thresholds will be addressed for solution on buses greater than 200 kV. All other buses will be identified and noted and considered when comparing portfolios.
Low Voltage	1. System Intact 2. Voltages less than TO thresholds will be addressed for solution on buses greater than 200 kV. All other buses will be identified and noted and considered when comparing portfolios. 3. Contingent 4. Voltages less than TO thresholds will be addressed for solution on buses greater than 200 kV. All other buses will be identified and noted and considered when comparing portfolios.

5.3.4 Off-peak Linear Analysis Results

The primary analysis was performed on a 2019, summer off-peak model. This model was chosen due to the likelihood of a high wind output during summer off-peak conditions. This analysis began with the transmission determined in the energy analysis, and it continued in a highly iterative fashion, with between 60 and 110 iterations were performed on each of the Native Voltage, Native Voltage with DC, and 765 kV scenarios. It also contained several different phases, as discussed below. Each of the phases was conducted in an iterative manner, with the transmission refinement relying heavily upon reruns of the Category A, B, and C analyses.

- **Category A and B (System Intact and N-1) analysis** focused upon the identification and mitigation of 200 kV and above Category A and B constraints. A large amount of transmission was added to the model during this period, with the end result being a system without an 200 kV and above constraints under system intact or single contingency conditions.
- **Category C (N-2) analysis** is based upon the results of the Category A and B analysis. It focused on potentially cascading system events, which were simulated in the model as any transmission element which has a 125% or greater loading under a Category C event.
- **Transmission refinement/optimization** was conducted to ensure that the transmission design was not overbuilt. It analyzed the transmission added through the energy and previous off-peak analysis to determine that the lines proposed were used and useful. If any line was found to be lightly loaded, it was removed from the model, and analyses were conducted to ensure that no new constraints occurred without the line.

These analyses resulted in a set of new transmission for each scenario that resolved all the thermal overloads on the system under peak conditions. This transmission was then used as an input for later analysis. Refer to Figures 5.3-7–5.3-9.

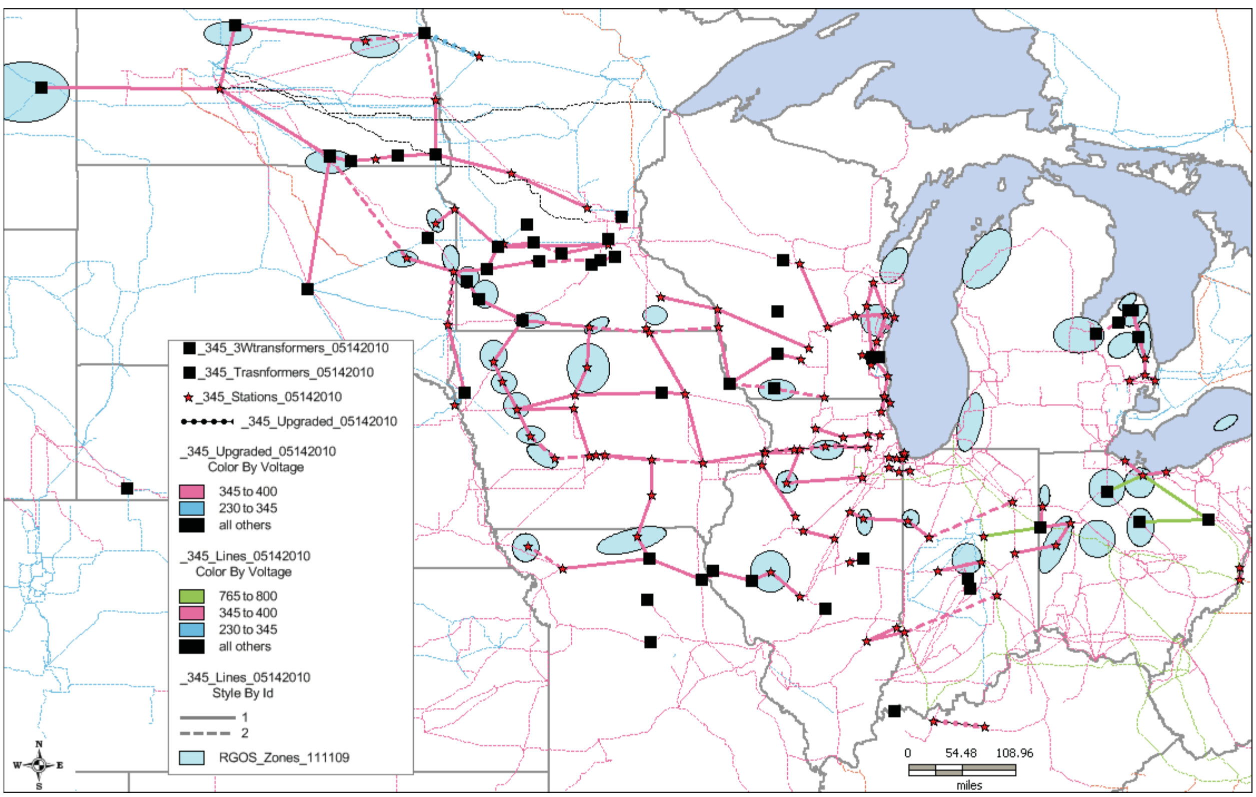

Figure 5.3-7: Native Voltage Off-peak Analysis

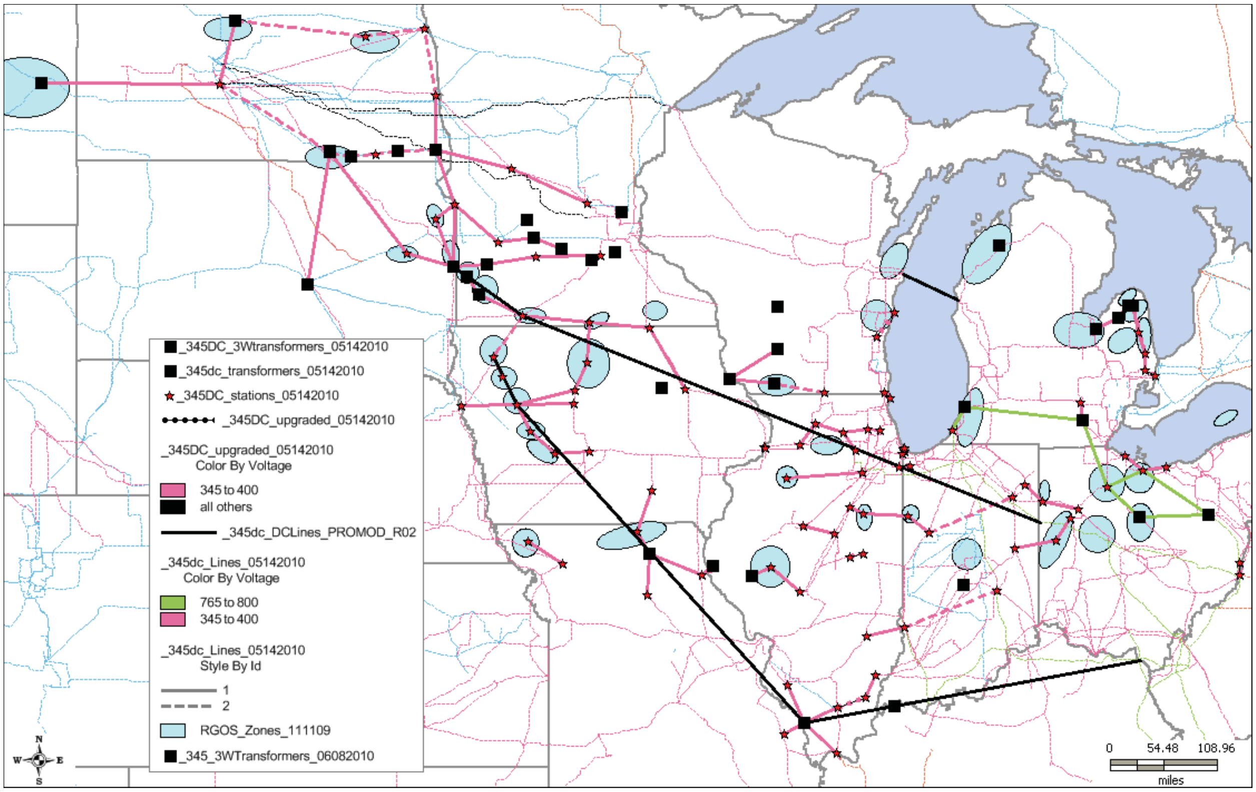

Figure 5.3-8: Native Voltage with DC Off-peak Analysis

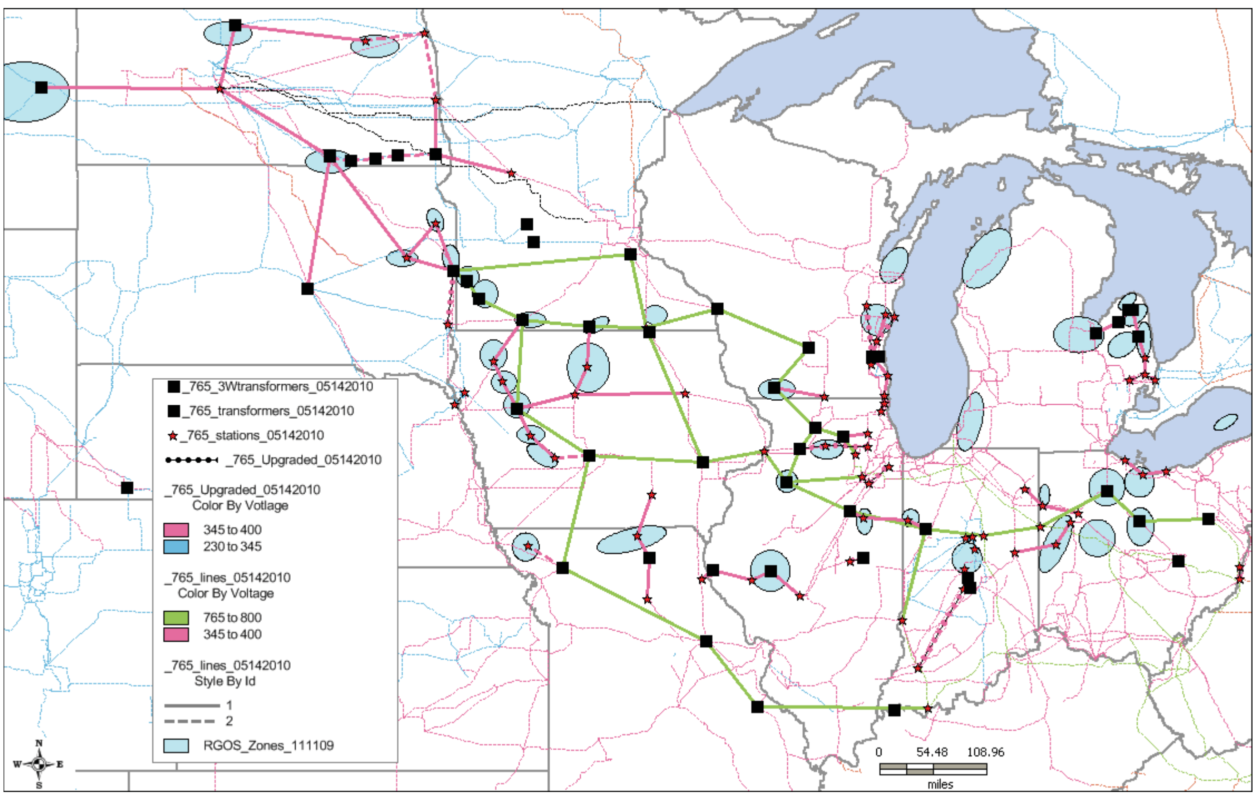

Figure 5.3-9: 765 Kv Off-peak Analysis

5.3.5 Sensitivity Analysis Results

A set of sensitivities were run on a peak and light load case. These sensitivities included both linear and AC analysis, and the results are discussed in more detail below.

5.3.5.1 Peak Sensitivity Analyses Results

Peak sensitivity analyses were conducted to ensure system reliability when the transmission system is experiencing the highest level of loading. Analyses included both linear and AC analysis in order to capture thermal and voltage overloads. Peak sensitivity started with the transmission from the final off-peak linear analysis for each scenario. Refer to Figures 5.3-10–5.3-12.

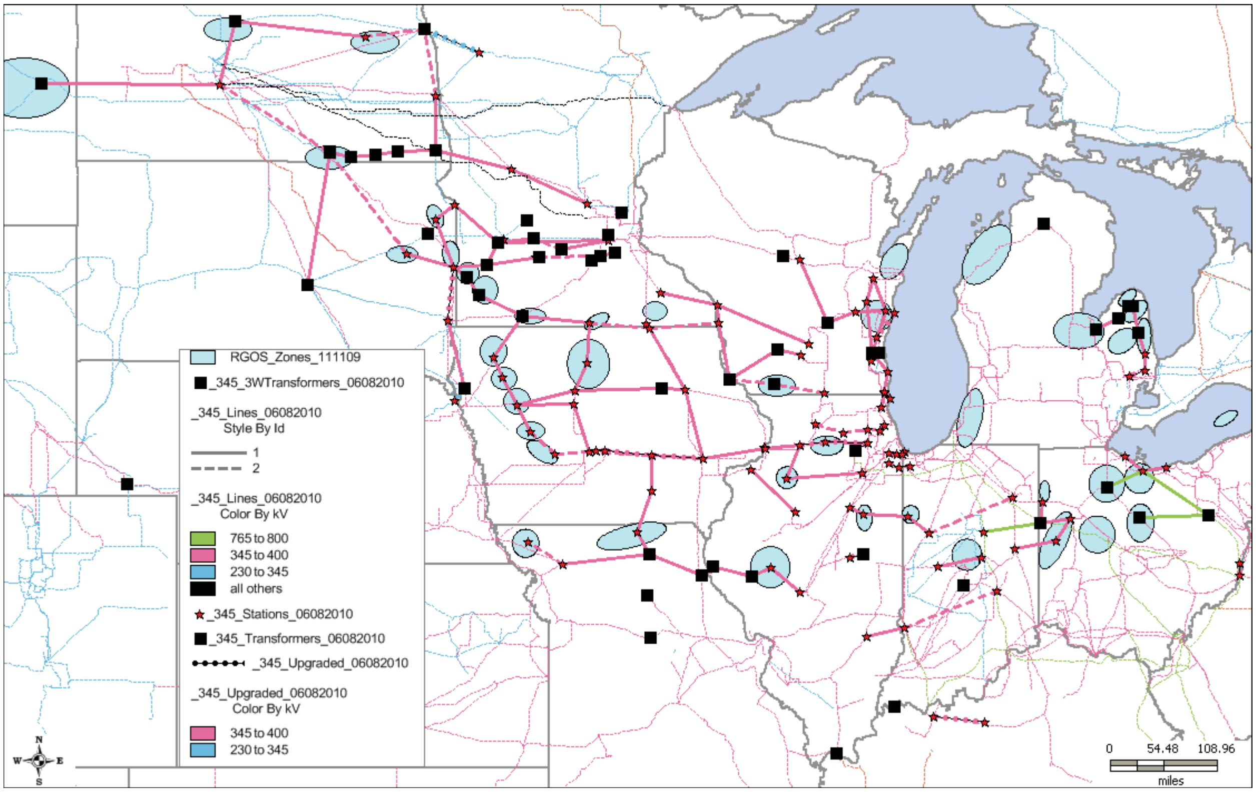

Figure 5.3-10: Native Voltage Peak Analysis

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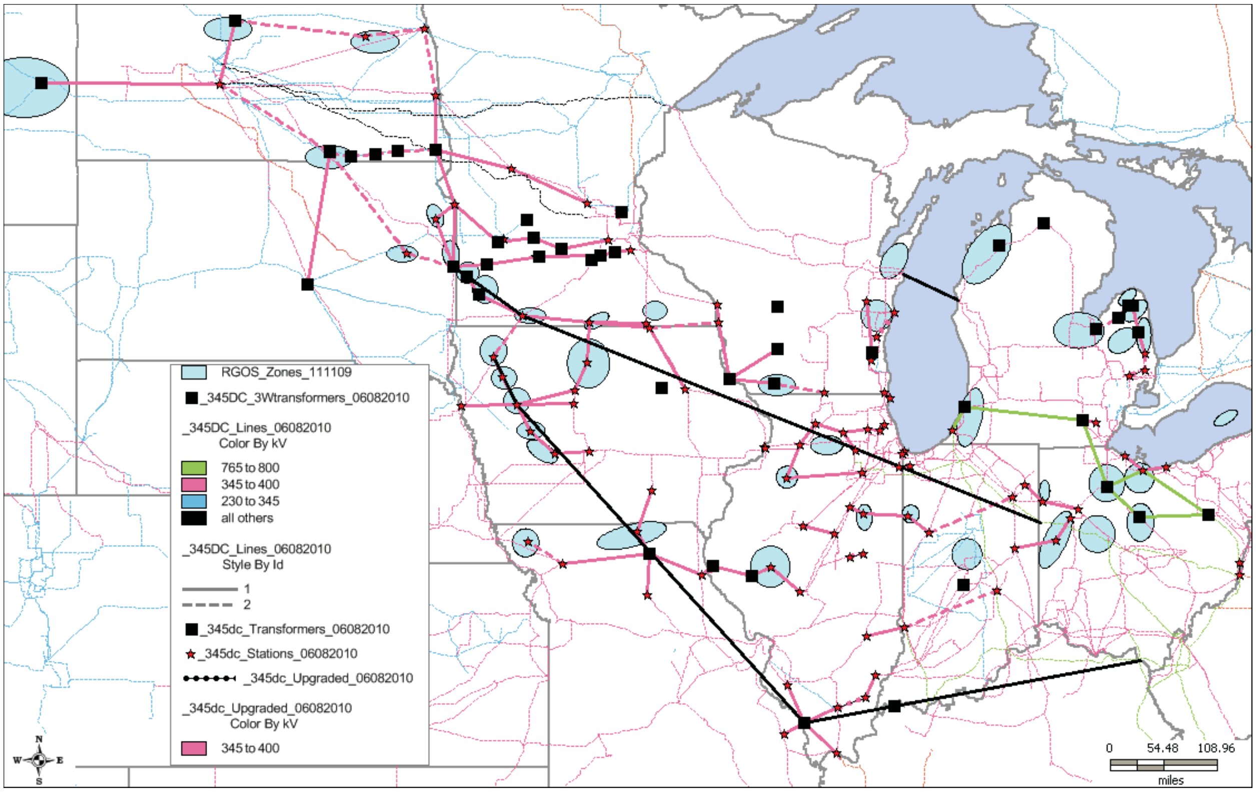

Figure 5.3-11: Native Voltage with DC Peak Analysis

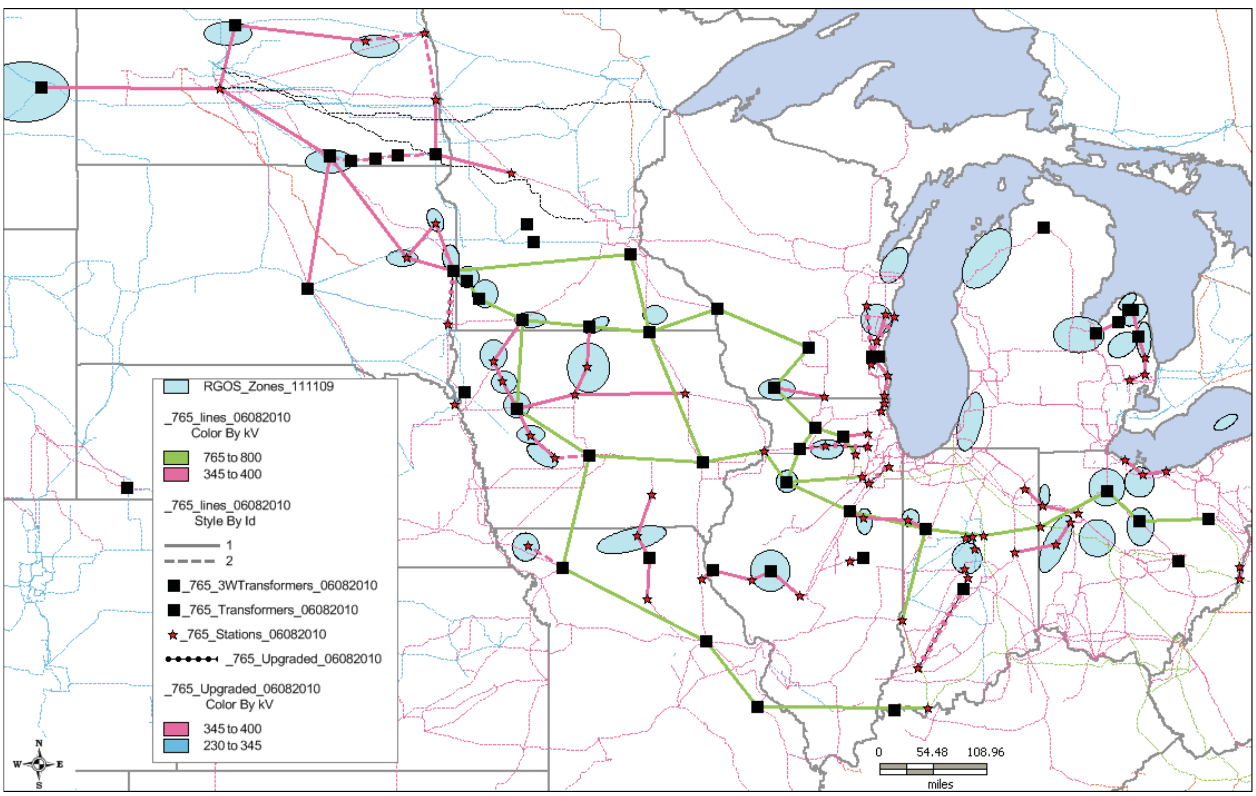

Figure 5.3-12: 765 kV Peak Analysis

5.3.5.2 Light Load Sensitivity Analyses Results

Light load sensitivity analyses were conducted to ensure system reliability with a full transmission buildout, without the support of wind from the wind zones. In particular, this scenario was designed to determine and mitigate any reactive (voltage) constraints which may occur due to the large reactive impact of the lightly loaded new transmission that was added during the off-peak and peak analyses. Light load analysis began with the transmission from the final peak sensitivity and relied upon AC analysis to determine any new thermal or voltage constraints.

5.3.6 Final Off-peak AC Analysis Results

The final step taken during RGOS Power Flow analysis was to run an off-peak AC analysis using transmission developed through the light load sensitivity. Final off-peak AC analysis had two (2) functions:

1. To test the transmission additions added in the peak and light load sensitivity analyses to ensure these additions did not create any reliability violations under off-peak conditions. This provided a final check, under a scenario with the highest wind output, ensuring RGOS plans were not harmful.
2. To find and resolve any lingering voltage violations.

After final off-peak analysis was completed, RGOS transmission scenarios were finalized and economic analyses were performed on each of the scenarios.

5.3.7 Lower Voltage Constraints

Refer to Table 5.3-7. Although RGOS analyses mitigated all constraints on the 200 kV and above transmission system, it did not explicitly attempt to mitigate constraints on the transmission system below 200 kV. These constraints were eliminated from the RGOS scope to minimize the study timeline and—due to the high level of Transmission Owner interaction—mitigate these lower voltage issues. All transmission constraints would require mitigatation prior to any transmission plan or prior to any portion of a transmission plan being moved to MTEP Appendix A for approval and subsequent construction.

Although thermal analysis did not mitigate all sub-200 kV constraints, it did identify and track these constraints throughout the process. The first iteration of the Power Flow analysis, performed on the off-peak model with indicative transmission added from the final energy analysis, contained between 166 and 228 sub-200 kV overloaded lines, depending on scenario. After the final transmission scenarios had been developed and applied to the models, the off-peak model had 76–190 sub-200 kV overloaded lines. These final constraints would have to be mitigated prior to any RGOS plan being moved to MTEP Appendix A.

Table 5.3-7: Sub-200 kV Constraints

Scenario	Initial Sub-200 kV Constraints	Final Sub-200 kV Constraints
Native Voltage	228	190
Native Voltage with DC	147	76
765 kV	166	127

5.3.8 Energy Model Results

The production cost model is also used to evaluate the different strategies refined within the Power Flow reliability work effort. The information in this section was derived from the evaluating the transmission overlays as of the end of the off-peak reliability analysis. Because of this, transmission added because of light load or peak analyses are not included in this production cost model evaluation.

The production cost simulation models reliability at a high level. Unlike Power Flow analysis, which can simulate all possible system contingencies, the production cost model focuses solely upon those contingencies provided by the user that will have significant re-dispatch effects. Within this analysis, contingencies related to RGOS zones were not modeled as completely as the contingencies that may have resulted from adding the new overlay transmission. It is also important to note the events modeled focus primarily on the 230 kV and above transmission system. The ultimate effects of contingency limitations are there are unknown costs and benefits due to re-dispatch that have not yet been explored.

5.3.8.1 Cost Savings

RGOS focuses on the addition of incremental wind to meet the RPS requirements throughout the study footprint and the transmission that facilitates the delivery of the energy. By adding the wind to the system without any RGOS transmission, a reduction in adjusted production costs is recognized within the study footprint as well as some of the defined neighboring regions. This reduction is the result of adding low-cost energy to the system. This can be seen in column 2 of Table 5.3-8, which represents the change in adjusted production cost savings compared to a model that does not include RGOS wind or transmission. Adding the different transmission strategies shows additional benefit can be achieved within the study footprint.

Table 5.3-8: Adjusted Production Cost Savings (2010 USD in Millions)

Pool	+ RGOS Wind	Wind+Native	Wind+765	Wind+Native DC
PJM	$560	$527	$512	$500
MISO	$3,265	$3,664	$3,767	$3,747
TVASUB	($16)	($20)	($28)	($18)
MAPPCOR	$1,222	$1,293	$1,317	$1,339
SPP	($34)	($36)	($17)	$25
SERCNI	$8	$15	$18	$5
IMO	$11	$19	$21	$24
MHEB	($14)	($7)	($5)	$3
NYISO	($13)	($8)	($14)	($13)
RGOS (no mapp)	$3,805	$4,220	$4,317	$4,304
Eastern Int	$4,988	$5,446	$5,571	$5,613

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Another metric that can be taken from the production cost model is load cost savings. In Table 5.3-9, it can be seen costs to load reduce with the addition of RGOS wind in most modeled regions, and then reduce even more with the addition of transmission to the system. This potential benefit is recognized more within the RGOS study footprint. However, other regions benefit from the greater availability of cheaper generation due to a greater abundance of low-cost energy within the study footprint.

Table 5.3-9: Load Cost Savings (2010 USD in Millions)

Pool	+ RGOS Wind	Wind+Native	Wind+765	Wind+Native DC
PJM	$865	$1,769	$1,984	$2,021
MISO	$1,688	$2,170	$2,283	$2,021
TVASUB	$212	$307	$296	$360
MAPPCOR	$1,776	$1,591	$1,405	$1,188
SPP	$41	($3)	($66)	$125
SERCNI	$57	$279	$290	$502
IMO	$104	$145	$201	$205
MHEB	$50	$28	$22	$5
NYISO	($38)	($14)	($12)	($17)
RGOS (no mapp)	$2,291	$3,352	$3,533	$3,226
Eastern Int	$4,754	$6,274	$6,404	$6,409

5.3.8.2 RGOS Zone Energy Delivered

RGOS modeled an incremental 28 GW of wind within the study footprint to meet aggregate RPS requirements assumed within the study, resulting in modeling of 88.5 TWh of energy to be delivered to the system. Refer to Table 5.3-10, which shows approximately 8% of the wind was curtailed when adding RGOS-only wind. Curtailment occurred at locational Marginal Prices (LMP) of -$40 defined within the model. The curtailment is a result of LMPs being suppressed due to modeled constraints on the system. It is expected this curtailment may be less than what actually should have been seen because of the lack of appropriately modeled constraints around the wind zones and bulk delivery paths. Refer to Table 5.3-10, which shows this curtailment of RGOS energy zones disappears when RGOS transmission is added to the system.

Table 5.3-10: RGOS Wind Zone Energy Delivered

Overlay	Installed RGOS Wind Zone		Delivered Energy (MWh)	Curtailment
	Nameplate (MW)	Modeled Energy (MWh)		
Base Case (wind added with no transmission)	28,325	88,560,920	81,417,776	8.07%
Native Voltage	28,325	88,560,920	88,533,050	0.03%
765 kV	28,325	88,560,920	88,560,920	0.00%
Native with DC	28,325	88,560,920	88,560,920	0.00%

5.3.8.3 Overlay Line Utilization Summary

Because the production model analyzes every hour within the modeled year, flow information on each of the modeled RGOS lines can be identified. Tables 5.3-11–5.3-13 summarize the max instantaneous loading of the RGOS lines identified in each overlay strategy. This loading is identified as a percentage of the stated rating within the tables. Also, these loadings represent system intact loadings. Because of this, some lines identified within the power flow analysis are primarily needed for reliability and thus load poorly under system intact conditions. More detailed information on each line can be found in the spreadsheet identified as Appendix 6: Production Cost Model Summary Results.

Table 5.3-11: Native Voltage Max Loading Summary

Utilization	Voltage (kV) & Rating (MW)		
	230 kV 340 MW	345 kV 1600 MW	765 kV 5000 MW
Total Lines	4	134	6
Loading at or above 20%	2	123	5
Loading at or above 30%	1	95	2
Loading at or above 40%	1	47	1
Loading at or above 50%	0	27	0

Table 5.3-11: Native Voltage Max Loading Summary

Utilization	Voltage (kV) & Rating (MW)		
	230 kV 340 MW	345 kV 1600 MW	765 kV 5000 MW
Loading at or above 60%	0	10	0
Loading at or above 70%	0	4	0
Loading at or above 80%	0	1	0
Loading at or above 90%	0	0	0
Loading at or above 100%	0	0	0

Table 5.3-12: 765 kV Max Loading Summary

Utilization	Voltage (kV) & Rating (MW)	
	345 kV 1600 MW	765 kV 5000 MW
Total Lines	62	34
Loading at or above 20%	52	34
Loading at or above 30%	31	30
Loading at or above 40%	19	26
Loading at or above 50%	11	14
Loading at or above 60%	3	7
Loading at or above 70%	0	3
Loading at or above 80%	0	3
Loading at or above 90%	0	0
Loading at or above 100%	0	0

Table 5.3-13: Native Voltage with DC Max Loading Summary

Utilization	Voltage (kV) & Rating (MW)			
	345 kV 1600 MW	765 kV 5000 MW	DC 1600	DC 6400
Total Lines	92	9	1	2
Loading at or above 20%	83	9	1	2
Loading at or above 30%	56	6	1	2
Loading at or above 40%	44	5	1	2
Loading at or above 50%	32	3	1	2
Loading at or above 60%	18	2	1	2
Loading at or above 70%	11	2	1	2
Loading at or above 80%	6	1	1	2
Loading at or above 90%	5	0	1	2
Loading at or above 100%	2	0	1	2

5.3.8.4 Interface Flow Summary

Hundreds of lines and autotransformers were modeled for RGOS-developed strategies. More detailed information can be found in Appendix 7: Native Voltage Transmission Detail Flow Information for the Native Voltage strategy; Appendix 8: 765 kV Transmission Detail Flow Information for the 765 kV strategy; and Appendix 9: Native Voltage with DC Transmission Detail Flow Information for the Native Voltage with DC strategy.

Another way to summarize the impact of RGOS transmission strategies is to conceptualize the flow of energy over defined interfaces. For purposes of this study, interfaces were defined as transmission lines crossing state boundaries. Table 5.3-14 provides information for the net energy flow within states containing RGOS lines that cross state borders for the Native Voltage overlay strategy.

Table 5.3-14: Native Voltage Strategy Net State Interface Flow Summary (RGOS Lines Only)

State(s)	Max Export (MW)	Max Import (MW)	# of Hours Exporting	# of Hours Importing
Dakotas Net	1,982	-489	8,376	380
IA Net	2,039	-833	7,729	1,028
IL Net	1,887	-2,546	3,779	4,974
IN Net	329	-2,052	202	8,555
MN Net	919	-2,031	1,399	7,354

Table 5.3-14: Native Voltage Strategy Net State Interface Flow Summary (RGOS Lines Only)

State(s)	Max Export (MW)	Max Import (MW)	# of Hours Exporting	# of Hours Importing
MO Net	1,213	-412	7,571	1,180
MT Net	223	-296	3,047	5,627
OH Net	889	-1,612	898	7,857
WI Net	1,974	-1,079	6,580	2,175

Figure 5.3-13 provides the net energy duration curve for each of the states previously identified with the modeled Native Voltage overlay. Referencing Table 5.3-14 and Figure 5.3-13, it can be seen areas with higher incremental wind penetration tend to be net exporters while states with more load and less wind capability tend to be net importers.

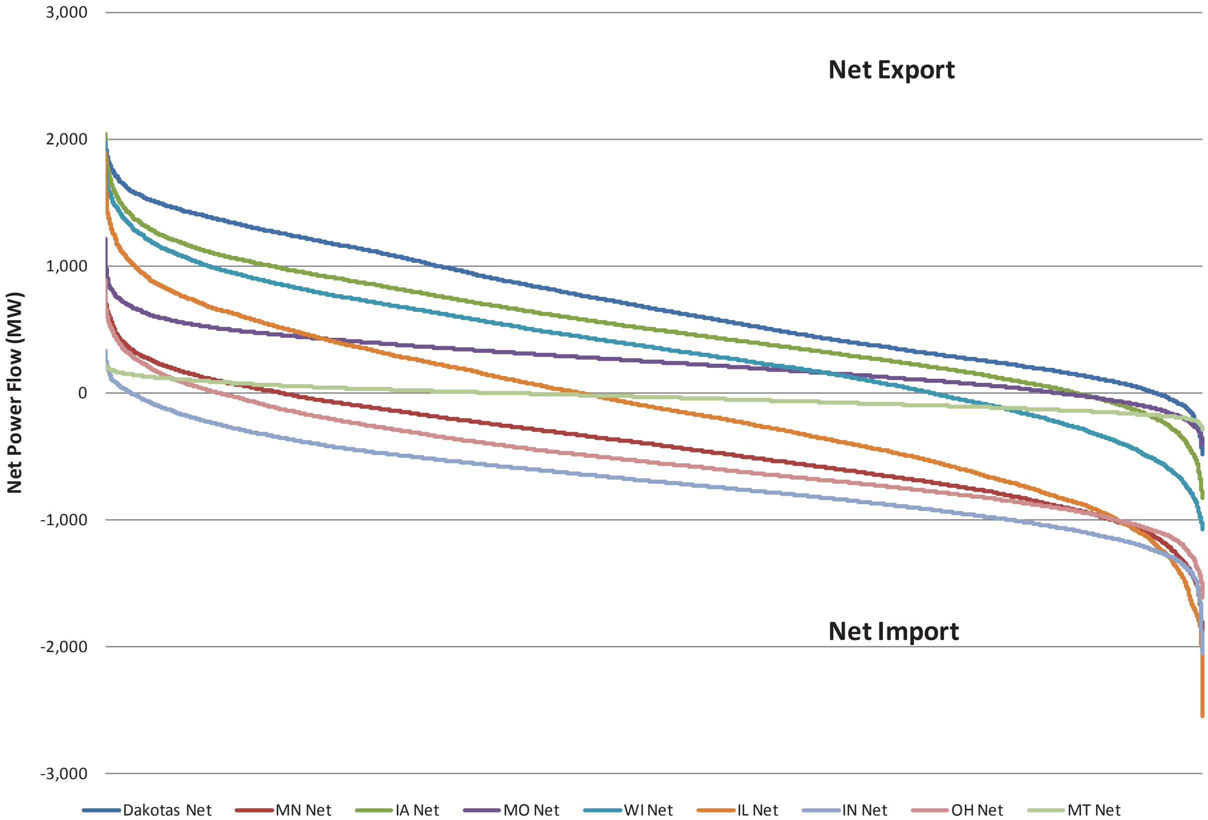

Figure 5.3-13: Native Voltage Strategy Net State Interface Duration Curves (RGOS Lines Only)

Table 5.3-15 and Figure 5.3-14 represent net state energy information for the 765 kV strategy overlay. It is evident more energy flows on the lines with the 765kV overlay than with the Native Voltage overlay. This should be expected because of the higher ratings and lower impedance of 765 kV transmission lines.

Table 5.3-15: 765 kV Strategy Net State Interface Flow Summary (RGOS Lines Only)

State(s)	Max Export (MW)	Max Import (MW)	# of Hours Exporting	# of Hours Importing
Dakotas Net	2,925	-672	8,351	405
IA Net	3,935	-1,401	8,121	639
IL Net	1,752	-6,447	929	7,830
IN Net	1,424	-3,552	537	8,222
MN Net	2,637	-2,184	6,932	1,822
MO Net	4,308	-2,003	7,154	1,604
MT Net	215	-297	2,915	5,789
OH Net	2,073	-3,479	701	8,058
WI Net	2,438	-2,019	5,430	3,326

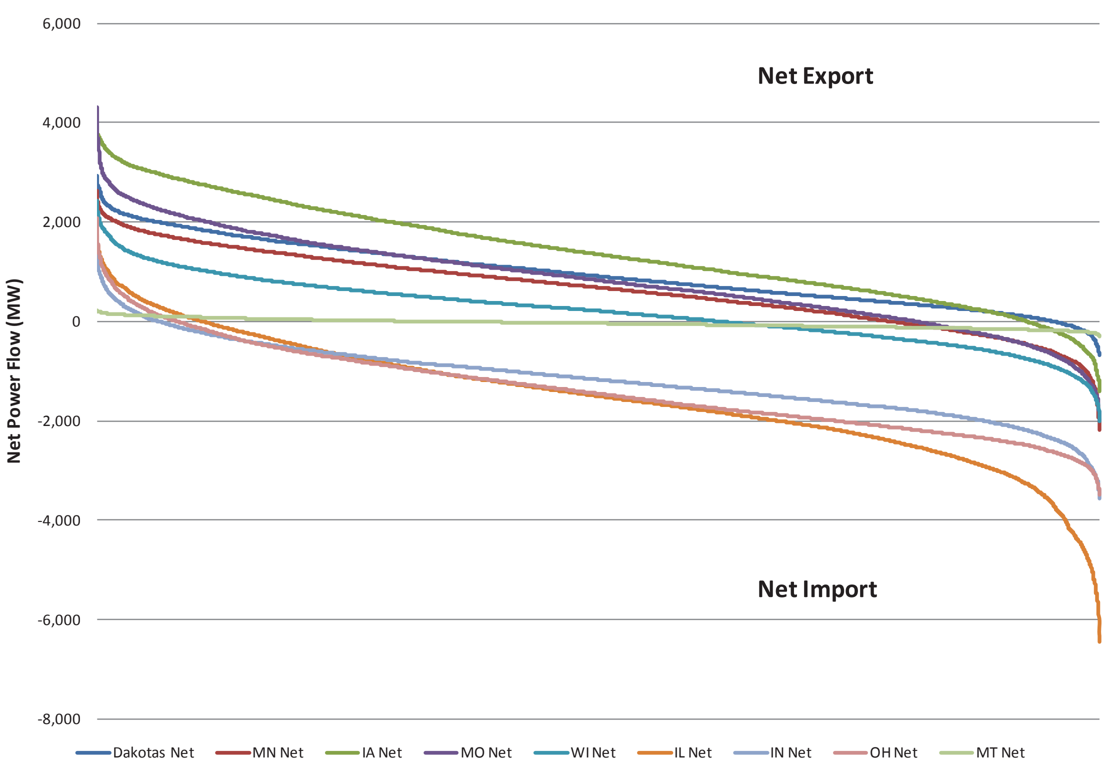

Figure 5.3-14: 765 kV Strategy Net State Interface Duration Curves (RGOS Lines Only)

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Table 5.3-16 and Figure 5.3-15 show net state energy information for the Native Voltage with DC transmission strategy. The purpose of DC transmission across the RGOS study footprint is to deliver high levels of energy across the system with minimal impact on existing transmission that it (DC transmission) bypasses. Because of the source and sink locations of the DC lines, the Dakotas, Minnesota, and Iowa see a high impact for net state export while Ohio experiences large imports due to most of the DC transmission sinking within Ohio state boundaries.

Table 5.3-16: Native Voltage with DC Strategy Net State Interface Flow Summary (RGOS Lines Only)

	Max Export (MW)	Max Import (MW)	# of Hours Exporting	# of Hours Importing
Dakotas Net	3,628	-249	8,704	56
IA Net	5,774	-610	8,450	309
IL Net	1,646	-3,622	3,566	5,194
IN Net	-81	-1,806	0	8,760
MI Net	2,485	-3,129	1,321	7,439
MN Net	4,793	-1,290	8,134	625
MO Net	1,100	-1,125	4,437	4,317
MT Net	241	-284	3,627	5,050
OH Net	2,814	-10,222	491	8,269
WI Net	1,600	-1,600	6,970	1,790

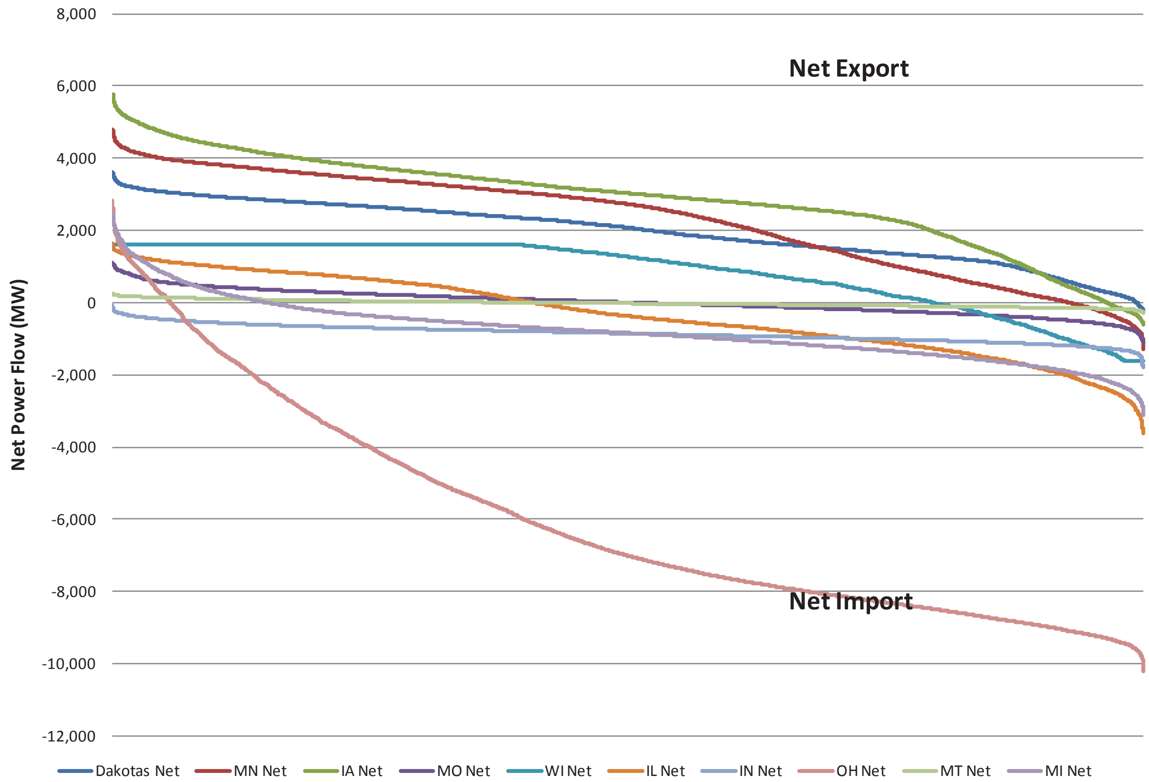

Figure 5.3-15: Native Voltage with DC Strategy Net State Interface Duration Curves (RGOS Lines Only)

To show in greater detail where energy is actually flowing, the following tables and figures show specific state-to-state RGOS line energy flow information. Max power flow and number of positive hours represent "from" to "to" flow while the min power flow and number of negative hours represent the opposite.

Table 5.3-17 and Figure 5.3-16 show the bulk of the energy flow tends to go west to east in the Native Voltage overlay study footprint.

Table 5.3-17: Native Voltage Strategy State Interface Flow Summary (RGOS Lines Only)

Interface	Max Power Flow (MW)	Min Power Flow (MW)	# of Hours Positive	# of Hours Negative
Dak to IA	400	-337	4,759	3,959
Dak to MN	2,042	-298	8,485	272
IA to IL	760	-455	7,835	911
IA to MO	438	-687	4,201	4,517
IA to WI	566	-100	8,674	81
IL to IN	2,060	-166	8,753	6
IN to OH	1,612	-889	7,857	898
MN to IA	980	-1,409	4,515	4,233

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Table 5.3-17: Native Voltage Strategy State Interface Flow Summary (RGOS Lines Only)

Interface	Max Power Flow (MW)	Min Power Flow (MW)	# of Hours Positive	# of Hours Negative
MN to WI	462	-284	8,433	322
MO to IL	716	-462	7,802	941
MT to Dak	223	-296	3,047	5,627
NE to IA	42	-157	436	8,240
WI to IL	2,204	-741	8,440	316

* Positive numbers represent flows from A to B (Dakotas to MN) while negative numbers represent flow from B to A (MN to Dakotas).

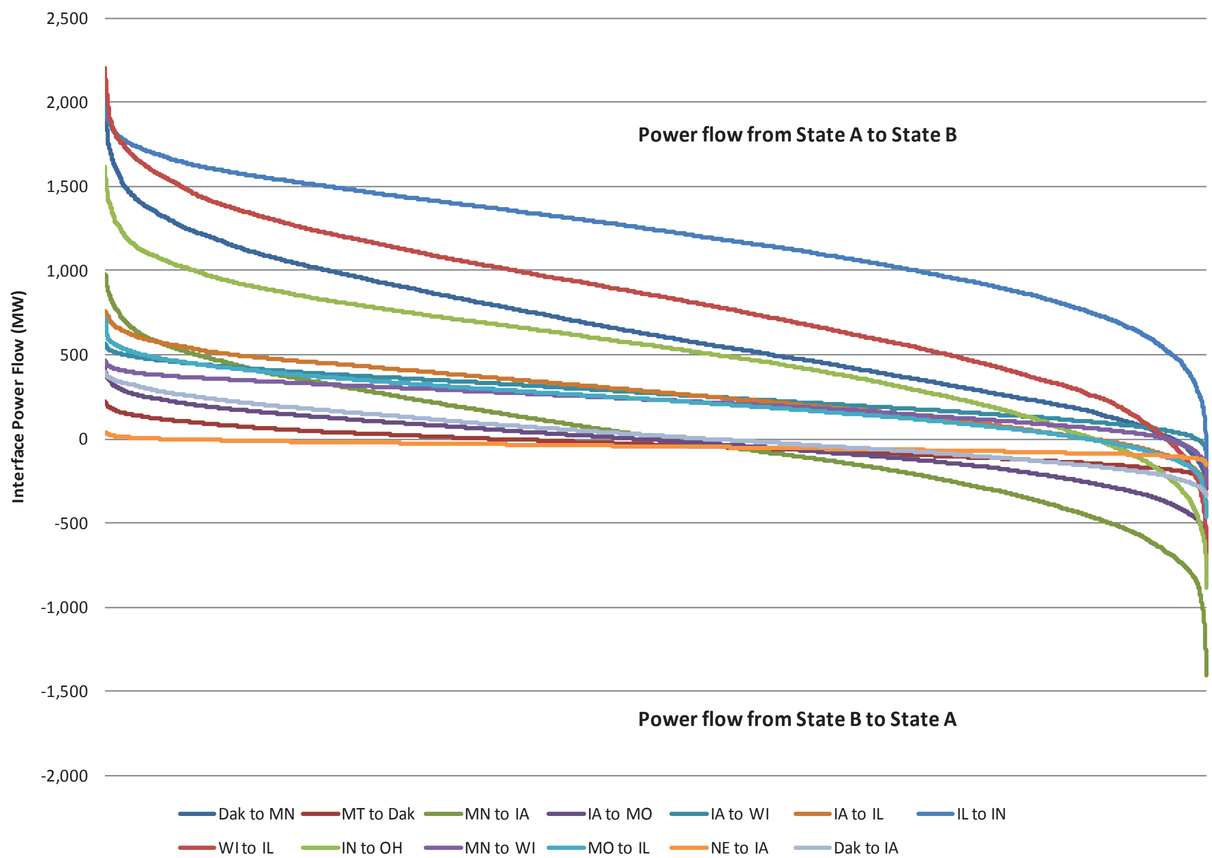

Figure 5.3-16: Native Voltage Strategy State Interface Duration Curves (RGOS Lines Only)

As previously noted, the 765 kV overlay shows many of the same characteristics of the Native Voltage but at higher capacity levels. Table 5.3-18 and Figure 5.3-17 provide energy flow information for this strategy.

Table 5.3-18: 765 kV Strategy State Interface Flow Summary (RGOS Lines Only)

Interface	Max Power Flow (MW)	Min Power Flow (MW)	# of Hours Positive	# of Hours Negative
Dak to MN	2,943	-795	8,218	537
IA to IL	4,103	-993	8,623	137
IA to MO	2,056	-2,639	5,163	3,595
IA to WI	2,773	-372	8,696	63
IL to IN	3,545	-2,021	8,254	505
IN to OH	3,479	-2,073	8,058	701
MN to IA	5,097	-2,468	7,841	917
MO to IL	525	-256	7,417	1,301
MO to IN	2,440	-922	8,194	564
MT to Dak	215	-297	2,915	5,789
WI to IL	3,795	-1,750	8,423	336

* Positive numbers represent flows from A to B (Dakotas to MN) while negative numbers represent flow from B to A (MN to Dakotas).

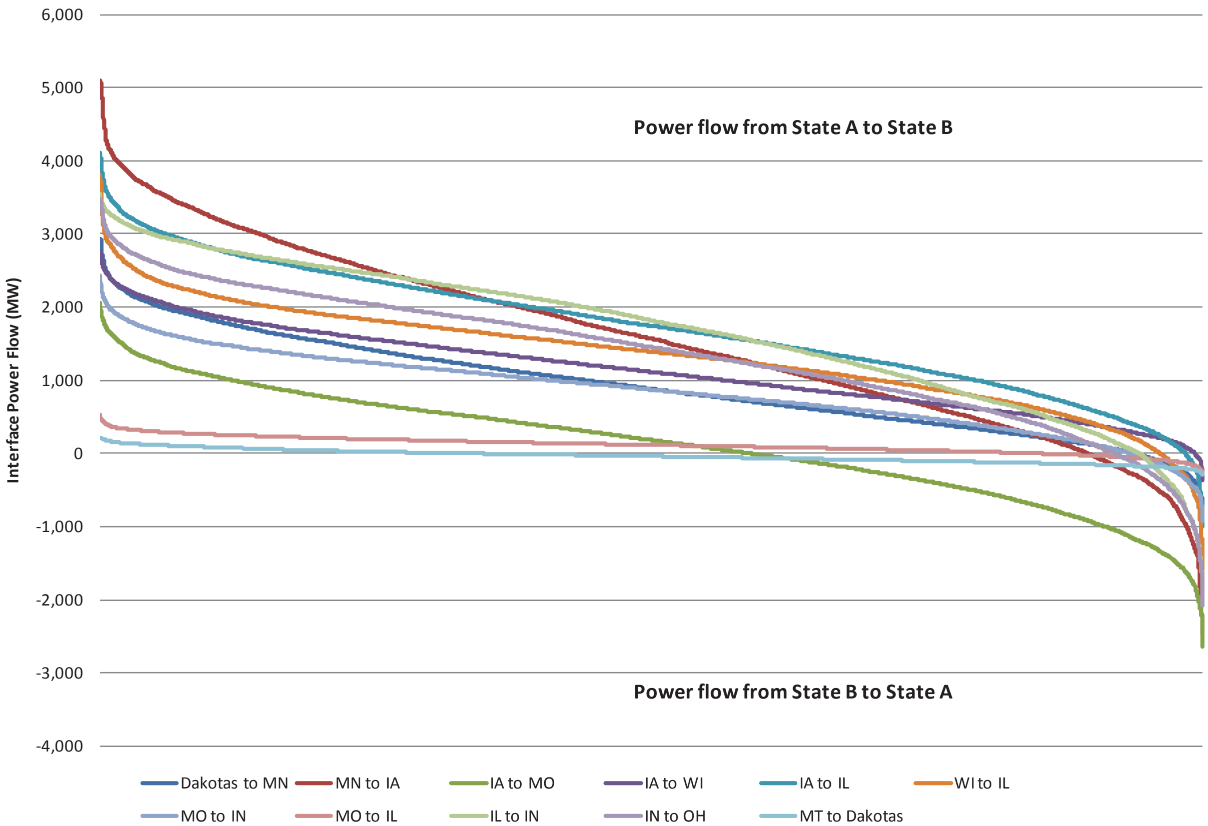

Figure 5.3-17: 765 kV Strategy State Interface Duration Curves (RGOS Lines Only)

Table 5.3-19 and Figure 5.3-18 represent energy flow information for the Native Voltage with DC overlay. Because the DC overlay interconnects into the existing system at only a few points, new state interfaces are developed—the Illinois to Ohio interface, for example. It can also be seen some interface characteristics are different because of where the DC interconnects. For example, the general flow of energy goes from Missouri to Illinois in other overlays. However, with the DC line tying to the system south of a St. Louis in Illinois, the general energy flow of that interface flows from Illinois to Missouri.

Table 5.3-19: Native Voltage with DC Strategy State Interface Flow Summary (RGOS Lines Only)

Interface	Max Power Flow	Min Power Flow	# of Hours Positive	# of Hours Negative
Dak to MN	3,768	-322	8,681	79
IA to IL	6,400	0	8,308	0
IA to MO	324	-922	572	8,166
IL to IN	1,721	-131	8,750	10
IL to OH	8,000	0	8,397	0
IN to OH	493	-687	3,610	5,127
MN to IA	1,664	-1,496	4,531	4,225
MN to IL	6,400	0	8,300	0

Table 5.3-19: Native Voltage with DC Strategy State Interface Flow Summary (RGOS Lines Only)

Interface	Max Power Flow	Min Power Flow	# of Hours Positive	# of Hours Negative
MO to IL	552	-1,180	1,120	7,633
MT to Dak	241	-284	3,627	5,050
OH to MI	2,141	-1,968	4,167	4,589
WI to MI	1,600	-1,600	6,970	1,790
* Positive numbers represent flows from A to B (Dakotas to MN) while negative numbers represent flow from B to A (MN to Dakotas).				

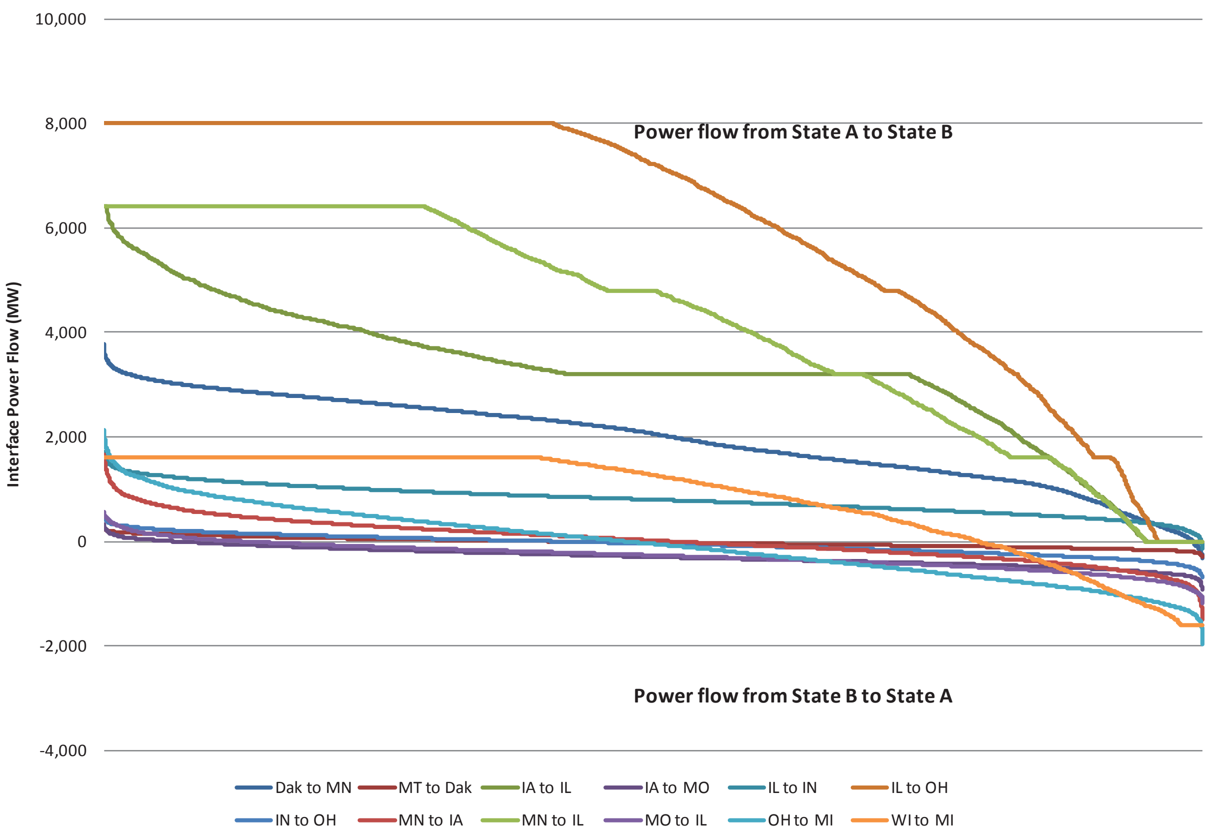

Figure 5.3-18: Native Voltage with DC Strategy State Interface Duration Curves (RGOS Lines Only)

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To demonstrate a more integrated look of the impact of the RGOS lines added to the system, the following tables and figures show the interface energy flow summary from state-to-state with RGOS lines as well as existing transmission of 230 kV and greater.

Table 5.3-20 and Figure 5.3-19 represent the state interface flow of the base case. The base case is defined as adding RGOS energy zones to the existing transmission system without adding additional RGOS transmission.

Table 5.3-20: Base Case State Interface Summary (All Lines 230 kV and Greater)

INTERFACE	Max Power Flow (MW)	Min Power Flow (MW)	# of Hours Positive	# of Hours Negative
DK-MHEB	550	-500	1,968	6,771
IA-IL	1,098	-991	6,822	1,931
IA-MO	616	-776	5,194	3,536
IA-NE	1,650	-1,944	5,140	3,615
IA-SD	1,064	-880	4,395	4,350
IL-IN	6,383	-4,308	8,013	746
IL-KT	1,189	-165	8,738	21
IL-MO	1,897	-1,873	4,467	4,290
IN-OH	7,040	-3,390	8,064	695
MI-IN	3,981	-2,355	6,625	2,130
MI-OH	2,599	-1,921	6,571	2,186
MN-DAK	553	-1,514	254	8,504
MN-IA	1,246	-1,670	4,989	3,762
MN-MHEB	834	-855	26	8,734
MN-WI	2,256	-734	8,698	62
OH-PA	1,924	-3,745	2,558	6,198
WI-IL	1,314	-1,682	7,084	1,675
WI-MI	333	-77	8,243	478

* Positive numbers represent flows from A to B (Dak to MHEB) while negative numbers represent flow from B to A (MHEB to Dak).

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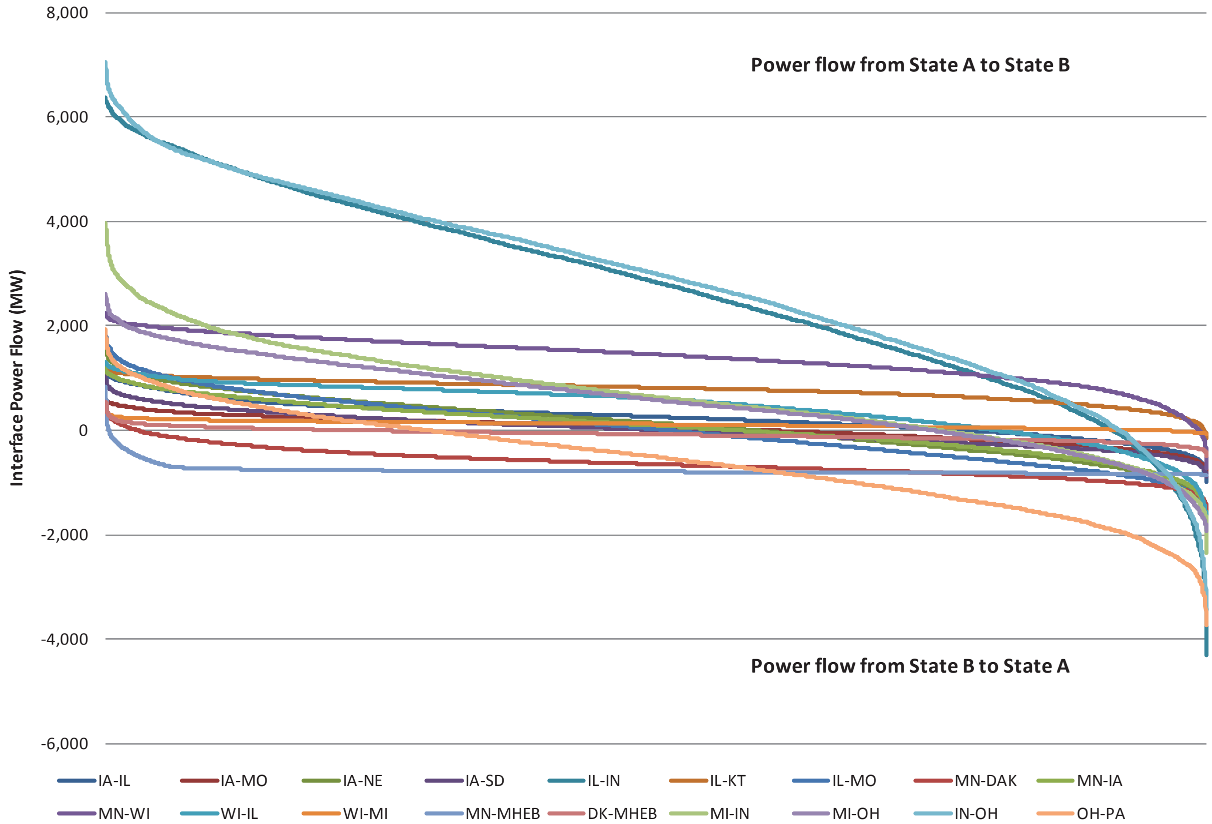

Figure 5.3-19: Base Case State Interface Duration Curves (All Lines 230 kV and Greater)

Table 5.3-21 and Figure 5.3-20 represent the interface information for the Native Voltage overlay with existing transmission added. The impact of adding transmission to one or some of the interfaces may also have an effect on the energy flows of unaltered interfaces.

Table 5.3-21: Native Voltage Strategy State Interface Summary (All Lines 230 kV and Greater)

INTERFACE	Max Power Flow (MW)	Min Power Flow (MW)	# of Hours Positive	# of Hours Negative
DK-MHEB	487	-481	1,790	6,952
IA to WI	566	-100	8,675	81
IA-IL	2,245	-1,407	7,865	890
IA-MO	1,000	-1,321	5,293	3,464
IA-NE	1,859	-1,755	4,458	4,297
IA-SD	909	-1,224	2,889	5,865
IL-IN	8,729	-3,808	8,499	261
IL-KT	1,195	-182	8,724	36
IL-MO	2,138	-2,814	3,050	5,704

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Table 5.3-21: Native Voltage Strategy State Interface Summary (All Lines 230 kV and Greater)

INTERFACE	Max Power Flow (MW)	Min Power Flow (MW)	# of Hours Positive	# of Hours Negative
IN-OH	7,882	-2,385	8,531	229
MI-IN	4,148	-2,336	6,302	2,455
MI-OH	2,754	-2,093	6,435	2,323
MN-DAK	811	-3,834	420	8,340
MN-IA	1,481	-2,201	4,789	3,967
MN-MHEB	788	-907	29	8,731
MN-WI	2,861	-1,184	8,664	96
OH-PA	1,989	-3,675	3,256	5,497
WI-IL	4,337	-2,141	8,259	501
WI-MI	341	-70	8,355	370

* Positive numbers represent flows from A to B (Dak to MHEB) while negative numbers represent flow from B to A (MHEB to Dak).

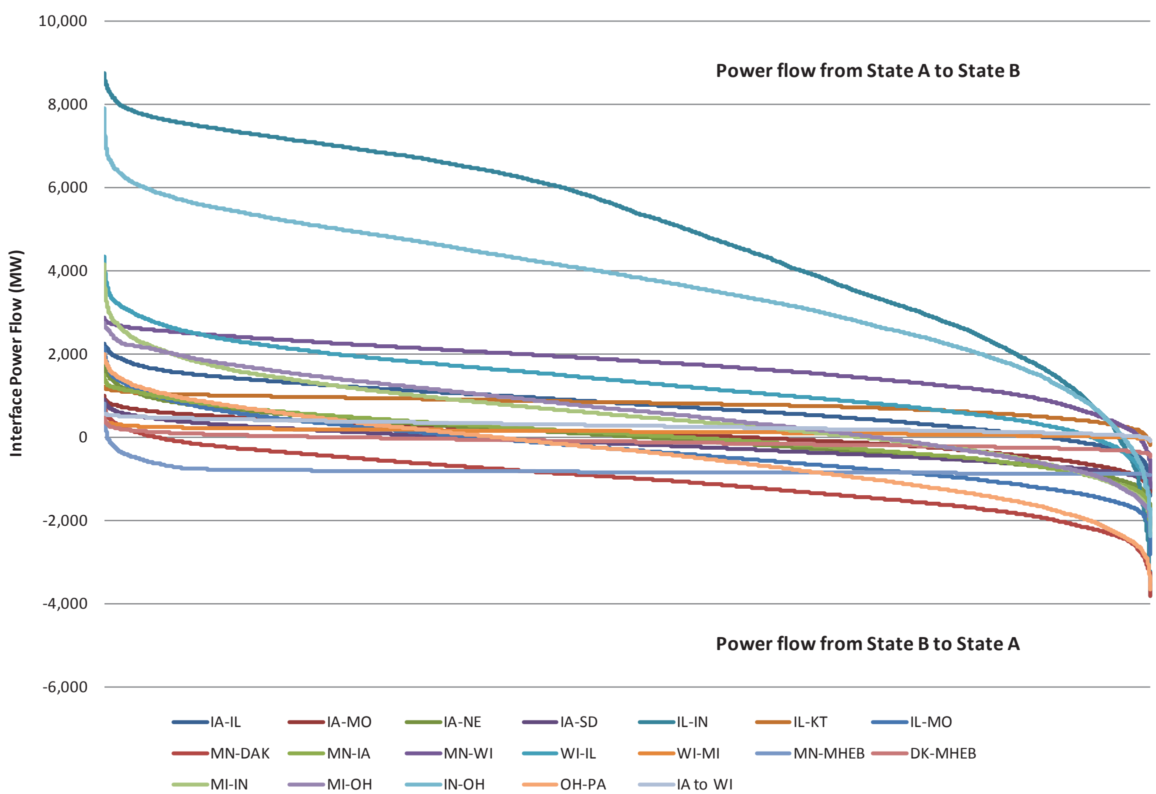

Figure 5.3-20: Native Voltage Strategy State Interface Duration Curves (All Lines 230 kV and Greater)

As mentioned previously, the 765 kV system shows those interfaces with new transmission have higher energy flow impacts than those with the Native Voltage overlay. This can be seen in Table 5.3-22 and Figure 5.3-21.

Table 5.3-22: 765 kV Strategy State Interface Summary (All Lines 230 kV and Greater)

Interface	Max Power Flow (MW)	Min Power Flow (MW)	# of Hours Positive	# of Hours Negative
Dak-MHEB	544	-473	1,476	7,275
IA-IL	5,158	-1,596	8,437	320
IA-MO	2,569	-3,191	5,363	3,395
IA-NE	1,620	-1,467	4,314	4,432
IA-SD	651	-811	3,745	5,001
IA-WI	2,773	-372	8,696	63
IL-IN	11,086	-4,906	8,490	269
IL-KT	1,204	-252	8,716	44
IL-MO	2,258	-2,323	3,995	4,763
IN-OH	12,019	-4,860	8,423	336
MI-IN	4,004	-2,478	5,533	3,225
MI-OH	2,694	-2,277	6,044	2,714
MN-DAK	1,140	-4,299	395	8,363
MN-IA	5,931	-3,450	7,444	1,316
MN-MHEB	819	-902	24	8,736
MN-WI	2,422	-633	8,684	76
MO-IN	2,440	-922	8,194	564
OH-PA	2,453	-3,720	4,027	4,730
WI-IL	4,984	-2,698	8,247	512
WI-MI	343	-71	8,333	393
* Positive numbers represent flows from A to B (Dak to MHEB) while negative numbers represent flow from B to A (MHEB to Dak).				

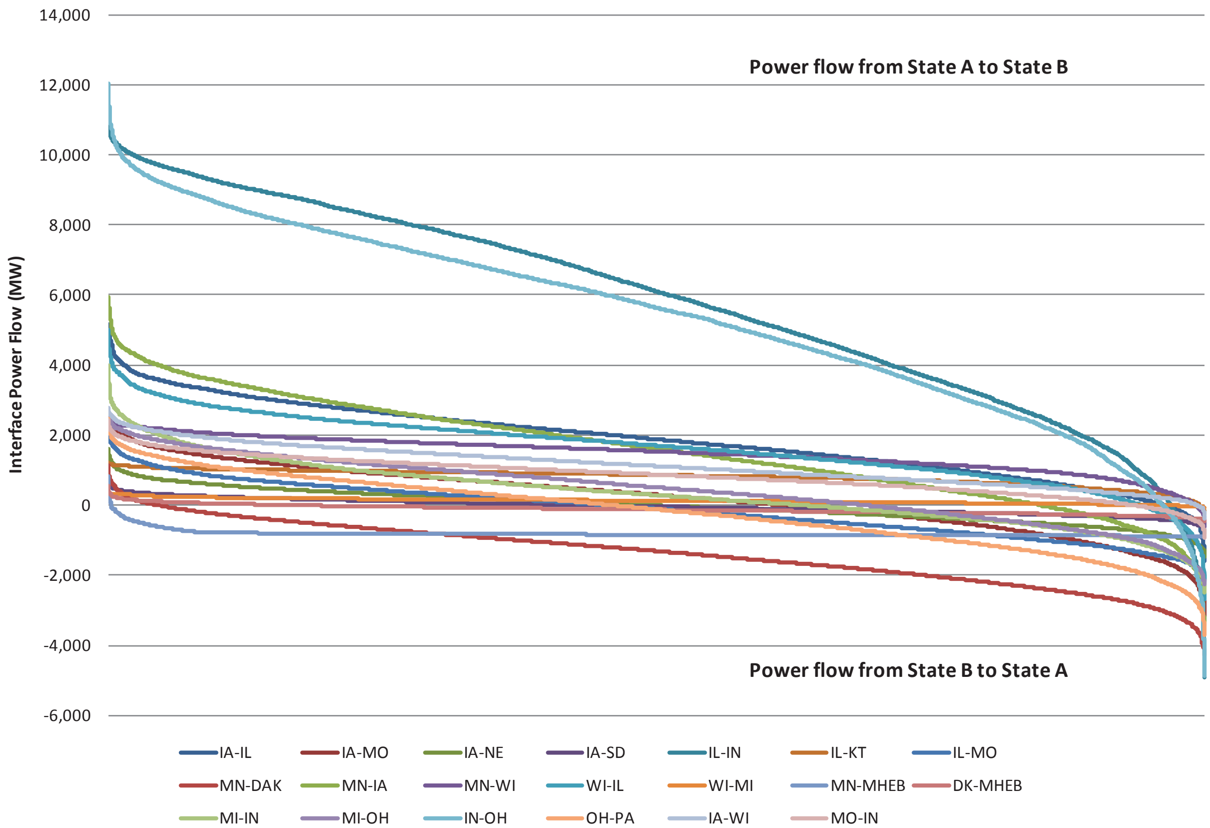

Figure 5.3-21: 765 kV Strategy State Interface Duration Curves (All Lines 230 kV and Greater)

The DC transmission in the Native Voltage with DC overlay shows much of the same impacts with the existing system as without. Native Voltage with DC continues to demonstrate the transfer of large amounts of energy but also shows that selection of locations for the DC terminals can change characteristics of the energy flow across the system. This change in characteristics can be seen on the Iowa and Minnesota interface and the Missouri to Illinois interface. Refer to Table 5.3-23 and Figure 5.3-22.

Table 5.3-23: Native Voltage with DC Strategy State Interface Summary (All Lines 230 kV and Greater)

Interface	Max Power Flow (MW)	Min Power Flow (MW)	# of Hours Positive	# of Hours Negative
DK-MHEB	444	-512	638	8,114
IA-IL	7,508	-1,073	8,448	311
IA-MO	741	-1,687	1,254	7,501
IA-NE	1,046	-2,828	638	8,120
IA-SD	908	-852	6,432	2,322
IL-IN	7,732	-4,287	6,860	1,900
IL-KT	1,263	-233	8,689	68

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Table 5.3-23: Native Voltage with DC Strategy State Interface Summary (All Lines 230 kV and Greater)

Interface	Max Power Flow (MW)	Min Power Flow (MW)	# of Hours Positive	# of Hours Negative
IL-MO	3,276	-1,663	6,451	2,304
IL-OH	8,000	0	8,397	0
IN-OH	6,085	-2,977	7,712	1,046
MI-IN	4,813	-3,096	5,020	3,735
MI-OH	4,775	-2,606	6,619	2,138
MN-DAK	716	-5,530	103	8,657
MN-IA	1,854	-2,688	2,013	6,737
MN-IL	6,400	0	8,300	0
MN-MHEB	922	-903	23	8,737
MN-WI	2,119	-1,137	8,233	527
OH-PA	2,309	-3,685	3,974	4,784
WI-IL	1,599	-2,213	3,259	5,500
WI-MI	1,819	-1,655	7,081	1,679
* Positive numbers represent flows from A to B (Dak to MHEB) while negative numbers represent flow from B to A (MHEB to Dak).				

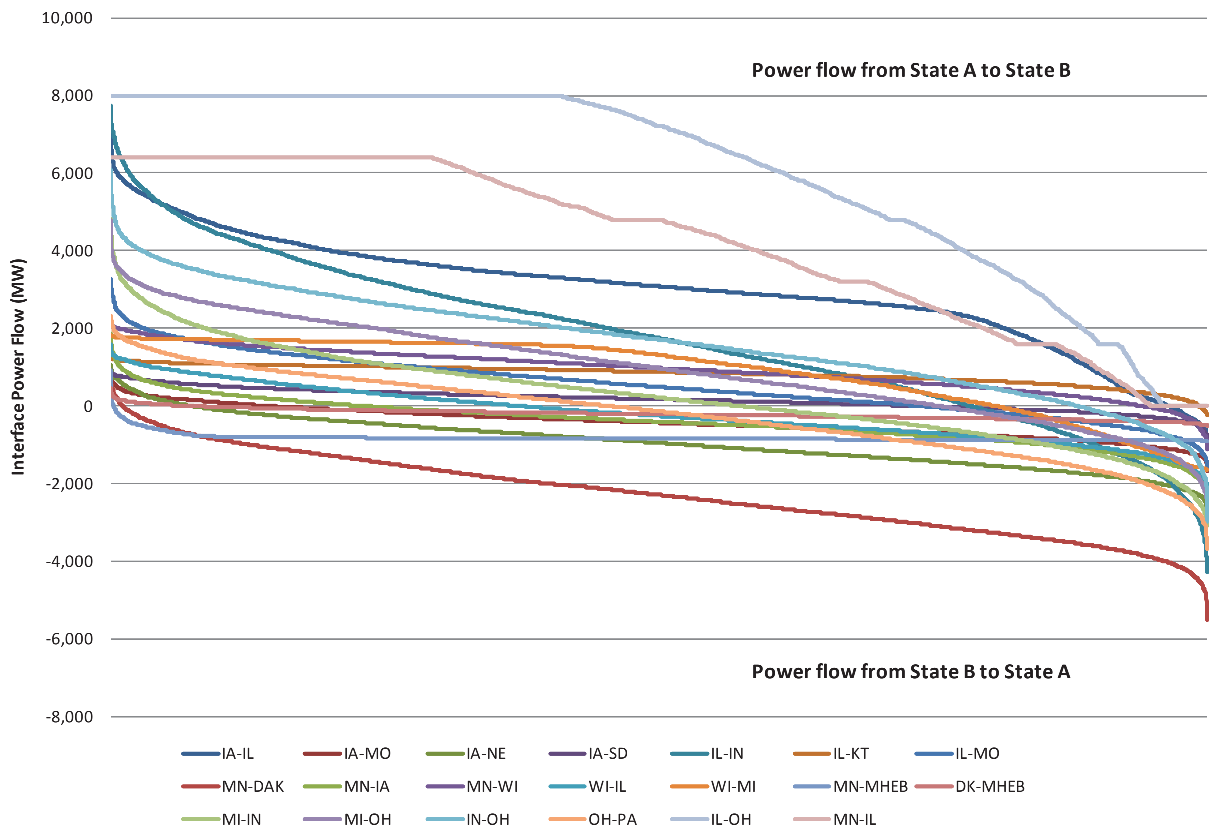

Figure 5.3-22: Native Voltage with DC Strategy State Interface Duration Curves (All lines 230 kV and Greater)

5.3.9 Sensitivity Analysis for RGOS Plans - Robustness Testing

With intensive stakeholder collaboration taking place under the Technical Review Group (TRG), three (3) distinct long-term transmission expansion scenarios have been developed to meet state renewable energy standards and goals encompassing the entire study footprint, as discussed in section 5. In parallel with RGOS study process, a collaborative effort on robust business case development has been undertaken through the MTEP10 planning process to enable a more holistic value assessment of transmission projects or portfolios. The sensitivity analysis for the three (3) RGOS plans has been performed within the context of the MTEP process to facilitate the business case development for new transmission.

The primary focus of sensitivity analysis effort is to determine the total values of the three (3) proposed transmission plans by means of a robustness testing process. To perform robustness testing, each of the three transmission solutions is assessed against a set of value measures across a broad range of plausible future scenarios. As a result, robustness testing under multiple futures provides additional quantifiable benefits to ensure a more complete evaluation on the performance of the three (3) transmission scenarios, and aid in identifying the best-fit long-term strategy which will result in the least future regrets regardless of policy decisions.

Recognizing the need for consideration of additional value measures and further methodology development in transmission business case analysis, the overall benefits of the three long-term strategies identified through the robustness testing process are indicative and are subject to change depending on the assumptions made to quantify the identified value measures and additional value measure inclusion. Without further development of value measure methodology including both financially quantifiable measures and non-financial measures, it will be premature to determine the overall comparative benefits of the RGOS transmission plans and select the definitive long-term strategy. However, with the substantial amount of valuable information resulting from sensitivity analysis, it allows policy makers and stakeholders to recognize that there is a broader set of values beyond satisfying public policy needs to support the implementation of regional plans.

5.3.9.1 Future Scenario Selection and Weights

The Planning Advisory Committee Process (PAC) developed an array of future scenarios (Futures). RGOS used the following:

- **S1: CARP Business As Usual with high Demand and Energy Growth Rates:** Considered the status quo scenario, with a quick recovery from the economic downturn in demand and energy projections. This future scenario models the power system as it exists today with reference values and trends with the exception of demand and energy growth rates.
- **S2: CARP Federal RPS:** Requires that 20% of the energy consumption in the Eastern Interconnect come from renewable resources by 2025. State mandates are the same as those modeled in the Business as Usual Future and any additional renewable energy is met with wind to satisfy the 20% renewable energy requirement.
- **S4: CARP Federal RPS, Carbon Cap and Trade, Smart Grid and Electric Cars:** Combines the impact of multiple future policy scenarios into one future. Smart grid is modeled within the demand growth rate. It is assumed that an increased penetration of smart grid will lower the overall growth of demand. Electric vehicles are modeled within the energy growth rate. Electric vehicles are assumed to increase off-peak energy usage and as such increase the overall energy growth rate.
- **S8: PAC Business as Usual with Mid-Low Demand and Energy Growth Rates:** Considered the status quo future scenario and continues the economic downturn-affected growth in demand, energy, and inflation rates.
- **S10: PAC Carbon Cap and Trade with Nuclear:** Models a declining cap on future CO2 emissions with an aggressive nuclear build out as carbon neutral resources.

The flexibility provided by the multi-dimensional scenario planning analysis allows a more complete robustness analysis around the long-term transmission plans. The weighting of the futures and how a transmission plan performs based on the assigned weights must be taken into account in order to more accurately select the appropriate strategy. To achieve this end, Planning Advisory Committee (PAC) sectors were requested to provide weights for the selected futures based on the possibility of each future relative to the others. The straight sector average weights assigned to each future are tabulated in Table 5.3-24.

Table 5.3-24: Future Scenario PAC Sector Average Weights

Future Scenarios	Weights
S8: PAC Business as Usual Mid-Low D+E	34%
S2: CARP Federal RPS Future	26%
S10: PAC Carbon Future - Carbon Cap with Nuclear	15%
S1: CARP Business as Usual with high growth rate for D+E	14%
S4: CARP Federal RPS + Carbon Cap + Smart Grid + Electric Cars	11%

5.3.9.2 Robustness Testing Process and Value Measures

As illustrated in Figure 5.3-23, robustness testing involves a comprehensive value assessment for transmission solutions utilizing a decision tree based methodology. To perform robustness testing, each transmission solution is tested across multiple future scenarios which it might not be designed for. The value of the transmission for each given future is then evaluated and quantified against a complete set of value measures. By applying the assigned future weights to the values derived from each future, the overall weighted average value is determined for each transmission solution. The ultimate goal of robustness testing is to identify the preferred transmission strategy that can provide the best value under most, if not all, future outcomes in order to minimize the risk associated with the various uncertainties surrounding policy discussions.

The Midwest ISO utilizes PROMOD IV®, a commercial production cost model, to evaluate potential economic benefits of transmission plans. Production cost model simulations are performed with and without each developed transmission scenario. Taking the difference between these two (2) simulation results provides the economic benefits associated with each specific plan.

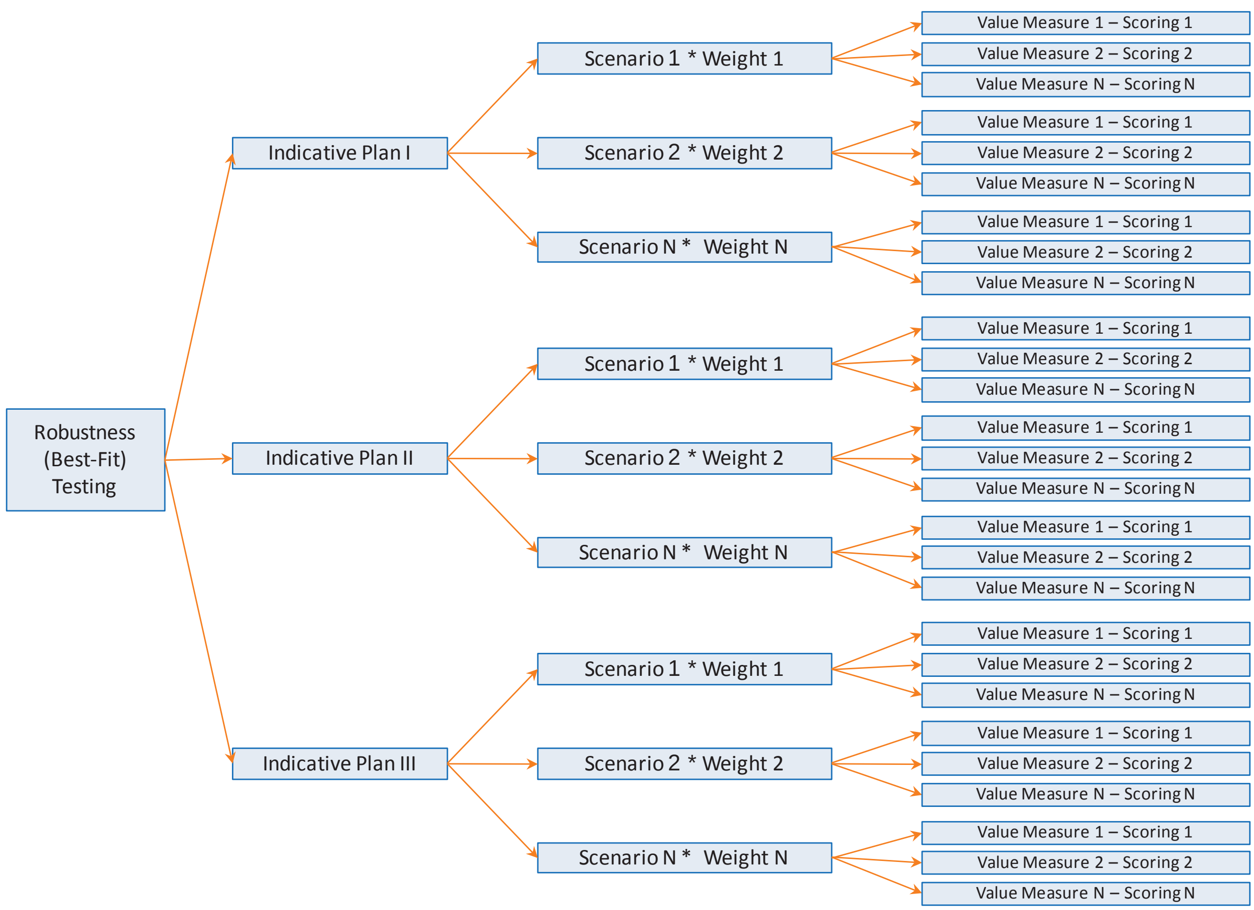

Figure 5.3-23: Indicative Robustness Testing Decision Tree Diagram

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As a key component of transmission value assessment, the following financially quantifiable measures have been considered for making comparisons on the performance of the three (3) RGOS plans:

a. **Adjusted Production Cost Savings** where total annual generation production costs include fuel, variable operations and maintenance (O&M) and start up costs, and are adjusted with off-system purchases and sales. The off-system purchases and sales are quantified using load weighted LMP and gen weighted LMP respectively. Adjusted production cost savings can be achieved through reduction of transmission congestion costs and more efficient generation resource utilization.

b. **Load Cost Savings** where load cost represents the annual load payments, measured by projections in hourly load weighted LMP. Load cost savings and adjusted production cost savings are essentially two alternative benefit measures to address the single type of economic value and are not additive measures. Load cost savings is not used to calculate the total value of the RGOS plans in MTEP10.

c. **Capacity Loss Savings** where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour. The intent is to capture the value of reducing the amount of capacity reserves that are required to maintain system reliability. The avoided capacity investment due to loss reduction is quantified using a generic overnight construction cost of $960,000 per MW.

d. **Capacity Savings Due to Planning Reserve Margin Reduction:** The intent of this measure is to capture the value associated with transmission plans by potentially lowering the overall Planning Reserve Margin requirement through congestion relief. Recognizing a relatively small reduction in reserve requirement would allow a significant amount of benefits to accrue, this measure is under consideration for inclusion in future evaluation of transmission plans/portfolios.

e. **Carbon Emission Reduction Cost Savings:** To address carbon reduction legislation in some future scenarios, a certain cost on carbon is placed combined with uneconomic coal retirement deployment to achieve the high level carbon reductions. The cost of carbon is modeled in a way to only impact the unit dispatch as a penalty and exclude the costs associated with carbon emissions from production costs. The benefits of carbon emission reduction are additive to the adjusted production cost savings described above. The corresponding carbon cost modeled in each scenario is used to quantify the dollar value of carbon emission reductions.

f. **Generation Revenue Due to Wind Curtailment Reduction:** With the new transmission corridors to access the remote wind resources, the curtailment level of wind energy is minimized substantially, particularly for the futures with aggressive RPS requirements. The revenue is quantified using annual generation weighted LMP for the RGOS footprint as an estimate. The intent of this measure is only to provide a standalone value associated with wind curtailment reduction and is not included in the overall value calculation, as this value is embedded in adjusted production cost savings described above.

Robustness testing for the three (3) long-term strategies has been focused on financially quantifiable measures as a starting point. There are other benefit measures including qualitative and risk factors that need to be taken into account to provide a more thorough analysis and allow a more complete value to be captured through the robust business case development process. Midwest ISO will continue to collaborate with stakeholders on further development of value measures as an ongoing effort in the next few planning cycles.

5.3.9.3 RGOS Transmission Plan Value Assessment Results

From the aforementioned list of financially quantifiable measures, only the mutually exclusive or additive measures were used to calculate the total value of RGOS transmission plans to avoid overstating the value of the plans. The straight sum of adjusted production cost savings, capacity loss savings and carbon emission reduction cost savings were used to determine the value of each plan for a given future scenario. Although the capacity savings due to PRM reduction is additive, it has not been evaluated due to time constraints. The overall aggregated financially quantifiable value for each RGOS plan is then determined by applying the PAC-assigned future weights to the value derived for each future. The total financially quantifiable value results for the three (3) RGOS plans are indicative, subject to change depending on the assumptions made to quantify the identified value measures and additional value measure inclusion. In general, the additive financially quantifiable benefits are considered for transmission value assessment. However, for the potential market efficiency projects, the RECBII economic benefit metric, a blend of 70% adjusted project cost benefit and 30% load cost savings, is still in place for transmission value evaluation. Specifically, the financially quantifiable value of each RGOS transmission plan was determined as follows:

Value of transmission plan (per future) = Sum of values of financially quantifiable measures

= Adjusted production cost savings + Capacity loss savings + Carbon emission reductions[4]

Value of transmission plan (overall) = Sum of value of the plan per future * future weights

=34%*Scenario 8 +15%*Scenario 10+14%*Scenario 1+26%*Scenario 2+11%*Scenario 4

For each RGOS transmission plan, the value of each individual financially quantifiable measure under each given future, the total value per future and the overall weighted value are succinctly illustrated through the decision tree diagrams in Figures 5.3-24–5.3-26.

[4] The capacity savings due to PRM reduction is additive and is under development for inclusion in the total value evaluation.

Looking at the results, a wide range of potential benefits are achieved across the five (5) selected futures. Based on the robustness analysis process described above, the three RGOS plans are expected to bring an annual weighted financially quantifiable benefits ranging from $1,064 million to $1,830 million in year 2025 for RGOS study footprint. It is important to reiterate that values derived in this section are indicative and have only been used for the purpose of performance comparison among the three (3) long-term transmission strategies.

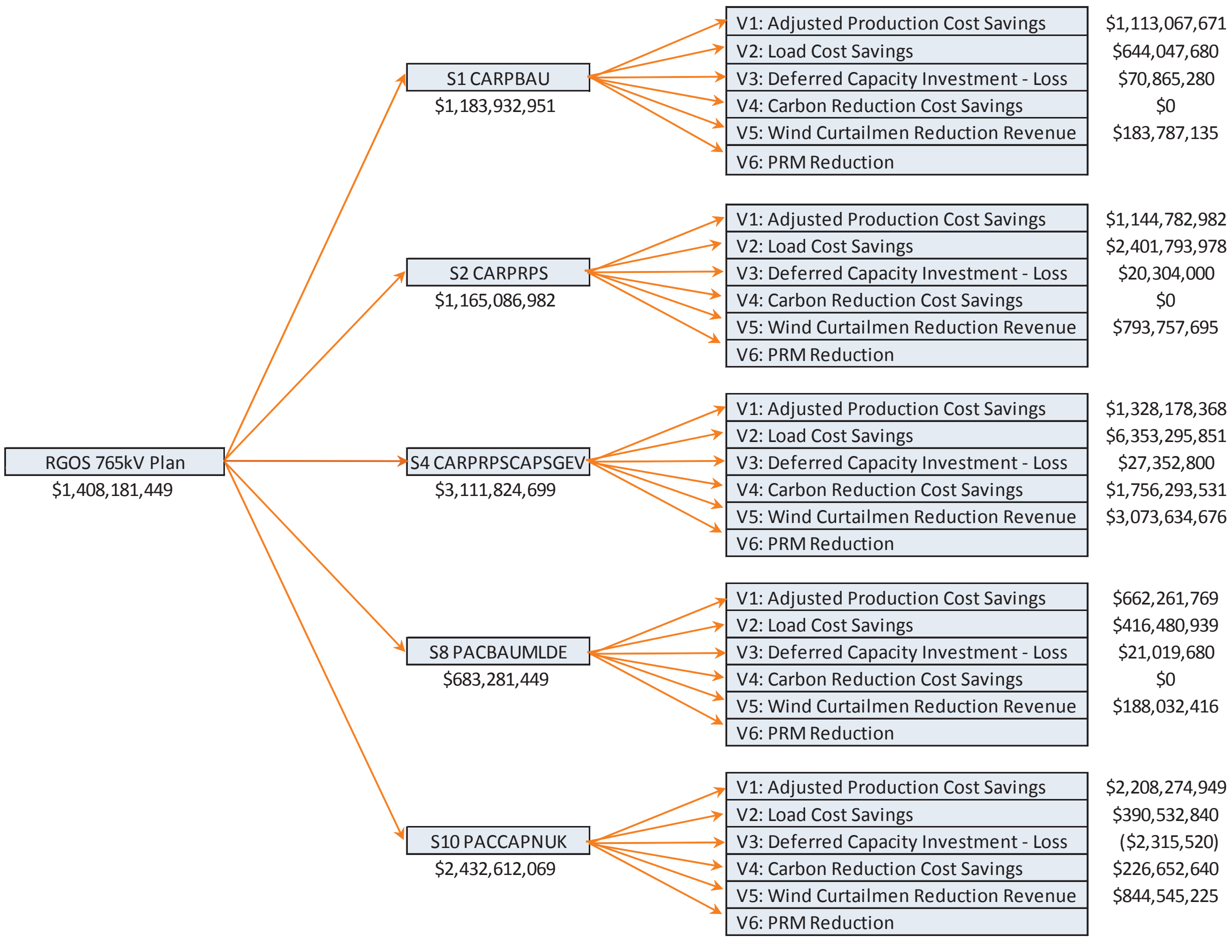

Figure 5.3-24: Indicative RGOS 765kV Plan Robustness Testing Results[5]

[5] The RGOS transmission plans are still in development and the plan version used for robustness testing is as of May 25, 2010. All the results illustrated in the diagram are **2025 annual benefits** and are calculated for RGOS study footprint.

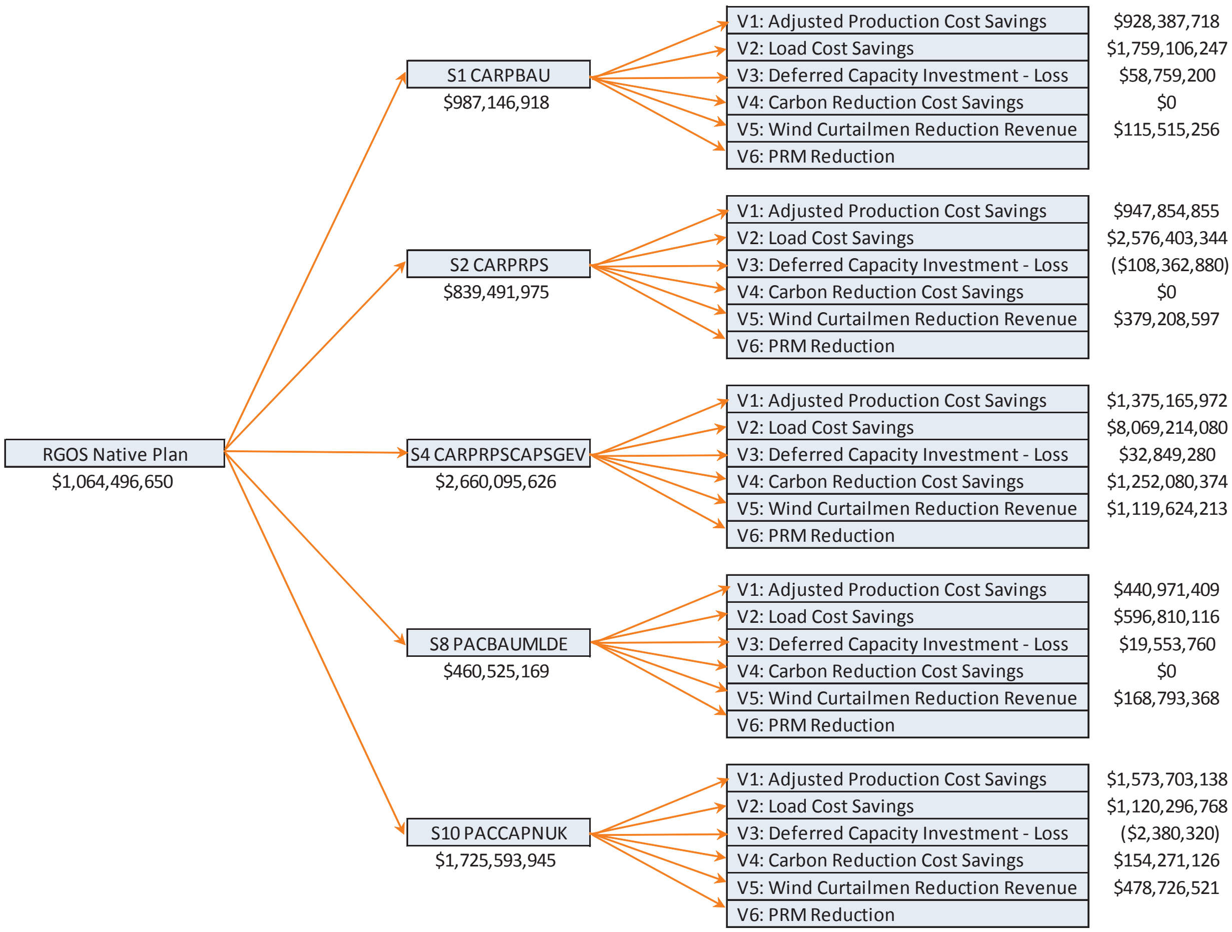

Figure 5.3-25: Indicative RGOS Native Voltage Plan Robustness Testing Results[6]

[6] The RGOS transmission plans are still in development and the plan version used for robustness testing is as of May 25, 2010. All the results illustrated in the diagram are **2025 annual benefits** and are calculated for RGOS study footprint.

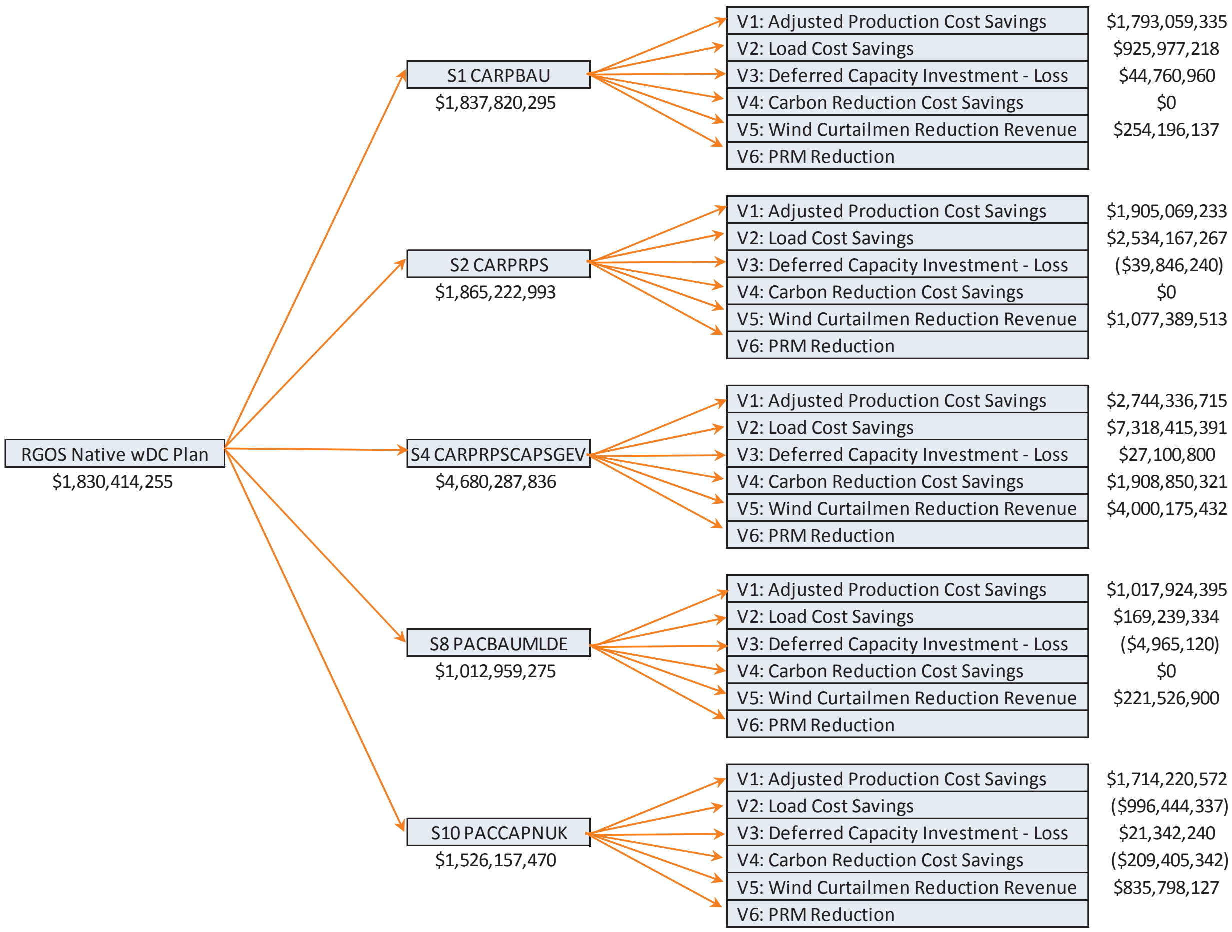

Figure 5.3-26: Indicative RGOS Native Voltage with DC Plan Robustness Testing Results[7]

[7] The RGOS transmission plans are still in development and the plan version used for robustness testing is as of May 25, 2010. All the results illustrated in the diagram are **2025 annual benefits** and are calculated for RGOS study footprint.

Table 5.3-25 summarizes the annual costs, financially quantifiable values, and benefit-to-cost ratios associated with each of the three (3) RGOS transmission plans. It shows the Native with DC option provides the highest benefit-to-cost ratio based on an annual analysis in year 2025. However, before determining an overall definitive long-term transmission strategy, an expanded business case analysis has to be in place with consideration of a more complete list of value measures. Each RGOS plan has its own risks and other pertinent factors that may significantly impact the way the preferred long-term strategy is identified, as described in section 1.

Table 5.3-25: RGOS Transmission Plan Cost and Benefit Comparison - 2025 USD in Millions

Transmission Plan Options	2025 Annual Transmission Cost [8]	2025 Annual Total Financially Quantifiable Value [9]	2025 B/C Ratio [10]
RGOS 765kV	4,684	1,408	0.30
RGOS Native	3,816	1,064	0.28
RGOS Native With DC	4,868	1,830	0.38

Table 5.3-26 shows results of some additional quantifiable benefits, not necessarily financially quantifiable, that can be incorporated into the decision-making process. Moving forward, Midwest ISO will continue to refine the list of value measures and develop a methodology to better utilize non-financially quantifiable value measures, as well as ensure extensive stakeholder involvement throughout the process.

Table 5.3-26: RGOS Transmission Plan Comparison – Other Quantifiable Measures

Transmission Plan Options	Acres of Right-of-way	Hourly Transmission Utilization (%) [11]
RGOS 765kV	136,637	17%
RGOS Native	126,637	16%
RGOS Native With DC	150,094	21%

[8] Annual cost in 2025$ is calculated using 18.3% the Midwest ISO annual average charge rate based 2010 attachment O and 3% escalation rate. The RGOS plans are assumed to be in service at 2019. It is important to note that the cost estimates are used for benefit-to-cost ratio calculation only.

[9] The total financially quantifiable value numbers are indicative and are subject to change depending on the assumptions on how to quantify the identified value measures and additional value measure development.

[10] The benefit-to-cost ratios are indicative and calculated using 2025 annual values only, **not** present values. The results are only intended to provide the comparison between transmission plans relative to each other.

[11] The percentage of hourly new transmission utilization is calculated for the CARPBAU future only, using the straight average of the hourly flows on the new RGOS transmission lines divided by the ratings.

6 Construction Cost Estimates

6.1 Estimating Assumptions

Cost of construction assumptions were developed through the study stakeholder process. Several assumptions were used to determine both capital and present value costs associated with the generation and transmission overlays developed. Table 6.1-1 and Table 6.1-2 summarize capital expenditures. Not shown in the tables is the cost for wind generation, which is $2M per MW (2010 USD).

Table 6.1-1: Line Mile Costs - $M/mile (2010 USD)

kV	IA	IL	IN	MI	MN	MO	MT	ND	OH	SD	WI
345	$1.6	$1.5	$2.0	$1.8	$1.8	$0.9	$1.4	$1.4	$2.0	$1.4	$2.1
2-345	$2.3	$2.0	$2.0	$2.7	$2.5	$2.3	$1.9	$1.9	$2.0	$1.9	$2.7
500	$2.1	$1.8	$1.8	$0.0	$2.4	$1.8	$1.8	$1.8	$1.8	$1.8	$2.8
765	$3.2	$2.8	$2.8	$3.6	$3.5	$3.2	$2.8	$2.8	$2.8	$2.8	$4.0
230	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
161	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
138	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
115	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
DC (OH)	$2.2	OH - Overhead Construction									
DC (Mar)	$3.0	Mar - Marine									

Table 6.1-2: Substation Costs (2010 USD)

kV	# Bays	($M)
115	2	$9.0
138	2	$9.0
161	2	$9.0
230	2	$9.0
345	2	$11.8
765	2	$25.1
DC Station +/-800 kV - Bi-Pole, 6400 MW		$549.0
DC Station +/- 400 kV - Bi-Pole 1000 MW		$340.0
Two bays (3 CBs)		

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Table 6.1-3: Transformer Costs (2010 USD)

kV	($M)
765/345	$28.2
765/161	$20.7
765/138	$20.7
765/115	$20.7
345/230	$6.5
345/161	$5.7
345/138	$5.7
345/115	$5.7
Note 765 Transformers include on-site spare.	

Table 6.1-4: Reactive Costs (2010 USD)

kV	($M/MVAR)
345	$0.0224
765	$0.0560

Other factors used in developing capital costs included using a 50% multiplier for additions to existing substations. Existing substations were costed at half the price of a new substation unless more than two (2) bays were added, in which case no multiplier was applied. All transmission rebuilds were priced as new construction and a 1.1 multiplier was applied to all line mileages to account for adjustments in right-of-way calculations. River crossing costs included $14.0M (2010 USD) for each crossing of the Mississippi River and $7.0M for the Missouri River. Cost factors used to perform net present value calculations are shown in Tables 6.1-5 and 6.1-6.

Table 6.1-5: Net Present Value Factors

Value Factor	Generation	Transmission
Income Tax Rate	40.0%	40.0%
Inflation Rate	3.0%	3.0%
Book Life	20	40
Salvage	0	0

Table 6.1-5: Net Present Value Factors

Value Factor	Generation	Transmission
Tax Life	15	15
Discount Rate	7.0%	7.0%
O&M (% of Investment)	0.20%	0.20%

Table 6.1-6: Net Present Capitalization Cost Factors

Capitalization	Ratio of Fund	Cost of Fund
Bonds	50.00%	6.00%
Preferred	0.00%	7.50%
Common	50.00%	13.38%
Short Term Debt	0.00%	5.00%

6.2 Transmission Scenario Overlay Cost Estimate Results

Cost values were calculated on three levels, 2010 Capital, 2010 Levelized Annual and 2010 $/MWh (2010 USD) for generation and each of the three transmission overlays, Native Voltage (345 kV), 765 kV and Native DC. Capital costs represent the dollar amount if an entire overlay was built and paid for today. The levelized annual cost represents an equal payment to be made each year for the life of the respective overlay if the overlay was financed via typical utility options (represented by Table 6.2-1). A $/MWh value was calculated by dividing the 2010 levelized annual costs by the total annual delivered wind energy from the renewable energy zones.

Important in these calculations was the disbursement of capital dollars across the future investment horizon. An overlay of this magnitude will be constructed across several years. When that money will be spent is not yet known, so assumptions must be made. The assumption used is that the earliest investment would be in 2015 and the latest would be 2025. As noted in Section 1.4 Starter Projects, a set of initial transmission projects have been identified. The total costs for these initial projects were spread over the 2015-2018 horizon. Remaining overlay costs were then equally apportioned through 2025 for each overlay, respectively. For generation investment, the generation capital was rationed from 2015 through 2025 based on RPS requirements.

Line miles and substation costs were calculated on a state-by-state basis as well as Midwest ISO vs PJM. Transmission lines that had end point substations in both the Midwest ISO were considered a Midwest ISO investment and likewise for PJM. Some costs however, such as AC lines where the end substations were in different RTO’s were calculated as Joint transmission investment. DC transmission and substations were calculated on a state-by-state basis, however, were also labeled as Joint with respect to Midwest ISO vs PJM.

Refer to Tables 6.2-1 to 6.2-7 on the following pages, which provide a detailed capital cost and net present value summary.

Table 6.2-1: Native Voltage (345 kV) 2010 Capital Costs

		IA	IL	IN	MI	MN	MO	MT	ND	OH	SD	WI	Total
New AC Transmission		$2,280	$1,051	$962	$222	$2,211	$317	$52	$1,435	$1,036	$855	$2,073	$12,495
	Midwest ISO	$2,280	$504	$372	$222	$2,211	$317	$52	$1,435	$380	$855	$2,073	$10,702
	PJM	$0	$547	$410	$0	$0	$0	$0	$0	$352	$0	$0	$1,309
	Joint	$0	$0	$180	$0	$0	$0	$0	$0	$304	$0	$0	$484
Upgraded AC Transmission		$196	$261	$165	$75	$0	$0	$0	$48	$40	$91	$116	$993
	Midwest ISO	$196	$56	$165	$75	$0	$0	$0	$48	$0	$91	$116	$748
	PJM	$0	$205	$0	$0	$0	$0	$0	$0	$40	$0	$0	$245
	Joint	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total AC Transmission		$2,476	$1,312	$1,127	$297	$2,211	$317	$52	$1,483	$1,076	$945	$2,190	$13,487
	Midwest ISO	$2,476	$560	$537	$297	$2,211	$317	$52	$1,483	$380	$945	$2,190	$11,449
	PJM	$0	$753	$410	$0	$0	$0	$0	$0	$391	$0	$0	$1,554
	Joint	$0	$0	$180	$0	$0	$0	$0	$0	$304	$0	$0	$484
DC Transmission (Joint)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
River Crossings (Midwest ISO)		$14	$14	$0	$0	$14	$7	$0	$14	$0	$0	$14	$77
AC Substations		$396	$291	$162	$120	$169	$169	$46	$413	$451	$121	$399	$2,737
	Midwest ISO	$396	$215	$96	$120	$169	$169	$46	$413	$195	$121	$399	$2,338
	PJM	$0	$77	$66	$0	$0	$0	$0	$0	$256	$0	$0	$398
DC Substations (Joint)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total		$2,887	$1,618	$1,289	$417	$2,394	$493	$98	$1,910	$1,526	$1,066	$2,603	$16,301
	Midwest ISO	$2,887	$788	$633	$417	$2,394	$493	$98	$1,910	$575	$1,066	$2,603	$13,865
	PJM	$0	$829	$476	$0	$0	$0	$0	$0	$647	$0	$0	$1,952
	Joint	$0	$0	$180	$0	$0	$0	$0	$0	$304	$0	$0	$484
	DC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Table 6.2-2: Native Voltage (345 kV) 2010 Net Present Value

	Capital Costs in 2010 USD ($M)				NPV of Revenue Requirements (2010, $M)			
Year	**Midwest ISO**	**PJM**	**Joint**	**Total**	**Midwest ISO**	**PJM**	**Joint**	**Total**
2015	$1,047	$257	$121	$1,424	$1,382	$339	$160	$1,880
2016	$1,047	$257	$121	$1,424	$1,330	$326	$154	$1,810
2017	$1,047	$257	$121	$1,424	$1,280	$314	$148	$1,742
2018	$1,047	$257	$121	$1,424	$1,233	$302	$142	$1,677
2019	$1,382	$132	$0	$1,515	$1,567	$150	$0	$1,717
2020	$1,382	$132	$0	$1,515	$1,508	$144	$0	$1,652
2021	$1,382	$132	$0	$1,515	$1,452	$139	$0	$1,591
2022	$1,382	$132	$0	$1,515	$1,397	$134	$0	$1,531
2023	$1,382	$132	$0	$1,515	$1,345	$129	$0	$1,474
2024	$1,382	$132	$0	$1,515	$1,295	$124	$0	$1,419
2025	$1,382	$132	$0	$1,515	$1,247	$119	$0	$1,366
Total	$13,865	$1,952	$484	$16,301	$15,036	$2,219	$604	$17,859
Levelized Annual Cost					$1,419	$209	$57	$1,686
$/MWh					$16.0	$2.4	$0.6	$19.0

Table 6.2-3: 765 kV 2010 Capital Costs

Transmission Type		IA	IL	IN	MI	MN	MO	MT	ND	OH	SD	WI	Total
New AC Transmission		$3,592	$2,206	$1,115	$222	$1,924	$1,732	$52	$1,477	$965	$722	$1,313	$15,322
	Midwest ISO	$3,592	$476	$10	$222	$1,924	$1,514	$52	$1,477	$375	$722	$1,264	$11,629
	PJM	$0	$1,514	$418	$0	$0	$218	$0	$0	$588	$0	$0	$2,738
	Joint	$0	$215	$687	$0	$0	$0	$0	$0	$3	$0	$49	$955
Upgraded AC Transmission		$367	$112	$0	$0	$0	$8	$0	$18	$0	$337	$150	$992
	Midwest ISO	$167	$112	$0	$0	$0	$0	$0	$0	$0	$159	$150	$588
	PJM	$201	$0	$0	$0	$0	$8	$0	$18	$0	$177	$0	$404
	Joint	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total AC Transmission		$3,959	$2,318	$1,115	$222	$1,924	$1,741	$52	$1,495	$965	$1,059	$1,463	$16,314
	Midwest ISO	$3,758	$588	$10	$222	$1,924	$1,514	$52	$1,477	$375	$882	$1,415	$12,217
	PJM	$201	$1,514	$418	$0	$0	$226	$0	$18	$588	$177	$0	$3,142
	Joint	$0	$215	$687	$0	$0	$0	$0	$0	$3	$0	$49	$955
DC Transmission (Joint)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
River Crossings (Midwest ISO)		$14	$14	$0	$0	$14	$7	$0	$14	$0	$0	$14	$77
AC Substations		$435	$718	$214	$146	$584	$344	$41	$447	$379	$205	$346	$3,858
	Midwest ISO	$435	$106	$50	$146	$584	$344	$41	$447	$101	$205	$346	$2,805
	PJM	$0	$612	$164	$0	$0	$0	$0	$0	$278	$0	$0	$1,054
DC Substations (Joint)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total		$4,408	$3,049	$1,329	$367	$2,522	$2,092	$94	$1,956	$1,344	$1,263	$1,823	$20,249
	Midwest ISO	$4,207	$708	$60	$367	$2,522	$1,866	$94	$1,938	$476	$1,086	$1,775	$15,099
	PJM	$201	$2,126	$582	$0	$0	$226	$0	$18	$865	$177	$0	$4,196
	Joint	$0	$215	$687	$0	$0	$0	$0	$0	$3	$0	$49	$955
	DC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Table 6.2-4: 765 kV 2010 Net Present Value

	Capital Costs in 2010 USD ($M)				NPV of Revenue Requirements (2010, $M)			
Year	**Midwest ISO**	**PJM**	**Joint**	**Total**	**Midwest ISO**	**PJM**	**Joint**	**Total**
2015	$1,047	$257	$121	$1,424	$1,382	$339	$160	$1,880
2016	$1,047	$257	$121	$1,424	$1,330	$326	$154	$1,810
2017	$1,047	$257	$121	$1,424	$1,280	$314	$148	$1,742
2018	$1,047	$257	$121	$1,424	$1,233	$302	$142	$1,677
2019	$1,559	$453	$67	$2,079	$1,767	$513	$76	$2,356
2020	$1,559	$453	$67	$2,079	$1,700	$494	$73	$2,268
2021	$1,559	$453	$67	$2,079	$1,637	$476	$71	$2,183
2022	$1,559	$453	$67	$2,079	$1,576	$458	$68	$2,101
2023	$1,559	$453	$67	$2,079	$1,517	$441	$65	$2,023
2024	$1,559	$453	$67	$2,079	$1,460	$424	$63	$1,947
2025	$1,559	$453	$67	$2,079	$1,406	$408	$61	$1,874
Total	$15,099	$4,196	$955	$20,249	$16,287	$4,494	$1,081	$21,862
				Levelized Annual Cost	$1,537	$424	$102	$2,064
				$/MWh	$17.4	$4.8	$1.2	$23.3

Table 6.2-5: Native DC 2010 Capital Costs

Transmission Type		IA	IL	IN	MI	MN	MO	MT	ND	OH	SD	WI	Total
New AC Transmission		$1,967	$1,271	$735	$1,013	$1,906	$383	$52	$1,684	$1,279	$928	$851	$12,070
	Midwest ISO	$1,967	$681	$255	$1,013	$1,906	$383	$52	$1,684	$419	$928	$851	$10,140
	PJM	$0	$590	$480	$0	$0	$0	$0	$0	$587	$0	$0	$1,657
	Joint	$0	$0	$0	$0	$0	$0	$0	$0	$273	$0	$0	$273
Upgraded AC Transmission		$0	$126	$20	$109	$0	$0	$0	$0	$40	$0	$297	$592
	Midwest ISO	$0	$111	$20	$109	$0	$0	$0	$0	$0	$0	$297	$537
	PJM	$0	$15	$0	$0	$0	$0	$0	$0	$40	$0	$0	$55
	Joint	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total AC Transmission		$1,967	$1,397	$755	$1,123	$1,906	$383	$52	$1,684	$1,319	$928	$1,148	$12,662
	Midwest ISO	$1,967	$792	$275	$1,123	$1,906	$383	$52	$1,684	$419	$928	$1,148	$10,677
	PJM	$0	$605	$480	$0	$0	$0	$0	$0	$627	$0	$0	$1,712
	Joint	$0	$0	$0	$0	$0	$0	$0	$0	$273	$0	$0	$273
DC Transmission (Joint)		$1,079	$719	$837	$121	$269	$539	$0	$0	$239	$11	$121	$3,935
River Crossings (Midwest ISO)		$14	$14	$0	$0	$14	$7	$0	$14	$0	$0	$14	$77
AC Substations		$170	$356	$127	$299	$161	$112	$46	$446	$387	$105	$124	$2,334
	Midwest ISO	$170	$268	$68	$287	$161	$112	$46	$446	$121	$105	$124	$1,908
	PJM	$0	$89	$59	$13	$0	$0	$0	$0	$266	$0	$0	$426
DC Substations (Joint)		$549	$412	$0	$170	$275	$0	$0	$0	$686	$275	$170	$2,536
Total		$3,778	$2,899	$1,719	$1,713	$2,626	$1,042	$98	$2,144	$2,631	$1,319	$1,577	$21,544
	Midwest ISO	$2,150	$1,074	$343	$1,409	$2,082	$502	$98	$2,144	$540	$1,033	$1,286	$12,662
	PJM	$0	$694	$539	$13	$0	$0	$0	$0	$893	$0	$0	$2,138
	Joint	$0	$0	$0	$0	$0	$0	$0	$0	$273	$0	$0	$273
	DC	$1,628	$1,131	$837	$291	$544	$539	$0	$0	$925	$286	$291	$6,471

Table 6.2-6: Native DC 2010 Net Present Value

	Capital Costs in 2010 USD ($M)				NPV of Revenue Requirements (2010, $M)			
Year	**Midwest ISO**	**PJM**	**Joint/DC**	**Total**	**Midwest ISO**	**PJM**	**Joint/DC**	**Total**
2015	$1,047	$257	$121	$1,424	$1,382	$339	$160	$1,880
2016	$1,047	$257	$121	$1,424	$1,330	$326	$154	$1,810
2017	$1,047	$257	$121	$1,424	$1,280	$314	$148	$1,742
2018	$1,047	$257	$121	$1,424	$1,233	$302	$142	$1,677
2019	$1,211	$159	$894	$2,264	$1,372	$180	$1,014	$2,566
2020	$1,211	$159	$894	$2,264	$1,321	$173	$976	$2,470
2021	$1,211	$159	$894	$2,264	$1,271	$167	$939	$2,377
2022	$1,211	$159	$894	$2,264	$1,224	$161	$904	$2,288
2023	$1,211	$159	$894	$2,264	$1,178	$155	$870	$2,203
2024	$1,211	$159	$894	$2,264	$1,134	$149	$838	$2,121
2025	$1,211	$159	$894	$2,264	$1,092	$143	$806	$2,041
Total	$12,662	$2,138	$6,744	$21,544	$13,816	$2,408	$6,950	$23,175
				Levelized Annual Cost	$1,304	$227	$656	$2,188
				$/MWh	$14.7	$2.6	$7.4	$24.7

Table 6.2-7: Generation 2010 Net Present Value

	Capital Costs in 2010 USD ($M)			NPV of Revenue Requirements (2010, $M)		
Year	**Midwest ISO**	**PJM**	**Total**	**Midwest ISO**	**PJM**	**Total**
2015	$22,305	$3,990	$26,289	$28,366	$5,074	$33,434
2016	$3,136	$1,007	$4,144	$3,839	$1,233	$5,073
2017	$2,550	$794	$3,344	$3,005	$936	$3,941
2018	$2,947	$1,055	$4,002	$3,343	$1,197	$4,540
2019	$1,394	$835	$2,230	$1,522	$912	$2,435
2020	$2,828	$1,092	$3,921	$2,973	$1,148	$4,122
2021	$3,871	$871	$4,741	$3,917	$881	$4,797
2022	$1,520	$1,154	$2,675	$1,481	$1,124	$2,606
2023	$1,549	$1,183	$2,734	$1,453	$1,109	$2,563
2024	$1,586	$1,210	$2,797	$1,431	$1,092	$2,524
2025	$1,051	$172	$1,223	$914	$149	$1,063
Total	$44,737	$13,363	$58,100	$52,244	$14,856	$67,098
			Levelized Annual Cost	$4,931	$1,402	$6,334
				$/MWh		
			Native Voltage	$55.7	$15.8	$71.5
			765 kV	$55.7	$15.8	$71.5
			Native DC	$55.7	$15.8	$71.5

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7 RGOS 2011 Candidate MVP Portfolio Selection

Although RGOS focused on the development of holistic system solutions meeting long-term needs for the integration of renewable resources into the transmission system, it is important to identify an initial group of projects that are compatible with the three overlays that provide a practical first step towards meeting the renewable resource requirements. Midwest ISO staff has developed an analytical framework to identify the best potential transmission projects. These RGOS-identified projects will require additional, more detailed analysis. Because a Midwest ISO long-range transmission expansion strategy has not yet been determined and was not within the analytical scope of this study, it is important to note that the potential transmission projects do not pre-determine Midwest ISO long-range strategic aims. It is also important to note that these transmission projects prove compatible with all potential strategies.

7.1 Candidate Multi-Value Project Identification Process

The RGOS inputs into the Candidate Multi-Value Projects (MVPs) portfolio were identified by means of the process outlined below. Please note that other studies were considered in collecting the Candidate MVP portfolio; not all of the projects in that portfolio are from the RGOS study effort.

Step 1: Identify useful corridors common to multiple Midwest ISO studies.

Corridors represent general paths for transmission that do not discriminate between voltages or potential intermediate connection points. Studies to be considered when identifying corridors include the following:

- Regional Generation Outlet Study overlay development results
- Generation Interconnection studies:
  - Definitive Planning Phase (DPP)
  - System Planning and Analysis (SPA)
- MTEP related studies:
  - MTEP Appendix B and C projects, which address future reliability concerns
  - Top congested flowgate studies
  - Cross-border top congested flowgate studies
  - Narrowly constrained areas

Step 2: Identify RPS timing needs and synchronize with Generation Interconnection Queue (GIQ) locations.

Refer to Table 7.1-1, which shows renewable portfolio requirements starting in 2015. All states within Midwest ISO with RPS mandates or load-serving entity goals are listed.

Table 7.1-1: Renewable Portfolio Standard Requirements

Year	WI	MN (w/o Xcel)	Xcel MN	IL	MI	OH	MO	MT	PA	SD	ND	IA
	(Of Energy Served)											(MW)
2015	10.0%	12.0%	18.0%	10.0%	10.0%	3.5%	5.0%	15.0%	5.5%	10.0%	10.0%	105
2016	10.0%	17.0%	25.0%	11.5%	10.0%	4.5%	5.0%	15.0%	6.0%	10.0%	10.0%	105
2017	10.0%	17.0%	25.0%	13.0%	10.0%	5.5%	5.0%	15.0%	6.5%	10.0%	10.0%	105
2018	10.0%	17.0%	25.0%	14.5%	10.0%	6.5%	10.0%	15.0%	7.0%	10.0%	10.0%	105
2019	10.0%	17.0%	25.0%	16.0%	10.0%	7.5%	10.0%	15.0%	7.5%	10.0%	10.0%	105
2020	10.0%	20.0%	30.0%	17.5%	10.0%	8.5%	10.0%	15.0%	8.0%	10.0%	10.0%	105
2021	10.0%	20.0%	30.0%	19.0%	10.0%	9.5%	15.0%	15.0%	8.0%	10.0%	10.0%	105
2022	10.0%	20.0%	30.0%	20.5%	10.0%	10.5%	15.0%	15.0%	8.0%	10.0%	10.0%	105
2023	10.0%	20.0%	30.0%	22.0%	10.0%	11.5%	15.0%	15.0%	8.0%	10.0%	10.0%	105
2024	10.0%	20.0%	30.0%	23.5%	10.0%	12.5%	15.0%	15.0%	8.0%	10.0%	10.0%	105
2025	10.0%	25.0%	30.0%	25.0%	10.0%	12.5%	15.0%	15.0%	8.0%	10.0%	10.0%	105

Locations of generation interconnection queue requests to the Midwest ISO transmission system can be seen in Figure 7.1-1. This map represents wind queue locations as of the end of July, 2010.

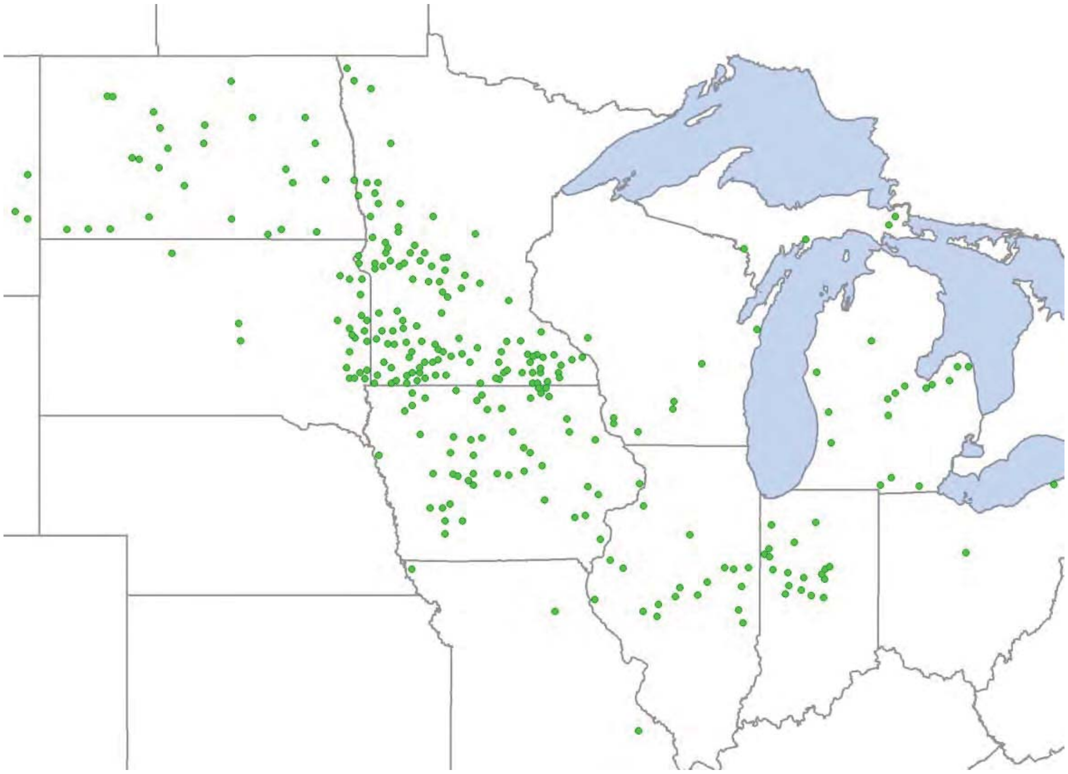

Figure 7.1-1: Location of Midwest ISO Generation Interconnection Queue Requests

Step 3: Evaluate constructability of transmission.

Construction dynamics possibly requiring longer lead times for projects include the following:

- Interstate transmission coordination
- River crossings
- Commonsense coordination of projects; i.e., a group of lines may not make sense until another group is constructed first
- Midwest ISO/PJM cross-border projects

Certain projects may have shorter lead times; for example, when stringing second circuits on "existing" double circuit capable transmission structures.

7.1.1 RGOS-identified Candidate Multi-Value Projects

An initial set of transmission projects was identified using the inspection steps described in section 1, and served as an input into the design of the overall Candidate MVP portfolio. Selected Candidate MVPs are compatible with RGOS-developed overlays and provide potential value for other needs identified within the transmission system, such as congestion relief and mitigation of reliability concerns. Refer to Figure 7.1-2, which depicts Candidate MVPs from the RGOS analysis. Estimated cost for this RGOS Candidate MVP set is approximately $5.8 Billion (2010 USD), $4.4 billion of which is within Midwest ISO borders.

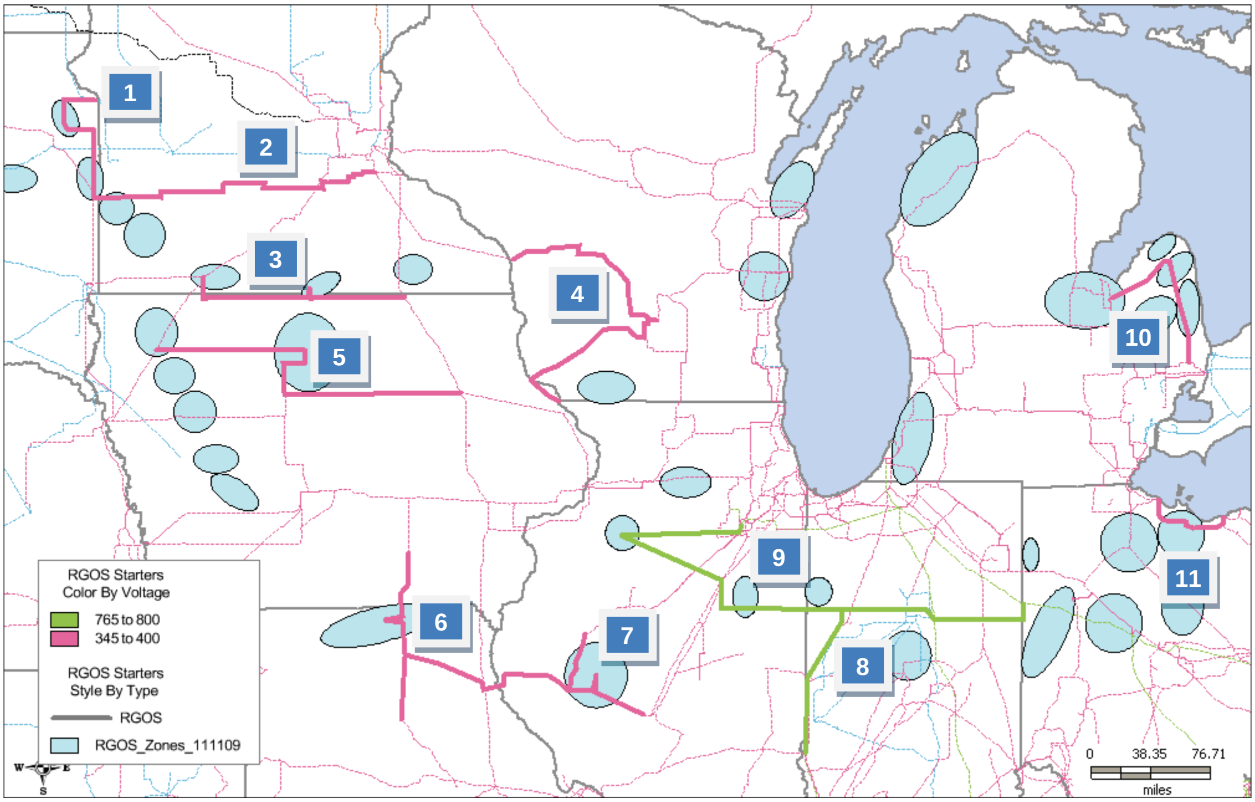

Figure 7.1-2: RGOS-identified Candidate Multi-Value Projects

The following numbered list corresponds to the numbered identifiers in Figure 7.1-2 and furnishes additional details on the rationale guiding specific Candidate MVP selection.

1. **Big Stone to Brookings 345 kV line (2010 estimated installed cost: $150M):** This line provides access to and collection from renewable energy areas located in the eastern South Dakota portion of the Buffalo Ridge area. This corridor is identified in all RGOS overlays at the 345 kV voltage level. The corridor is also compatible with current Generation Interconnection Queue (GIQ) locations.

2. **Brookings to Twin Cities 345 kV line (2010 estimated installed cost: $700M):** This line, as approved the Minnesota Public Utilities Commission, delivers energy from the Buffalo Ridge area to a major load center in the Twin Cities and beyond. This 345 kV project also provides collection points for renewable energy, as well as reliability benefits. This corridor is identified in all RGOS overlay scenarios, although at different voltage levels. Proceeding with 345 kV construction does not negate a long-range 765 kV transmission expansion strategy. The 765 kV strategy can be adjusted to accommodate this selection.

3. **Lakefield Junction to Mitchell County 345 kV line constructed at 765 kV specifications (2010 estimated installed cost: $600M):** This line provides for an additional West to East path for energy delivery from the Buffalo Ridge area. This corridor has been identified in all of the RGOS overlays, as well as in other studies such as the Top Congested Flowgate analysis in the 2009 MTEP process and recent GIQ SPA analysis. This corridor is also compatible to collect resources associated with current GIQ locations. By developing this corridor using 765 kV construction, all potential long-term strategies remain viable.

4. **North LaCrosse to North Madison to Cardinal, Dubuque to Spring Green to Cardinal 345 kV lines (2010 estimated installed cost: $811M):** The development of these corridors will provide for the continuation and extension of the west to east transmission path to provide more areas with greater access to the high wind areas within the Buffalo Ridge and beyond. These corridors are compatible with the RGOS overlays as well as other studies such as the GIQ SPA and DPP studies. These projects can be well-integrated regardless of the long-range transmission expansion strategy adopted by Midwest ISO; e.g., Native Voltage, 765 kV, and 345 kV plus DC.

5. **Sheldon to Webster to Blackhawk to Hazleton 345 kV line (2010 estimated installed cost: $458M):** This set of transmission projects provides both a collection of renewable energy in high wind areas and an additional west to east transmission path for delivery of energy to other parts of the study footprint. This combination of collection and delivery is compatible with the RGOS overlays (with proper adjustments made) and has shown to be compatible with corridors identified within the GIQ SPA studies.

6. **Ottumwa to Adair to Thomas Hill, Adair to Palmyra 345 kV lines (2010 estimated installed cost: $295M):** This set of transmission is compatible with the all RGOS overlays and provides access to quality wind resources within the Midwest ISO footprint in Missouri. This corridor development provides an additional north to south path and begins a new west to east transmission path for energy delivery across the footprint.

7. **Palmyra to Meredosia to Pawnee, Ipava to Meredosia 345 kV lines (2010 estimated installed cost: $345M):** This transmission is compatible with the RGOS overlays and provides access to quality Illinois wind potential located within the Midwest ISO footprint. These lines provide reliability support to the Ipava area with the new 345 kV connections. It also continues the new west to east path that will help bridge some of the market constraints across Illinois.

8. **Sullivan to Meadow Lake to Greentown to Blue Creek 765 kV line (2010 estimated installed cost: $908M):** 765 kV transmission is native to Indiana. This transmission plan is part of the 765 kV overlay but can also be compatible with the other overlays such as the 345 kV lines discussed previously. This transmission provides access to the wind potential in the Benton County area of Indiana and provides an additional west to east energy delivery route. Both Midwest ISO and PJM generation interconnection queues include potential resources in this area. It will also provide the completion of a 765 kV loop within Indiana to help mitigate some of the market constraints associated with the existing Rockport to Jefferson 765 kV line. A similar line was identified as a potential solution to constraints associated with the Southwest Indiana generation energy delivery. Note a version of this project was previously proposed as a joint project between PJM and Midwest ISO. Because of this, costs may be split between Midwest ISO and PJM and would—in the event of a joint project undertaking—also require a coincident PJM analysis.

9. **Collins to Kewanee to Pontiac to Meadow Lake 765 kV line (2010 estimated installed cost: $964M):** 765 kV transmission is native to the PJM system in northern Illinois and Indiana. This corridor is identified primarily within the 765 kV overlay. However, it does have corridor compatibility within the other overlays. As previously discussed, Native Voltage and Native Voltage with DC transmission can both be adjusted appropriately to provide compatibility with any of the strategies. This line provides a second EHV path from the Chicago area to the east. It also provides a potential solution to the Wilton to Dumont related constraints that provides three (3) of the top 20 historical top congested flowgates within the Midwest ISO market. With the increasing pressure of wind within the Midwest ISO and the PJM portion of Illinois, specifically the Kewanee area, this transmission line will help release known and projected congestion associated with the transmission systems along Lake Michigan's southern shore.

10. **Michigan Thumb 345 kV transmission loop (2010 estimated installed cost: $510M):** This loop was evaluated under an Out-of-Cycle process for inclusion in MTEP10 Appendix A and approved by the Midwest ISO Board of Directors (BOD) in its August meeting. This accelerated review was required to meet the near-time needs of the Michigan renewable energy mandate. This transmission is compatible with the all of the strategies within the RGOS analysis and gives access to a high wind potential area within Michigan.

11. **Davis Besse to Beaver 345 kV line (2010 estimated installed cost: $71M):** This transmission provides access to and delivery of wind energy potential located around the shores of Lake Erie within Ohio. There is GIQ generation in the area and the transmission is identified within all of the RGOS-developed transmission strategies.

8 Going Forward

RGOS provides industry stakeholders and policy makers with a regional planning perspective identifying potential investment opportunities and demonstrating the integration of renewable energy policies into electrical system development. The purpose of the RGOS transmission development effort has been to explore long-term transmission strategies ensuring study-defined reliability objectives in delivery of renewable energy as well as compliance with RPS mandates encompassing states within the study footprint.

No consensus exists regarding the amount of renewable generation ultimately needed to comply with current and future RPS mandates. Some assert a much higher level of wind generation will be required than those included in RGOS analyses while others claim a lower amount. Regardless of the long-term uncertainties engendered by expansion or reduction of renewable energy standards, states within the Midwest ISO system will need new transmission to meet current and near-term renewable energy requirements, ensure reliable operation of the transmission grid, relieve current and projected areas of congestion, and facilitate the generation interconnection queue process.

As a result of the RGOS effort, Midwest ISO has identified the next, most immediate step to transmission investment: a set of robust Candidate Multi-Value Projects (MVPs) meeting current renewable energy mandates and the regional reliability needs of its members. This Candidate MVP project portfolio, comprised of results from RGOS, multiple congestion studies, and numerous generation interconnection studies, will undergo rigorous analysis as a first step towards a regional transmission plan to meet the policy driven needs of the states in the Midwest ISO footprint.

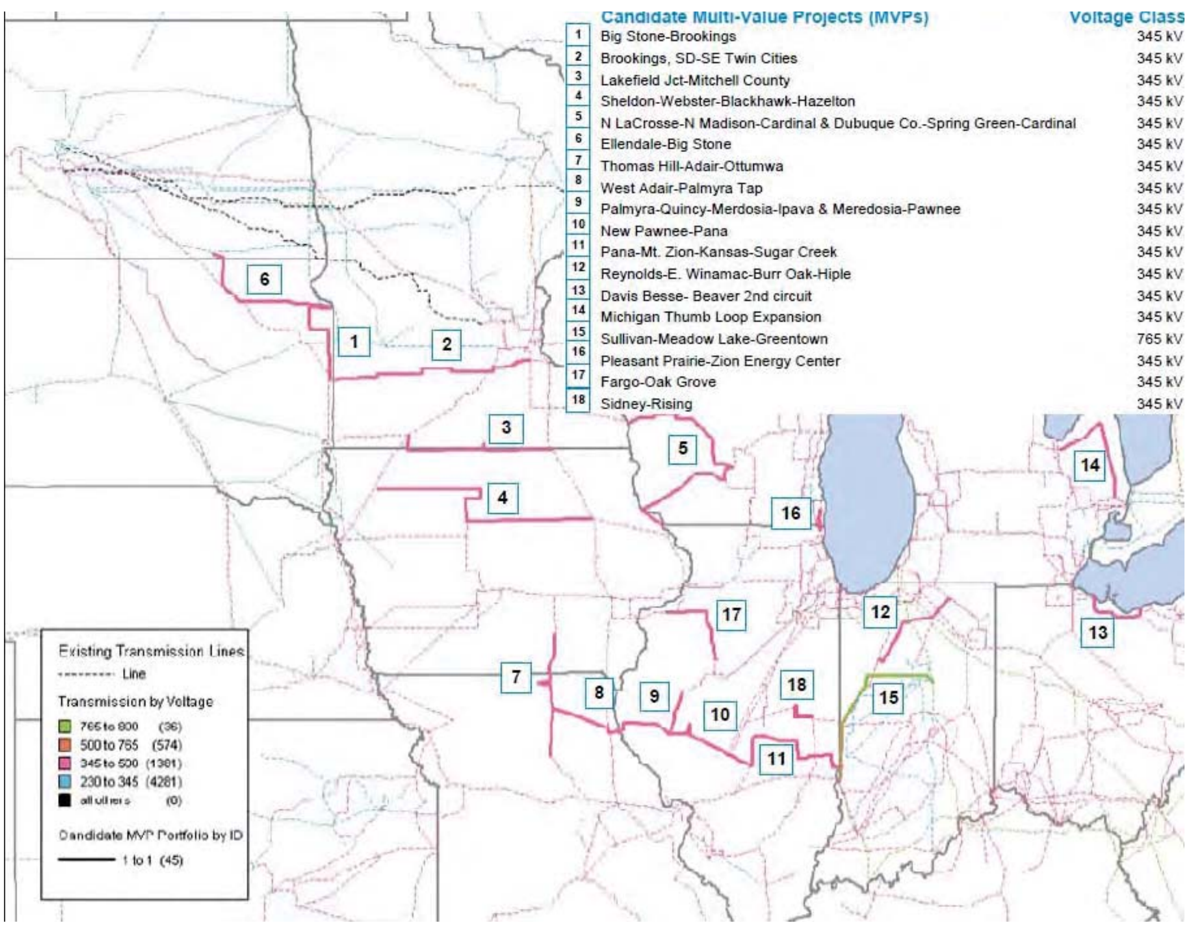

Figure 8-1: Proposed Midwest ISO Candidate Multi-Value Project Portfolio #1

Candidate MVP portfolio analysis is designed to be a fluid, adaptable, and dynamic planning approach based upon the concept of providing a high level of benefits relative to project cost under a number of different future possibilities, culminating in a regional plan that reliably and efficiently delivers value to load. In the MTEP11 study cycle, this portfolio will be thoroughly evaluated to ensure project value and to confirm system reliability with all Candidate MVPs included, with a goal of moving any applicable projects to MTEP Appendix A as MVPs. In 2012 and subsequent years, Candidate MVP portfolio analyses will continue to develop portfolios addressing long-term system value drivers and needs.

A Candidate MVP portfolio has been identified by analyzing transmission needs from multiple transmission and economic studies, which include the following:

- RGOS
- Studies conducted in the generation interconnection process
- Congestion studies such as the Top Congested Flowgate Study and the Cross Border Congested Flowgate Study
- MTEP reliability studies

Transmission solutions from these studies were evaluated for comparability and ability to be built within the near-term. These projects will continue to be evaluated in more detail into 2011, both to ensure project robustness and to confirm system reliability with inclusion of the Candidate MVP portfolio. This analysis was previously referred to as “Starter Project” analysis, but nomenclature was modified to further align its evaluation with the July 15th cost allocation filing at FERC.

Candidate MVP analyses will be used to find the total value of the portfolio of proposed projects, and using reliability and economic analyses, to determine if these projects are eligible for MVP cost allocation. To ensure total value of the projects is accurately captured, Midwest ISO will continue to refine and develop the set of metrics and methodology used to evaluate the total value of a portfolio of projects in the robustness testing step discussed in section 4. This refinement will take place with heavy stakeholder involvement through such forums as the Planning Advisory Committee (PAC) and the Planning Subcommittee (PS).

Appendix 1: Site Selection Methodology

A1.1 Developing Wind Resource Datasets

In this task, high resolution (2km x 2km) mesoscale wind data was developed for years 2004, 2005, and 2006 in 10-minute intervals at various hub heights. Mesoscale is a term used to describe a three dimensional numerical weather model. AWS Truewind determined the best mesoscale model and configuration to use for developing its high resolution wind resource dataset by testing and validating a number of potential modeling configurations. The validation covered one full year of simulations and compared the results with actual wind measurements from ten measurement sites throughout the study region. Results of this model included, temperature, pressure, wind speed, wind direction, wind density, turbulent kinetic energy at five heights, specific humidity, incoming long-wave and short-wave radiation and precipitation. With a validated mesoscale wind dataset it was then possible to model power output for various wind farm configurations at various hub heights.

A1.1.1 Site Selection Process

The goal of this task was to identify potential wind sites in the study region, both on-shore and off-shore, with a combined total rated capacity of at least 3,000 gigawatts (GW). An additional task, through a selection process, was to identify a subset of those wind sites totaling 600,000 megawatts (MW) from which to develop a wind database.

Providing a consistent set of resource estimates for ranking and selecting sites required the preparation of a seamless map of 11-year average wind speeds at 80 meters height for the EWITS region. A representative example wind speed map is shown in Figure A1.1-1. The map has been rendered using Ventyx Velocity Suite[12] and is a representation of wind resources across the United States. The data was compiled from both state and regional sources; thus, level of detail may vary. The scale ranges from Class 1 winds under 12.5 mph to Class 7 winds over 19.7 mph. This image is displayed at 500-meter resolution. While the EWITS and JCSP study regions were the same, wind data was not produced for entirety of the study regions because of time and cost considerations, plus lack of potential wind sites. The map in Figure A1.1.-2 shows the site selection wind development area.

[12] Ventyx®, Velocity Suite© 2008

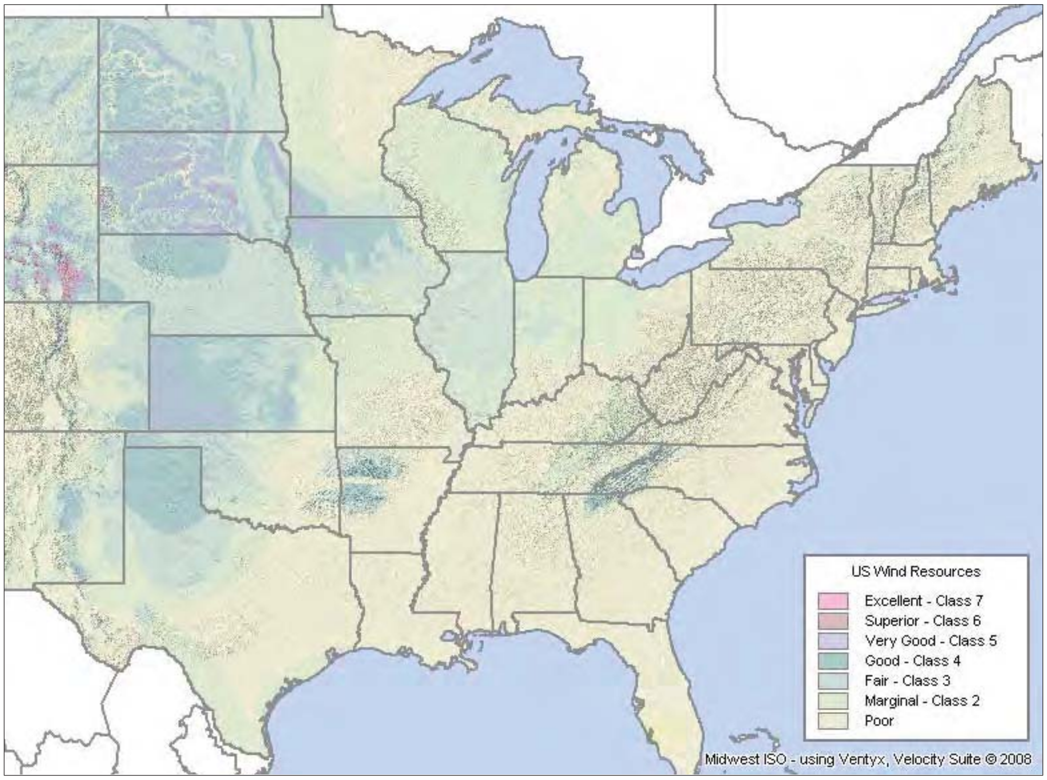

Figure A1.1-1: Example of US Wind Resource Map

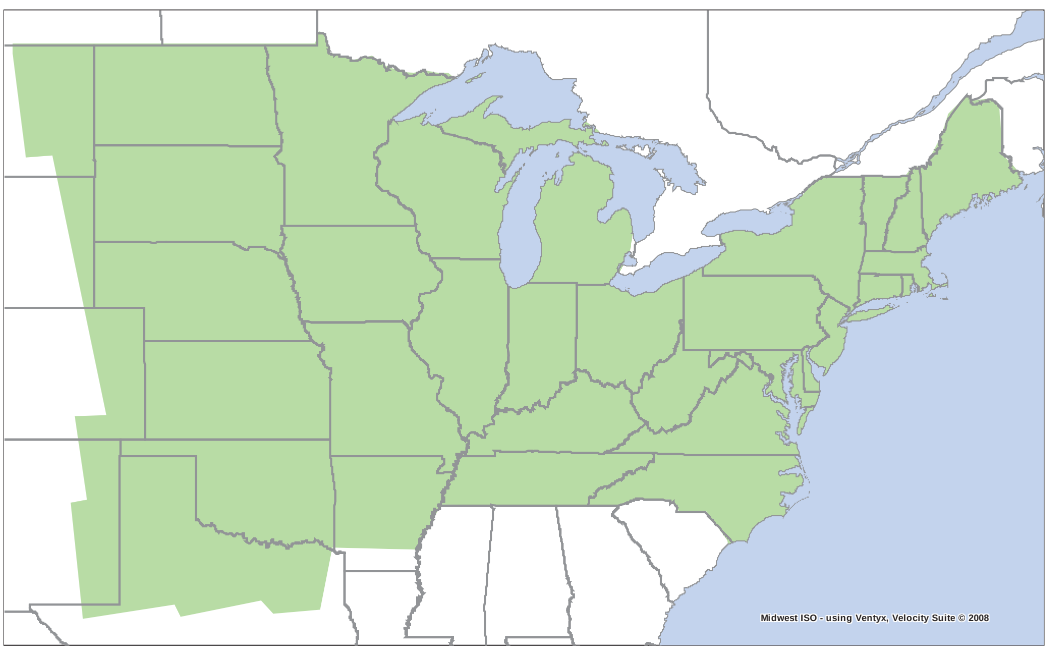

Figure A1.1-2: Site Selection Wind Development Area

Using the 11-year average wind speed at 80 meters, a map of the estimated net capacity factor for a composite IEC Class 2 wind turbine was then created.

These maps are created using Geographic Information System (GIS) software, which allows the spatial representation of the data on a map in unique layers. In addition to capacity factor, other layers such as land area, topography, lakes, rivers, cities, metropolitan areas, state and federal lands, airports, slope, etc. were utilized. Using the capacity factor map and an assumption for how many wind turbines could be placed in a specified area allows estimation of total potential wind capacity and energy in the Eastern United States. Any areas where it is undesirable or impossible for wind turbines to be located were excluded from consideration. With a capacity factor map layer combined with an exclusion map layer, the net potential wind development could be determined for the study region. Maps of exclusion areas to apply to the site selection process were created and the various criteria are listed below.

- Maps Layers from the USGS National Land Cover Database (2001):
  - Open Water
  - 200m buffer of Developed Low Intensity
  - 500m buffer of Developed Medium Intensity
  - 500m buffer of Developed High Intensity
  - Woody Wetlands
  - Emergent Herbaceous Wetland
- Map Layers from the ESRI data base:
  - Parks
  - Parks Detailed
  - Federal Lands (non – public)
  - 10,000ft buffer of small airports (all hub sizes)
  - 20,000ft buffer of large airports (hub sizes medium and large)
- Map Layers from the Conservation Biology Institute:
  - GPACT value of 1, 2, 7 & 8 (Typically these are managed areas, public and private)
- Map Layers from Other Sources:
  - Slopes greater than 20%
  - Areas outside the study region

Several methodologies were used to further prioritize the potential wind farms. The AWS Truewind site-screening program builds wind farms one grid cell at a time with 2km x 2km resolution, adding grids to the farm until an exclusion area boundary is met. A wind farm produced could be as small as 2km x 2 km or extremely large in rural areas. It was therefore necessary to specify a minimum and maximum size wind farm to ensure reasonable site sizes. In addition, to ensure geographic diversity within the sites, if two sites in an area were adjacent the program selected the site with the highest capacity factor and excluded the other. Thus the model logically reduces the amount of wind capacity identified to something less that the total potential capacity. Even this reduction methodology does not reduce the amount of wind sites to the specified 3,000 GW of capacity targeted as the capacity to use in the site selection process. In addition, if the program were to select the top 3,000 GW of wind sites, these sites would then all be in the central part of the country, which is less than ideal. Using previous wind studies and the work done by the JCSP, NREL identified target amounts of wind capacity within each state. These combined methodologies produced over 7800 sites totaling over 3,000 GW of rated capacity. Mesoscale wind data was applied to potential sites identified from this list.

Refer to Figure A1.1-3.

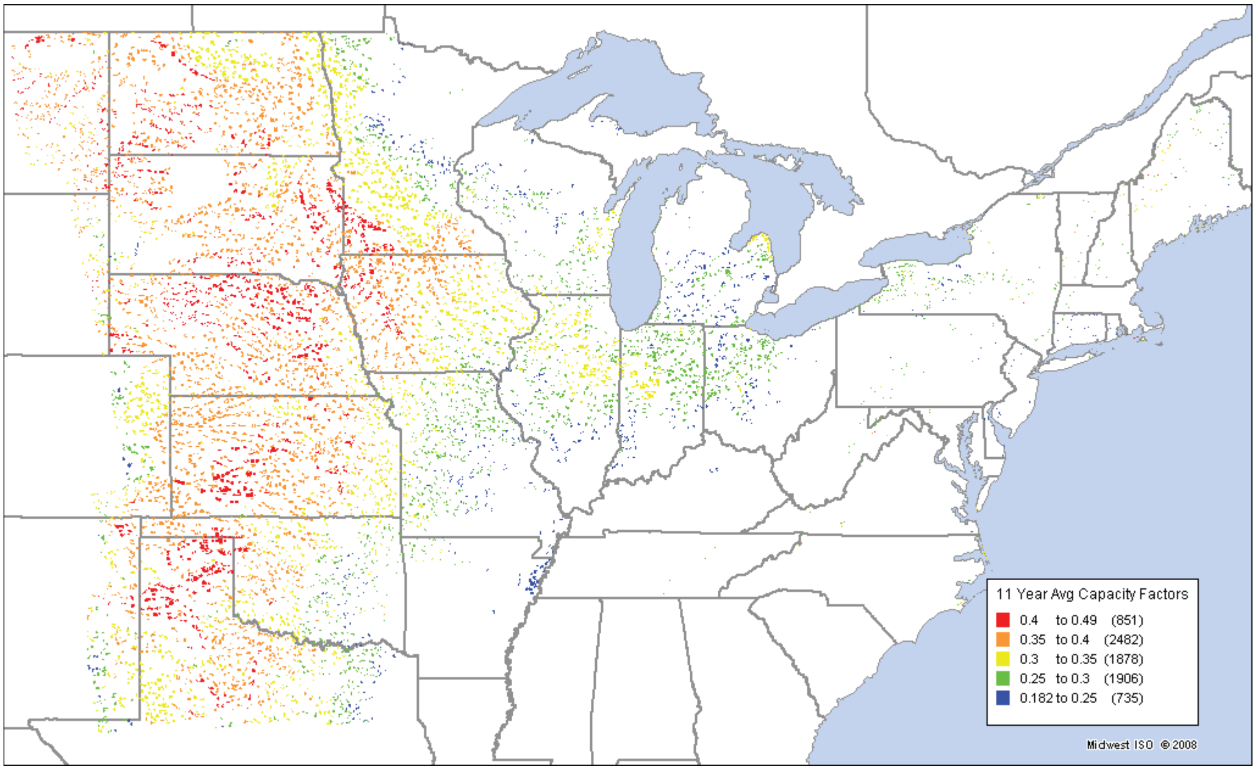

Figure A1.1-3 Potential Sites for Onshore Site Selection by Capacity Factor

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From the 7,856 sites in site selection list, NREL identified 1,513 sites totaling 651,091 MW, for AWS Truewind to apply the three (3) years of 10-minute mesoscale wind data. These 1,513 sites are referred to as the "selected sites". These sites are shown in Figure A1.1-4.

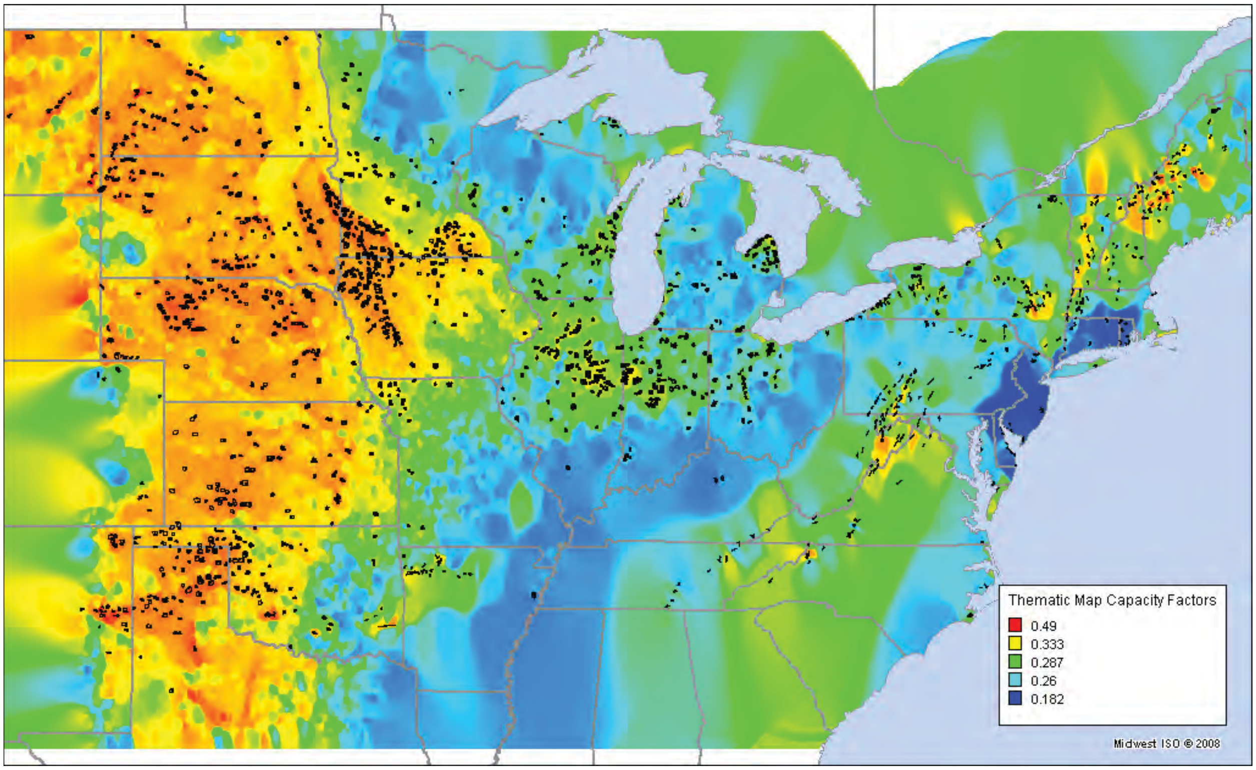

Figure A1.1-4 NREL Selected Site for Mesoscale Wind farm Modeling

The NREL-selected sites with the mesoscale wind modeling are available in on the NREL website for years 2004, 2005, and 2006. Throughout this process, Midwest ISO worked with NREL, reviewing data and providing feedback. Having modeled wind in the past; reviewed numerous wind studies; worked with stakeholders, wind developers, state regulators; conducted the JCSP study, and with a need for wind data in ongoing studies and future studies, Midwest ISO was in a unique position to provide feedback and review the data.

From this reviewing process, Midwest ISO identified an additional need outside of the scope of the original request of AWS Truewind. Midwest ISO performed a gap analysis of the wind sites selected and identified additional sites where it wanted mesoscale wind data developed. NREL was able to work with AWS Truewind to incorporate these additional sites, and the data is included on the NREL website. Refer to Figure A1.1-5.

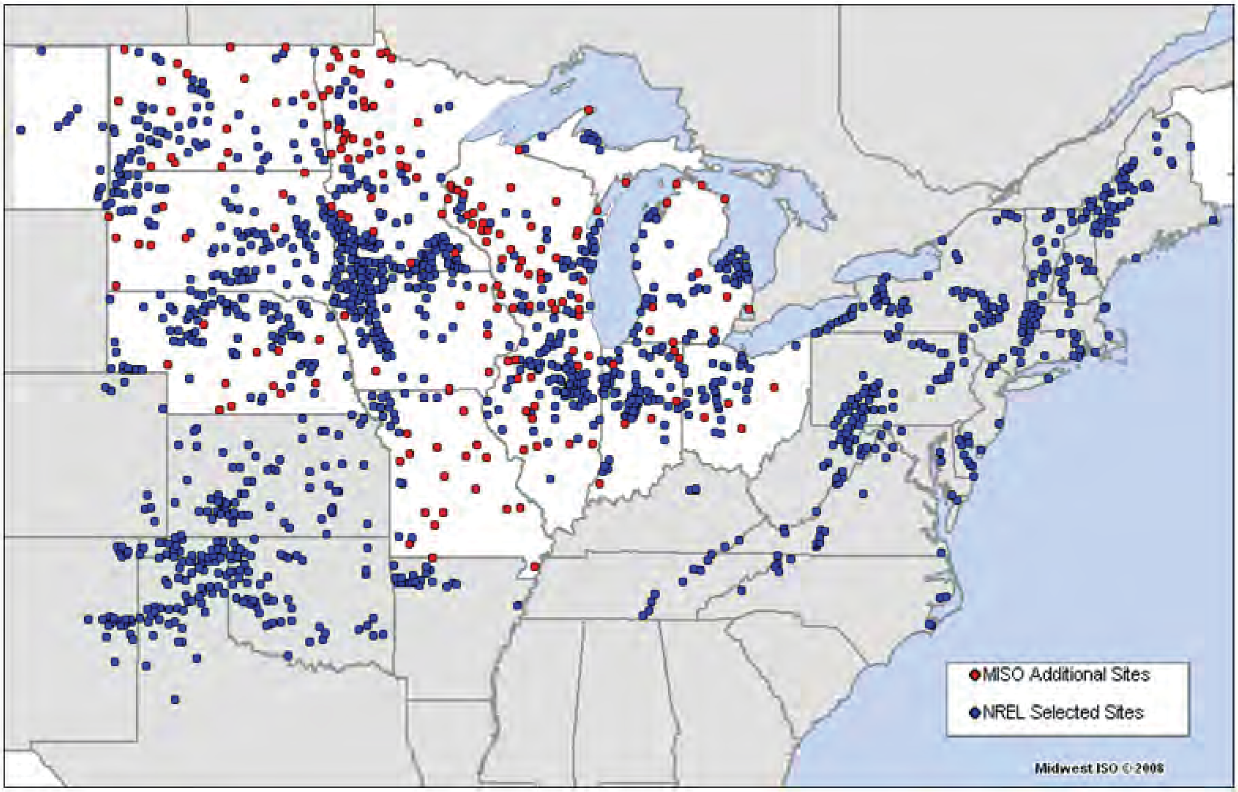

Figure A1-5 NREL and RGOS Study Region Selected Sites

A1.2 Generate Wind Plant Output

A detailed explanation of the procedure to calculate the wind plant output is on the NREL website. AWS Truewind ran a simulation model to convert the mesoscale wind data to the selected sites. Blended power curves were then created and used to calculate the power output of each site. The International Electrotechnical Commission (IEC) 1 and 2 curves were based on a composite of three commercial turbines (GE, Vestas, Gamesa brands). The IEC 3 curve was based on two turbines (GE 1.5xle and Gamesa G90). The IEC 1 and 2 turbines were assumed to have a hub height of 80 m and the IEC 3 turbine 100 m.

A single text file for the output was created for each site. The output included 10-minute simulated wind speed at 80 and 100 meters, with power outputs for IEC class 1 and 2 at 80 meters and IEC class 3 at 100 meters. All outputs were time stamped to Greenwich Mean Time (GMT). In addition, the program selected the most appropriate IEC class based on the maximum mean speed within the site adjusted for air density, for the specific year of study. Since the data was developed for years 2004, 2005, and 2006, the selected turbine class could vary in different years. All turbines in the plant were the same type (1, 2 or 3) as determined from the average wind speed with an adjustment for site altitude. The power output for the selected IEC class is provided in the last column of the file. A header is provided for each site identifying the site number, its rated capacity, the selected IEC class, and the losses for each turbine class. The 10-minute data may be converted to hourly data by taking the average output for each hour. This methodology was accomplished by Midwest ISO and NREL in their studies.

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A1.2.1 Forecasts and One Minute Samples

AWS Truewind produced hourly forecasts for three different time horizons: next-day, six-hour, and four-hour for use in hourly production modeling. In addition, they developed one minute samples of wind generation. The procedures are described in depth in the documentation on the NREL website.

A1.2.2 Wind Statistics

- Onshore Site Selection:
  - 7,856 sites considered with a capacity of 3,086,915 MW.
  - Range of selected sites 11 year average capacity factor is 18.2% to 49.0%, the average capacity factor is 33.0 %.
- Mesoscale Data containing the following:
  - Data in Greenwich Mean Time (GMT)
  - 10-minute data for years 2004, 2005, 2006
  - Power output for IEC 1 & 2 turbines at 80 meters and IEC 3 turbines at 100 meters
  - Wind speeds at 80 and 100 meters
  - Max capacity, preferred turbine type and losses provided for each site
  - Onshore NREL Selected Sites
  - 1,326 sites selected by NREL with a capacity of 580,763 MW

Table A1.2-1: Onshore Site Selection Capacity Factors by Year

CF Year	Annual	Minimum	Maximum
2004 Capacity Factor	36.9%	2.4%	81.7%
2005 Capacity Factor	36.3%	2.4%	80.9%
2006 Capacity Factor	37.4%	4.2%	82.1%
3 Year Average Capacity Factor	**36.9%**	**3.0%**	**81.5%**

- Onshore Midwest Additional Sites:
  - 187 additional sites selected by the Midwest ISO with a capacity of 70,328 MW
  - 1,513 total sites totaling 651,091 MW with mesoscale wind data developed
  - Three (3) Year Annual, Min & Max capacity factor for all 1,513 sites of 36.5, 2.3% and 82.5%

Refer to Figure A1.2-1, which shows the distribution of all selected sites by rated capacity. The bulk of the sites fall between 200 MW and 600 MW in size. A small number of "megasites" with rated capacities exceeding 1000 MW were also chosen. All of the megasites are located in the Great Plains.

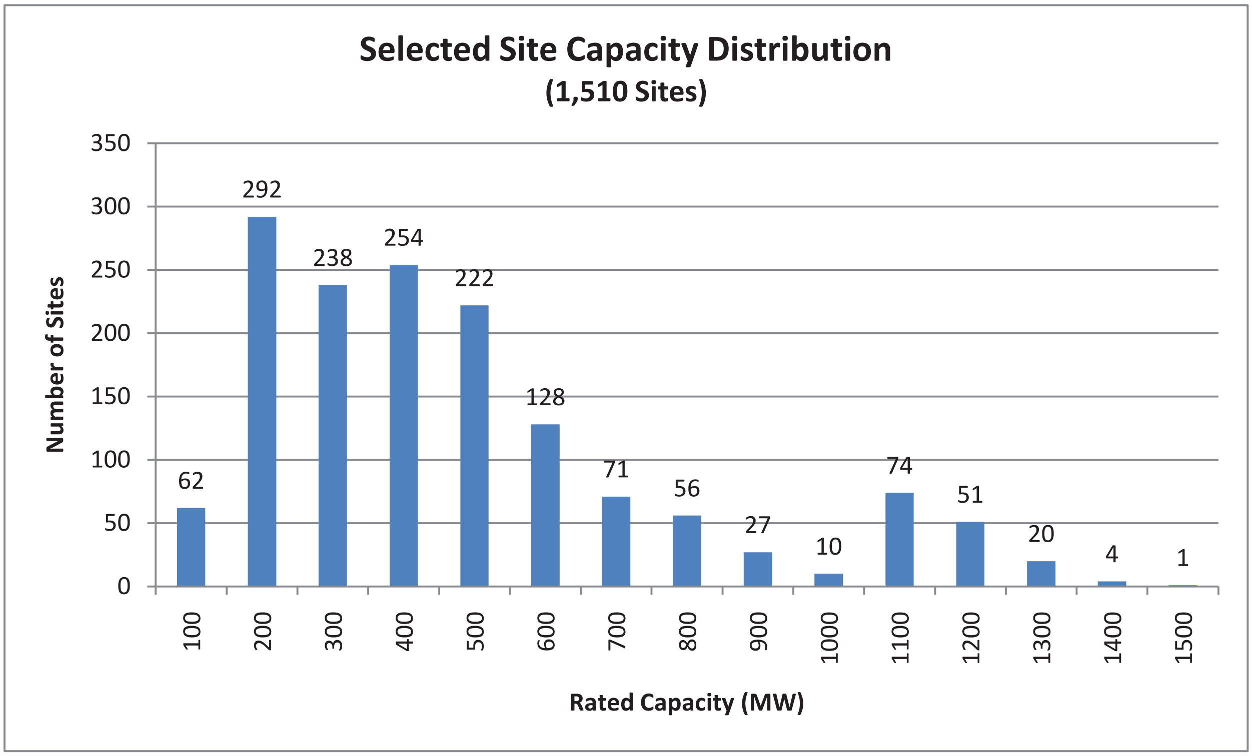

Figure A1.2-1: Distribution of Site Capacity for all 1,513 Selected Onshore Sites

The following figures represent the minimum and maximum system wind for the NREL sites for each year of mesoscale data. To understand and visualize the mesoscale data, Midwest ISO created thematic maps which represented the power output for the eastern interconnect in a color coded map corresponding to the wind power. To illustrate the hourly variance of wind, multiple images were created and combined into 'wind movies' for 2004, 2005, and 2006. These movies represent the mesoscale hourly power output of the NREL selected sites.

The data is presented as per unit power output with red having a value of 0.9 and dark blue with a value of 0.0. These movies are available to download at the following website: http://www.jcspstudy.org/. The Figures A1.2-2 and A1.2-3 showing minimum and maximum system wind were taken from the wind movie.

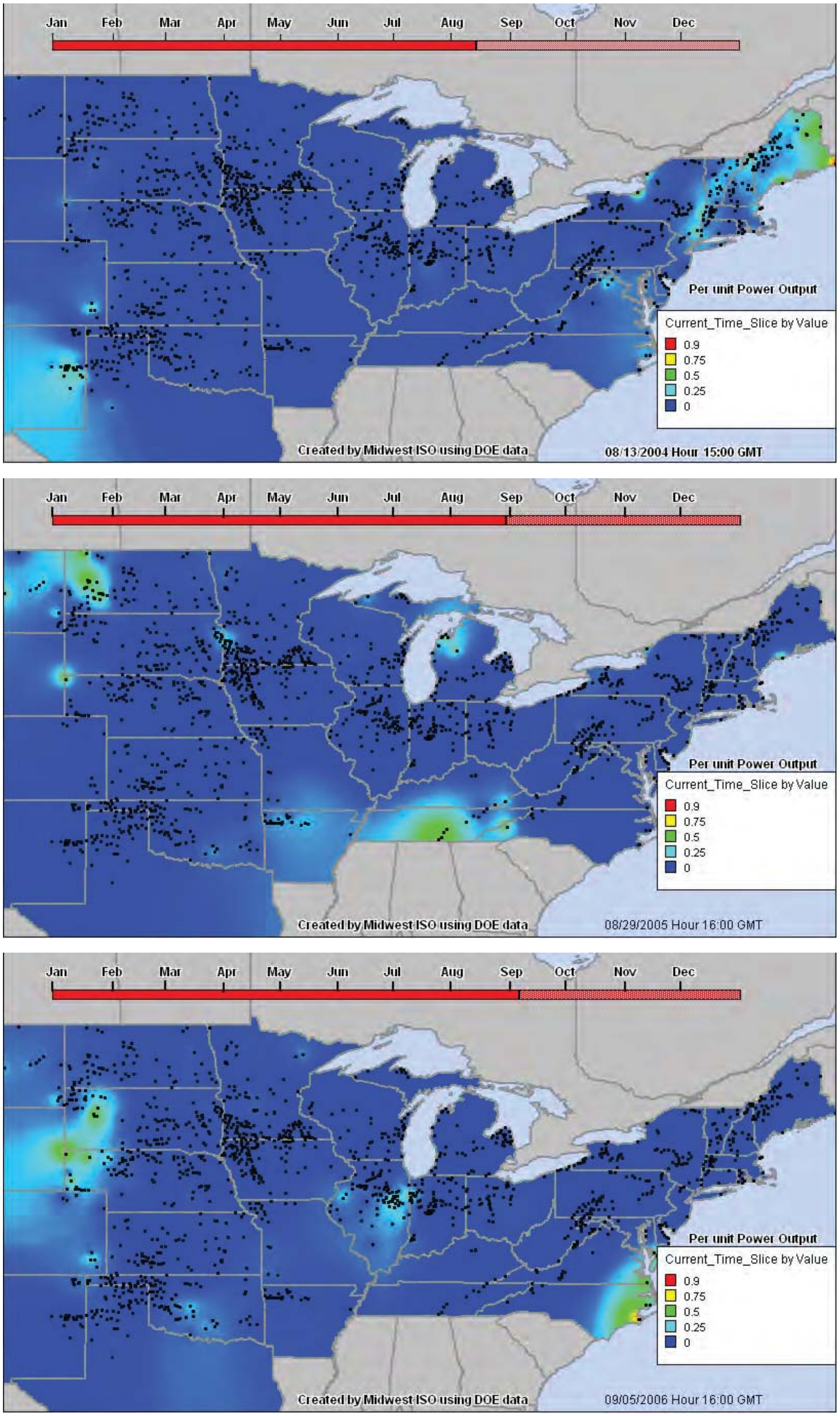

Figure A1.2-2: Minimum Power Output of the NREL Selected Sites for Each Year

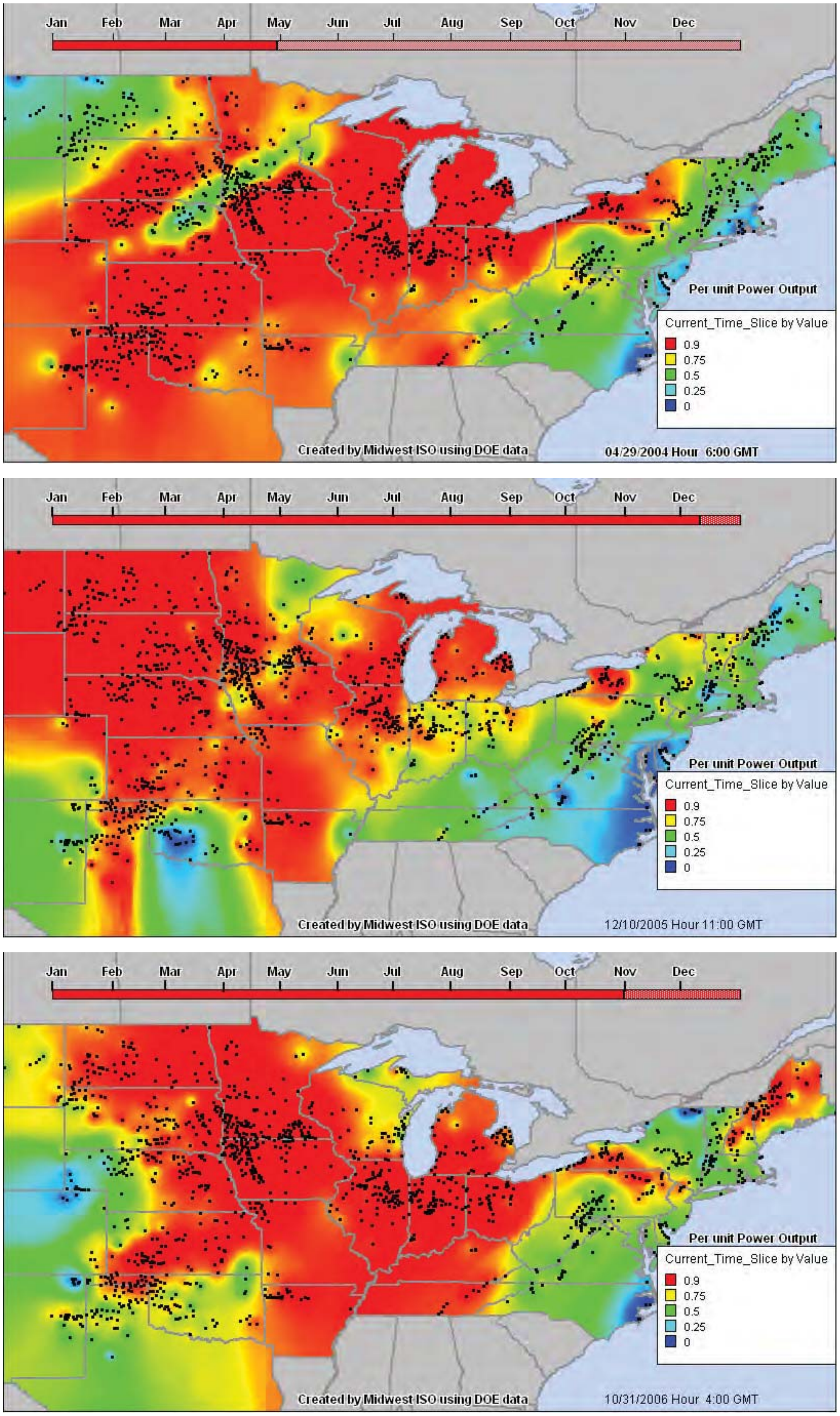

Figure A1.2-3: Maximum Power Output of the NREL Selected Sites for Each Year

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A1.3 Renewable Energy Zone Scenario Development

A1.3.1 Wind Analysis

Several capacity factor metrics were calculated to analyze the wind data to determine the appropriate measures for ranking the renewable energy zones. The purpose for examining the various capacity factor metrics was to first answer questions about the variability and timing of wind production and also to determine if there were areas where wind energy performed better. A statistical analysis of the data had to be performed to be able to questions such as the following:

- Is using the three year average capacity factor enough or should the capacity factor for each year be considered a separate criteria?
- How is a site treated which may have a lower capacity factor than another site but tends to produce more energy during on-peak hours?
- Does wind really blow more in the evening than during the day?

To provide answers, a range of statistics was created based on time and applied to each site. The various capacity factor metrics are described in Table A1.3-1, below.

Table A1.3-1 Summary of Capacity Factor Metrics

Metric	Capacity Factor (CF) Metric
11 Year CF	CF based on 11 year average wind speed at 80m
2004 CF	CF for 2004
2005 CF	CF for 2005
2006 CF	CF for 2006
3 Year CF	Average CF for 2004, 2005 and 2006
On-peak CF	3 year CF for hours between 6am to 10pm EST
Afternoon On-peak CF	3 year CF for hours between 3pm to 6pm EST
Summer On-peak CF	3 year CF on-peak hours for June, July and August
Summer Aft On-peak CF	3 year CF for afternoon on-peak hours for June, July & August
Off-peak CF	3 year CF for hours between 10pm to 6am EST

Figures A.3-1 through A.3-3 provide an overview of some of the capacity factor metrics per state. The off-peak average capacity factors were higher than the on-peak and significantly higher than the summer afternoon on-peak hours. A linear relationship can be seen between the average capacity factors and their changes for the different metrics. Spikes or dips in the data indicate the average capacity factors in a given state performed better or worse relative to the other states. This is seen in the afternoon on-peak hours with a slight dip for Missouri and a slight increase for Indiana.

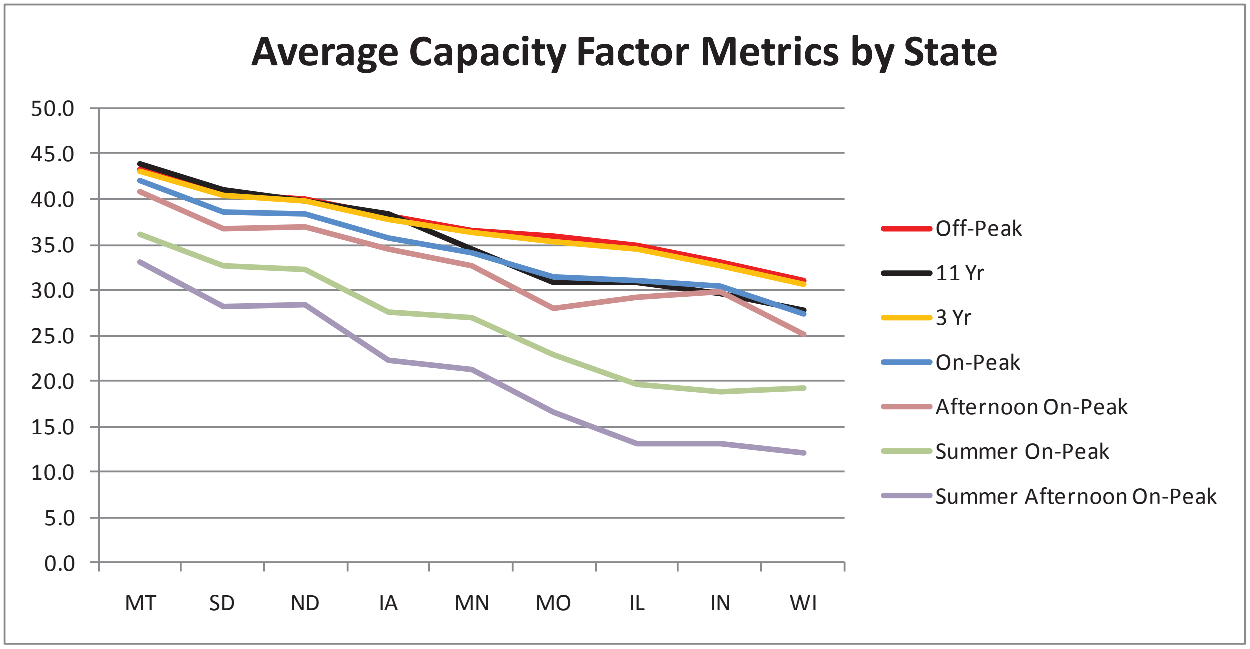

Figure A1.3-1 Average Capacity Factor Metrics by State

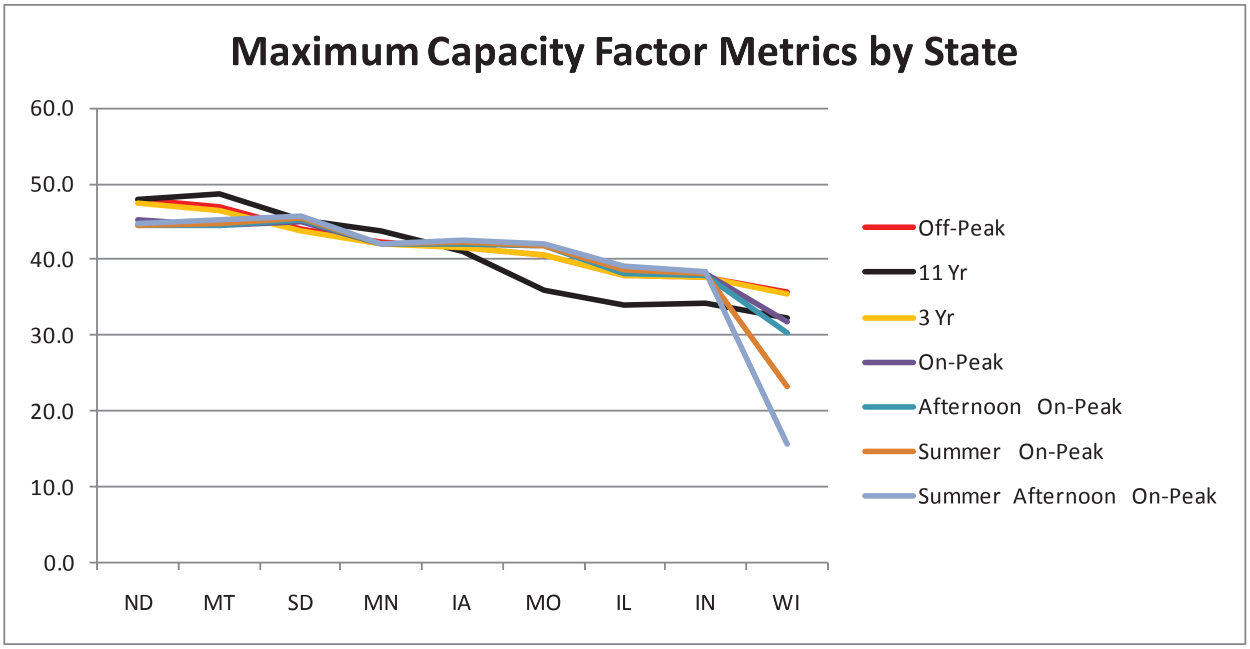

Figure A1.3-2 Maximum Capacity Factor Metrics by State

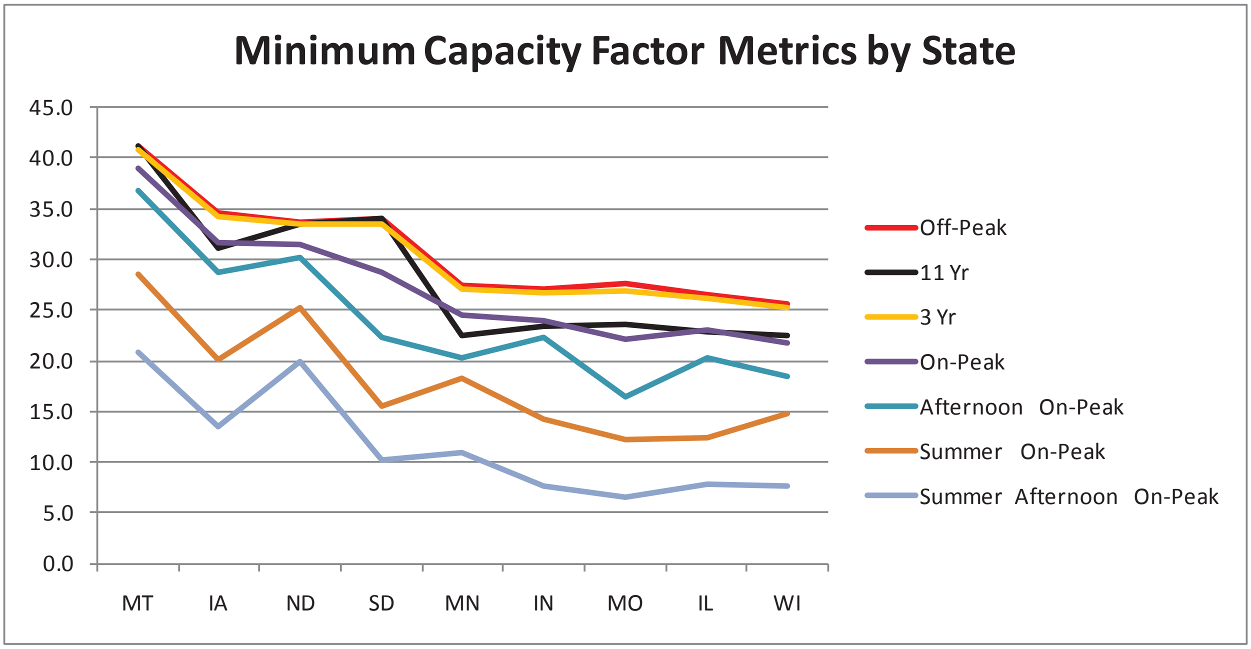

Figure A1.3-3 Minimum Capacity Factor Metrics by State

Some other metrics developed for analysis include correlation of wind to load, ramp, and correlation of wind sites to distance from each other. The following figures demonstrate some of the results from this work.

Figure A1.3-4 represents the wind output correlation to load for Midwest ISO. A correlation of 1.0 is a perfect correlation, meaning load and wind exactly match each other. A correlation of 0.0 represents no correlation, meaning that load and wind act completely independent of each other. The correlation values demonstrate that there was not a strong correlation between wind output and load. In other words, one cannot generally expect a specific wind output based on load levels. However, in general, wind output is typically higher during off-peak hours as opposed to on-peak hours (when load is less) as shown in the previous figures. Similar results hold true on a state by state basis for all the states in Midwest ISO.

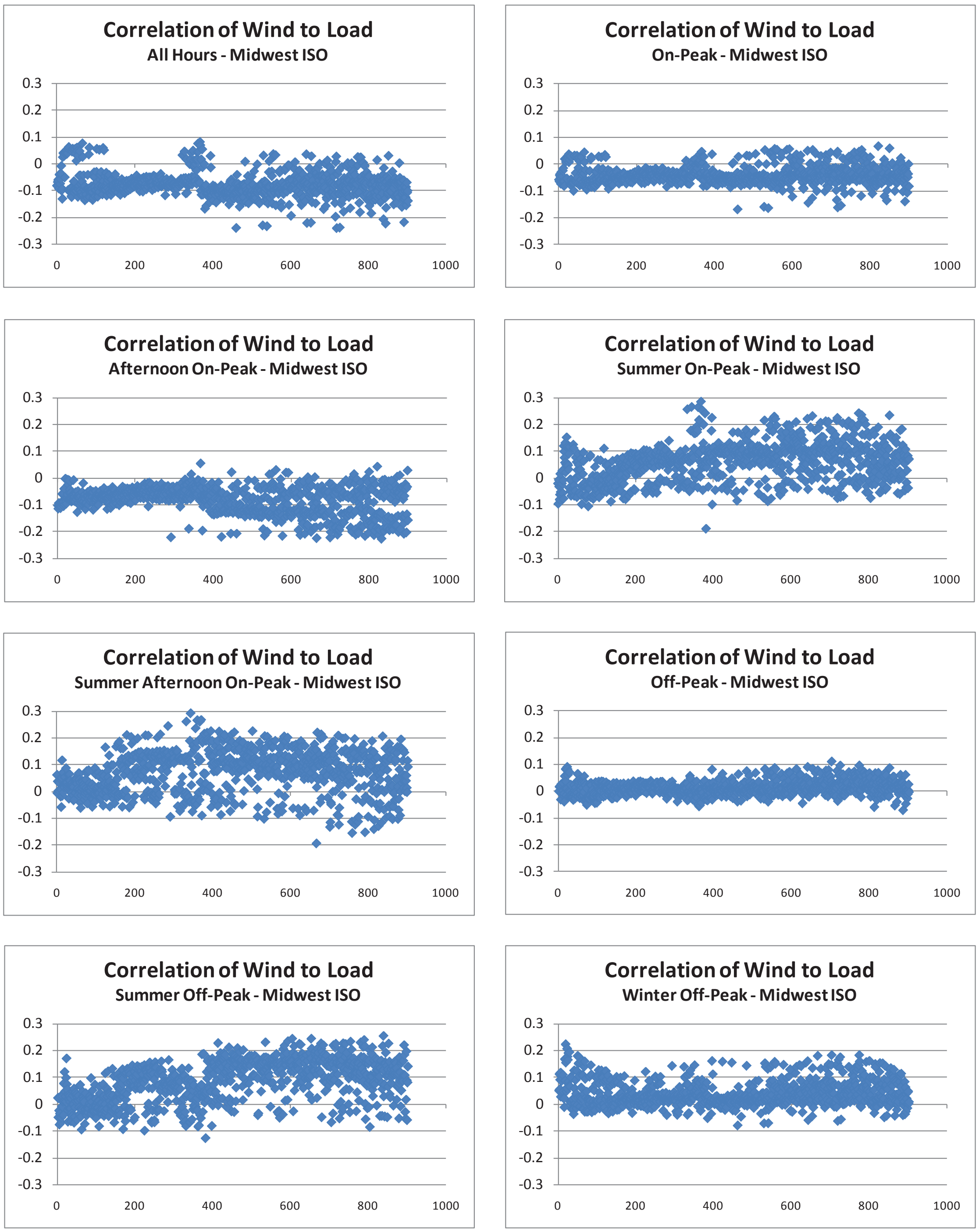

Figure A1.3-4 Correlation of Wind to Load in the Midwest ISO

Hourly ramping of the wind was calculated by looking at the delta of wind output from one hour to the next. A distribution of these values was created and a correlation to load ramp was calculated. As expected, the correlations were relatively close to zero and insignificant. Refer to Figure A.3-5 for results from Iowa (IA), Illinois (IL), Minnesota (MN), and Wisconsin (WI).

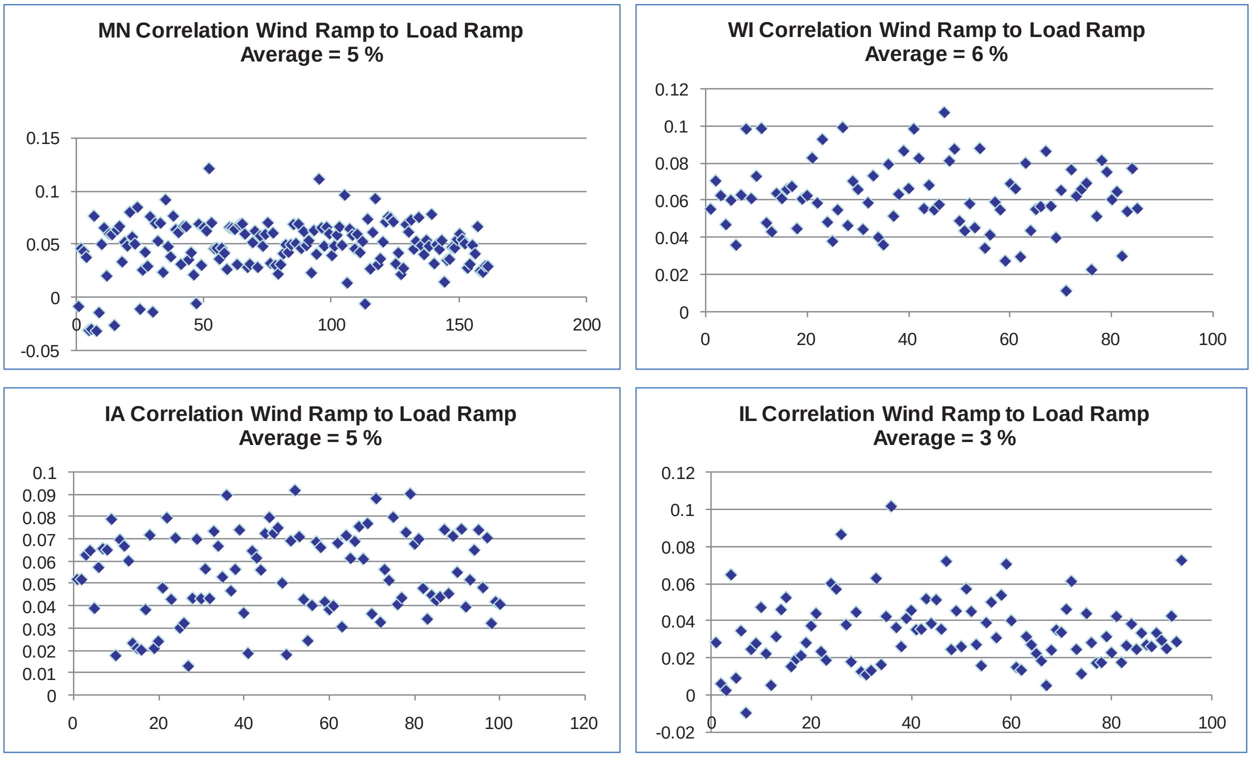

Figure A1.3-5: Correlation of Wind Ramp to Load Ramp

Figure A1.3-6 represents the correlation of individual sites to each other. The green line represents distance separation east to west, the blue line north to south. The figure demonstrates that as the distance between two sites becomes large, the correlation of the wind at those two sites reduces. In other words, the further apart two sites are, the less likely they will have similar wind profiles. This is an obvious expectation since two (2) sites located next to each other would be expected to have similar capacity factor characteristics.

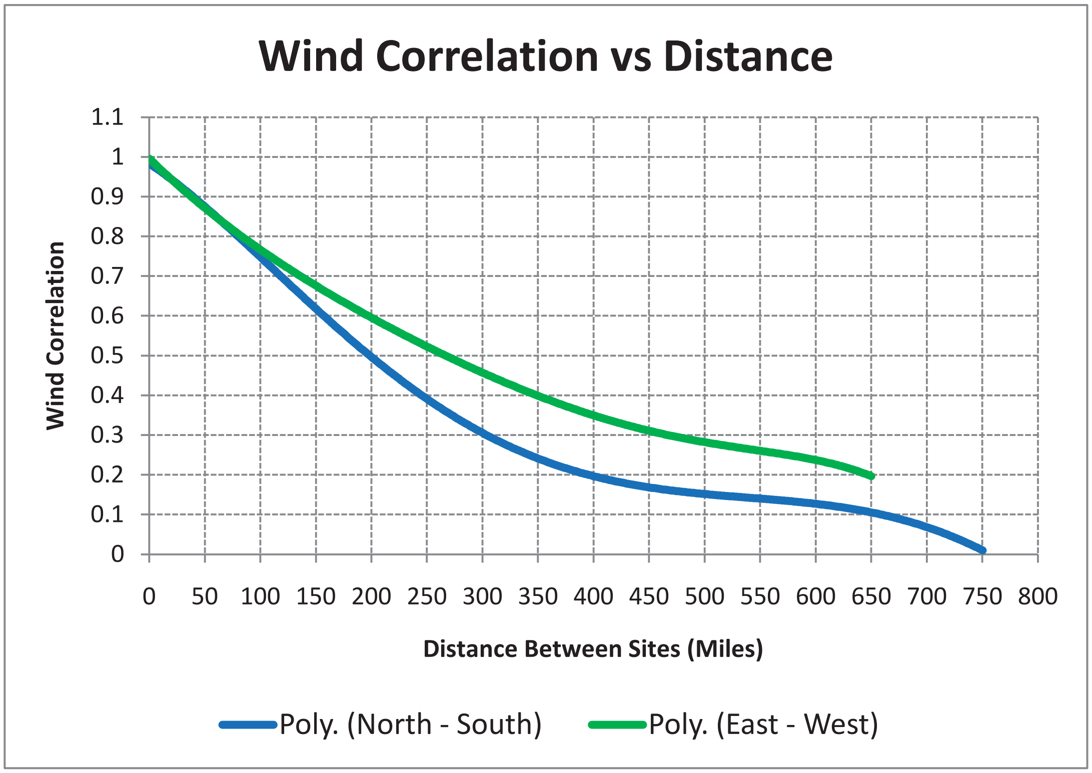

Figure A1.3-6: Correlation of Wind Sites to Distance

Appendix 2: Midwest ISO Member State RPS Requirements

Refer to Table A2-1. The following information, derived from the US Department of Energy's National Renewable Energy Laboratory (NREL) Database of State Incentives for Renewables & Efficiency, highlights general aspects of various state Renewable Portfolio Standards (RPS) legislation within the Midwest ISO purview. The information can be found at http://www.dsireusa.org/.

Note the Ohio mandate is defined differently from most other states. The Ohio mandate focuses on an alternative energy mandate that can include resources such as clean coal and nuclear capacity. The total state mandate is 25% by 2024. However, it has been expressed in this report as that portion that meets the renewable technology minimum of 12.5% by 2024. Note, too, the Pennsylvania mandate is similar to the Ohio mandate, focusing not only on renewable resources but also alternative technologies such as Integrated Gasification Combined Cycle (IGCC). The entire Pennsylvania mandate is approximately 18% of energy served. However, for the purposes of this study, only the Tier I portion of the mandate emphasizing renewable resources is referenced.

Table A2-1: Midwest ISO Region State RPS Requirements

State	Applicable Sectors	Eligible Resources	Technology Minimum	DSIRE Reference Web Address
Wisconsin	Municipal Utility, Investor-Owned Utility, Rural Electric Cooperative	Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Geothermal Heat Pumps, Municipal Solid Waste, Solar Light Pipes, Solar Pool Heating, Anaerobic Digestion, Tidal Energy, Wave Energy, Fuel Cells using Renewable Fuels, Geothermal Direct-Use	None	http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=WI05R&re=1&ee=1
Minnesota	Municipal Utility, Investor-Owned Utility, Rural Electric Cooperative	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Municipal Solid Waste, Hydrogen, Co-Firing, Anaerobic Digestion	Wind or Solar (Xcel only): 25% by 2020; maximum of 1% from solar	http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MN14R&re=1&ee=1
Illinois	Investor-Owned Utility, Retail Supplier	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Biodiesel, Eligible Efficiency Technologies	Wind (IOUs): 75% of annual requirement (18.75% of sales in compliance year 2024-2025); Wind (ARES): 60% of annual requirement (15% of sales in compliance year 2024-2025); PV (All): 6% of annual requirement in compliance year 2015-2016 and thereafter (1.5% of total sales in compliance year 2024-2025)	http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=IL04R&re=1&ee=1

Table A2-1: Midwest ISO Region State RPS Requirements

State	Applicable Sectors	Eligible Resources	Technology Minimum	DSIRE Reference Web Address
Michigan	Municipal Utility, Investor-Owned Utility, Rural Electric Cooperative, Retail Supplier	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Municipal Solid Waste, CHP/Cogeneration, Coal-Fired w/CCS, Gasification , Anaerobic Digestion, Tidal Energy, Wave Energy, Eligible Efficiency Technologies	None	http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MI16R&re=1&ee=1
Ohio	Investor-Owned Utility, Retail Supplier	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Fuel Cells, Municipal Solid Waste, Waste Heat, Energy Storage, Clean Coal, Advanced Nuclear , Anaerobic Digestion, Microturbines, Eligible Efficiency Technologies	Renewables: 12.5% by 2024 (includes solar-electric minimum) Solar-Electric: 0.5% by 2024	http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=OH14R&re=1&ee=1
Missouri	Investor-Owned Utility	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Municipal Solid Waste, Anaerobic Digestion, Small Hydroelectric, Fuel Cells using Renewable Fuels	Solar-Electric: 2% of annual requirement (0.3% of sales in 2021)	http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MO08R&re=1&ee=1
Montana	Investor-Owned Utility, Retail Supplier	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Anaerobic Digestion, Fuel Cells using Renewable Fuel	None	http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MT11R&re=1&ee=1
Pennsylvania	Investor-Owned Utility, Retail Supplier	Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Fuel Cells, Geothermal Heat Pumps, Municipal Solid Waste, CHP/Cogeneration, Waste Coal, Coal Mine Methane, Coal Gasification, Anaerobic Digestion, Other Distributed Generation Technologies, Eligible Efficiency Technologies	Tier I: ~8% by compliance year 2020-2021 (includes PV minimum); Tier II: 10% by compliance year 2020-2021; PV: 0.5% by compliance year 2020-2021	http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=PA06R&re=1&ee=1
South Dakota (Goal)	Municipal Utility, Investor-Owned Utility, Rural Electric Cooperative	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Municipal Solid Waste, Hydrogen, Electricity Produced from Waste Heat , Anaerobic Digestion, Eligible Efficiency Technologies	None	http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=SD02R&re=1&ee=1
North Dakota (Goal)	Municipal Utility, Investor-Owned Utility, Rural Electric Cooperative	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Hydrogen, Electricity from Waste Heat, Anaerobic Digestion	None	http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=ND04R&re=1&ee=1
Iowa	Utility	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Municipal Solid Waste, Anaerobic Digestion	None	http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=IA01R&re=1&ee=1

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Appendix 3: Indicative Transmission Design

This Appendix depicts and describes the indicative transmission overlays resulting from formulation of five (5) renewable energy zone scenarios. Also refer to section 5 of this document, which provides greater detail on design process background and results. These scenarios include the following:

- **Local:** In the Local scenario the renewable energy requirements and goals will be met with resources located within the same state as the load.
- **Regional:** In the Regional scenario renewable energy requirements and goals will be met with resources located in the highest ranking renewable energy zones regardless of the zones location relative to the RGOS II load. This scenario will utilize the high capacity factor zones recommended by UMTDI from RGOS I.
- **Regional Optimized:** The Regional scenario results in capacity in excess of what is needed to at least cover the renewable requirements/goals. In the optimized case the capacity in some zones reduced such that there is just enough resources to cover the requirements/goals.
- **Combination 50/50:** In the Combination scenario renewable energy requirements and goals will be met with a combination of 50% of the resources located within the eastern states (RGOS II) and 50% from the western states (RGOS I/UMTDI). Emphasis will be given to state requirements to locate part or all of their resources used to meet renewable energy requirements and goals within those states.
- **Combination 75/25:** This scenario is similar to Combination 50/50 except that 75% of the renewable energy requirements will be met from the west states (RGOS I/UMTDI).

The following tables and charts depict results from the indicative transmission workshop whereby the renewable energy zone scenarios above were used to develop indicative transmission overlays to serve the energy and capacity from each scenario. This work was accomplished using several transmission build-out possibilities that included 345 kV, 765 kV, and DC. Each of the various scenarios has a table showing transmission mileage, a table listing transmission capital costs, and a map depicting the transmission overlay.

A3.1 Local 345 kV

Refer to Tables A3.1-1 and A3.1-2.

Table A3.1-1: Local 345 kVSum of Line Lengths (Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	1001	999	188	271	230	611	228	880	4408
765				195			268		462
2-345	454	238	187		2701		59	135	3775
Grand Total	**1455**	**1237**	**376**	**466**	**2931**	**611**	**554**	**1016**	**8645**

Table A3.1-2: Local 345 kV Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$1,501	$1,999	$339	$488	$460	$611	$455	$2,201	$8,054
765				$702			$1,070		$1,772
2-345	$953	$618	$431		$6,753		$148	$406	$9,309
Grand Total	**$2,454**	**$2,616**	**$770**	**$1,189**	**$7,212**	**$611**	**$1,673**	**$2,608**	**$19,135**

Generation	
MW of Capacity	Cost (M$)
45,700	**$91,400.00**

Total Costs (2010 USD in Millions)	
Transmission	$19,135
Generation	$91,400
Transformers	
Substations	
Reactors	
Total	**$110,535**

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Refer to Figure A3.1-1.

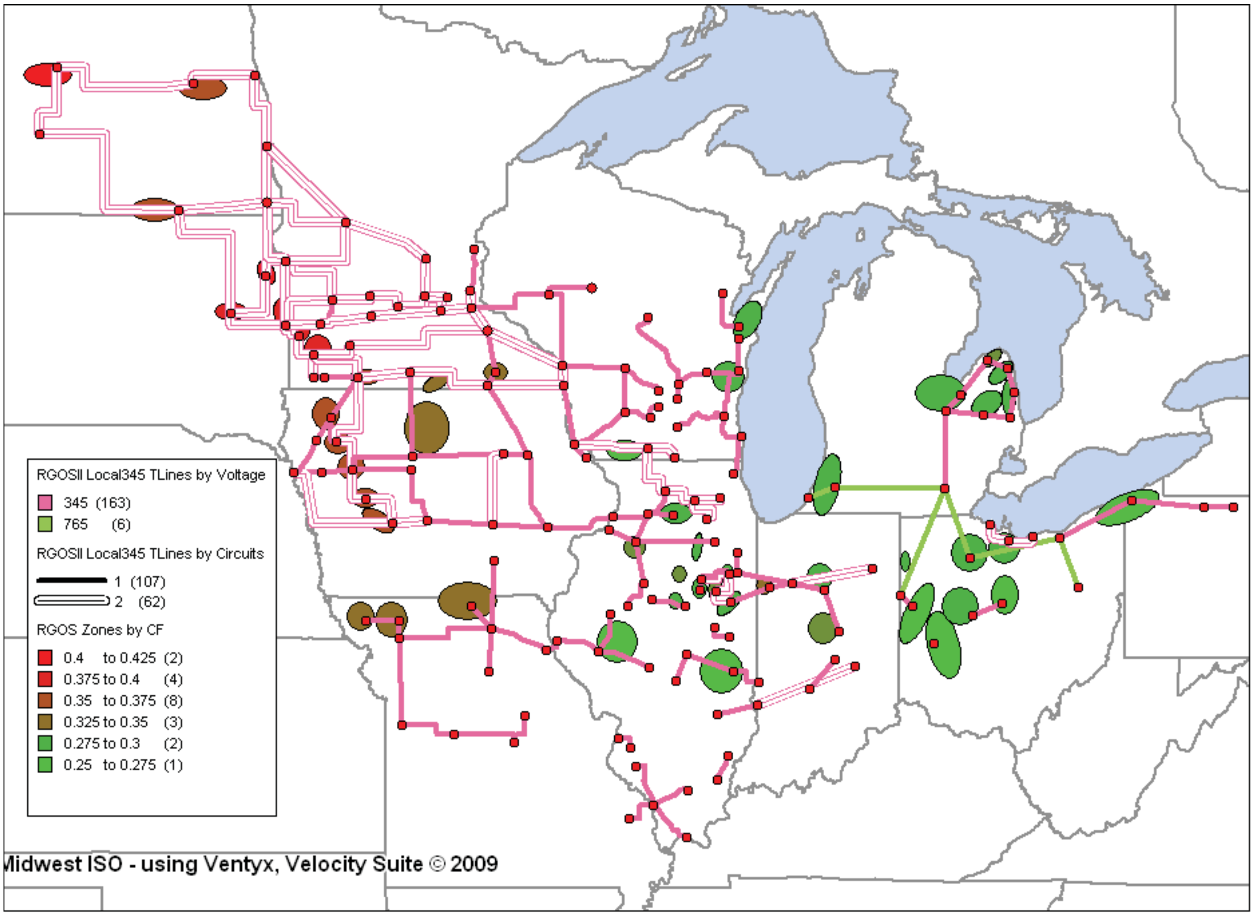

Figure A3.1-1: RGOS Local 345 kV

A3.2 Local 765 kV

Refer to Tables A3.2-1 and A3.2-2.

Table A3.2-1: Local 765 kV Sum of Line Lengths (Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	1001	1005	110	196	230	611	228	880	4260
765		432	396	319			269		1416
2-345	454	238			2701			135	3528
Grand Total	**1455**	**1674**	**506**	**515**	**2931**	**611**	**496**	**1016**	**9204**

Table A3.2-2: Local 765 kV Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$1,501	$2,009	$198	$353	$460	$611	$455	$2,201	$7,788
765		$1,816	$1,741	$1,148			$1,074		$5,779
2-345	$953	$618			$6,753			$406	$8,730
Grand Total	**$2,454**	**$4,443**	**$1,939**	**$1,502**	**$7,212**	**$611**	**$1,529**	**$2,608**	**$22,298**

Generation	
MW of Capacity	Cost (M$)
45,700	**$91,400.00**

Total Costs (2010 USD in Millions)	
Transmission	$22,298
Generation	$91,400
Transformers	
Substations	
Reactors	
Total	**$113,698**

006724

Refer to Figure A3.2-1.

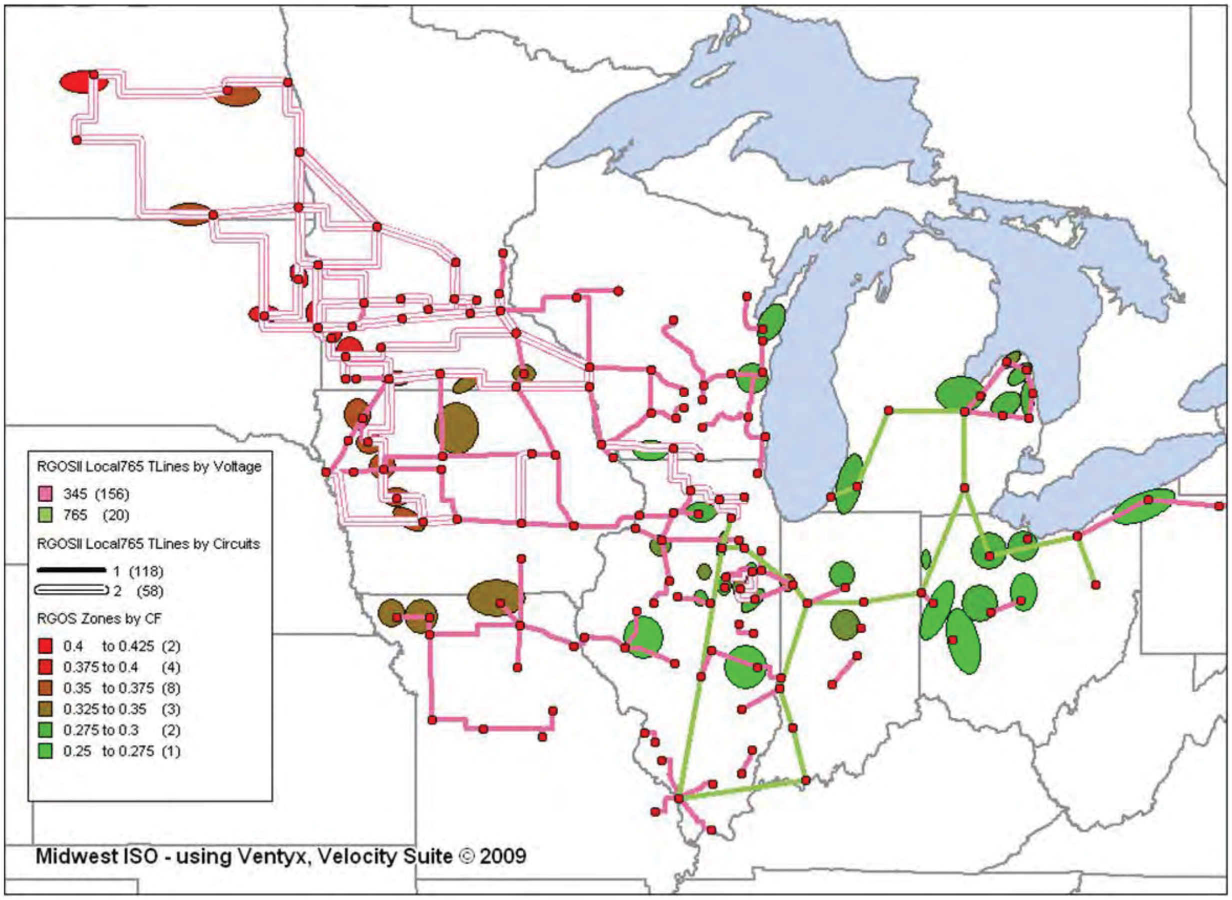

Figure A3.2-1: RGOS Local 765 kV

A3.3 Combo (50/50) 345 kV

Refer to Tables A3.3-1 and A3.3-2.

Table A3.3-1: Combo (50/50) 345 kV Sum of Line Lengths (in Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	1162	997	241	196	230	486		880	4192
765			59	165			155		379
2-345	454	152	254		2701		94	135	3790
Grand Total	**1616**	**1148**	**555**	**361**	**2931**	**486**	**249**	**1016**	**8361**

Table A3.3-2: Combo (50/50) 345 kV Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$1,743	$1,993	$434	$353	$460	$486		$2,201	$7,670
765			$261	$593			$621		$1,474
2-345	$953	$394	$585		$6,753		$234	$406	$9,325
Grand Total	**$2,696**	**$2,387**	**$1,279**	**$946**	**$7,212**	**$486**	**$855**	**$2,608**	**$18,470**

Generation

MW of Capacity	Cost (M$)
32,650	**$65,300.00**

Total Costs (2010 USD in Millions)

Transmission	$18,470
Generation	$65,300
Transformers	
Substations	
Reactors	
Total	**$83,770**

Refer to Figure A3.3-1.

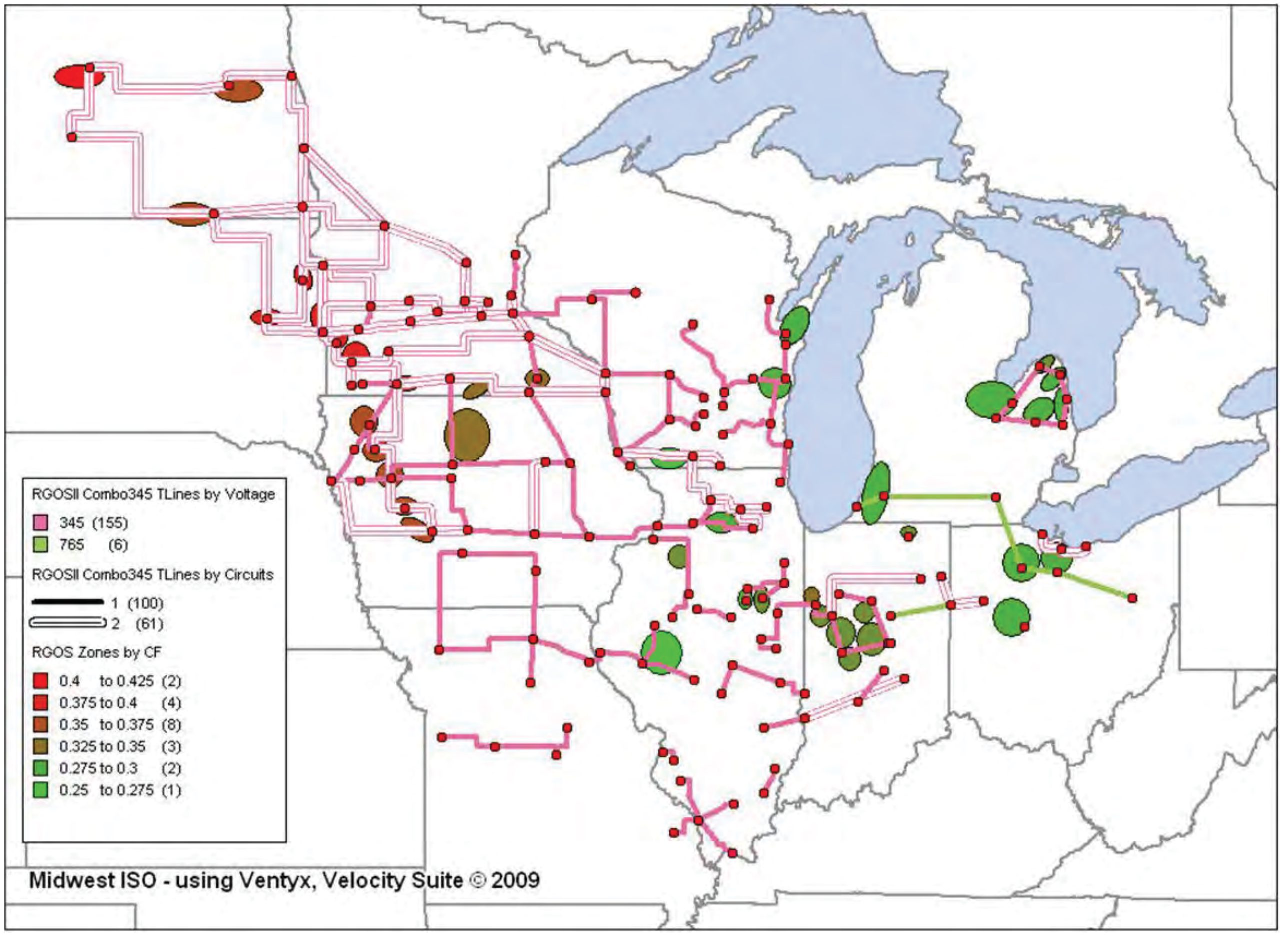

Figure A3.3-1: RGOS Combo (50/50) 345 kV

A3.4 Combo (50/50) 765 kV

Refer to Tables A3.4-1 and A3.4-2.

Table A3.4-1: Combo (50/50) 765 kV Sum of Line Lengths (in Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	443	772	93	196	33	277		828	2642
765	650	505	260	319	1166	324	237	162	3623
2-345	197				1338		59	21	1615
Grand Total	**1290**	**1276**	**353**	**515**	**2537**	**601**	**296**	**1011**	**7880**

Table A3.4-2: Combo (50/50) 765 Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$664	$1,543	$168	$353	$66	$277		$2,070	$5,141
765	$2,731	$2,121	$1,144	$1,148	$5,597	$1,361	$947	$776	$15,826
2-345	$414				$3,346		$147	$62	$3,970
Grand Total	**$3,810**	**$3,664**	**$1,312**	**$1,502**	**$9,008**	**$1,638**	**$1,094**	**$2,909**	**$24,937**

Generation

MW of Capacity	Cost (M$)
32,650	**$65,300.00**

Total Costs (2010 USD in Millions)

Transmission	$24,937
Generation	$65,300
Transformers	
Substations	
Reactors	
Total	**$90,237**

006728

Refer to Figure A3.4-1.

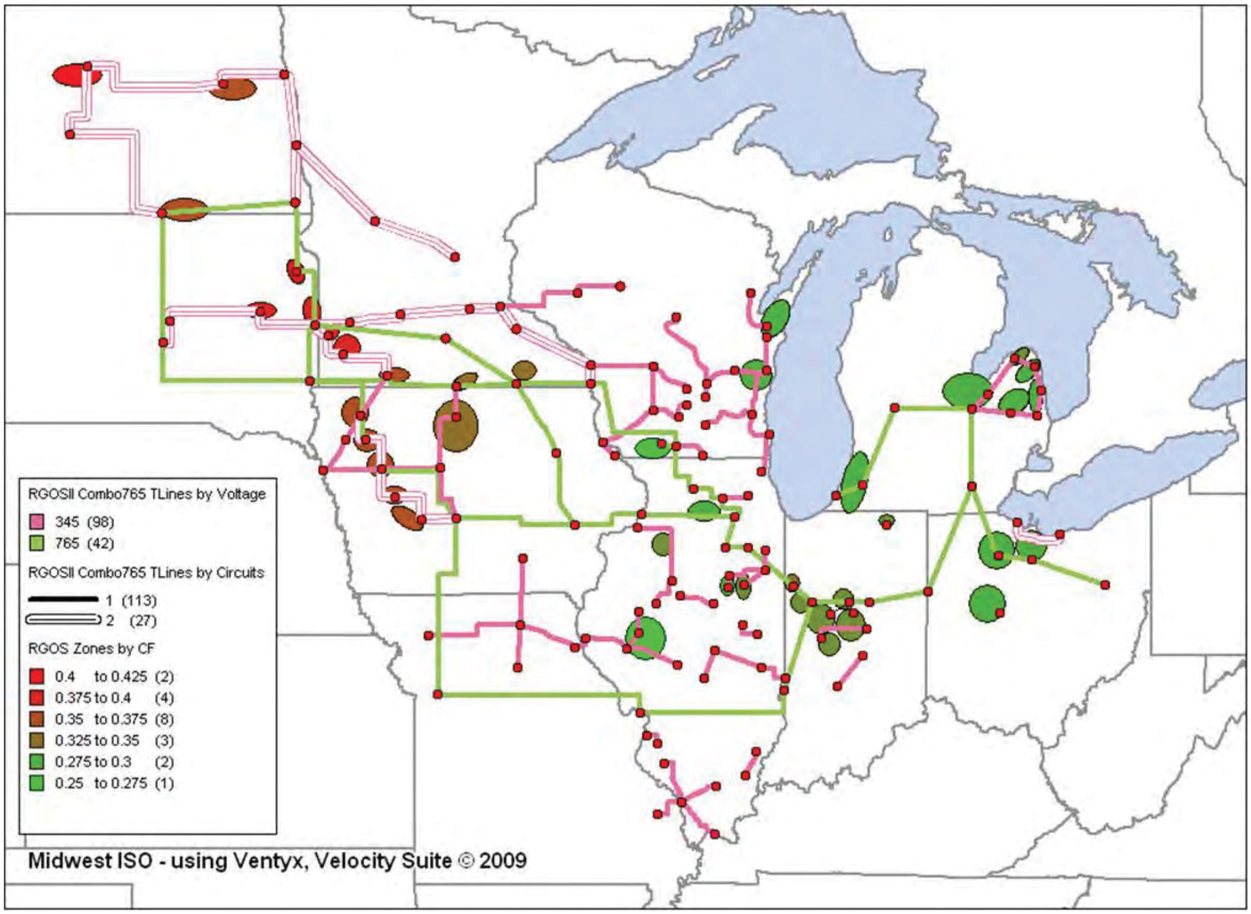

Figure A3.4-1: RGOS Combo (50/50) 765 kV

A3.5 Combo (75/25) 345 kV

Refer to Tables A3.5-1 and A3.5-2.

Table A3.5-1: Combo (75/25) 345 kV Sum of Line Lengths (in Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	1162	997	241	196	230	486		880	4192
765			59	165			155		379
2-345	454	152	254		2701		94	135	3790
Grand Total	**1616**	**1148**	**555**	**361**	**2931**	**486**	**249**	**1016**	**8361**

Table A3.5-2: Combo (75/25) 345 kV Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$1,743	$1,993	$434	$353	$460	$486		$2,201	$7,670
765			$261	$593			$621		$1,474
2-345	$953	$394	$585		$6,753		$234	$406	$9,325
Grand Total	**$2,696**	**$2,387**	**$1,279**	**$946**	**$7,212**	**$486**	**$855**	**$2,608**	**$18,470**

Generation

MW of Capacity	Cost (M$)
31,150	**$62,300.00**

Total Costs (2010 USD in Millions)

Transmission	$18,470
Generation	$62,300
Transformers	
Substations	
Reactors	
Total	**$80,770**

Refer to Figure A3.5-1.

006730

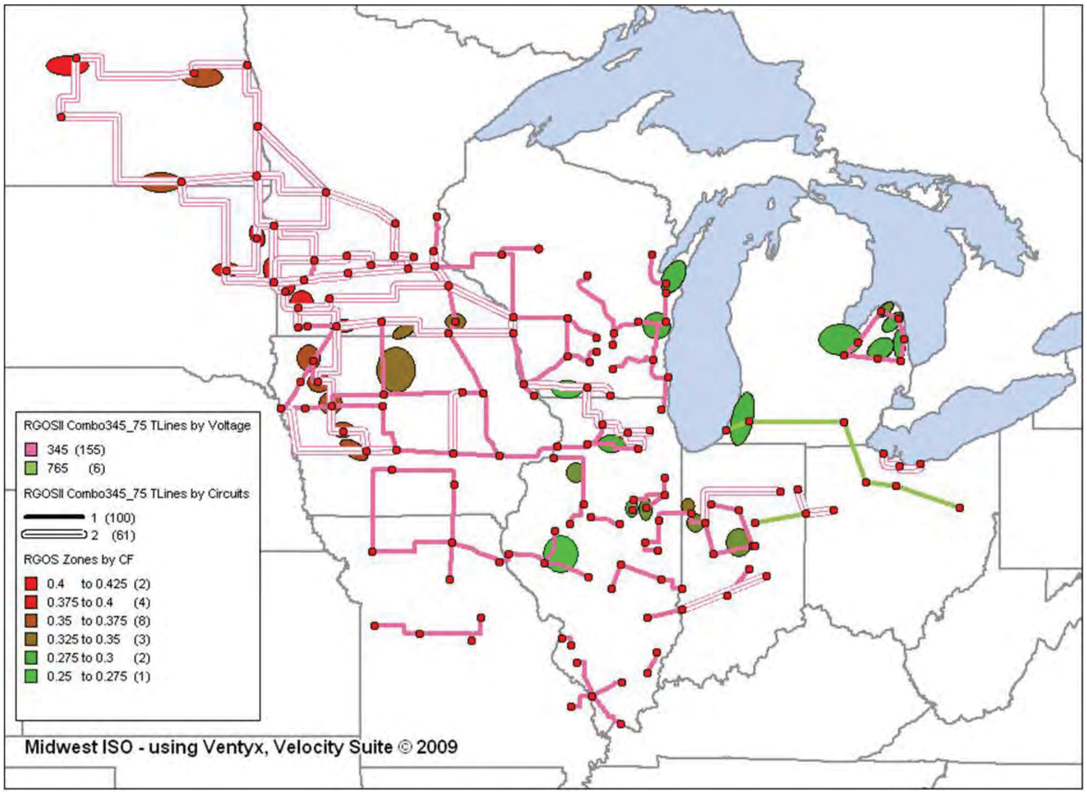

Figure A3.5-1: RGOS Combo (75/25) 345 kV

A3.6 Combo (75/25) 765 kV

Refer to Tables A3.6-1 and A3.6-2.

Table A3.6-1: Combo (75/25) 765 kV Sum of Line Lengths (in Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	443	772	93	196	33	277		828	2642
765	650	505	260	319	1166	324	237	162	3623
2-345	197				1338		59	21	1615
Grand Total	**1290**	**1277**	**353**	**515**	**2537**	**601**	**296**	**1011**	**7880**

Table A3.6-2: Combo (75/25) 765 kV Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$664	$1,543	$168	$353	$66	$277		$2,070	$5,141
765	$2,731	$2,121	$1,144	$1,148	$5,597	$1,361	$947	$776	$15,826
2-345	$414				$3,346		$147	$62	$3,970
Grand Total	**$3,810**	**$3,664**	**$1,312**	**$1,502**	**$9,008**	**$1,638**	**$1,094**	**$2,909**	**$24,937**

Generation

MW of Capacity	Cost (M$)
31,150	**$62,300.00**

Total Costs (2010 USD in Millions)

Transmission	$24,937
Generation	$62,300
Transformers	
Substations	
Reactors	
Total	**$87,237**

006732

Refer to Figure A3.6-1.

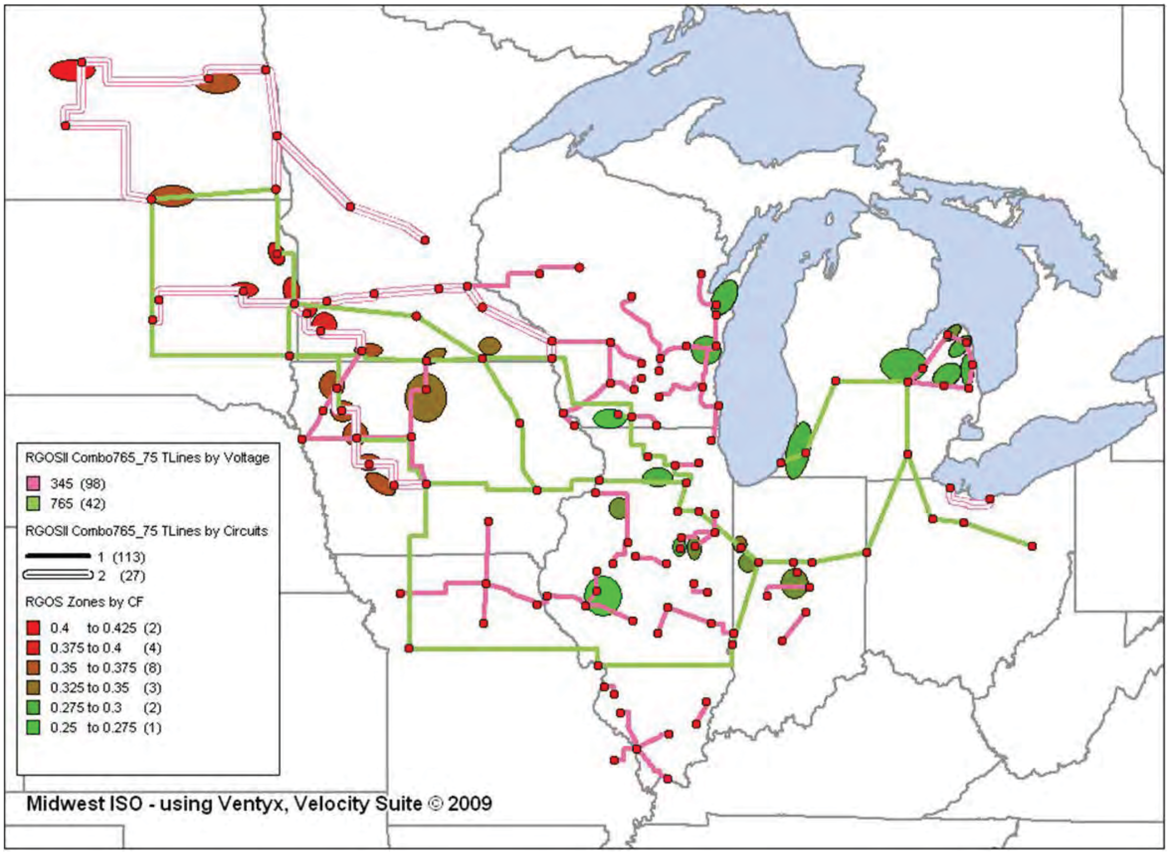

Figure A3.6-1: RGOS Combo (75/25) 765 kV

A3.7 Regional 345 kV

Refer to Tables A3.7-1 and A3.7-2.

Table A3.7-1: Regional 345 kV Sum of Line Lengths (in Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	887	869	39	196	214	486		797	3488
765	150				67		269		487
2-345	729	152			3439			286	4606
400								60	60
800	335	532	489		280	229	363	103	2332
Grand Total	**2101**	**1553**	**528**	**196**	**4000**	**715**	**632**	**1247**	**10973**

Table A3.7-2: Regional 345 kV Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$1,330	$1,739	$71	$353	$427	$486		$1,993	$6,399
765	$631				$324		$1,076		$2,031
2-345	$1,532	$394			$8,598			$859	$11,382
400								$887	$887
800	$3,159	$7,225	$7,131		$3,039	$1,716	$6,854	$1,437	$30,561
Grand Total	**$6,652**	**$9,358**	**$7,202**	**$353**	**$12,388**	**$2,201**	**$7,930**	**$5,176**	**$51,260**

Generation

MW of Capacity	Cost (M$)
33,450	**$66,900.00**

Total Costs (2010 USD in Millions)

Transmission	$51,260
Generation	$66,900
Transformers	
Substations	
Reactors	
Total	**$118,160**

006734

A3.8 Regional 345 kV Optimized

Refer to Tables A3.8-1 and A3.8-2.

Table A3.8-1: Regional 345 kV Optimized Sum of Line Lengths (in Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	887	869	39	196	214	486		797	3488
765	150				67		269		487
2-345	729	152			3439			286	4606
400								60	60
800	335	532	489		280	229	363	103	2332
Grand Total	**2101**	**1553**	**528**	**196**	**4000**	**715**	**632**	**1247**	**10973**

Table A3.8-2: Regional 345 kV Optimized Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$1,330	$1,739	$71	$353	$427	$486		$1,993	$6,399
765	$631				$324		$1,076		$2,031
2-345	$1,532	$394			$8,598			$859	$11,382
400								$887	$887
800	$3,159	$7,225	$7,131		$3,039	$1,716	$6,854	$1,437	$30,561
Grand Total	**$6,652**	**$9,358**	**$7,202**	**$353**	**$12,388**	**$2,201**	**$7,930**	**$5,176**	**$51,260**

Generation

MW of Capacity	Cost (M$)
30,400	$60,800.00

Total Costs (2010 USD in Millions)

Transmission	$51,260
Generation	$60,800
Transformers	
Substations	
Reactors	
Total	**$112,060**

Refer to Figure A3.8-1.

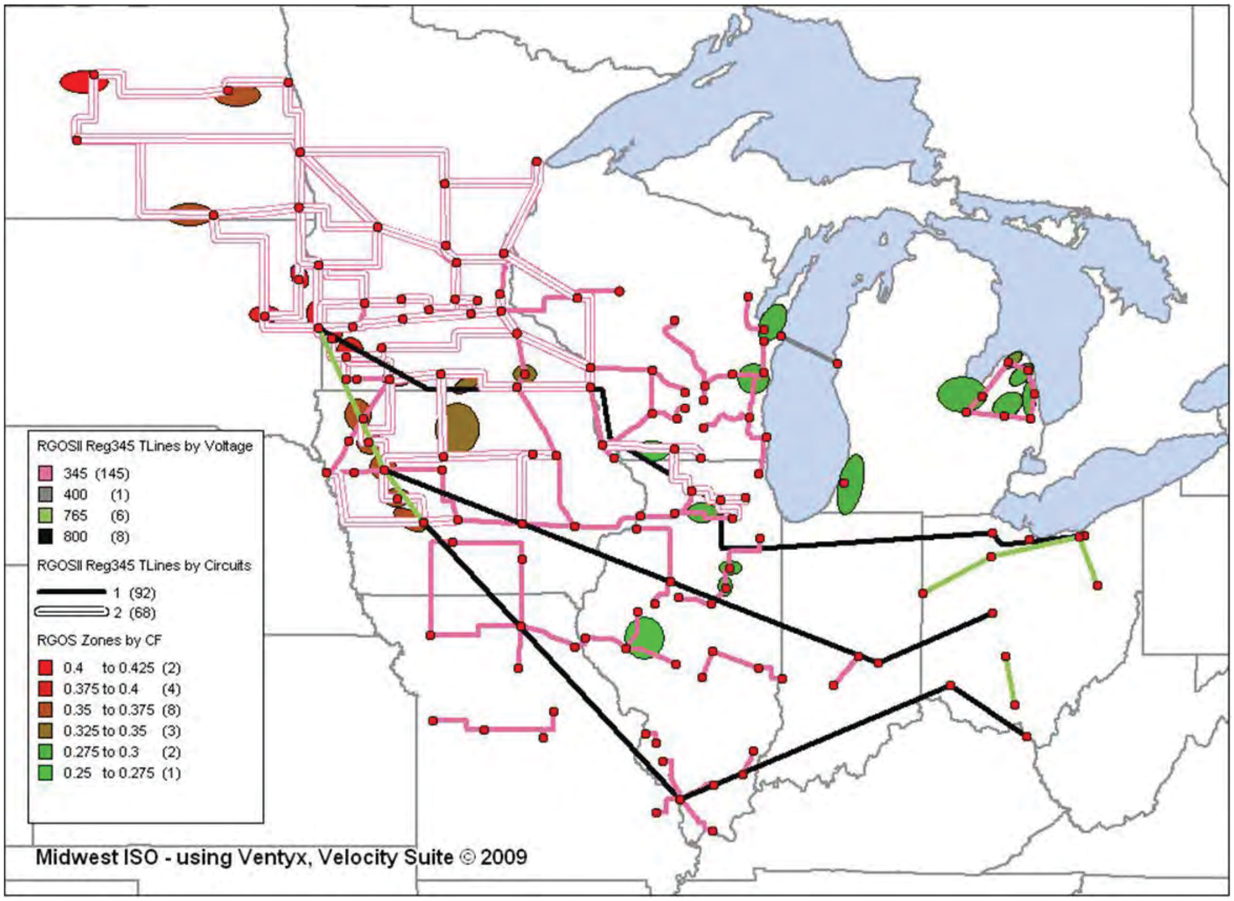

Figure A3.8-1: RGOS Regional 345 kV (with Optimized)

A3.9 Regional 765 kV with DC

Refer to Tables A3.9-1 and A3.9-2.

Table A3.9-1: Regional 765 kV with DC Sum of Line Lengths (in Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	350	781	39	196	32	277		842	2517
765	651	505	354	319	1656	324	317	148	4274
2-345	337				1232			21	1590
400								60	60
800	166	297	437		280	222	3	101	1506
Grand Total	**1504**	**1583**	**830**	**515**	**3200**	**823**	**320**	**1172**	**9947**

Table A3.9-2: Regional 765 kV with DC Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$524	$1,563	$71	$353	$63	$277		$2,105	$4,957
765	$2,735	$2,121	$1,559	$1,148	$7,948	$1,361	$1,269	$708	$18,850
2-345	$707				$3,080			$62	$3,849
400								$887	$887
800	$1,577	$4,286	$4,594		$3,039	$1,699	$2,428	$1,434	$19,057
Grand Total	**$5,544**	**$7,970**	**$6,224**	**$1,502**	**$14,129**	**$3,337**	**$3,696**	**$5,197**	**$47,600**

Generation

MW of Capacity	Cost (M$)
33,450	$66,900.00

Total Costs (2010 USD in Millions)

Transmission	$47,600
Generation	$66,900
Transformers	
Substations	
Reactors	
Total	**$114,500**

006737

A3.10 Regional 765 kV with DC Optimized

Refer to Tables A3.10-1 and A3.10-2.

Table A3.10-1: Regional 765 kV with DC Optimized Sum of Line Lengths (in Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	350	781	39	196	32	277		842	2517
765	651	505	354	319	1656	324	317	148	4274
2-345	337				1232			21	1590
400								60	60
800	166	297	437		280	222	3	101	1506
Grand Total	**1504**	**1583**	**830**	**515**	**3200**	**823**	**320**	**1172**	**9947**

Table A3.10-2: Regional 765 kV with DC Optimized Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$524	$1,563	$71	$353	$63	$277		$2,105	$4,957
765	$2,735	$2,121	$1,559	$1,148	$7,948	$1,361	$1,269	$708	$18,850
2-345	$707				$3,080			$62	$3,849
400								$887	$887
800	$1,577	$4,286	$4,594		$3,039	$1,699	$2,428	$1,434	$19,057
Grand Total	**$5,544**	**$7,970**	**$6,224**	**$1,502**	**$14,129**	**$3,337**	**$3,696**	**$5,197**	**$47,600**

Generation

MW of Capacity	Cost (M$)
30,400	**$60,800.00**

Total Costs (2010 USD in Millions)

Transmission	$47,600
Generation	$60,800
Transformers	
Substations	
Reactors	
Total	**$108,400**

006738

Refer to Figure A3.10-1.

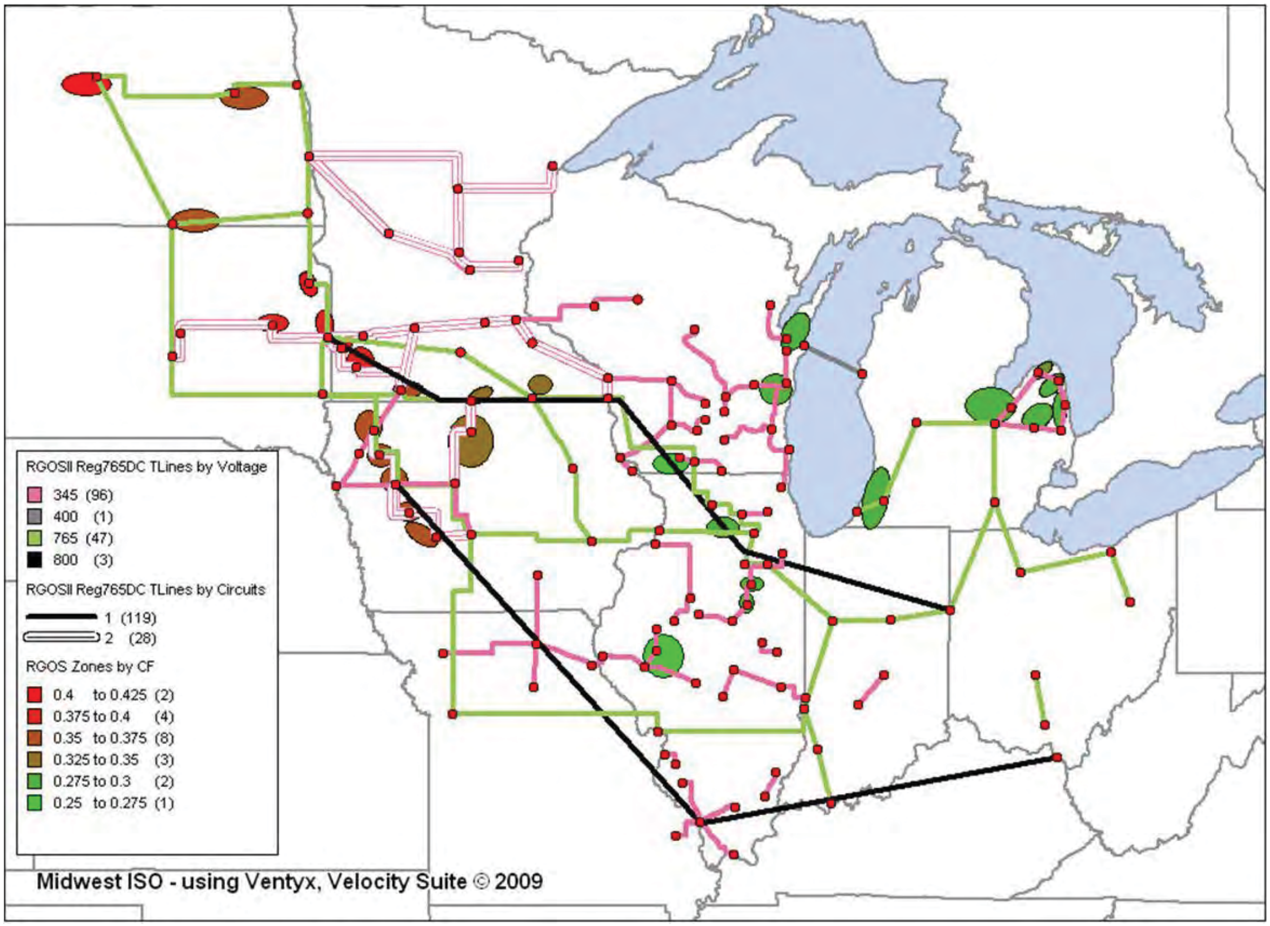

Figure A3.10-1: RGOS Regional 765 kV with DC (with Optimized)

A3.11 Regional 765 kV DC West

Refer to Tables A3.11-1 and A3.11-2.

Table A3.11-1: Regional 765 kV DC West Sum of Line Lengths (in Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	350	755	39	196	32	277		842	2491
765	410	495	393	319	1169		317		3102
2-345	337				1232			21	1590
400								60	60
800	166	166			280	222		99	934
Grand Total	**1263**	**1415**	**432**	**515**	**2712**	**499**	**317**	**1022**	**8176**

Table A3.11-2: Regional 765 kV DC West Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$524	$1,509	$71	$353	$63	$277		$2,105	$4,903
765	$1,723	$2,077	$1,728	$1,148	$5,610		$1,269		$13,555
2-345	$707				$3,080			$62	$3,849
400								$887	$887
800	$1,577	$2,788			$3,039	$1,699		$1,429	$10,531
Grand Total	**$4,532**	**$6,374**	**$1,798**	**$1,502**	**$11,791**	**$1,976**	**$1,269**	**$4,483**	**$33,726**

Generation

MW of Capacity	Cost (M$)
33,450	**$66,900.00**

Total Costs (2010 USD in Millions)

Transmission	$33,726
Generation	$66,900
Transformers	
Substations	
Reactors	
Total	**$100,626**

006740

A3.12 Regional 765 kV DC West Optimized

Refer to Tables A3.12-1 and A3.12-2.

Table A3.12-1: Regional 765 kV DC West Optimized Sum of Line Lengths (in Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	350	755	39	196	32	277		842	2491
765	410	495	393	319	1169		317		3102
2-345	337				1232			21	1590
400								60	60
800	166	166			280	222		99	934
Grand Total	**1263**	**1415**	**432**	**515**	**2712**	**499**	**317**	**1022**	**8176**

Table A3.12-2: Regional 765 kV DC West Optimized Sum of Line Lengths (in Miles)Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$524	$1,509	$71	$353	$63	$277		$2,105	$4,903
765	$1,723	$2,077	$1,728	$1,148	$5,610		$1,269		$13,555
2-345	$707				$3,080			$62	$3,849
400								$887	$887
800	$1,577	$2,788			$3,039	$1,699		$1,429	$10,531
Grand Total	**$4,532**	**$6,374**	**$1,798**	**$1,502**	**$11,791**	**$1,976**	**$1,269**	**$4,483**	**$33,726**

Generation

MW of Capacity	Cost (M$)
30,400	**$60,800.00**

Total Costs (2010 USD in Millions)

Transmission	$33,726
Generation	$60,800
Transformers	
Substations	
Reactors	
Total	**$94,526**

006741

Refer to Figure A3.12-1.

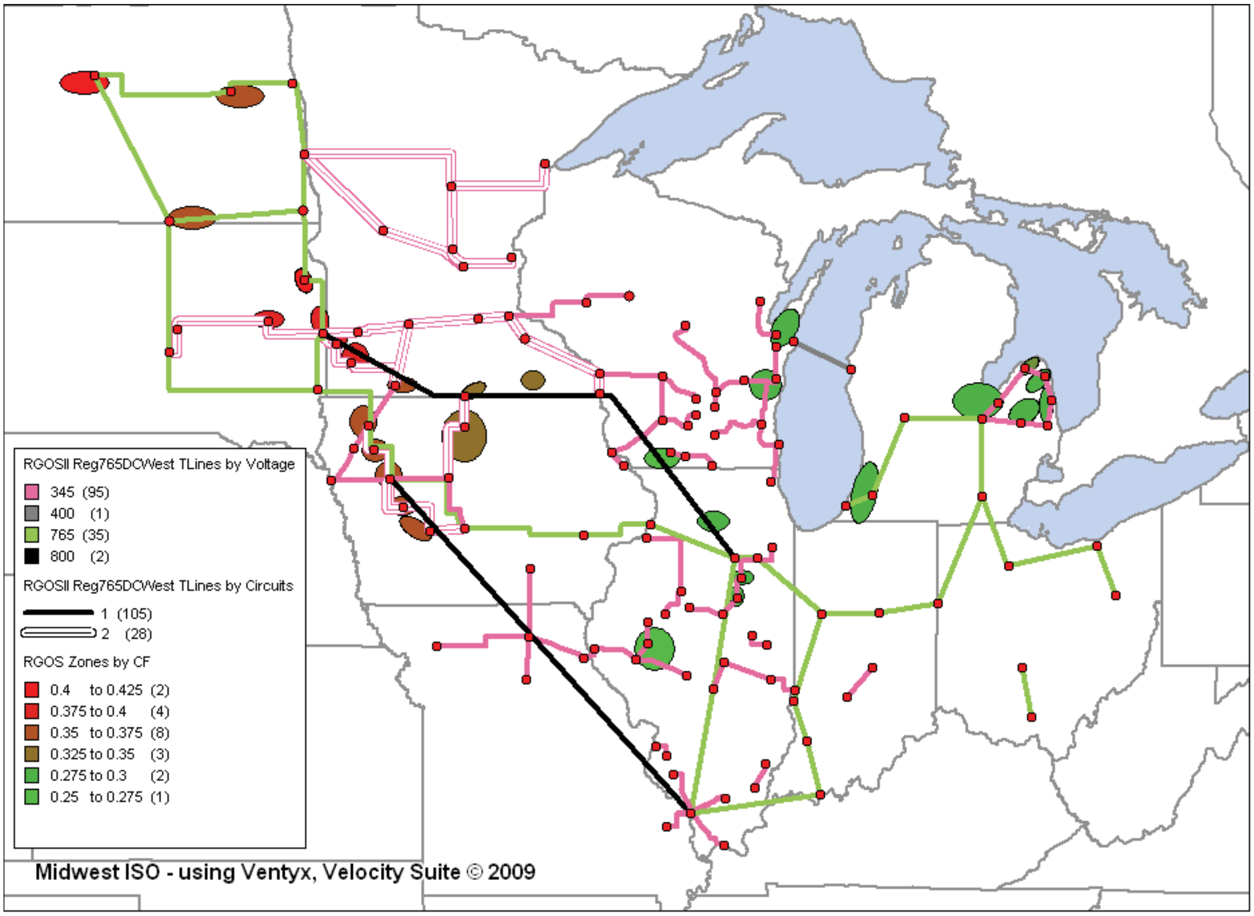

Figure A3.12-1: RGOS Regional 765 kV DC West (with Optimized)

A3.13 Regional 765 kV

Refer to Tables A3.13-1 and A3.13-2.

Table A3.13-1: Regional 765 kV Sum of Line Lengths (in Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	350	781	39	196	32	277		842	2517
765	651	834	411	319	1656	324	317	148	4660
2-345	337				1232			21	1589
400								60	60
Grand Total	**1338**	**1615**	**450**	**515**	**2919**	**601**	**317**	**1071**	**8827**

Table A3.13-2: Regional 765 kV Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$524	$1,563	$71	$353	$63	$277		$2,105	$4,957
765	$2,735	$3,503	$1,807	$1,148	$7,948	$1,361	$1,269	$708	$20,480
2-345	$707				$3,079			$62	$3,849
400								$887	$887
Grand Total	**$3,967**	**$5,066**	**$1,877**	**$1,502**	**$11,090**	**$1,638**	**$1,269**	**$3,763**	**$30,173**

Generation

MW of Capacity	Cost (M$)
33,450	**$66,900.00**

Total Costs (2010 USD in Millions)

Transmission	$30,173
Generation	$66,900
Transformers	
Substations	
Reactors	
Total	**$97,073**

006743

A3.14 Regional 765 kV Optimized

Refer to Tables A3.14-1 and A3.14-2.

Table A3.14-1: Regional 765 kV Optimized Sum of Line Lengths (in Miles)

Type (kV)	States								Total Line Length
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	350	781	39	196	32	277		842	2517
765	651	834	411	319	1656	324	317	148	4660
2-345	337				1232			21	1589
400								60	60
Grand Total	**1338**	**1615**	**450**	**515**	**2919**	**601**	**317**	**1071**	**8827**

Table A3.14-2: Regional 765 kV Optimized Sum of Total Cost

Type (kV)	States								Grand Total
	IA	IL	IN	MI	MN/Dak	MO	OH/PA	WI	
345	$524	$1,563	$71	$353	$63	$277		$2,105	$4,957
765	$2,735	$3,503	$1,807	$1,148	$7,948	$1,361	$1,269	$708	$20,480
2-345	$707				$3,079			$62	$3,849
400								$887	$887
Grand Total	**$3,967**	**$5,066**	**$1,877**	**$1,502**	**$11,090**	**$1,638**	**$1,269**	**$3,763**	**$30,173**

Generation

MW of Capacity	Cost (M$)
30,400	**$60,800.00**

Total Costs (2010 USD in Millions)

Transmission	$30,173
Generation	$60,800
Transformers	
Substations	
Reactors	
Total	**$90,973**

006744

Refer to Figure A3.14-1.

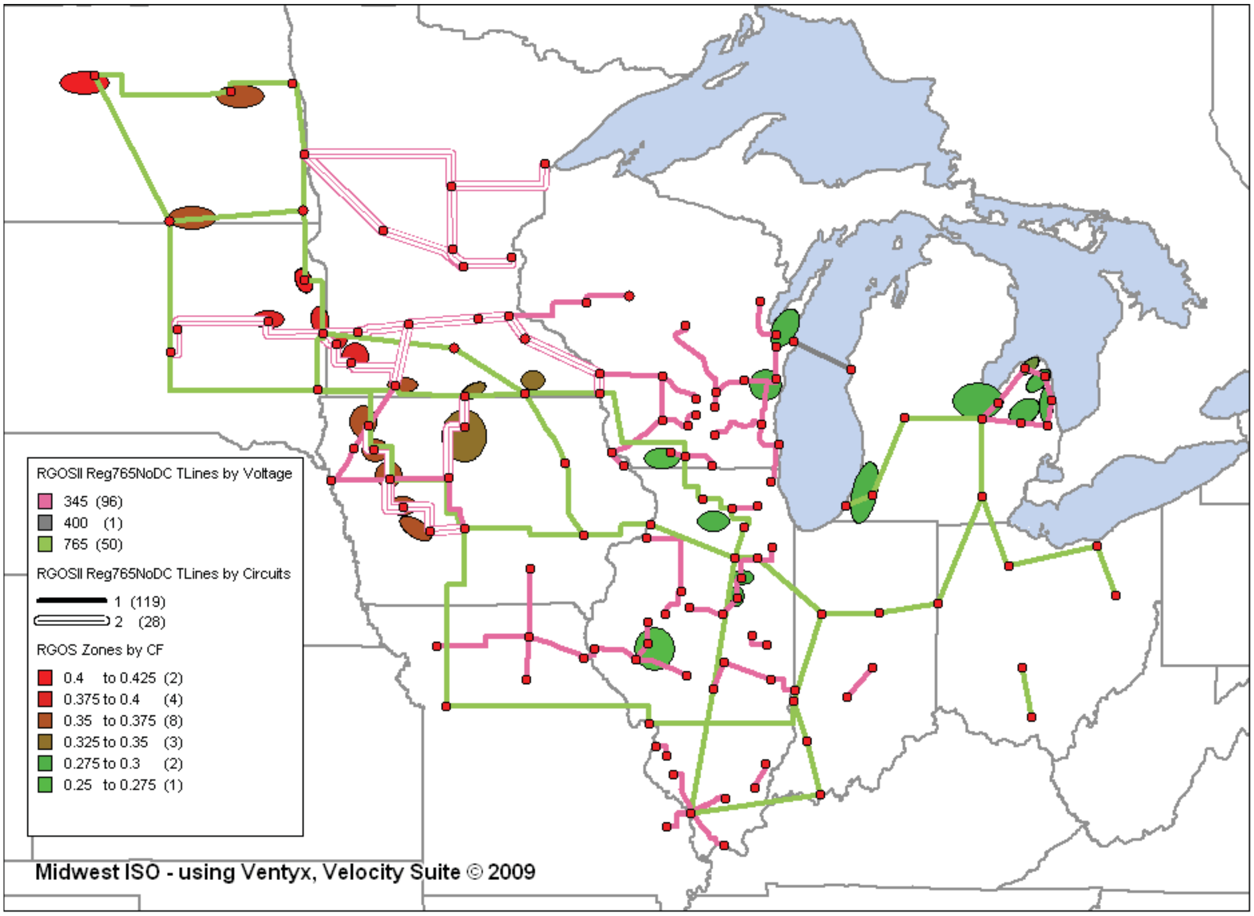

Figure A3.14-1: RGOS Regional 765 kV Optimized

006745

MISO Transmission Expansion Plan
2011

006746

Appendices

1. Executive Summary

The annual MISO Transmission Expansion Plan (MTEP) identifies solutions to meet transmission needs and create value opportunities over the next decade and beyond. These solutions are defined via the implementation of a comprehensive planning approach which identifies essential transmission projects for approval and subsequent construction. MISO staff recommends the projects listed and described in MTEP11 Appendix A[1] to the MISO Board of Directors for their review and approval.

MTEP11, the eighth edition of this publication, is the culmination of more than 18 months of collaboration between MISO planning staff and stakeholders. The primary purpose of this and other MTEP iterations is to identify transmission projects that:

- Ensure the reliability of the transmission system over the planning horizon.
- Provide economic benefits, such as increased market efficiency.
- Facilitate public policy objectives, such as meeting Renewable Portfolio Standards.
- Address other issues or goals identified through the stakeholder process.

MTEP11 recommends $6.5[2] billion in new transmission expansion through the year 2021 for inclusion in Appendix A and construction. This is part of a continuing effort to ensure a reliable and efficient electric grid that keeps pace with energy and policy demands. Key findings and activities from the MTEP11 cycle include:

- **Recommendation of the first Multi Value Project portfolio for approval by the MISO Board of Directors:** The portfolio is comprised of 17 projects, costing $5.6 billion.[3] The proposed Multi Value Project (MVP) portfolio will create a regional network that provides reliability, public policy and economic benefits spread across MISO, such as
  - **Reliability benefits:** The proposed MVP portfolio mitigates approximately 650 reliability violations for more than 6,700 system conditions, increasing the transmission system's robustness under normal operation and extreme events.
  - **Public policy benefits:** The proposed MVP portfolio enables the delivery of 41 million MWh of renewable energy.
  - **Economic benefits:** The proposed MVP portfolio provides benefits in excess of the portfolio cost under all scenarios studied. These benefits are spread throughout the system, and each zone[4] receives benefits of at least 1.6 and up to 2.8 times the costs it incurs.
  - **Qualitative benefits:** The proposed MVP portfolio provides a number of additional qualitative benefits. For example, the transmission will support a variety of generation policies through utilizing a set of energy zones which support wind, natural gas and other fuel sources
  - **Job creation:** The construction of the proposed MVP portfolio will create between 17,000 and 39,800 direct jobs, or between 28,400 and 74,000 total jobs, including construction, supplier and downstream impacts.
- **Recommendation of 199 new Baseline Reliability, Generation Interconnection, or Other projects totaling $1.4 billion for approval by the MISO Board of Directors[5]:** These projects, together with proposed projects listed in Appendix B, ensure compliance with all reliability standards

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[1] Projects in Appendix A reflect planned projects approved by or recommended for approval by the Board of Directors. Projects in Appendix B represent proposed projects for which a need has been identified, but are not timely or require additional analysis. Appendix C contains projects for which the need has not been verified.

[2] $6.5 billion figure includes the $849 million in projects that were either approved or conditionally approved at the June 2011 MISO Board of Directors meeting.

[3] Portfolio cost is as submitted and reflects nominal in-service date costs in whole or in part; the portfolio cost is equivalent to $5.2 billion in 2011 dollars. Total portfolio cost includes the Brookings County project, conditionally approved in June 2011 and the Michigan Thumb project, approved in December 2010.

[4] Benefits were calculated based on the MISO proposed Local Resource Zones for Resource Adequacy

[5] Total includes $118.5 million of projects that were approved during the June approval cycle.

and requirements and allow for the interconnection of approximately 2,700 MW of wind, nuclear, and other generation.

- **Economic assessment of transmission expansion:** In addition to the proposed Multi Value Project portfolio, Appendices A and B contain a variety of planned and proposed transmission projects. Although premised largely on reliability, a subset of these projects will deliver market congestion reduction benefits of 0.9 to 1.0 times their cost beginning in 2016.
- **Confirmation of Long-Term Generation Resource Adequacy:** The system has adequate capacity to meet its reserve requirements or Loss of Load Expectation (LOLE) criteria through 2021 based on currently announced generation retirements. However, these conclusions do not take into account capacity retirements that might be required by regulations imposed by the U.S. Environmental Protection Agency (EPA), which could significantly, and rapidly, erode reserve margins.
- **Determination of the potential impacts of EPA regulations on generation retirements:** At the direction of stakeholders and Board of Directors, MISO evaluated the potential impacts of four new EPA regulations, including the impact of carbon reduction requirements. This study found the following potential impacts:
    - **Units at risk for retirement:** Depending on economic conditions, including the cost of environmental regulation compliance, approximately 13 GW of existing coal generation is at-risk for retirement.
    - **Potential cost of compliance:** The total 20-year net present value capital cost of compliance is expected to exceed $30 billion. This value includes the cost of retrofits on the system, the cost of replacement capacity, the cost of fixed operations and maintenance and the cost of transmission upgrades. This cost of compliance could increase the cost of energy by $5/MWh.
    - **Generation Resource adequacy impacts:** If no replacement capacity is identified for Resource Adequacy purposes, then the system reserve margin could decrease to 6.6 percent in 2021. The 2021 reserve requirement is 18.2 percent.
- **Full implementation of a regional transmission planning approach:** The proposed MVP portfolio is the realization of more than eight years of process, policy and engineering analysis. These solutions are premised on the integration of local and regional needs into a transmission solution that, when combined with the existing transmission system, provides the least cost delivered energy to customers.

In MTEP11, MISO completed analyses showing the near and long term affects of proposed transmission lines. In the coming years, MISO, through the continued integration of reliability, economic and public policy projects, will continue to drive grid efficiencies by ensuring that near-term projects support long-term goals.

The MISO planning approach

MISO is guided in its planning efforts by a set of principles established by its Board of Directors. These principles were created to improve and guide transmission investment in the region and to furnish an element of strategic direction to the MISO transmission planning process. These principles, confirmed in August 2011, are as follows:

- **Guiding Principle 1:** Make the benefits of an economically efficient energy market available to customers by providing access to the lowest electric energy costs.
- **Guiding Principle 2:** Provide a transmission infrastructure that safeguards local and regional reliability and supports interconnection-wide reliability.
- **Guiding Principle 3:** Support state and federal energy policy objectives by planning for access to a changing resource mix.
- **Guiding Principle 4:** Provide an appropriate cost mechanism that ensures the realization of benefits over time is commensurate with the allocation of costs.
- **Guiding Principle 5:** Develop transmission system scenario models and make them available to state and federal energy policy makers to provide context and inform the choices they face.

To support these principles, a transmission planning process has been implemented reflecting a view of project value inclusive of reliability, market efficiency, public policy and other value drivers across all planning horizons studied. A number of conditions must be met through this process to build long-term transmission that can support future generation growth and accommodate new energy policy imperatives. These conditions are intertwined with the planning principles put forth by the MISO Board of Directors and include:

- A robust business case for the plan.
- Increased consensus around regional energy policies.
- A regional tariff matching who benefits with who pays over time.
- Cost recovery mechanisms to reduce financial risk.

The following activities were undertaken to fulfill these conditions and—through them—the planning principles enunciated by the Board of Directors:

- **Safeguarding local and regional reliability:** System reliability must be maintained throughout all MISO planning efforts, both on a local and interconnection-wide basis. This requirement can be difficult, in the face of changing generation and energy policy standards. Throughout 2011, MISO continued the transformation of the planning process to create an integrated transmission network that supports current and future reliability needs, while minimizing the cost of delivered energy. This value-based planning approach demonstrates a robust view of project benefits, through the analyses of many potential reliability, economic and policy-driven variables.
- **Distributing benefits commensurate with costs**: The MISO planning approach is premised on the allocation of transmission costs in a manner that is commensurate with their benefits. To ensure this goal was met, MISO created a complete business case for the proposed Multi Value Project portfolio which demonstrated the regional spread of the economic benefits of the portfolio. In the future, MISO will continue to refine the business case for transmission projects and portfolios, as staff seek to optimize the transmission system to deliver the least-cost energy to consumers.
- **Responding to evolving energy policy:** MISO examines multiple future scenarios in order to capture the impact of a wide array of potential policy outcomes. These future scenarios include varied demand and energy growth levels, and they also include the implementation of new policies which may have large impacts on the transmission system. For example, MISO conducted a thorough analysis of the U.S. Environmental Protection Agency (EPA) regulations to determine the impacts and action which will need to be taken as the regulations go into effect.

Investments in system reliability and efficiency

To respond to existing energy mandates and safeguard the system reliability, MTEP11 recommends 215 new projects for inclusion in Appendix A. These projects represent an incremental $6.5 billion in transmission infrastructure investment within the MISO footprint and fall into the following four categories:

- **Multi Value Projects (16 projects, $5.1[6] billion):** Projects providing regional public policy, reliability and/or economic benefits.
- **Baseline Reliability Projects (40 projects, $424 million):** Projects required to meet North American Electric Reliability Corporation (NERC) reliability standards. These standards impact facilities of a voltage greater than 100kV and represent the minimum standard applied across the MISO footprint.
- **Generator Interconnection Projects (26 projects, $273 million[7]):** Projects required to reliably connect new generation to the transmission grid. The projects recommended for approval will allow for the connection of approximately 2,700 MW of wind, nuclear, and other generation
- **Other Projects (133 projects, $681 million):** A wide range of projects, such as those designed to provide local economic benefit but not meeting the threshold requirements for qualification as Market Efficiency Project (MEP), and projects required to support the lower voltage transmission system.

The addition of new transmission projects in MTEP11 brings the total number of projects in Appendix A to 553, representing an expected investment of $10.0 billion through 2021. When completed, the projects will result in approximately 6,600 miles of new or upgraded transmission lines. Since the first MTEP cycle closed in 2003, transmission projects recommended for approval total $14.3 billion, of which $4.3 billion is associated with projects already in service.

MTEP11 contains 24 new Appendix A projects meeting cost-sharing eligibility criteria under the Baseline Reliability Project or Generator Interconnection provisions of the MISO Tariff. This report also features 16 projects meeting Multi Value Project cost sharing methodology criteria.

Economic assessment of planned and proposed projects

As previously described, projects currently contained in Appendices A and B are primarily intended to address a reliability issue or need on the transmission system. However, those projects also have potential to create additional value, including the following:

- Adjusted Production Cost Savings
- Reduced Energy And Capacity Losses
- Reduced Reserve Margins

For example, Table 1-1 shows an estimated Adjusted Production Cost benefit of $867 million in 2016 against a first year modeled transmission portfolio cost of approximately $1.1 billion. This benefit will lead to 20 to 40 year present value benefits of $9.1 to $20.6 billion, and economic benefit-to-cost ratios of 0.9 to 1.0. These economic benefits are in addition to the benefits derived from increased system reliability considerations initially driving the need for the majority of these projects.

	2016 Adjusted Production Cost savings	20 Year Present Value, 3 percent Discount Rate	20 Year Present Value, 8.2 percent Discount Rate	40 Year Present Value, 3 percent Discount Rate	40 Year Present Value, 8.2 percent Discount Rate
MISO East	$367	$5,627	$3,844	$8,742	$4,638
MISO Central	$145	$2,210	$1,509	$3,433	$1,821
MISO West	$355	$5,436	$3,714	$8,447	$4,482
MISO	$867	$13,273	$9,066	$20,622	$10,941

Table 1-1: Adjusted Production Cost benefits, in millions of 2016 dollars

6 Portfolio cost shown is as submitted and reflects nominal in-service date costs in whole or in part; equivalent to $4.7 billion in 2011 dollars. The Michigan Thumb Loop Expansion project with a cost of $510 million (2011 dollars) was approved in MTEP 10 and is part of the proposed Multi Value Project Portfolio. Its costs are not included in the above figure.

7 Project cost shown is the total cost, not just the cost shared or Transmission Owner contribution.

The value-based planning process

Uncertainties surrounding future policy decisions create challenges for those involved in the planning function and cause hesitancy for those with the resources to undertake transmission expansion projects. To minimize the risk in building a system under such conditions, the planning process must allow consideration of transmission projects in the context of potential outcomes. The goal is to identify plans resulting in the optimum amount of future value and the least amount of future regrets in areas such as cost incurred, right of way used, and benefits achieved.

MTEP11 identified and examined a wide array of future scenarios, which include the following:

- **The Business As Usual (BAU) with Mid-Low Demand and Energy Growth Rates Future Scenario** is considered a status quo future scenario and continues the economic downturn-affected growth in demand, energy and inflation rates.
- **The Business as Usual (BAU) with Historic Demand and Energy Growth Rates Future Scenario** is considered a status quo scenario, with a quick recovery from the economic downturn in demand and energy projections.
- **The Carbon Constraint Future Scenario** models a declining cap on future CO2 emissions. The carbon cap is modeled after the Waxman-Markey Bill, which has an 83 percent reduction of CO2 emissions from a 2005 baseline by the year 2050.
- **The Combined Energy Policy Future Scenario** includes a 20 percent federal RPS, a carbon cap modeled after the Waxman-Markey Bill, a "smart" transmission grid, and electric vehicles.

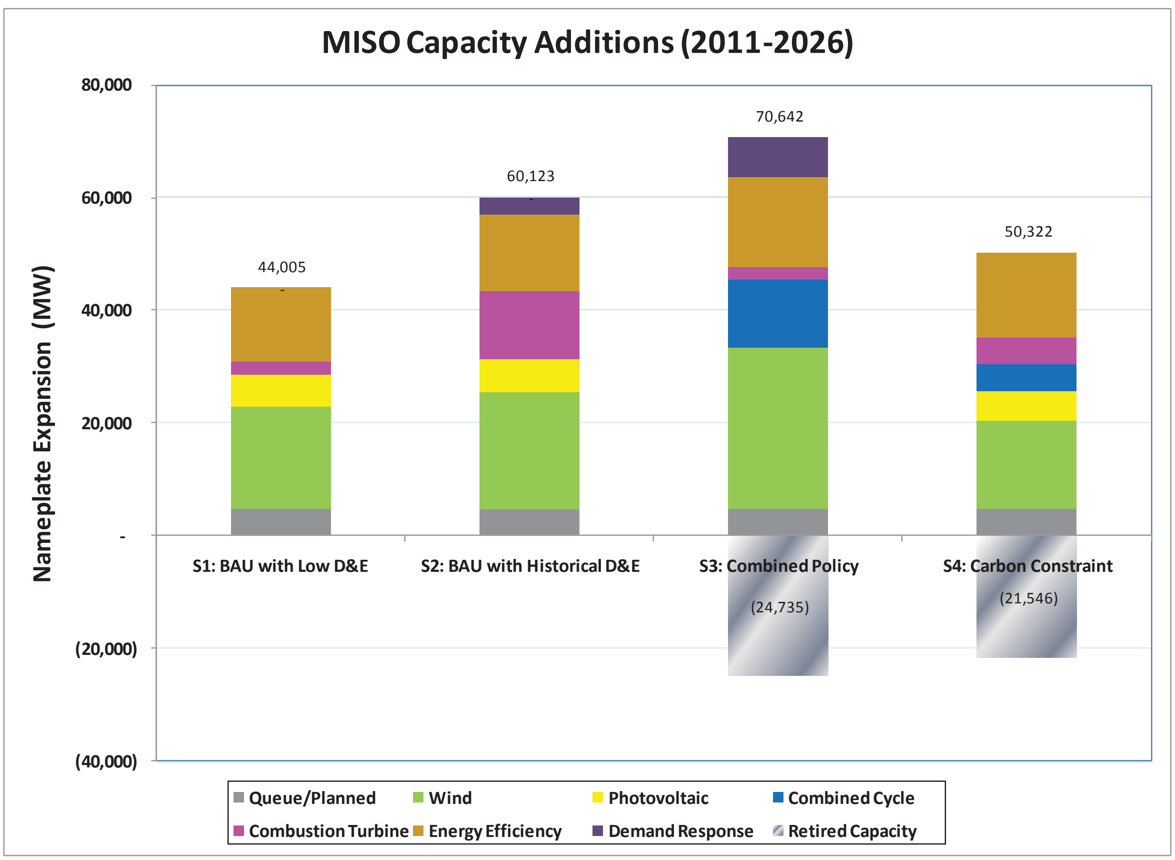


Figure 1-1: Generation Resources per Future Scenario

Potential retail rate impacts for future policy scenarios

To measure the potential impact to rate payers under each of the future scenarios, MISO projected potential impacts to the 2026 retail rate by calculating the impact of wholesale costs related to generation capital investment, production costs, transmission capital investment and distribution costs across the forecasted energy usage levels. In general, these rate impacts reflect differences between the type of generation and the associated transmission needed to integrate the generation in the various scenarios. Refer to Figure 1-1 for additional detail on theoretical impacts under various futures.

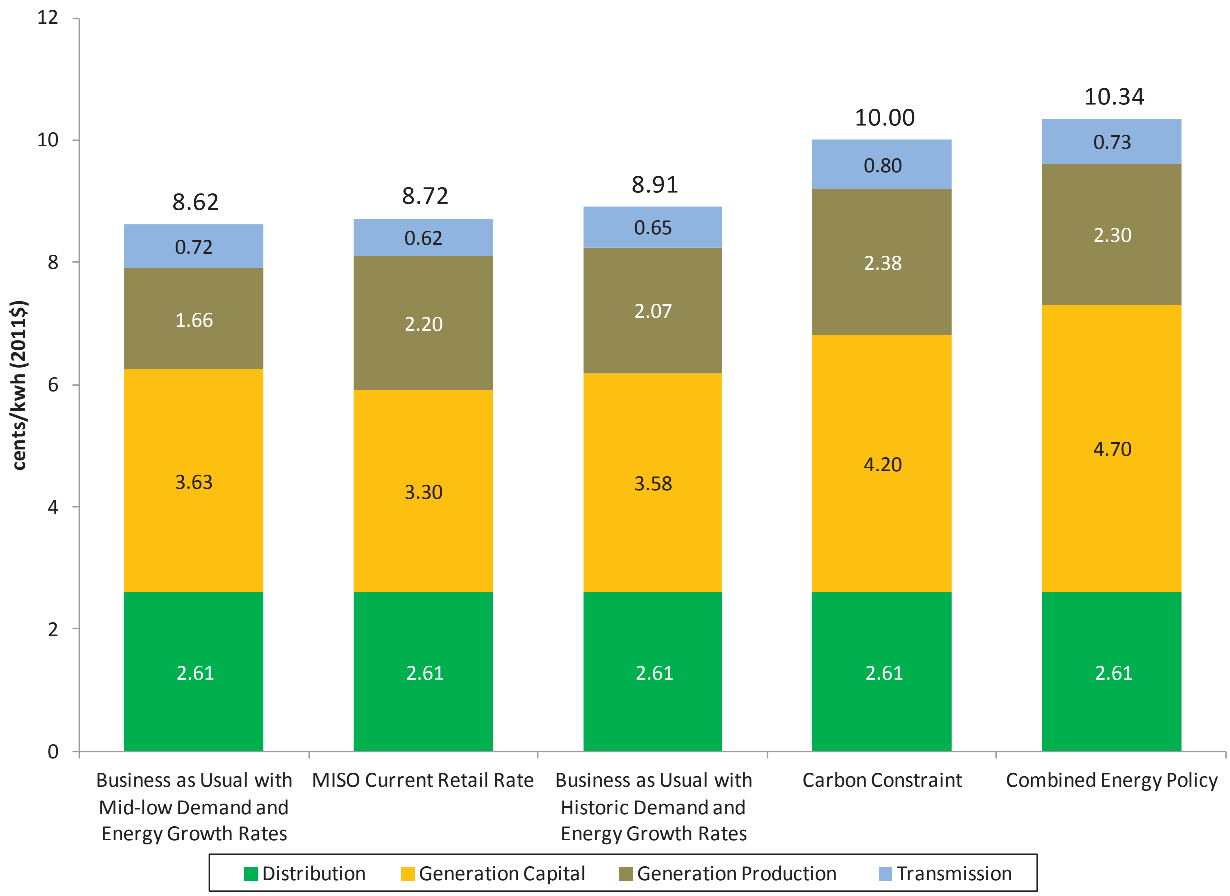


Figure 1-2: Comparison of estimated retail rate for each future scenario (cents per KWh in 2011 dollars)

Assuming that wholesale costs flow through to retail rates, rates for retail customers are projected to increase faster than inflation in all but one scenario, but the magnitude of the rate increases will vary greatly depending on actual economic and policy conditions. Assuming that all of the increase or decrease in wholesale costs flows through to the retail customer, this impact could range from a decrease of 1 percent for the Business as Usual with Mid-low Demand and Energy Growth Rate Future to an increase of 18.7 percent for the Combined Energy Policy Future.

Proposed MVP portfolio

The proposed MVP portfolio is the culmination of more than eight years of transmission planning solutions, as transmission projects identified in MTEP03 through MTEP10 were brought together to form a cohesive, regional plan. Approximately 11 months of intensive studies were performed on the candidate portfolio, with heavy stakeholder involvement and review. At the end of the study, MISO recommends a proposed MVP portfolio for review and approval by the Board of Directors.

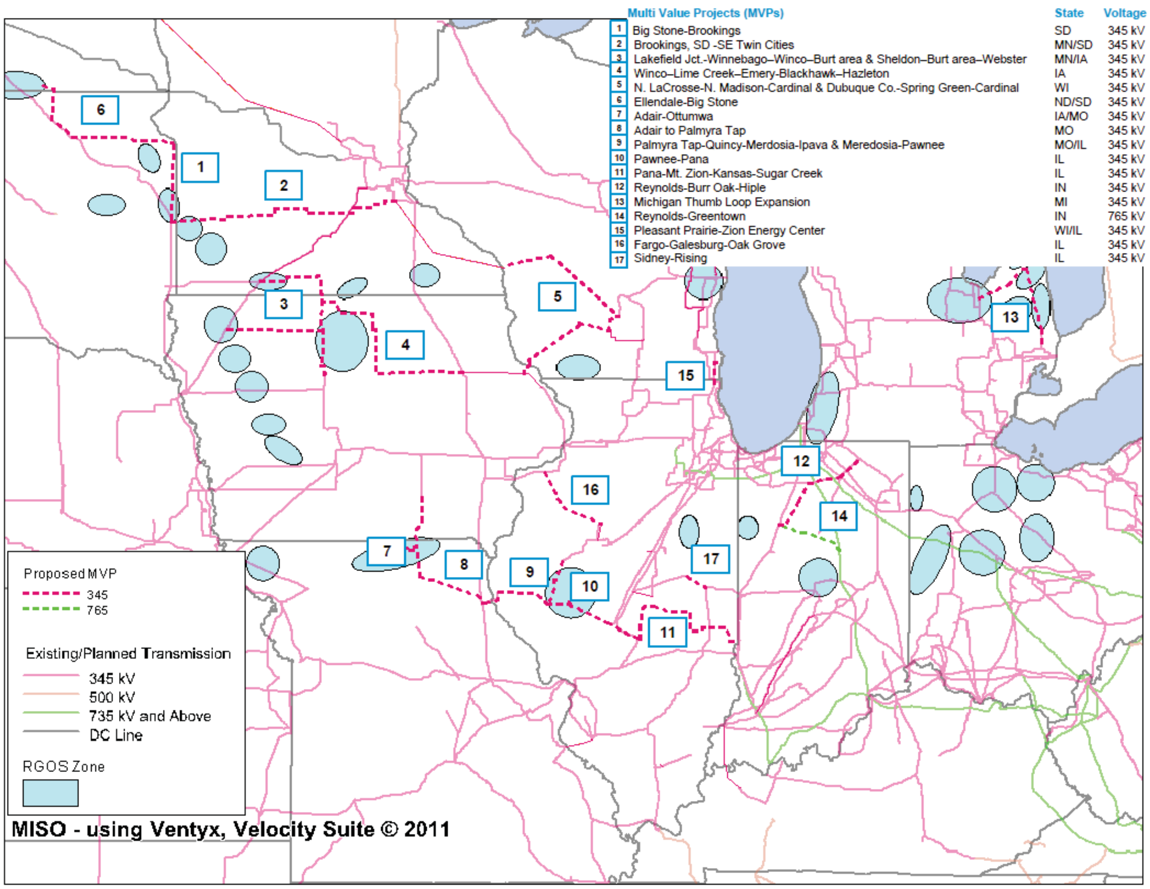


Figure 1-3: Proposed MVP portfolio

The proposed MVP portfolio combines reliability, economic and public policy drivers to provide a transmission solution that provides benefits in excess of its costs throughout the MISO footprint. This portfolio, when integrated into the existing and planned transmission network, resolves about 650 reliability violations for more than 6,700 system conditions, enabling the delivery of 41 million MWh of renewable energy annually to load. The portfolio also provides strong economic benefits; all zones[8] within the MISO footprint see benefits of at least 1.6 to 2.8 times their cost.

[8] Benefits were calculated based on the MISO proposed Local Resource Zones for Resource Adequacy

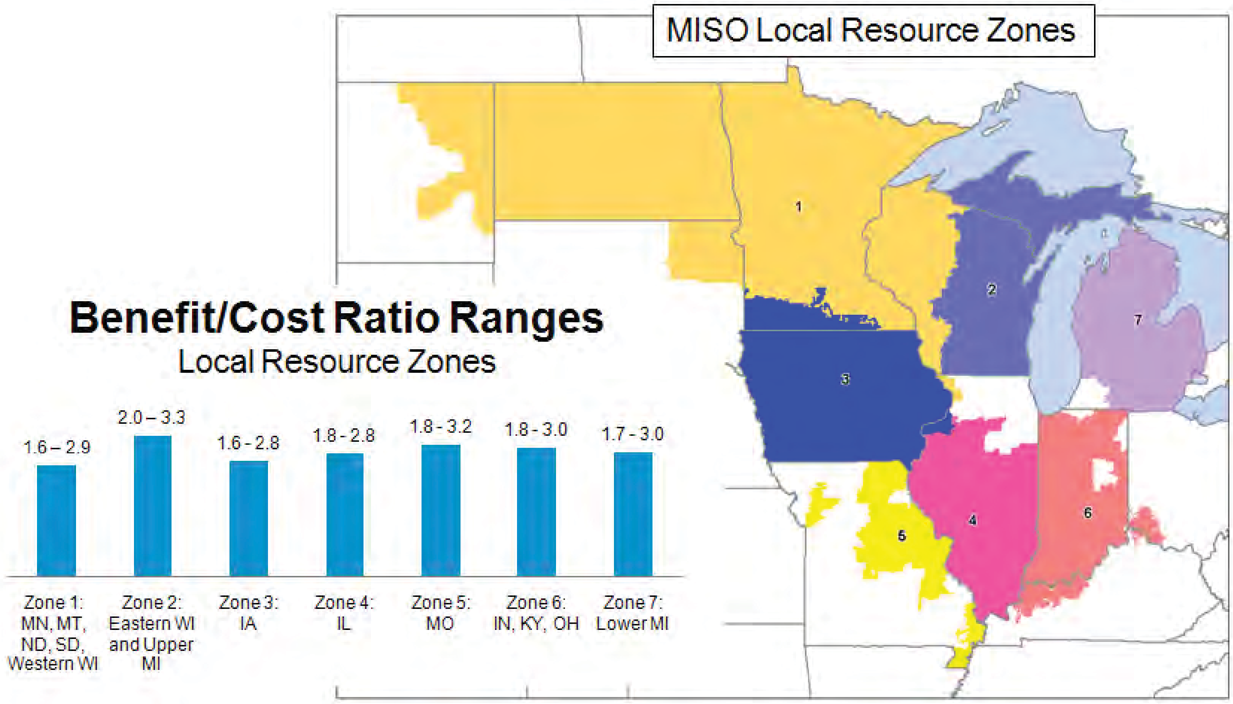


Figure 1-4: Proposed MVP portfolio Zonal benefit-cost ratios

The portfolio also creates a transmission network that is able to respond to the ever-evolving reliability, generation and policy-based needs of the MISO footprint. For example, although the study was premised on a set of energy zones created to distribute wind capacity throughout the footprint in a least-cost pattern, these energy zones were also located with respect to existing infrastructure, such as transmission lines and natural gas pipelines. As a result the transmission will support a variety of different generation fuel sources, and with the fuel sources, a variety of generation policies.

Resource adequacy and risk assessment

MTEP11 includes a forecast of resource adequacy based on projections of future generation and load to supplement and inform the assessment of the transmission system. The results of a study of the period 2012–2021 indicate that MISO will have sufficient generating capacity to meet demand through 2021, excluding the impacts of the EPA regulations. Net internal demand is expected to be 89 GW in 2012 and 97 GW in 2021[9]. A total of 113 GW of resources are expected to be available to meet this demand in 2012 for the MISO region, increasing to 115 GW in 2021.

9 Net internal demand is equal to the median forecasted load. There is a 50 percent chance that peak load levels will exceed this prediction, while there is a 50 percent likelihood that peak load levels will be less than this prediction.

Reserve margin	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Reserve margin (MW)	23,930	22,438	22,064	21,368	20,760	20,065	19,287	19,950	19,031	18,032
Reserve margin (percent)	27.0	24.8	24.2	23.3	22.5	21.5	20.5	21.0	19.9	18.6
Planning reserve margin requirement (percent)	17.4	17.3	17.3	17.2	17.4	17.8	17.8	18	18.2	18.2

Table 1.2: 2012-2021 forecasted reserves

The MISO Planning Reserve Margin requirement varied throughout the 10-year period studied, from 17.4 percent in 2012 to 18.2 percent in 2021. The reserve margins projected through the assessment time frame varies from 27.0 percent to 18.6 percent for 2012-2021. The expected ability of forecasted resources to meet demand projections is anticipated to exceed the reliability levels represented by the accepted industry standard of one day in 10 years through 2019. However, these conclusions do not take into account capacity retirements that might be required by regulations imposed by the U.S. Environmental Protection Agency (EPA) which could significantly, and rapidly, erode reserve margins**.**

EPA impact analysis

The U.S. Environmental Protection Agency (EPA) is finalizing four proposed regulations that will affect the MISO system. They require utilities to choose between retrofitting their generators with environmental controls or retiring them. At the direction of stakeholders and the Board of Directors, MISO evaluated the potential impacts of the new regulations, including the impact of carbon reduction requirements. This study evaluated the effects on capacity cost, resource adequacy, cost of energy and transmission reliability.[10]

A survey of the current fleet within MISO revealed 298 generation units will be affected by the four proposed regulations. The capacity of the units at risk for retirement is 12.7 GW, based on the assumptions surrounding the cost of environmental regulation compliance.

The compliance cost of retrofitted units and replacement generation due to the EPA regulations are estimated to exceed $30 billion. Identifying all the costs to maintain regulation compliance and system reliability, a 7.0 to 7.6 percent increase in retail rates could be realized.

10 The EPA Regulation Impact Analysis was based on assumptions for proposed EPA regulations. The finalization of these regulations has the potential to introduce change and uncertainty.

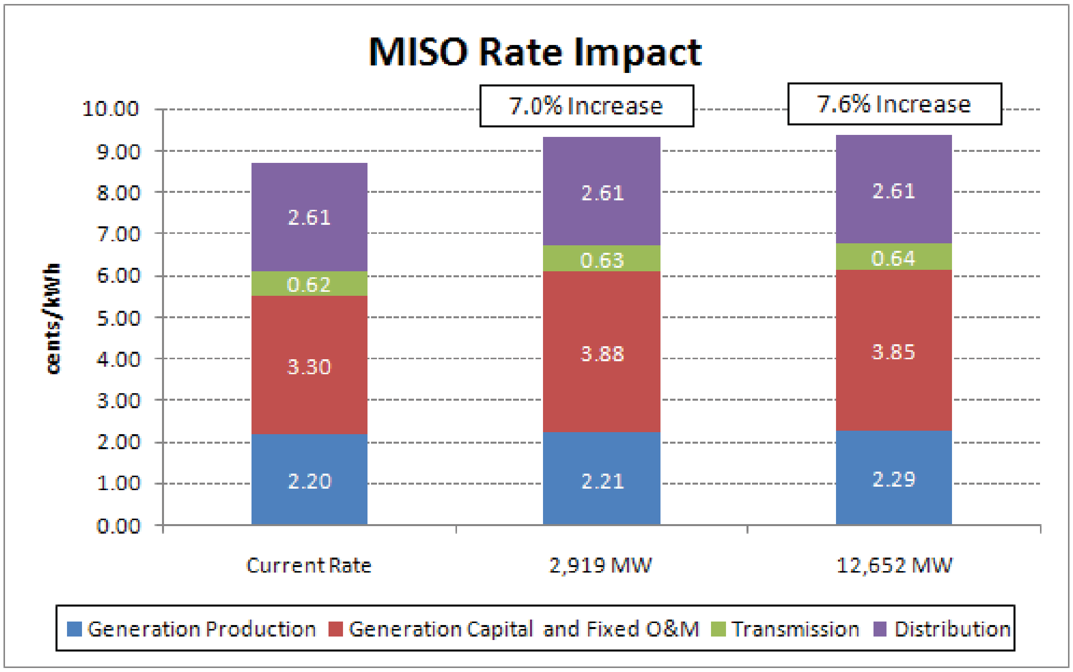


Figure 1-5: MISO rate impact

The proposed EPA regulations could also have an impact on the system's ability to meet demand. If no replacement capacity is identified for Resource Adequacy purposes, then the system reserve margin could decrease to 6.6 percent in 2021. The 2021 reserve requirement is 18.2 percent. However, if capacity is replaced with new and more reliable resources, there is a potential that Planning Reserve Margin (PRM) requirements could decrease by 0.2 to 1.0 percent.

Reserve margin	Forecasted reserves, without EPA regulations		Forecasted reserves, with EPA regulations	
	2016	2021	2016	2021
Adjusted resources (percent)	22.5	18.6	10.1	6.6
Reserve requirement (percent)	17.4	18.2	17.4	18.2

Table 1-3: Potential EPA impacts on resource adequacy

Conclusion

MISO is proud to have an independent, transparent and inclusive planning process that is well positioned to study and address future transmission and policy-based needs in the region. We are also grateful for the input and support from our stakeholder community, which allows us to create well-vetted, cost-effective and innovative solutions to energize the heartland. We welcome feedback and comments from stakeholders, regulators and interested parties on the evolving electric transmission power system. For detailed information about MISO, MTEP11, renewable energy integration, cost allocation and other planning efforts, please visit www.misoenergy.org.

2. MTEP11 overview

2.1 Investment summary

This section provides investment summaries of transmission system upgrades identified in MTEP11 and past MTEP studies that are still in the construction planning or execution processes.[11] Chapter 2.4 describes the definitions of Appendix A, B, and C.

- Approximately $6.5 billion is being added to Appendix A in this planning cycle, of which about $5.1[12] billion is the proposed Multi Value Project portfolio.
- The estimated investment of the projects in MTEP11 Appendix A and Appendix B for 2011–2016 is $7.5 billion.
- Appendix A contains $6.99 billion in investment through 2016 and an additional $3.2 billion from 2017-2021.
- Appendix B contains $0.48 billion of investment through 2016. Appendix B also contains $29 billion in investment for 2017–2026, primarily comprised of two alternate Regional Generation Outlet Study (RGOS) plans.
- Appendix C contains $6.5 billion in investment through 2016 and $37 billion in investment for 2017–2021.

Included in Appendix C is the MTEP08 reference future extra high voltage conceptual transmission overlay in 2018. Portions of the MTEP08 extra high voltage plan have been moved to the RGOS planning effort. There are also a number of large transmission proposals to address the renewable energy requirements in the region, with a $12 billion proposal in 2020. Therefore, there are many alternative and competing plans for renewable energy integration working their way through the planning process. Not all these proposals will reach Appendix A.

Approximately $6.5 billion is being added to Appendix A in this planning cycle, of which about $5.1 billion is the proposed Multi Value Project portfolio.

The expected project spending by year for Appendices A and B from 2011-2021 is in Figure 2.1-1. Projects may be comprised of multiple facilities. Investment totals by year assume that 100 percent of a project's investment occurs when the facility goes into service. Since a large facility may require capital investment over multiple years, this assumption causes these numbers to appear 'lumpier' than the actual expenditures.

[11] A summary of MTEP transmission investment including projects which have gone into service is included in section 3.

[12] Cost shown is as submitted and reflects nominal in-service date costs in whole or in part; equivalent to $4.7 billion in 2011 dollars. The Michigan Thumb Loop Expansion project with a cost of $510 million (2011 dollars) was approved in MTEP 10 and is part of the proposed Multi Value Project Portfolio. Its costs are not included in the above figure.

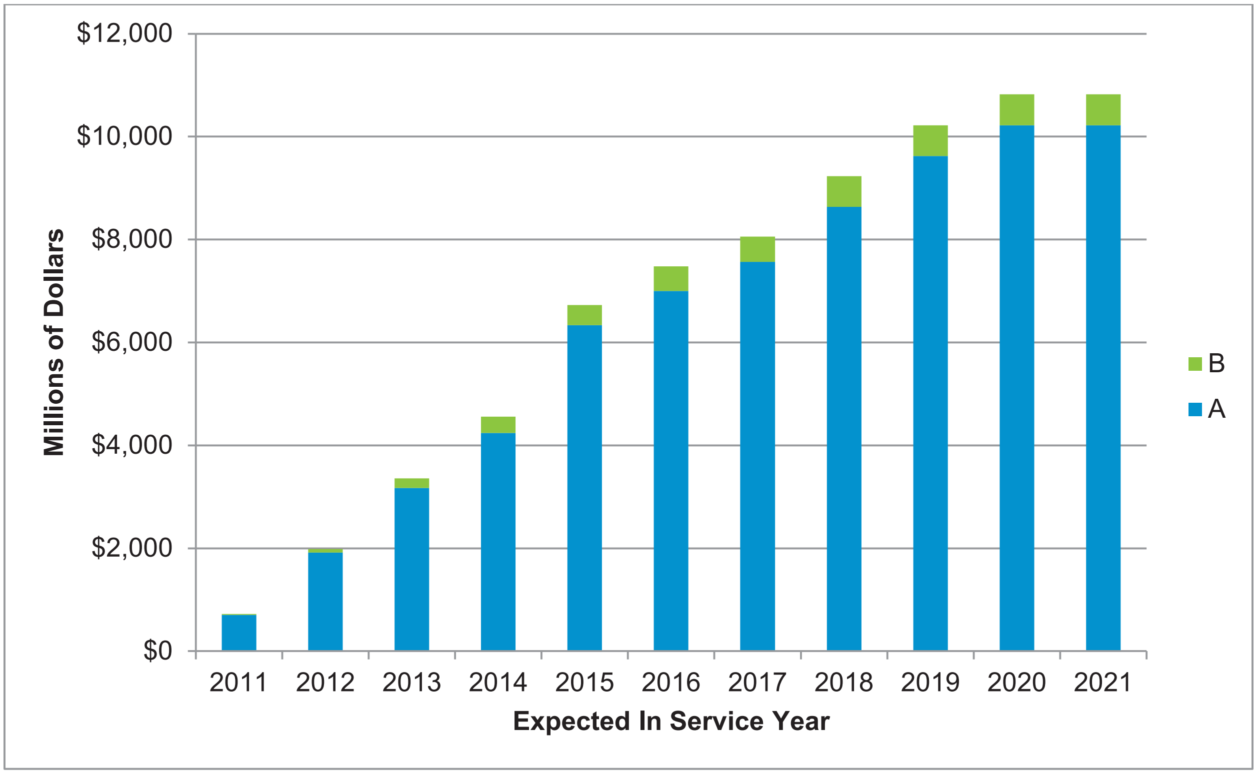


Figure 2.1-1: MTEP11 cumulative projected investment by year and Appendix

Transmission investment by Planning Region through 2021 is shown in Table 2.1-1. This table includes projects in Appendix A approved in prior MTEP planning cycles. Note that the projects are associated with a single planning region, though some projects may be in more than one planning region. These statistics are representative of investment in the planning regions.

Region	Appendix A	Appendix B	Appendix C
Central	$2,265,830,000	$219,152,000	$8,996,773,000
East	$1,537,876,000	$148,701,000	$6,872,277,000
West	$6,415,878,000	$233,899,000	$27,929,197,000
Total	$10,219,584,000	$601,752,000	$43,798,247,000

Table 2.1-1: Projected transmission investment by Planning Region through 2021

Table 2.1-2 shows new investment in 2011 Appendix A projects by preliminary cost allocation category and eligibility for cost sharing. Those categories are Baseline Reliability Project, Generation Interconnection Project, Transmission Service Delivery Project, Multi Value Projects, Market Efficiency Project and other. There were no Market Efficiency Projects and transmission delivery service projects in MTEP11. The numbers in Table 2.1-2 are a subset of Appendix A values shown in Table 2.1-1. These have a target Appendix of 'A in MTEP11' and are new to Appendix A in this planning cycle. Approximately $6.5 billion of investment is being added to Appendix A in this planning cycle. Actual cost allocations for shared projects are based on annual carrying charges and not total project investment; shared means that these projects are eligible for cost sharing. Not all costs of shared projects are eligible for sharing. For example, some Baseline Reliability Project costs and Generation Interconnection Projects are not shared, though only 10 percent of some Generation Interconnection Project costs may be shared to pricing zones. Projects are associated with single planning region, though they may have investment in multiple planning regions.

Region	Share status	BRP	GIP	MVP[13]	Other
Central	Not shared	$8,351,000	$22,620,000		$62,111,000
	Shared	$40,826,000		$1,749,703,000	
Central total		$49,177,000	$22,620,000	$1,749,703,000	$62,111,000
East	Not shared	$11,700,000			$122,661,000
	Shared	$113,900,000	$22,180,000	$271,000,000	
East total		$125,600,000	$22,180,000	$271,000,000	$122,661,000
West	Not shared	$52,094,000	$37,494,000		$491,850,000
	Shared	$197,357,000	$191,094,000	$3,105,021,000	
	Excluded				$4,900,000
West total		$249,451,000	$228,588,000	$3,105,021,000	$496,750,000
Grand total		$424,228,000	$273,388,000	$5,125,724,000	$681,522,000

Table 2.1-2: MTEP11 new Appendix A investment by allocation category & Planning Region

[2] The Michigan Thumb Loop Expansion project with a cost of $510 million (2011 dollars) was approved in MTEP 10 and is part of the proposed Multi Value Project Portfolio. Its costs are not included in the above table. Costs shown is as submitted and reflects nominal in-service date costs in whole or in part; equivalent to $4.7 billion in 2011 dollars.

A breakdown of new Appendix A project data reveals the new transmission build is spread over many states, with Illinois, Wisconsin, Iowa and Minnesota getting around $1 billion in new investment. The majority of that investment comes from the proposed Multi Value Project portfolio. South Dakota, Indiana, and Missouri also have significant projects. These geographic trends change over time as existing capacity in other parts of the system is consumed and new build becomes necessary there.

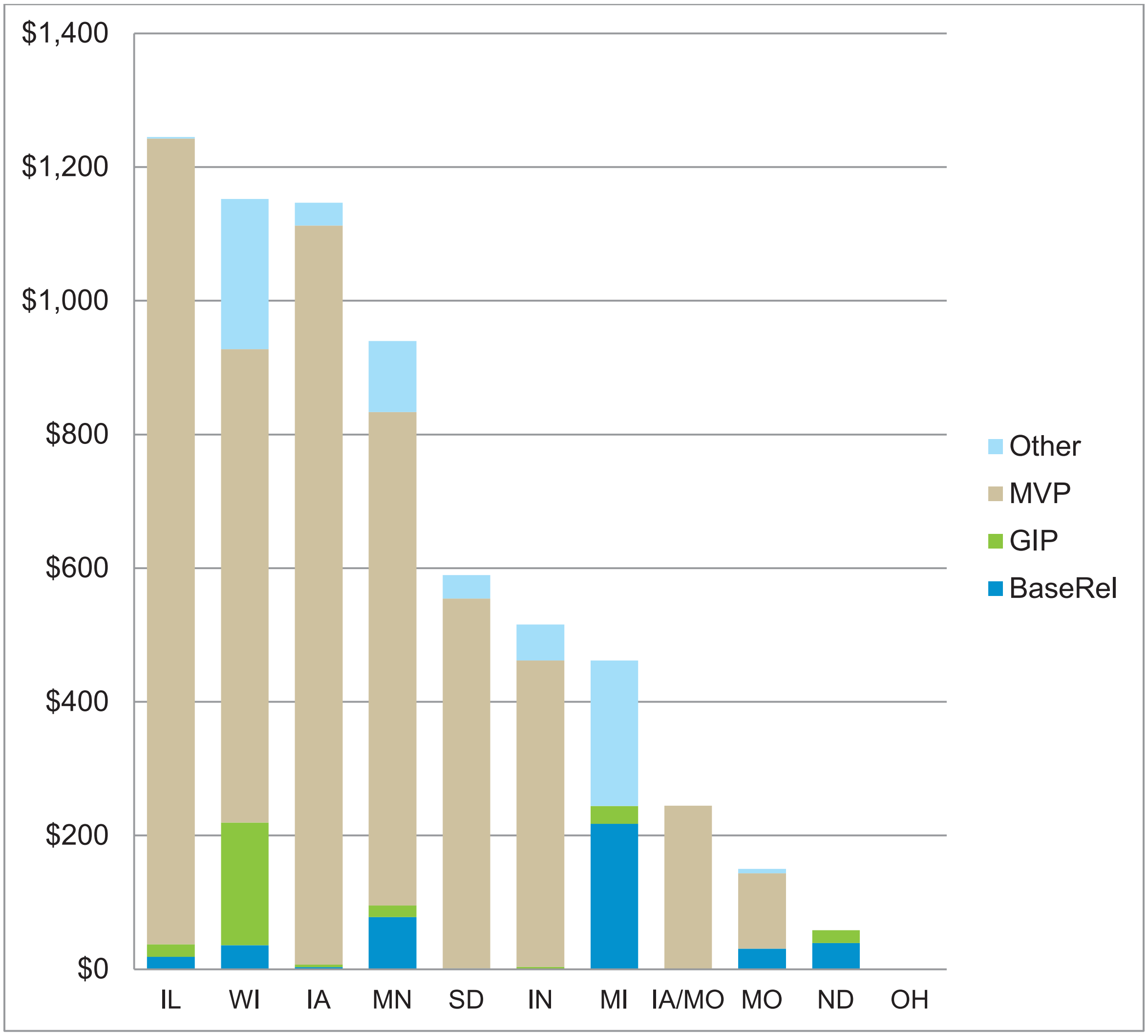


Figure 2.1-2: New Appendix A investment with allocation categorized by state

2.2 Appendix overview

Appendix A and B line summary

There are approximately 6,600 miles of new or upgraded transmission lines projected from 2011-–2021 in MTEP11 Appendices A and B.

- Of approximately 53,200 miles of line under MISO functional control, about 2,965 miles of transmission line upgrades are projected through 2021.
- About 3,695 miles of transmission involving lines on new transmission corridors is projected through 2021.
- Figure 2.2-1 depicts miles of new or upgraded lines by voltage class identified in Appendices A and B.

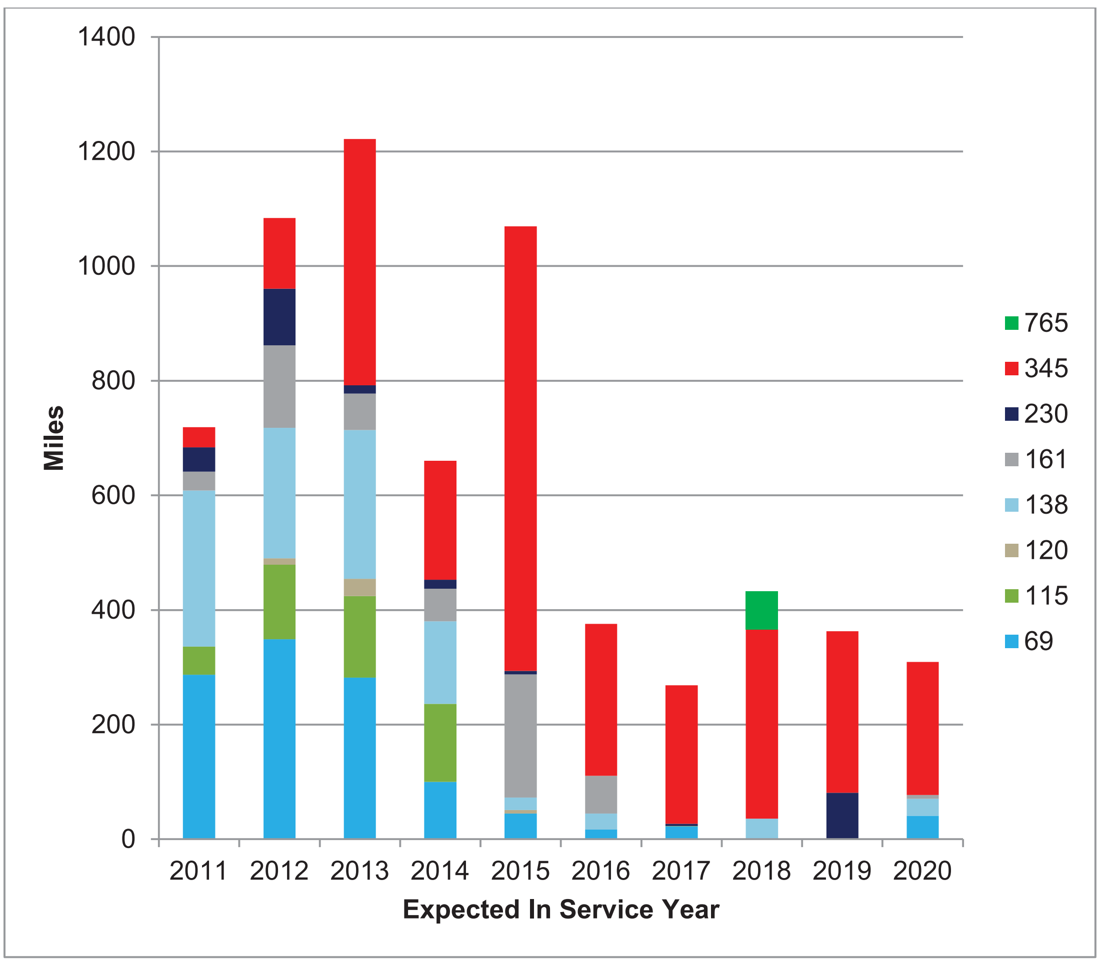


Figure 2.2-1: New or upgraded line miles by voltage class in Appendix A & B through 2021

Refer to Figure 2.2-2, which delineates new transmission line mileage by state for Appendices A and B through expected in service date of 2021.

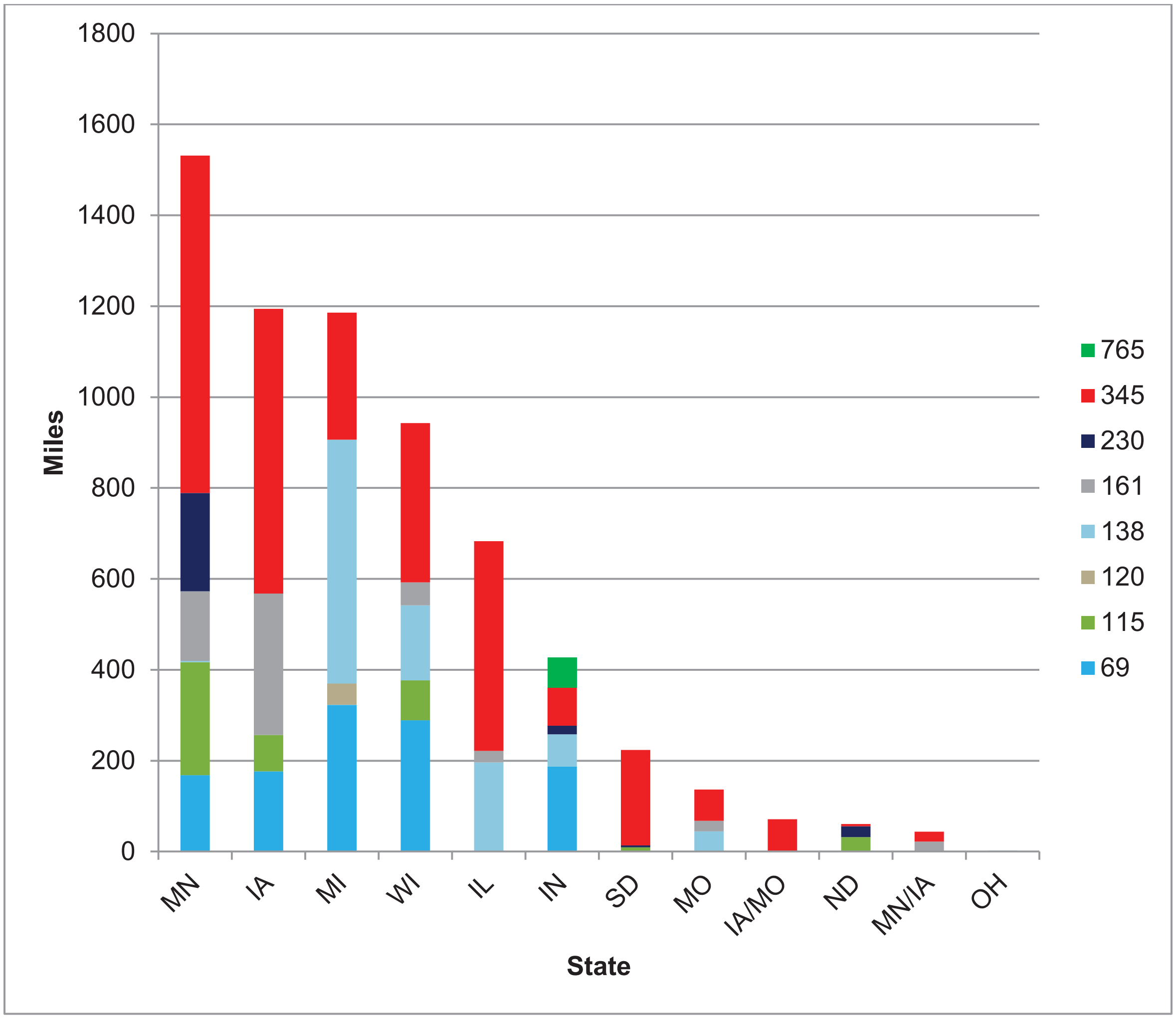


Figure 2.2-2: New or upgraded line miles by state for Appendices A and B through expected in service date of 2021 by voltage class (kV)

Appendix C summary

MTEP11 Appendix C lists and describes $48.6 billion of conceptual and proposed transmission investment. The MTEP08 reference future Extra High Voltage (EHV) conceptual overlay is $14 billion in 2018, comprised of approximately 65 projects. A number of those projects have been integrated into the Regional Generation Outlet Study effort and are now in Appendix B. Eleven of the MTEP08 reference future projects are now part of six proposed projects in the proposed Multi Value Projects portfolio. There are multiple proposals to enable integration and delivery of large amounts of renewable energy. One 765 kV proposal is for $12 billion in 2020. There are two direct current proposals for renewable energy, —$1.9 billion and $1.6 billion, respectively — in 2014. There is a proposal for 765 kV backbone transmission in lower Michigan for $2.5 billion in 2016. Some of these are competing proposals, so not all of the investment is expected. Many of the project proposals in Appendix C were added in order to address traditional reliability needs in the future. Some of these projects have just entered the planning process or are being revisited due to changes, such as load forecast adjustments caused by the economic downturn.

2.3 Cost sharing summary

Multi Value Projects

Multi Value Projects represent a new project type eligible for cost sharing effective since July 16, 2010, and conditionally accepted by the Federal Energy Regulatory Commission on December 16, 2010. Multi Value Projects provide numerous benefits, including, improved reliability, reduced congestion costs, and meeting public policy objectives. As discussed in more detail in Section 4.1, MISO staff is recommending a portfolio of Multi Value Projects to the MISO Board of Directors for inclusion into Appendix A of MTEP 11. The proposed Multi Value Project portfolio includes the Michigan Thumb Loop project, approved in August 2010; the Brookings to Minneapolis-St. Paul project, conditionally approved in June 2011; and 15 additional projects being proposed to the MISO Board of Directors for the first time. The cost of the proposed MVP portfolio in 2011 dollars is $5.2 billion, including the $1.2 billion in projects that have previously been approved or conditionally approved by the MISO Board of Directors. See Table 4.1-1 for individual project costs.

> The costs of Multi Value Projects will have a 100 percent regional allocation and will be recovered from customers through a monthly energy usage charge calculated using the applicable MVP Usage Rate.

The costs of Multi Value Projects will have a uniform 100 percent regional allocation based on withdrawals and will be recovered from customers through a monthly energy usage charge. This charge will apply to all MISO load, excluding load under Grandfathered Agreements, and also to export and wheel-through transactions not sinking in PJM.

Figure 2.3-1 shows a 40-year projection of indicative annual MVP Usage Rates based on the proposed MVP portfolio using current year cost estimates and estimated in-service dates. Additional detail on the indicative MVP Usage Rate, including indicative annual MVP charges by Local Balancing Authority, is included in Appendix A-3.

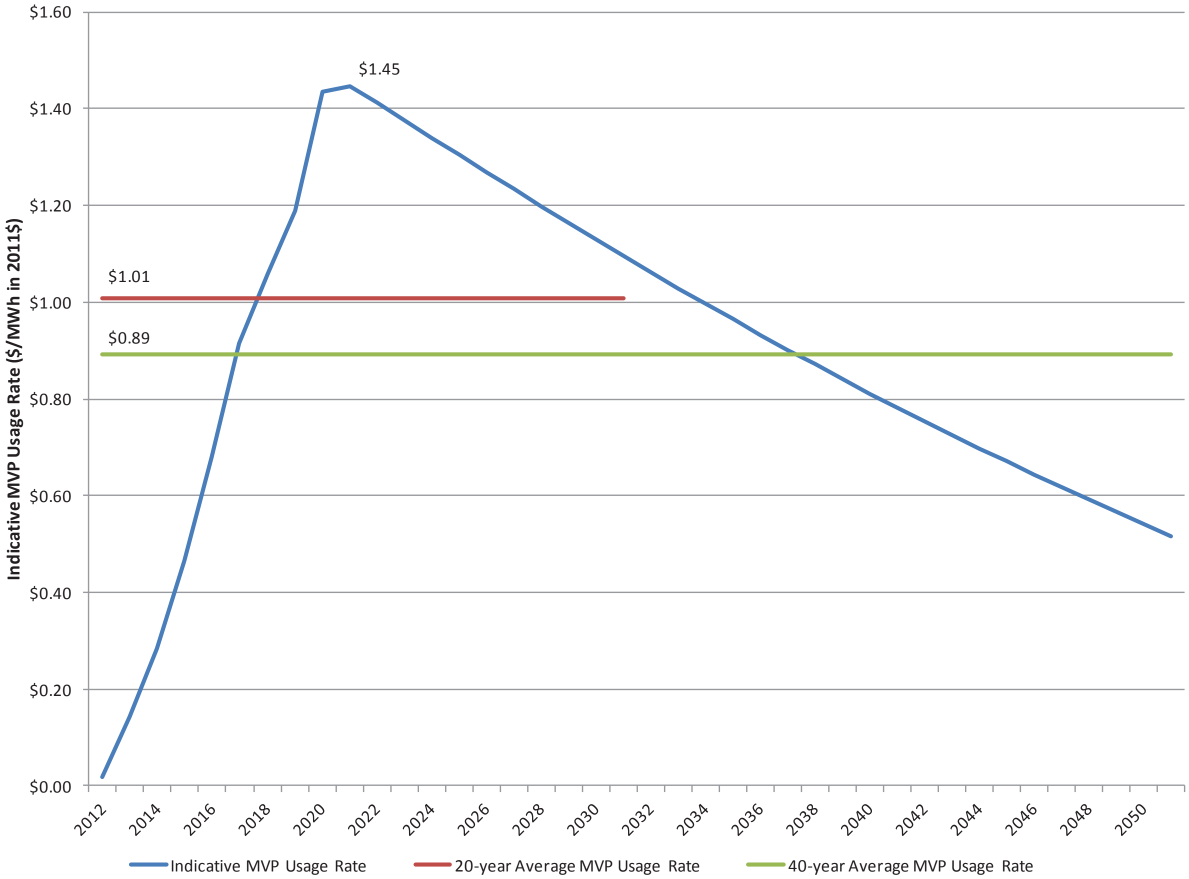


Figure 2.3-1: Indicative MVP usage rate for proposed MVP portfolio from 2012 to 2051

Baseline Reliability, Market Efficiency, and Generation Interconnection Projects

A total project cost of $446.6 million, associated with new Baseline Reliability Projects and Generation Interconnection Projects for inclusion in MTEP 11 Appendix A, are eligible for cost sharing. The cost includes 12 Baseline Reliability Projects at $247.2 million and 10 Generation Interconnection Projects at $199.3 million. A total of $99.7 million of that goes directly to the generator. Of the $346.9 million in project costs, excluding the portion allocated to generators and eligible for cost sharing, 88.7 percent or $307.8 million remains in the pricing zone where the project is located. The remaining 11.3 percent, or $39.1 million, is allocated to neighboring pricing zones or system-wide to all pricing zones. Additional details on the new Baseline Reliability Projects and Generation Interconnection Projects eligible for cost sharing in MTEP 11 are in Appendix A-1.

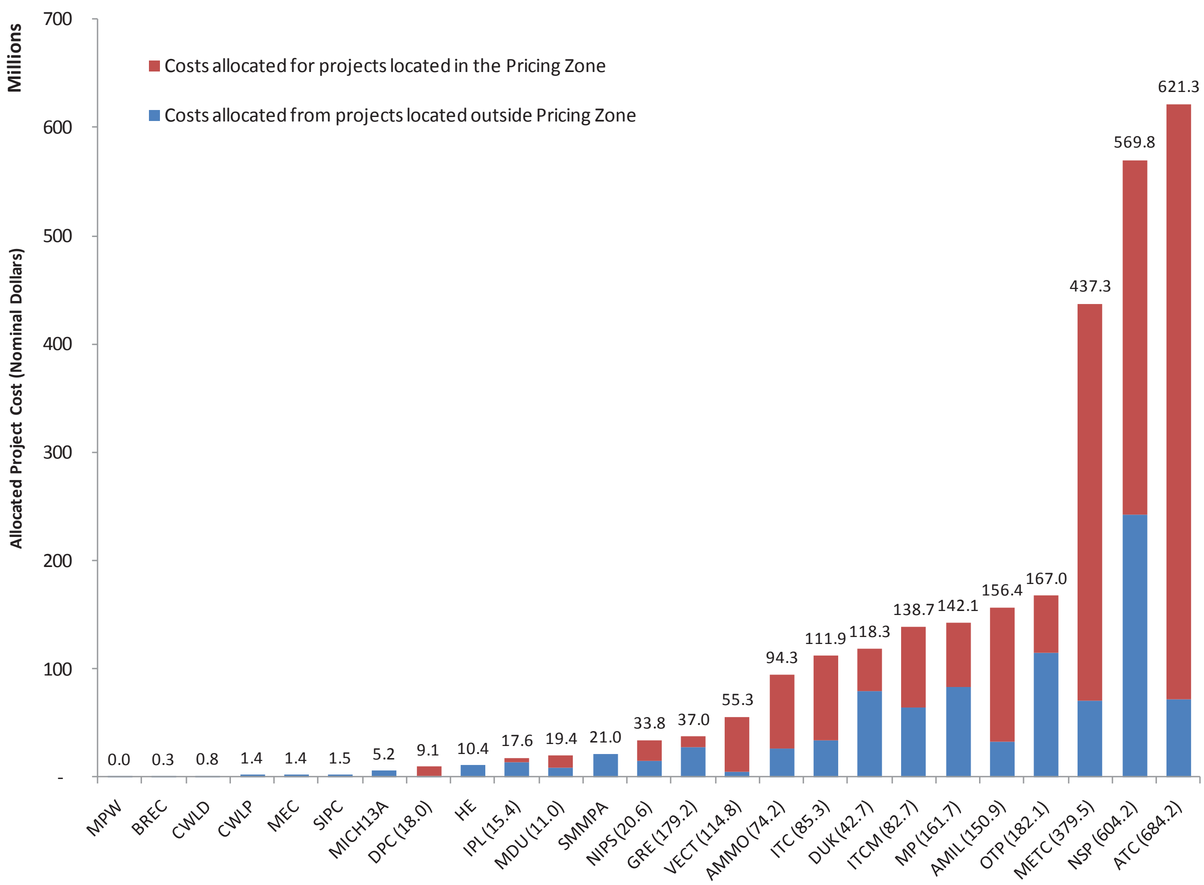
Since the cost sharing methodologies for Baseline Reliability Projects, Generation Interconnection Projects, and Market Efficiency Projects were implemented in 2006, there have been 136 projects eligible for cost sharing. That's $3.4 billion in transmission investment, with each project type representing the following number of projects and total project cost:

- Baseline Reliability Projects – 79 projects, $2.9 billion.
- Generation Interconnection Projects – 56 projects, $550.4 million with $279.1 million allocated directly to the generator.
- Market Efficiency Project – 1 project, $5.6 million.

Figure 2.3-2 provides the breakdown, by pricing zone, of all project costs assigned to the zone based on the cost allocation at the time of approval for Baseline Reliability Projects, Generation Interconnection Projects, and Market Efficiency Projects from MTEP06 to the current MTEP11 report. The costs of approximately $2.8 billion, allocated to each pricing zone from prior MTEP report cycles, have been updated to reflect the current estimates on in-service project cost and in-service date. They do not include projects that have been withdrawn.

The red bar represents the Transmission Owner's share of project costs not allocated to other pricing zones, equal to $1.8 billion across all pricing zones. The blue bar represents the portion of project costs allocated to a pricing zone for projects located in other pricing zones, equal to $927 million across all pricing zones. Note that the values shown in Figure 2.3-2 exclude the portion of Generation Interconnection Projects assigned directly to the generator.

Additional detail by pricing zone on the information shown in Figure 2.3-2 is located in Appendix A-2.2. The cost values for the new MTEP11 cost shared projects have been converted to reflect indicative annual charges for those projects for 2012 to 2021. See Appendix A-2.1.



() = Transmission Owner transmission investment

Figure 2.3-2: Allocated project cost from MTEP06 to MTEP11 for approved Baseline Reliability, Generation Interconnection, and Market Efficiency Projects.[14]

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[14] Costs allocated for projects located in the now non-existent First Energy pricing zone are included in the values shown. The MI13AG and MI13ANG zones have been combined into the MICH13A zone.

2.4 MTEP Project types and Appendix overview

MTEP Appendices A, B and C indicate the status of a given project in the MTEP planning process. Projects start in Appendix C when submitted into the MTEP process, transfer to Appendix B when MISO has documented the project need and effectiveness, then move to Appendix A after approval by the MISO Board of Directors. While moving from Appendix C to Appendix B to Appendix A is the most common progression through the appendices, projects may also remain in Appendix C or Appendix B for a number of planning cycles or may go from C to B to A in a single cycle.

MTEP11 Appendix A lists projects approved by the MISO Board of Directors in prior MTEPs but have not been built, and also lists projects and associated facilities recommended to the MISO Board of Directors for approval in this cycle. The new projects are indicated as "A in MTEP11" in the target Appendix field in the Appendix listing. The Appendix ABC field is indicated as B>A, or C>B>A, for new projects and A for previously approved projects. Projects in Appendix A are classified on the basis of their respective designation in Attachment FF to the Tariff.

- Baseline Reliability Projects are required to meet North American Electric Reliability Corp. (NERC) standards. Costs for a Baseline Reliability Projects may be shared if the voltage level and project cost meet the thresholds designated in the Tariff.
- Generation Interconnection Projects are upgrades that ensure the reliability of the system when new generators interconnect. The customer may share the costs of network upgrades if a contract for the purchase of capacity or energy is in place, or if the generator is designated as a network resource. Not all GIPs are eligible for cost sharing.
- Transmission Service Delivery Projects are required to satisfy a Transmission Service request. The costs are assigned to the requestor.
- Market Efficiency Projects, formerly referred to as regionally beneficial projects, meet Attachment FF requirements for reduction in market congestion. Market Efficiency Projects are shared based on benefit to cost ratio of the project, cost and voltage thresholds.
- Multi Value Projects meet Attachment FF requirements to provide regional public policy economic and/or reliability benefits. Costs are shared with loads and export transactions in proportion to metered MWh consumption or export schedules.

Projects start in Appendix C when submitted into the MTEP process, transfer to Appendix B when MISO has documented the project need and effectiveness, then move to Appendix A after approval by the MISO Board of Directors.

A project not meeting any of these classifications is designated as 'Other.' The 'Other' category incorporates a wide range of projects, including those intended to provide local reliability or economic or similar benefits; but not meeting requirements as Market Efficiency Projects or Multi Value Projects (MVPs). Many other projects are required on the transmission system, less than 100 KV, which is not part of the bulk electric system under MISO functional control.

MTEP Appendix A

MTEP Appendix A contains transmission expansion plan projects recommended by MISO staff and approved by the MISO Board of Directors for implementation by Transmission Owners.

Projects in Appendix A have a variety of drivers. Many are required for maintaining system reliability in accordance with the North American Electric Reliability Corporation (NERC) Planning Standards. Others may be required for Generation Interconnection or Transmission Service. Some projects may be required for regional reliability organization standards. Other projects may be required to provide distribution interconnections for load serving entities. Appendix A projects may be required for economic reasons, to reduce market congestion or losses in a particular area. They may also be needed to reduce resource adequacy requirements through reduced losses during system peak or reduced planning reserve. Projects may be required to enable public policy requirements, such as current state renewable portfolio standards. All projects in Appendix A address one or more MISO documented transmission issues.

Projects in Appendix A may be eligible for regional cost-sharing per provisions in Attachment FF of the Tariff. Such a project must go through the following process to be moved into Appendix A:

- MISO staff must validate that the project addresses one or more transmission issue.
- MISO staff must consider and review alternatives with the Transmission Owner.
- MISO staff must consider and review costs with the Transmission Owner.
- MISO staff must endorse the project.
- MISO staff must verify that the project is qualified for cost-sharing as a Baseline Reliability Project, Generation Interconnection Project, Market Efficiency Project or Multi Value Project per provisions of Attachment FF.
- MISO staff must hold a stakeholder meeting to review any such project or group of projects in which costs can be shared, or other major projects for zones where 100 percent of costs are recovered under Tariff.
- MISO staff must take the new project to the Board of Directors for approval. Projects are moved to Appendix A following a presentation at any regularly scheduled Board meeting.

Appendix A is periodically updated and posted as projects go through the process and are approved. Projects are generally moved to Appendix A in conjunction with the annual review of the MTEP report. A June mid-cycle approval option is available for projects which have been under study in an open process for an appropriate period of time and need to be approved prior to the normal December cycle. However, should circumstances dictate, recommended projects need not wait for completion of the next MTEP for Board of Directors approval and inclusion in Appendix A.

MTEP Appendix B

Projects in Appendix B have been analyzed to ensure they effectively address one or more documented transmission issues. In general, MTEP Appendix B contains projects still in the Transmission Owners planning process or still in the MISO review and recommendation process. It may contain multiple solutions to a common set of transmission issues. Projects in Appendix B are not yet recommended or approved by MISO, so they are not evaluated for cost sharing. There may be some potential Baseline Reliability Projects, Market Efficiency Projects or Multi Value Projects for which MISO staff has not been able to prove the need. Thus, while some projects may eventually become eligible for cost-sharing, the target date does not require a final recommendation for the current MTEP cycle. The project will likely be held in Appendix B until the review process is complete and the project is moved to Appendix A.

MTEP Appendix C

Appendix C may contain projects still in the early stages of the Transmission Owner planning process or have just entered the MTEP study process and have not been reviewed. Like those projects in Appendix B, they are not evaluated for cost sharing. There are also some long-term conceptual projects in Appendix C which will require significant planning before they are ready to go through the MTEP process and move into Appendix B or Appendix A. Appendix C may also contain project alternatives to the best alternative in Appendix B. Therefore, a project could revert from B to C if a better alternative is determined and the Transmission Owner is not ready to withdraw the previous best alternative. Appendix C projects are not included in the MTEP initial power flow models used to perform baseline reliability studies.

2.5 Economic assessment of recommended and proposed expansion

Expansion plan

MISO MTEP Appendix A/B contains planned/proposed projects that primarily address reliability needs. However, these projects may also provide economic benefits, including:[15]

- Adjusted Production Cost (APC) savings
- CO_2 emission reductions
- Energy loss benefits

Study results

This analysis models a subset of Appendix A and B projects scheduled to be in-service by 2016. Not all Appendix A and B projects are modeled. The analysis models projects that have expected in-service dates between July 15, 2011, and December 31, 2016. Except the Michigan Thumb Loop Expansion, the proposed MVP portfolio is excluded. Projects not driving economic benefits, such as capacitor banks, circuit breaker upgrades and control room upgrades, are excluded as well.

The PROMOD® simulations and economic analysis show that the Appendix A/B projects will bring not only reliability, but substantial economic benefit to MISO. Over the 20 to 40 years following 2016, Appendix A and B projects will create approximately $9.1 to 20.6 billion in present value benefits.

The PROMOD® simulations and economic analysis show that the Appendix A/B projects will bring not only reliability, but substantial economic benefit to MISO. In 2016, these projects will create $867 million in annual Adjusted Production Cost savings, when a total of $5.2 billion of new transmission projects are modeled. Over the following 20 to 40 years, these projects will create $9.1 to $20.6 billion dollars in Adjusted Production Cost savings, creating benefits that range from 0.9 to 1.0 times the cost of the projects modeled. Additionally, these projects will provide even greater economic benefits under higher load growth or higher gas price assumptions.

The simulations and analysis also show that the Appendix A/B projects create benefits through a reduction in line losses. In 2016, the annual energy loss decrease is about 45.8 GWH, which equates to about $41 million in annual savings.

Finally, the Appendix A/B projects provide CO_2 relief for the MISO system. The increased transmission capacity will allow for less expensive power to be imported and less wind to be curtailed. This leads to a forecasted decrease in coal unit generation and therefore a CO_2 reduction of 8 million tons.

More detailed methodology and benefit calculation assumptions are described later in this chapter.

[15] MISO benefits include all MISO members as of 12/6/2011. First Energy is excluded.

Economic benefits

Table 2.5-1 shows the Adjusted Production Cost savings for the MTEP11 Appendix A/B projects. The MTEP11 Appendix A/B projects will provide MISO $867 million in Adjusted Production Cost savings.

	2016 Adjusted Production Cost savings	20 Year Present Value, 3 percent Discount Rate	20 Year Present Value, 8.2 percent Discount Rate	40 Year Present Value, 3 percent Discount Rate	40 Year Present Value, 8.2 percent Discount Rate
MISO East	$367	$5,627	$3,844	$8,742	$4,638
MISO Central	$145	$2,210	$1,509	$3,433	$1,821
MISO West	$355	$5,436	$3,714	$8,447	$4,482
MISO	$867	$13,273	$9,066	$20,622	$10,941

Table 2.5-1: Economic benefits, in millions of 2011 dollars

As discussed, the full portfolio of Appendix A and B projects is not modeled. Thus, the total cost of the MTEP11 Appendix A/B projects in the MTEP11 2016 power flow case is $5.2 billion. Table 2.5-2 shows the Benefit- to-Cost ratio of the Appendix A/B projects, based on the economic benefits in 2.5-1 and $5.2 billion project cost, under different timeframes and discount rates.

Discount Rate	Present Value Timeframe	B/C Ratio
3 percent	20 Years	0.88
8.2 percent	20 Years	0.86
3 percent	40 Years	1.00
8.2 percent	40 Years	0.91

Table 2.5-2: B/C ratio of MTEP11 Appendix A/B projects

Benefits will change with variation in the underlying assumptions. To see how the benefits are affected by other factors, MISO conducted sensitivity runs. The sensitivities tested were:

1) Higher load growth: Load is 5 percent higher than the load in reference future;
2) Lower load growth: Load is 5 percent lower than the load in reference future;
3) Higher gas price: Gas prices are 40 percent higher than those in the reference future;
4) Lower gas price: Gas prices are 40 percent lower than those in the reference future;

	Base case	5 percent higher load	5 percent lower load	40 percent higher gas price	40 percent lower gas price
Annual Adjusted Production Cost savings (million $)	$867	$1,047	$748	$1,062	$716
20 Year Present Value, 3 percent Discount Rate (million $)	$13,273	$16,012	$11,457	$16,244	$10,959
20 Year Present Value, 8.2 percent Discount Rate (million $)	$9,066	$10,937	$7,826	$11,096	$7,485
40 Year Present Value, 3 percent Discount Rate (million $)	$20,622	$24,877	$17,800	$25,239	$17,026
20 Year Present Value, 8.2 percent Discount Rate (million $)	$10,941	$13,198	$9,444	$13,390	$9,033

Table 2.5-3: The Adjusted Production Cost savings, Load Cost savings and market congestion benefits of the MTEP11 Appendix A/B project for MISO in different sensitivities

Discount Rate	Present Value Timeframe	Annualized project cost (million $)	Base case	5 percent higher load	5 percent lower load	40 percent higher gas price	40 percent lower gas price
3 percent	20 Years	$901	0.88	1.06	0.76	1.08	0.73
8.2 percent	20 Years	$924	0.86	1.04	0.74	1.05	0.71
3 percent	40 Years	$792	1.00	1.21	0.87	1.23	0.83
8.2 percent	40 Years	$872	0.91	1.10	0.79	1.11	0.75

Table 2.5-4: Benefit-to-cost ratio sensitivity

The base case benefits-to-cost ratio of MTEP11 Appendix A/B projects range from 0.71 to 1.23. The benefits-to-cost ratio tend to be higher in the high load case and high gas price case, and lower in the low load case and low gas price case.

The benefits captured in this section only include the economic benefits in generation production cost savings. Benefits not captured include operating reserve benefits, planning reserve margin benefits and reliability benefits. Benefits to cost ratios will be larger and may be greater than 1.0 if all those benefits are captured. Furthermore, the projects in current MTEP11 Appendix A/B are mainly reliability projects. They need to be built to relieve the reliability violations in the system. Economic benefits are side benefits from those projects. A benefit to cost ratio of less than 1 does not imply the projects are not needed.

The proposed Multi Value Project portfolio provides a wide range of benefits, as described in MTEP11 Chapter 4.1.

Loss benefits

Loss benefits refer to the benefit of reduced line losses that occur when new high voltage transmission lines (Appendix A/B) are added to the system.

Loss benefits attributed to Appendix A/B projects are summarized in Table 2.5-5. The decrease in losses in 2016 is 45,781 MWH. Using the company's hourly load-weighted LMP to price this energy loss yields a savings of approximately $41 million.

Loss benefits refer to the benefit of reduced line losses that occur when new high voltage transmission lines (Appendix A/B) are added to the system.

The loss at peak hour in MISO increases approximately 346.8MW from without Appendix A/B case to with Appendix A/B case, so the capacity loss benefits are actually negative. This is because Appendix A/B projects will allow more long-distance import from non-MISO entities at peak hour to displace MISO generation. Consequently, the long distance power transportation increases losses. Since the capacity loss benefit is negative, the value of capacity loss benefit will be $0.

	Energy loss benefit	Value of energy loss benefit	Capacity of loss (peak) benefit	Value of capacity loss benefit	Maximum hourly loss decrease
MISO	45,781 MWH	$41 million	-346.8 MW	$0	391.4 MW

Table 2.5-5: MISO loss benefits with Appendix A/B project in 2016

Other benefits

Table 2.5-6 shows the annual generation and capacity factor changes for different types of MISO units. After adding the Appendix A/B projects, capacity factors on fossil fuel generators stay the same or decline somewhat. MISO generation (excluding wind) decreases by about 10,457 GWH. Adding the Appendix A/B projects leads to less wind energy being curtailed (10,143 GWH).

This drives annual CO_2 emission to decrease by approximately 8 million tons.

Table 2.5-6 also indicates that coal units and combined cycle units generate less in the case, including Appendix A/B projects. This drives annual CO_2 emission to decrease by approximately 8 million tons. That reduction is relative to the case without Appendix A/B projects, not the case without added wind generation. From Table 2.5-6, we can see the reduction in ST Coal, CT Gas and combined cycle units. The combined effect in CO_2 emission is about 2 percent.

		Generation (MWH)	Capacity Factor
Combined Cycle	No Appendix projects.	25,267,913	21.22 percent
	With Appendix projects.	20,804,817	17.47 percent
	Change	-4,463,096	-3.75 percent
CT Gas	No Appendix projects.	3,252,613	1.61 percent
	With Appendix projects.	2,352,304	1.16 percent
	Change	-900,309	-0.45 percent
CT Oil	No Appendix projects.	68,820	0.16 percent
	With Appendix projects.	15,908	0.04 percent
	Change	-52,913	-0.12 percent
Hydro	No Appendix projects.	3,744,454	34.25 percent
	With Appendix projects.	3,744,116	34.25 percent
	Change	-338	0.00 percent
IGCC	No Appendix projects.	5,860,686	76.29 percent
	With Appendix projects.	5,854,798	76.21 percent
	Change	-5,888	-0.08 percent
Nuclear	No Appendix projects.	71,312,762	88.91 percent
	With Appendix projects.	71,312,762	88.91 percent
	Change	0	0.00 percent
ST Coal	No Appendix projects.	383,096,341	68.34 percent
	With Appendix projects.	378,307,444	67.49 percent
	Change	-4,788,897	-0.85 percent
ST Gas	No Appendix projects.	708,331	2.86 percent
	With Appendix projects.	453,482	1.83 percent
	Change	-254,849	-1.03 percent
ST Oil	No Appendix projects.	12,209	0.24 percent
	With Appendix projects.	12,399	0.24 percent
	Change	189	0.00 percent
Wind	No Appendix Projects	42,108,491	27.99 percent
	With Appendix Projects	52,251,508	34.73 percent
	Change	10,143,018	6.74 percent

Table 2.5-6: 2016 generation and capacity factor change for different type units

	CO_2 emission (ton)
No Appendix projects.	423,370,598
With Appendix projects.	415,237,057
Emission decrease	8,133,541

Table 2.5-7: 2016 annual CO2 emission change for different type units

Study methodology and assumptions

The data for the economic benefit assessment comes from two PROMOD® case runs: one case without the Appendix A and B projects, and one case with these projects.

Only those projects that will not drive economic benefits are excluded to provide a more accurate analysis. Examples of projects not adding economic benefit include capacitor banks, circuit breaker upgrades, rebuilds of existing lines or substations and control room upgrades. These projects will not cause impedance or rating changes to existing lines, and will not affect system topology from steady-state economic study perspective.

PROMOD® cases

The MTEP11 2016 summer peak power flow case, which has been reviewed by MISO stakeholders and incorporates the latest PJM system update, was used as the starting point for this study. Two 2016 PROMOD® cases were developed:

- 2016 PROMOD® case with Appendix A/B projects.
- 2016 PROMOD® case without Appendix A/B projects.

Both cases use the same MTEP11 BAU (Business As Usual with low demand and energy growth rate) Future database (containing all the generator, load, fuel and environmental information). The detailed information associated with the BAU Future can be found in Appendix E2. The only difference between these two PROMOD cases is the power flow cases (i.e., the transmission topologies) that are used.

Power flow case

To develop these two PROMOD® cases, two power flow cases are required:

- One power flow case with Appendix A/B projects.
- One power flow case without Appendix A/B projects.

For both power flow cases, the Transmission Systems outside of the MISO footprint are the same; from the Eastern Interconnection Regional Reliability Organization (ERAG) 2010 series 2016 summer peak power flow case. The MISO portion, in the power flow case with Appendix A/B projects, is from the MTEP11 2016 summer peak power flow case, including all Appendix A/B projects except proposed Multi Value Projects. The MISO portion, in the power flow case without Appendix A/B projects, is from the ERAG 2010 series 2011 summer peak power flow case, representing the current transmission topology in MISO. Table 2.5-8 summarizes the differences between these two power flow cases.

	Power flow case with Appendix A/B	Power flow case without Appendix A/B
MISO transmission	MTEP11 2016 summer peak (ERAG 2011 summer peak + Appendix A/B)	ERAG 2011 summer peak
Non-MISO transmission	ERAG 2016 summer peak	ERAG 2016 summer peak
Generation/load/interchange	Not used in PROMOD(R)	Not used in PROMOD(R)

Table 2.5-8: Power flow cases difference

In the power flow case with the Appendix A/B projects, the Michigan Thumb Loop project is in the case. None of the other proposed Multi Value Projects were included in the case because the proposed MVP portfolio is not finalized. Among them, only 3 out of 16 projects have an expected in-service date on or before 2016. The benefits of proposed MVP projects are evaluated together as a portfolio in the proposed MVP Portfolio Study. They are not included in the power flow case with Appendix A/B projects used in this study.

New generators

The new generators identified in MTEP11 Steps 1 and 2, under the BAU Future, are included in this study. More details on these generators can be found in Appendix E2.

Event file

The event file contains the list of flow gates which will be treated as transmission constraints. The quality of the event file has a big impact on the quality of the study results. As PROMOD® has a limit on the number of events, all N-1 or N-2 contingencies cannot be included in the event file. The event file for this 2016 PROMOD® case includes the flowgates from:

- MISO master flowgates file.
- NERC book of flowgates.
- Appendix A/B projects that have rating upgrades were also included in the event file with different ratings in each of the two PROMOD® cases.

The PROMOD® Analysis Tool (PAT) was also used to identify events with potential reliability problems. Those events were also included in the event file.

Economic benefits

From each PROMOD® case, The Adjusted Production Cost (APC) was calculated. The APC is equal to the production cost adjusted by sales revenue and purchases cost.

The comparison of the economic indices from two PROMOD® cases (with Appendix A/B case, and without Appendix A/B case) yields the Adjusted Production Cost savings. These savings are the annual Adjusted Production Cost decrease from the case without Appendix A/B projects to the case with Appendix A/B projects, so there is a cost savings.

Loss benefits

- Energy loss benefit (MWH) is the annual loss decrease (MWH) from without Appendix A/B case to with Appendix A/B case.
- Capacity loss benefit (MW) for MISO is the loss decrease (MW) from without Appendix A/B case to with Appendix A/B case in MISO's peak load hour.
- Dollar value of energy loss benefit is the annual MISO loss cost decrease from without Appendix A/B case to with Appendix A/B case. Company loss cost is calculated by multiplying a company's hourly losses by its load- weighted LMP. The annual sum of these values for all MISO companies is the annual MISO loss cost.
- Dollar value of capacity loss benefit represents the value of deferring additional generation construction. It is calculated using \$650/kW-\$1200/kW, the price range for the construction of

different units. If the capacity loss benefit is positive, the corresponding dollar value is the capacity loss benefit multiplied by these prices. If the capacity loss benefit is negative, this value will be 0.

- Maximum hourly loss decrease is the maximum hourly loss decrease (MW) from without Appendix A/B case to with Appendix A/B case.

Other impacts

- Generation, capacity factor and CO_2 emission change compares two things: 1) the change of generation and the capacity factor of different types of units and 2) change of CO_2 emission between with and without Appendix A/B projects cases.

2.6 MTEP 11 futures retail rate impact

The electricity industry is facing significant policy changes from the state and federal level. These changes are generating uncertainty for the industry and its customers, including potential rate increases to retail electricity customers. As shown in Figure 4.1-2, all but 1 of the 12 states in the MISO footprint has enacted a Renewable Portfolio Standard (RPS) mandate or goal. There is a great deal of uncertainty about how these goals will be achieved, including the location of future generation and the required transmission to enable renewable integration. In addition to state policies, there is on-going discussion at the federal level on implementation of policies, including federal RPS, carbon reduction, smart grid and others. To address these potential futures, MISO examines multiple scenarios through its long-term planning process to capture the wide range of potential policy outcomes.

Current retail electricity rates

The current cost of electricity to the retail customer must be considered before examining the potential impact of the future scenarios. In MISO the current average retail rate, weighted by load in each state, for residential, commercial and industrial sector, is 8.7 cents/kWh, about 10 percent lower than the national average of 9.7 cents/kWh.[16] Refer below to Figure 2.6-1, which provides the average retail rate in cents per kWh for each state in the MISO footprint. It shows the rate paid by consumers varies greatly across the MISO footprint. Based on information provided by the Energy Information Administration (EIA) in Annual Energy Outlook 2011; the generation, transmission and distribution cost components of the retail electricity rate in 2011 are estimated to average 63.0 percent, 7.1 percent and 29.9 percent, respectively.[17] This equates to approximately 5.5 cents/kWh for generation, 0.6 cents/kWh for transmission and 2.6 cents/kWh for distribution.[18] For this rate impact analysis, it is assumed the average MISO residential customer uses approximately 1,000 kWh of electricity each month, equivalent to annual electricity charges of $1,044; based on an 8.7 cents/kWh retail rate.

The electricity industry is facing significant policy changes from the state and federal level. These changes are generating uncertainty for the industry and its customers, including potential rate increases to retail electricity customers.

[16] Data courtesy of the Energy Information Administration (EIA) Electric Power Monthly from March 2011. MISO average rate was calculated by taking the load weighted average of the 12 states in the MISO footprint.

[17] MISO average generation, transmission and distribution components were calculated based on rate component data provided in the EIA Annual Energy Outlook in 2011 for the following modeling regions: MRO-East, MRO-West, RFC-MI, RFC-West, SERC-Central, and SERC-Gateway. The modeling regions were weighted based on MISO load in each of the regions.

[18] Each category assumes some allocation of general and administrative expenses.

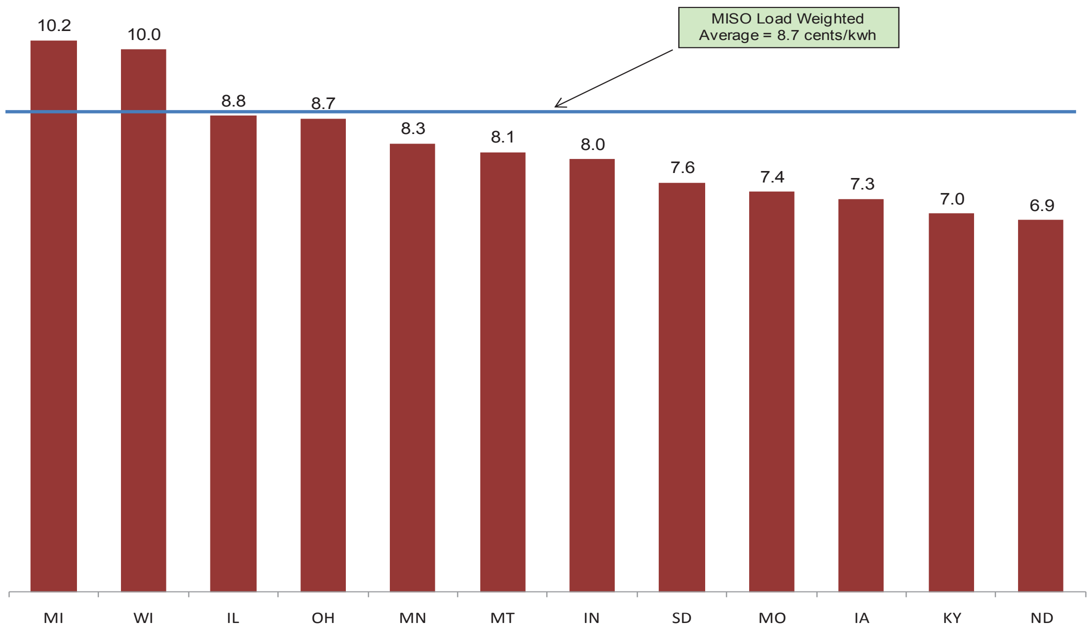

Figure 2.6-1: MISO retail rate for all sectors in cents/kWh (2011 dollars)

Future policy scenarios

MISO examined a number of policy-driven future generation expansion scenarios to develop an array of "best plans" for a range of possible outcomes. These scenarios derive from policy discussions, and they will evolve depending on the direction of legislation. The scenarios represent a range of potential policies and have been used to estimate potential impacts to retail rate payers in the MISO footprint.[19]

- Business as Usual with Mid-low Demand and Energy Growth Rates assumes a slow recovery from the economic downturn and its impact on demand and energy projections. This scenario assumes existing standards for resource adequacy, renewable mandates and little or no change in environmental legislation.

- Business as Usual with Historic Demand and Energy Growth Rates assumes a quicker recovery from the economic downturn and a return to historic demand and energy growth rates. This scenario assumes existing standards for resource adequacy, renewable mandates and little or no change in environmental legislation.

- Carbon Constraint models a declining cap on CO_2 emissions. The carbon cap is modeled after the Waxman-Markey bill, with a modified timeline to reach a 42 percent reduction by 2033 from 2005 levels. For the 2026 rate impacts calculated in this analysis, a 25 percent carbon reduction is targeted.

- Combined Energy Policy combines the impact of multiple policy scenarios into one future. Smart grid is modeled within the demand growth rate. It is assumed an increased penetration of smart grid applications will lower overall demand growth. Growth in electric vehicle usage is captured with a higher energy growth rate and is assumed to increase off-peak energy usage.

[19] For additional description of the MTEP 11 scenarios refer to section 4.3 and Appendix E.2

To meet the various policy objectives, all scenarios included in this rate impact analysis require significant investment in generation and transmission expansion across the 15-year study horizon. This is expected to affect retail electricity rates, especially since a large share of generation and transmission assets have or soon will reach the end of their recoverable book-life. For example, approximately 55 percent of the generating capacity in the MISO footprint is at least 30 years old. As shown in this analysis, all but one of the scenarios shows retail rates increasing at a rate greater than inflation.

Overview of rate impact methodology and results

To measure the potential impact to rate payers under each of the scenarios; MISO projected a 2026 retail rate by estimating annual revenue requirements for the generation, transmission and distribution rate components.[20] This projection was based on the following assumptions:

- Transmission component
  - Includes proposed MVP portfolio (constant across all scenarios).
  - Additional required reliability transmission investment through 2026 (constant across all scenarios).[21]
  - Non-depreciated current transmission that would still be recoverable in 2026 (constant across all scenarios).
- Generation component
  - Production costs for MISO generation resources associated with each scenario in 2026; including fuel, emissions, and variable operations and maintenance expenses.
  - Capital costs, including fixed operations and management, associated with the capacity expansion for each scenario through 2026.[22]
  - Non-depreciated current generation that would still be recoverable in 2026 (constant across all scenarios).
- Distribution component
  - Assumes that the distribution component of the current MISO retail rate at 2.6 cents/kWh will grow at the assumed rate of inflation through 2026.

To calculate MISO's 2026 retail rate, revenue requirements for the generation, transmission and distribution components described above were distributed uniformly across the forecasted 2026 energy usage levels. The 2026 rate was then discounted, using the assumed inflation rate to 2011 for comparison to the current MISO retail rate. The results of this calculation for each scenario are shown in Figure 2.6-2, which depicts the impact the scenarios could have on customer's retail rates. Note that the rates calculated for the future scenarios include costs for generation, transmission and distribution; but do not include general and administrative costs.

All but one of the scenarios shows that retail rates can be expected to grow at a rate faster than would be experienced if rates simply increased by inflation.

All but one of the scenarios shows that retail rates can be expected to grow at a rate faster than would be experienced if rates simply increased by inflation. However, the magnitude of this impact varies greatly across the four scenarios, from a 1 percent decrease for the Business as Usual with Mid-low Demand and Energy Growth Rate scenario to a 19 percent increase for the Combined Energy Policy Future. Major rate drivers for each scenario are discussed in more detail in the next section.

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[20] Additional detail on the rate calculation methodology is provided in Appendix E.3.
[21] Based on the proposed MVP portfolio listed in Table 4.1-1 in Section 4.1 with a total project cost of more than $5.2 billion.
[22] Refer to Section 4.3 for details on the capacity expansion, by fuel type, for each MTEP 11 Future. Generation siting maps for each MTEP 11 Future are also provided in Section 4.3.

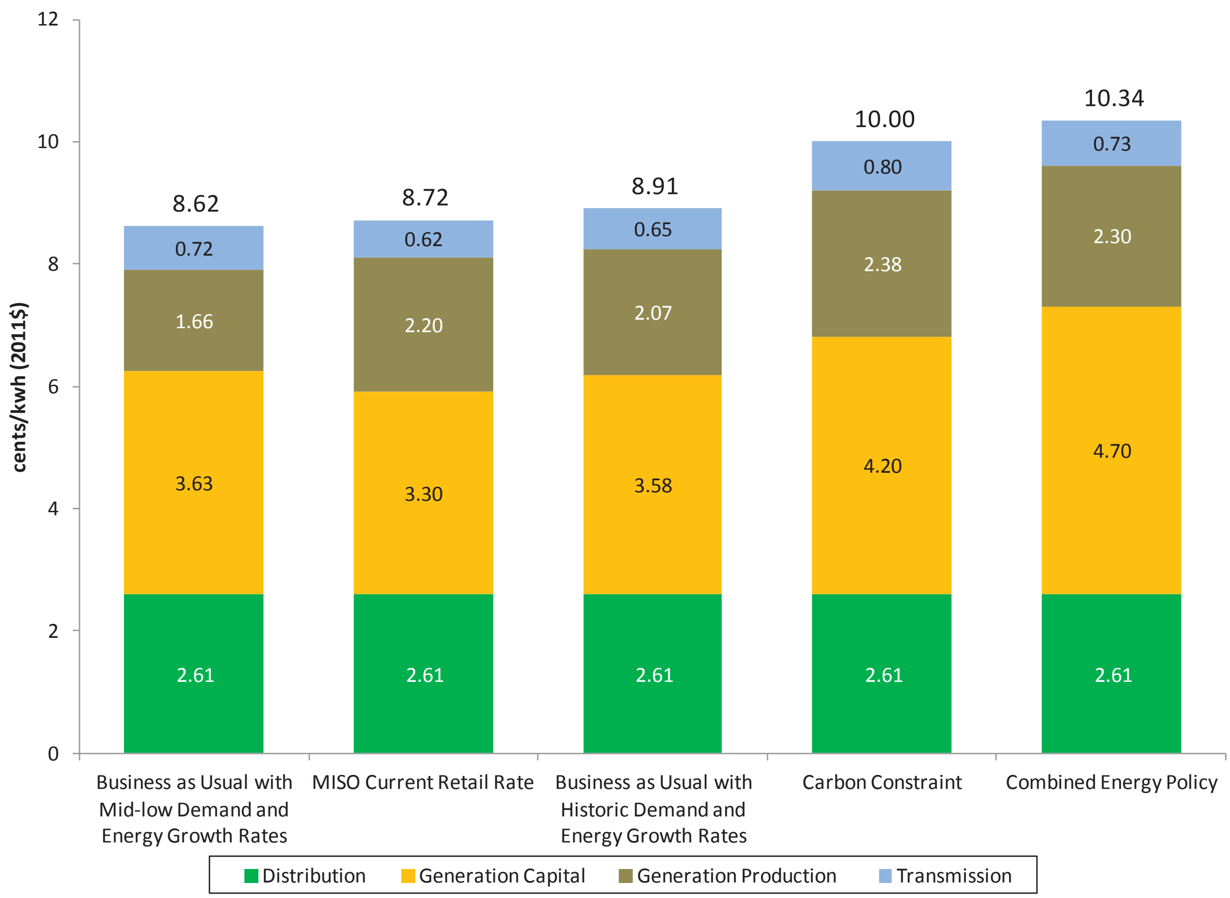

Figure 2.6-2: Comparison of estimated retail rate for each future scenario
(Cents per KWh in 2011 Dollars)

Scenario	Rate (cents/kWh)	Percent (Change from current retail rate)
BAU with Mid-low Demand and Energy Growth Rates	8.62	-1.2 percent
MISO Current Retail Rate	8.72	0.0 percent
BAU with Historic Demand and Energy Growth Rates	8.91	+2.1 percent
Carbon Constraint	10.00	+14.7 percent
Combined Energy Policy	10.34	+18.6 percent

Table 2.6-1: 2026 retail rate impacts in 2011 dollars of for each future scenario

Rate impact drivers under future policy scenarios

Table 2.6-2 compares the Business as Usual with Mid-low Demand and Energy Growth Rates (BAUMLDE) scenario's estimated retail rate to the current retail rate. This is done by using the rate components to illustrate what is driving the overall estimated decrease of $12 to the average residential ratepayer's annual electricity costs.[23] The BAUMLDE is the only scenario where we find an estimated retail rate marginally lower than the current MISO retail rate. Two factors contribute to this lower rate:

1) The lower demand growth rate will require fewer new capacity resources, though there are 23,900 MW of wind and solar resources added to meet the state renewable mandates.
2) The increased output of renewable resources, which typically have no fuel costs, and therefore very low production costs, from 8 percent of output in 2011 to 16 percent in 2026, reduces generation production cost.

	Rate component				
	Generation capital[24]	Generation production	Transmission	Distribution	Total
MISO current retail rate (cents per kWh2011 dollars)	3.30	2.20	0.62	2.61	8.72
BAUMLDE future retail rate (cents per kWh2011 dollars)	3.63	1.66	0.72	2.61	8.62
Percentage change in projected retail rate	10.1 percent	-24.4 percent	16.4 percent	-	-1.2 percent
Projected change in avg. residential rate payer's annual electricity bill	$39.96	$(64.26)	$12.14	-	$ (12.15)

Table 2.6-2: Comparison of BAUMLDE future retail rate to current

[23] Residential annual electricity costs calculated assuming average monthly usage of 1,000 kWh.
[24] Generation Capital includes both annual capital charges and fixed O&M expenses.

Table 2.6-3 below compares the Business as Usual with Historic Demand and Energy Growth Rates (BAUHDE) scenario estimated retail rate to the MISO current retail rate to illustrate which component is influencing the overall estimated annual increase of $22 to the average residential ratepayer's electricity costs. The increase in generation capital and transmission in the BAUHDE scenario is in part driven by the need to meet the state renewable mandates included in the study. To meet the current state RPS mandates in the MISO footprint, an additional 26,800 MW of wind and solar resources are added through 2026. Offsetting the increase in generation and transmission investment is a reduction in generation production costs as low cost renewable resources deliver an increasing share of total energy, accounting for 8 percent of output in 2011 and increasing to 16 percent in 2026.

	Rate component				
	Generation capital	**Generation production**	**Transmission**	**Distribution**	**Total**
MISO current retail rate (cents per kWh 2011 dollars)	3.30	2.20	0.62	2.61	8.72
BAUHDE future retail rate (cents per kWh 2011 dollars)	3.58	2.07	0.65	2.61	8.91
Percentage change in projected retail rate	8.4 percent	-6.0 percent	6.1 percent	-	2.1 percent
Projected change in avg. residential rate payer's annual electricity bill	$33.33	$ (15.76)	$ 4.52	-	$22.09

Table 2.6-3: Comparison of BAUHDE future retail rate to current

Table 2.6-4 below compares the estimated rate under the Carbon Constraint scenario, which targets a 25 percent reduction in CO_2 emissions by 2026 from 2005 levels, leading to an estimated 15 percent increase over the current MISO retail rate, equating to a $154 increase over the current residential ratepayer's annual electricity costs.

In the Carbon Constraint scenario, there is approximately 21,600 MW of resources retired to achieve required carbon reduction levels. However, due to the very low effective demand growth rate after considering demand response, only 10,000 MW of non-renewable generation is added. Approximately 21,000 MW of renewable resources are added to meet the state RPS mandates. This additional 31,000 MW of resources is driving the 28 percent increase in the generation capital component of the carbon constraint scenario compared to the current retail rate.

One of the drivers for the 9 percent increase in the generation production component is the increase in energy served by natural gas fueled resources -- from 2 percent in 2011 to 18 percent in 2026. For the transmission component, note that while the percentage increase is much higher than for the BAUMLDE and BAUHDE scenarios, this does not represent an increase in transmission investment, since the same level of transmission investment is assumed for all scenarios. The energy growth rate is lower, so the cost per kWh is higher, and the transmission costs are spread over less energy.

	Rate component				
	Generation capital	Generation production	Transmission	Distribution	Total
MISO current retail rate (cents per kWh2011 dollars)	3.30	2.20	0.62	2.61	8.72
Carbon Cap Constraint future retail rate (cents per kWh2011 dollars)	4.20	2.38	0.80	2.61	10.00
Percentage change in projected retail rate	27.5 percent	8.5 percent	30.5 percent	-	14.7 percent
Projected change in average residential rate payer's annual electricity bill	$108.63	$ 22.37	$22.52	-	$153.51

Table 2.6-4: Comparison of Carbon Constraint future retail rate to current

Table 2.6-5 below compares the Combined Energy Policy estimated retail rate - including a 20 percent Federal RPS, carbon constraint, smart grid investment and increased electric vehicle usage - to the MISO current retail rate by rate component. This illustrates the drivers of the overall estimated increase of 19 percent, equating to a $195 increase for the average residential ratepayer's annual electricity cost.

Similar to the Carbon Constraint future, the Combined Energy Policy future assumes the retirement of 24,500 MW of generation resources to achieve the 25 percent reduction in carbon emissions from 2005 levels by 2026. The estimated 43 percent increase in the generation capital component is driven by the 43,200 MW of new resources, including 28,800 MW of new wind generation to meet the 20 percent Federal RPS.

For the generation production component, the increased usage of natural gas resources for the Combined Energy Policy scenario (from 2 percent of energy served in 2011 to 18 percent in 2026) is slightly less than for the Carbon Constraint Future. That's likely due to the increased percentage of energy served by low-production cost wind generation -- from 8 percent in 2011 to 21 percent in 2026.

	Rate Component				
	Generation capital	**Generation production**	Transmission	Distribution	**Total**
MISO current retail rate (cents per kWh 2011 dollars)	3.30	2.20	0.62	2.61	8.72
Combined energy policy future retail rate (cents per kWh 2011 dollars)	4.70	2.30	0.73	2.61	10.34
Percentage change in projected retail rate	42.5 percent	4.6 percent	19.0 percent	-	18.6 percent
Projected change in average residential rate payer's annual electricity bill	$168.35	$ 12.25	$14.01	-	$194.61

Table 2.6-5: Comparison of combined energy policy future retail rate to current

Potential rate impacts from the four future scenarios demonstrate that higher electricity rates are likely. The magnitude of the increase will vary, depending on actual economic and policy situations. The range of outcomes illustrates the importance of performing long-term scenario analyses to provide decision-makers with the information needed to minimize rate increases to customers.

3. Historical MTEP plan status

This section provides an update on the implementation of projects approved in the MISO Transmission Expansion Plan (MTEP) - and furnishes a historical perspective of all past MTEP approved plans. These projects were approved by the MISO Board of Directors in previous MTEP cycles or are recommended for approval in MTEP11. Any given MTEP Appendix A contains newly approved projects, along with previously approved projects not in service when the MTEP Appendices were prepared.

3.1 MTEP10 status report

MISO transmission planning responsibilities include monitoring progress and implementation of essential expansions identified in the MTEP. The MISO Board of Directors approved the last MTEP (MTEP10) in December 2010. This section provides a review of the status of previously approved projects listed in MTEP10 Appendix A.

The MISO Board of Directors has been receiving quarterly updates on the status of active plans since December 2006. The information in this report reflects the 2nd Quarter of 2011 status report to the Board of Directors, which included status on MTEP10 Appendix A projects through June 30, 2011.

Tracking the progress of projects ensures a good faith effort to move projects forward, as prescribed in the Transmission Owner's agreement. Most approved projects do move forward, despite possible complications, such as equipment procurement delays, construction difficulties and regulatory processes taking longer than anticipated. A project is only considered 'off-track' if MISO cannot determine a reasonable cause for delays, as described above. These approved MTEP projects have completed the planning process and are the solution to Transmission System issues. They may be driven by reliability issues, Transmission Service requests, Generation Interconnection requests or market flow constraints. More than half of the MTEP Appendix A projects is comprised of multiple facilities.

MTEP10 Appendix A has 586 projects comprised of 1,025 facilities. These figures have been updated to reflect the progress of members' projects. MTEP10 Appendix A includes expansion facilities through 2020. A total of 99 percent of the approved facilities included in MTEP10 are in service, on track or have encountered reasonable delays. That translates to $4.680 billion of the $4.727 billion included in MTEP10 Appendix A.

There were 101 in-service date adjustments to projects. Little or no impact on reliability is expected because in-service date adjustments were primarily driven by the economic slowdown. Transmission Owners may adjust project in-service dates to match system needs.

Withdrawn projects should be examined to ensure the planning process of MISO and its members address required system additions, and there was a good reason for withdrawing the project, or a different project covers the need. MTEP10 Appendix A contains projects approved in past MTEPs not yet in service, so withdrawn facilities may have been approved in prior MTEPs but withdrawn after MTEP10 was approved. There were 33 facilities (3 percent of 1025) withdrawn for the following reasons:

- The customer's plans changed or the service request was withdrawn.
- The plan was replaced with another plan.
- The plan was redefined to better meet the needs.
- The load forecast dictated that the project was no longer needed.

All withdrawn facilities were withdrawn for valid reasons. The majority were cancelled because service requests were withdrawn or load forecast was reduced.

3.2 MTEP implementation history

This section encompasses the implementation and status of all approved MTEP plans, including the current MTEP plan. A historical perspective shows extensive variability in transmission plan development. This is normal, caused by the long development time of transmission plans and the regular and periodic updating of the transmission plans.

Refer to Figure 3.2-1, which depicts cumulative investment dollars for projects, categorized by plan status, for MTEP03 through the current MTEP11 cycle. MTEP11 data depicted in Figure 3.2-1, subject to Board approval, is from the current MTEP study and will be added to the data tracked by the MISO Board of Directors. The steady increase in planned facilities testifies to the coordinated planning efforts of MISO and its Transmission Owners. These statistics include only MISO members who participated in this planning cycle.

- Since MTEP03 $4.4 billion of approved projects have been constructed and are in service.
- $199 million of MTEP projects are currently flagged as being under construction. However, there are over $900 million of projects with expected in service dates in 2011.
- $9.3 billion of MTEP projects are currently planned.
- Since MTEP03 $480 million of MTEP projects have been withdrawn.

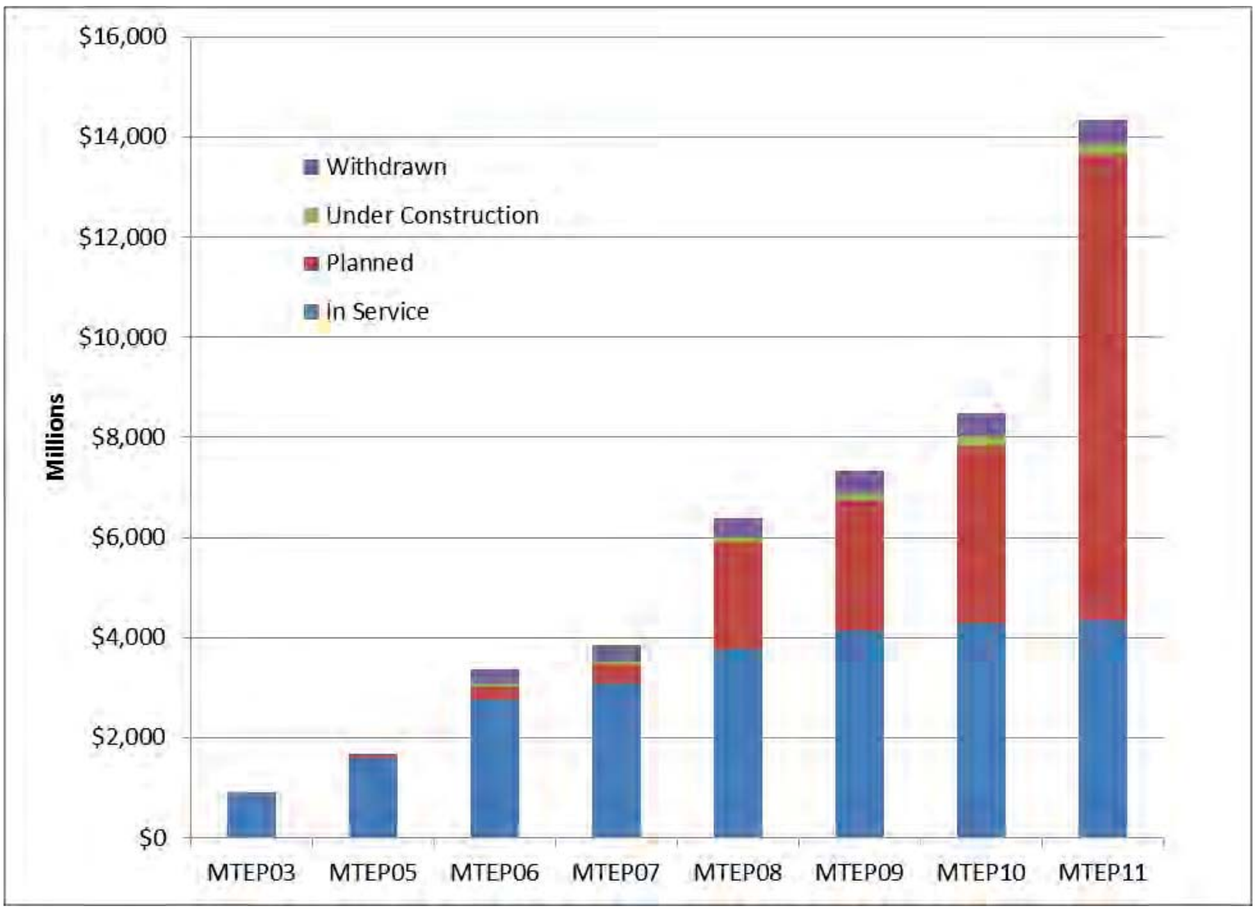

Figure 3.2-1: Cumulative approved investment by facility status

Figure 3.2-2 depicts MTEP project investment by facility status for each MTEP iteration. The historical perspective shows extensive variability in development. This is caused by the long development time of transmission plans and the regular and periodic updating of the transmission plans. The irregular shape of the graph represents the maturation of the MTEP process, and demonstrates the good faith effort of MISO Transmission Owners to implement the approved plan.

- MTEP06 and MTEP07 were approved in the same calendar year, which accounts for the comparatively small number of projects in MTEP07.
- In MTEP08, the number of developing needs increased the number of planned projects, including several large upgrades.
- MTEP09 was a year for analysis and determination of the best plans to serve those needs. The in-service category can be seen increasing in past MTEPs as projects are built.
- MTEP10 contains significant adjustments for reduced load forecasts and presents a transmission planning approach driven by proposed Multi Value Projects (MVPs), an adaptable rather than fixed methodology, which takes into account market and policy uncertainties and defines an array of multiple facility scenarios capable of performing well no matter what the future holds, integrating mandated renewable energy sources and providing market benefits.
- MTEP11 contains most of the proposed Multi Value Project (MVP) portfolio which is comprised of approximately $5.1 billion in transmission investment.

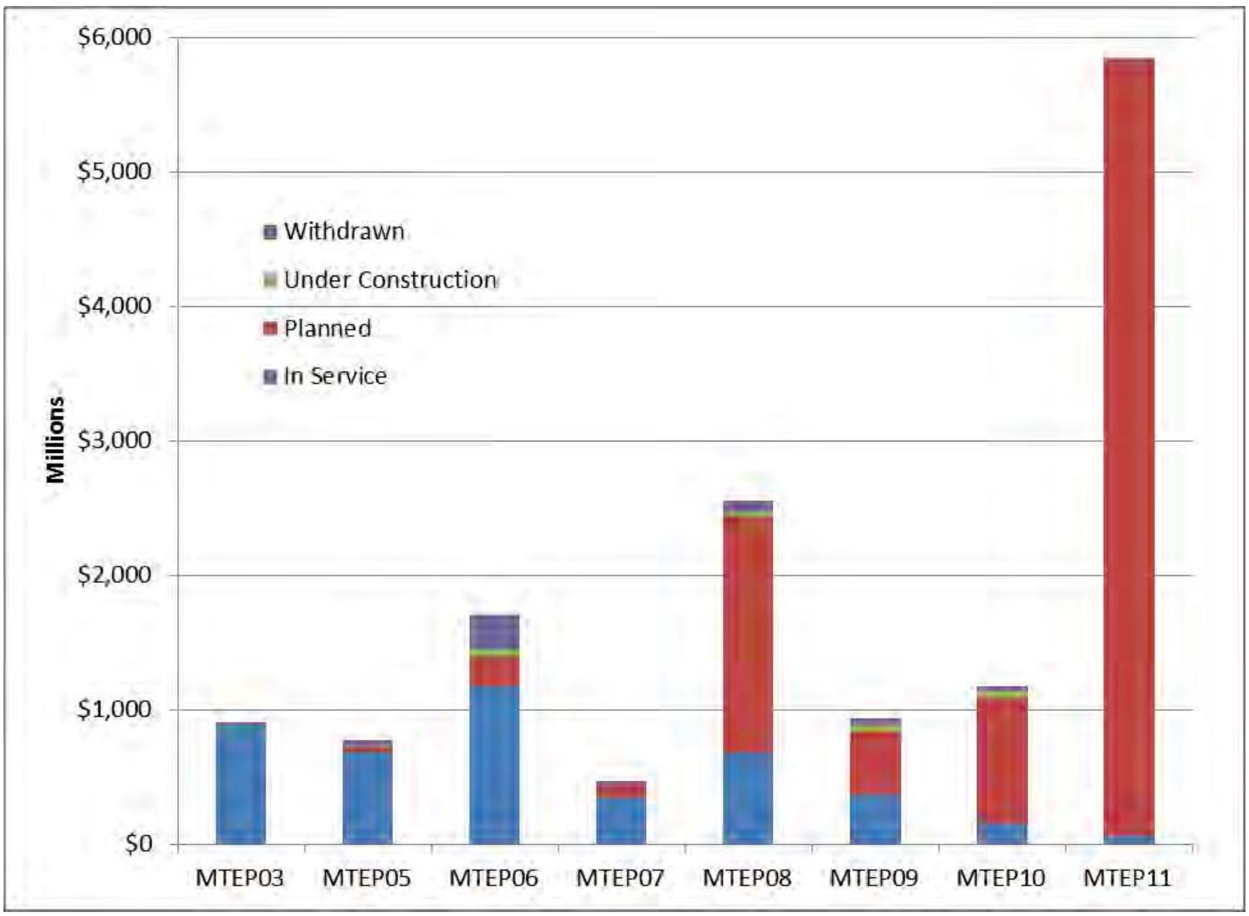

Figure 3.2-2: Approved MTEP investment by facility status

4. Regional energy policy studies

4.1 Proposed Multi Value Project portfolio

MISO staff recommends that the proposed Multi Value Project (MVP) portfolio be approved by the MISO Board of Directors for inclusion into Appendix A of MTEP11. This recommendation is based on the strong reliability, public policy and economic benefits of the portfolio that are distributed across the MISO footprint in a manner that is commensurate with the portfolio's costs. In short, the proposed portfolio will:

- Provide benefits in excess of its costs under all scenarios studied, with its benefit to cost ratio ranging from 1.8 to 3.0.
- Maintain system reliability by resolving reliability violations on approximately 650 elements for more than 6,700 system conditions and mitigating 31 system instability conditions.
- Enable 41 million MWh of wind energy per year to meet renewable energy mandates and goals.
- Provide an average annual value of $1,279 million over the first 40 years of service, at an average annual revenue requirement of $624 million.
- Support a variety of generation policies by using a set of energy zones which support wind, natural gas and other fuel sources.

This report summarizes the key reliability, public policy and economic benefits of the proposed MVP portfolio, as well as the scope of the analyses used to determine these benefits. Additional information on the portfolio and study analyses will be available in the full MVP portfolio report, which is scheduled to be published later in 2011.

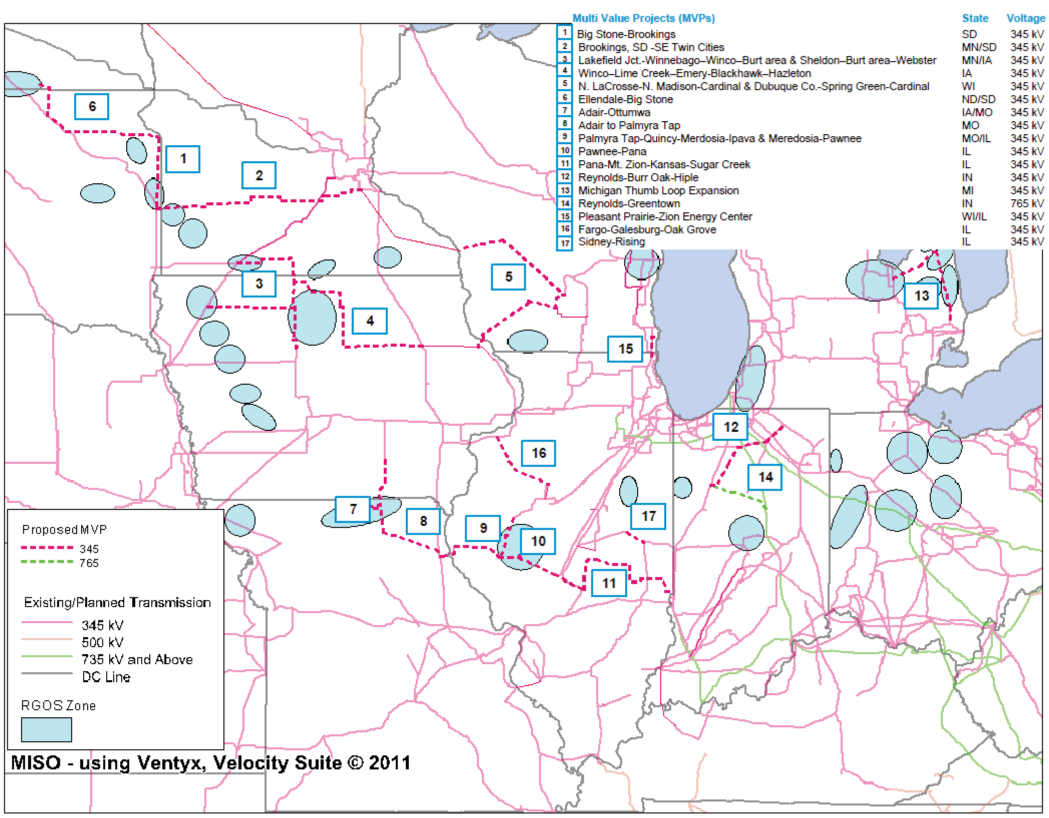

Figure 4.1-1: Proposed MVP portfolio

The proposed MVP portfolio includes the Brookings Project, conditionally approved in June 2011, and the Michigan Thumb Loop project, approved in August 2010. It also includes 15 additional projects which, when integrated into the transmission system, provide multiple kinds of benefits under all studied future scenarios[25].

	Project	State	Voltage (kV)	In Service Year	Cost (M, 2011$)[26]
1	Big Stone–Brookings	SD	345	2017	$191
2	Brookings, SD–SE Twin Cities	MN/SD	345	2015	$695
3	Lakefield Jct. Winnebago–Winco–Burt area & Sheldon–Burt area–Webster	MN/IA	345	2016	$506
4	Winco–Lime Creek–Emery–Black Hawk–Hazleton	IA	345	2015	$480
5	N. LaCrosse–N. Madison–Cardinal & Dubuque Co.–Spring Green–Cardinal	WI	345	2018/2020	$714
6	Ellendale–Big Stone	ND/SD	345	2019	$261
7	Adair–Ottumwa	IA/MO	345	2017	$152
8	Adair–Palmyra Tap	MO/IL	345	2018	$98
9	Palmyra Tap–Quincy–Merdosia–Ipava & Meredosia–Pawnee	IL	345	2016/2017	$392
10	Pawnee–Pana	IL	345	2018	$88
11	Pana–Mt. Zion–Kansas–Sugar Creek	IL/IN	345	2018/2019	$284
12	Reynolds–Burr Oak–Hiple	IN	345	2019	$271
13	Michigan Thumb Loop expansion	MI	345	2015	$510
14	Reynolds–Greentown	IN	765	2018	$245
15	Pleasant Prairie–Zion Energy Center	WI/IL	345	2014	$26
16	Fargo–Galesburg-Oak Grove	IL	345	2018	$193
17	Sidney–Rising	IL	345	2016	$90
Total					$5,197

Table 4.1-1: Proposed MVP portfolio

[25] More information on these scenarios may be found in the business case description.
[26] Costs shown are inclusive of transmission underbuild upgrades and upgrades driven by short circuit requirements.

Public policy decisions over the last decade have driven changes in how the transmission system is planned. The recent adoption of Renewable Portfolio Standards (RPS) and clean energy goals across the MISO footprint have driven the need for a more regional and robust transmission system to deliver renewable resources from often remote renewable energy generators to load centers.

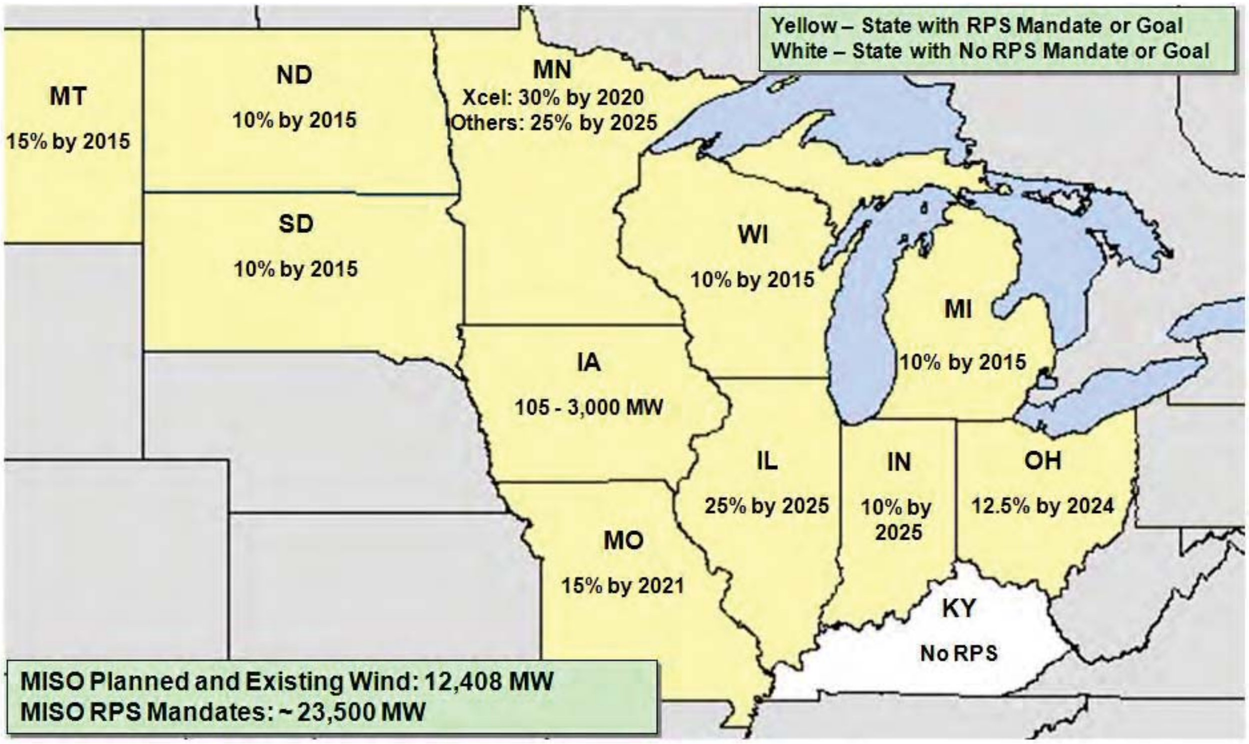

Figure 4.1-2: Renewable energy mandates and clean energy goals within the MISO footprint[27],[28]

Beginning with the MTEP03 Exploratory Studies, MISO and stakeholders began to explore how to best provide a value added regional planning process to complement the local planning of MISO members. These explorations continued in later MTEP cycles and in specific targeted studies. In 2008, MISO, with the assistance of state regulators and industry stakeholders such as the Midwest Governor's Association (MGA), the Upper Midwest Transmission Development Initiative (UMTDI) and the Organization of MISO States (OMS), began the Regional Generation Outlet Study (RGOS) to identify a set of value based transmission portfolios necessary to enable Load Serving Entities (LSEs) to meet their RPS mandates.

The recent adoption of Renewable Portfolio Standards (RPS) across the MISO footprint have driven the need for a more regional and robust transmission system to deliver renewable resources from often remote renewable energy generators to load centers

The goal of the RGOS analysis was to design transmission portfolios that would enable RPS mandates to be met at the lowest delivered wholesale energy cost. The cost calculation combined the expenses of the new transmission portfolios with the capital costs of the new renewable generation, balancing the trade offs of a lower transmission investment to

27 Existing and planned wind as included in the Candidate MVP Portfolio. State RPS mandates and goals include all policies signed into law by June 1, 2011.

28 The higher number for Iowa's state RPS mandates and goals reflects the wind online rather than a statutory requirement.

deliver wind from low wind availability areas, typically closer to large load centers; against a larger transmission investment to deliver wind from higher wind availability areas, typically located further from load centers.

While much consideration was given to wind capacity factors when developing the energy zones utilized in the RGOS and Candidate MVP Portfolio Analyses, the zones were chosen with consideration of more factors than wind capacity. Existing infrastructure, such as transmission and natural gas pipelines, also influenced the selection of the zones. As such, although the energy zones were created to serve the renewable generation mandates, they could be used for a variety of different generation types, to serve various future generation policies. Figure 4.1-3 depicts the correlation between the natural gas pipelines in the MISO footprint and the energy zones.

The zones were chosen with consideration of more factors than wind capacity. Existing infrastructure, such as transmission and natural gas pipelines, also influenced the selection of zones.

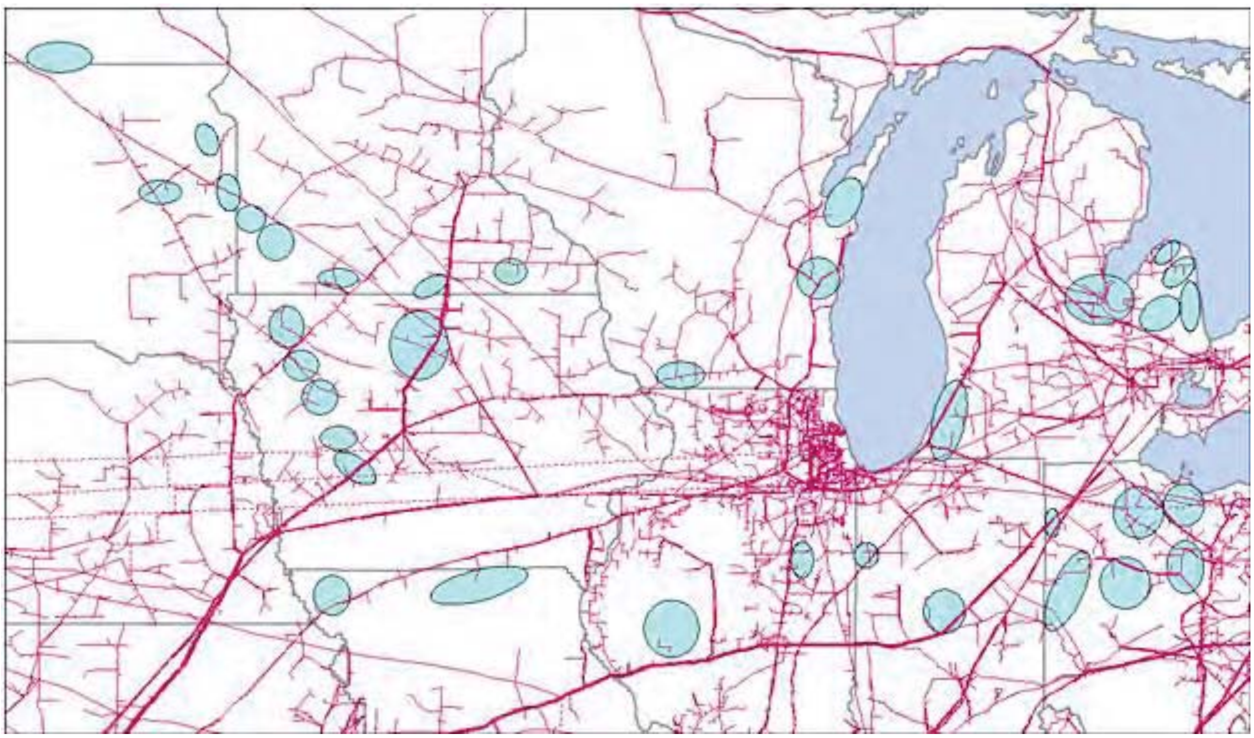

Figure 4.1-3: RGOS and Candidate MVP Incremental Energy Zones and natural gas pipelines

The output from the study, a proposed MVP portfolio, will reduce the wholesale cost of energy delivery for the consumer by enabling the delivery of low cost generation to load, reducing congestion costs and increasing system reliability, regardless of the future generation mix.

The RGOS analysis produced three reliable transmission portfolios. Elements common between these three portfolios, and common with previous reliability, economic and generation interconnection analyses, were identified to create the 2011 Candidate MVP portfolio. This portfolio represented a set of “no regrets” projects which were believed to provide multiple kinds of reliability and economic benefits under all alternate futures studied.

The 2011 Candidate MVP Portfolio Analysis hypothesized that this set of candidate projects creates a high value transmission portfolio, enabling MISO states to meet their near term RPS mandates. This study evaluated the Candidate MVP portfolio against the MVP cost allocation criteria to prove or disprove this hypothesis, as well as to confirm that the benefits of the portfolio would be widely distributed across the footprint. The output from the study, a proposed MVP portfolio, will reduce the wholesale cost of energy delivery for the consumer by enabling the delivery of low cost generation to load, reducing congestion costs and increasing system reliability, regardless of the future generation mix.

Over the course of the Candidate MVP Portfolio Analysis, the MVP portfolio was refined into the proposed portfolio that is now recommended to the MISO Board of Directors for approval. The portfolio was refined to ensure that the portfolio as a group and each project contained within it was justified under the MVP criteria, discussed below, and to ensure that the portfolio benefit to cost ratio was optimized.

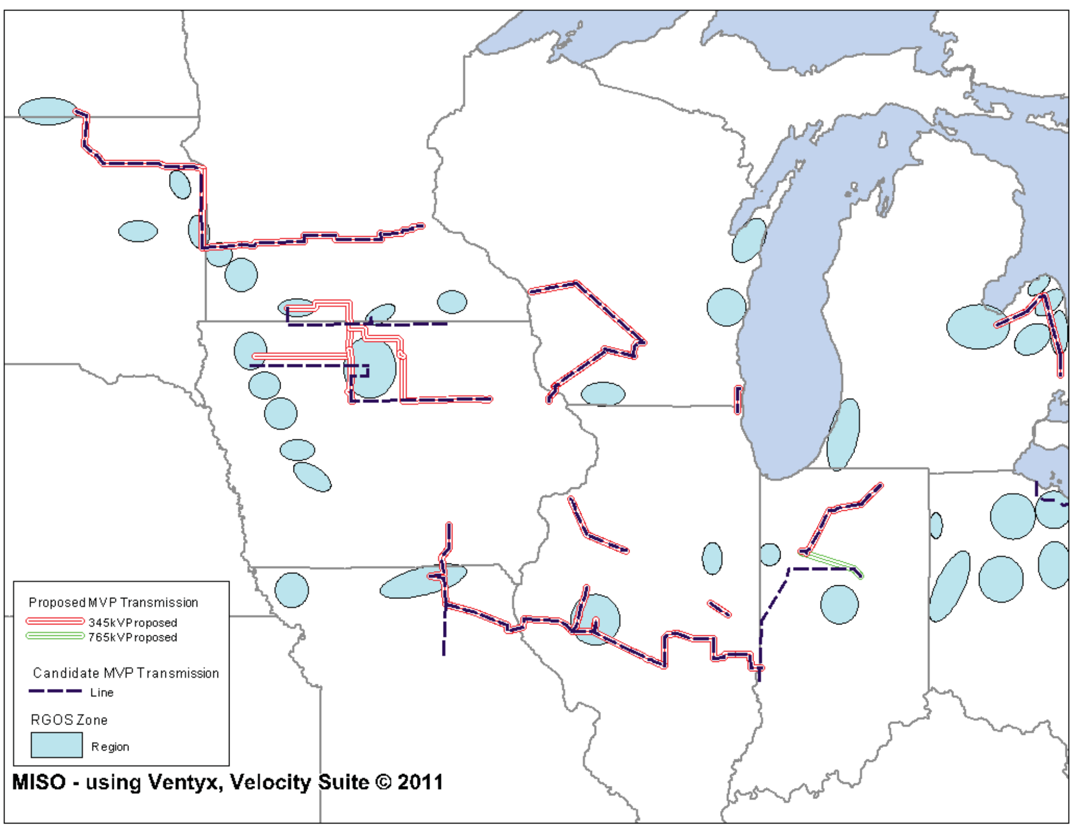

Figure 4.1-4: Candidate versus proposed MVP portfolio

The proposed MVP portfolio will enable the delivery of the renewable energy required by public policy mandates, in a manner more reliable and economic than it would be without the associated transmission upgrades. Specifically, the portfolio mitigates approximately 650 reliability constraints under 6,700 different transmission outage conditions, for steady state and transient conditions under both peak and shoulder load scenarios. Some of these conditions could be severe enough to cause cascading outages on the system. By mitigating these constraints, approximately 41 million MWh per year of renewable generation can be delivered to serve the MISO state renewable portfolio mandates.

Under all future policy scenarios studied, the proposed MVP portfolio delivers widespread regional benefits to the transmission system. For example, based on scenarios that did not consider new energy policies, the benefits of the proposed portfolio were shown to range from 1.8 to 3.0 times its total cost. These benefits are spread across the system, in a manner commensurate with their costs, as demonstrated in Figure 4.1-5.

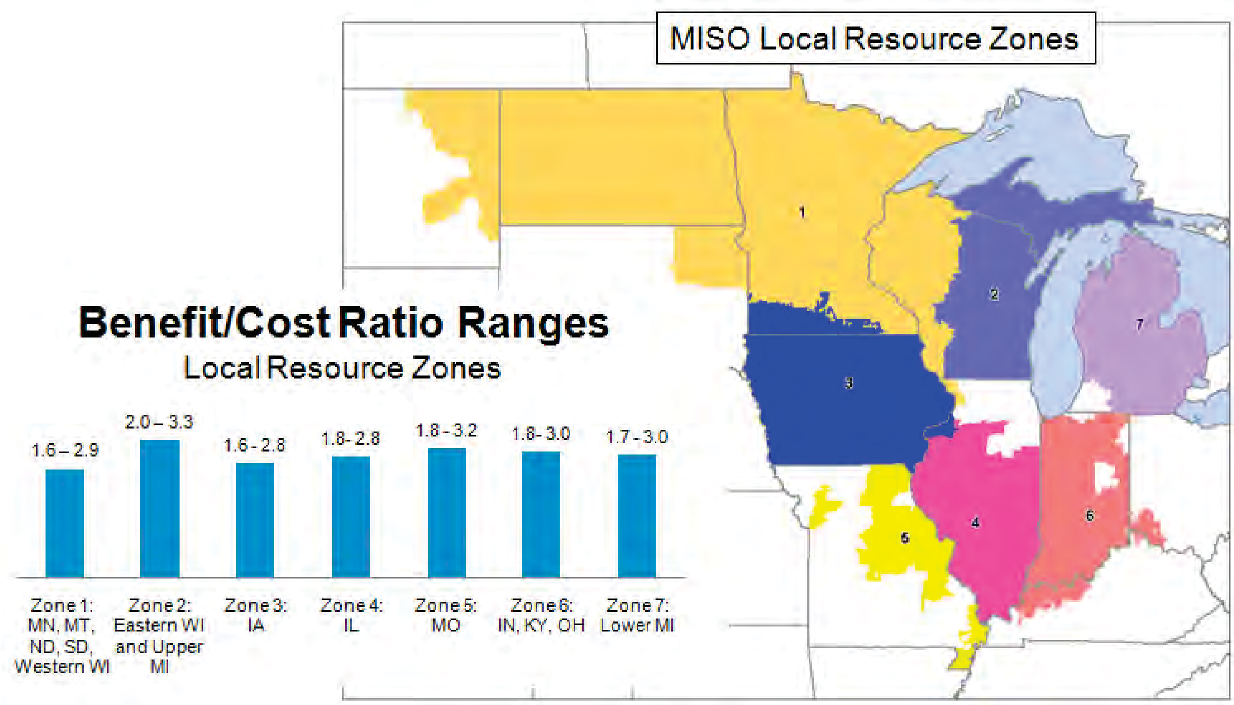

Figure 4.1-5: Proposed MVP portfolio benefits spread

The benefits created by the proposed MVP portfolio are spread across the system, in a manner commensurate with its costs.

Taking into account the significant economic value created by the portfolio, the distribution of these value, and the ability of the portfolio to meet MVP criterion 1 through its reliability and public policy benefits, MISO staff recommends the 2011 proposed MVP portfolio to the MISO Board of Directors for their review and approval.

Additional information on the proposed MVP portfolio, and the analyses used to design the portfolio, will be summarized in the full MVP portfolio report. This report will be published later in 2011.

MISO planning approach

The goal of the MISO planning process is to develop a comprehensive expansion plan that reflects a fully integrated view of project value inclusive of reliability, market efficiency, public policy and other value drivers across all planning horizons. This process is guided by a set of principles established by the MISO Board of Directors, adopted on August 18, 2005. The principles were created in an effort to improve and guide transmission investment in the region and to furnish an element of strategic direction to the MISO transmission planning process. These principles, modified and approved by the MISO Board of Directors System Planning Committee on May 16, 2011, are:

- **Guiding Principle 1:** Make the benefits of an economically efficient energy market available to customers by providing access to the lowest electric energy costs.
- **Guiding Principle 2:** Provide a transmission infrastructure that safeguards local and regional reliability and supports interconnection-wide reliability.
- **Guiding Principle 3:** Support state and federal energy policy objectives by planning for access to a changing resource mix.
- **Guiding Principle 4:** Provide an appropriate cost mechanism that ensures the realization of benefits over time is commensurate with the allocation of costs.
- **Guiding Principle 5:** Develop transmission system scenario models and make them available to state and federal energy policy makers to provide context and inform the choices they face.

A number of conditions must be met to build longer term transmission able to support future generation growth and accommodate new energy policies. These conditions are intertwined with the planning principles put forth by the MISO Board of Directors and supported by an integrated, inclusive transmission planning approach. The conditions that must be met to build transmission include:

- A robust business case that demonstrates value sufficient to support the construction of the transmission project.
- Increased consensus on current and future energy policies.
- A regional tariff that matches who benefits with who pays over time.
- Cost recovery mechanisms that reduce financial risk.

Multi Value Project portfolio drivers

The 2011 Candidate MVP Portfolio Analysis was based on the need to economically and reliably help states meet their public policy needs. The study identified a regional transmission portfolio that will enable the MISO Load Serving Entities (LSEs) to meet their Renewable Portfolio Standards (RPS). The analyses and their results describe a robust business case for the portfolio. This business case demonstrates that not only will the proposed MVP portfolio reliably enable Renewable Portfolio Standards to be met, but it will do so in a manner where its economic benefits exceed its costs.

While the study focused upon the RPS requirements, the transmission portfolio will ultimately have widespread benefits beyond the delivery of wind and other renewable energy. It will enhance system reliability and efficiency under a variety of different generation build outs. It will also open markets to competition, reducing congestion and spreading the benefits of low cost generation across the MISO footprint. The Candidate MVP Portfolio Analysis focused on identifying and increasing the benefits of the transmission portfolio, including the reliability, economic and public policy drivers.

Tariff requirements

The Candidate MVP Portfolio Analysis and the recommendation of the proposed MVP portfolio were premised on the MVP criteria described in Attachment FF of the MISO Tariff and shown below.

Criterion 1

A Multi Value Project must be developed through the transmission expansion planning process to enable the transmission system to deliver energy reliably and economically in support of documented energy policy mandates or laws enacted or adopted through state or federal legislation or regulatory requirement. These laws must directly or indirectly govern the minimum or maximum amount of energy that can be generated. The MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade.

Criterion 2

A Multi Value Project must provide multiple types of economic value across multiple pricing zones with a Total MVP benefit to cost ratio of 1.0 or higher, where the total MVP benefit to cost ratio is described in Section II.C.7 of Attachment FF to the MISO Tariff. The reduction of production costs and the associated reduction of LMPs from a transmission congestion relief project are not additive and are considered a single type of economic value.

Criterion 3

A Multi Value Project must address at least one transmission issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic based transmission issue that provides economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs based on the definition of financial benefits and Project Costs provided in Section II.C.6 of Attachment FF.

The MVP cost allocation criteria requires evaluation of the portfolio on a reliability, economic and energy delivery basis. The scope of the analysis was designed to demonstrate this value, both on a project and portfolio basis. The projects in the MVP portfolio were evaluated against MVP criteria 1 and their ability to reliably enable the renewable energy mandates of the MISO states was quantified.

In addition, the Tariff identifies specific types of economic value which can be provided by Multi Value Projects. These values are:

- Production cost savings where production costs include generator startup, hourly generator no-load, generator energy and generator Operating Reserve costs. Production cost savings can be realized through reductions in both transmission congestion and transmission energy losses. Productions cost savings can also be realized through reductions in Operating Reserve requirements within Reserve Zones and, in some cases, reductions in overall Operating Reserve requirements for the Transmission Provider.
- Capacity losses savings where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour including associated planning reserve.
- Capacity savings due to reductions in the overall Planning Reserve Margins resulting from transmission expansion.
- Long-term cost savings realized by Transmission Customers by accelerating a long-term project start date in lieu of implementing a short-term project in the interim and/or long-term cost savings realized by Transmission Customers by deferring or eliminating the need to perform one or more projects in the future.

- Any other financially quantifiable benefit to Transmission Customers resulting from an enhancement to the transmission system and related to the provisions of Transmission Service.

The full proposed portfolio was evaluated against the benefits defined in the Tariff for MVP projects. In addition to the benefits described above, the operating reserve and wind siting benefits for the portfolio were quantified, as allowed under the last Tariff defined economic value. These benefits are described more fully in the economic benefit section later in the report.

Public policy needs

Twelve of 13 states in the MISO footprint have enacted either RPS requirements or renewable energy goals which require or recommend varying amounts of load be served with energy from renewable energy resources. The Candidate MVP Portfolio Analysis focused on the transmission necessary to economically and reliably meet the state RPS mandates. Figure 4.1-6 below provides additional details on these renewable energy requirements and goals.

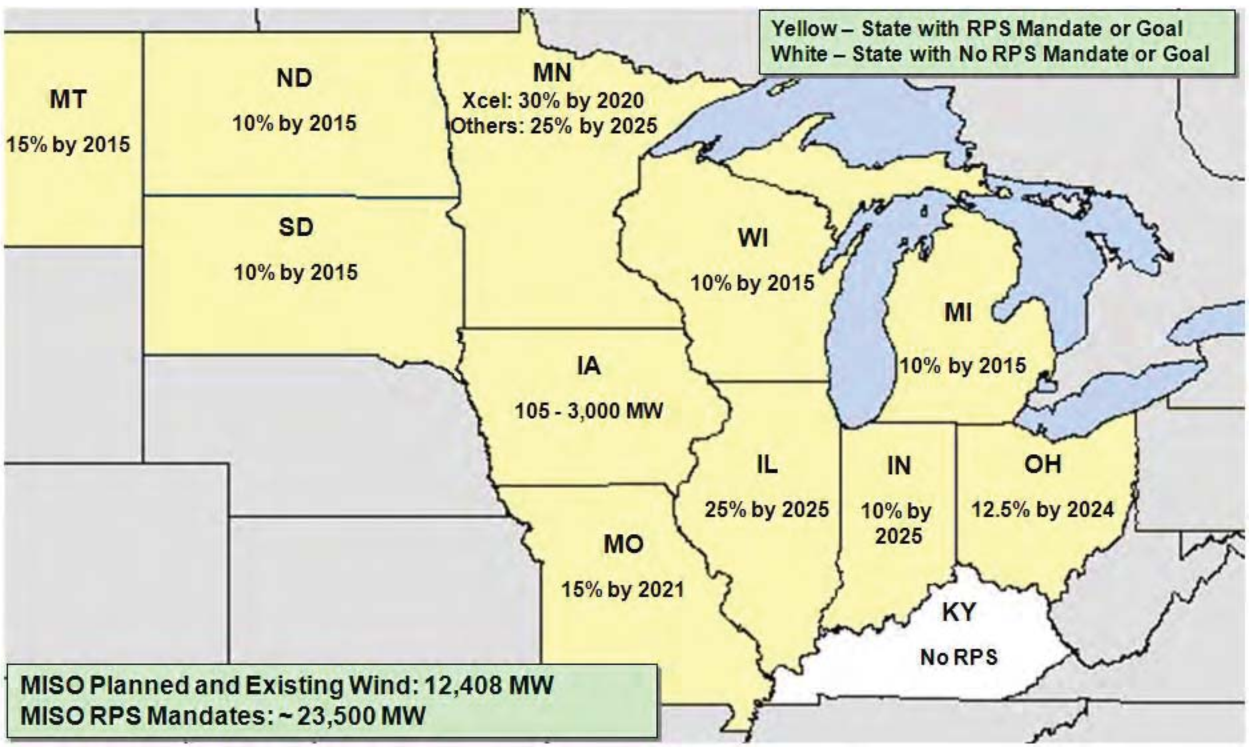

Figure 4.1-6: RPS mandates and goals within the MISO footprint

RPS mandates vary from state to state in their specific requirement details and implementation timing, but they generally start in about 2010 and are indexed to increase with load growth. While state laws support a number of different types of renewable resources, and multiple types of renewable resources will play a role in meeting state RPS mandates, the majority of renewable energy resources installed in the foreseeable future will likely focus on harnessing the abundant wind resources throughout the MISO footprint.

Enhanced reliability and economic drivers

The ultimate goal of the MISO planning process is to reliably deliver energy to load at the lowest possible cost. This requires a strategy premised upon a low cost approach to transmission and generation investment. This premise supports the overall constructability of the transmission portfolio, while reducing financial risk associated with overbuilding the system.

Transmission strategy

A transmission strategy addressing both local needs and regional drivers allows the MISO system to realize significant economic and reliability benefits. Regional transmission, such as the transmission in the proposed MVP portfolio, increases reliability in the MISO footprint, opens the market to increased competition and provides access to low cost generation, regardless of fuel type. Development of a strong regional transmission backbone is analogous to the development of the U.S. Interstate Highway System. While developed for specific wartime reasons, the system has realized significant additional benefits in subsequent years. Similarly, the proposed MVP portfolio will create reliability, economic and public policy benefits that reach beyond the immediate needs exhibited in this analysis.

> The goal of the Candidate MVP Portfolio Analysis was to design a transmission portfolio which takes advantage of the linkages between local and regional reliability and economic benefits to bring value to the entire MISO system.

The overall goal for the Candidate MVP Portfolio Analysis was to design a transmission portfolio which takes advantage of the linkages between local and regional reliability and economic benefits to bring value to the entire MISO system. The portfolio was designed using reliability and economic analyses, applying several futures scenarios to determine the robustness of the designed portfolio under a number of future potential energy policies.

Development of the Candidate MVP portfolio

In order to provide widespread benefits commensurate with costs, MISO developed an initial portfolio of candidate MVP projects that were hypothesized to provide widespread benefits across the footprint. The projects selected as candidates for possible inclusion in the broader portfolio were then intensively evaluated in the Candidate MVP Portfolio Analysis to ensure they were justified and contributed to the portfolio business case.

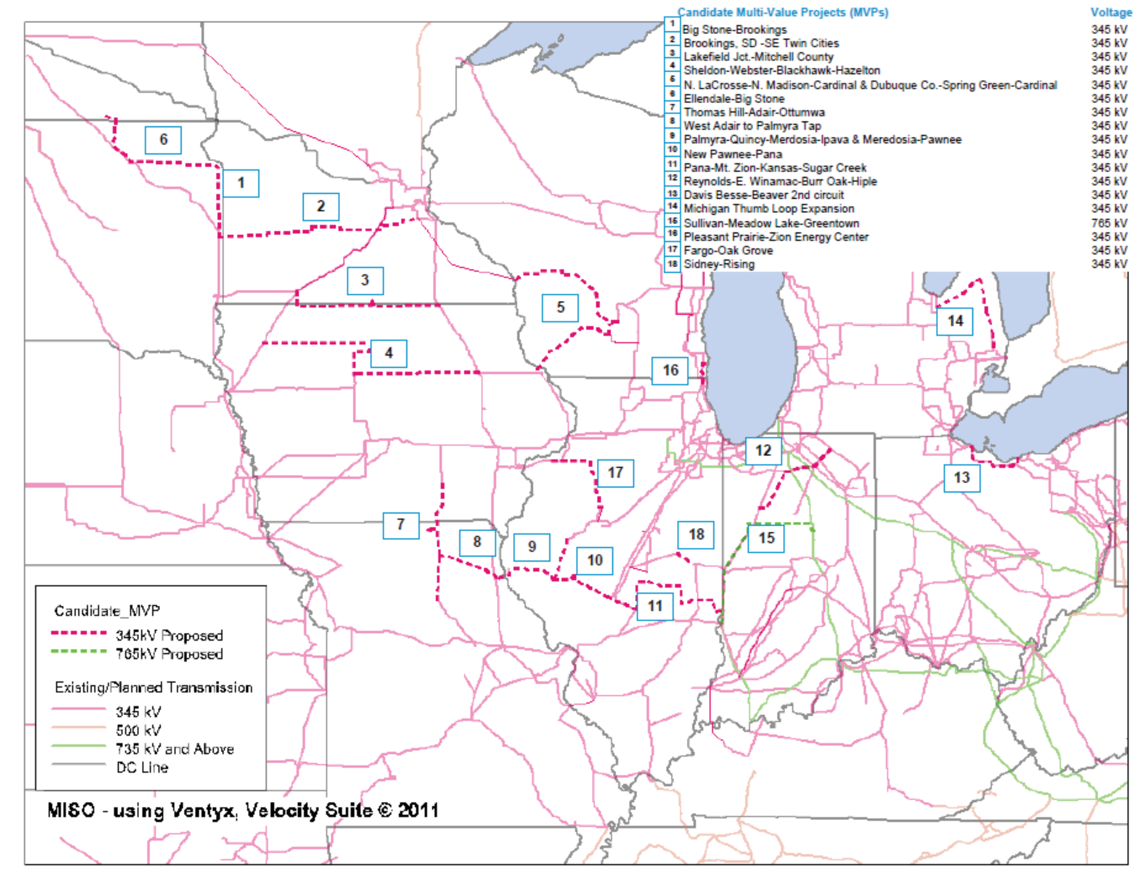

Figure 4.1-7: Initial 2011 Candidate MVP portfolio

The Candidate MVP portfolio was the first portfolio developed for review under the recent Tariff revisions establishing the MVP cost allocation classification. It was developed by considering regional system enhancements that could potentially provide multiple types of value, including enhanced reliability, reduced congestion, increased market efficiency, reduced real power losses and the deferral of otherwise needed capital investments in transmission. The portfolio was designed to enhance and complement the existing system performance, working cohesively with the individual elements of the portfolio and with the existing transmission grid, to produce a more robust and efficient system. Ultimately, the first portfolio represents a set of "no regrets" projects, providing benefits to the system in all futures scenarios studied.

Historical studies

MISO began to investigate the transmission required to integrate wind and provide the best value to consumers in 2002. The analyses continued through subsequent MTEP cycles, with exploratory and energy market analyses. As the demand for renewable energy grew, driven largely by an increasing level of renewable energy mandates or goals, additional regional studies were conducted to determine the transmission necessary to support these policy objectives. These studies included the Joint and Coordinated System Plan (JCSP), the Regional Generation Outlet Studies (RGOS), and analyses by the Organization of MISO States (OMS) Cost Allocation and Regional Planning (CARP) group.

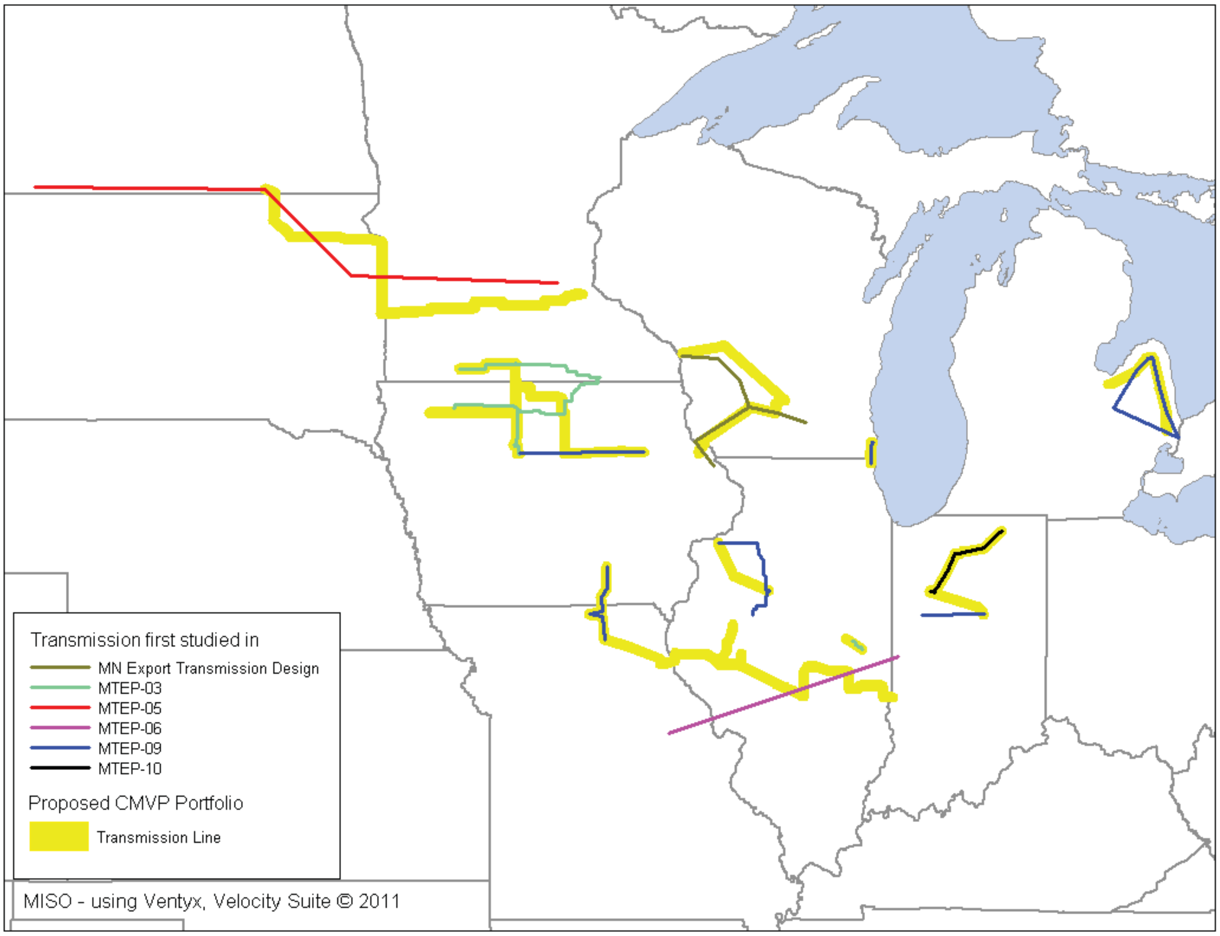

Figure 4.1-8: Prior study input into Candidate MVP portfolio

As analyses continued, the policy and economic drivers behind a regional transmission plan continued to grow. This growth was partly fueled by the development of the MISO energy and operating reserve market, which allows for regional transmission to provide regional benefits through increasing market efficiency, enabling low cost generation to be delivered to load. Simultaneously, an increase in state energy policy mandates drove the need for a robust regional transmission network, capable of responding to legislated changes in generation requirements.

Wind siting strategy

As an increasing number of states in the MISO footprint began to enact renewable energy mandates or goals, a strategy for siting wind generation was required to minimize the cost of delivered energy to consumers. To determine the low cost solution, encompassing generation and transmission capital cost, MISO developed a set of potential energy zones or locations where wind generation could feasibly be located, on a state by state basis[29]. In conjunction with state regulators and other stakeholders, MISO used these zones to explore a number of long term transmission and generation strategies to meet the state RPS requirements. These analyses focused on the tradeoffs between local wind generation, which typically requires less transmission expansion but a larger amount of wind turbines to deliver a given amount of wind energy; versus regional wind generation, which requires fewer wind turbines at the cost of higher levels of transmission expansion.

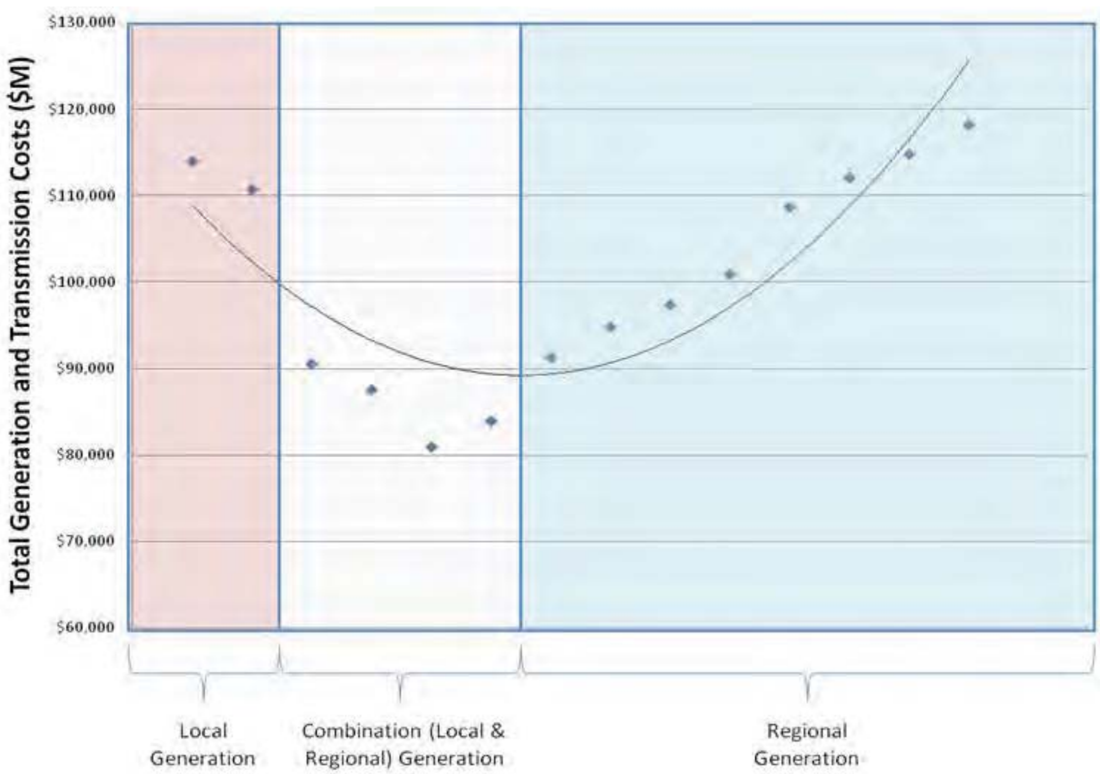

Figure 4.1-9: Capital costs of transmission and generation

[29] More information on the zone development may be found in the RGOS report at http://www.midwestiso.org/Library/Repository/Study/RGOS/Regional percent20Generation percent20Outlet percent20Study.pdf.

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The study results demonstrated that the low cost approach to wind generation siting, when both generation and transmission capital costs are considered, is a combination of local and regional wind generation locations, as shown by the white area in Figure 4.1-9. This approach was affirmed by the Midwest Governors' Association as the best method for wind zone selection and used as the basis for the final phase of the RGOS analysis in 2010. It was also used as the basis for the wind siting approach for the Candidate MVP Portfolio Analysis. The set of energy zones chosen for the Candidate MVP Portfolio Analysis are shown below in Figure 4.1-10 as blue ovals.

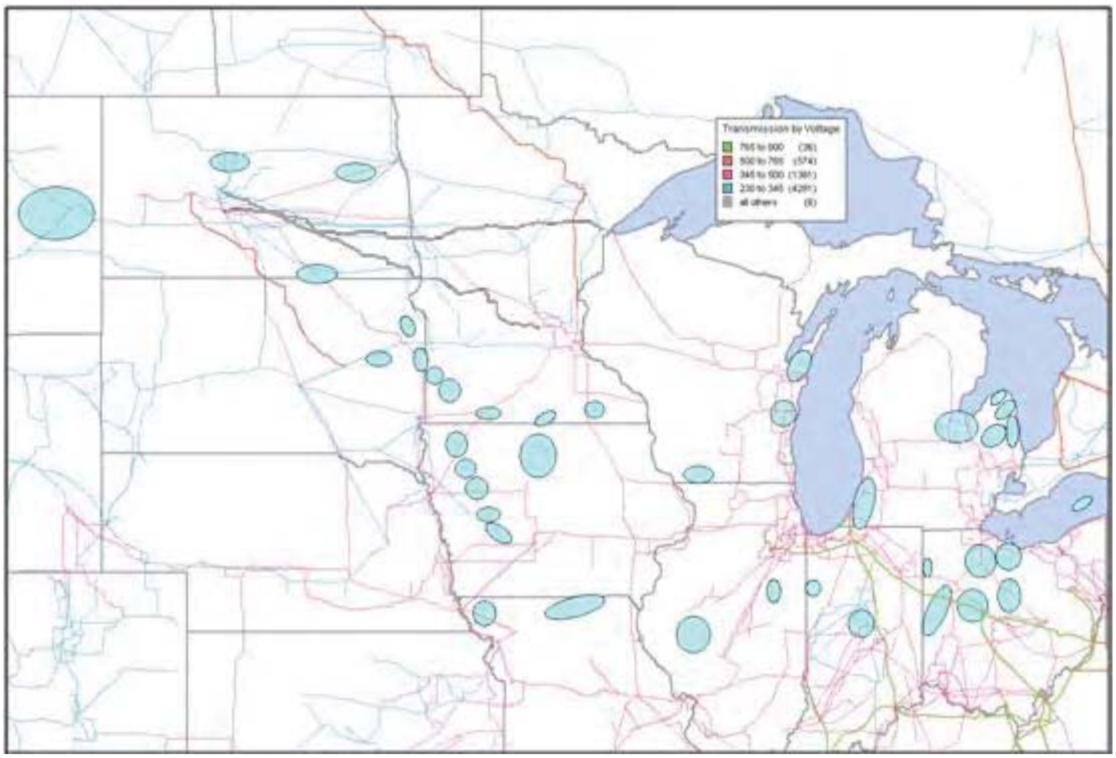

Figure 4.1-10: Candidate MVP Incremental Energy Zones[30]

[30] Zones shown represent the rough geographic area of each energy zone.

Candidate MVP Portfolio Analysis study scope

The Candidate MVP Portfolio Analysis combined the MISO Board of Director Planning Principles and the conditions precedent to transmission construction to develop a transmission portfolio that meets public policy, economic and reliability requirements. The analysis built a robust business case for the recommended transmission, using the newly created Multi Value Project (MVP) cost allocation methodology approved by FERC. The candidate transmission was tested against a variety of potential policy futures. This maximized the value of the transmission portfolio and reduced potential negative risks associated with its construction due to changes in future demand and energy growth. The output of the study was a justified portfolio of proposed MVPs for inclusion in MTEP11 Appendix A and, if approved by the MISO Board of Directors, subsequent construction.

The MVP cost allocation criterion requires the evaluation of the portfolio on a reliability, economic and energy delivery basis.

The MVP cost allocation criteria requires the evaluation of the portfolio on a reliability, economic and energy delivery basis. The analyses were designed to demonstrate this value, both on a project and portfolio basis. To this end, the Candidate MVP Portfolio Analysis included the studies and output shown in table 4.1-2.

These analyses focused on three main areas. The project valuation analyses focused on justifying each individual MVP project against the MVP criteria. The portfolio valuation analyses determined the benefits of the portfolio in aggregate, quantifying additional reliability and economic benefits. Finally, a series of system performance analyses were performed to ensure that the system reliability will be maintained with the proposed MVP portfolio in service.

Analysis Type	Analysis Output	Purpose
Steady state	List of thermal overloads mitigated by the proposed MVP portfolio transmission projects	Project valuation
Alternatives	Relative value of the candidate MVP projects against a stakeholder or MISO identified alternative Can include steady state and production cost analyses	Project valuation
Underbuild requirements	Document any incremental transmission required to mitigate constraints created by the addition of the proposed MVP portfolio	System performance
Short circuit	Document any incremental upgrades required to mitigate any short circuit / breaker duty violations	System performance
Stability	List of violations mitigated by the proposed MVP portfolio transmission projects Includes both transient and voltage stability analysis	System performance / Portfolio valuation
Generation enabled	Document wind curtailed, and additional wind that is enabled by the proposed MVP portfolio	Portfolio valuation
Production cost	Adjusted Production Cost (APC) benefits of the entire proposed MVP portfolio	Portfolio valuation
Robustness testing	Quantification of portfolio benefits under various policy futures or transmission conditions	Portfolio valuation
Operating reserves Impact	Impact of the proposed MVP portfolio on existing operating reserve zones and quantification of this benefit	Portfolio valuation
Planning Reserve Margin (PRM) benefits	Capacity savings due to reductions in the system wide Planning Reserve Margin caused by the addition of the proposed MVP portfolio to the transmission system	Portfolio valuation
Transmission loss reductions	Capacity losses savings, where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour	Portfolio valuation
Wind generation capital investment	Quantification of the incremental wind generator capital cost savings enabled by the wind siting methodology supported by the proposed MVP portfolio	Portfolio valuation
Avoided capital investment (transmission)	Document the future baseline transmission investment that may be avoided due to the installation of the proposed MVP portfolio	Portfolio valuation

Table 4.1-2: Candidate MVP Portfolio Analyses and Output

Proposed MVP portfolio overview

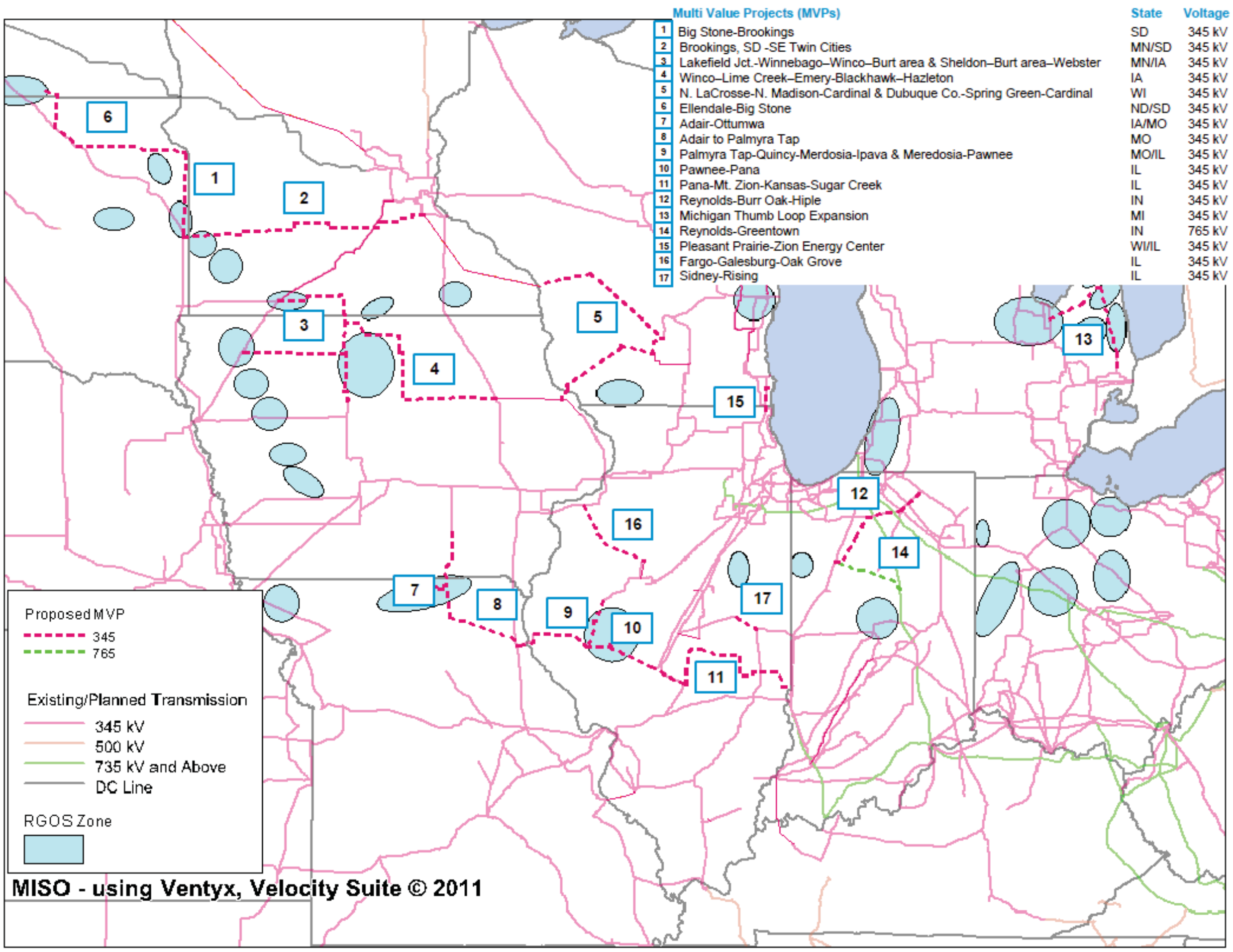

Figure 4.1-11: 2011 proposed MVP portfolio

The proposed MVP portfolio consists of 17 projects spread across the MISO footprint. These projects work together with the existing transmission network to enhance the reliability of the system, support public policy goals and enable the more efficient dispatch of market resources. Table 4.1-3 below describes the projects that make up the proposed MVP portfolio.

	Project	State	Voltage (kV)	In Service Year	Cost (M, 2011$)
1	Big Stone–Brookings	SD	345	2017	$191
2	Brookings, SD–SE Twin Cities	MN/SD	345	2015	$695
3	Lakefield Jct. –Winnebago–Winco–Burt area & Sheldon–Burt area–Webster	MN/IA	345	2016	$506
4	Winco–Lime Creek–Emery–Black Hawk–Hazleton	IA	345	2015	$480
5	N. LaCrosse–N. Madison–Cardinal & Dubuque Co. –Spring Green–Cardinal	WI	345	2018/2020	$714
6	Ellendale–Big Stone	ND/SD	345	2019	$261
7	Adair–Ottumwa	IA/MO	345	2017	$152
8	Adair–Palmyra Tap	MO/IL	345	2018	$98
9	Palmyra Tap–Quincy–Merdosia–Ipava & Meredosia–Pawnee	IL	345	2016/2017	$392
10	Pawnee–Pana	IL	345	2018	$88
11	Pana–Mt. Zion–Kansas–Sugar Creek	IL/IN	345	2018/2019	$284
12	Reynolds–Burr Oak–Hiple	IN	345	2019	$271
13	Michigan Thumb Loop Expansion	MI	345	2015	$510
14	Reynolds–Greentown	IN	765	2018	$245
15	Pleasant Prairie–Zion Energy Center	WI/IL	345	2014	$26
16	Fargo-Galesburg–Oak Grove	IL	345	2018	$193
17	Sidney–Rising	IL	345	2016	$90
	Total				$5,197

Table 4.1-3: Proposed MVP portfolio

Reliability benefits and analyses

The proposed MVP portfolio maintains system reliability by resolving violations on approximately 650 transmission elements for more than 6,700 system conditions. It also mitigates 31 system instability conditions. More information on these constraints can be found in Appendix E4, and a full write up of the analyses will be included in the full MVP portfolio report. A description of the reliability analysis results follows in the next section.

Steady state

A series of steady state analyses were conducted to determine the transmission line overloads and system voltage constraints mitigated by the proposed MVP portfolio. The primary steady state analysis was performed on a set of 2021 shoulder peak models, with both 2021 and 2026 mandated wind levels considered. Shoulder peak models were chosen for the primary analysis, as the high wind levels required by the renewable portfolio mandates are more likely to create system constraints under these conditions. A 2021 peak analysis was also conducted to ensure the full reliability benefits of the proposed portfolio were captured. Each set of analyses were performed on: 1) a model with the RPS mandated wind, without any incremental transmission; 2) a model with the RPS mandated wind and the MVP portfolio. The results from the two analyses were compared to determine what constraints were mitigated by the proposed MVP portfolio.

The proposed MVP portfolio maintains system reliability by resolving violations on approximately 650 transmission elements for more than 6,700 system conditions.

A total of 384 thermal overloads were mitigated by the proposed MVP portfolio under shoulder peak conditions, for approximately 4,600 system conditions. In addition, approximately 100 additional thermal overloads and 150 voltage violations were mitigated by the proposed MVP portfolio in the summer peak analysis.

Stability

Transient Stability

MISO performed a set of transient stability analyses to ensure the ability of existing and proposed generation to remain synchronous with other system generation under severe fault conditions, as required by NERC and regional reliability standards. Two scenarios were studied to evaluate the impact of major fault conditions without any voltage or damping criteria violations. The first scenario included all the incremental wind zones with none of the proposed MVPs portfolio modeled, and the second scenario included incremental wind zones and the proposed MVP portfolio.

Based on the comparative analysis involving simulation of approximately 650 fault conditions under both scenarios, there were 31 fault conditions that without the proposed MVP portfolio would cause the system to experience undamped oscillations, causing generators to trip offline or incur damage due to high speed rotation, creating safety risks for plant personnel and potentially causing a large scale loss of load. These conditions were resolved by the addition of the proposed MVP portfolio to the system, and no additional stability violations were determined with the MVP portfolio in service.

Voltage Stability Analysis

MISO performed voltage stability analyses to identify voltage collapse conditions under high energy transfer conditions from major generation resources to major load sinks. Such transfers may occur during critical dispatch scenarios, such as when local area generation near large load centers are offline and remote generation resources are supplying energy to the load centers. Two scenarios were studied to evaluate the incremental energy transfer capability. The first scenario included all the incremental wind zones with none of the proposed MVP portfolio modeled, and the second scenario included all the incremental wind zones and the proposed MVP portfolio.

MISO did not observe any voltage stability issues with the proposed MVP portfolio in place, and with the high energy transfers corresponding to the highest wind resource output levels. Additionally, the comparative transfer analysis simulated high transfer conditions from the wind rich West Region of the MISO footprint to major load centers such as Minneapolis-St. Paul, Madison, St Louis and Des Moines. The results, shown in Appendix E4, illustrate that the addition of the proposed MVP portfolio causes an increase in transfer capability from wind rich regions to major load centers that ranges from 960 to 1,841 MW. This additional transfer capacity will increase system reliability and robustness, allowing additional energy sources to be dispatched to serve load centers as needed.

Short circuit

The addition of significant amounts of new high voltage transmission to the grid can increase the system connectivity, resulting in lowered impedance for short circuit currents. This can cause available fault currents throughout the system to exceed circuit breaker interrupting capabilities. MISO staff and Transmission Owners performed a series of high level short circuit analyses to identify any breaker or substation equipment needing to be upgraded after the addition of the proposed MVP portfolio to the transmission system. These analyses were performed directly by the affected Transmission Owners, with MISO staff providing modeling information for the proposed MVP projects. Any identified circuit breaker upgrades were verified through independent analysis by MISO staff, and their costs were included in the portfolio. Overall, nine circuit breakers were identified for replacement, at a total cost of $2.2 million.

Underbuild requirements

To ensure that the proposed MVP portfolio works well with the existing system to maintain reliability, MISO conducted analyses to determine any constraints that are present with the proposed MVP Portfolio and not present without the proposed portfolio. Any new constraints were identified for mitigations, and the appropriate mitigation was determined in coordination with the impacted Transmission Owners.

Below is a full list of the underbuild upgrades. Overall, approximately $70 million of transmission investment is associated with such underbuild.

Underbuild requirements
Burr Oak to East Winamac 138 kV line uprate
Lake Marian 115/69 kV transformer replacement
Arlington to Green Isle 69 kV line uprate
Columbus 69 kV transformer replacement
Casey to Kansas 345 kV line uprate
Lake Marian to NW Market Tap 69 kV line uprate
Franklin 115/69 kV transformer replacements
Castle Rock to ACEC Quincy 69 kV line uprate
Kokomo Delco to Maple 138 kV line uprate
Wabash to Wabash Container 69 kV line uprate
Spring Green 138/69 kV transformer replacement
Davenport to Sub 85 161 kV line uprate
West Middleton West Towne 69 kV line uprate
Ottumwa Montezuma 345 kV line uprate

Table 4.1-4: Proposed MVP portfolio underbuild requirements

Alternatives assessment

To ensure the proposed MVP portfolio provides cost-effective benefits to the MISO system, MISO considered alternatives to the Candidate MVP portfolio. In addition, similar alternatives were also considered in the prior studies which led to the selection of the initial Candidate MVP portfolio.

A “do-nothing” alternative was first considered. This alternative was used as a baseline to determine the system performance in delivering future generation requirements to load. It was demonstrated that, without major additions to the regional transmission system, significant generation curtailment would be required to maintain system reliability. Such a system would lead to heavy system loading conditions, potential instabilities, reduced reliability margins and would limit the ability of the states in the MISO footprint to meet their renewable energy mandates. As such, it was determined that significant system enhancements would be needed to meet renewable energy mandates and maintain system reliability.

An alternative build-out based on a piecemeal resolution of each facility experiencing an overload was considered. Such a plan would build incremental local upgrades to mitigate the reliability issues directly caused by the injection of the mandated wind into the transmission system. This would result in a minimum of 650 transmission projects, as compared to the 17 larger projects that comprise the proposed

MVP portfolio. MISO does not believe that 650 projects on the existing system could be completed in the same reliable or timely manner as the construction of the proposed MVP portfolio.

Also, this alternative would cost approximately $4.7 billion, based only upon the constraints found in the steady state reliability analysis. Additional investment would most likely be required to mitigate the constraints found in the stability analyses. This alternative would provide much lower benefits to the MISO system, as it does not provide long term solutions that increase the regional transmission capability. This solution would enable less wind to be delivered, endangering the ability of the states in the MISO footprint to meet their renewable energy mandates. It would provide significantly less economic benefits, as the regional values quantified below would be reduced or eliminated.

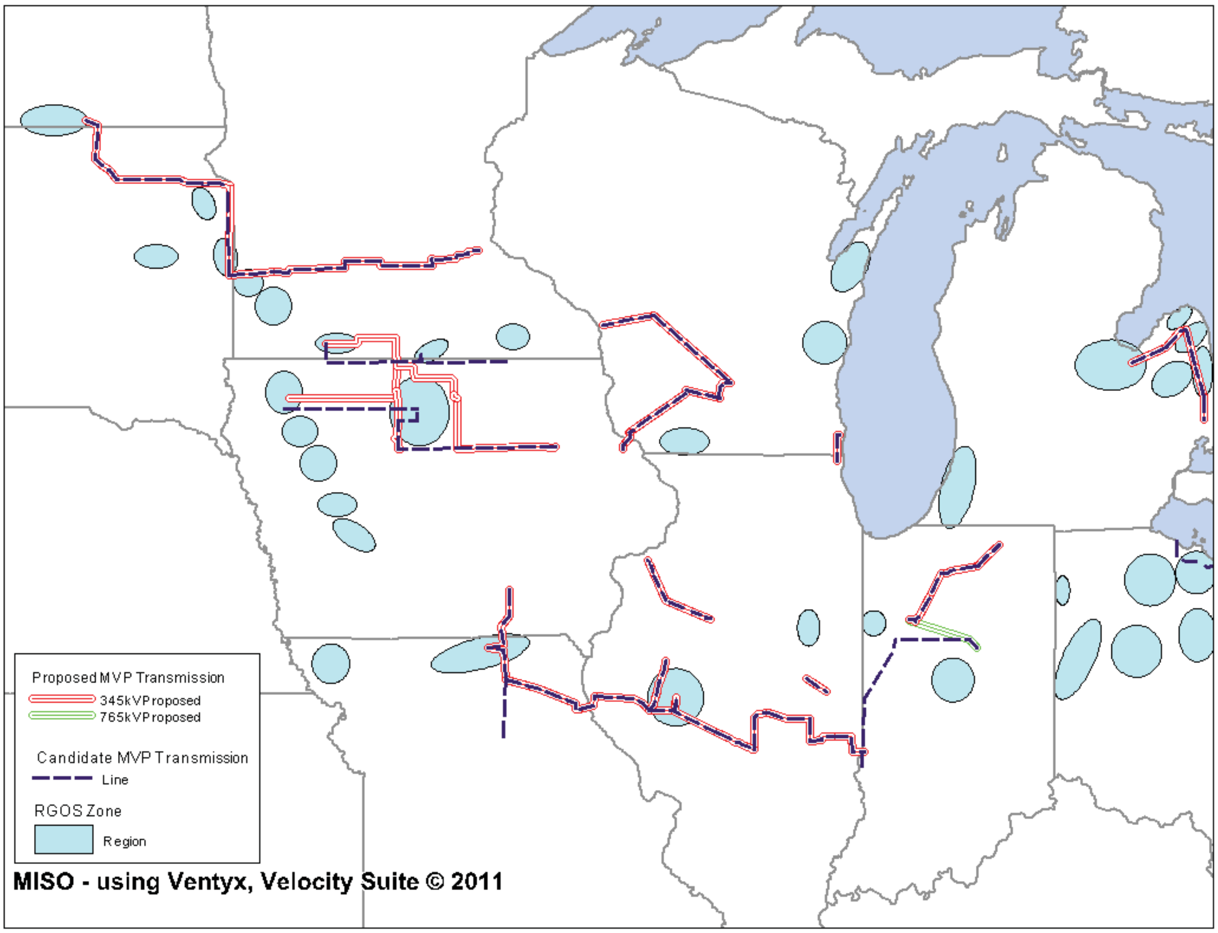

Figure 4.1-12: Candidate versus proposed MVP portfolio

The final alternative considered was the optimization of a regional transmission solution. Analysis surrounding this alternative began with the creation of the Candidate MVP portfolio, a derivative of the highest value transmission solutions from studies beginning in 2003 and continuing to the present. This candidate portfolio was optimized by evaluating each transmission line separately and in the context of other lines in the portfolio. This optimization included analyses of a different transmission configuration in Iowa, the removal of the Adair to Thomas Hill line, an option to reconfigure the transmission lines across southern Illinois and the removal of the Reynolds to Sullivan 765 kV line segment from the candidate portfolio. Although not all these changes were found to be justified, the investigations into the proper portfolio configuration increased the reliability, economic and public policy benefits of the final, proposed MVP portfolio.

Public policy benefits

The proposed MVP portfolio was built upon a set of energy zones that, although they can be used for alternative forms of generation, were premised upon a low cost approach to wind generation siting. Through resolving reliability constraints that would otherwise result in the curtailment of wind generation, the proposed MVP portfolio enables the delivery of 41 million MWh of renewable energy annually to support the renewable energy mandates of the MISO states through at least 2026.

> Through resolving reliability constraints that would otherwise result in the curtailment of wind generation, the proposed MVP portfolio enables the delivery of 41 million MWh of renewable energy annually.

Economic benefits

Multi Value Projects represent the next step in the evolution of the MISO transmission system: a regional network that, when combined with the existing system, provides value in excess of its costs under a variety of future policy and economic conditions. These benefits are quantified below. More information on the method used to quantify the values can be found in Appendix E5, and a more detailed analysis will be included in the full MVP portfolio report, which will be published later in 2011.

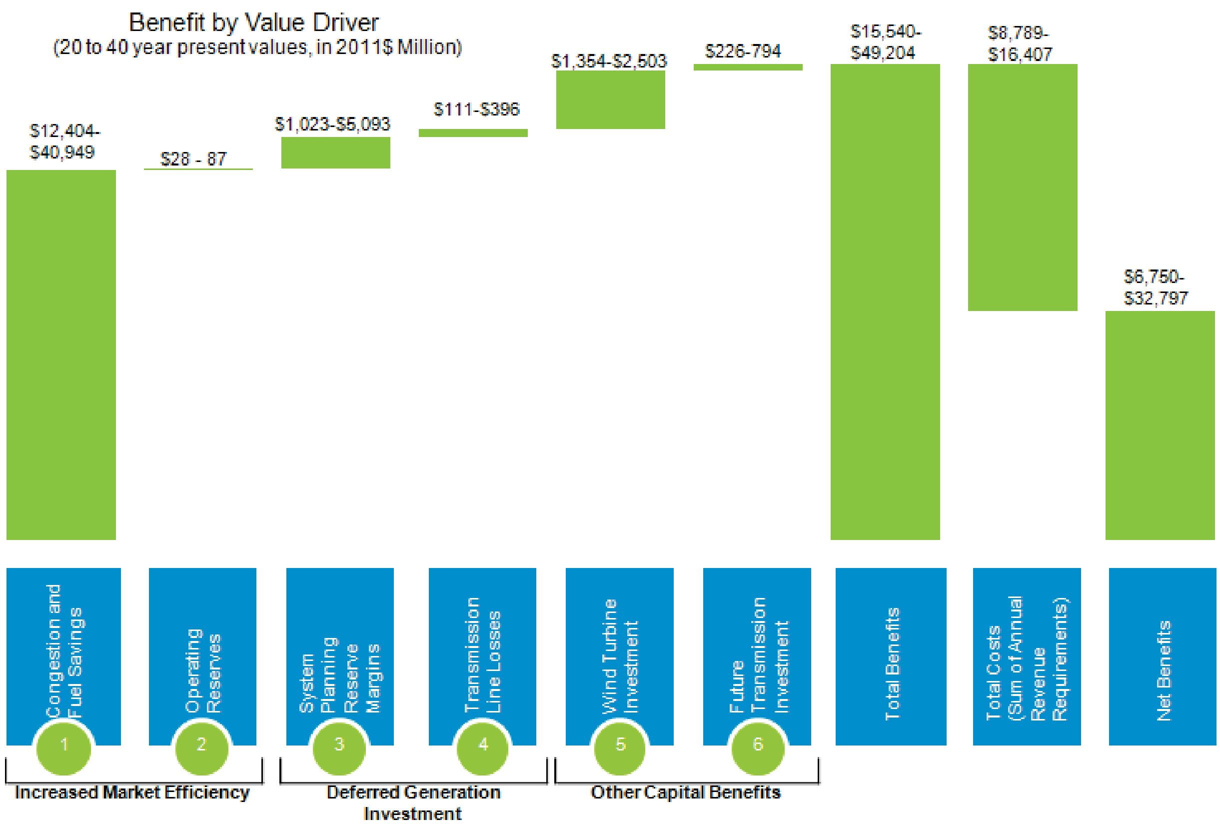

Figure 4.1-13: Proposed MVP portfolio economic benefits

Congestion and fuel savings

The proposed MVP portfolio allows for a more efficient dispatch of generation resources, opening markets to competition and spreading the benefits of low cost generation throughout the footprint. These benefits were quantified through a series of production cost analyses, which captured the economic benefits of the proposed MVP transmission and the wind it enables. These benefits reflect the savings achieved through the reduction of transmission congestion costs and through more efficient generation resource utilization.

In order to show the economic benefits of the portfolio under a variety of different potential policy based futures, MISO calculated four sets of Adjusted Production Cost (APC) benefits. The futures analyzed were designed to 'bookend' the range of potential future policy outcomes, ensuring that all of the most likely future policy scenarios and their impacts were within the range bounded by the results. The futures analyzed are described below.

- Business As Usual with Continue Low Demand and Energy Growth assumes that current energy policies will be continued, with continuing recession level low demand and energy growth projections.
- Business As Usual with High Demand and Energy Growth assumes that current energy policies will be continued, with demand and energy returning to pre-recession growth rates
- Carbon Constrained assumes that current energy policies will be continued, with the addition of a carbon cap modeled on the Waxman-Markey Bill.
- Combined Energy Policy assumes multiple energy policies are enacted, including a 20 percent federal RPS, a carbon cap modeled on the Waxman Markey Bill, implementation of a smart grid and widespread adoption of electric vehicles.

More information on these futures may be found in Appendix E2.

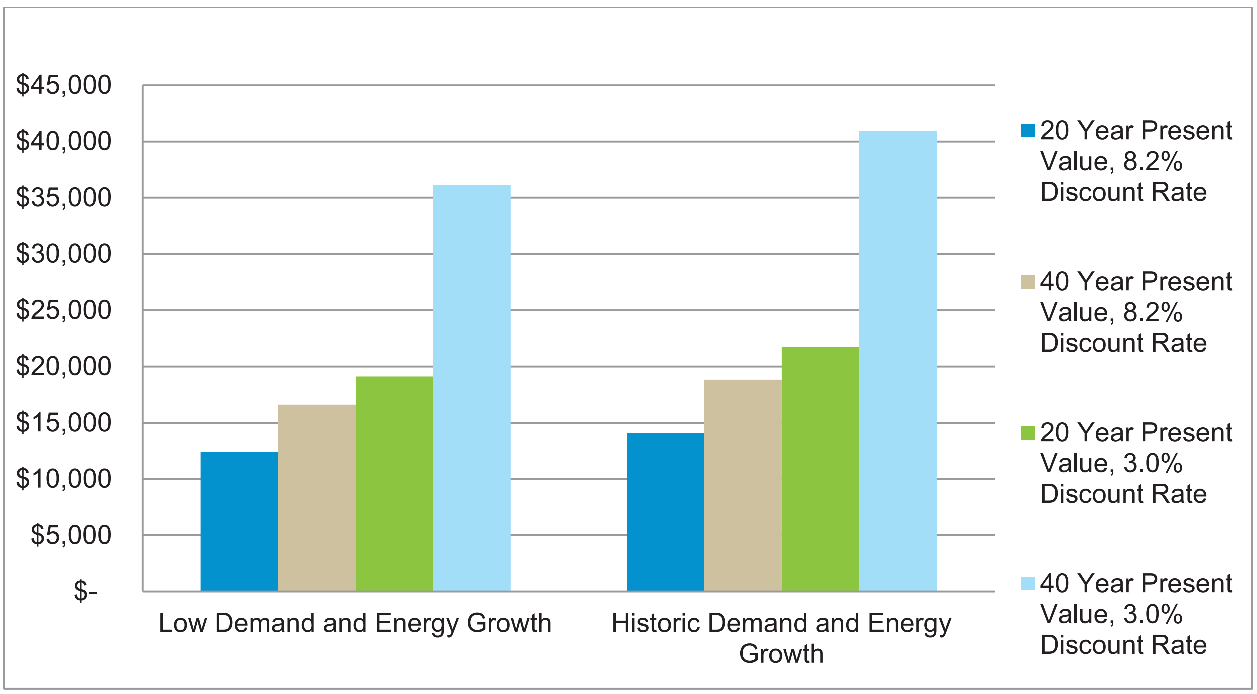

Figure 4.1-14: Proposed MVP portfolio Adjusted Production Cost Benefits

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The future scenarios without any new energy policy mandates provide a baseline of the proposed MVP portfolio's benefits under current policy conditions. Additionally, the evaluation of the Carbon Constrained and Combined Policy future scenarios provide 'bookends' which help show the full range of benefits that may be provided by the portfolio. When the 'Business as Usual' future scenarios with no new energy policies were analyzed, the proposed MVP portfolio will produce an estimated $12.4 to $40.9 billion in 20 to 40 year Present Value (PV) Adjusted Production Cost (APC) benefits, depending on the timeframe, discount rate, energy growth rates and demand growth rates considered. This benefit would increase to a maximum present value of $91.7 billion under the Combined Policy future scenario.

Operating reserves

In addition to the energy benefits quantified in production cost analyses, the proposed MVP portfolio will also reduce operating reserve costs. The MVPs decrease congestion on the system, increasing the transfer capability into several key areas that would otherwise have to hold additional operating reserves under certain system conditions.

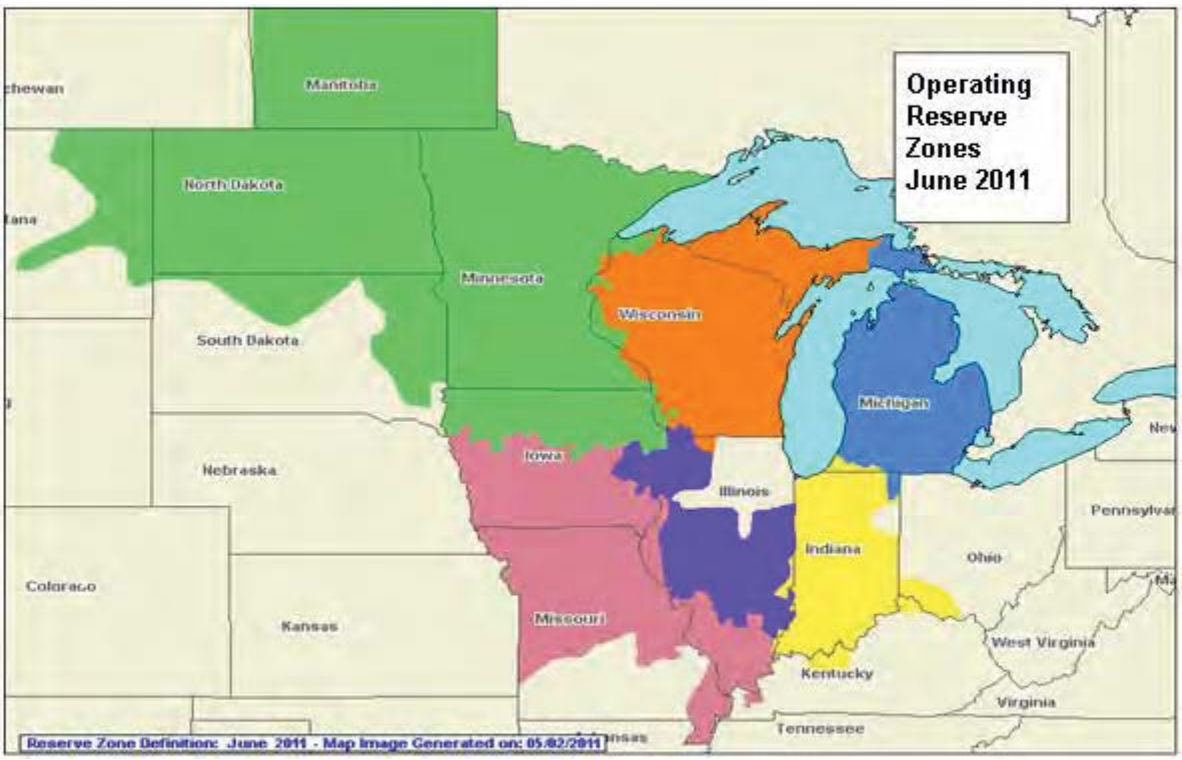


Figure 4.1-15: Operating reserve zones

MISO determined that the addition of the proposed MVP portfolio will eliminate the need for the Indiana operating reserve zone, and the need for additional system reserves to be held in other zones across the footprint would be reduced by half. This creates the opportunity to locate an average of 690,000 MWh of operating reserves annually where it would be most economical to do so, as opposed to holding these reserves in prescribed zones, creating benefits of $28 to $87 million in 20 to 40 year present value terms.

System planning reserve margin

The system planning reserve is calculated by determining the amount of generation required to meet a one day in 10 year Loss of Load Expectation (LOLE). It has two components: the unconstrained system Planning Reserve Margin (PRM), and the congestion contribution. The proposed MVP portfolio reduces transmission congestion across MISO, thereby reducing the system PRM and decreasing the amount of generation needed to maintain the PRM.

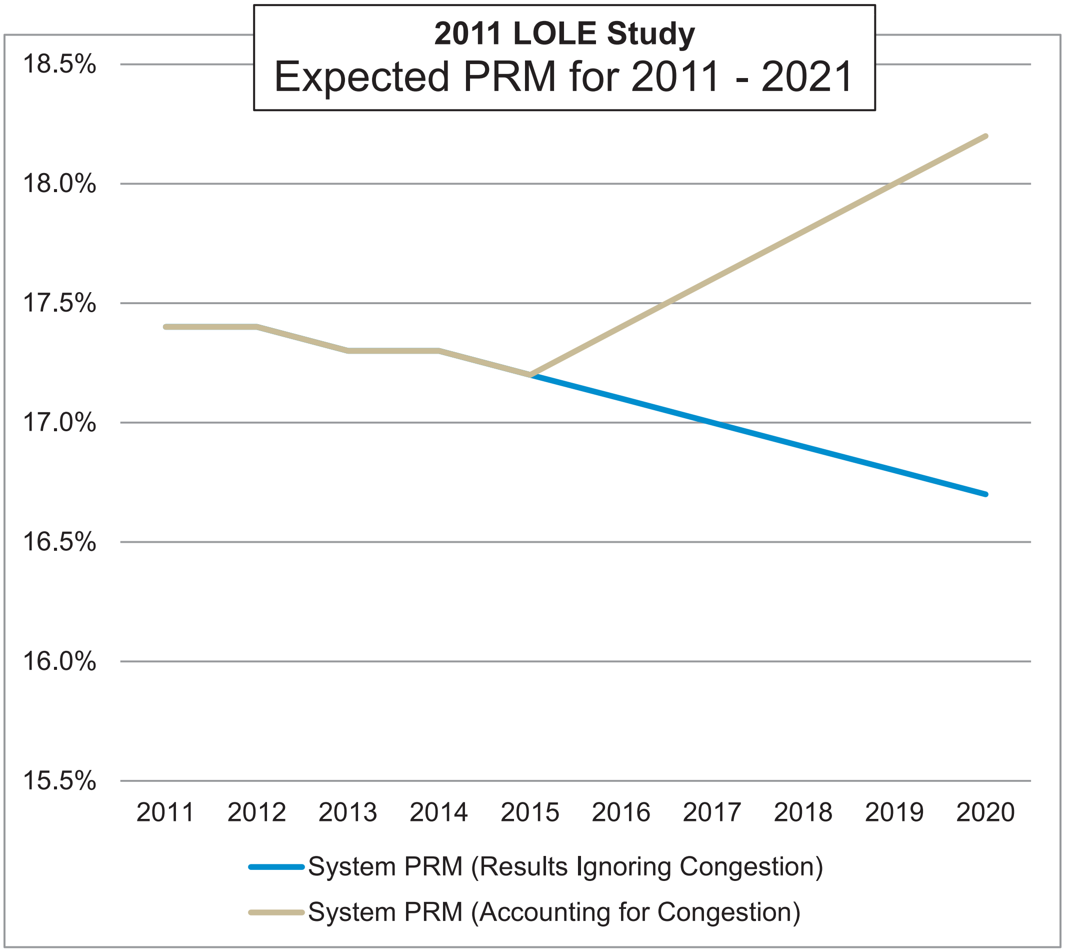


Figure 4.1-16: Expected planning reserve margin, with and without congestion

Through reducing the PRM, the proposed MVP portfolio allows the deferral of new generation, creating $1.0 to $5.1 billion in present value benefits, depending on whether a 20 or 40 year present value is considered, as well as the future growth and discount rates.

Transmission line losses

The addition of the proposed MVP portfolio to the transmission network reduces overall system losses, reducing the generation needed to serve the combined load and transmission line losses. The energy value of these loss reductions is considered in the congestion and fuel savings benefits, but the loss reduction also helps to reduce future generation capacity needs. Specifically, when installed generation capacity is only just sufficient to meet peak system load plus the planning reserve margin, a reduction in transmission losses creates benefits through reducing the amount of generation that must be built. This creates $111 million to $396 million in present value savings, depending on the timeline of the present value calculations, the discount rate and energy/demand growth rates.

Wind turbine investment

As discussed previously, MISO determined a wind siting approach that results in a low cost solution, when transmission and generation capital costs are considered. This approach sources generation in a combination of local and regional locations, placing wind local to load, where less transmission is required; and regionally, where the wind is the strongest. However, this strategy depends on a strong regional transmission system to deliver the wind energy. Without this regional transmission backbone, the wind generation would have to be sited close to load, requiring the construction of significantly larger amounts of wind capacity to produce the renewable energy mandated by public policy.

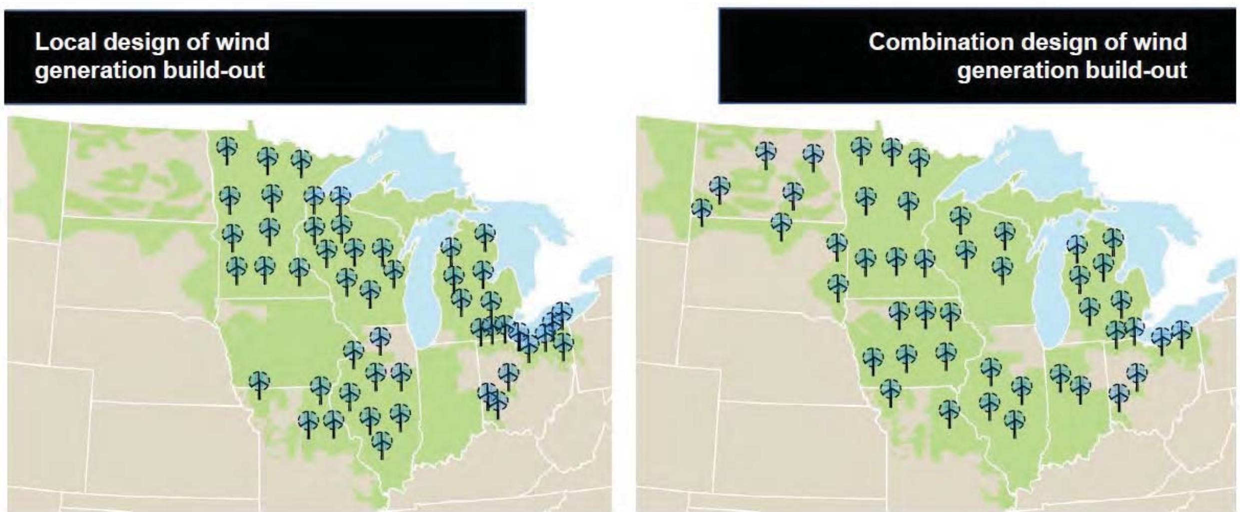


Figure 4.1-17: Local versus combination wind siting

In the RGOS study, it was determined that 11 percent less wind would need to be built to meet renewable energy mandates in a combination local/regional methodology relative to a local only approach. Approximately 2.9 GW less generation capacity is required for the combination siting approach, creating present value benefits of $1.4 billion to $2.5 billion.

Transmission investment

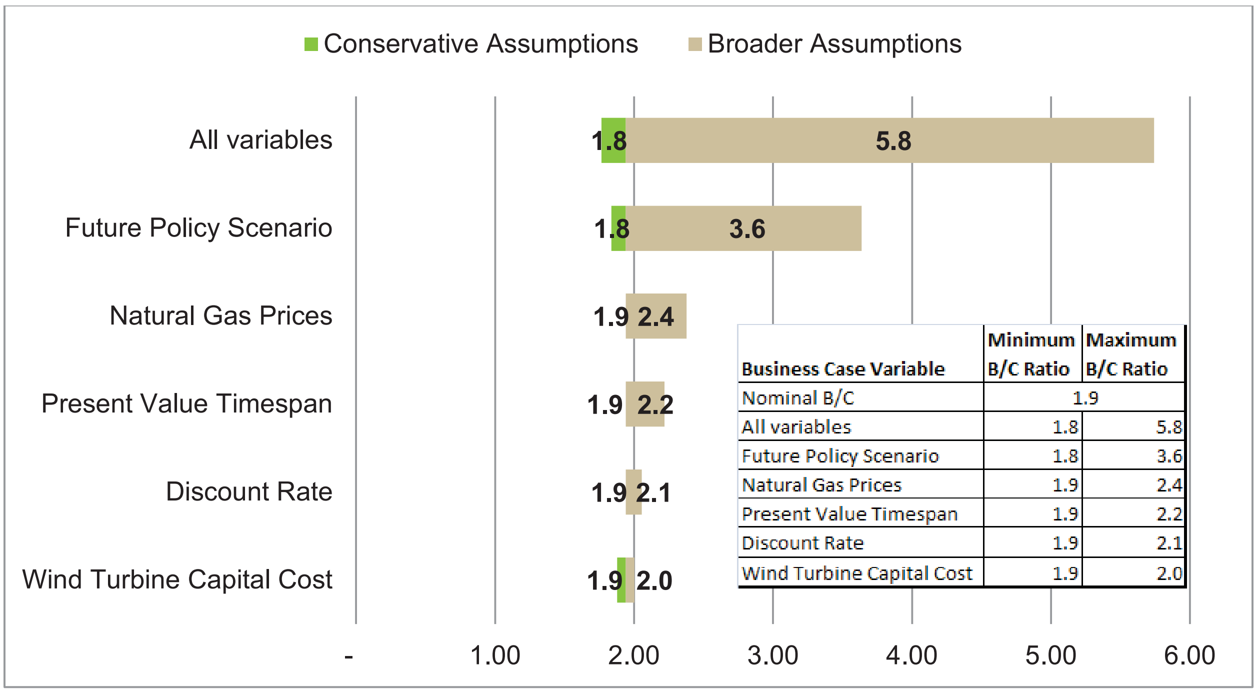
In addition to relieving constraints under shoulder peak conditions, the proposed MVP portfolio will eliminate some future baseline reliability upgrades. A modeling simulating 2031 summer peak load conditions was created to determine what future baseline reliability upgrades would not be needed, and this model was run both with and without the proposed MVP portfolio. The proposed MVP portfolio eliminates the need for baseline reliability upgrades on 23 lines between 2026 and 2031. This creates benefits which have 20 and 40 year present values of $268 and $1,058 million, respectively.

Business case variables and impacts

The projected benefits created by the proposed MVP portfolio are dependent on projections of future policy and economic variables.

The most critical variables considered were:

- Future energy policies
    - Includes a range of policy, demand and energy growth assumptions
    - Sensitivities were conducted to determine the impact of a legislated cost of carbon or national renewable energy mandate
- Length of Present Value Calculations: 20 or 40 years from the portfolio's in service date
- Discount Rate: 3 percent to 8.2 percent
- Natural gas prices: \$5-\$8 (Business as Usual Scenarios)
  \$8-\$10 (Combination Policy and Carbon Constrained Futures)
- Wind turbine capital cost: 2.0 to 2.9 \$M/MW



Business Case Variable	Minimum B/C Ratio	Maximum B/C Ratio
Nominal B/C	1.9	
All variables	1.8	5.8
Future Policy Scenario	1.8	3.6
Natural Gas Prices	1.9	2.4
Present Value Timespan	1.9	2.2
Discount Rate	1.9	2.1
Wind Turbine Capital Cost	1.9	2.0

Figure 4.1-18: Benefit – cost variations due to business case assumptions

Under existing energy policies, the proposed MVP portfolio creates benefits that are at least 1.8 times its cost.

Depending on which variables are assumed, the present value of the benefits created by the entire portfolio can vary between \$18.5 and \$126.0 billion in 20 to 40 year present value terms. This savings yield benefits ranging from 1.8 to 5.7 times the portfolio cost.

It should be noted that the benefits of the portfolio do not depend upon the implementation of any particular future energy policy to exceed the portfolio costs. Under existing energy policies, a conservative discount rate of 8.2 percent and 20 year present value terms, the portfolio produces benefits that are 1.8 times its cost. However, if other energy policies or enacted, or a lower discount rate is used, this benefit has the potential to greatly increase.

Portfolio benefits and cost spread

A key principle of the MISO planning process is that the benefits from a given transmission project must be spread commensurate with its costs. The MVP cost allocation methodology distributes the costs of the portfolio on a load ratio share across the MISO footprint, so the proposed MVP portfolio must be shown to deliver a similar spread of benefits.

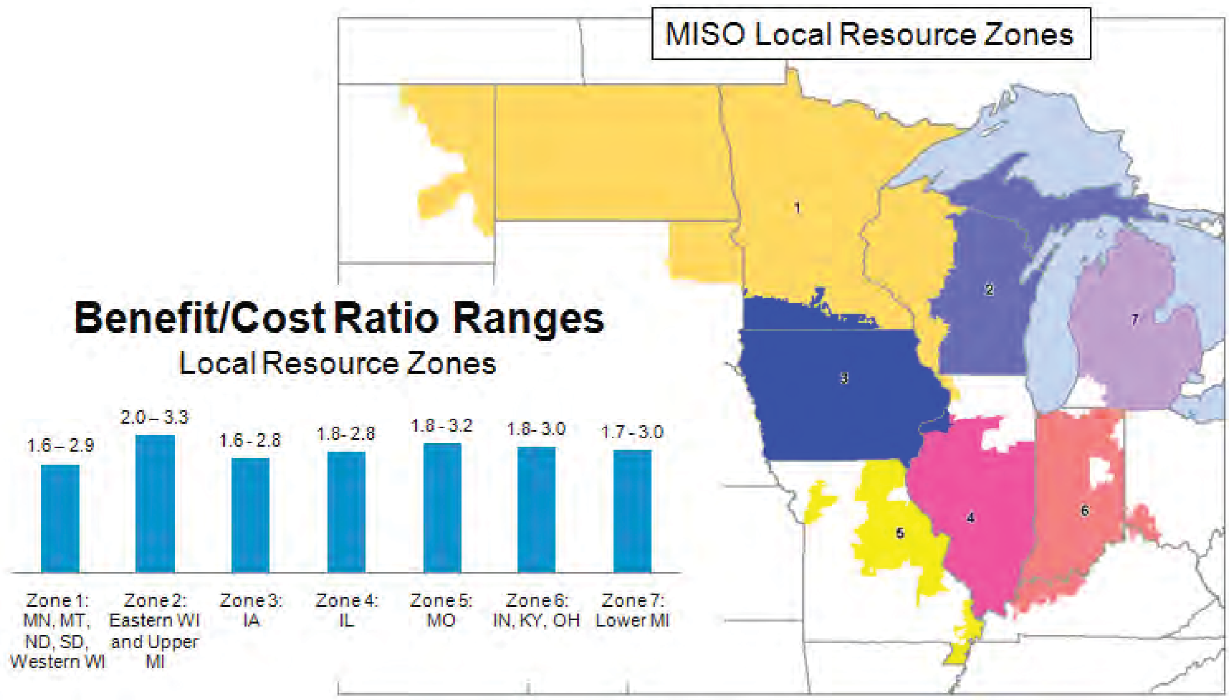


Figure 4.1-19: Proposed MVP portfolio production cost benefits spread

The proposed MVP portfolio provides benefits across the MISO footprint in a manner that is roughly equivalent to its costs allocation. For each of the local resource zones, as shown in Figure 4.1-19 above, the portfolio's benefits are at least 1.6 to 2.9 times the cost allocated to the zone.

Qualitative and social benefits

The previous sections demonstrated that the proposed MVP portfolio provides widespread economic benefits across the MISO system. However, these metrics do not fully quantify the benefits of the portfolio. Other benefits, based on qualitative or social values, are discussed in the next sections. These sections suggest that the quantified values from the economic analysis may be conservative because they do not account for the full potential benefits of the portfolio.

Enhanced generation policy flexibility

Although the proposed Multi Value Project portfolio was primarily evaluated on its ability to reliably deliver energy required by the renewable energy mandates, the portfolio will provide value under a variety of different generation policies. The energy zones, which were a key input into the Candidate MVP portfolio Analysis, were created to support multiple generation fuel types. For example, the correlation of the energy zones to the existing transmission lines and natural gas pipelines were a major factor considered in the design of the zones. This can be seen in Figure 4.1-20, which shows the correlation between the energy zones and natural gas pipelines.

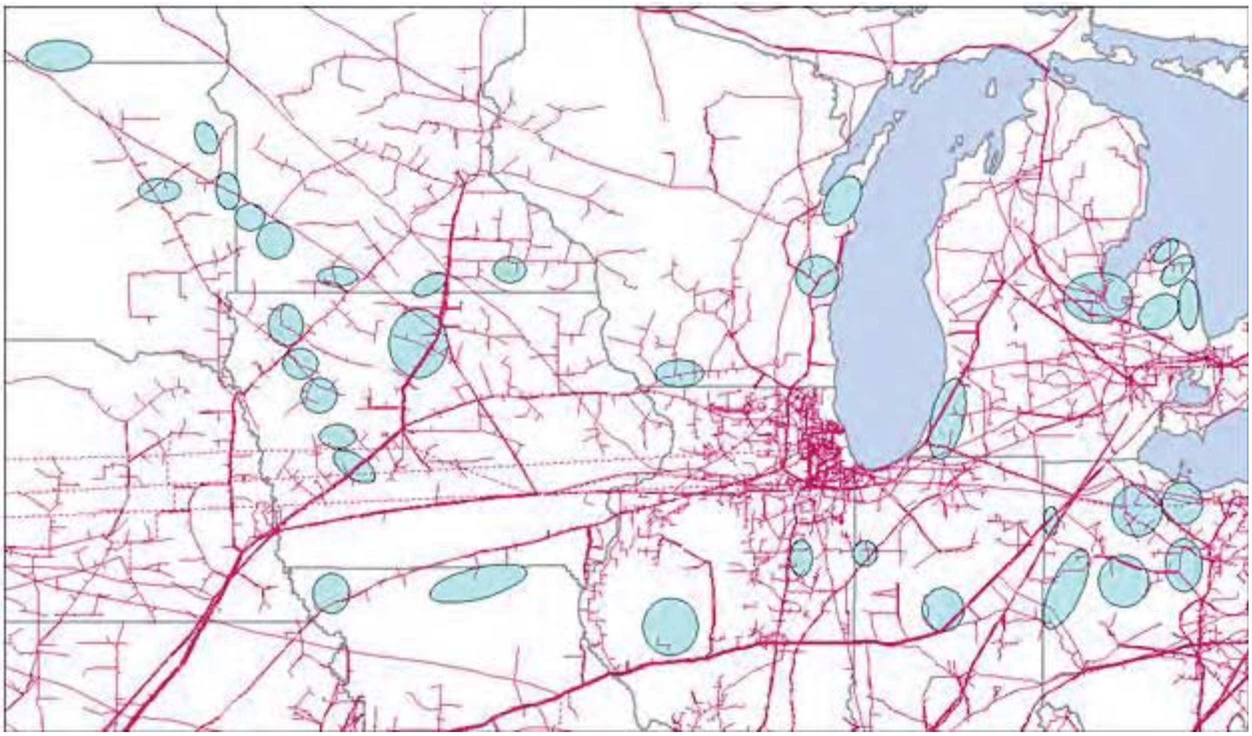


Figure 4.1-20: Energy zone correlation with natural gas pipelines

Increased system robustness

A transmission system blackout, or similar event, can have wide spread repercussions, resulting in billions of dollars of damage. The blackout of the Eastern and Midwestern U.S. during August 2003 affected more than 50 million people and had an estimated economic impact of between $4 and $10 billion.[31]

The proposed MVP portfolio creates a more robust regional transmission system which decreases the likelihood of future blackouts by:

- Strengthening the overall transmission system by decreasing the impacts of transmission outages.
- Increasing access to additional generation under contingent events.
- Enabling additional transfers of energy across the system during severe conditions.

[31] Data sourced from: *The Economic Impacts of the August 2003 Blackout*, The Electricity Consumers Resource Council (ELCON)

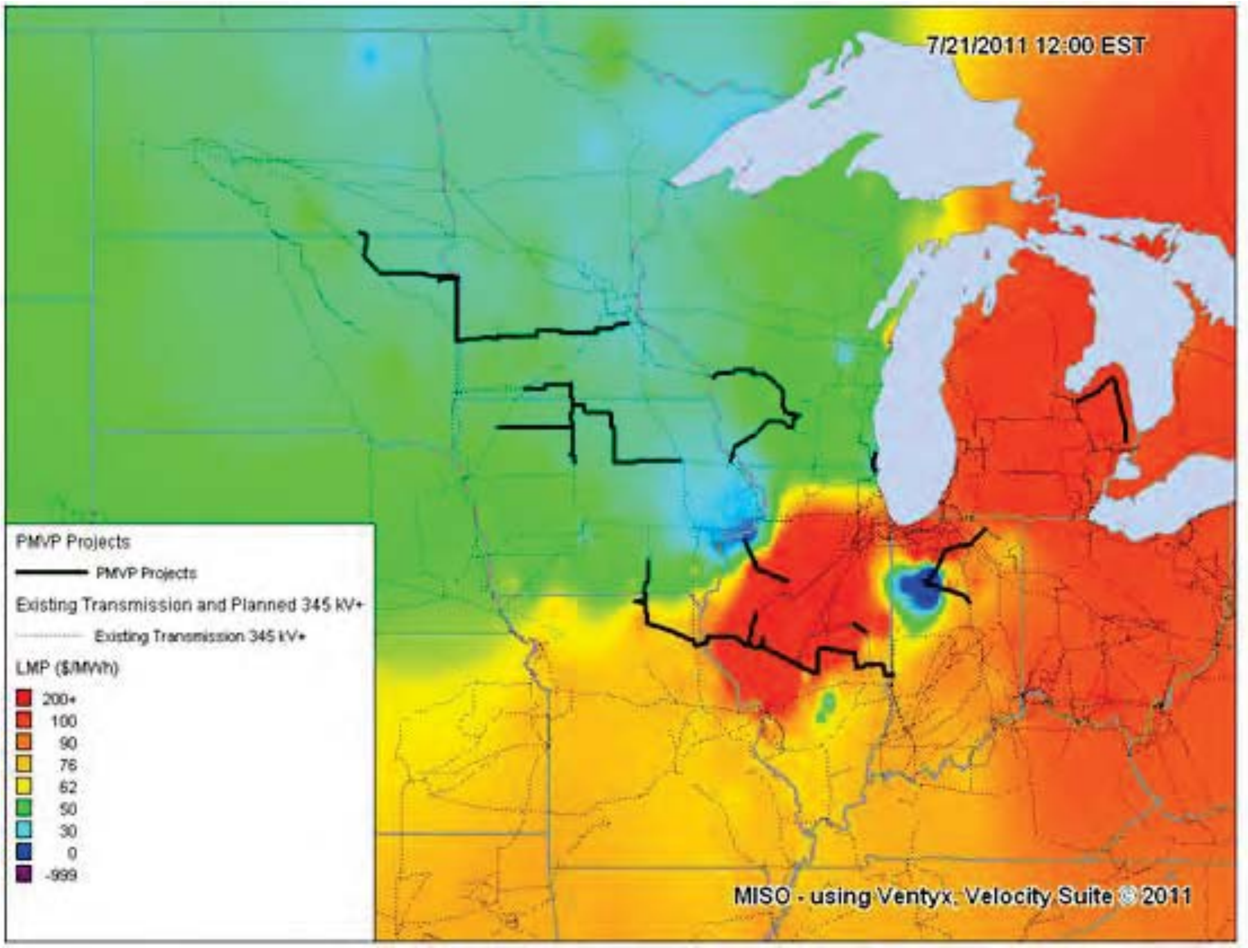


Figure 4.1-21: June 2011 LMP map with proposed MVP portfolio overlay

The proposed MVP portfolio will increase the transfer capability across the system, allowing access to additional generation resources to offset the impact and cost of severe or emergency conditions.

For example, the proposed MVP portfolio will allow the system to respond more efficiently during high load periods. During the week of July 17, 2011, high load conditions existed in the eastern portion of the MISO footprint, while the western portion of the footprint experienced lower temperatures and loads. Thermal limitations on west to east transfers across the system limited the ability of low cost generation from the west to serve the high load needs in the east, as shown in Figure 4.1-21. The proposed MVP portfolio will increase the transfer capability across the system, allowing access to additional generation resources to offset the impact and cost of severe or emergency conditions.

Decreased natural gas risk

Natural gas prices have historically varied widely, causing corresponding fluctuations in the cost of energy from natural gas fueled generation. Also, recent Environmental Protection Agency (EPA) regulations and proposed regulations limiting the emissions permissible from power plants will likely lead to more natural gas fired generation. This may put additional upward pressure on natural gas costs as demand increases. However, the proposed MVP portfolio can help partially offset the associated natural gas price risk by providing additional access to generation that uses fuels other than natural gas (e.g. nuclear, wind, solar and coal) during periods with high natural gas prices.

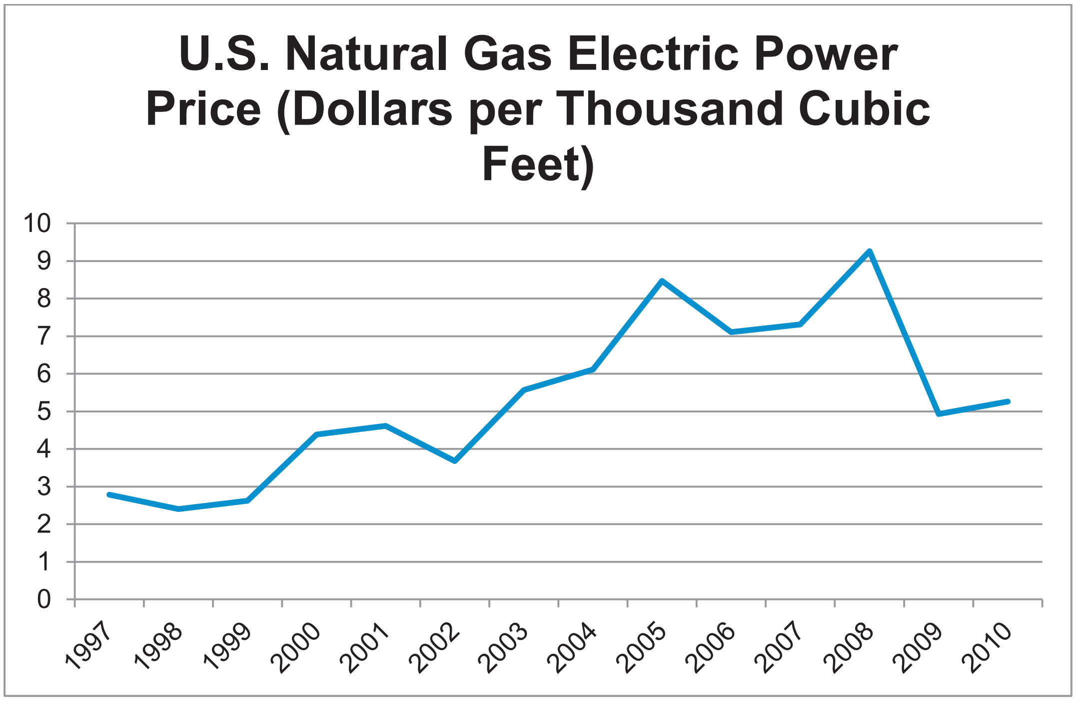


Figure 4.1-22: Historic U.S. natural gas electric power prices

Assuming a natural gas price increase of 25 percent to 60 percent, the proposed MVP portfolio provides 5 percent to 40 percent higher production cost benefits.

Decreased wind generation volatility

As the geographical distance between wind generation increases, the correlation in the wind output decreases. This leads to a higher average output from wind for a geographically diverse set of wind plants, relative to a closely clustered group of wind plants. The proposed MVP portfolio will increase the geographic diversity of wind resources that can be delivered, increasing the average wind output available at any given time.

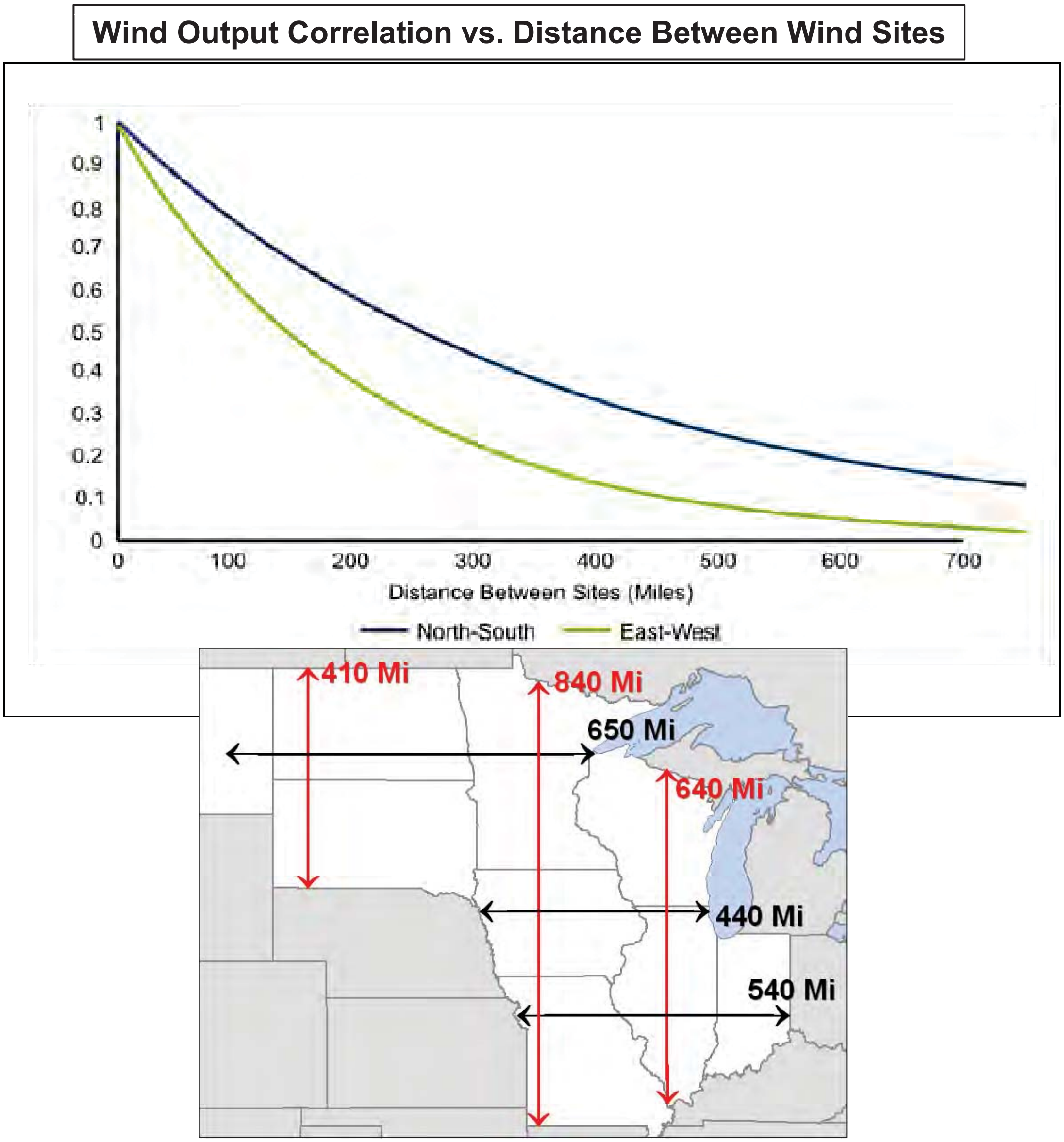


Figure 4.1-23: Wind Output correlation to distance between wind sites

Local investment and job creation

In addition to the direct benefits of the proposed MVP portfolio, studies have shown the indirect economic benefits of transmission investment. They estimated that, for each million dollars of transmission investment:

- Between $0.2 and $2.9 million of local investment is created.
- Between 2 and 18 employment years are created.[32]

The wide variations in these numbers are primarily due to the extent to which materials, equipment and workers can be sourced from a 'local' region. For example, each million dollars of local investment supports 11 to 14 employment years of local employment, as compared to 2 to 18 employment years which are created for non-location specific transmission investment.

The proposed MVP portfolio supports the creation of between 17,000 and 39,800 local jobs, as well as $1.1 to $9.2 billion in local investment. This calculation is based upon a creation of $0.3 to $1.9 million local investment and 3 to 7 employment years per million of transmission investment.

Carbon reductions

The proposed MVP portfolio enables the more economical dispatch of generation, as low cost wind resources displace higher cost generation. This redispatch creates a reduction in the total carbon output produced by MISO generation of between 8.3 to 17.8 million tons annually.

Some of the future policy scenarios included a cost of carbon. This carbon cost is additive to the overall system production cost, and it was based upon a carbon cost of $50 per ton.

If such a carbon cost was to occur, benefits would increase by between $3.8 and $15.4 billion in 20 and 40 year present value terms, respectively.

Conclusions and recommendations

MISO staff recommends the proposed MVP portfolio to the MISO Board of Directors for their review and approval. This recommendation is premised on the ability of the portfolio to meet MVP criterion 1, as each project in the portfolio was shown to more reliably enable the delivery of wind generation in support of the renewable energy mandates of the MISO states in a cost effective manner.

The recommendation is also supported by the strong economic benefits of the portfolio, which delivers a large amount of value in excess of costs under all conditions and policy scenarios studied. Furthermore, these benefits are spread across the MISO footprint, in a manner commensurate with the allocation of the portfolio's costs.

The proposed MVP portfolio reliably enables the delivery of wind generation in support of public policy needs, while delivering value in excess of its cost in all scenarios studied.

[32] Source: *Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada*, The Brattle Group

4.2 EPA Regulation Impact Analysis

Study disclaimer

The objective of the MISO EPA Regulation Impact Analysis is to inform stakeholders. MISO has no intention or authority to direct generation unit strategies. That authority belongs exclusively to the individual asset owners. The MISO analysis provides an overview of the impacts from the MISO regional perspective. Any sub regional evaluation of the data would be an incorrect interpretation and application of the results.

The detailed results of the analysis were derived from a limited set of economic assumptions that included low demand and energy growth, low gas prices and variation of carbon prices with sensitivities performed on gas and carbon prices. Retirement impacts can change with different assumptions for these variables. The study also assumes that the natural gas Transmission System is sufficient to accommodate the increased dependence on the natural gas fleet. This addresses some of those issues, but can't capture all future outcomes. To better understand the affects of changing inputs and risks of the uncertainty of carbon, additional analysis needs to be performed.

An additional caveat - since completion of this analysis - the EPA finalized the Cross State Air Pollution Rule (CSAPR). In general, the final regulation mandated more restrictive emission limits for some states than was modeled in this analysis. The final CSAPR has stronger state limitations in most cases but allows for a national trading program, which may allow for more flexibility in meeting the limits. In general, the rule appears to have the greatest impact in the near-term (1-3 years) operation of the generation fleet due to the reduction in the number and availability of both SO_2 and NO_X allowances. The magnitude of this change on the MISO system is being evaluated in a follow-up study.

The EPA Regulation Impact Analysis was based on assumptions for *proposed* EPA regulations. Finalization of the remaining three regulations has the potential to introduce the risk of additional change and uncertainty, similar to what occurred with the CSAPR regulation. Any of the final regulations could differ from what was modeled in this analysis.

EPA impact results summary

Over the last two years the U.S. Environmental Protection Agency (EPA) issued four proposed regulations that will affect the MISO system. One of the rules was finalized in July while the other three are still in draft form. The regulations will impact unit operations in the near-term (1-3 years) in addition to requiring utilities retrofit their generators with environmental controls or retire them in the 2015 timeframe. At the direction of its members, stakeholders and Board of Directors, MISO evaluated the impacts of the new regulations, including carbon requirements. This study evaluated the impacts on capacity cost, Resource Adequacy, cost of energy and transmission reliability.

A survey of the current fleet within MISO revealed a number of generation units will be affected. Impacts ranged from the installation of control equipment and expected redispatch to meet emission budgets, to potential retirement of units where the costs to comply outweigh the benefits of continued operation.

MISO evaluated the four proposed regulations separately and in combination with each other over a nine month study period. This report focuses on the four rules as they were developed in draft form. The impact of the finalized Clean Air Transport Rule/Cross State Air Pollution Rule will be undertaken in an exhaustive follow-on study that is currently underway.

The four proposed EPA regulations are:

- Cooling Water Intake Structures (CWIS) – section 316(b) of the Clean Water Act (CWA).
- Coal Combustion Residuals (CCR).
- Clean Air Transport Rule (CATR) as proposed in 2010. This regulation was finalized as the Cross State Air Pollution Rule (CSAPR) in July, 2011 after the study work was finalized.
- Mercury and Air Toxics Standards (MATS), formerly known as EGU Maximum Achievable Control Technology (MACT).

A survey of MISO's current fleet revealed that a number of generation units will be affected. Impacts ranged from the installation of control equipment and expected redispatch to meet emission budgets, to potential retirement of units where the costs outweigh the benefits of continued operation. Figure 4.2-1 shows that there are 298 coal units affected by these four proposed regulations and that the majority of the units (63 percent) are affected by three or all four regulations.

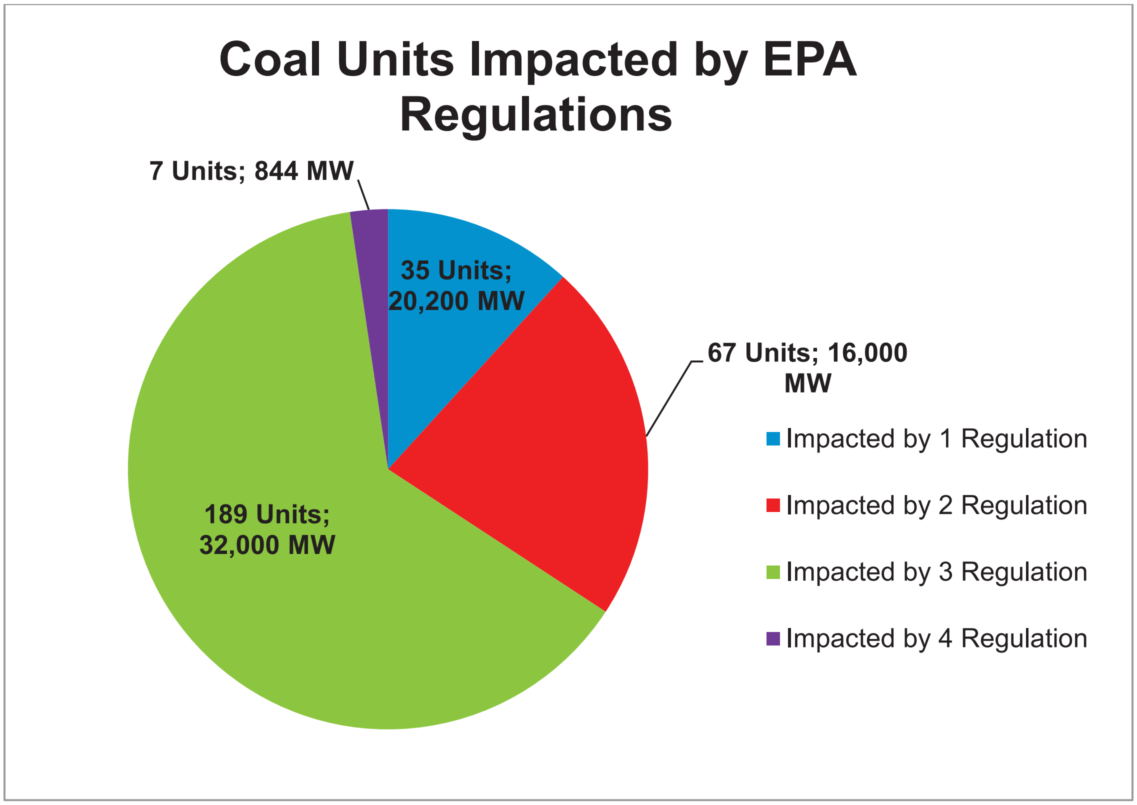


Figure 4.2-1: Number of coal units affected by EPA regulations.

The studies were conducted with the Electric Generation Expansion Analysis System (EGEAS) software package developed by the Electric Power Research Institute (EPRI) commonly used by utility generation planners. MISO performed more than 400 sensitivity screens using the EGEAS capacity expansion model to identify the units most at-risk for retirement. The sensitivities consisted of variation in costs for natural gas, cost uncertainty risk and retrofit compliance.

MISO identified nearly 13,000 MW of units at risk for retirement. Those units were offered to the EGEAS model as an economic choice to retrofit for compliance or retirement. The model makes this decision by comparing alternatives and selecting an expansion forecast that minimizes costs, capital investment, production, emissions and annual fixed operations and maintenance.

Nearly 13GW of generation is at risk of retiring.

MISO ran two economic alternatives. The first evaluated a $4.50 natural gas cost, compliance for all the identified regulations and an expected cost for compliance with the regulations based on MISO stakeholder feedback through the study process. The second analysis evaluated increased compliance costs on the system. These increased costs are represented through a production cost adder coupled with the production of carbon on the system and is proxy for costs associated with the uncertainty around rules not finalized, additional life extension costs needed for balance of plant as well as the considered risk around the uncertainty of the treatment of green-house gases. It is expected that one or all are within the assumption error bounds for this analysis and the impacts will be considered in the fleet strategies of the asset owners. The results of the EGEAS analysis produced:

- 2,919 MW of coal fleet capacity at-risk for retirement under all likely scenarios. As of the publishing of this study, retirement requests of the coal fleet have amounted to 2,500 MW in the MISO Attachment Y process.
- 12,652 MW of coal fleet capacity at-risk for retirement identified to be within prudence considerations and error bounds for the assumptions of the MISO study.

The EGEAS retirement analysis minimizes the total system net present value costs over a twenty year planning period plus a forty year extension period. When the 2,919 MW and 12,652 MW of retired capacity were forced into the model, it was shown that the overall net present value of system costs varied by approximately 1 percent. This value is within the tolerance of assumption error. Additionally, MISO did not consider unit life extension costs in its evaluation. Because of these two considerations, it is expected that the higher value of nearly 13,000 MW is more realistic of the potential retirements on the system.

Using a suite of planning products, MISO's evaluation on the range of potential impacts indicates the following:

- Total 20-year net present value capital cost of compliance may range from $31.6 billion for 2,919 MW of retirement to $33.0 billion for 12,652 MW of retirement. Both values are in 2011 dollars and include the cost of retrofits on the system, replacement capacity, fixed operations and maintenance and transmission upgrades. The perceived balance in total system capital investment occurs because the average cost for installation of control technologies for a unit is approximately equivalent to the cost of a new combustion turbine that represents an alternative solution to compliance with the rules.

It will cost MISO approximately $30 billion to comply with the new regulations, regardless of compliance strategy, increasing rates by more than 7 percent.

  - Capital costs for retrofits are $28.2 billion and $22.5 billion, respectively.
  - Maintenance of the Planning Reserve Margin (PRM) is obligated under the MISO tariff. So it is expected that any capacity retirements would eventually be matched with replacement capacity to support PRM requirements. To maintain this requirement, it is estimated that the replacement costs would be $1.7 billion and $9.6 billion.

- The bulk of the capital investment for the generation fleet is expected to occur in the 2014/2015 time frame to meet 2015/2016 requirements established through the proposed MATS regulation. This includes potential need for replacement resources as 12,652 MW of capacity retirements would erode the current installed reserves to below planning reserve margin values by 6 to 7 percentage points, Table 4.2-1.
- The annual fixed operations and maintenance impacts the total cost impact by $1.1 billion and $0.0, respectively.
- Retirement of units will have an impact on localized Transmission System reliability. To ensure voltage and transmission thermal support on the system, an estimated $580 million and $880 million, respectively, of additional transmission upgrades could be necessary to maintain system reliability. The transmission numbers depend on location and any change from the study assumptions could result in different costs. This assumes that no replacement capacity is at the retired units. If it is, the transmission upgrade costs will decrease.

- By replacing traditionally less reliable capacity with new resources, there is a potential that Planning Reserve Margin (PRM) requirements could decrease by having a more reliable fleet. Loss of Load Expectation (LOLE) analysis showed reductions of 0.2 to 1.0 percent. However, if no replacement capacity is identified for Resource Adequacy purposes, then analysis shows that the LOLE on the system could be on the order of 0.21 to 1.028 days/year. The current target is 0.1 days/year. Refer to Chapter 5.2 for more information on EPA impacts on resource adequacy.
- There will also be an increase in the MISO load-weighted LMP of between $1.2/MWh to $4.8/MWh (2011 dollars). This is driven by two key factors: (1) newly retrofitted units are less efficient because of the emission controls, and (2) retired coal facilities are replaced with natural gas fired capacity resulting in a greater dependence on the higher cost energy.
- Identifying all the costs to maintain regulation compliance and system reliability, retail rates could increase 7.0 to 7.6 percent.

		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
No retirements	Reserve Margin (MW)	23,930	22,438	22,064	21,368	20,760	20,065	19,287	19,950	19,031	18,032
	Reserve Margin (percent)	27.0%	24.8%	24.2%	23.3%	22.5%	21.5%	20.5%	21.0%	19.9%	18.6%
2.9 GW Retirements (impacts adjusted for expected derates)	Reserve Margin (MW)	21,603	20,111	19,737	19,041	18,433	17,738	16,960	17,623	16,704	15,705
	Reserve Margin (percent)	24.3%	22.2%	21.7%	20.8%	19.9%	19.0%	18.1%	18.6%	17.5%	16.2%
12.6 GW Retirements (impacts adjusted for expected derates)	Reserve Margin (MW)	12,544	11,052	10,678	9,982	9,374	8,679	7,901	8,564	7,645	6,646
	Reserve Margin (percent)	14.1%	12.2%	11.7%	10.9%	10.1%	9.3%	8.4%	9.0%	8.0%	6.6%

Table 4.2-1 Potential system reserve margin impacts of retirements compared to the MISO 2011 Long Term Resource Assessment

The generation capacity cost components include both the costs to retrofit and to build new capacity to eventually replace that which is retired. From the previous information, this twenty year net present value cost for 12,652 MW of retirement is approximately $32.1 billion. Table 4.2-2 shows where those costs are incurred in reference to the fleet to meet the proposed regulations. The investment identified is expected to occur prior to implementation of the MATS regulation and the lead time for the addition of control technology or new resources will include planning, regulatory approval, engineering, procurement, construction and installation that may require three to five years to implement on the system.

Technology	Impacted Capacity (MW)	Average Costs ($/kW)
No Action Required	9,569	0
Require Fabric Filters (Baghouse)	27,921	150
Require DSI and ACI or FGD	20,427	478
Replacement Greenfield Combustion Turbine Capacity for Retirement	12,652	663

Table 4.2-2 Average overnight construction costs to comply with the proposed regulations.

There is a compliance risk with the proposed regulations. Additional investment in the generation fleet and the Transmission System will maintain bulk power system reliability – at a cost. However, another risk not addressed directly that must be recognized is the time in which units must be compliant. Figure 4.2-2 demonstrates a high level timetable of rule implementation and compliance deadlines. If it is determined that capacity should be retired, it would take at least two to three years to build a combustion turbine to replace it. Also, if Transmission System reliability requires bulk transmission upgrades, a minimum of five years could be required for a transmission line to become operational. The time from final regulation to compliance may be difficult for some situations throughout the system.

Perhaps one of the most significant risk factors will be taking the existing units out for maintenance to install the needed compliance equipment. Given the tight window for compliance, much of the capacity on the MISO system will need to take their maintenance outages concurrently. The need to take multiple units out of service on extended outage has significant potential to impact resource adequacy.

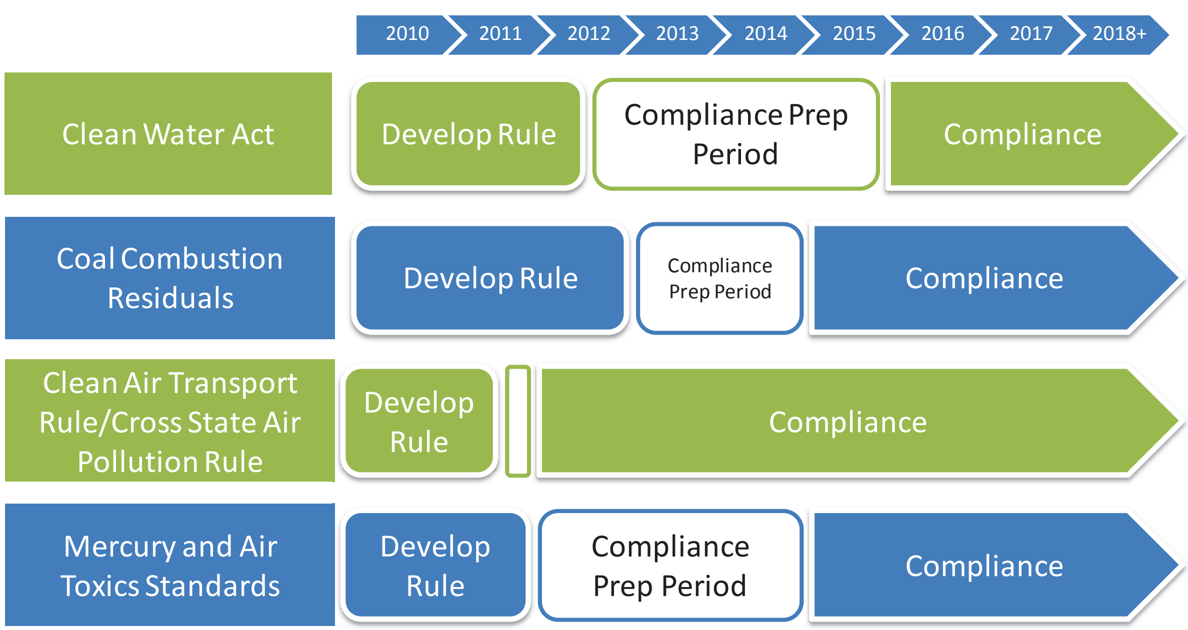


Figure 4.2-2: **Estimated timeline for regulation development and implementation**

Sensitivities impact

Just as in the MISO Transmission Expansion Plan (MTEP), MISO uses a scenario planning process in the analysis and evaluation of these EPA regulations. Evaluating the impact requires that many conditions be considered separately and in combination. MISO evaluated six scenarios with 77 sensitivities for each of the scenarios.

- Base conditions, no new regulations.
- Cooling Water Intake Structures section – 316(b) of the Clean Water Act (CWA).
- Coal Combustion Residuals (CCR).
- Clean Air Transport Rule (CATR) as proposed in 2010. This regulation was finalized as the Cross State Air Pollution Rule (CSAPR) in July, 2011 after the study work was finalized.
- Mercury and Air Toxics Standards (MATS) formerly known as EGU Maximum Achievable Control Technology (MACT).
- Combination of all four regulations.

Figure 4.2-3 demonstrates the sensitivities evaluated for each analysis. Since there are six regulation scenarios there would be six branches to this decision tree. Only the first branch is shown in Figure 4.2-3.

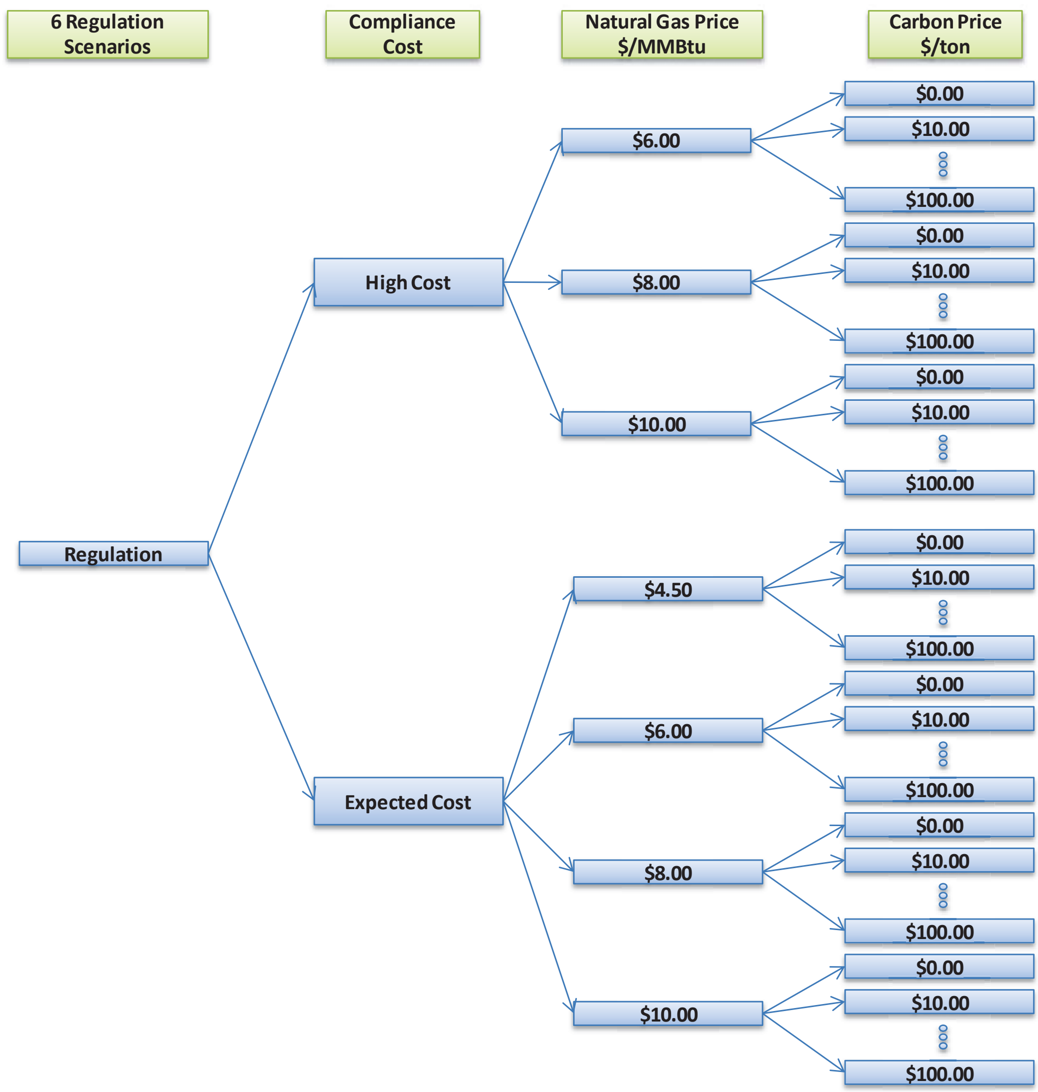


Figure 4.2-3: Decision tree of EPA cases

For each of the scenarios, 77 sensitivity cases consisting of two variations in compliance costs, natural gas costs and uncertainty risk costs represented as a cost to carbon production were modeled to produce a combined total of more than 400 sensitivity cases. The results indicated that up to 23,000 MW of coal capacity could be at-risk because of regulation compliance.

From these sensitivity cases, a few general conclusions can be made.

- EPA regulation impacts: Compliance associated with the Mercury and Air Toxics Standards (MATS) produces the most at-risk units, since its compliance costs and emission reductions have the greatest impact of the proposed regulations.

- Stringent Rule Application: Higher compliance costs to meet more stringent rules result in more at risk units. Evaluating all natural gas and carbon sensitivities for the stringent rule application cases resulted in up to 23,000 MW of at-risk capacity. However, running the same sensitivities at the more expected compliance costs as recommended and reviewed through the MISO stakeholder process, up to 13,000 MW of capacity was considered to be at risk.

- Natural gas costs: Lower natural gas prices produced more at-risk capacity than higher gas prices. The lower natural gas prices provide more incentive to retire capacity as the alternative resources provide competitive energy costs for the system. Conversely, when gas prices are high, the coal units find enough revenue on the system to cover compliance costs and keep general energy prices lower.

- Risk costs: MISO evaluated the risks associated with uncertainty in regulation compliance through costs added to megawatt-hour production. This cost was represented by adding a price to carbon. Because of this, higher compliance costs put more economic pressure on the coal units within the system, and the economics favor natural gas and carbon neutral capacity. So more coal units are at-risk for retirement with the higher compliance costs applied.

The units at-risk for retirement range from 0 MW to 23,000 MW based on the economic assumptions within the sensitivities. Cases where no units were identified to be at-risk for retirement include low compliance costs, higher gas prices and no risk costs applied. This occurs because it minimizes cost for compliance while increasing potential revenue within the energy market through higher natural gas prices. Cases that produce at-risk generation of up to 23,000 MW include stringent rule application, low gas prices and varying levels of risk costs.

Figure 4.2-4 depicts an example of the impacts of the cost of compliance, gas and risk from the identified potential retirements of 2,919 MW with all four EPA regulations.

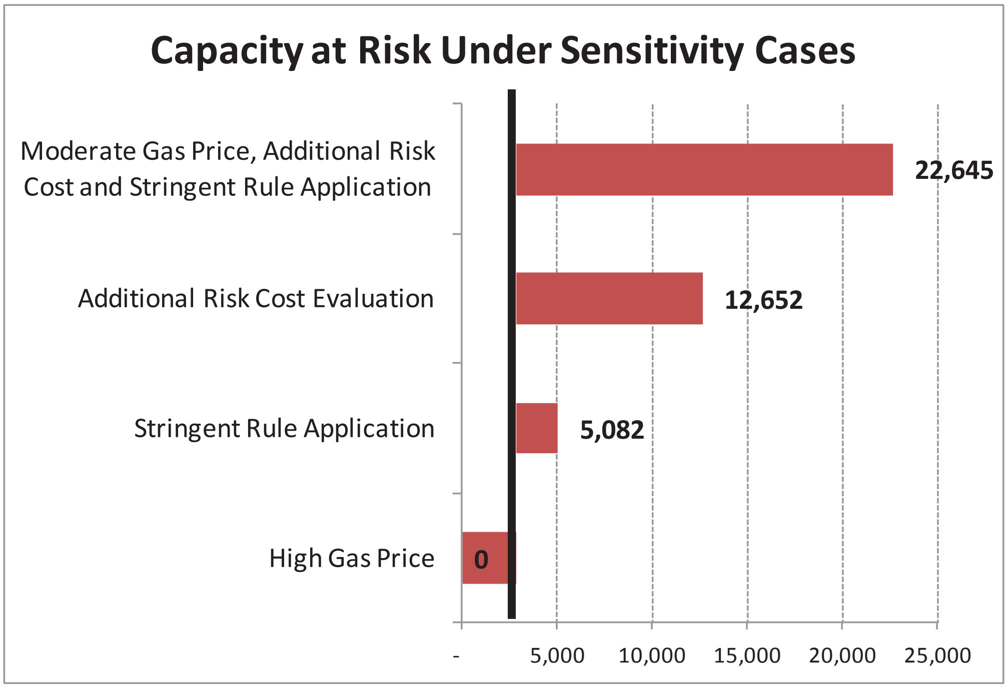


Figure 4.2-4: Tornado chart demonstrating the impacts of sensitivities on potential capacity retirements

Rate impact

In general, the retail rates on the system are driven by the costs of generation production, generation capital, transmission capital and distribution capital. The MISO EPA regulation analysis identifies costs that impact three of the four components of the rates.

The greatest impact on the rates comes from the capital cost component. The capital cost increase comes in two forms, the EPA capital compliance cost and the capital cost for replacement capacity. Figure 4.2-5 demonstrates the comparison of the rate impact of the two retirement scenarios with the current average system rate. The overall increase in the rates because of compliance with the EPA regulations is approximately 7.0 to 7.6 percent.

The relatively small rate increase difference between the two scenarios is due to the balance of capital cost configurations. The total EPA regulation related capital cost comes in three forms - 1) control equipment, 2) capital cost for replacement capacity and 3) transmission capital cost needed for retired capacity. The relationship between the three costs is a balance between retired capacity to forgo costs for control equipment while adding replacement capacity and transmission costs for the forgone capacity, versus more control costs to retrofit generation. In other words, as retirements increase, the total control equipment cost decrease, while replacement capacity and transmission costs increase – and vice versa. A balance of all three costs occurs to end up with the least cost strategy.

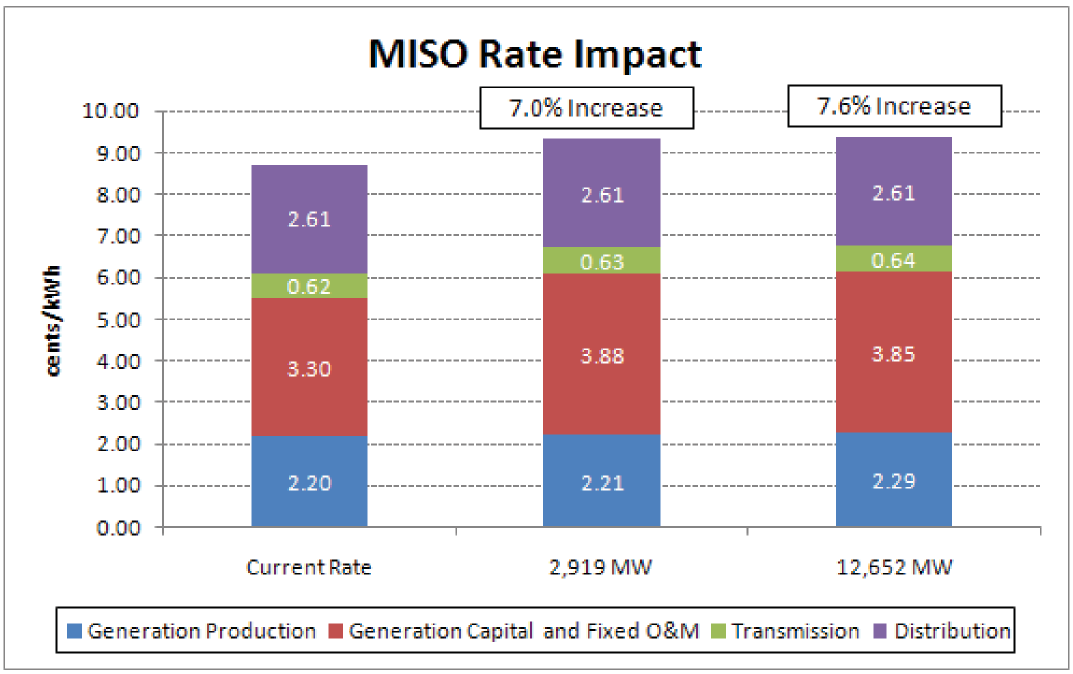


Figure 4.2-5: MISO rate impact

4.3 Generation portfolio analysis

MISO performed regional assessments using the Electric Generation Expansion Analysis System (EGEAS) on the MISO footprint as of June 1, 2011. Using assumed projected demand, energy for each company and common assumptions for resource forecasting, MISO developed models to identify least cost generation portfolios needed to meet resource adequacy requirements of the system for each future scenario.

Future scenario definitions

Scenario-based analysis provides the opportunity to develop plans for different future scenarios. A future scenario is a postulate of what *could be*, which guides the assumptions made about a given model. The outcome of each modeled future scenario is a generation expansion plan, or generation portfolio. Generation portfolios identify the 'least cost' generation required to meet reliability criteria based on the assumptions for each scenario. MTEP11 has examined multiple future scenarios:

MISO developed models to identify least cost generation portfolios needed to meet resource adequacy requirements of the system for each future scenario.

1. Business As Usual with Low Demand and Energy Growth Rates
2. Business As Usual with Historical Demand and Energy Growth Rates
3. Combined Energy Policy
4. Carbon Constraint

A more detailed discussion of the assumptions and methodology around these scenarios is presented later in Section 4.3 and in Appendix E.2.

Figure 4.3-1 on the following page represents capacity expansions for each defined future scenario through the 2026 PROMOD® study year. The capacity added is required to maintain stated reliability targets for each region. Stated targets for MISO are defined by means of the Module E Resource Adequacy Assessment.

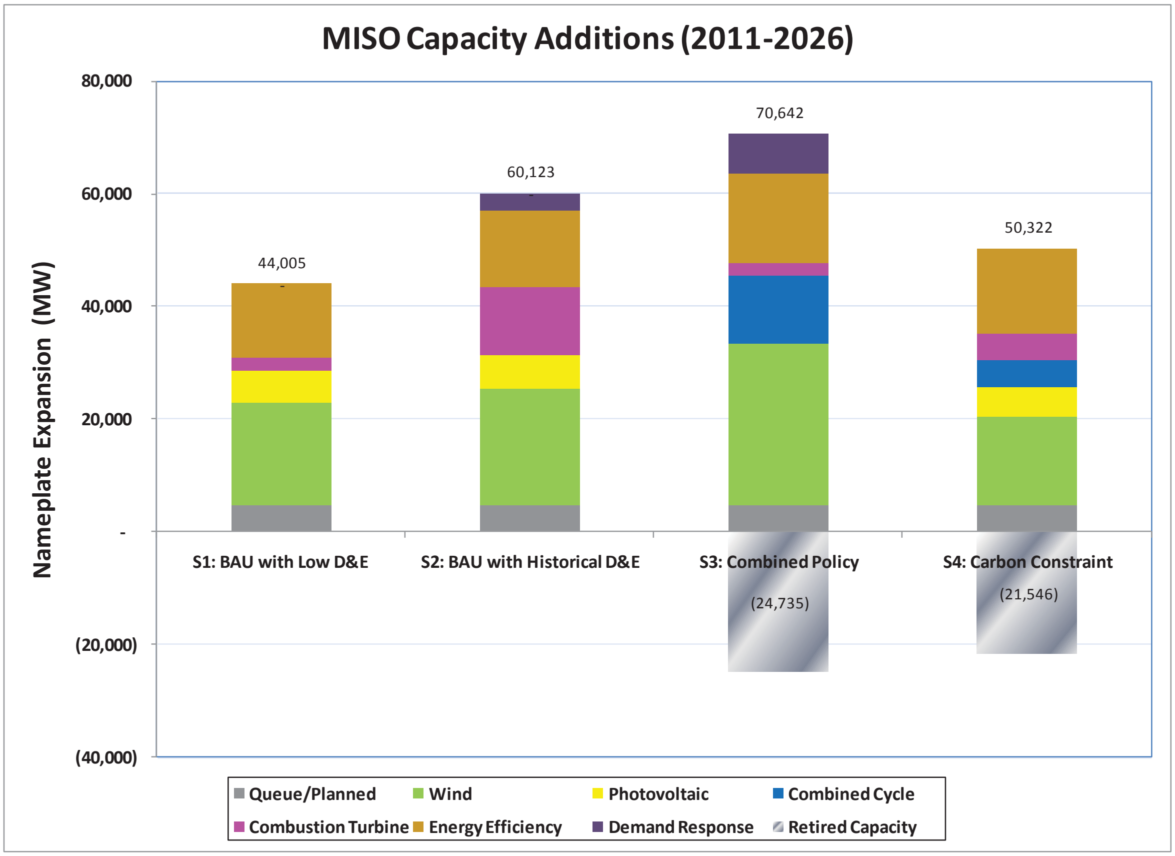


Figure 4.3-1: MISO modeled system aggregate nameplate installed MW from 2026 PROMOD Model.

Recognizing that redundancies across the existing MTEP10 future scenarios and assumptions did not provide any additional information, MISO staff, along with the planning advisory committee, narrowed down to four the scenarios for analysis in MTEP11. A diverse set of generation scenarios emerges when examining the MTEP11 future. While making comparisons across futures with different growth rates for demand and energy can be difficult, some observations can be made when studying future scenarios as a group or when comparing one to another.

Traditionally, most base load capacity needs have been met with coal and nuclear generation. Gas-fired combined cycle units have taken over some of the base load generation role thanks to the discovery of large quantities of shale gas and subsequent lower prices. Rising construction costs, pending EPA regulations and many uncertainties surrounding the future of nuclear generation are also factors. In the combined energy policy and Carbon Constraint scenarios coal units are retired in order to achieve the 42 percent carbon reduction cap. To achieve these targets within the specified time, 55 percent (~44,000 MW) of the oldest and least efficient coal units were retired in the analyses for the combined energy policy scenario and 50 percent (~40,000 MW) were retired in the Carbon Constraint scenario. Much of this base load generation capacity was replaced with natural gas-fired combined cycles and energy efficiency programs.

In all future scenarios, the addition of state-mandated renewable energy capacity overshadows thermal capacity, because most states within the MISO footprint have renewable energy standards and an abundance of existing capacity. The presence of lower demand and energy starting points and growth rates during the study are also factors. A large portion of capacity needs are being met through demand response and energy efficiency programs, which are allowed to compete against traditional supply-side resources in the EGEAS program for the first time in MTEP11. The Global Energy Partners study conducted for MISO in 2010 provided the demand response and energy efficiency estimates.

Figure 4.3-2 demonstrates the value of costs for the study period through 2026. Production and capital costs are provided. Production costs include fuel, variable and fixed operations and maintenance and emissions costs (where applicable). Capital costs represent the annual revenue needed for new capacity. Each future scenario has a unique set of input assumptions, such as demand and energy growth rates, fuel prices, carbon costs and RPS requirements, which drive the future capacity expansion capital investments and total production costs.

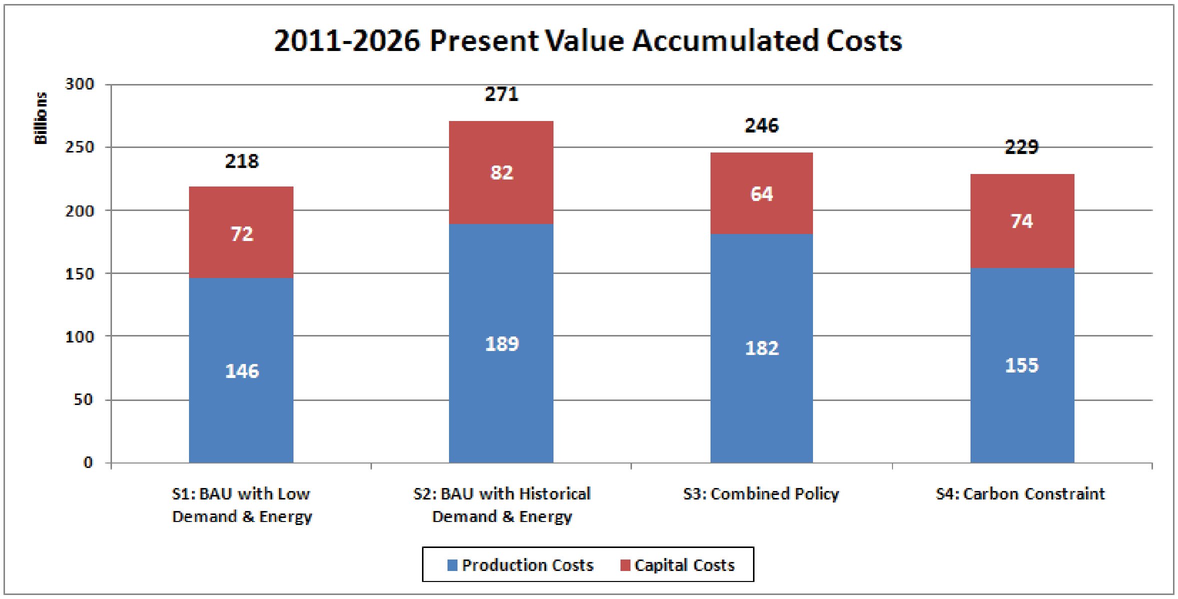


Figure 4.3-2: MISO present value of cumulative costs in 2011 U.S. dollars

Each of the future scenarios has a different impact on carbon dioxide output. Refer to Figure 4.3-3, which demonstrates the varying impact for each of the defined future scenarios. Figure 4.3-3 compares 2005 carbon production provided by the dispatch of a 2005 EGEAS model and year-end 2030 carbon production associated with the capacity expansion for each future scenario.

Continued demand and energy growth at levels close to historic trends will result in the need for additional generating capacity. If this capacity is dominated by coal or natural gas, carbon output will increase on an annual basis. The increased penetration of renewable resources and energy efficiency will result in a system reduction in carbon dioxide.

The increased penetration of renewable resources and energy efficiency will result in a system reduction in carbon dioxide.

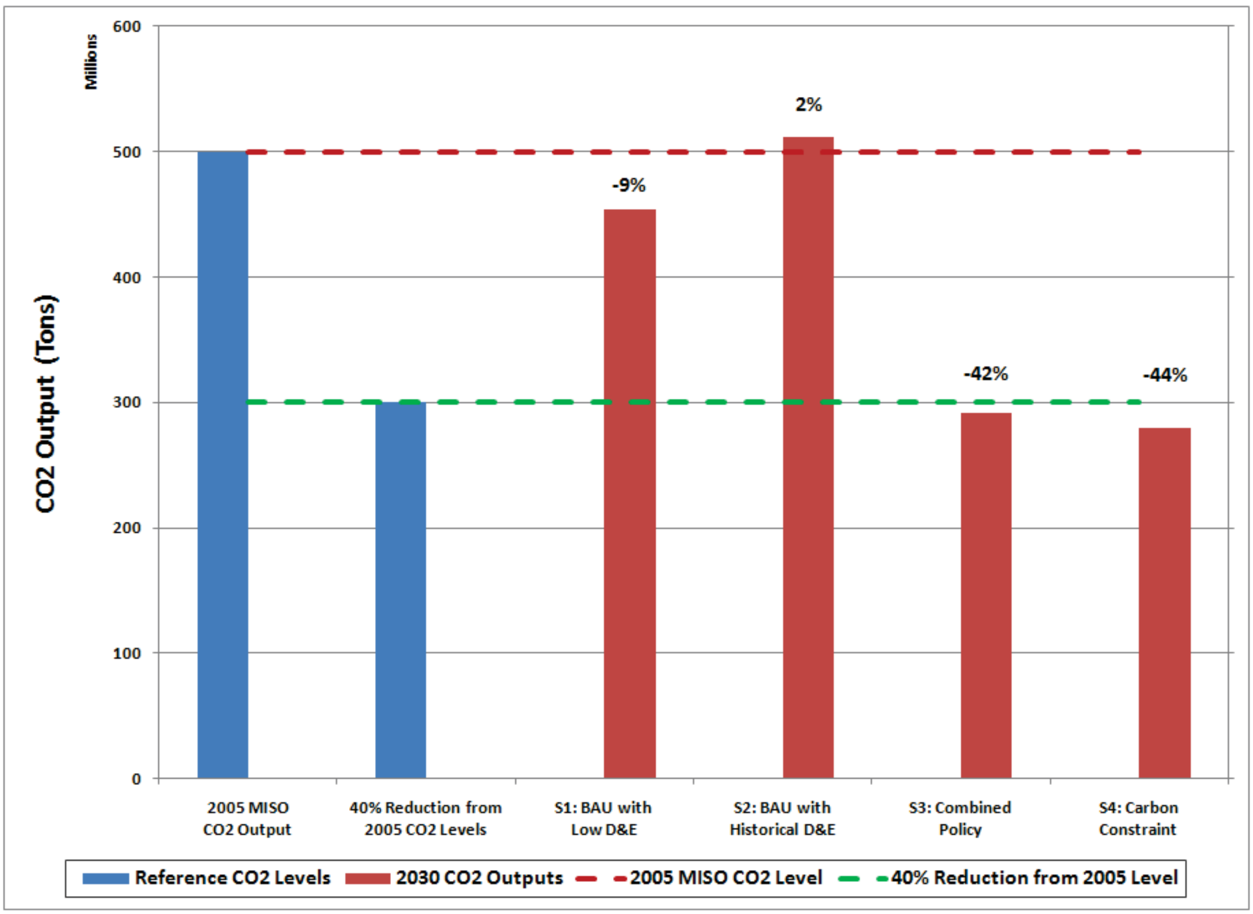


Figure 4.3-3: MISO carbon production

Siting of capacity

Generation resources forecasted from the expansion model for each of the scenarios are specified by fuel type and timing, but these resources are not site-specific. Completing the process requires a siting methodology tying each resource to a specific bus in the power flow model. A guiding philosophy and rule-based methodology, in conjunction with industry expertise, was used to site forecasted generation. Refer to Figure 4.3-4, which depicts capacity siting associated with the Business As Usual with Historical Demand and Energy Growth Rates scenario. Likewise, Figure 4.3-5 shows the associated demand response siting for the BAU with Historical Demand and Energy Growth Rates scenario. The siting methodology used for this and the other future scenarios is explained further in Appendix E2.

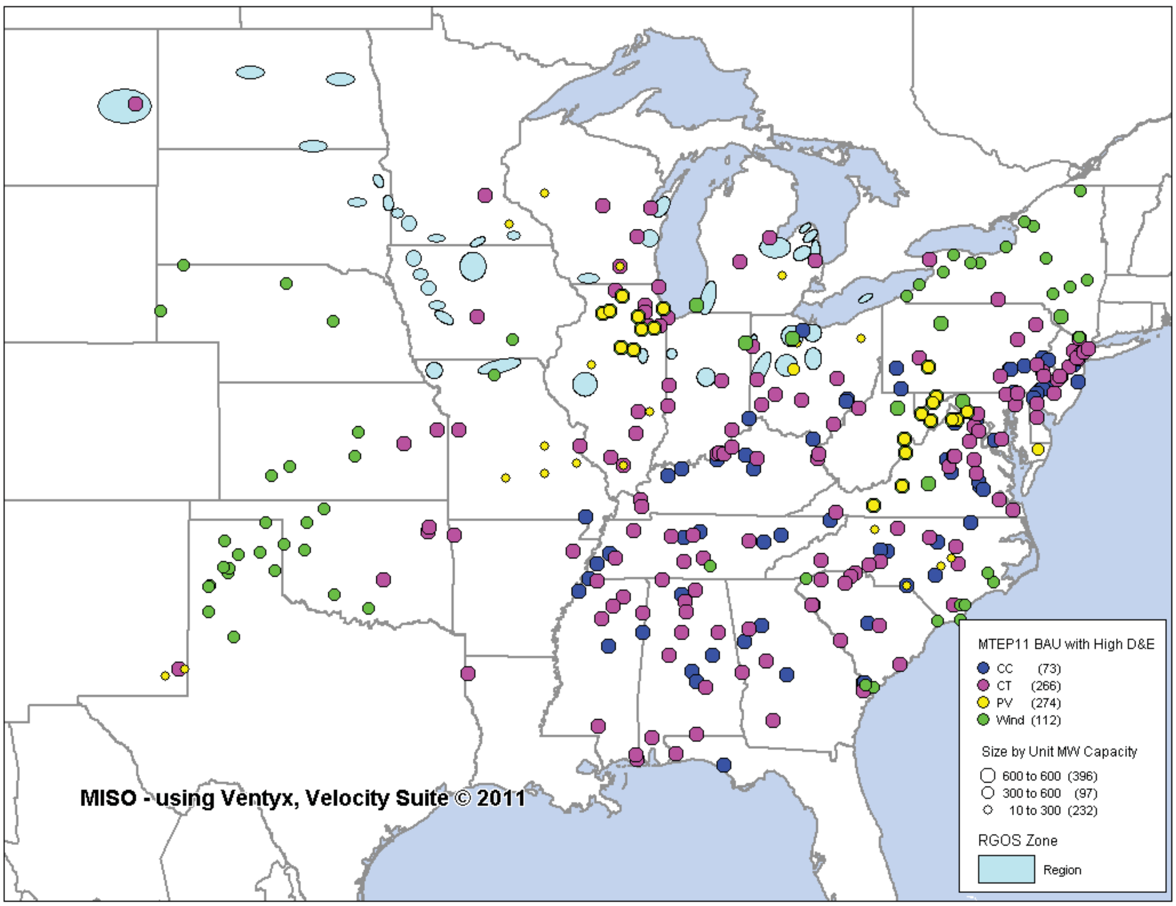


Figure 4.3-4: Future capacity sites for MISO BAU with historical demand and energy growth rates scenario

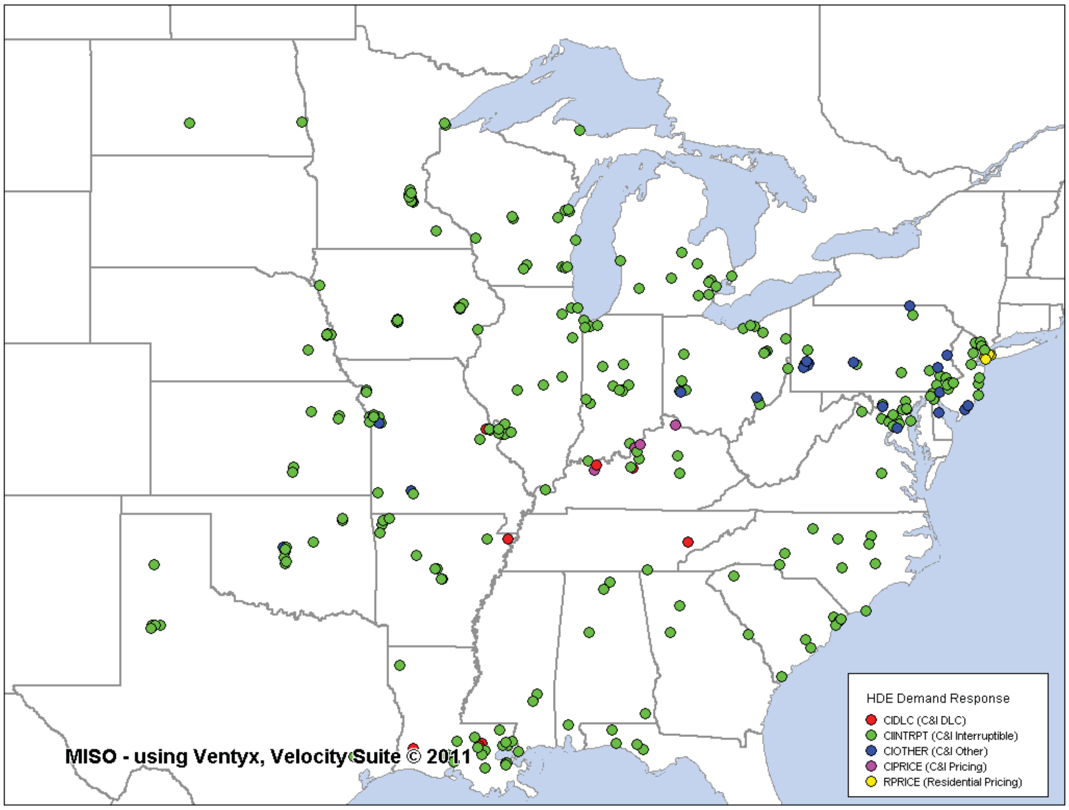


Figure 4.3-5 Future DR sites for MISO BAU with historical demand and energy scenario

Generation futures development

A planning horizon of at least 15 years is needed to accomplish long range economic transmission development, since large projects normally take 10 years to complete. Performing a credible economic assessment over this time is challenging. Long-range resource forecasting, power flow and security constrained economic dispatch models are required to extend to at least 15 years. Since no single model can perform all of the functions for integrated transmission development, a value-based planning process is developed by integrating the best models available. This allows the evaluation of the long-term transmission requirements to proceed.

The following broad steps outline the value-based planning process that MISO has been implementing. It starts with the analysis of value drivers and ends with a reliability assessment to meet both economic and reliability needs.

- Step 1: Create a regional generation resource forecast.
- Step 2: Site the new generation resources into the power flow and economic models for each future scenario.
- Step 3: Design preliminary transmission plans for each future scenario, if needed.
- Step 4: Test for robustness.
- Step 5: Perform reliability assessment, consolidation and sequencing.
- Step 6: Final design of integrated plan.
- Step 7: Cost allocation.

MISO's planning approach continues to evolve to integrate its planning. One focus of the MTEP 11 planning effort is to refresh a set of available future scenarios to capture potential energy policy outcomes.

In recognition of the uncertainty of energy policies and availability of associated resources in the 15-20 year time frame, a multi-dimensional regional resource forecasting is required, to identify what's necessary to supplement generation interconnection queue capacity. The regional resource forecast model determines, on a consistent least-cost basis, the type and timing of new generation and energy efficiency needs driven by energy policies and other long-term integrated resource plans generation not reflected in the current queue.

This section summarizes Steps 1 and 2 of the integrated transmission planning process, where regional resource forecasting is performed using scenario-based analysis to identify and site generation for several potential future scenarios. With the increasingly interconnected nature of organizations and federal interests, forecasting greatly enhances the planning process for electricity infrastructure. The futures analysis provides information on the cost and effects of environmental legislation, wind development, demand-side management programs, legislative actions or inactions and many other potential scenarios which can be postulated and performed.

Future scenarios and assumptions for the models for Steps 1 and 2 were developed with stakeholder involvement. The MISO Planning Advisory Committee (PAC) provided the opportunity for stakeholder input necessary to comply with FERC Order 890 planning protocols. Scenarios have been developed and subsequently refreshed to reflect shifts in energy policies in the last few years, in coordination with the committee, through efforts in MTEP09, MTEP10, the Joint Coordinated System Planning and the Eastern Wind Integration and Transmission Study.

In MTEP11, four primary future scenarios were used for robustness (best-fit) testing of proposed transmission plans associated with major studies, such as the 2011 Candidate MVP Portfolio study and transmission project evaluation under various market efficiency studies. New to MTEP 11 future scenario development is the inclusion of Global energy study estimated DSM projections, which are offered as demand side resources to compete against conventional supply-side resources based on economics. A notable portion of capacity needs are being met through demand side programs which are economically chosen for each of the MTEP11 futures.

MISO consulted with Global Energy Partners LLC (Global) in 2010 to perform an evaluation of Demand Response (DR) and Energy Efficiency (EE) potential in the MISO footprint. This effort developed a 20-year forecast for the MISO region and the rest of the Eastern Interconnection. This study demonstrated the enhanced modeling capabilities of DSM programs in the Electric Power Research Institute's (EPRI) Electric Generation Expansion Analysis System (EGEAS), the regional resource forecasting software tool used to assist in long term resource planning as part of Step 1 of the MTEP seven-step process. The study found DR and EE programs could significantly affect the load growth and future generation needs of the system. In MTEP11, Global provided DR and EE estimates for EGEAS to perform regional resource forecasting. An associated siting methodology for chosen demand response programs was also developed to facilitate business case development of proposed transmission plans. See the links below for more complete study results:

Volume 1: https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=78818

Volume 2: https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=78819

The assumptions for the models and the results presented in this document reflect the prices and policies leading to publication. MISO recognizes changes have occurred in many of these assumptions and will continue to update.

A full discussion of the assumptions and results of Steps 1 and 2 of the economic analysis process can be found in Appendix E2 of this document.

The following describes the various future scenarios in greater detail:

- The Business As Usual with Low Demand and Energy Growth Rates future scenario is considered the status quo scenario and continues the impact of the economic downturn on demand, energy and inflation rates. This scenario models the power system as it exists today with reference values and trends, with the exception of demand, energy and inflation growth rates. The demand, energy and inflation growth rates are based on recent historical data and assume existing standards for resource adequacy, renewable mandates and that environmental legislation remains unchanged. Renewable Portfolio Standard (RPS) requirements vary by state, and have many potential resources that can apply.
- The Business As Usual with Historical Demand and Energy Growth Rates future scenario is considered a status quo scenario, with a quick recovery from the economic downturn in demand and energy projections. This scenario models the power system as it exists today with reference values and trends—with the exception of demand and energy growth rates—and is based on recent historical data prior to the economic downturn. This scenario assumes existing standards for resource adequacy renewable mandates and that environmental legislation will remain unchanged. Renewable Portfolio Standard (RPS) requirements vary by state and have many potential renewable resources that can apply.
- The Combined Energy Policy future scenario was developed to capture the effects of multiple future policy scenarios into one future. This scenario includes a federal Renewable Portfolio Standard, a carbon cap and trade, smart grid and electric vehicles. The RPS is modeled assuming all states are required to meet a 20 percent federal RPS mandate by 2025. The carbon cap is modeled after the Waxman-Markey bill, which requires an 83 percent reduction of CO2 emissions from a 2005 baseline by the year 2050. That is achieved through a linear reduction from 2011 to 2050 with mid point goals of 3 percent in 2015, 17 percent in 2023 and 42 percent in 2033. This future employs coal retirements, with the oldest and least efficient coal units retired first. Smart grid is modeled by reducing the demand growth rate, assuming that a higher penetration of smart grid will lower the overall growth of demand. Electric vehicles are modeled by increasing the energy growth rate. They are assumed to increase off-peak energy usage and—increase the overall energy growth rate.
- The Carbon Constraint future scenario models a declining cap on future CO2 emissions. It is modeled in the same way as in the Combined Energy Policy future scenario. Renewable Portfolio Standard (RPS) requirements vary by state, and have many potential renewable resources that can apply.

Refer to Table 4.3-1, which illustrates the key input variables for each future scenario. Each future has a unique set of input assumptions driven by a range of policy decisions. With extensive stakeholder involvement under the Planning Advisory Committee, the consensus has been reached with respect to the methodology for determining baseline demand and energy growth rates for each of MTEP11 futures. The demand and energy growth rates were then adjusted to reflect the economically chosen DSM programs during the EGEAS capacity expansion analyses, which offer Global energy study estimated DSM projections as demand side resource options for each scenario. The resulted effective demand and energy growth rates for the four MTEP 11 futures are tabulated as follows:

Future scenarios	MISO wind penetration (GW)	Effective Demand Growth Rate	Effective Energy Growth Rate	Gas price	Carbon Cost / reduction target
Business As Usual with Low Demand & Energy	29	0.78%	0.79%	$5.00	None
Business As Usual With Historical Demand & Energy	32	1.28%	1.42%	$5.00	None
Combined Energy Policy	40	0.52%	0.68%	$8.00	$50/ton (42 percent by 2033)
Carbon Constraint	27	0.03%	0.05%	$8.00	$50/ton (42 percent by 2033)

Table 4.3-1: Future scenario input assumptions

5. MISO resource assessment

5.1 Reserve margin requirements

As directed under Module E of the MISO Tariff, the system planning reserve is calculated by determining the amount of generation required to meet a 1 day in 10 years (0.1 day per year) Loss of Load Expectation (LOLE). The MISO Planning Reserve Margin (PRM), based on the system-wide MISO concident load peak and resources based on their installed capacity rating (that is, PRMSYSIGEN), for the 2011/2012 Planning Year (PY) is 17.40 percent, increasing 2 percentage points from the 2010/2011's 15.40 percent. The Planning Reserve Margin based on Unforced Capacity (PRM_UCAP) declined from 4.50 percent to 3.81 percent, and applies to the non-coincident peak of each Load Serving Entity (LSE).

The majority of the 2 percent PRMSYSIGEN increase can be attributed to three factors. In approximate values: The increased uncertainty of forecasting the load contributed to 0.8 percent of the increase; the forced outage rates of resources were up and contributed to 0.7 percent of the increase; and the external system support was found less effective and contributed to 0.6 percent of the increase. While these three factors contributed a total increase of 2.1 percent, other factors contributed an offsetting decrease of about 0.1 percent.

> The system planning reserve is calculated by determining the amount of generation required to meet a 1 day in 10 years (0.1 day per year) Loss of Load Expectation (LOLE). The MISO Planning Reserve Margin (PRMSYSIGEN) for the 2011/2012 Planning Year (PY) is 17.40 percent.

Unlike previous years, the 2011 PRM reflects no component due to transmission congestion. For example, had there been no congestion in the two previous years, the PY 2009 value would have been 0.6 percent marginally lower than its 15.4 percent, and the PY 2010 value would have been lower by 0.4 percent. All previous congestion was due to effects of bottled-up resources that could not likely be counted as available to serve system wide load. Like previous studies, the 2011 MISO LOLE found no evidence of load pockets where the lack of resources would require importing more than the Transmission System's ability to deliver.

Benefits associated with system-wide diversity must be considered since compliance with Module E Resource Adequacy Requirements is based on representing each Load Serving Entity's (LSE) non-coincident monthly peak demand on the appropriate individual CPnodes. MISO has determined that a diversity factor of 4.55 percent will be used for the 2011/12 Planning Year. This is an increase from the 3.00 percent diversity factor used last year. MISO believes the 1.55 percent increase in diversity factor is appropriate in order to appropriately capture the diversity of all LSEs within the MISO BA without significantly increasing the loss of load risk to the MISO system. After consideration for load diversity, the PRM is based on the Load Serving Entity's non-coincident peak and resources based on their installed capacity rating (that is, PRMLSEIGEN), and the value is 12.06 percent.

Projected planning reserve margin requirements for 2012 through 2020 are also calculated in the LOLE Study and are utilized in Section 5.2 as a comparison to the projected reserves. The complete 2011 report on MISO Loss of Load Expectation (LOLE) study can be found at the following link:

https://www.midwestiso.org/Library/Repository/Meeting percent20Material/Stakeholder/LOLEWG/2011/2011 percent20LOLE percent20Report.pdf

5.2 Long term resource assessment

Although current load and resource forecasts do not predict insufficient capacity within the next 10 years, various uncertainties could change that forecast. Less capacity expansion than expected, increased level of generation unit retirements, uncertainty around load forecast, increased forced outage rates due to an aging generation infrastructure and possible lack of external support - are all uncertainties which may negatively affect future Resource Adequacy. The risk of these uncertainties on reliability is assessed through Loss of Load Expectation (LOLE) analysis and the results summarized in this section.

Absent EPA regulations, MISO projects sufficient capacity relative to demand over the next 10 years ……

With EPA regulations and no replacement capacity, the system reserve margin could decrease to 6.9 percent in 2021

Of specific interest is the uncertainty around the pending EPA regulations, one of which has been finalized. The passage of these regulations could lead to increased unit retirements throughout the MISO region; quickly eroding reserve margins from their projected levels.

Recent proposals from the Environmental Protection Agency (EPA) and the uncertainty around carbon control may force retirements of generation within the MISO footprint, which would quickly erode reserve margins from their projected levels. With the anticipated decline of coal generation due to EPA regulations, environmental and economic trends; approximately 3,000 MW of coal generation could be retired in the MISO system by 2015, for a natural gas cost of $4.5/MMBtu and no carbon cost applied. These coal retirements could grow to 12.6 GW of generation, at a carbon cost of $50/ton. If no replacement capacity is identified for Resource Adequacy purposes, then the system reserve margin could decrease to 6.9 percent in 2021. Table 5.2-1 below shows the impact of these scenarios on 2016 and 2021 reserve margins. Refer to MTEP11 chapter 4.2 for more information about the EPA Regulation Impact Study.

Reserve margin	3 GW coal generation retirements		12.6 GW coal generation retirements	
	2016	2021	2016	2021
Projected reserve margin (percent)	19.9	16.2	10.1	6.9
Planning reserve margin requirements (percent)	17.4	18.2	17.4	18.2

Table 5.2-1: Potential EPA impacts on resource adequacy

Absent EPA regulations, MISO projects sufficient capacity relative to demand over the next 10 years. The following section summarizes this situation, and provides forecasts of future demand, capacity, and reserves through 2021. Risks, such as the proposed EPA regulations, are also examined to gauge the potential affect on resource adequacy.

The MISO 2011 Long Term Resource Assessment report will be posted at:
https://www.misoenergy.org/Planning/SeasonalAssessments/Pages/SeasonalAssessments.aspx

Refer to Appendix E6 for a more detailed discussion and breakdown of the data presented below.

Forecasted demand

MISO Load Serving Entities are required by current resource adequacy practices to report their non-coincident peak forecasted demand to MISO out 10 years. These demands were collected from the Module E Capacity Tracking (MECT) tool and aggregated to a MISO level. MISO's total internal demand and net internal demand for the 10th-year peak are expected to be approximately 101 GW and 97 GW, respectively. The forecasted MISO annual growth rate from 2012-2021 is approximately 1.0 percent, a slight increase from the 2010 LTRA.

Demand (MW)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Unrestricted non-coincident	97,206	99,149	99,560	100,313	101,034	101,761	102,574	103,515	104,475	105,520
Estimated diversity	4,230	4,315	4,333	4,366	4,397	4,429	4,464	4,505	4,547	4,592
Total internal	92,976	94,834	95,227	95,947	96,637	97,332	98,110	99,010	99,929	100,928
Direct control load management	1,118	1,118	1,118	1,118	1,118	1,118	1,118	1,118	1,118	1,118
Interruptible load	3,093	3,093	3,093	3,093	3,093	3,093	3,093	3,093	3,093	3,093
Net internal demand	88,765	90,623	91,016	91,736	92,426	93,121	93,899	94,799	95,718	96,717

Table 5.2-2: 2012-2021 forecasted demand

Forecasted capacity

MISO's total designated capacity for the 10th year peak is expected to be approximately 115 GW. A total of 2,549 MW of Generation Interconnection queue projects[33] are expected to be available for the 10th year peak based on a thorough study of the queue. Behind-the-Meter Generation (BTMG) is treated as a capacity resource and not a load modifier to align with the current resource adequacy practices outlined within Module E and standard industry practice.

Capacity (MW)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Internal designated capacity resources	103,698	103,698	103,698	103,698	103,698	103,698	103,698	103,698	103,698	103,698
External designated capacity resources	4,894	4,894	4,894	4,894	4,894	4,894	4,894	4,894	4,894	4,894
Behind-the-meter generation	3,608	3,608	3,608	3,608	3,608	3,608	3,608	3,608	3,608	3,608
Future planned resources	495	862	881	904	986	986	986	2,549	2,549	2,549
Total designated capacity	112,695	113,062	113,081	113,104	113,186	113,186	113,186	114,749	114,749	114,749

Table 5.2-3: 2012-2021 forecasted capacity

Forecasted reserves

The target reserve margin requirement varies throughout the 10-year period, from 17.4 percent in 2012 to 18.2 percent in 2021. The reserve margins projected through the assessment time vary from 27.0 percent to 18.6 percent for 2012-2021. This is in excess of the MISO target reserve margins through 2019.

Reserve margin	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Reserve margin (MW)	23,930	22,438	22,064	21,368	20,760	20,065	19,287	19,950	19,031	18,032
Reserve margin (percent)	27.0	24.8	24.2	23.3	22.5	21.5	20.5	21.0	19.9	18.6
Planning reserve margin requirement (percent)	17.4	17.3	17.3	17.2	17.4	17.8	17.8	18	18.2	18.2

Table 5.2-4: 2012-2021 forecasted reserves

[33] Generator Interconnection Queue data as of March 28th, 2011

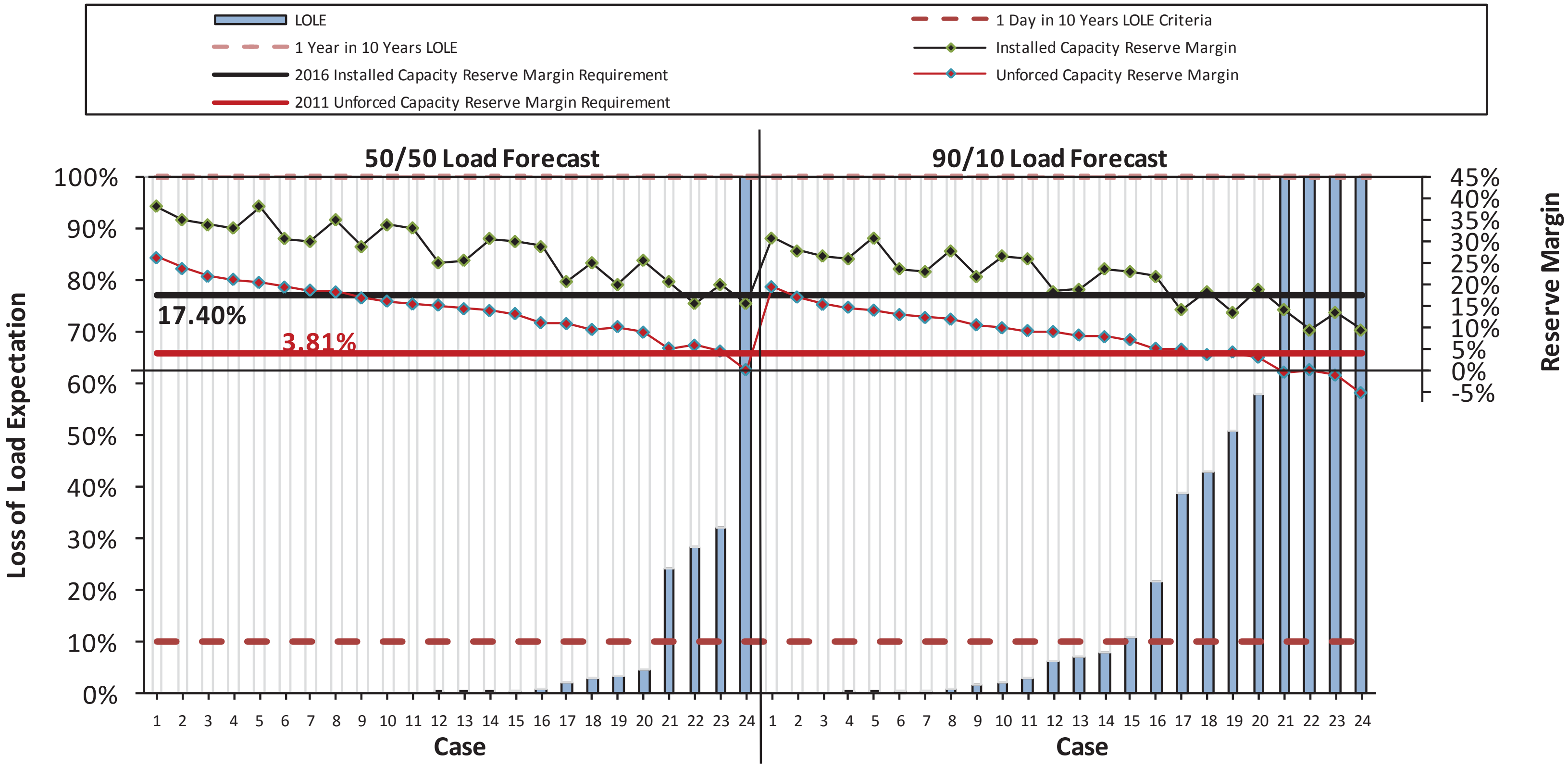
Forecasted risk

To quantify effects each future uncertainty has on the 50/50 and 90/10 load level scenarios, 48 sensitivities were run. The various sensitivities simulate increased forced outage rates across the footprint, no load modifying resources, no external support and increased unit retirements due to the pending EPA regulations (3 GW of coal retirements and 12.6 GW) for both 2016 and 2021. In each case, variables were changed to observe the effects on Loss of Load Expectation (LOLE).

Both 2016 and 2021 had 48 identical cases created to observe its effect on LOLE. An additional eight cases were run for 2021 based on the premise that Generation Interconnection gas-fired projects, approximately 5,000 MW, would have a 100 percent chance of being built, if MISO experiences 12.6 GW of early coal retirement due to EPA regulations.

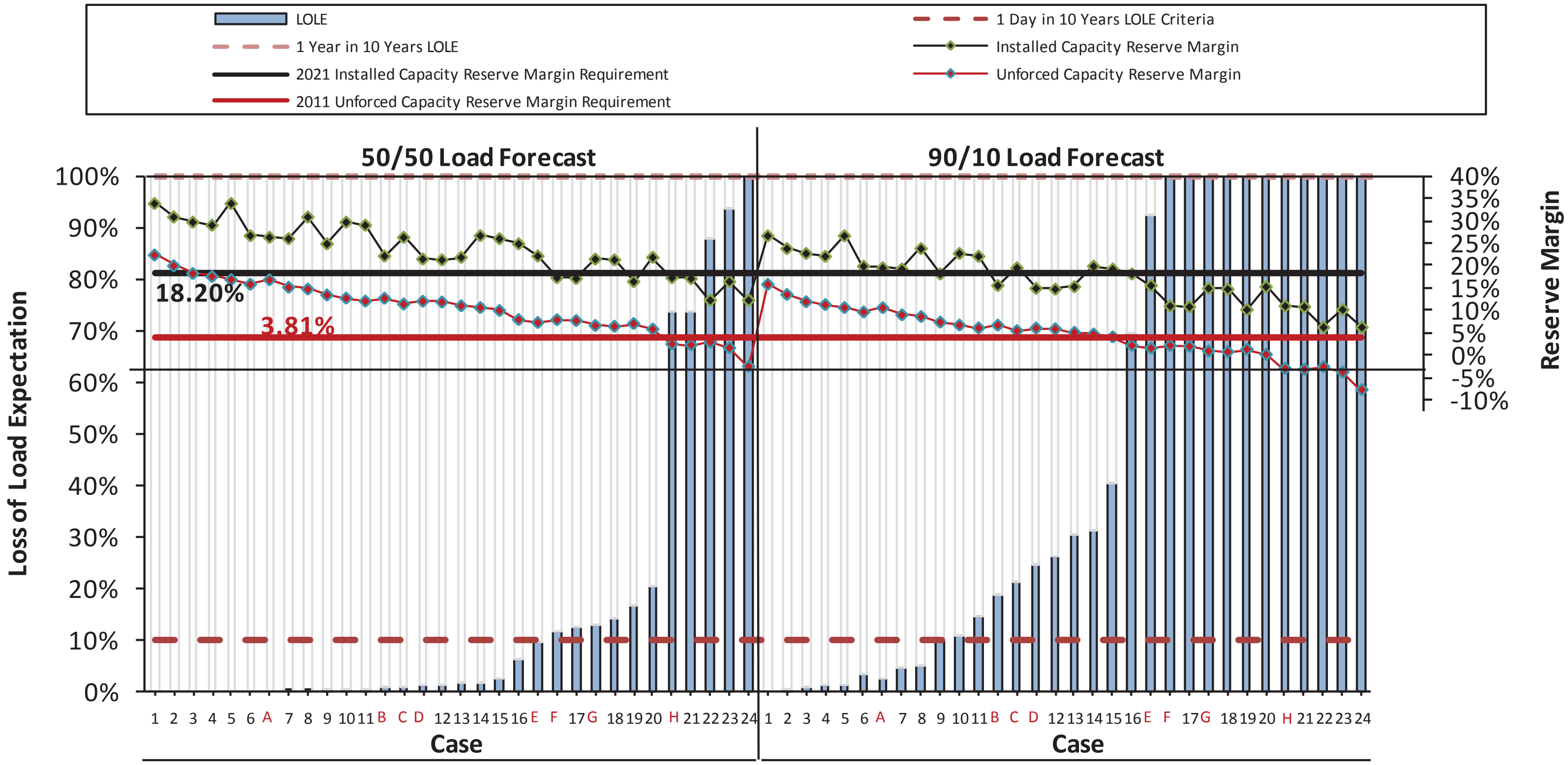
An LOLE of one day in 10 years is an industry standard benchmark for minimum system reliability. When studying the 2016 and 2021 systems, with no early coal facility retirements due to environmental regulations, the analysis shows only a few cases exceeding this benchmark for each year. It should be noted that this is only when unlikely significant impacts occur to the system, such as a 90/10 load forecast with either combination of no external support, no load modifying resources, or 50 percent higher forced outage rates.

A summary of results for 2016 and 2021 is given in figures 5.2-1 and 5.2-2, respectively. The summary shows the LOLE and corresponding reserve margin for each case run in the analysis. Uncertainty exists given the potential effect of pending environmental legislation on MISO's system. The results indicate risk exponentially exceeding one day in 10 years given increased early retirement of MISO base generation, combined with current future generation resources expected to be built in the Generation Interconnection Queue.



1	Base	9	(EXT), (LMR)	17	(12.6 GW), (LMR)
2	3 GW EPA Retire (3 GW)	10	(FOR), (LMR)	18	(12.6 GW), (FOR)
3	No Load Modifying Resources (LMR)	11	(FOR), (EXT)	19	(12.6 GW), (EXT)
4	No External Resources (EXT)	12	12.6 GW EPA Retire (12.6 GW)	20	(3 GW), (FOR), (LMR), (EXT)
5	50% Increased Forced Outage Rates (FOR)	13	(3 GW), (EXT), (LMR)	21	(12.6 GW), (FOR), (LMR)
6	(3 GW), (LMR)	14	(3 GW), (FOR), (LMR)	22	(12.6 GW), (EXT), (LMR)
7	(3 GW), (EXT)	15	(3 GW), (FOR), (EXT)	23	(12.6 GW), (FOR), (EXT)
8	(3 GW), (FOR)	16	(FOR), (LMR), (EXT)	24	(12.6 GW), (FOR), (LMR), (EXT)

Figure 5.2-1: Year 2016 LOLE sensitivity to variable adjustment



1	Base	B	(12.6 GW) (Gas), (LMR)	18	(12.6 GW), (FOR)
2	3 GW EPA Retire (3 GW)	C	(12.6 GW) (Gas), (FOR)	19	(12.6 GW), (EXT)
3	No Load Modifying Resources (LMR)	D	(12.6 GW) (Gas), (EXT)	20	(3 GW), (FOR), (LMR), (EXT)
4	No External Resources (EXT)	12	(12.6 GW)	H	(12.6 GW) (Gas), (FOR), (LMR), (EXT)
5	50% Increased Forced Outage Rates (FOR)	13	(3 GW), (EXT), (LMR)	21	(12.6 GW), (FOR), (LMR)
6	(3 GW), (LMR)	14	(3 GW), (FOR), (LMR)	22	(12.6 GW), (EXT), (LMR)
A	12.6 GW EPA Retire (12.6 GW) w/Partial Gas Replacement (Gas)	15	(3 GW), (FOR), (EXT)	23	(12.6 GW), (FOR), (EXT)
7	(3 GW), (EXT)	16	(FOR), (LMR), (EXT)	24	(12.6 GW), (FOR), (LMR), (EXT)
8	(3 GW), (FOR)	E	(12.6 GW) (Gas), (FOR), (LMR)		
9	(EXT), (LMR)	F	(12.6 GW) (Gas), (EXT), (LMR)		
10	(FOR), (LMR)	17	(12.6 GW), (LMR)		
11	(FOR), (EXT)	G	(12.6 GW) (Gas), (FOR), (EXT)		

Figure 5.2-2: Year 2021 LOLE sensitivity to variable adjustment

6. Near and long-term reliability analyses

MISO performs an annual Reliability Assessment through its MISO Transmission Expansion Plan (MTEP).

MISO also conducts Baseline Reliability studies in support of MTEP to ensure the Transmission System is in compliance with two entities: applicable national Electric Reliability Organization (ERO) reliability standards and reliability standards adopted by Regional Reliability Organizations applicable within the Transmission Provider region. MISO's studies typically include simulations to assess transmission reliability in the near and long term, using power flow models representing conditions two, five and 10 years out.

MISO identified various transmission issues through the studies. Planned and proposed transmission upgrades needed to mitigate identified issues are included in the 2011 MISO Transmission Expansion Plan. Planned transmission upgrades are in MTEP Appendix A following MISO Board of Directors approval. Proposed transmission upgrades are in MTEP Appendix B.

In MTEP 2011, MISO conducted regional studies using the following base models:

- 2013 Summer Peak
- 2016 Summer Peak
- 2016 Shoulder Peak
- 2016 Light Load
- 2021 Summer Peak
- 2021 Shoulder Peak

MISO member companies and external RTO companies use firm drive-in and drive-out transactions to determine net interchanges for these models. These are documented in the 2011 series Multi-Area Modeling Working Group (MMWG) interchange. MISO determines total generation necessary to be dispatched for each of the models after aggregating total load with input received from Transmission Owners.

Generation dispatch within the model building process has become complex. Growing inputs from various planning processes and expected shifts in generation portfolio within the MISO footprint are big reasons.

Inputs in the dispatching process:

- Generation retirements
- Generator market cost curves
- Generator deliverable capacity designation
- Wind generation output modeling under various system conditions
- Incremental generation needed to meet applicable renewable mandates

Scenario	West Sub Region		Central Sub Region		East Sub Region		Total Load (MW)	Total Generation (MW)	Total MISO Interchange (MW)
	Load (MW)	Generation (MW)	Load (MW)	Generation (MW)	Load (MW)	Generation (MW)			
2013 Summer Peak	41,515	40,065	42,004	39,356	24,906	25,896	108,425	105,317	-3,108
2016 Summer Peak	43,271	41,183	42,736	40,931	25,559	27,809	111,567	109,923	-1,644
2016 Shoulder Peak	31,529	32,945	33,467	32,659	21,294	20,847	86,289	86,451	162
2016 Light Load	22,262	20,778	28,185	29,264	9,883	9,511	60,330	59,553	-777
2021 Summer Peak	45,921	41,378	41,126	41,595	26,768	26,816	113,815	109,788	-4,027
2021 Shoulder Peak	34,557	37,749	33,876	30,757	19,932	18,630	88,365	87,136	-1,229

Table 6-1: MTEP11 models summary

Associated power flow models in MISO Planning Regions are modeled above. Loads are received directly from members. Generation dispatched by MISO in each region is derived from a number of factors, such as modeling of wind. The 5- and 10-year out models have wind zones dispatched in wind integration studies (Regional Generation Outlet Study and proposed Multi Value Project study). Wind zone modeling is based on wind generation required to meet state renewable portfolio standards. Wind projects required to meet state renewable portfolio standards are incrementally needed beyond existing and planned wind with signed interconnection agreements. These wind zones are spread throughout the MISO footprint. The size of these wind zones is determined in two ways: 1) consideration of existing and planned wind near the region and 2) aggregate MISO renewable portfolio standards requirements in 5- and 10-year scenarios. MISO models all planned and incremental wind-existing required to meet state mandates at 20 percent of capacity in summer peak and 90 percent of capacity in shoulder and light load scenarios.

A total of 38 Baseline Reliability Projects (6-MISO East, 6-MISO Central and 26-MISO West Region) and 27 Generation Interconnection projects (3-MISO East, 8-MISO Central and 16-MISO West Region), adding up to $702 million, are being recommended in the current planning cycle. More than $676 million in sub-transmission investment is also planned.

Near term assessment

Near term assessment involves study of the MTEP 2- and 5-year out models. A total of 38 Baseline Reliability Projects (6-MISO East, 6-MISO Central and 26-MISO West Region) and 27 Generation Interconnection Projects (3-MISO East, 8-MISO Central and 16-MISO West Region), adding up to $693 million, are recommended in the planning cycle. More than $685 million in sub-transmission investment is also planned. Detailed documentation of these plans is included in Appendix D1.

Straits power flow control – back to back HVDC voltage source converter

A notable near term Baseline Reliability plan in MTEP11 is the Straits HVDC project. Through the years, power transfers through transmission in the Upper Peninsula (UP) of Michigan have increased so much that re-dispatching local generation around the area’s constraints is now a formidable task. The peninsula’s system has been split for extended periods in the past few years. The split was created by opening the electrical connections between Indian Lake and Hiawatha 138 kV stations. Consequently, the Transmission System east of Hiawatha is supplied by local generation and lower Michigan through two Straits 138 kV cables. While operating in this mode for extended periods has effectively trapped through flows, performing maintenance on METC lines in lower Michigan has become harder because of the eastern Upper Peninsula’s reliance on METC tie lines.

The planned addition of 200 MW Straits back-to-back DC Voltage Source Converter (VSC) will eliminate the need to split the system to prevent overloads. This improves reliability by keeping the system intact. This will improve system reliability. Modern voltage source converter HVDC technology, unlike line commutated converter HVDC technology, provides dynamic reactive power to improve system voltages. It can also be tuned to improve system damping during system swings. This VSC is expected to be able to produce approximately 100 MVARs of reactive power.

All transmission plans in the final NERC Reliability Assessment include additional planned and proposed transmission projects or operating steps. They are necessary to meet system performance requirements of applicable standards. Noteworthy MISO near term issues within the RFC footprint have been documented below and grouped into the local regions:

Minnesota

Most constraints in Minnesota are on the 115 kV transmission lines. In most cases, use of existing Special Protection Schemes (SPS) and Operating Guides (Op-Guide) alleviate thermal issues. Coal Creek runback, Taconite Harbor special protection schemes and Ramsey special protection schemes are notable SPS and Operating Guides used in the constraint mitigation.

Iowa

Generation re-dispatch mitigates most identified Iowa constraints. In almost all cases, these constraints are driven by wind. While in the long term, proposed Multi Value Projects will provide needed outlet for these wind resources, in the near term they will need to be curtailed to alleviate thermal constraints.

Southeast Wisconsin

Category C events (See Appendix E1 for descriptions of NERC TPL standards) drive a number of southeast Wisconsin generator outlet issues. Generation curtailment associated with outages local to the generators will be used to relieve these constraints.

Marquette County-Michigan

Thermal loading issues in Marquette County in the Upper Peninsula of Michigan driven by Category C events were identified in both 2- and 5-year-out models. Local mining load curtailment will be used to mitigate these constraints.

Illinois

A few 138 kV constraints in the Mount Vernon and St. Louis metropolitan areas are thermal constraints driven by Category C events. These conditions will be mitigated by reconductoring of a few sections and load curtailment at some stations. Constraints electrically tied closely to the Taum Sauk Pumping Station are identified in the shoulder scenario with Taum Sauk operating in a pumping mode. The situation will be mitigated by a curtailment of interruptible pumping load. Generation redispatch will mitigate a majority of the remaining constraints.

Tippecanoe County-Indiana

A number of 138 kV loadings here are driven by wind. Proposed Multi Value projects, when approved, will alleviate loadings in the long term planning horizon. Use of wind curtailment through established Operating Guides will be employed to alleviate issues in the near term

Cincinnati-Ohio

A couple of 138 kV circuits on the east side of the metropolitan area are overloaded for various category C events. Operating guides involving load switching and operating lines radially will alleviate the thermal constraints in the near term. A proposed project to reconductor circuits is being evaluated for the long term.

Long term assessment

Long term assessment primarily focuses on reliability issues driven by renewable generation. In addition to existing and planned wind, an incremental 8.5 GW of nameplate capacity is needed in the 10-year planning horizon to meet renewable mandates. The mandates grow further to 10.7 GW in the 15-year out horizon. Growth in wind within five years is compelling wind curtailments. These curtailments will be significant in the long term. The proposed Multi Value Project Study (see Chapter 4.1) shows a possible curtailment of more than 34 TWHr wind energy, in lieu of no long term transmission plans to integrate wind. This equates to about 63 percent of the MISO renewable portfolio standards requirement. As part of the MVP Study, significant transmission (about $5 billion) is planned in the current planning cycle. Though primarily intended to alleviate wind driven constraints in MISO, these projects provide long term help by offloading the underlying 100 kV system, and providing increased outlet for conventional generation as well. These CMVP projects mitigate thermal constraints on about 500 branches for more than 6,400 category B and C contingent events, encompassing study of shoulder and summer peak scenarios.

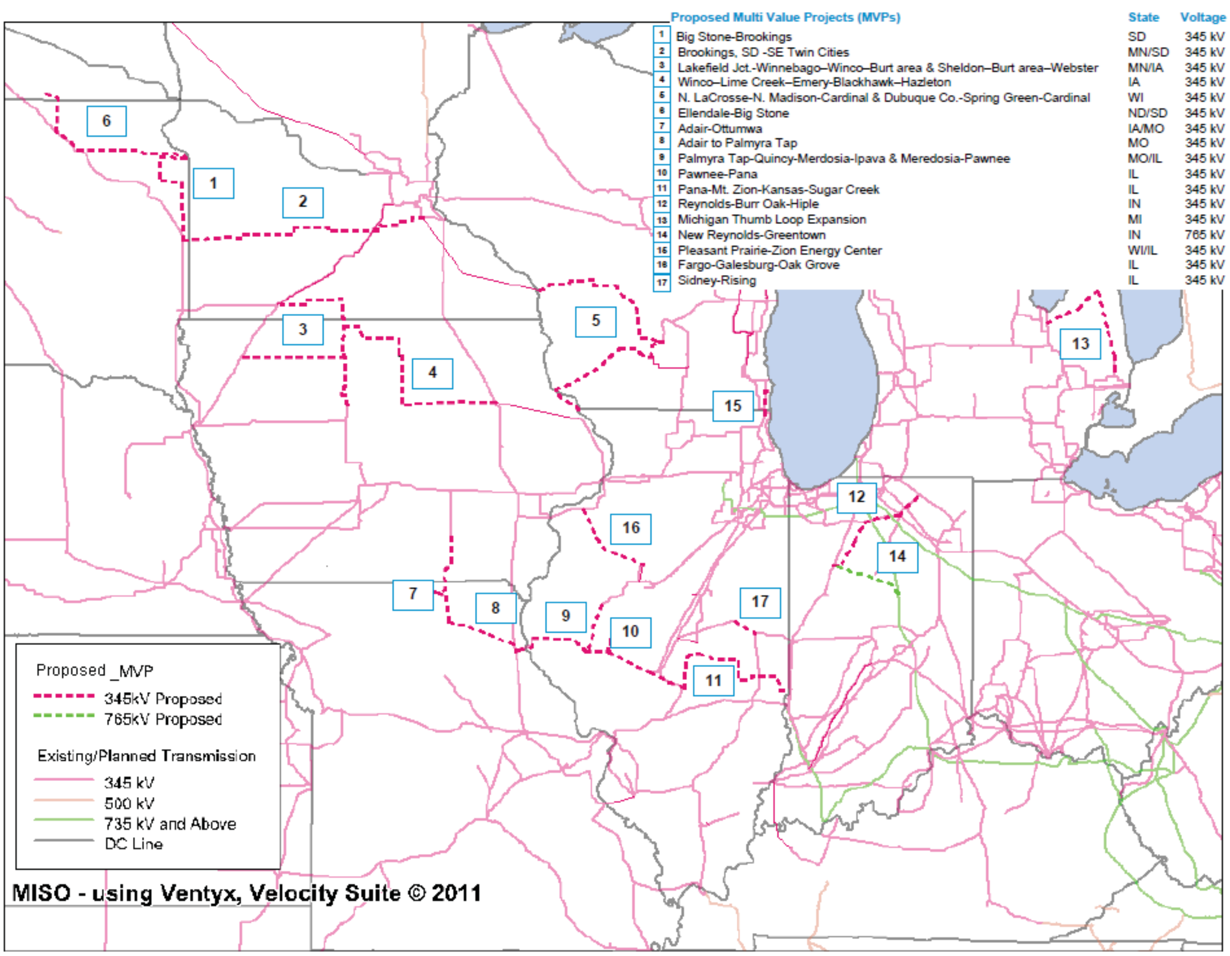


Figure 6-1: 2011 Proposed MVP portfolio

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A brief summary of these new plans is documented below:

Ellendale to Big Stone to Brookings

A new line planned from North Dakota into Minnesota provides an outlet to North Dakota wind by directly transferring wind energy at 345 kV, thus offloading the existing 230 kV circuits.

Brookings to Twin Cities

In addition to transferring wind from North Dakota, this new 345 kV line helps transfer additional southwestern Minnesota wind into Minneapolis-St. Paul. Through various transformations throughout the path, this circuit provides on and off ramps for power transfer.

North LaCrosse to North Madison to Cardinal

This new transmission, a continuation of the northern 345 kV path, connects the North Lacrosse station at the Minnesota-Wisconsin border into the Madison load center.

Pleasant Prairie to Zion Energy Center

Creating a new tie line between American Transmission Company (ATC) and Commonwealth Edison (ComEd), this new 345 kV circuit provides an outlet for southeast Wisconsin generation noted in the near term assessment, in addition to allowing wind energy transfer from the Dakotas and Minnesota.

Lakefield to Winnebago to Winco-Burt, Lime Creek to Emery to Blackhawk to Hazleton, Sheldon to Burt to Webster 345kV

These lines facilitate transfer of wind from MISO's West Region closer to large load centers in Illinois and Wisconsin by connecting existing wind heavy areas around Lakefield and Sheldon, and further accessing wind in central Iowa from the Lime Creek area to Hazleton. It provides on and off ramps for power transfer through intermediate transformations.

Dubuque County to Spring Green to Cardinal and Oak Grove to Galesburg to Fargo

Both projects, one connecting to Madison, Wisconsin; and the other to the northern Illinois station at Fargo, provide an outlet for the Western Region wind and connections to load centers. The two projects also help offload transmission constraints out of the Quad Cities Station.

Ottumwa to Adair to Palmyra Tap

This new line provides an outlet for a wind zone in Missouri, and offloads transmission constraints driven through transfers between Iowa and Illinois.

Palmyra Tap to Pawnee to Sugar Creek

This 300 mile line connects Palmyra Tap station at the Missouri-Illinois border to Sugar Creek at the Illinois-Indiana border. The project helps facilitate wind energy transfer between MISO's West and East planning regions.

Sidney to Rising

This new line helps offload underlying transmission and facilitates power transfer between Illinois and Indiana by closing a short electrical distance between two existing 345 stations, providing increased reliability between the states.

Reynolds to Hiple

This new circuit offloads the existing 138 kV parallel circuits by connecting Reynolds station in Indiana's wind heavy Tippecanoe County to Hiple in northeast Indiana.

Reynolds to Greentown

This 765 kV circuit helps further offload existing transmission by creating a new 765 kV station at Reynolds and transferring wind to the closest existing 765 kV station at Greentown. The circuit significantly reduces loadings on 138 kV as well as 345 kV transmission network in Indiana.

6.1 Reliability analysis results

The results of MTEP11 Reliability Analyses are included in Appendix D.2–D.8 and posted at the Midwest ISO File Transfer Protocol (FTP) site at ftp://mtep.midwestiso.org/mtep11/. MISO Planning Regions are separated into West, Central and East. Refer to Table 6.1-1-2 on the following pages, which shows generation, load, losses and interchange modeled in each of the five planning models used in MTEP11 Reliability Analysis.

Planning Region	BA Name	2013 Summer Peak			
		Generation	Load	Loss	Interchange
East	NIPSCO	3,149	3,716	50	-617
	METC	12,730	9,722	317	2,691
	ITCT	10,017	10,883	218	-1,084
Central	HE	1,249	827	34	388
	DEI	6,716	7,980	307	-1,577
	Vectren	1,561	1,708	22	-169
	DEO&K	4,656	5,561	133	-1,042
	IP&L	3,371	3,312	72	-17
	BREC	1,660	1,638	10	11
	CWLD	28	266	1	-239
	AmerenMO	9,350	9,251	148	-49
	AmerenIL	9,948	9,867	186	-104
	CWLP	562	330	3	230
	SIPC	256	345	5	-94
West	WEC	7,208	7,067	142	-9
	XEL	8,704	10,277	267	-1,846
	MP	2,632	1,465	77	1,090
	SMMPA	176	556	1	-381
	GRE	2,960	2,787	87	83

MISO

Planning Region	BA Name	2013 Summer Peak			
		Generation	Load	Loss	Interchange
	OTP	1,250	1,702	74	-527
	ALTW	4,056	3,895	73	88
	MPW	242	161	1	80
	MEC	6,294	4,716	93	1,485
	MDU	161	548	9	-395
	DPC	1,215	926	62	228
	ALTE	2,710	2,540	92	75
	WPS	2,164	2,782	71	-691
	MGE	260	795	12	-547
	UPPC	34	224	16	-206

Table 6.1–1: Near term model (2013) generation, load, losses and interchange results by balancing area

Planning Region	BA Name	2016 Summer Peak				2016 Shoulder Peak				2016 Light Load			
		Generation	Load	Loss	Interchange	Generation	Load	Loss	Interchange	Generation	Load	Loss	Interchange
East	NIPSCO	3,150	3,837	52	-739	1,436	2,953	49	-1,565	2,003	2,092	36	-126
	METC	12,806	9,971	299	2,537	7,827	8,351	231	-756	2,347	3,602	126	-1,381
	ITCT	11,853	11,165	236	452	11,584	9,475	235	1,874	5,161	3,908	119	1,135
Central	HE	1,443	827	40	576	1,207	827	28	352	1,625	827	25	773
	DEI	6,846	8,138	307	-1,606	4,863	5,972	185	-1,301	3,485	3,803	82	-408
	Vectren	1,591	1,708	22	-139	899	1,708	26	-835	1,747	1,708	21	19
	DEO&K	4,656	5,569	130	-1,047	3,946	4,040	76	-174	3,169	2,514	42	609
	IP&L	3,415	3,456	73	-118	2,218	2,417	50	-253	1,179	1,174	16	-15
	BREC	1,719	1,671	12	37	1,259	1,473	12	-225	1,449	1,451	13	-15
	CWLD	30	351	3	-325	30	254	2	-225	24	173	1	-150
	AmerenMO	9,513	9,351	172	-10	6,806	7,510	134	-838	7,258	7,456	113	-312
	AmerenIL	10,905	9,988	221	696	10,623	7,986	168	2,468	8,847	8,170	131	546
	CWLP	561	330	3	228	562	330	3	229	330	330	1	-2
	SIPC	253	362	5	-114	247	262	5	-19	154	133	2	19
West	WEC	7,752	7,300	145	298	6,128	5,300	108	712	2,525	3,281	69	-834
	XEL	8,426	10,602	255	-2,437	6,977	7,471	233	-733	5,005	5,392	221	-614

Planning Region	BA Name	2016 Summer Peak				2016 Shoulder Peak				2016 Light Load			
		Generation	Load	Loss	Interchange	Generation	Load	Loss	Interchange	Generation	Load	Loss	Interchange
	MP	2,594	1,525	44	1,018	1,907	1,414	39	416	1,742	1,296	82	372
	SMMPA	185	676	1	-492	43	484	1	-436	22	347	1	-325
	GRE	3,001	2,960	39	-51	1,996	2,074	23	-155	997	1,252	26	-285
	OTP	1,241	1,429	81	-270	1,032	1,016	80	-65	1,198	1,037	74	84
	ALTW	4,307	4,048	81	178	4,697	2,950	97	1,649	2,998	2,926	130	-58
	MPW	247	165	1	81	273	127	1	145	63	98	1	-36
	MEC	6,319	5,427	101	791	4,523	3,848	77	591	2,380	2,036	82	262
	MDU	188	575	9	-396	134	410	6	-283	152	292	7	-147
	DPC	1,187	1,027	60	100	561	752	41	-232	319	478	32	-192
	ALTE	2,892	2,654	87	148	2,033	1,940	64	27	1,524	1,233	37	251
	WPS	2,522	2,829	68	-377	2,603	2,143	57	402	1,789	1,328	41	418
	MGE	288	830	12	-555	10	583	11	-585	40	341	6	-308
	UPPC	35	227	14	-207	29	174	8	-152	25	116	2	-94

Table 6.1–2: Generation, load, losses and interchange results by balancing authority

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Long term models

Planning Region	BA Name	2021 Summer Peak				2021 Shoulder Peak			
		Generation	Load	Loss	Interchange	Generation	Load	Loss	Interchange
East	NIPSCO	3,027	4,006	70	-1,049	1,851	4,006	81	-1,206
	METC	12,419	10,368	332	1,720	6,885	10,368	251	-1,074
	ITCT	11,370	11,744	248	-622	9,895	11,744	186	979
Central	HE	1,553	827	32	693	972	827	24	333
	DEI	7,118	6,299	256	557	4,128	6,299	226	-2,257
	Vectren	1,590	1,708	24	-142	1,235	1,708	15	-51
	DEO&K	4,426	5,200	127	-905	3,429	5,200	99	-657
	IP&L	3,247	3,684	70	-511	2,081	3,684	53	-715
	BREC	1,668	1,789	10	-132	1,307	1,789	8	-31
	CWLD	85	266	1	-182	70	266	1	-129
	AmerenMO	9,495	9,042	184	270	6,925	9,042	157	-1,200
	AmerenIL	11,469	10,635	257	577	9,939	10,635	216	1,436
	CWLP	669	330	2	336	444	330	2	197
	SIPC	277	380	6	-109	226	380	5	-62
West	WEC	7,129	7,632	154	-666	5,559	7,632	130	-124
	XEL	8,521	11,186	344	-3,015	7,542	11,186	478	-1,257

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Planning Region	BA Name	2021 Summer Peak				2021 Shoulder Peak			
		Generation	Load	Loss	Interchange	Generation	Load	Loss	Interchange
	MP	2,538	1,643	95	800	2,066	1,643	84	760
	SMMPA	176	754	1	-580	99	754	1	-464
	GRE	2,793	3,199	95	-504	1,951	3,199	82	-511
	OTP	1,595	1,575	80	-61	2,256	1,575	113	966
	ALTW	4,382	4,276	102	4	5,352	4,276	148	2,024
	MPW	273	170	2	102	222	170	1	90
	MEC	6,253	5,670	106	477	6,906	5,670	146	2,516
	MDU	250	618	9	-378	427	618	9	-42
	DPC	1,148	1,105	59	-16	830	1,105	70	-61
	ALTE	3,420	2,833	92	492	1,876	2,833	87	-283
	WPS	2,486	2,910	64	-490	2,538	2,910	77	258
	MGE	385	899	12	-527	96	899	24	-560
	UPPC	30	228	7	-205	29	228	3	-147

Table 6.1–3: Long term model generation, load, losses and interchange results by balancing authority

6.2 Steady state analysis results

MTEP11 Appendix E1.1.4 lists contingencies tested in steady state analysis. Contingencies were simulated in MTEP11 2013 summer peak, 2016 summer peak, shoulder peak and light load, 2021 summer peak and shoulder peak models. All steady state analysis-identified constraints and associated mitigations are tabulated in results tables in MTEP11 Appendix D.3.

6.3 Voltage stability analysis results

MTEP11 Appendix E1.1.1 lists types of transfers tested in voltage stability analysis. The study did not find low voltage areas or voltage collapse points for critical contingencies in transfer scenarios close to the base load levels modeled in the MTEP11 2016 summer peak and shoulder peak models. A summary report with associated p-v plots is documented in MTEP11 Appendix D.4.

6.4 Dynamic stability analysis results

MTEP11 Appendix E1.1.4 lists types of disturbances tested in dynamic stability analysis. Disturbances were simulated in MTEP11 2016 light load and shoulder peak load models. The system was stable. Results tables listing all simulated disturbances along with damping ratios are tabulated in MTEP11 Appendix D.5.

6.5 Generator deliverability analysis results

Generator deliverability analysis was performed in MTEP11 to ensure continued deliverability of aggregate deliverable network resources. A total of 370 MW of deliverability is restricted due to constraints identified in MTEP11. These constraints have not been planned for in the current MTEP cycle and will be investigated in the subsequent MTEP cycle (MTEP12). This compares to more than 900 MW in MTEP10 and more than 3,000 MW of restricted deliverability in MTEP09. This progressive reduction in restricted deliverability has been accomplished through planned upgrades in past MTEP cycles.

MTEP10 Deliverability Constraint	Total Generation Restricted	Percentage of MWs Impacted	Rating (MVA)	Percent Overload	MTEP Project ID	Target Appendix MTEP11
Boone Jct.--Ft. Dodge 161 kV line	226	23 percent	147	115.8	2941	C
East Calamus--Grand Mound 161 kV line	237	24 percent	176	112.8	1619	In Service in MTEP11, A in MTEP08

Table 6.5-1: The list of mitigations for the outstanding constraints from MTEP10 that were proven effective

The description of table 6.5-2 column headings is below.

- An Overload Branch is caused by "bottling-up" of aggregate deliverable generation. Deliverability was tested only up to the granted NR (Network Resource) levels of the existing and future NR units modeled in the MTE11 2016 case.
- Use the Map ID to find an approximate location of the overloaded element on Fig. 6.5-1
- Contingency is the outage created in the overload. In some cases, the system may be system intact, so there is no outage. Detailed contingency definitions are included in the Appendix.
- Rating is the rating of the overloaded element used in the analysis. It's normal if the system is intact, but an emergency for post contingent constrained branches.
- Delta Increase is the difference in loading after ramping up generation compared to before ramping up of generation in the "gen pocket."

Overloaded Branch	Area	Map ID	Contingency	Rating (MVA)	Delta Increase
Wilmarth to Swan Lake 115 kV line	XEL	1	Wilmarth to Helena 345 kV line	110	19.19 percent
Wilmarth to Eastwood 115 kV line	XEL	1	Wilmarth to Summit 115 kV line	190.8	4.59 percent
Medford Jct. to Waseca Junction 69 kV line	ALTW	1	Loon Lake to Loon Lake Tap 115 kV line	30	8.23 percent
Turkey Hill 345/138 kV transformer[34]	AMIL	2	C-BLWN-4511 Caokia 345/138 kV transformer Cahokia to Baldwin 345 kV line	672	1.81 percent

Table 6.5-2: The MTEP11 constraints that limit deliverability of about 370 MW of Network Resources. See Appendix D6 for the detailed results with a list of impacted Network Resources.

[34] The Turkey Hill 345/138 kV transformer has a MTEP Appendix C project 3001 that will mitigate the deliverability constraint. Projects targeted as mitigation for deliverability constraints will be moved to Appendix B.

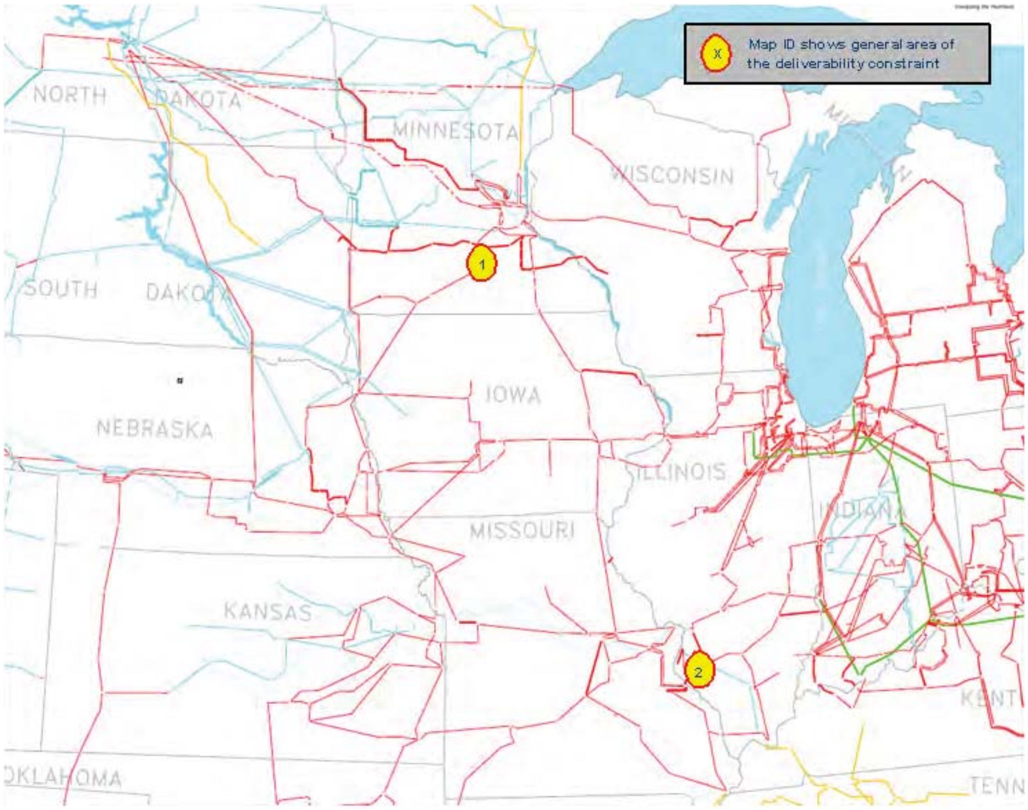

Figure 6.5-1: General location of MTEP11 2016 SUPK baseline generator deliverability constraints

MISO will create a Technical Review Group of stakeholders to address generator deliverability issues in the MTEP12 planning cycle.

6.6 Long Term Transmission Rights (LTTR)

This section documents planned upgrades to address constraints driving infeasibility of Long Term Transmission Rights. Refer to Table 6.6-1, which shows the uplift costs associated with the infeasible LTTRs in the 2011 Annual Allocation.

Year	Total Stage1A (GW)	Total LTTR Payment ($M)	Total Infeasible Uplift ($M)	Uplift Ratio
2011 Allocation	354.3	211.2	7.6	3.60 percent

Table 6.6-1: Uplift costs associated with infeasible LTTR in the 2010 annual allocation

Refer to Table 6.6-2, which further details the infeasible uplift to binding constraints from the annual auction. Binding constraints are filtered for those with values greater than $75,000. Planned mitigations have been documented against constraints where future proposed or planned upgrades have already been identified through other planning studies. MISO constraints with no identified plans in the current planning cycle result in uplift of less than $600 thousand or less than 10 percent. MISO will coordinate with its Transmission Owners on investigation of these constraints in MTEP12 planning cycle. Additionally, MISO will coordinate with adjacent RTOs on seams constraints.

Constraint	Summer 2011	Fall 2011	Winter 2011	Spring 2012	Grand Total	Planned Mitigation
'3442' (Rising 345/138 TR1 (flo) Dresden - Pontiac 345kV)	$0	$1,160,037	$245,685	$0	$1,405,721	P2239 Rising to Sidney 345kV CMVP Line ISD: 11/15/2016
'3191' (IP Rising 345/138 XFMR 1 (flo) Clinton - Brokaw 345 (IP4535))	$661,750	$0	$0	$0	$661,750	P2239 Rising to Sidney 345kV CMVP Line ISD: 11/15/2016
FOX_LK 500 161 kV to RUTLAND 500 161 kV	$93,517	$362,743	$0	$12,870	$469,130	3205 Lakefield-Burt & Sheldon-Webster 345 kV line 3213 Candidate MVP Portfolio 1 - Winco to Hazleton 345 kV
'3570' (Pleasant Prairie-Zion Energy Center 345 flo Cherry Valley-Silver Lake 345 R)	$8,163	$217,895	$317	$5,725	$232,100	P2844 Pleasant Prairie - Zion Energy Center CMVP ISD: 3/6/2014 and P3022 Oak Grove Galesburg- Fargo CMVP ISD: 11/15/2018

Constraint	Summer 2011	Fall 2011	Winter 2011	Spring 2012	Grand Total	Planned Mitigation
'3451' (Edwards-Kewanee (CE) 138kV (flo) Powerton-Goodings Gr (R)+Powerton (R)-Powerton (B) 345kV)	$230,959	$0	$0	$0	$230,959	Palmyra Tap – Meredosia – Pawnee + Meredosia – Ipava CMVP Line ISD: 11/15/2016 and 11/15/2017
CEDAR_RG 3 138 kV to OHMSTEAD 1 138 kV	($153)	$211,978	$2,702	($495)	$214,033	no planned upgrade
LUCAS 358 161 kV to LUCAS 369 69.0 kV	$79,263	$47,607	$0	$79,263	$206,134	P3170 CMVP line from Ottumwa – Adair – Palmyra Tap – Thomas Hill ISD: 11/15/2018
'3443' (Coffeen North-Ramsey 345kV (flo) Praire State-W Mt Vernon 345kV + W Mt Vernon 345/138kV TR4)	$0	$197,097	$0	$0	$197,097	P2237, P2238 and P2240 CMVP line from Pana to Mount Zion to Kansas to Sugar Creek 345 kV ISD: 11/15/2018 and 11/15/2019
'3180' (W. Mt. Vernon-E. W. Frankfort 345 (flo) St. Francois-Lutesville 345)	$7,438	$174,845	$0	$0	$182,282	P2295 Upgrade terminal equipment on W. Mt. Vernon-E. W. Frankfort 345 kV ISD: 6/1/2015
'6214' (Bunge-Hastings 161 kV flo Cooper-St. Joe 345 kV)	$58,400	$79,302	$37,151	($264)	$174,589	No MISO planned upgrade
'3771' (Pleasant Prairie - Zion 345kV)	($188)	$172,630	$0	($2,460)	$169,982	P2844 Pleasant Prairie - Zion Energy Center CMVP ISD: 3/6/2014 and P3022 Oak Grove-Galesburg - Fargo CMVP ISD: 11/15/2018
RICH2 4 230 kV to ROSEAUMP 400 230 kV	$22,475	$100,784	$0	$23,259	$146,518	Manitoba Constraint
'3646' (Nucor-Whitestown 345kV (flo) Rockport-Jefferson 765kV)	$0	$107,761	$17,251	$0	$125,012	P3203 Reynolds to Greentown 345kV CMVP ISD: 12/31/2013

Constraint	Summer 2011	Fall 2011	Winter 2011	Spring 2012	Grand Total	Planned Mitigation
'3737' (Alliat Hills 345/161 Xfmr flo Tiffin-Duane Arnold 345 + Tiffin-Hills 345)	$0	$99,826	$22,465	$0	$122,291	P1344 Build a new 345 kV Morgan Valley (Beverly) substation which taps the Arnold - Tiffin 345 kV line ISD: 12/31/2014
'6061' (Richer -- Roseau 230kV line (R50M))	$0	$113,054	$0	$0	$113,054	Manitoba Constraint
'2571' (Marktown - Inland Steel 5 138kV (flo) Burnham - Munster 345kV)	$0	$104,875	$6,743	$0	$111,618	P2792 Northwest Circuit reconfiguration ISD: 12/1/2013
WINBALTW 572 69.0 kV to DELEAST 794 69.0 kV	$8,288	$0	$0	$102,475	$110,762	no planned upgrade
ROSEAUMP 400 230 kV to MORNVLL 400 230 kV	$48,038	$30,945	$9,035	$21,987	$110,005	Manitoba Constraint
KANSAS00 HAB 138 kV to HARBOR01 4 138 kV	$0	$96,544	$5,946	$0	$102,489	Manitoba Constraint
'1613' (Volunteer - Phipps Bend 500)	$14,828	$101,497	($20,853)	$5,282	$100,754	TVA Constraint
'549' (Dresden-Elwood 1222 345 kV l/o Dresden-Electric 1223 345 kV)	$100,293	$0	$434	$0	$100,727	PJM Constraint
'3312' (Lanesville 345/138kV Xfmr (flo) Lanesville - Brokaw - Pontiac 345kV)	$28,717	$31,182	$33,304	$0	$93,203	P2236, P2237, P2238 345kV loop around area including additional 345/138kV transformers.
'2497' (State Line-Wolf Lake 138)	$0	$90,273	$0	$0	$90,273	P2792 Northwest Circuit reconfiguration ISD: 12/1/2013
'6124' (Sub K/Tiffin-Arnold 345kV)	$84,536	$0	$0	$4,922	$89,459	P3022 Oak Grove Galesburg- Fargo 345kV CMVP line ISD: 6/1/2016 and P3127 Dubuque - Cardinal 345kV CMVP line ISD: 12/31/2020

Constraint	Summer 2011	Fall 2011	Winter 2011	Spring 2012	Grand Total	Planned Mitigation
'3353' (Lanesville 345/138 (flo) Kincaid - Pawnee 345 + 2106 SPS)	$81,727	($14,531)	$16,830	$0	$84,026	P2236, P2237, P2238 345kV loop around area including additional 345/138kV transformers.
6007' (GENTLMN3 345 REDWILO3 345 1)	($270)	$96,112	($14,467)	($639)	$80,737	MRO Contraint
'2336' (BentnHrbr-Palisades345/Cook-Palisades345)	$0	$76,971	$0	$0	$76,971	no planned upgrade

Table 6.6-2: Infeasible uplift to binding constraints from the annual auction

Appendices

Most MTEP11 appendices are available and accessible on the MISO public webpage. Confidential appendices, such as D.2 - D.8, are available on the MISO MTEP11 FTP site. Access to the FTP site requires an id and password.

A link to the MTEP11 appendices, on the MISO public website, is below:

https://www.midwestiso.org/Library/Pages/ManagedFileSet.aspx?SetId=694

The confidential appendices are located at:

ftp://mtep.midwestiso.org/mtep11/

- **Appendix A: Projects recommended for approval**
  - Section A.1, A.2, A.3: Cost allocations
  - Section A.4: MTEP11 Appendix A new projects
- **Appendix B: Projects with documented need & effectiveness**
- **Appendix C: Projects in review and conceptual projects**
- **Appendix D: Reliability studies analytical details with mitigation plan (ftp site)**
  - Section D.1: Project justification
  - Section D.2: Modeling documentation
  - Section D.3: Steady state
  - Section D.4: Voltage stability
  - Section D.5: Transient stability
  - Section D.6: Generator deliverability
  - Section D.7: Contingency coverage
  - Section D.8: Nuclear plant assessment
- **Appendix E: Additional MTEP11 Study support**
  - Section E.1: Reliability planning methodology
  - Section E.2: Generations futures development
  - Section E.3: MTEP11 futures retail rate impact methodology
  - Section E.4: Proposed MVP portfolio steady state and stability results
  - Section E.5: Proposed MVP portfolio business case presentation
  - Section E.6: Resource assessment results
- **Appendix F: Stakeholder substantive comments**

APPENDIX C

AGENCY MATERIAL CORRESPONDENCE

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In addition to informal communication, the following table is a summary of significant communication with federal, state, and local agencies and Tribes.

Table 1. Agency Coordination Dates and Events

Agency	Date	Event
Federal		
Bureau of Indian Affairs	7/27/2012	Project notification letter mailed
	8/7/2012	Meeting with BSSE project team
	9/25/2012	Project update – corridor notification letter mailed
	2/5/2013	Project update – preliminary route notification mailed
	5/6/2013	Preferred route notification letter sent
	5/23/2013	Preferred route response
Federal Aviation Administration	7/27/2012	Project notification letter mailed
	9/20/2012	Response received from FAA
	9/25/2012	Project update – corridor notification letter mailed
	12/18/2012	Response from FAA regarding BSSE project mailing. List criteria and procedures required if siting near a public or military airport.
	2/5/2013	Project update – preliminary route notification mailed
	5/6/2013	Preferred route notification letter sent
		No preferred route letter response received
Federal Highway Administration, South Dakota Office	7/27/2012	Project notification letter mailed
	9/25/2012	Project update – corridor notification letter mailed
	1/24/2013	Letter and meeting minutes from 1/16/2013 South Dakota interagency meeting sent
	2/5/2013	Project update – preliminary route notification mailed
	5/6/2013	Preferred route notification letter sent
	5/13/2013	Preferred route response
National Park Service	7/27/2012	Project notification letter mailed
	9/25/2012	Project update – corridor notification letter mailed
	1/24/2013	Letter and meeting minutes from SD agency meeting sent
	2/5/2013	Project update – preliminary route notification mailed
	5/6/2013	Preferred route notification letter sent
	7/10/2013	Preferred route response

Agency	Date	Event
Natural Resources Conservation Service	7/27/2012	Project notification letter mailed
	9/25/2012	Project update – corridor notification letter mailed
	1/24/2013	Letter and meeting minutes from 1/16/2013 SD agency meeting sent
	2/5/2013	Project update – preliminary route notification mailed
	3/22/2013	Email response from NRCS concerning WRP easement along James River
	5/6/2013	Preferred route notification letter sent
	5/23/2013	Response to preferred route
United States Army Corps of Engineers – South Dakota Office	7/27/2012	Project notification letter mailed
	8/13/2012	Project response letter
	8/28/2012	Attendance at interagency meeting for initial suggestions, concerns and overall feedback
	9/25/2012	Project update – corridor notification letter mailed
	1/16/2013	Attendance at South Dakota interagency meeting to provide information on preliminary routes
	1/24/2013	Letter and meeting minutes from SD agency meeting sent
	2/5/2013	Project update – preliminary route notification mailed
	2/6/2013	Email from USACE outlining environmental policies/procedures overseen by their agency
	2/13/2013	Letter from USACE concerning Section 10 waters permit guidelines
	5/6/2013	Preferred route notification letter sent
	7/9/2013	Phone conversation stating that previous guidelines sent in 2/13/2013 letter still apply to preferred route
United States Department of Agriculture Rural Development	7/27/2012	Project notification letter mailed
	9/25/2012	Project update – corridor notification letter mailed
	2/5/2013	Project update – preliminary route notification mailed
	5/6/2013	Preferred route notification letter sent
		No preferred route letter response received
United States Department of Interior, Bureau of Reclamation	7/27/2012	Project notification letter mailed
	9/25/2012	Project update – corridor notification letter mailed
	2/5/2013	Project update – preliminary route notification mailed
	5/6/2013	Preferred route notification letter sent
		No preferred route letter response received

Agency	Date	Event
United States Fish and Wildlife Service – South Dakota Ecological Services, Sand Lake Wetland Management District (WMD) and Waubay Wetland Management District (WMD)	7/27/2012	Project notification letter mailed
	7/31/2012	Meeting with BSSE project team (Waubay WMD and Sand Lake WMD staff)
	8/7/2012	Response letter received from Ecological Services Office
	8/28/2012	Attendance at South Dakota interagency meeting for initial suggestions, concerns and overall feedback – Ecological Services and WMD staff
	9/25/2012	Project update – corridor notification letter mailed
	1/16/2013	Attendance at South Dakota interagency meeting to provide information on preliminary routes – Ecological Services and WMD staff
	1/24/2013	Letter and meeting minutes from SD agency meeting sent
	2/4/2013	Email from SD USFWS in response to interagency meeting follow up letter—concerns listing status of skipper species
	2/5/2013	Project update – preliminary route notification mailed
	3/13/2013	Phone conversation discussing when USFWS comments on preliminary route will be submitted to HDR, as well as discussion about NEPA review process for grassland easements.
	3/20/2013	Email comments on the transmission line route selection from USFWS
	5/6/2013	Preferred route notification letter sent
	6/6/2013 and 6/20/2013	Emails from USFWS Waubay WMD containing easement updates along preferred route
	7/24/2013	Preferred route response including comments on easements and listed species
United States Forest Service	7/27/2012	Project notification letter mailed
	9/25/2012	Project update – corridor notification letter mailed
	2/5/2013	Project update – preliminary route notification mailed
	5/6/2013	Preferred route notification letter sent
		No preferred route letter response received
United States Geological Survey	7/27/2012	Project notification letter mailed
	9/25/2012	Project update – corridor notification letter mailed
	2/5/2013	Project update – preliminary route notification mailed
	5/6/2013	Preferred route notification letter sent
		No preferred route letter response received

006873

Agency	Date	Event
Sisseton-Wahpeton Oyate THPO	7/27/2012	Project notification letter mailed
	9/25/2012	Project update – corridor notification letter mailed
	10/2/2012	BSSE project team agency meeting following study area being narrowed to corridors
	2/5/2013	Project update – preliminary route notification mailed
	2/8/2013	Meeting with THPO representatives to discuss preliminary routes
	3/29/2013	Email informing BSSE team the SWO THPO's preference for the Aberdeen route (which was subsequently carried forward as preferred route)
	5/6/2013	Preferred route notification letter sent
	5/7/2013	Meeting with THPO to discuss preferred route
	6/13/2013	Meeting with THPO to discuss preferred route and survey approach
Sisseton-Wahpeton Oyate Fish & Wildlife Office	5/8/2013	Meeting to discuss preferred route
State of South Dakota		
South Dakota Aeronautics Commission	7/27/2012	Project notification letter mailed
	9/25/2012	Project update – corridor notification letter mailed
	2/5/2013	Project update – preliminary route notification mailed
	5/6/2013	Preferred route notification letter sent
		No preferred route letter response received
South Dakota Bureau of Administration	7/27/2012	Project notification letter mailed
	9/25/2012	Project update – corridor notification letter mailed
	2/5/2013	Project update – preliminary route notification mailed
	5/6/2013	Preferred route notification letter sent
		No preferred route letter response received
South Dakota Bureau of Finance and Management	7/27/2012	Project notification letter mailed
	9/25/2012	Project update – corridor notification letter mailed
	2/5/2013	Project update – preliminary route notification mailed
	5/6/2013	Preferred route notification letter sent
		No preferred route letter response received

006874

Agency	Date	Event
South Dakota Department of Agriculture	7/27/2012	Project notification letter mailed
	8/16/2012	Email response received – no comments
	9/25/2012	Project update – corridor notification letter mailed
	1/16/2013	Attendance at South Dakota interagency meeting to provide information on preliminary routes
	1/24/2013	Letter and meeting minutes from SD agency meeting sent
	2/5/2013	Project update – preliminary route notification mailed
	5/6/2013	Preferred route notification letter sent
	7/8/2013	Preferred route response – no comments
South Dakota Department of Environmental and Natural Resources	7/27/2012	Project notification letter mailed
	8/15/2012	Response from SD DENR received
	9/25/2012	Project update – corridor notification letter mailed
	1/16/2013	Attendance at South Dakota interagency meeting to provide information on preliminary routes
	1/24/2013	Letter and meeting minutes from SD agency meeting sent
	2/5/2013	Project update – preliminary route notification mailed
	5/6/2013	Preferred route notification letter sent
	5/29/2013	Preferred route response – general comments
South Dakota Department of Game, Fish and Parks	7/27/2012	Project notification letter mailed
	8/14/2012	Response letter from SD GFP
	8/28/2012	Attendance at interagency meeting for initial suggestions, concerns and overall feedback
	9/25/2012	Project update – corridor notification letter mailed
	10/31/2012	Letter sent from SDGFP requesting shape files once corridors are refined further and routes developed.
	1/16/2013	Attendance at South Dakota interagency meeting to provide information on preliminary routes
	1/24/2013	Letter and meeting minutes from SD agency meeting sent
	2/5/2013	Project update – preliminary route notification mailed
	5/6/2013	Preferred route notification letter sent
	6/11/2013	Preferred route response

Agency	Date	Event
South Dakota Department of Health	7/27/2012	Project notification letter mailed
	9/25/2012	Project update – corridor notification letter mailed
	1/24/2013	Letter and meeting minutes from 1/16/2013 SD agency meeting sent
	2/5/2013	Project update – preliminary route notification mailed
	5/6/2013	Preferred route notification letter sent
		No preferred route letter response received
South Dakota Department of Public Safety, Office of Emergency Management	7/27/2012	Project notification letter mailed
	9/25/2012	Project update – corridor notification letter mailed
	2/5/2013	Project update – preliminary route notification mailed
	5/6/2013	Preferred route notification letter sent
		No preferred route letter response received
South Dakota Department of Transportation	7/27/2012	Project notification letter mailed
	8/28/2012	Attendance at South Dakota interagency meeting for initial suggestions, concerns and overall feedback
	9/25/2012	Project update – corridor notification letter mailed
	1/24/2013	Letter and meeting minutes from SD agency meeting sent
	2/5/2013	Project update – preliminary route notification mailed
	5/6/2013	Preferred route notification letter sent
		No preferred route letter response received
South Dakota Energy Infrastructure Authority	2/5/2013	Project update – preliminary route notification mailed
	5/6/2013	Preferred route notification letter sent
		No preferred route letter response received
South Dakota Farm Bureau	1/24/2013	Letter and meeting minutes from 1/16/2013 SD agency meeting sent
	2/5/2013	Project update – preliminary route notification mailed
	5/6/2013	Preferred route notification letter sent
South Dakota Geological Survey	7/27/2012	Project notification letter mailed
	9/25/2012	Project update – corridor notification letter mailed
	2/5/2013	Project update – preliminary route notification mailed
	5/6/2013	Preferred route notification letter sent
		No preferred route letter response received

Agency	Date	Event
South Dakota Office of Economic Development	7/27/2012	Project notification letter mailed
	9/25/2012	Project update – corridor notification letter mailed
	1/24/2013	Letter and meeting minutes from 1/16/2013 SD agency meeting sent
	2/5/2013	Project update – preliminary route notification mailed
	5/6/2013	Preferred route notification letter sent
		No preferred route letter response received
South Dakota Office of Emergency Management	7/27/2012	Project notification letter mailed
	8/9/2012	Response received – providing information on floodplain managers at county level
	2/5/2013	Project update – preliminary route notification mailed
	5/6/2013	Preferred route notification letter sent
South Dakota Office of Tribal Government Relations	7/27/2012	Project notification letter mailed
	9/25/2012	Project update – corridor notification letter mailed
	2/5/2013	Project update – preliminary route notification mailed
	5/6/2013	Preferred route notification letter sent
		No preferred route letter response received
South Dakota State Historic Preservation Office	7/27/2012	Project notification letter mailed
	8/13/2012	Response letter received
	8/28/2012	Attendance at South Dakota interagency meeting for initial suggestions, concerns and overall feedback on the project
	9/25/2012	Project update – corridor notification letter mailed
	1/16/2013	Attendance at South Dakota interagency meeting to provide information on preliminary routes
	1/24/2013	Letter and meeting minutes from SD agency meeting sent
	2/5/2013	Project update – preliminary route notification mailed
	5/6/2013	Preferred route notification letter sent
	6/13/2013	Meeting with SHPO and SWO THPO to discuss preferred route and survey approach
	7/23/2013	Level 1 Records Search report sent to SHPO
	7/30/2013	Letter response to Level I Records Search

Agency	Date	Event
Counties		
Brown County	7/27/2012	Project notification letter mailed
	8/29/2012	County meeting about routing considerations
	9/25/2012	Project update – corridor notification letter mailed
	1/28/2013	BSSE project team presented a routing process webinar
	2/5/2013	Project update – preliminary route notification mailed
	5/24/2013	Preferred route notification email sent
	5/30/2013	Phone conversation with Brown County
Clark County	7/27/2012	Project notification letter mailed
	8/28/2012	County meeting about routing considerations
	9/25/2012	Project update – corridor notification letter mailed
	2/5/2013	Project update – preliminary route notification mailed
	5/24/2013	Preferred route notification email sent
Codington County	7/27/2012	Project notification letter mailed
	8/29/2012	County meeting about routing considerations
	9/25/2012	Project update – corridor notification letter mailed
	2/5/2013	Project update – preliminary route notification mailed
	5/24/2013	Preferred route notification email sent
Day County	7/27/2012	Project notification letter mailed
	8/29/2012	County meeting about routing considerations
	9/25/2012	Project update – corridor notification letter mailed
	1/28/2013	BSSE project team presented a routing process webinar
	2/5/2013	Project update – preliminary route notification mailed
	4/26/2013	Letter from the Day County Auditor to HDR expressing three townships' opposition to the line
	5/24/2013	Preferred route notification email sent
	5/30/2013	Phone conversation with Day County
Deuel County	7/27/2012	Project notification letter mailed
	8/29/2012	County meeting about routing considerations
	9/25/2012	Project update – corridor notification letter mailed
	2/5/2013	Project update – preliminary route notification mailed
	5/24/2013	Preferred route notification email sent

Agency	Date	Event
Grant County	7/27/2012	Project notification letter mailed
	8/29/2012	County meeting about routing considerations
	9/25/2012	Project update – corridor notification letter mailed
	1/29/2013	BSSE project team presented a routing process webinar
	2/5/2013	Project update – preliminary route notification mailed
	5/24/2013	Preferred route notification email sent
	5/30/2013	Phone conversation with Grant County
Hamlin County	7/27/2012	Project notification letter mailed
	8/29/2012	County meeting about routing considerations
	9/25/2012	Project update – corridor notification letter mailed
	2/5/2013	Project update – preliminary route notification mailed
	5/24/2013	Preferred route notification email sent
Marshall County	7/27/2012	Project notification letter mailed
	8/30/2012	County meeting about routing considerations
	9/25/2012	Project update – corridor notification letter mailed
	1/29/2013	BSSE project team presented a routing process webinar
	2/5/2013	Project update – preliminary route notification mailed
	5/24/2013	Preferred route notification email sent
Roberts County	7/27/2012	Project notification letter mailed
	8/30/2012	County meeting about routing considerations
	9/25/2012	Project update – corridor notification letter mailed
	2/5/2013	Project update – preliminary route notification mailed
	5/24/2013	Preferred route notification email sent
Spink County	7/27/2012	Project notification letter mailed
	8/28/2012	County meeting about routing considerations
	9/25/2012	Project update – corridor notification letter mailed
	2/5/2013	Project update – preliminary route notification mailed
	5/24/2013	Preferred route notification email sent
Cities and Townships		
Notification letters were sent to 90 towns and cities, and 106 townships in South Dakota		

AGENCY LETTERS

July 27, 2012

Name

RE: Request for Information
Montana-Dakota Utilities Co. and Otter Tail Power Company
Proposed Big Stone South to Ellendale 345kV Transmission Line Project
North Dakota and South Dakota

Dear ,

(Intro Sentence) The project will require a *Transmission Facility Siting Permit* from the South Dakota Public Utilities Commission (PUC).

Montana-Dakota and Otter Tail Power Company plan to construct a 345kV transmission line in North Dakota and South Dakota and a new Ellendale 345kV Junction Substation in North Dakota. The transmission line will be approximately 150 to 175 miles long. We call it the Big Stone South to Ellendale (BSSE) Project. The transmission line will connect a new Ellendale 345kV Junction Substation, proposed to be located about 1.5 miles west of Ellendale in Dickey County, North Dakota to the proposed Big Stone South Substation, which is part of a separate project and is anticipated to be located near the Big Stone Plant at Big Stone City in Grant County, South Dakota. The Big Stone South Substation is proposed by the Big Stone South to Brookings Project and is not a part of the BSSE Project. The BSSE Project will increase the transfer capacity on the current transmission system, serve as a generation outlet, and add system reliability.

Because the project is in the preliminary planning stages, exact route alternatives have not yet been established. Our consultant, HDR Engineering, Inc. is gathering data to prepare the PUC Application. To assist in project siting and design, we are sending this letter to provide you with the opportunity to review the area. ***We are seeking any comments and supporting information relevant to the study area that would help identify opportunities and constraints for siting the proposed transmission line.*** You can see the project study area on the enclosed map.

To help us identify and evaluate potential resource issues that could be included in the corridor analysis and ultimately the PUC Application, which we expect to submit August 2013, please provide Chad Miller (contact information below) with any information pertaining to the BSSE Project by August 15, 2012.

Also, in the near future, Montana-Dakota and Otter Tail Power Company are planning to host a project information meeting in Pierre, SD or in the Project area. You may also want to attend to share any initial feedback on the project that you may have. Meeting information will be emailed to you or another person that you designate.

If you have questions or comments during your review, or if you would like a GIS file of the study area, please contact Chad Miller at (701) 222-7865 or chad.miller@mdu.com.

Sincerely,

Montana-Dakota Utilities Co.

Henry Ford
Project Developer

Otter Tail Power Company

Dean Pawlowski
Project Developer

Enclosures: Figure 1 - Study Area Map

Big Stone South to Ellendale

September 25, 2012

ADDRESS

RE: Project update with study corridors
Montana-Dakota Utilities Co. and Otter Tail Power Company
Proposed Big Stone South to Ellendale 345 kV Transmission Line Project

Dear,

This is an update on the Big Stone South to Ellendale transmission line project. You may recall that Montana-Dakota Utilities Co. and Otter Tail Power Company plan to construct a 345 kV transmission line approximately 150 miles to 175 miles long between a new Ellendale Junction substation, proposed to be located near Ellendale in Dickey County, North Dakota, and the proposed Big Stone South substation, which is part of a separate project and will be located near Big Stone City in Grant County, South Dakota. This transmission project will improve reliability, increase system capacity and support public policy by enabling renewable energy to integrate into the system.

Since you received our notification letter we have:

- Launched www.BSSEtransmissionline.com
- Established a toll-free information line at (886) 283-4678.
- Identified study corridors within the study area.

Our project team gathered input at meetings with federal, state, and local agencies on routing constraints and opportunities within the initial study area. This input along with field reviews, data available in the project area, and engineering factors helped to develop study corridors, which are indentified on the enclosed map. We evaluated the following criteria:

- Existing rights-of-way (transmission lines, pipelines, railway, or roads), survey lines, and natural division lines.
- Populated areas.
- High densities of environmental natural features.
- River crossing locations.
- Public and private airports.
- Length.

We are seeking information related to the study corridors to help us identify a location for the transmission line. If your jurisdiction is now outside the study corridors, we appreciate your feedback to date and we welcome any additional thoughts you have on the project development.

We will be hosting open house meetings at six locations throughout the study corridors the week of October 15, 2012. The following table provides detailed information for each of the open house meetings. You are welcome to attend and share your feedback with the project team.

Montana-Dakota Utilities Co. and Otter Tail Power Company
Big Stone South to Ellendale Project 345 kV Transmission Line

Monday, October 15	Tuesday, October 16	Wednesday, October 17	Thursday, October 18
5:00 – 7:00 pm **Wheaton Library Community Room** 901 1st Avenue North Wheaton, MN 56296	11:00 am – 1:00 pm **Milbank Visitor Center Community Room** 1001 East 4th Avenue Milbank, SD 57252	11:00 am – 1:00 pm **Dakota Event Center** 720 Lamont Street Aberdeen, SD 57401	11:00 am – 1:00 pm **Marshall County Meeting Room** 909 South Main Street Britton, SD 57430
	5:00 – 7:00 pm **The Galley** 230 Highway 12 Webster, SD 57274	5:00 – 7:00 pm **Fireside Restaurant & Lounge** 415 1st Avenue North Ellendale, ND 58436	

We appreciate your ongoing participation in this project and look forward to continuing to work with you. If you have questions, comments, feedback or would like a GIS file of the study corridors, please contact Chad Miller at (701) 222-7865 or chad.miller@mdu.com.

Chad Miller
Montana Dakota Utilities Co.
400 North Fourth Street
Bismarck, ND 58501-4092

Sincerely,

Montana-Dakota Utilities Co.

Henry Ford
Project Developer

Otter Tail Power Company

Dean Pawlowski
Project Developer

Enclosures: Figure 1 - Study Corridors Map

February 5, 2013

ADDRESS

RE: Project Update with Preliminary Routes
Montana-Dakota Utilities Co. and Otter Tail Power Company
Proposed Big Stone South to Ellendale 345 kV Transmission Line Project

Dear,

Montana-Dakota Utilities Co. and Otter Tail Power Company will hold public meetings the week of February 25, 2013, to obtain feedback on the preliminary routes for the Big Stone South to Ellendale 345 kV transmission line project. As you may recall, the project consists of a proposed 345 kV transmission line that will be 150 miles to 175 miles long. The project will be located between the proposed Ellendale Junction substation, which would be located near Ellendale in Dickey County, North Dakota, and the proposed Big Stone South substation, which is part of a separate project and will be located near Big Stone City in Grant County, South Dakota. Construction of this project will improve reliability, increase system capacity and support public policy by enabling renewable energy to integrate into the system. You can find more information by visiting www.BSSEtransmissionline.com or by calling our toll-free information line at (888) 283-4678.

In October 2012, the project team gathered input from federal, state, and local agencies and the public at open house meetings within the initial study area and study corridors. This input along with field reviews, data available in the project area, and engineering factors helped to develop preliminary routes, identified on the enclosed map. The preliminary routes minimize effects upon constraints within the corridors and are the focus of route development. We evaluated the following criteria to identify the preliminary routes:

- Existing rights-of-way (transmission lines, pipelines, railway, or roads), survey lines, and natural division lines
- Populated areas
- High densities of environmental natural features
- River crossing locations
- Public and private airports
- Length

Now we are seeking information related to the preliminary routes and encourage you to attend one of our upcoming meetings. If your jurisdiction is now outside of the updated study corridors that the preliminary routes are located within (see enclosed map), you may not want to continue to provide feedback. If so, we understand and thank you for your earlier involvement. If not, we welcome your continued participation, knowing that we currently are not reviewing route options outside of the updated study corridors.

The project team will hold open house meetings at five locations during the week of February 25, 2013. These meetings will include a brief presentation followed by an open house format during which attendees may review maps and talk with project specialists. You are welcome to attend and share your ideas with the project team.

<table>
<tr><th>Monday, February 25</th><th>Tuesday, February 26</th><th>Wednesday, February 27</th></tr>
<tr><td rowspan="2">Groton Area School
5:30 – 7:00 pm
Presentation at 6:00 pm
Groton, SD</td><td>Fireside Restaurant and Lounge
11:30 am – 1:00 pm
Presentation at 12:00 pm
Ellendale, ND</td><td>The Galley
11:30 am – 1:00 pm
Presentation at 12:00 pm
Webster, SD</td></tr>
<tr><td>Amacher Auditorium
5:30 – 7:00 pm
Presentation at 6:00 pm
Britton, SD</td><td>Milbank Visitor Center
5:30 – 7:00 pm
Presentation at 6:00 pm
Milbank, SD</td></tr>
</table>

We appreciate your ongoing participation in this project and look forward to continuing to work with you. If you have questions, comments or feedback, please contact Chad Miller at (701) 222-7865 or chad.miller@mdu.com or mail him at:

Chad Miller
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, ND 58501-4092

Sincerely,

Montana-Dakota Utilities Co.

Henry Ford
Project Developer

Otter Tail Power Company

Dean Pawlowski
Project Developer

Enclosures: Preliminary Routes Map

May 6, 2013

ADDRESS

RE: Project Update with Preferred Route
Montana-Dakota Utilities Co. and Otter Tail Power Company
Proposed Big Stone South to Ellendale 345 kV Transmission Line Project

Dear NAME,

Montana-Dakota Utilities Co. and Otter Tail Power Company have selected a preferred route for the proposed Big Stone South to Ellendale 345 kV transmission line project. As you may recall, the line will be 160 miles to 170 miles long and will be routed between a new substation to be located near Ellendale in Dickey County, North Dakota, and Big Stone South substation, which is part of a separate project and will be located near Big Stone City in Grant County, South Dakota. The Mid-Continent Independent System Operator (MISO, formally Midwest Independent Transmission System Operator) identified the need for this transmission line to improve reliability, increase electric system capacity and support public policy by enabling renewable and other forms of energy to integrate into the electric system. You can find more information by visiting www.BSSEtransmissionline.com, calling our toll-free information line at (888) 283-4678, or contacting Chad Miller (information below).

In January, February and March 2013, we gathered input from tribal, federal, state, and local agencies and the public. We discussed routing constraints and opportunities near preliminary routes. Using this input, along with environmental and engineering considerations, the project team developed the preferred route. (See enclosed map. Please note three areas on the map called Additional Route Segments where the project team has not yet identified the preferred route.)

We evaluated the following criteria to identify the preferred route:

- Existing rights-of-way (transmission lines, pipelines, railway, or roads), survey lines, and natural division lines
- Populated areas
- High densities of important natural features
- High densities of cultural properties and sensitive traditional areas
- River crossing locations
- Public and private airports
- Length
- Input from agencies and landowners
- Input from tribes

The project is seeking comments related to the preferred route. If your jurisdiction is now outside of the preferred route, we appreciate your input to date. We are no longer reviewing route options outside of the preferred route; however, you are welcome to continue to provide feedback if you have thoughts on the project. For agencies with jurisdiction or interests within the preferred route, we are requesting comments on any permits or approvals that may be necessary or any other feedback that may affect the design, construction or schedule of the Project. Particularly, Insert agency-specific language here.

Please note that Montana-Dakota Utilities Co. and Otter Tail Power Company will be finalizing the route details in the next month in order to submit state routing permit applications in late summer 2013. Therefore, we request response from your office within 30 days of receipt of this letter so that, where feasible and appropriate, we may incorporate them into the application materials and route design. We appreciate your ongoing participation in this project and look forward to continuing to work with you. If you have questions, comments or feedback, please contact Chad Miller at (701) 222-7865, chad.miller@mdu.com, or by mail at the address below.

Chad Miller
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, ND 58501-4092

Sincerely,

Montana-Dakota Utilities Co.

Henry Ford
Project Developer

Otter Tail Power Company

Dean Pawlowski
Project Developer

Enclosures: Preferred Route Map

AGENCY RESPONSES

United States Department of the Interior

BUREAU OF INDIAN AFFAIRS
Great Plains Regional Office
115 Fourth Avenue S.E., Suite 400
Aberdeen, South Dakota 57401

IN REPLY REFER TO:
DESCRM
MC-208

MAY 17 2013

Chad Miller
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, North Dakota 58501-4092

Dear Mr. Miller:

We received your letter regarding the proposed Big Stone South to Ellendale 345 kV Transmission Line Project. We have considered the potential for both environmental damage and impacts to archaeological and Native American religious sites on lands held in trust by the Bureau of Indian Affairs, Great Plains Region. You should be aware, however, that Tribes or Tribal members may have lands in fee status near the site of interest. These lands would not necessarily be in our databases, and the Tribes should be contacted directly to ensure all concerns are recognized. The action considered has the following notification date and project location:

- May 6, 2013 RE: Project Update with Preferred Route
  Montana-Dakota Utilities Co. and Otter Tail Power Company
  Proposed Big Stone South to Ellendale 345kV Transmission Line Project

We have no environmental objections to this action as long as the project complies with all pertinent laws and regulations. Questions regarding environmental opinions and conditions can be addressed to Jeffrey Davis, Environmental Protection Specialist, at (605) 226-7656.

We also find that the listed action will not affect cultural resources on Tribal or individual landholdings for which we are responsible. Methodologies for the treatment of cultural resources now known or yet to be discovered – particularly human remains – must nevertheless utilize the best available science in accordance with provisions of the Native American Graves Protection and Repatriation Act, the Archaeological Resources Protection Act of 1979 (as amended), and all other pertinent legislation and implementing regulations. Archaeological concerns can be addressed to Dr. Carson N. Murdy, Regional Archaeologist, at (605) 226-7656.

Sincerely,

Deputy Regional Director – Indian Services

006893

U.S. Department
of Transportation
**Federal Aviation
Administration**

Federal Aviation Administration
Bismarck Airports District Office
2301 University Drive, Building 23B
Bismarck, ND 58504

September 20, 2012

Mr. Chad Miller
Environmental Scientist
Montana Dakota Utilities
400 North Fourth Street
Bismarck, ND 58501-4092

Re: Montana-Dakota Utilities Company and Otter Tail Power Company
Proposed Big Stone South to Ellendale 345 kV Transmission Line Project
North Dakota and South Dakota

Dear Mr. Miller:

The Code of Federal Regulations (CFR) Title 14 Part 77.9 states that any person/organization who intends to sponsor any of the following construction or alterations must notify the Administrator of the FAA:

- any construction or alteration exceeding 200 foot above ground level
- any construction or alteration:
    - within 20,000 foot of a public use or military airport which exceeds a 100:1 surface from any point on the runway of each airport with its longest runway more than 3,200 foot
    - within 10,000 foot of a public use or military airport which exceeds a 50:1 surface from any point on the runway of each airport with its longest runway no more than 3,200 foot
    - within 5,000 foot of a public use heliport which exceeds a 25:1 surface
- any highway, railroad or other traverse way whose prescribed adjusted height would exceed the above noted standards
- when requested by the FAA

Objects that are considered obstructions under the standards described in this Part 77.17 are presumed hazards to air navigation unless further aeronautical study concludes that the object is not a hazard.

We request you utilize the FAA "Notice Criteria Tool" link on the web at https://oeaaa.faa.gov and we request you file notice when the tool determines that FAA requests that you file. The FAA website for obstruction evaluation provides this tool to assist proponents in applying the appropriate slope calculations above and for impacts to Federal airways and airports navigation/communication facilities/equipment (including those which are not located on or near airports).

The Notice of Proposed Construction or Alteration Form 7460-1 may be obtained and filed online at https://oeaaa.faa.gov. FAA requires a minimum notice of 45 days prior to construction start; however FAA encourages you provide notice well in advance of construction in order to avoid delays/impacts to your project.

If you require additional information regarding the filling requirements for your project, please contact the appropriate FAA representative using the Air Traffic Areas of Responsibility map for Off-Airport Construction at https://oeaaa.faa.gov.

Also, we recommend that the design, construction, and operation of the project and related improvements (including construction, drainages, and operation of the proposal and any potential wetland mitigation or wildlife mitigation sites) do not create a hazardous wildlife attractant to public use airports. Hazardous wildlife and hazardous wildlife separation distances are defined in FAA Advisory Circular (AC) 150/5200-33, Hazardous Wildlife Attractants on or near airports.

If you are uncertain if the proposed development will cause a wildlife hazard for airports, we recommend you consult with the United States Department of Agriculture, APHIS, Wildlife Services or another qualified wildlife biologists. We recommend any wildlife biologist consulting on a matter such as this, meet the qualifications identified in FAA Advisory Circular 150/5200-36, "Qualifications for wildlife biologist conducting wildlife hazard assessments and training curriculums for airport personnel involved in controlling wildlife hazards on airports".

Sincerely,

Patricia L. Dressler

Patricia L. Dressler
Environmental Protection Specialist

U.S. Department
of Transportation
Federal Aviation Administration

Federal Aviation Administration
Bismarck Airports District Office
2301 University Drive, Building 23B
Bismarck, ND 58504

December, 18, 2012

Mr. Chad Miller
Environmental Scientist
Montana Dakota Utilities
400 North Fourth Street
Bismarck, ND 58501-4092

Re: Big Stone South to Ellendale Project Update
Montana-Dakota Utilities Company and Otter Tail Power Company
Proposed Big Stone South to Ellendale 345 kV Transmission Line Project

Dear Mr. Miller:

The Federal Aviation Administration (FAA) Bismarck Airports District Office has reviewed your update dated September 25, 2012.

The Code of Federal Regulations (CFR) Title 14 Part 77.9 states that any person/organization who intends to sponsor any of the following construction or alterations must notify the Administrator of the FAA:

- any construction or alteration exceeding 200 foot above ground level
- any construction or alteration:
    - within 20,000 foot of a public use or military airport which exceeds a 100:1 surface from any point on the runway of each airport with its longest runway more than 3,200 foot
    - within 10,000 foot of a public use or military airport which exceeds a 50:1 surface from any point on the runway of each airport with its longest runway no more than 3,200 foot
    - within 5,000 foot of a public use heliport which exceeds a 25:1 surface
- any highway, railroad or other traverse way whose prescribed adjusted height would exceed the above noted standards
- when requested by the FAA

Objects that are considered obstructions under the standards described in this Part 77.17 are presumed hazards to air navigation unless further aeronautical study concludes that the object is not a hazard.

FAA requests that you utilize the FAA "Notice Criteria Tool" link on the web at https://oeaaa.faa.gov for each structure and we request you file notice when the tool determines that FAA requests that you file. The FAA website for obstruction evaluation provides this tool to assist proponents in applying the appropriate slope calculations above and for impacts to Federal airways and airports navigation/communication facilities/equipment (including those which are not located on or near airports).

The Notice of Proposed Construction or Alteration Form 7460-1 may be obtained and filed online at https://oeaaa.faa.gov. FAA requires a minimum notice of 45 days prior to construction start; however FAA encourages you provide notice well in advance of construction in order to avoid delays/impacts to your project.

If you require additional information regarding the filling requirements for your project, please contact the appropriate FAA representative using the Air Traffic Areas of Responsibility map for Off-Airport Construction at https://oeaaa.faa.gov.

Also, we recommend that the design, construction, and operation of the project and related improvements (including construction, drainages, and operation of the proposal and any potential wetland mitigation or wildlife mitigation sites) do not create a hazardous wildlife attractant to public use airports. Hazardous wildlife and hazardous wildlife separation distances are defined in FAA Advisory Circular (AC) 150/5200-33, Hazardous Wildlife Attractants on or near airports.

If you are uncertain if the proposed development will cause a wildlife hazard for airports, we recommend you consult with the United States Department of Agriculture, APHIS, Wildlife Services or another qualified wildlife biologists. We recommend any wildlife biologist consulting on a matter such as this, meet the qualifications identified in FAA Advisory Circular 150/5200-36, "Qualifications for wildlife biologist conducting wildlife hazard assessments and training curriculums for airport personnel involved in controlling wildlife hazards on airports".

Sincerely,

Patricia L. Dressler
Environmental Protection Specialist

U.S. Department
of Transportation
Federal Highway Administration

South Dakota Division

116 East Dakota Avenue, Suite A
Pierre, South Dakota 57501-3110
Phone: 605-224-7326, Ext. 3047
Ron.McMahon@dot.gov
Fax: 605-224-8307

May 13, 2013

In Reply Refer To:
HDA-SD

Mr. Chad Miller
Montana-Dakota Utilities Company
400 North Fourth Street
Bismarck, ND 58501-4092

Re: Big Stone South to Ellendale
345kV Transmission Line
Montana-Dakota U & Otter Tail

Dear Mr. Miller:

The Federal Highway Administration (FHWA) has reviewed your May 6, 2013 letter seeking comments related to the preferred route. As previously discussed back in October 2012 and February 2013, FHWA will not be participating. Our State partners would have more interest and input concerning the proposed routes and necessary permits needed.

My understanding is that the State partners have been invited to participate.

If you have any questions, please advise.

Sincerely,

R. McMahon

Ron McMahon, P. E.
Project Development Team Leader

1Yem

BSS+E
Big Stone South to Ellendale

REC'D: FHWA-SD
MAY 8 AM 11 10

May 6, 2013

John Rohlf
South Dakota Federal Highway Administration
116 East Dakota Ave Suite A
Pierre, SD 57501

RE: Project Update with Preferred Route
Montana-Dakota Utilities Co. and Otter Tail Power Company
Proposed Big Stone South to Ellendale 345 kV Transmission Line Project

Dear John,

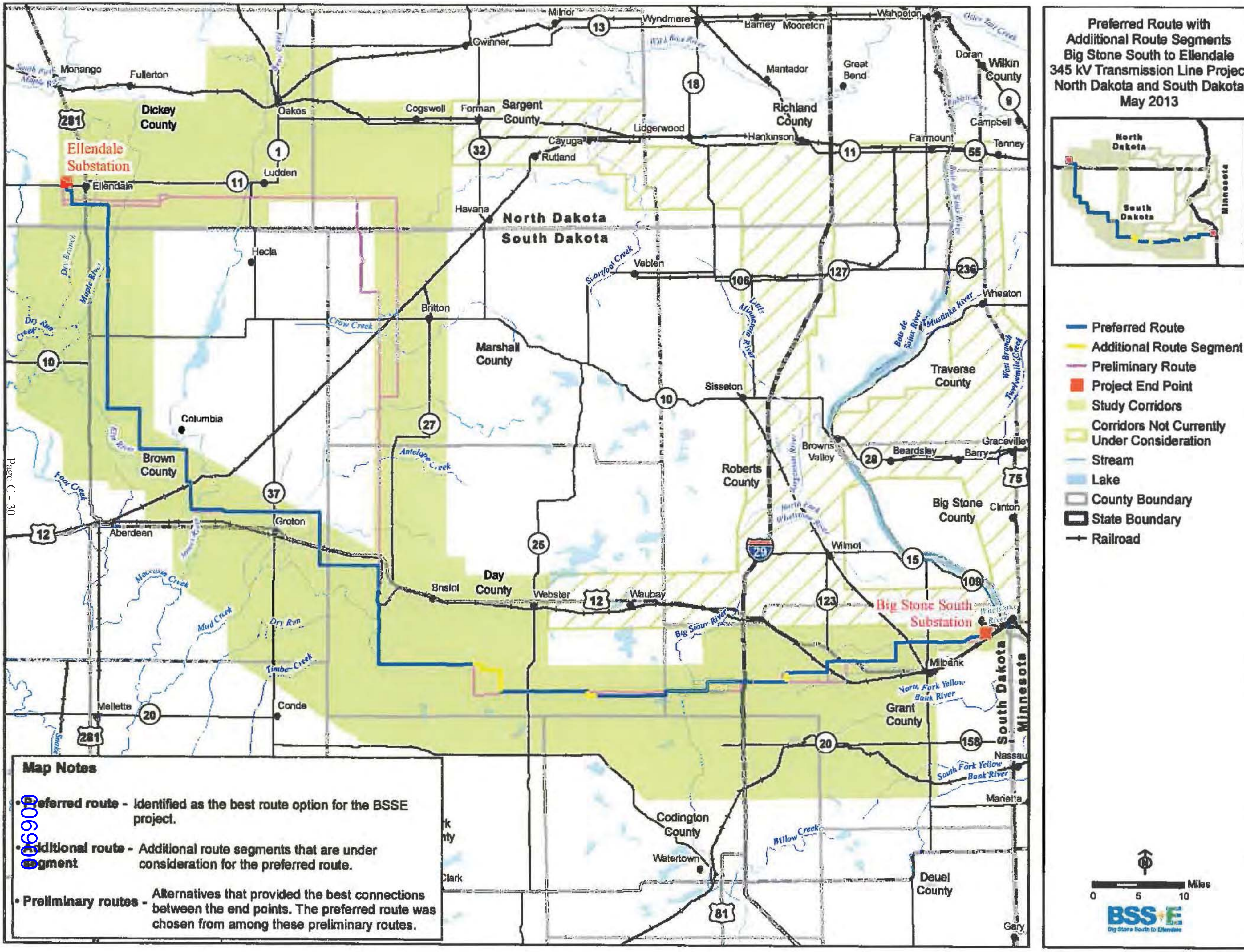
Montana-Dakota Utilities Co. and Otter Tail Power Company have selected a preferred route for the proposed Big Stone South to Ellendale 345 kV transmission line project. As you may recall, the line will be 160 miles to 170 miles long and will be routed between a new substation to be located near Ellendale in Dickey County, North Dakota, and Big Stone South substation, which is part of a separate project and will be located near Big Stone City in Grant County, South Dakota. The Mid-Continent Independent System Operator (MISO, formally Midwest Independent Transmission System Operator) identified the need for this transmission line to improve reliability, increase electric system capacity and support public policy by enabling renewable and other forms of energy to integrate into the electric system. You can find more information by visiting www.BSSEtransmissionline.com, calling our toll-free information line at (888) 283-4678, or contacting Chad Miller (information below).

In January, February and March 2013, we gathered input from tribal, federal, state, and local agencies and the public. We discussed routing constraints and opportunities near preliminary routes. Using this input, along with environmental and engineering considerations, the project team developed the preferred route. (See enclosed map. Please note three areas on the map called Additional Route Segments where the project team has not yet identified the preferred route.)

We evaluated the following criteria to identify the preferred route:

- Existing rights-of-way (transmission lines, pipelines, railway, or roads), survey lines, and natural division lines
- Populated areas
- High densities of important natural features
- High densities of cultural properties and sensitive traditional areas
- River crossing locations
- Public and private airports
- Length
- Input from agencies and landowners
- Input from tribes

The project is seeking comments related to the preferred route. If your jurisdiction is now outside of the preferred route, we appreciate your input to date. We are no longer reviewing route options outside of the


Preferred Route with Additional Route Segments Big Stone South to Ellendale 345 kV Transmission Line Project North Dakota and South Dakota May 2013
North Dakota
South Dakota
Minnesota
Preferred Route
Additional Route Segment
Preliminary Route
Project End Point
Study Corridors
Corridors Not Currently Under Consideration
Stream
Lake
County Boundary
State Boundary
Railroad
Miles
0
5
10
BSSE
Big Stone South to Ellendale
Ellendale Substation
Big Stone South Substation
Dickey County
Sargent County
Richland County
Wilkin County
Brown County
Marshall County
Roberts County
Traverse County
Big Stone County
Day County
Grant County
Codington County
Deuel County
Aberdeen
Ellendale
Oakes
Groton
Bristol
Webster
Waubay
Sisseton
Milbank
Watertown
Wahpeton
Map Notes
• Preferred route - Identified as the best route option for the BSSE project.
• Additional route segment - Additional route segments that are under consideration for the preferred route.
• Preliminary routes - Alternatives that provided the best connections between the end points. The preferred route was chosen from among these preliminary routes.

0006900

preferred route; however, you are welcome to continue to provide feedback if you have thoughts on the project. For agencies with jurisdiction or interests within the preferred route, we are requesting comments on any permits or approvals that may be necessary or any other feedback that may affect the design, construction or schedule of the Project.

Please note that Montana-Dakota Utilities Co. and Otter Tail Power Company will be finalizing the route details in the next month in order to submit state routing permit applications in late summer 2013. Therefore, we request response from your office within 30 days of receipt of this letter so that, where feasible and appropriate, we may incorporate them into the application materials and route design. We appreciate your ongoing participation in this project and look forward to continuing to work with you. If you have questions, comments or feedback, please contact Chad Miller at (701) 222-7865, chad.miller@mdu.com, or by mail at the address below.

Chad Miller
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, ND 58501-4092

Sincerely,

Montana-Dakota Utilities Co.

Henry Ford
Project Developer

Otter Tail Power Company

Dean Pawlowski
Project Developer

Enclosures: Preferred Route Map

From:	Miller, Chad
To:	Hyland, Emily
Cc:	Hunker, Brian M.
Subject:	FW: BSSE Transmission Line - response requested to preferred route mailing
Date:	Wednesday, July 10, 2013 12:41:09 PM
Attachments:	BSSE_Fig1_8X11_PreferredRoute_AgencyNotification_20130430.pdf.pdf.pdf

Sincerely,

Chad Miller

From: Beu, Jane [mailto:jane_beu@nps.gov]
Sent: Wednesday, July 10, 2013 12:39 PM
To: Miller, Chad
Cc: Jane_beu
Subject: Fwd: BSSE Transmission Line - response requested to preferred route mailing

Chad -

We did receive and review your earlier correspondence regarding the Montana-Dakota Utilities Co. and Otter Trail Power Company. Our office receives more than 2,000 of these early coordinations every year and unfortunately we do not have the staff to responde to each inquiry. If we would have concerns you would hear from out office within 30 days.

On this particular project we have no comments.

Thanks you,

Jane G. Beu
Outdoor Recreation Planner
National Park Service
Midwest Regional Office
601 Riverfront Drive
Omaha, NE 68102
402-661-1544
402-661-1545 (fax)
jane_beu@nps.gov

---------- Forwarded message ----------
From: **Anderson, Karen** <karen_anderson@nps.gov>
Date: Mon, Jul 8, 2013 at 3:23 PM
Subject: Fwd: BSSE Transmission Line - response requested to preferred route mailing
To: Jane Beu <jane_beu@nps.gov>

You're the PO for SD, aren't you? If not, my apologies.
But if you are, I believe you review and comment on this action.
Is Nick Chevance still involved in actions of this sort?

Karen Anderson   karen_anderson@nps.gov
Rivers Trails & Conservation Assistance

National Park Service
601 Riverfront Dr.
Omaha, NE 68102
402-661-1542
http://www.nps.gov/ncrc/programs/rtca/

---------- Forwarded message ----------
From: **Pickle, Joyce E.** <Joyce.Pickle@hdrinc.com>

Date: Mon, Jul 8, 2013 at 3:19 PM
Subject: BSSE Transmission Line - response requested to preferred route mailing
To: "ppicha@nd.gov" <ppicha@nd.gov>, "mary.podoll@nd.usda.gov" <mary.podoll@nd.usda.gov>, "Sam.E.Werner@usace.army.mil" <Sam.E.Werner@usace.army.mil>, "karen_anderson@nps.gov" <karen_anderson@nps.gov>, "patricia.dressler@faa.gov" <patricia.dressler@faa.gov>, "Northdakota.Fhwa@dot.gov" <Northdakota.Fhwa@dot.gov>, "jdschumacher@nd.gov" <jdschumacher@nd.gov>, "jobserv@nd.gov" <jobserv@nd.gov>, "kcwanner@nd.gov" <kcwanner@nd.gov>, "ndda@nd.gov" <ndda@nd.gov>, "sjdavis@nd.gov" <sjdavis@nd.gov>, "Duttenhefner, Kathy G. (kgduttenhefner@nd.gov)" <kgduttenhefner@nd.gov>, "gcfisher@nd.gov" <gcfisher@nd.gov>, "Olson, Paige (Paige.Olson@state.sd.us)" <Paige.Olson@state.sd.us>, "richard.pearson@state.sd.us" <richard.pearson@state.sd.us>, "Bill.Smith@state.sd.us" <Bill.Smith@state.sd.us>, "Sarah.Land@state.sd.us" <Sarah.Land@state.sd.us>, "darin.bergquist@state.sd.us" <darin.bergquist@state.sd.us>, "hunter.roberts@state.sd.us" <hunter.roberts@state.sd.us>, "chris.maxwell@state.sd.us" <chris.maxwell@state.sd.us>
Cc: "Miller, Chad" <Chad.Miller@mdu.com>

Greetings!

On May 6, 2013, Montana-Dakota Utilities Co. and Otter Tail Power Company mailed a letter to your agency regarding their selected preferred route for the proposed Big Stone South to Ellendale (BSSE) 345 kV transmission line project. The BSSE project team is requesting comment from your agency on the preferred route (see the attached preferred route map) prior to the South Dakota and North Dakota state permit application submittals which are anticipated to be submitted starting in late-August. We would appreciate your review of the preferred route and request that you provide any comments by Friday, July 19, 2013 so we may incorporate them into the application materials and route design.

We appreciate your ongoing participation in this project and look forward to continuing to work with you. If you have questions or comments you would like us to address for the BSSE project, please send a hardcopy, email, or .pdf copy of your response to Chad Miller at (701) 222-7865, chad.miller@mdu.com, or by mail at the address below.

Chad Miller
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, ND 58501-4092

Sincerely,

JOYCE PICKLE

HDR Engineering, Inc.
Environmental Project Manager

701 Xenia Avenue South, Suite 600 | Minneapolis, MN 55416
Office: 763.591.5443 | Mobile: 763.567.3406
joyce.pickle@hdrinc.com | hdrinc.com

006903

Current, Rhonda

From: Thompson, Sara - NRCS, Huron, SD <sara.thompson@sd.usda.gov>
Sent: Friday, March 22, 2013 9:45 AM
To: Pickle, Joyce E.
Cc: Hagel, Todd - NRCS, Bismarck, ND; Vander Wilt, Jeffrey - NRCS, Huron, SD; Houge, Brenda - NRCS, Huron, SD
Subject: Infrastructure request: BSSE Transmission line - information and questions
Attachments: Easement Modification Package Checklist Final Draft.xlsx

Importance: High

Hi Joyce,

I have been in contact with our national office regarding the next steps for you to take if routing the transmission line over/on a WRP easement. For WRP easements the easiest process is going to be spanning the easement, since that would only require a subordination agreement and I would think be much easier to get approval for. As I stated earlier, our agency does not have the authority to modify (modification includes subordinating for a ROW) EWPP-FPE easements. Attached is a checklist that I would use to document the request for modification. The main thing is for you to provide your analysis of alternatives and document compelling public need. Also, we could use any existing NEPA documentation you have. Once we have established no alternatives and need then I would go to the USFWS and Conservation District for concurrence. Please take a look at the checklist and give me a call so we can discuss further how to proceed.

As far as costs go, the proponent must agree to cover all costs associated with the modification including restoration, fixing anything disturbed during construction and real estate and legal fees. If you are simply looking for a subordination agreement (spanning the easement), we will not need to address ecological equivalents. However, if you are proposing an actual acreage swap (in the event structures must be placed on the easement we would modify those acres out and add new acres in) we must verify that the land they are adding to the easement is ecologically, and financially, as valuable or more valuable than that which is being removed.

I have copied Todd Hagel on this; he manages the easement programs in ND.

Thanks,

Sara Thompson
NRCS Easement Programs
200 Fourth Street SW
Huron, SD 57350
(605) 352-1281
(605) 352-1270 (fax)

United States Department of Agriculture

NRCS

Natural Resources Conservation Service
Federal Building, 200 Fourth St. SW
Huron, South Dakota 57350

Phone: (605) 352-1200
Fax: (605) 352-1261

May 16, 2013

Mr. Chad Miller
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, ND 58501-4092

RE: Project Update with Preferred Route
Montana-Dakota Utilities Co. and Otter Tail Power Company
Proposed Big Stone South to Ellendale 345 kV Transmission Line Project

Dear Mr. Miller:

Thank you for the opportunity to provide comments on the above project, The project will have no effect on prime or important farmland.

The Natural Resources Conservation Service (NRCS) would advise the applicant to consult with the local NRCS and Farm Service Agency (FSA) offices regarding any USDA easements or contract in the project area that may be affected.

If you have any questions, please contact Barb Hall, GIS Specialist, at (605)352-1256.

Sincerely,

Barb Hall acting for

DEANNA M. PETERSON
State Soil Scientist

DEPARTMENT OF THE ARMY
CORPS OF ENGINEERS, OMAHA DISTRICT
SOUTHDAKOTA REGULATORY OFFICE
28563 POWERHOUSE ROAD, ROOM 118
PIERRE, SOUTH DAKOTA 57501-6174

REPLY TO
ATTENTION OF

August 13, 2012

South Dakota Regulatory Office
28563 Powerhouse Road, Room 118
Pierre, South Dakota 57501

HDR Engineering, Inc.
Attn: Brian Hunker
701 Xenia Avenue South, Suite 600
Minneapolis, Minnesota 55416

Dear Mr. Hunker,

Reference is made to the preliminary information received August 1, 2012, concerning Department of the Army authorization requirements for the proposed Big Stone South to Ellendale 345kV Transmission Line Project in Grant County, South Dakota.

The Corps' jurisdiction is derived from Section 404 which calls for Federal regulation of the discharge of dredged or fill material into certain waterways, lakes and/or wetlands, (i.e. waters of the United States). If the proposed project involves either the discharge of dredged or fill material into waters subject to Federal regulation, it is requested the project proponent submit an application for a Department of the Army permit.

Regarding your request for comment relative to environmental impacts, this office assesses project impacts, including environmental impacts, after receipt of the detailed, site specific information required via our permit application process.

You can obtain additional information about the Regulatory Program and download forms from our website: https://www.nwo.usace.army.mil/html/od-rsd/frame.html.

If you have any questions or need any assistance, please feel free to contact this office at the above Regulatory Office address or telephone Carolyn Kutz at (605) 224-8531.

Sincerely,

Steven E. Naylor

Steven E. Naylor
Regulatory Program Manager,
South Dakota

006906

Big Stone South to Ellendale

January 24, 2013

Carolyn Kutz
SD USACE
28563 Powerhouse Road Room 118
Pierre, SD 57501

RE: Montana-Dakota Utilities Co. and Otter Tail Power Company
Proposed Big Stone South to Ellendale 345kV Transmission Line Project
South Dakota Interagency Meeting

Dear Carolyn:

Montana-Dakota Utilities Co. and Otter Tail Power Company would like thank you for attending the interagency meeting that was held on January 16, 2013, in Pierre, South Dakota to review the preliminary routes for the Big Stone South to Ellendale Project. For those of you who were unable to attend we appreciate your contributions to date. We would like to take this time to encourage you to provide any additional feedback on the preliminary routes. Also, please confirm any jurisdiction or required processes based on the preliminary routes. Attached for your reference and information are the meeting notes.

We discussed the Section 10 permitting process for an aerial crossing of the James River and coverage under the nationwide permit for the transmission line project. It is our understanding that the U.S. Army Corps of Engineers will look at each wetland crossing as a single complete project based on the discussion we had at the interagency meeting. Can you please verify this is the case? Please also confirm that the coordination that has occurred to date, along with future updates on the preferred route selection and the alternatives and need analysis that will be included as part of the state routing process, should be sufficient to support the alternatives and need requirements of the Section 10 permit process. If any other information is required by your office ahead of the Section 404 and Section 10 applications, please let us know. We appreciate your assistance on this matter.

In the meeting, we inquired about how you would like to receive future project updates. Based on the feedback heard we will be providing update emails with associated maps to show project progress.

Thank you for your continued assistance, please forward responses to questions or if you have any further questions or comments, contact Chad Miller at (701) 222-7865 or chad.miller@mdu.com.

Chad Miller

Montana Dakota Utilities Co.
400 North Fourth Street
Bismarck, ND 58501-4092

Sincerely,

Montana-Dakota Utilities Co. | Otter Tail Power Company

Henry Ford
Project Developer

Dean Pawlowski
Project Developer

Enclosure: Meeting Notes

From: Crooke, Patsy J NWO [mailto:Patsy.J.Crooke@usace.army.mil]
Sent: Wednesday, February 06, 2013 10:21 AM
To: Miller, Chad
Subject: BSSE Transmission line project (UNCLASSIFIED)

Classification: UNCLASSIFIED
Caveats: NONE

Chad:
Dan forwarded me you letter of January 24, 2013. In the letter you requested confirmation that the Corps will look at each wetland crossing as a single and complete project. Per regulatory definition at 33 CFR 320.2(i), "For linear projects, the single and complete project will apply to each crossing of a separate water of the US at that location; except that for linear projects crossing a single waterbody several times at separate and distant locations, each crossing is considered a single and complete project. However, individual channels in a braided stream or river, or individual arms of a large, irregularly-shaped wetland or lake, etc., are NOT separate waterbodies." So, yes, each wetland crossing will be looked at accordingly.

Regarding the alternatives, these are only necessary for compliance with the 404(b)(1) Guidelines (individual permitting process). It is likely that Nationwide Permit #12 will cover this project, even for the crossing over the James River. I have attached a Fact Sheet for NWP #12 for your review. See the notification requirements on page 2.

I hope this helps. Certainly give me a call if you need further clarification or discussion.

Patsy

Patsy Crooke
Project Manager
USACE/NDRO
1513 S 12th Street
Bismarck, ND 58504
701.255.0015
FAX: 701.255.4917
patsy.j.crooke@usace.army.mil

Classification: UNCLASSIFIED
Caveats: NONE

DEPARTMENT OF THE ARMY
CORPS OF ENGINEERS, OMAHA DISTRICT
SOUTHDAKOTA REGULATORY OFFICE
28563 POWERHOUSE ROAD, ROOM 118
PIERRE, SOUTH DAKOTA 57501-6174

REPLY TO
ATTENTION OF

February 13, 2013

South Dakota Regulatory Office
28563 Powerhouse Road, Room 118
Pierre, South Dakota 57501

Montana Dakota Utilities Co.
Attn: Chad Miller
400 North Fourth Street
Bismarck, North Dakota 58501-4092

Dear Mr. Miller:

Reference is made to the information received January 28, 2013, concerning the interagency meeting in Pierre, South Dakota for the proposed Big Stone South to Ellendale 345 kV Transmission Line Project in South Dakota.

The Corps' jurisdiction is derived from Section 10 of the Rivers and Harbors Act of March 3, 1899, and Section 404 of the Clean Water Act passed by Congress in 1972. Section 10 calls for Federal regulation of activities in or affecting navigable waters of the United States including adjacent wetlands. Section 404 calls for Federal regulation of the discharge of dredged or fill material into certain waterways, lakes and/or wetlands, (i.e. waters of the United States).

In regard to the our discussion on the Section 10 permitting process for an aerial crossing of the James River, I have inserted a table from the US Army Corps of Engineers Regulation from Part 33 CFR 322.5(i)(2) – Special Policies that address the minimum clearance requirements that must be adhered to for the installation of a transmission line over a Section 10 waters of the United States.

Nominal System Voltages, kV	Minimum Additional Clearance (feet) above clearance required for bridges
115 and below	20
138	22
161	24
230	26
350	30
500	35
700	42
750-765	45

006909

Under the USACE meeting notes, bullet No. 3 states "All other wetland crossings will likely qualify for Nationwide Permit coverage with no PCN". In accordance with Nationwide Permit #12 Utility Line Activities, a PCN is required under certain circumstances which are outlined under "Notification" in the Nationwide Permit #12 fact sheet that is attached.

You can obtain additional information about the Regulatory Program and download forms from our website: http://www.nwo.usace.army.mil/Missions/RegulatoryProgram/SouthDakota.aspx

If you have any questions or need any assistance, please feel free to contact this office at the above Regulatory Office address or telephone Carolyn Kutz at (605) 224-8531.

Sincerely,

Steven E. Naylor
Regulatory Program Manager,
South Dakota

Enclosures

cmk
KUTZ/cmk

006910

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Ecological Services
420 South Garfield Avenue, Suite 400
Pierre, South Dakota 57501-5408

August 7, 2012

Mr. Chad Miller
Montana-Dakota Utilities Company
400 North Fourth
Bismarck, North Dakota 58501

Re: Big Stone South to Ellendale 345 kV Transmission Line Project, Numerous Counties in North Dakota, South Dakota, and Possibly Minnesota

Dear Mr. Miller:

This letter is in response to your request dated July 27, 2012, for environmental comments regarding the above referenced project involving the construction of a new 345 kV transmission line beginning at the new Ellendale Substation in Dickey County, North Dakota, and ending at the proposed Big Stone South Substation in Grant County, South Dakota. The transmission line may cross into Minnesota also.

Please consult the National Wetlands Inventory maps, available online at http://wetlands.fws.gov/, to determine what wetlands exist in the proposed project area. If a project may impact wetlands or other important fish and wildlife habitats, the U.S. Fish and Wildlife Service (Service), in accordance with the National Environmental Policy Act of 1969 (42 U.S.C. 4321-4347) and other environmental laws and rules, recommends complete avoidance of these areas, if possible; then minimization of any adverse impacts; and finally, replacement of any lost acres; in that order. Alternatives should be examined and the least damaging practical alternative selected. If wetland impacts are unavoidable, a mitigation plan addressing the number and types of wetland acres to be impacted and the methods of replacement should be prepared and submitted to the resource agencies for review.

The current study area falls under the jurisdiction of four of the Service's Wetland Management Districts (WMD) in South Dakota and two WMD's in North Dakota. WMD's administer easements and fee title properties in several counties in this study area. To determine whether Service interest lands exist at the proposed project site, the exact locations of these properties, and any additional restrictions that may apply regarding these sites, please contact the following Service offices:

Brown and Spink Counties in South Dakota
Jay Peterson
Sand Lake Wetland Management District
39650 Sand Lake Drive
Columbia, South Dakota 57433
Telephone No. (605) 885-6320

Marshall, Roberts, Day, Clark, Codington, and Grant Counties in South Dakota
Connie Mueller
Waubay Wetland Management District
44401 134A Street
Waubay, South Dakota 57273
Telephone No. (605) 947-4521

Hamlin and Deuel Counties in South Dakota
Natoma Buskness
Madison Wetland Management District
P.O. Box 48
Madison, South Dakota 57042
Telephone No. (605) 256-2974

Beadle County, South Dakota
Clarke Dirks
Huron Wetland Management District
Federal Building, Room 309
200 4th Street SW
Huron, South Dakota 57350
Telephone No. (605) 352-5894

Dickey County, North Dakota
Kulm Wetland Management District
1 First Street, SW
P.O. Box E
Kulm, North Dakota 58456
Telephone No. (701) 647-2866

Sargent and Richland Counties in North Dakota
Tewaukon National Wildlife Refuge
9754 143 1/2 Avenue SE
Cayuga, North Dakota 58013
Telephone No. (701) 724-3598

Enclosed you will find the county-by-county endangered species list for each state within the study area - South Dakota, North Dakota, and Minnesota.

If the Federal action agency or their designated representative determines that the project will have "no effect" on federally listed species, Service concurrence is not necessary per section 7 of the Endangered Species Act (ESA). If the Federal action agency or their designated representative determines that this project "may adversely affect" listed species in South Dakota, it should request formal consultation from this office. If a "may affect - not likely to adversely affect" determination is made for this project, it should be submitted to this office for concurrence. For more information regarding Federal action agency responsibilities as related to section 7 of the ESA, please refer to the Service's Endangered Species Act Consultation Handbook, available online at http://www.fws.gov/endangered/consultations/index.html.

Please contact our office again when the final route has been determined for the transmission line so that we may provide more detailed information about wetlands, fisheries, and endangered species.

The Service appreciates the opportunity to provide comments. If you have any questions regarding these comments, please contact Charlene Bessken of this office at (605) 224-8693, Extension 231.

Sincerely,

Scott Larson

Scott V. Larson
Field Supervisor
South Dakota Field Office

Enclosures

cc: FWS/Sand Lake WMD; Columbia, SD
FWS/Madison WMD; Madison, SD
FWS/Waubay WMD; Waubay, SD
FWS/Huron WMD; Huron, SD
FWS/Kulm WMD; Kulm, ND
FWS/Tewaukon WMD; Cayuga, ND
FWS/ND ES Field Office; Bismarck. ND
FWS/Twin Cities ES Field Office; Bloomington, MN

South Dakota Listed Species by County List
(updated 17 April 2012)

The bald eagle was removed from the List of Endangered and Threatened Wildlife effective August 8, 2007. The protections provided to the bald eagle under the Bald and Golden Eagle Protection Act and the Migratory Bird Treaty Act have continued to remain in place after the species was delisted. National Bald Eagle Management Guidelines (http://www.fws.gov/pacific/eagle/NationalBaldEagleManagementGuidelines.pdf) have been developed. This rule change does not affect the bald eagle's status as a threatened or endangered species under State laws or suspend any other legal protections provided by State law.

E = Endangered
T = Threatened
C = Candidate

XN = Experimental/Non-essential Population
CH = Critical Habitat
PCH = Proposed Critical Habitat

County	Group	Species	Certainty of Occurrence	Status
Aurora	Bird Fish	Crane, Whooping Shiner, Topeka	Known Known	E E
Beadle	Bird Fish	Crane, Whooping Shiner, Topeka	Known Known	E E
Bennett	Bird Plant	Crane, Whooping Orchid, Western Prairie Fringed[1]	Known Possible	E T
Bon Homme	Bird Bird Bird Fish Fish	Crane, Whooping Tern, Least Plover, Piping Shiner, Topeka Sturgeon, Pallid	Possible Known Known Known Known	E E T (CH) E E
Brookings	Fish Plant Invertebrate Invertebrate	Shiner, Topeka Orchid, Western Prairie Fringed[1] Dakota Skipper Poweshiek Skipperling[8]	Known Possible Known Known	E T C C
Brown	Bird Bird Fish Invertebrate	Curlew, Eskimo Crane, Whooping Shiner, Topeka Dakota Skipper	Extremely Rare Known Known Known	E E E C
Brule	Bird Bird Bird Fish	Crane, Whooping Tern, Least Plover, Piping Sturgeon, Pallid	Known Known Possible Known	E E T E

County	Group	Species	Certainty of Occurrence	Status
Buffalo	Bird	Crane, Whooping	Known	E
	Bird	Tern, Least	Known	E
	Bird	Plover, Piping	Possible	T
	Fish	Sturgeon, Pallid	Known	E
Butte	Bird	Crane, Whooping	Known	E
	Bird	Greater Sage Grouse	Known	C
	Bird	Sprague's Pipit	Possible Breeding/Migration	C
Campbell	Bird	Crane, Whooping	Known	E
	Bird	Plover, Piping	Known	T (CH)
	Bird	Tern, Least	Known	E
	Fish	Sturgeon, Pallid	Possible	E
	Bird	Sprague's Pipit	Possible Migration	C
Charles Mix	Bird	Crane, Whooping	Known	E
	Bird	Plover, Piping	Known	T (CH)
	Bird	Tern, Least	Known	E
	Fish	Sturgeon, Pallid	Possible	E
Clark	Bird	Crane, Whooping	Known	E
	Fish	Shiner, Topeka[3]	Possible	E
	Invertebrate	Poweshiek Skipperling[8]	Known	C
Clay	Bird	Plover, Piping	Known	T (CH)
	Bird	Tern, Least	Known	E
	Fish	Sturgeon, Pallid	Possible	E
	Fish	Shiner, Topeka	Known	E
	Plant	Orchid, Western Prairie Fringed[1]	Possible	T
	Mussel	Mussel, Scaleshell[6]	Historic	E
Codington	Bird	Crane, Whooping	Known	E
	Fish	Shiner, Topeka	Known	E
	Invertebrate	Dakota Skipper	Known	C
	Invertebrate	Poweshiek Skipperling[8]	Known	C
Corson	Bird	Crane, Whooping	Known	E
	Bird	Plover, Piping	Known	T (CH)
	Bird	Tern, Least	Known	E
	Mammal	Ferret, Black-footed	Possible	E
	Fish	Sturgeon, Pallid	Possible	E
	Bird	Sprague's Pipit	Possible Breeding/Migration	C
Custer	Bird	Crane, Whooping	Possible	E
	Mammal	Ferret, Black-footed	Known	E
	Bird	Sprague's Pipit	Possible Migration	C

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County	Group	Species	Certainty of Occurrence	Status
Davison	Bird	Crane, Whooping	Possible	E
	Fish	Shiner, Topeka	Known	E
Day	Bird	Crane, Whooping	Possible	E
	Bird	Plover, Piping	Known	T
	Invertebrate	Dakota Skipper	Known	C
	Invertebrate	Poweshiek Skipperling[8]	Known	C
Deuel	Fish	Shiner, Topeka[3]	Known	E
	Invertebrate	Dakota Skipper	Known	C
	Invertebrate	Poweshiek Skipperling[8]	Known	C
Dewey	Bird	Crane, Whooping	Known	E
	Bird	Plover, Piping	Known	T (CH)
	Bird	Tern, Least	Known	E
	Mammal	Ferret, Black-footed[4]	Known	XN
	Fish	Sturgeon, Pallid	Known	E
	Bird	Sprague's Pipit	Possible Migration	C
Douglas	Bird	Crane, Whooping	Known	E
	Fish	Shiner, Topeka	Possible	E
Edmunds	Bird	Crane, Whooping	Known	E
	Invertebrate	Dakota Skipper	Known	C
Fall River	Bird	Greater Sage Grouse	Known	C
	Bird	Sprague's Pipit	Possible Migration	C
Faulk	Bird	Crane, Whooping	Known	E
Grant	Fish	Shiner, Topeka[3]	Possible	E
	Invertebrate	Dakota Skipper	Known	C
	Invertebrate	Poweshiek Skipperling[8]	Known	C
Gregory	Bird	Crane, Whooping	Known	E
	Bird	Plover, Piping	Known	T (CH)
	Bird	Tern, Least	Known	XN
	Mammal	Ferret, Black-footed[4]	Possible	E
	Fish	Sturgeon, Pallid	Known	E
	Insect	Beetle, American Burying[2]	Known	E
Haakon	Bird	Crane, Whooping	Known	E
	Bird	Plover, Piping	Known	T
	Bird	Tern, Least	Known	E
	Bird	Sprague's Pipit	Possible Migration	C
Hamlin	Bird	Crane, Whooping	Possible	E
	Fish	Shiner, Topeka[3]	Known	E
	Invertebrate	Dakota Skipper	Known	C
	Invertebrate	Poweshiek Skipperling[8]	Known	C

County	Group	Species	Certainty of Occurrence	Status
Hand	Bird Fish	Crane, Whooping Shiner, Topeka	Known Known	E E
Hanson	Bird Fish	Crane, Whooping Shiner, Topeka	Possible Known	E E
Harding	Bird Bird Bird	Crane, Whooping Greater Sage Grouse Sprague's Pipit	Possible Known Possible Breeding/Migration	E C C
Hughes	Bird Bird Bird Fish	Crane, Whooping Plover, Piping Tern, Least Sturgeon, Pallid	Known Known Known Known	E T (CH) E E
Hutchinson	Bird Fish Plant	Crane, Whooping Shiner, Topeka Orchid, Western Prairie Fringed[1]	Possible Known Possible	E E T
Hyde	Bird Bird Bird Fish	Crane, Whooping Plover, Piping Tern, Least Sturgeon, Pallid	Known Known Known Known	E T E E
Jackson	Bird Mammal Bird	Crane, Whooping Ferret, Black-footed[4] Sprague's Pipit	Known Possible Possible Migration	E XN C
Jerauld	Bird Fish	Crane, Whooping Shiner, Topeka[3]	Known Possible	E E
Jones	Bird Bird	Crane, Whooping Sprague's Pipit	Known Possible Migration	E C
Kingsbury	Bird Bird Fish	Crane, Whooping Plover, Piping Shiner, Topeka[3]	Known Known Possible	E T E
Lake	Fish Plant	Shiner, Topeka[3] Orchid, Western Prairie Fringed[1]	Possible Possible	E T
Lawrence	Bird Bird	Crane, Whooping Sprague's Pipit	Known Possible Migration	E C
Lincoln	Fish Fish Plant	Sturgeon, Pallid[7] Shiner, Topeka Orchid, Western Prairie Fringed[1]	Known Known Possible	E E T

County	Group	Species	Certainty of Occurrence	Status
Lyman	Bird Bird Bird Mammal Fish Bird	Crane, Whooping Tern, Least Plover, Piping Ferret, Black-footed Sturgeon, Pallid Sprague's Pipit	Known Known Possible Known Known Possible Migration	E E T E E C
Marshall	Bird Invertebrate Invertebrate	Crane, Whooping Dakota Skipper Poweshiek Skipperling[8]	Possible Known Known	E C C
McCook	Bird Fish Plant	Crane, Whooping Shiner, Topeka Orchid, Western Prairie Fringed[1]	Possible Known Possible	E E T
McPherson	Bird Bird Invertebrate	Crane, Whooping Sprague's Pipit Dakota Skipper	Known Possible Breeding/Migration Known	E C C
Meade	Bird Bird Bird	Crane, Whooping Tern, Least Sprague's Pipit	Known Known Possible Breeding/Migration	E E C
Mellette	Bird Mammal	Crane, Whooping Ferret, Black-footed[4]	Known Possible	E XN
Miner	Bird Fish Plant	Crane, Whooping Shiner, Topeka Orchid, Western Prairie Fringed[1]	Possible Known Possible	E E T
Minnehaha	Fish Plant	Shiner, Topeka Orchid, Western Prairie Fringed[1]	Known Possible	E T
Moody	Fish Plant Invertebrate	Shiner, Topeka Orchid, Western Prairie Fringed[1] Dakota Skipper	Known Possible Known	E T C
Pennington	Bird Bird Mammal Bird	Crane, Whooping Tern, Least Ferret, Black-footed[4] Sprague's Pipit	Known Known Known Possible Migration	E E XN C
Perkins	Bird Bird	Crane, Whooping Sprague's Pipit	Known Possible Breeding/Migration	E C
Potter	Bird Bird Bird Fish	Crane, Whooping Plover, Piping Tern, Least Sturgeon, Pallid	Known Known Known Known	E T (CH) E E

County	Group	Species	Certainty of Occurrence	Status
Roberts	Plant Invertebrate Invertebrate	Orchid, Western Prairie Fringed[1] Dakota Skipper Poweshiek Skipperling[8]	Possible Known Known	T C C
Sanborn	Bird Fish	Crane, Whooping Shiner, Topeka	Possible Known	E E
Shannon	Bird Mammal Plant Bird	Crane, Whooping Ferret, Black-footed[4] Orchid, Western Prairie Fringed[1] Sprague's Pipit	Known Possible Possible Possible Migration	E XN T C
Spink	Bird Fish	Crane, Whooping Shiner, Topeka[3]	Known Possible	E E
Stanley	Bird Bird Bird Fish Bird	Crane, Whooping Plover, Piping Tern, Least Sturgeon, Pallid Sprague's Pipit	Known Known Known Known Possible Migration	E T (CH) E E C
Sully	Bird Bird Bird Fish	Crane, Whooping Plover, Piping Tern, Least Sturgeon, Pallid	Known Known Known Known	E T (CH) E E
Todd	Bird Mammal Plant Insect	Crane, Whooping Ferret, Black-footed[4] Orchid, Western Prairie Fringed[1] Beetle, American Burying[2]	Possible Known Possible Known	E XN T E
Tripp	Bird Mammal Insect	Crane, Whooping Ferret, Black-footed[4] Beetle, American Burying[2]	Known Possible Known	E XN E
Turner	Bird Plant Fish	Crane, Whooping Orchid, Western Prairie Fringed[1] Shiner, Topeka	Possible Possible Known	E T E
Union	Bird Bird Fish Fish Plant Mussel	Plover, Piping Tern, Least Sturgeon, Pallid Shiner, Topeka Orchid, Western Prairie Fringed[1] Mussel, Scaleshell[6]	Known Known Possible Known Possible Historic	T E E E T E
Walworth	Bird Bird Bird Fish	Crane, Whooping Plover, Piping Tern, Least Sturgeon, Pallid	Known Known Known Possible	E T (CH) E E

County	Group	Species	Certainty of Occurrence	Status
Yankton	Bird	Curlew, Eskimo	Extremely Rare	E
	Bird	Plover, Piping	Known	T (CH)
	Bird	Tern, Least	Known	E
	Fish	Sturgeon, Pallid	Possible	E
	Fish	Shiner, Topeka[3]	Possible	E
	Plant	Orchid, Western Prairie Fringed[1]	Possible	T
	Mussel	Mussel, Scaleshell[6]	Historic	E
	Mussel	Mussel, Higgins Eye[5,6]	Possible	E
Ziebach	Bird	Crane, Whooping	Known	E
	Bird	Plover, Piping	Known	T (CH)
	Bird	Tern, Least	Known	E
	Mammal	Ferret, Black-footed[4]	Possible	XN
	Bird	Sprague's Pipit	Possible Migration	C

Notes

[1] The counties indicated for the Western Prairie Fringed Orchid are counties with potential habitat. Currently, there are no known populations of this species in South Dakota. Status surveys have been completed for the orchid in South Dakota. However, because of the ecology of this species, there is a possibility that plants may be overlooked.

[2] The American Burying Beetle is presently known for only Gregory, Todd and Tripp counties. One specimen was recently trapped in southern Bennett County. Historic specimens have been recorded from Haakon and Brookings Counties. A comprehensive status survey has never been completed for the American burying beetle in South Dakota. Until status surveys have been completed, the beetle could and may occur in any county with suitable habitat. Suitable habitat is considered to be any site with significant humus or topsoil suitable for burying carrion.

[3] Although Topeka Shiners have not been formally documented within Clark, Douglas, Grant, Jerauld, Kingsbury, Lake, Spink, or Yankton Counties, the species may still occur in these areas because they contain portions of known occupied Topeka Shiner streams and/or potentially occupied streams that exist within one or more of the three known inhabited watersheds in South Dakota: the James, Vermillion, and Big Sioux.

[4] Black-footed ferrets have been reintroduced in the Badlands National Park, Buffalo Gap National Grasslands, Cheyenne River Sioux Tribe Reservation, Lower Brule Sioux Reservation, Rosebud Sioux Reservation and Wind Cave National Park .

[5] A fresh dead shell of a Higgins Eye Mussel was found in the Missouri River below Gavins Point Dam on October 27, 2004.

[6] Shells of these species have been found, but no populations have been located.

[7] A pallid sturgeon was caught in Lincoln County from the Big Sioux River in May 2009.

[8] This list includes counties where Poweshiek skipperling has been confirmed within the past 25 years (1986 or later). Due to the sharp declines in the last several years, the list may include counties in which the species no longer occurs. Nevertheless, we recommend that agencies contact the South

Dakota Ecological Services Field Office if undertaking or planning projects that may affect Poweshiek skipperling habitat in these counties.

More specific information on these species can be found at our website at http://www.fws.gov or by calling our office for more information.

Any corrections or additions to this list should be submitted to Scott Larson, U.S. Fish and Wildlife Service, South Dakota Field Office, Ecological Services, 420 South Garfield Avenue, Pierre, SD; Telephone (605)224-8693.

County Occurrence of Endangered, Threatened and Candidate Species and Designated Critical Habitat in North Dakota

February 2012

Species	Adams	Barnes	Benson	Billings	Bottineau	Bowman	Burke	Burleigh	Cass	Cavalier	Dickey	Divide	Dunn	Eddy	Emmons	Foster	Go. Valley	Gr. Forks	Grant	Griggs	Hettinger	Kidder	Lamoure	Logan	McHenry	McIntosh	McKenzie
Interior Least Tern - E								X					X		X												X
Whooping Crane - E	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Black-footed Ferret - E	X			X		X							X				X		X		X						X
Pallid Sturgeon - E								X					X		X												X
Gray Wolf - E	X			X	X	X	X					X	X				X		X		X						X
Piping Plover - T			X				X	X				X	X	X	X	X						X		X	X	X	X
Western Prairie Fringed Orchid - T																											
Dakota Skipper - C					X		X						X	X											X		X
Poweshiek skipperling - C									X																		
Sprague's Pipit - C	X	X	X	X	X	X	X	X		X	X	X	X	X	X	X	X		X		X	X	X	X	X	X	X
Greater Sage-Grouse - C						X											X										
Designated Critical Habitat																											
Piping Plover			X				X	X				X	X	X	X							X		X	X	X	X

E - Endangered T - Threatened C - Candidate

Endangered west of Hwy 83 - Delisted east of Hwy 83

X

County Occurrence of Endangered, Threatened and Candidate Species and Designated Critical Habitat in North Dakota

February 2012

Species	McLean	Mercer	Morton	Mountrail	Nelson	Oliver	Pembina	Pierce	Ramsey	Ransom	Renville	Richland	Rolette	Sargent	Sheridan	Sioux	Slope	Stark	Steele	Stutsman	Towner	Traill	Walsh	Ward	Wells	Williams
Interior Least Tern - E	X	X	X	X		X										X										X
Whooping Crane - E	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Black-footed Ferret - E		X	X			X										X	X	X								
Pallid Sturgeon - E	X	X	X	X		X										X										X
Gray Wolf - E	X	X	X	X		X					X					X	X	X						X		X
Piping Plover - T	X	X	X	X		X		X			X				X	X				X				X	X	X
W. P. Fringed Orchid - T										X		X														
Dakota Skipper - C	X			X		X				X		X	X	X						X				X	X	
Poweshiek skipperling - C										X		X		X												
Sprague's Pipit - C	X	X	X	X		X	X	X	X	X	X		X	X	X	X	X	X		X	X		X	X	X	X
Greater Sage-Grouse - C																	X									
Designated Critical Habitat																										
Piping Plover	X	X	X	X		X		X			X				X	X				X				X		X

E - Endangered **T - Threatened** **C - Candidate** **Endangered west of Hwy 83 - Delisted east of Hwy 83**

X

Minnesota

County Distribution of Federally-Listed Threatened, Endangered and Candidate Species

County	Species	Status	Habitat
Aitkin	Canada lynx (*Lynx canadensis*)	Threatened	Northern forest
Anoka	No listed species present		
Becker	*Poweshiek skipperling (*Oarisma poweshiek*)	Candidate	Native Prairie
Beltrami	Canada lynx (*Lynx canadensis*)	Threatened	Northern forest
Benton	No listed species present		
Big Stone	Dakota skipper (*Hesperia dacotae)*	Candidate	Native prairie habitat
	*Poweshiek skipperling (*Oarisma poweshiek*)	Candidate	Native Prairie
Blue Earth	No listed species present		
Brown	Prairie bush-clover (*Lespedeza leptostachya*)	Threatened	Native prairie on well-drained soils
Carlton	Canada lynx (*Lynx canadensis*)	Threatened	Northern forest
Carver	No listed species present		
Cass	Canada lynx (*Lynx canadensis*)	Threatened	Northern forest
Chippewa	Dakota skipper (*Hesperia dacotae)*	Candidate	Native prairie habitat
	*Poweshiek skipperling (*Oarisma poweshiek*)	Candidate	Native Prairie
Chisago	Higgins eye pearlymussel (*Lampsilis higginsii*)	Endangered	St. Croix River
	Spectaclecase (*Cumberlandia monodonta*)	Endangered	St. Croix River

006924

County	Species	Status	Habitat
	Snuffbox (*Epioblasma triquetra*)	Endangered	Small to medium-sized creeks and some larger rivers, in areas with a swift current
	Winged mapleleaf (*Quadrula fragosa*)	Endangered	St. Croix River
Clay	Sprague's pipit (*Anthus spragueii*)	Candidate	Large (>350 acre) patches of grassland - prefer native grassland, but also use non-native planted grasslands.
	Dakota skipper (*Hesperia dacotae*)	Candidate	Native prairie habitat
	*Poweshiek skipperling (*Oarisma poweshiek*)	Candidate	Native Prairie
	Western prairie fringed orchid (*Platanthera praeclara*)	Threatened	Wet prairies and sedge meadow
Clearwater	Canada lynx (*Lynx canadensis*)	Threatened	Northern forest
Cook	Canada lynx (*Lynx canadensis*)	Threatened	Northern forest
	Canada lynx (*Lynx canadensis*)	Critical Habitat	Map of critical habitat in Minnesota
Cottonwood	*Poweshiek skipperling (*Oarisma poweshiek*)	Candidate	Native Prairie
	Prairie bush clover (*Lespedeza leptostachya*)	Threatened	Gravelly soil in dry to mesic prairies
Crow Wing	No species listed		
Dakota	Higgins eye pearlymussel (*Lampsilis higginsii*)	Endangered	Mississippi River
	Prairie bush clover (*Lespedeza leptostachya*)	Threatened	Native prairie on well-drained soils
Dodge	Dwarf trout lily (*Erythronium propullans*)	Endangered	North facing slopes and floodplains in deciduous forests
	Prairie bush clover (*Lespedeza leptostachya*)	Threatened	Native prairie on well-drained soils

006925

County	Species	Status	Habitat
Douglas	*Poweshiek skipperling (*Oarisma poweshiek*)	Candidate	Native Prairie
Faribault	No listed species present		
Fillmore	Leedy's roseroot (*Rhodiola integrifolia ssp. leedyi*)	Threatened	Cool, wet groundwater-fed limestone cliffs
Freeborn	No listed species present		
Goodhue	Dwarf trout lily (*Erythronium propullans*)	Endangered	North facing slopes and floodplains in deciduous forests
	Higgins eye pearlymussel (*Lampsilis higginsii*)	Endangered	Mississippi River
	Prairie bush clover (*Lespedeza leptostachya*)	Threatened	Native prairie on well-drained soils
Grant	No listed species present		
Hennepin	Higgins eye pearlymussel (*Lampsilis higginsi*)	Endangered	Mississippi River
Houston	Eastern massasauga (*Sistrurus catenatus*)	Candidate	Floodplain wetlands and nearby upland areas along the Mississippi River and Tributaries
	Higgins eye pearlymussel (*Lampsilis higginsii*)	Endangered	Mississippi River
Hubbard	No species listed		
Isanti	No species listed		
Itasca	Canada lynx (*Lynx canadensis*)	Threatened	Northern forest
Jackson	Prairie bush clover (*Lespedeza leptostachya*)	Threatened	Native prairie on well-drained soils
Kanabec	No species listed		
Kandiyohi	*Poweshiek skipperling (*Oarisma poweshiek*)	Candidate	Native Prairie

006926

County	Species	Status	Habitat
Kittson	Dakota skipper *(Hesperia dacotae)*	Candidate	Native prairie habitat
	*Poweshiek skipperling *(Oarisma poweshiek)*	Candidate	Native Prairie
	Western prairie fringed orchid *(Platanthera praeclara)*	Threatened	Wet prairies and sedge meadows
Koochiching	Canada lynx *(Lynx canadensis)*	Threatened	Northern forest
	Canada lynx *(Lynx canadensis)*	Critical Habitat	Map of lynx critical habitat in Minnesota
Lac Qui Parle	Dakota skipper *(Hesperia dacotae)*	Candidate	Native prairie habitat
	*Poweshiek skipperling *(Oarisma poweshiek)*	Candidate	Native Prairie
Lake	Canada lynx *(Lynx canadensis)*	Threatened	Northern forest
	Canada lynx *(Lynx canadensis)*	Critical Habitat	Map of lynx critical habitat in Minnesota
Lake of the Woods	Canada lynx *(Lynx canadensis)*	Threatened	Northern forest
	Piping plover *(Charadrius melodus)* Northern Great Plains Breeding Population	Threatened; and Critical Habitat	Sandy beaches, islands
Le Sueur	No listed species present		
Lincoln	Topeka shiner *(Notropis topeka)*	Endangered	Prairie rivers and streams
	Topeka shiner *(Notropis topeka)*	Critical Habitat	
	Dakota skipper *(Hesperia dacotae)*	Candidate	Native prairie habitat
	*Poweshiek skipperling *(Oarisma poweshiek)*	Candidate	Native Prairie

006927

County	Species	Status	Habitat
	Western prairie fringed orchid *(Platanthera praeclara)*	Threatened	Wet prairies and sedge meadow
Lyon	*Poweshiek skipperling *(Oarisma poweshiek)*	Candidate	Native Prairie
Mahnomen	*Poweshiek skipperling *(Oarisma poweshiek)*	Candidate	Native Prairie
Marshall	Canada lynx *(Lynx canadensis)*	Threatened	Northern forest
Martin	Prairie bush clover *(Lespedeza leptostachya)*	Threatened	Native prairie on well-drained soils
McLeod	*Poweshiek skipperling *(Oarisma poweshiek)*	Candidate	Native Prairie
Meeker	No listed species present		
Mille Lacs	No listed species present		
Morrison	No listed species present		
Mower	Prairie bush clover *(Lespedeza leptostachya)*	Threatened	Native prairie on well-drained soils
	Western prairie fringed orchid *(Platanthera praeclara)*	Threatened	Wet prairies and sedge meadows
Murray	Topeka shiner *(Notropis topeka)*	Endangered	Prairie rivers and streams
	Topeka shiner *(Notropis topeka)*	Critical Habitat	
	Dakota skipper *(Hesperia dacotae)*	Candidate	Native prairie habitat
	*Poweshiek skipperling *(Oarisma poweshiek)*	Candidate	Native Prairie
Nicollet	No listed species present		
Nobles	Topeka shiner *(Notropis topeka)*	Endangered	Prairie rivers and streams
	Topeka shiner *(Notropis topeka)*	Critical Habitat	

006928

County	Species	Status	Habitat
	Prairie bush clover *(Lespedeza leptostachya)*	Threatened	Native prairie on well-drained soils
	Western prairie fringed orchid *(Platanthera praeclara)*	Threatened	Wet prairies and sedge meadow
Norman	Dakota skipper *(Hesperia dacotae)*	Candidate	Native prairie habitat
	*Poweshiek skipperling *(Oarisma poweshiek)*	Candidate	Native Prairie
	Western prairie fringed orchid *(Platanthera praeclara)*	Threatened	Wet prairies and sedge meadows
Olmsted	Leedy's roseroot *(Rhodiola integrifolia ssp. leedyi)*	Threatened	Cool, wet groundwater-fed limestone cliffs
	Prairie bush clover *(Lespedeza leptostachya)*	Threatened	Native prairie on well-drained soils
Otter Tail	No species listed		
Pennington	Western prairie fringed orchid *(Platanthera praeclara)*	Threatened	Wet prairies and sedge meadows
Pine	Canada lynx *(Lynx canadensis)*	Threatened	Northern forest
	Spectaclecase *(Cumberlandia monodonta)*	Endangered	St. Croix River
Pipestone	Topeka shiner *(Notropis topeka)*	Endangered	Prairie rivers and streams
	Topeka shiner *(Notropis topeka)*	Critical Habitat	
	Dakota skipper *(Hesperia dacotae)*	Candidate	Native prairie habitat
	*Poweshiek skipperling *(Oarisma poweshiek)*	Candidate	Native Prairie

County	Species	Status	Habitat
	Western prairie fringed orchid *(Platanthera praeclara)*	Threatened	Wet prairies and sedge meadows
Polk	Sprague's pipit (*Anthus spragueii*)	Candidate	Large (>350 acre) patches of grassland - prefer native grassland, but also use non-native planted grasslands.
	Dakota skipper *(Hesperia dacotae)*	Candidate	Native prairie habitat
	Western prairie fringed orchid *(Platanthera praeclara)*	Threatened	Wet prairies and sedge meadows
Pope	Dakota skipper *(Hesperia dacotae)*	Candidate	Native prairie habitat
	*Poweshiek skipperling *(Oarisma poweshiek)*	Candidate	Native Prairie
Ramsey	Higgins eye pearlymussel *(Lampsilis higginsii)*	Endangered	Mississippi River
	Winged mapleleaf (*Quadrula fragosa*)	Endangered	St. Croix River
Red Lake	Western prairie fringed orchid *(Platanthera praeclara)*	Threatened	Wet prairies and sedge meadow
Redwood	Prairie bush clover *(Lespedeza leptostachya)*	Threatened	Native prairie on well-drained soils
Renville	Prairie bush clover *(Lespedeza leptostachya)*	Threatened	Native prairie on well-drained soils
Rice	Dwarf trout lily *(Erythronium propullans)*	Endangered	North facing slopes and floodplains in deciduous forest
	Prairie bush clover *(Lespedeza leptostachya)*	Threatened	Native prairie on well-drained soils
Rock	Topeka shiner *(Notropis topeka)*	Endangered	Prairie rivers and streams
	Topeka shiner *(Notropis topeka)*	Critical Habitat	

006930

County	Species	Status	Habitat
	Prairie bush clover *(Lespedeza leptostachya)*	Threatened	Native prairie on well-drained soils
	Western prairie fringed orchid *(Platanthera praeclara)*	Threatened	Wet prairies and sedge meadows
Roseau	Canada lynx *(Lynx canadensis)*	Threatened	Northern forest
	Sprague's pipit *(Anthus spragueii)*	Candidate	Large (>350 acre) patches of grassland - prefer native grassland, but also use non-native planted grasslands.
	*Poweshiek skipperling *(Oarisma poweshiek)*	Candidate	Native Prairie
St. Louis	Piping Plover *(Charadrius melodus)* Great Lakes Breeding Population	Endangered and Critical Habitat Designated in this county	Sandy beaches, islands
	Canada lynx *(Lynx canadensis)*	Threatened	Northern forest
	Canada lynx *(Lynx canadensis)*	Critical Habitat	Map of lynx critical habitat in Minnesota
Scott	No listed species present		
Sherburne	No listed species present		
Sibley	No listed species present		
Stearns	*Poweshiek skipperling *(Oarisma poweshiek)*	Candidate	Native Prairie
Steele	Dwarf trout lily *(Erythronium propullans)*	Endangered	North facing slopes and floodplains in deciduous forests
Stevens	No listed species present		
Swift	Dakota skipper *(Hesperia dacotae)*	Candidate	Native prairie habitat
	*Poweshiek skipperling *(Oarisma poweshiek)*	Candidate	Native Prairie
Todd	No listed species present		

County	Species	Status	Habitat
Traverse	Dakota skipper *(Hesperia dacotae)*	Candidate	Native prairie habitat
	*Poweshiek skipperling *(Oarisma poweshiek)*	Candidate	Native Prairie
Wabasha	Eastern massasauga (*Sistrurus catenatus*)	Candidate	Floodplain wetlands and nearby upland areas along the Mississippi River and Tributaries
	Higgins eye pearlymussel *(Lampsilis higginsii)*	Endangered	Mississippi River
	Sheepnose (*Plethobasus cyphyus*)	Endangered	Mississippi River
	Spectaclecase (*Cumberlandia monodonta*)	Endangered	Mississippi River
Wadena	No listed species present		
Waseca	No listed species present		
Washington	Higgins eye pearlymussel *(Lampsilis higginsii)*	Endangered	Mississippi River
	Snuffbox (*Epioblasma triquetra*)	Endangered	Small to medium-sized creeks and some larger rivers, in areas with a swift current
	Spectaclecase (*Cumberlandia monodonta*)	Endangered	St. Croix River
	Winged mapleleaf *(Quadrula fragosa)*	Endangered	St. Croix River
Watonwan	No listed species present		
Wilkin	*Poweshiek skipperling *(Oarisma poweshiek)*	Candidate	Native Prairie
Winona	Eastern massasauga (*Sistrurus catenatus*)	Candidate	Floodplain wetlands and nearby upland areas along the Mississippi River and Tributaries
	Higgins eye pearlymussel *(Lampsilis higginsi)*	Endangered	Mississippi River

006932

County	Species	Status	Habitat
	Sheepnose (*Plethobasus cyphyus*)	Endangered	Mississippi River
	Karner blue butterfly (*Lycaeides melissa samuelis*)	Endangered	Pine barrens and oak savannas on sandy soils and containing wild lupines (*Lupinus perennis*), the only known food plant of larvae.
Wright	No listed species present		
Yellow Medicine	Dakota skipper (*Hesperia dacotae)*	Candidate	Native prairie habitat
	*Poweshiek skipperling (*Oarisma poweshiek*)	Candidate	Native Prairie

Revised March 2012

Current, Rhonda

From:	Mueller, Connie <connie_mueller@fws.gov>
Sent:	Wednesday, March 20, 2013 1:50 PM
To:	Pickle, Joyce E.
Cc:	Michael Erickson; Heidi Riddle; Charlene Bessken; Jay Peterson; Rob Bundy
Subject:	USFWS comments on BSSE line

Ms. Pickle,

The BSSE transmission line is progressing toward route selection, and you have requested the U.S. Fish & Wildlife Service (USFWS) thoughts on the line, and the NEPA process.

As you are aware, USFWS is involved in two different ways with this project. The fee title and easement lands are covered by the Division of Refuges. Endangered species and migratory bird concerns are covered by the Division of Ecological Services. Comments provided here are a collection of thoughts from both Divisions in both South and North Dakota.

The USFWS does not have any comments on the preferred route selection beyond what has already been provided at the local meetings.

It appears that it will be difficult to avoid all wetland and grassland easement interests. If a grassland easement is crossed, or a wetland basin on a wetland easement contract is impacted, the NEPA process will be triggered. USFWS will provide guidance on the writing of the document; however, the final route selection will determine the exact details of the document. Below are a few elements that will likely need to be covered in the NEPA process, however, the list may be expanded when the final route is reviewed.

- When USFWS is satisfied that all efforts have been made to avoid easement impacts, acres of wetland and grassland easements impacted will need to be replaced with equal biological and financial acres of similar habitat. The exact pole locations will need to be surveyed and recorded. A reclusion clause is included if the line is ever decommissioned.

- USFWS has previously requested avoidance of all fee-title lands, and in particular the area in Dickey County that has been identified.

- Whooping cranes are known to stop over in areas near the line. To reduce the risk of a line strike, the Service's Region 6 Guidance for Minimizing Effects from Power Line Projects within the Whooping Crane Migration Corridor recommends that project proponents mark new lines within 1.0 mile of potentially suitable habitat and an equal amount of existing line within 1.0 mile of potentially suitable habitat (preferably within the 75-percent corridor, but at a minimum within the 95-percent corridor). Outside the corridor, project proponents should mark new lines within 1.0 mile of potentially suitable habitat.

- The Dakota skipper and Poweshiek skippering are two ESA candidate species that are known to occur on native prairie near the proposed transmission line in Grant/Day/Marshall Counties, SD and near the Dickey/Sargent County line in ND. As a matter of policy, the Service's Refuge Division treats candidate species as proposed, which may require a conference under Section 7 of the ESA. A survey of suitable habitat for these butterflies maybe prudent. If good habitat is located, surveys for the species should be conducted.

- Migratory birds – there is no take permit for migratory birds so a conservation plan and/or compensatory mitigation may need to be completed. Colonial nesting birds and grassland birds may be affected. You will need to detail how you are going to avoid and/or minimize the effect on migratory birds.

Connie Mueller

--
Connie Mueller, Project Leader
Waubay NWR Complex
605-947-4521 office

Current, Rhonda

From: Mueller, Connie <connie_mueller@fws.gov>
Sent: Thursday, June 06, 2013 2:43 PM
To: Pickle, Joyce E.
Subject: BSSE Route

Joyce,

Kulm and Sand Lake reported they have no new easements beyond what was included on the map Sue Kvas provided. Waubay does, but I don't have that ready to go yet. Will get it to you as soon as I can. Since we get annual updates from Sue Kvas we usually don't map them ourselves. It is taking longer than I expected.

Connie
--
Connie Mueller, Project Leader
Waubay NWR Complex
605-947-4521 office

Current, Rhonda

From: Mueller, Connie <connie_mueller@fws.gov>
Sent: Thursday, June 20, 2013 1:36 PM
To: Pickle, Joyce E.
Subject: Re: new easements

Joyce,

Thanks for your patience. All of the files have been checked, and to date there is only one additional easement which has been signed and falls on the BSSE line. This is a grassland easement located at the legal description: [redacted] less the gravel pit

The wetlands were previously protected and will be shown on the information provided by HAPET.

The other ones I mentioned earlier are in various stages of the process. If any of them are signed in the future, I will let you know.

Connie

On Fri, Jun 14, 2013 at 11:19 AM, Pickle, Joyce E. <Joyce.Pickle@hdrinc.com> wrote:

Thanks Connie, I appreciate the update. I'll look forward to more information once the status is available to you.

Thanks and have a good weekend!

Joyce

From: Mueller, Connie [mailto:connie_mueller@fws.gov]
Sent: Thursday, June 13, 2013 4:24 PM
To: Pickle, Joyce E.
Subject: new easements

Joyce,

There are four properties which this office has submitted as easement evaluations recently which would touch the proposed route which you provided. Some of these may have had offers made, and declined. To avoid providing you incorrect information, I have asked the realty office to provide me the current status of these properties. As soon as I hear back I will let you know. To provide you a sense of scope - two of them have wetland easements being considered and three have grassland easements under consideration.

Connie

--
Connie Mueller, Project Leader

Waubay NWR Complex

605-947-4521 office

--
Connie Mueller, Project Leader
Waubay NWR Complex
605-947-4521 office

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Ecological Services
420 South Garfield Avenue, Suite 400
Pierre, South Dakota 57501-5408

July 24, 2013

Mr. Chad Miller
Montana-Dakota Utilities Company
400 North Fourth Street
Bismarck, North Dakota 58501-4092

Re: Big Stone South to Ellendale 345 kV Transmission Line Project

Dear Mr. Miller:

This letter is in response to your informational letter dated May 6, 2013, that identifies preferred routes for the above referenced project involving the construction of a new 345 kV transmission line from Big Stone South in South Dakota to the Ellendale substation in North Dakota. The U.S. Fish and Wildlife Service (Service) has provided previous comments on this project and has participated in meetings and conference calls for this project. The preferred route will pass through Grant, Day, and Brown Counties in South Dakota and through Dickey County in North Dakota. This letter will serve as a response for the Service in both North Dakota and South Dakota as well as from both Ecological Services and Refuges Divisions.

According to the National Wetlands Inventory map (available online at http://wetlands.fws.gov/), wetlands exist in the proposed project area. If a project may impact wetlands or other important fish and wildlife habitats, the Service, in accordance with the National Environmental Policy Act of 1969 (42 U.S.C. 4321-4347) and other environmental laws and rules, recommends complete avoidance of these areas, if possible; then minimization of any adverse impacts; and finally, replacement of any lost acres; in that order. Alternatives should be examined and the least damaging practical alternative selected. If wetland impacts are unavoidable, a mitigation plan addressing the number and types of wetland acres to be impacted and the methods of replacement should be prepared and submitted to the resource agencies for review.

The location of your project falls within an area under the jurisdiction of the Service's Waubay, Sand Lake, and Kulm Wetland Management Districts (WMD). The Waubay WMD administers easements and fee title properties in Grant and Day Counties, the Sand Lake WMD administers Brown County, and the Kulm WMD administers Dickey County. You have previously requested and been provided a map depicting Service interest lands at the proposed project site. For any additional restrictions that may apply regarding these sites, the single point of contact for the WMDs will be the Waubay WMD. Please contact Connie Mueller at the Service's Waubay WMD, 44401 134A Street, Waubay, South Dakota 57273, Telephone No. (605) 947-4521.

In accordance with section 7(c) of the Endangered Species Act (ESA), as amended, 16 U.S.C. 1531 et seq., we have determined that the following federally listed species may occur in the project area (this list is considered valid for 90 days). Specific information on locations has already been provided for this project.

Species	Status	Expected Occurrence
Whooping crane (*Grus americana*)	Endangered	Migration.
Topeka shiner (*Notropis topeka*)	Endangered	Known resident.
Dakota skipper (*Hesperia dacotae*)	Candidate	Resident in native prairie, northeastern South Dakota and southwestern North Dakota.
Poweshiek skipperling (*Oarisma poweshiek*)	Candidate	Resident in native prairie, northeastern South Dakota and southwestern North Dakota.

Whooping cranes migrate through the Dakotas on their way to northern breeding grounds and southern wintering areas. They occupy numerous habitats such as cropland and pastures; wet meadows; shallow marshes; shallow portions of rivers, lakes, reservoirs, and stock ponds; and both freshwater and alkaline basins for feeding and loafing. Overnight roosting sites frequently require shallow water in which to stand and rest. Should construction occur during spring or fall migration, the potential for disturbances to whooping cranes exists. Disturbance (flushing the birds) stresses them at critical times of the year. We recommend remaining vigilant for these birds. There is little that can be done to reduce disturbance besides ceasing construction at sites where the birds have been observed. The birds normally do not stay in any one area for long during migration. Any whooping crane sightings should be reported to this office.

A short portion of the western segment of the proposed transmission line may be located inside the whooping crane migration corridor where 95 percent of confirmed sightings have occurred. We have enclosed the *"Region 6 Guidance for Minimizing Effects from Power Line Projects Within the Whooping Crane Migration Corridor"* to assist in the design of your project. In accordance with those guidelines, we recommend that you follow those guidelines, including development of compliance monitoring plans that are shared with the Service. We encourage you to work with the respective Ecological Services Field Offices in each state if there are questions whether to mark portions of the line near wetland areas outside the 95 percent migration corridor that may still be attractive to whooping cranes.

Topeka shiners are known to occupy numerous small streams within eastern South Dakota and are concentrated within the Big Sioux, Vermillion, and James River watersheds. If any instream construction is necessary for this project, additional measures may be necessary to ensure that adverse impacts to the Topeka shiner are not incurred as a result of this project.

The Dakota skipper may occur along the project route. The Dakota skipper is a candidate species and accordingly is not provided Federal protection under the ESA. Their candidate status defines this butterfly as a species in decline that the Service believes warrants listing as either threatened or endangered, and the Service expects to make a listing decision prior to the proposed construction date of 2016-2019. Dakota skippers are obligate residents of high quality prairie ranging from wet-mesic tallgrass prairie to dry-mesic mixed grass prairie. In northeastern South Dakota, Dakota skippers inhabit dry-mesic hill prairies with abundant purple coneflower but also use mesic to wet-mesic tallgrass prairie habitats characterized by wood lily and smooth camas. Dakota skippers have been documented from Brown, Day, and Grant Counties.

The Poweshiek skipperling is a candidate species and accordingly is not provided Federal protection under the ESA. Their candidate status defines this butterfly as a species in decline that the Service believes warrants listing as either threatened or endangered, and the Service expects to make a listing decision prior to the proposed construction date of 2016-2019. Preferred nectar plants include yellow ox-eye and purple coneflower. They also use tickseed, black-eyed susan, and pale-spike lobelia. Larval food plants are assumed to include spike-rush, sedges, prairie dropseed, and little bluestem. The habitat of Poweshiek skipperlings includes native tallgrass prairie, fens, grassy lake and stream margins, moist meadows, and wet-mesic to dry tallgrass prairie. They have a low dispersal capability, so fragmented and isolated prairie remnants are unlikely to be repopulated. They are vulnerable to extreme weather conditions, dormant season fire, and other disturbances (e.g., intense cattle grazing). Poweshiek skipperlings have been found in Day and Grant Counties.

If the Federal action agency or their designated representative determines that the project will have "no effect" on federally listed species, Service concurrence is not necessary per section 7 of the ESA. If a "may affect - not likely to adversely affect" determination is made for this project, it should be submitted to this office for concurrence. If the Federal action agency or their designated representative determines that this project "may adversely affect" listed species in South Dakota, it should request formal consultation from this office. For more information regarding Federal action agency responsibilities as related to section 7 of the ESA, please refer to the Service's Endangered Species Act Consultation Handbook, available online at http://www.fws.gov/endangered/consultations/index.html.

The proposed project involves new construction in an area that appears to be relatively undeveloped, although it will primarily be adjacent to an existing roadway which undoubtedly subjects the site to some level of human disturbances. Nonetheless, the potential for impacts to migratory birds exists in the path of the new alignment; therefore, we recommend initiation of project construction or soil disturbance activities outside of the primary breeding season for most migratory birds (approximately mid-April to mid-July) if possible.

The Migratory Bird Treaty Act (MBTA) prohibits the taking, killing, possession, and transportation (among other actions) of migratory birds, their eggs, parts, and nests, except when specifically permitted by regulations. While the MBTA has no provision for allowing unauthorized take, the Service realizes that some birds may be killed during construction of the project even if all known reasonable and effective measures to protect birds are used. The Service's Office of Law Enforcement carries out its mission to protect migratory birds through investigations and enforcement as well as by fostering relationships with individuals, companies, and industries that have taken effective steps to avoid take of migratory birds and by encouraging others to implement measures to avoid take of migratory birds. It is not possible to absolve individuals, companies, or agencies from liability even if they implement bird mortality avoidance or other similar protective measures. However, the Office of Law Enforcement focuses its resources on investigating and prosecuting individuals and companies that take migratory birds without identifying and implementing all reasonable, prudent, and effective measures to avoid that take. Companies are encouraged to work closely with Service biologists to identify available protective measures when developing project plans and/or avian protection plans and to implement those measures prior to/during construction, operation, or similar activities.

To the extent practicable, we recommend scheduling construction for late summer or fall/early winter to minimize disruption of migratory birds during the breeding season, February 1 to July 15. If work is proposed to take place during the breeding season, there may be take of migratory birds, their eggs, or active nests. Alternatively, a qualified biologist could conduct bird/nest surveys within five days prior to the initiation of construction. If active nests are identified, the project proponent should cease construction, maintain a sufficient buffer around active nests to avoid disturbing breeding activities, and contact the Service immediately. The Service recommends implementation of all practicable measures to avoid all take, such as suspending construction where necessary and/or maintaining adequate buffers to protect the birds until the young have fledged. The Service further recommends that, if you choose to conduct field surveys for nesting birds with the intent of avoiding take, you maintain any documentation of the presence of migratory birds, eggs, and active nests along with information regarding the qualifications of the biologist(s) performing the survey(s) and any avoidance measures implemented at the project site. We encourage your companies to conduct surveys for colonial nesting birds along the preferred route and avoid impacting colonies, if found, during the nesting season.

If changes are made in the project plans or operating criteria, or if additional information becomes available, the Service should be informed so that the above comments can be reconsidered.

The Service appreciates the opportunity to provide comments. If you have any questions regarding these comments, please contact Charlene Bessken of this office at (605) 224-8693, Extension 231.

Sincerely,

Scott Larson

Scott V. Larson
Field Supervisor
South Dakota Field Office

Enclosure

cc: FWS/Waubay WMD; Waubay, SD
(Attention: Connie Mueller)
FWS/Sand Lake WMD; Columbia, SD
(Attention: Harris Hoistad and Jay Peterson)
FWS/Kulm WMD; Kulm, ND
(Attention: Michael Erickson)
FWS/ND ES Field Office; Bismarck, ND
(Attention: Jeff Towner and Heidi Riddle)

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Mountain-Prairie Region

IN REPLY REFER TO:
FWS/R6
ES

MAILING ADDRESS:
P.O. Box 25486, DFC
Denver, Colorado 80225-0486

STREET LOCATION:
134 Union Boulevard
Lakewood, Colorado 80228-1807

FEB 04 2010

Memorandum

To: Field Office Project Leaders, Ecological Services, Region 6
Montana, North Dakota, South Dakota, Nebraska, Kansas

From: Assistant Regional Director, Ecological Services, Region 6

Subject: Region 6 Guidance for Minimizing Effects from Power Line Projects Within the Whooping Crane Migration Corridor

This document is intended to assist Region 6 Ecological Services (ES) biologists in power line (including generation lines, transmission lines, distribution lines, etc.) project evaluation within the whooping crane migration corridor. The guidance contained herein also may be useful in planning by Federal action agencies, consultants, companies, and organizations concerned with impacts to avian resources, such as the Avian Power Line Interaction Committee (APLIC). We encourage action agencies and project proponents to coordinate with their local ES field office early in project development to implement this guidance.

The guidance includes general considerations that may apply to most, but not every, situation within the whooping crane migratory corridor. Additional conservation measures may be considered and/or discretion may be applied by the appropriate ES field office, as applicable. We believe that in most cases the following measures, if implemented and maintained, could reduce the potential effects to the whooping crane to an insignificant and/or discountable level. Where a Federal nexus is lacking, we believe that following these recommendations would reduce the likelihood of a whooping crane being taken and resulting in a violation of Endangered Species Act (ESA) section 9. If non-Federal actions cannot avoid the potential for incidental take, the local ES field office should encourage project proponents to develop a Habitat Conservation Plan and apply for a permit pursuant to ESA section 10(a)(1)(B).

Finally, although this guidance is specific to impacts of power line projects to the whooping crane within the migration corridor, we acknowledge that these guidelines also may benefit other listed and migratory birds.

If you have any questions, please contact Sarena Selbo, Section 7 Coordinator, at (303) 236-4046.

Region 6 Guidance for Minimizing Effects from Power Line Projects Within the Whooping Crane Migration Corridor

1) Project proponents should avoid construction of overhead power lines within 5.0 miles of designated critical habitat and documented high use areas (these locations can be obtained from the local ES field office).

2) To the greatest extent possible, project proponents should bury all new power lines, especially those within 1.0 mile of potentially suitable habitat[1].

3) If it is not economically or technically feasible to bury lines, then we recommend the following conservation measures be implemented:

    a) Within the 95-percent sighting corridor (see attached map)

        i) Project proponents should mark[2] new lines within 1.0 mile of potentially suitable habitat and an equal amount of existing line within 1.0 mile of potentially suitable habitat (preferably within the 75-percent corridor, but at a minimum within the 95-percent corridor) according to the U.S. Fish and Wildlife Service (USFWS) recommendations described in APLIC 1994 (or newer version as updated).

        ii) Project proponents should mark replacement or upgraded lines within 1.0 mile of potentially suitable habitat according to the USFWS recommendations described in APLIC 1994 (or newer version as updated).

    b) Outside the 95-percent sighting corridor within a State's borders

    Project proponents should mark new lines within 1.0 mile of potentially suitable habitat at the discretion of the local ES field office, based on the biological needs of the whooping crane.

    c) Develop compliance monitoring plans

    Field offices should request written confirmation from the project proponent that power lines have been or will be marked and maintained (i.e., did the lines recommended for marking actually get marked? Are the markers being maintained in working condition?)

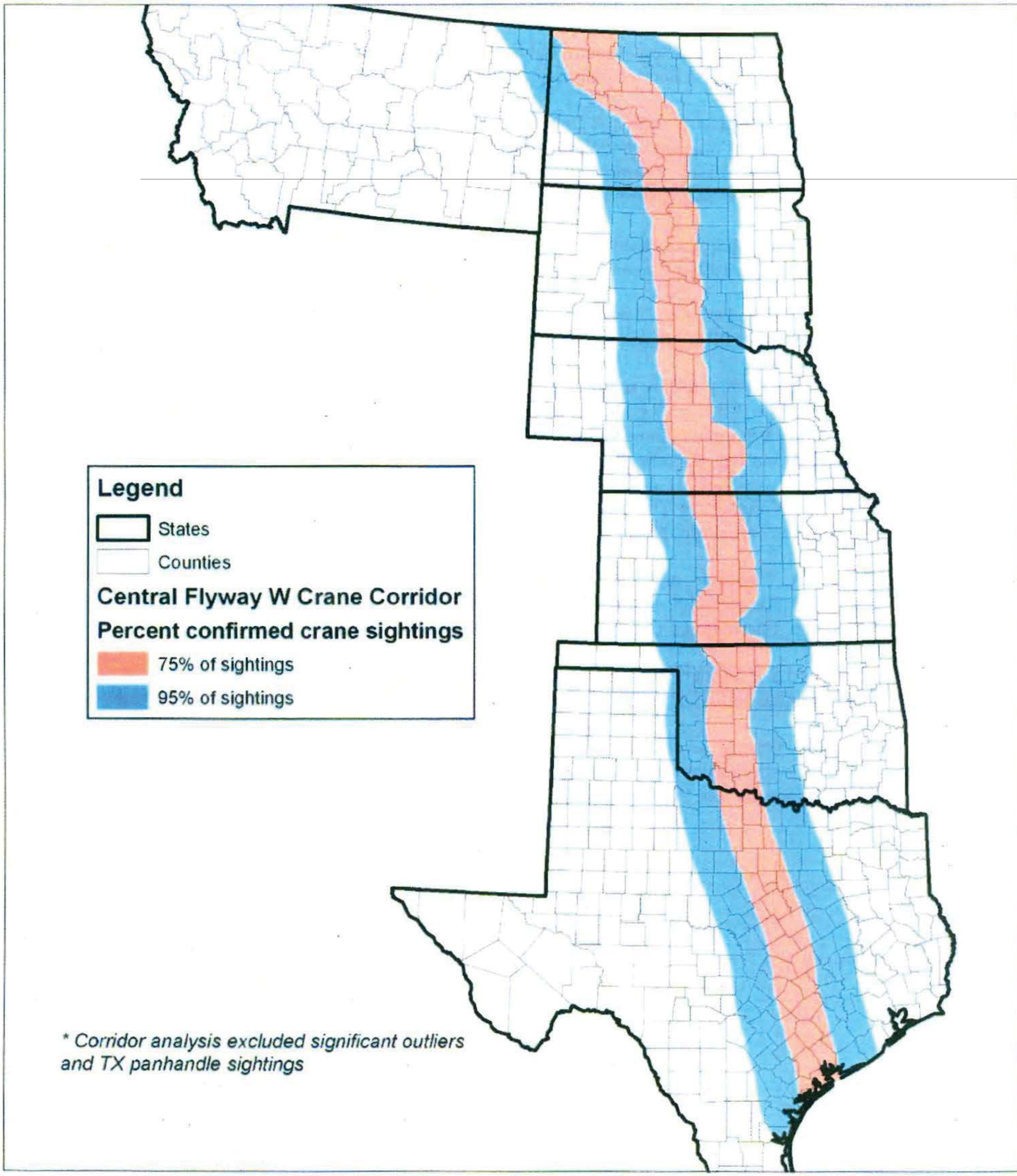
---

[1] Potentially suitable migratory stop over habitat for whooping cranes includes wetlands with areas of shallow water without visual obstructions (i.e., high or dense vegetation) (Austin & Richert 2001; Johns et al. 1997; Lingle et al. 1991; Howe 1987) and submerged sandbars in wide, unobstructed river channels that are isolated from human disturbance (Armbruster 1990). Roosting wetlands are often located within 1 mile of grain fields. As this is a broad definition, ES field office biologists should assist action agencies/applicants/companies in determining what constitutes potentially suitable habitat at the local level.

[2] Power lines are cited as the single greatest threat of mortality to fledged whooping cranes. Studies have shown that marking power lines reduces the risk of a line strike by 50 to 80 percent (Yee 2008; Brown & Drewien 1995; Morkill & Anderson 1991). Marking new lines and an equal length of existing line in the migration corridor maintains the baseline condition from this threat.

U.S. Fish & Wildlife Service

United States Central Flyway Whooping Crane Migration Corridor *



Produced for Ecological Services
Grand Island, NE
Current to: 2008
Basemap (Date): U.S. Counties
Meridian:
File:

006945

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Current, Rhonda

From: Dianne Desrosiers <DianneD@SWO-NSN.GOV>
Sent: Friday, March 29, 2013 11:46 AM
To: Pickle, Joyce E.
Cc: Jim Whitted; Waste'Win Young; Terry Clouthier
Subject: RE: Big Stone South to Ellendale Transmission Line Project - 1 of 6

Joyce
Good morning, I wanted to touch base with you before the Easter holiday. After review of the maps we believe Route A (in the red on the attached map) is the least intrusive with regard to cultural resources, due to the high volume of cultivated lands. If you have any questions please contact our office. We look forward to hearing from you and our upcoming meeting on May 7, 2013.

From: Pickle, Joyce E. [mailto:Joyce.Pickle@hdrinc.com]
Sent: Monday, March 25, 2013 3:24 PM
To: Stanfill, Alan; jmswhitted@yahoo.com; wyoung@standingrock.org; Dianne Desrosiers
Subject: Big Stone South to Ellendale Transmission Line Project - 1 of 6

Hello Dianne, Waste Wi and Jim – Alan let me know that you may have had problems getting the email with attachments that he sent out on March 13th, with maps and tables of land cover along the BSSE transmission line preliminary routes. I am hoping that sending you separate emails with attachments of 10 MB or less will work better. Please let me know if you receive this.

Attached is a table that gives percentage breakdowns of different land covers. Note that we have distinguished between cultivated and non-cultivated. There is also a “no data/cloud cover” category (less than 5% of the area) – this is in areas that we couldn’t make determinations because the aerial data we had was missing information.

The attached map is an index. Basically, Corridor A is the Aberdeen Route
Corridor B is the route that goes through North Dakota and then south along the Britton corridor, nearest the Keystone Pipeline.
Corridor C is similar to Corridor B, but takes the route that goes east of the Keystone Pipeline
Corridor D is the common route – this is the general route that will be taken, independent of whether the Aberdeen or Britton Route is selected.

Five more emails will follow with more detailed maps showing the preliminary routes and land cover.

Let me know if you have any questions.

Sincerely,
Joyce

JOYCE PICKLE
HDR Engineering, Inc.
Environmental Project Manager

701 Xenia Avenue South, Suite 600 | Minneapolis, MN 55416
Office: 763.591.5443 | Mobile: 763.567.3406
joyce.pickle@hdrinc.com | hdrinc.com

Current, Rhonda

From: Miller, Chad <Chad.Miller@mdu.com>
Sent: Thursday, August 16, 2012 8:41 PM
To: Hunker, Brian M.; Siedschlag, Emily
Subject: BSSE- SD Dept of AG comments

Please make sure Bill Smith is contact for future mailings to the SD DEPT of AG

Sincerely,

Chad Miller

From: Bill.Smith@state.sd.us [mailto:Bill.Smith@state.sd.us]
Sent: Thursday, August 16, 2012 4:51 PM
To: Miller, Chad
Subject: Request for Information-MDU Ottertail Power Proposed Big Stone South to Ellendale

Chad,

Pam Bergstrom (SD Department of Agriculture) was sent a letter regarding this project. Pam is no longer employed by our Department.

After reviewing your letter, I do not have any comments regarding this project.

If you have any questions, please feel free to contact me.

Sincerely,

Bill Smith

From: Smith, Bill
To: Pickle, Joyce E.
Subject: RE: BSSE Transmission Line - response requested to preferred route mailing
Date: Monday, July 08, 2013 3:34:48 PM

Joyce,

We have no comments at this time. Please continue to keep us in the loop.

Thanks,

Bill Smith

From: Pickle, Joyce E. [mailto:Joyce.Pickle@hdrinc.com]
Sent: Monday, July 08, 2013 3:19 PM
To: ppicha@nd.gov; mary.podoll@nd.usda.gov; Sam.E.Werner@usace.army.mil; karen_anderson@nps.gov; patricia.dressler@faa.gov; Northdakota.Fhwa@dot.gov; jdschumacher@nd.gov; jobserv@nd.gov; kcwanner@nd.gov; ndda@nd.gov; sjdavis@nd.gov; Duttenhefner, Kathy G. (kgduttenhefner@nd.gov); gcfisher@nd.gov; Olson, Paige; richard.pearson@state.sd.us; Smith, Bill; Sarah.Land@state.sd.us; Bergquist, Darin; Roberts, Hunter (TSD); chris.maxwell@state.sd.us
Cc: Miller, Chad
Subject: BSSE Transmission Line - response requested to preferred route mailing

Greetings!

On May 6, 2013, Montana-Dakota Utilities Co. and Otter Tail Power Company mailed a letter to your agency regarding their selected preferred route for the proposed Big Stone South to Ellendale (BSSE) 345 kV transmission line project. The BSSE project team is requesting comment from your agency on the preferred route (see the attached preferred route map) prior to the South Dakota and North Dakota state permit application submittals which are anticipated to be submitted starting in late-August. We would appreciate your review of the preferred route and request that you provide any comments by Friday, July 19, 2013 so we may incorporate them into the application materials and route design.

We appreciate your ongoing participation in this project and look forward to continuing to work with you. If you have questions or comments you would like us to address for the BSSE project, please send a hardcopy, email, or .pdf copy of your response to Chad Miller at (701) 222-7865, chad.miller@mdu.com, or by mail at the address below.

Chad Miller
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, ND 58501-4092

Sincerely,

JOYCE PICKLE
HDR Engineering, Inc.
Environmental Project Manager

701 Xenia Avenue South, Suite 600 | Minneapolis, MN 55416
Office: 763.591.5443 | Mobile: 763.567.3406
joyce.pickle@hdrinc.com | hdrinc.com

Current, Rhonda

From: Miller, Chad <Chad.Miller@mdu.com>
Sent: Wednesday, August 15, 2012 12:05 PM
To: Hunker, Brian M.; Siedschlag, Emily
Subject: BSSE- SD DENR comments

Sincerely,

Chad Miller

From: Patrick.Snyder@state.sd.us [mailto:Patrick.Snyder@state.sd.us]
Sent: Wednesday, August 15, 2012 11:57 AM
To: Miller, Chad
Cc: John.Miller@state.sd.us
Subject: Big Stone South to Ellendale Project

Chad,

Thanks for the opportunity to comment on the proposed project.

As this project is in the preliminary stages and no exact route has been established, all I can give you some very general comments.

There are numerous streams and lakes that are classified in South Dakota's Surface Water Quality Standards. The specific classified uses and associated water quality standards vary. Additionally, all waterbodies, including wetland, are considered waters of the state and impacts to these waters must be minimized.

When you submit your final plans, the department can provide more detailed comments concerning the waterbodies that may be impacted by this project.

If you have questions, please let me know.

Patrick Snyder
Environmental Scientist IV
South Dakota Department of Environment and Natural Resources

DEPARTMENT of ENVIRONMENT
and NATURAL RESOURCES
PMB 2020
JOE FOSS BUILDING
523 EAST CAPITOL
PIERRE, SOUTH DAKOTA 57501-3182
denr.sd.gov

May 29, 2013

Chad Miller
Montana-Dakota Utilities Company
400 North Fourth Street
Bismarck, ND 58501-4092

Dear Mr. Miller:

The South Dakota Department of Environment and Natural Resources (DENR) reviewed the proposed Big Stone South to Ellendale 345kV Transmission Line Project. The DENR finds that this construction, using conventional construction techniques, should not cause violation of any statutes or regulations administered by the DENR based on the following recommendations:

1. At a minimum and regardless of project size, appropriate erosion and sediment control measures must be installed to control the discharge of pollutants from the construction site. Any construction activity that disturbs an area of one or more acres of land must have authorization under the General Permit for Storm Water Discharges Associated with Construction Activities. Contact the Department of Environment and Natural Resources for additional information or guidance at 1-800-SDSTORM (737-8676) or http://denr.sd.gov/des/sw/StormWaterandConstruction.aspx.

2. A Surface Water Discharge (SWD) permit may be required if any construction dewatering should occur as a result of this project. Please contact this office for more information.

3. These segments of the Elm and Maple Rivers are classified by the South Dakota Surface Water Quality Standards and Uses Assigned to Streams for the following beneficial uses:

   (1) Domestic water supply waters;
   (5) Warmwater semi-permanent fish life propagation waters;
   (8) Limited contact recreation waters;
   (9) Fish and wildlife propagation, recreation, and stock watering waters; and
   (10) Irrigation waters.

   Because of these beneficial uses, special construction measures may have to be taken to ensure that the total suspended solids standard of 90 mg/L is not violated.

These segments of the James, Big Sioux and Whetstone Rivers are classified by the South Dakota Surface Water Quality Standards and Uses Assigned to Streams for the following beneficial uses:

(5) Warmwater semi-permanent fish life propagation waters;
(8) Limited contact recreation waters;
(9) Fish and wildlife propagation, recreation, and stock watering waters; and
(10) Irrigation waters.

Because of these beneficial uses, special construction measures may have to be taken to ensure that the total suspended solids standard of 90 mg/L is not violated.

This segment of the North Fork Whetstone River is classified by the South Dakota Surface Water Quality Standards and Uses Assigned to Streams for the following beneficial uses:

(6) Warmwater marginal fish life propagation waters;
(8) Limited contact recreation waters;
(9) Fish and wildlife propagation, recreation, and stock watering waters; and
(10) Irrigation waters.

Because of these beneficial uses, special construction measures may have to be taken to ensure that the total suspended solids standard of 150 mg/L is not violated.

4. Other tributaries and wetlands may be impacted by this project. These water bodies are considered waters of the state and are protected under the South Dakota Surface Water Quality Standards. The discharge of pollutants from any source, including indiscriminate use of fill material, may not cause destruction or impairment except where authorized under Section 404 of the Federal Water Pollution Control Act. Please contact the U.S. Army Corps of Engineers concerning these permits.

If you have any questions concerning these comments, please contact me at (605) 773-3351.

Sincerely,

John Miller

John Miller
Environmental Scientist
Surface Water Quality Program

South Dakota
Wildlife Division
Department of Game, Fish and Parks

Foss Building
523 East Capitol
Pierre, South Dakota 57501-3182

August 14, 2012

Chad Miller, Environmental Scientist
Montana Dakota Utilities
400 North 4th Street
Bismarck, ND 58501

Dear Mr. Miller,

This letter is in response to a request dated 27 July 2012 from Montana-Dakota Utilities and Otter Tail Power Company for review of a proposed 150 to 175 mile long 345 kV transmission line called Big Stone South to Ellendale (BSSE) project. This project is located within all or a portion of eleven counties in northeastern South Dakota.

NATURAL HERITAGE DATA
For more information on species at risk in the project area, please contact the South Dakota Natural Heritage Program. The Natural Heritage Program tracks species at risk and maintains a database of this information. Species at risk are those that are threatened, endangered (according to statute) or considered rare. Rare species are those that are declining and restricted to limited habitat, peripheral to a jurisdiction, isolated or disjunct due to geographic or climatic factors or that are classified as such due to lack of survey data. A list of the species monitored by the South Dakota Natural Heritage Program can be found at http://gfp.sd.gov/wildlife/threatened-endangered. Please contact our Database Manager, Casey Mehls at (605) 773-4345 or Casey.Mehls@state.sd.us to request a search of the database for records within the proposed project area. Please note that the absence of a species from the database does not preclude its presence in an area. Many places in South Dakota have not been surveyed for rare or protected species.

The following provides information on ecoregions and habitat important to South Dakota's wildlife that may be affected by the proposed project. In addition, we identify specific species or species-groups that may be affected by the proposed project. Recommendations are provided to avoid impacts to these habitats and species.

ECOREGIONS
A large portion of the Prairie Coteau ecoregion lies within the proposed project boundary. This ecoregion is unique to South Dakota (Bryce et al. 1998). Created by glaciers and lacking a drainage pattern, the hilly landscape has abundant seasonal, semi-permanent and permanent wetlands. The latter were formed in areas with little ice shear; many of these wetlands form a dense chain of lakes in this ecoregion. Precipitation levels (20-22 inches average annual) allow for woody (oak) growth around wetland margins increasing habitat and wildlife species diversity in the area. Potential

natural vegetation includes big and little bluestem, switchgrass, indiangrass, and blue grama.

GRASSLANDS

The proposed project area as well as the Prairie Coteau is located within the tall-grass prairie zone. Native grasslands within this zone are decreasing at an alarming rate. In South Dakota, less than one percent of native tall-grass prairie habitat remains (Samson et al. 1998). Tall-grass prairie is considered one of the most endangered resources in North America (Samson et al. 2004). Tall-grass prairie remnants occur in the proposed project area. The undulating, hilly landscape of the Prairie Coteau has made tillage in this ecoregion difficult and tracts of native tall-grass prairie remain on this coteau. These areas have high conservation value, especially areas with a high diversity of both plant and animal species where invasive plant species are limited or absent. We would suggest the routing of the proposed transmission line should avoid native prairie tracts in the Prairie Coteau ecoregion.

PRAIRIE BUTTERFLIES

The presence of prairie-obligate butterfly species is a good indicator of high quality prairie. Four rare prairie butterfly species are located within the proposed project area. These species are monitored by our Natural Heritage Program and include the following: Dakota skipper, ottoe skipper, poweshiek skipperling, and regal fritillary. Protection of remaining tracts of native prairie and associated nectar sources and larval host plants is required for the conservation of these rare butterfly species. There are potential disturbances to prairie butterfly species associated with the construction and maintenance of a transmission line. Increased activity and ground disturbance increases the chances of non-native, invasive plant species invasion. Chemical control of non-native, invasive species is a known threat to some butterfly species. Construction in prairie butterfly habitat should be avoided.

INVASIVE SPECIES

Disturbance to native vegetation should be kept to a minimum. Any areas disturbed should be revegetated using native seed sources. The Natural Resource Conservation Service Plant Materials Center in Bismarck, ND may serve as a good source of information on native plantings (http://plant-materials.nrcs.usda.gov/ndpmc/). Information on where to get native seeds and how and why to establish them can be found at the following links:

- Conservation Seed/Plant Vendors List
    - http://www.plant-materials.nrcs.usda.gov/pubs/ndpmcmt8152.pdf
- Prairie Landscaping Seed/Plant Vendors List
    - http://www.plant-materials.nrcs.usda.gov/pubs/ndpmcmt8151.pdf
- Origins of Native Grass and Forb Releases
    - http://www.plant-materials.nrcs.usda.gov/pubs/ndpmctn6786.pdf
- Five Reasons to Choose Native Grasses
    - http://www.plant-materials.nrcs.usda.gov/pubs/ndpmctn7875.pdf

WETLANDS

The proposed project area is located within the Prairie Pothole region. This glaciated region, characterized by high densities of wetland basins of various depths and sizes, extends from Iowa into Minnesota, the Dakotas, Montana, and parts of Canada. It is the major waterfowl production area in North America. Wetland losses in the Prairie Pothole Region are staggering and range from 99% in Iowa to 35% in South Dakota. The Prairie Coteau ecoregion of the Prairie Pothole has some of the highest (>420 basins/10 mi^2) wetland basin densities in South Dakota (Johnson and Higgins 1997). More specifically, this area is known to have some of the highest densities (>30 basins/10 $miles^2$) of natural semipermanent and permanent wetland basins in the state. In addition, natural permanent wetland basins of a variety of sizes are most dense in the northern portion of the Prairie Coteau. The large natural, permanent basins (lakes) are concentrated in a chain which extends along the north-south axis of the Prairie Coteau. In times of drought, these permanent lakes serve as stronghold for wetland-dependant wildlife.

Permanent lakes in the northeastern portion of the state provide excellent habitat for nesting waterbirds such as herons, grebes, egrets, etc. Some of the largest (> 200 nesting pairs) and most permanent waterbird nesting colonies in the state are located in the proposed project area (Drilling 2008). Waterbirds have difficulty navigating power lines especially during take off and landing. Also, waterfowl and other birds often make daily and seasonal movements over narrow strips of land or "passes" between wetlands and wetland complexes; placement of power lines along these narrow passes should be avoided. Placement of above-ground transmission lines should avoid spanning large wetlands nor should they be placed between wetlands or wetland complexes. We recommend placing new transmission lines along existing corridors such as within existing disturbed areas such as road right-of-ways that do not currently intersect wetlands or run along narrow pieces of land between wetlands or wetland complexes.

BIRD STRIKES

Strikes with above ground power lines are a known cause of bird mortality (Erickson et al. 2005). Waterfowl (ducks, geese, swans, and cranes), raptors, and passerines are species most susceptible to power line collisions. Electrocution of birds that perch, roost, or nest on power lines continues to be a source of mortality especially for eagles, hawks, and owls ((APLIC) 2006).

The Avian Power Line Interaction Committee (APLIC) has developed two documents that provide useful information on how to reduce power line strikes and electrocutions:

- *Suggested Practices for Avian Protection on Power Lines: The State of the Art in 2006* and
- *Mitigating Bird Collisions with Power Lines.*

Both of these documents are available from the Edison Institute (http://www.aplic.org).

PUBLIC LANDS

Game Production Areas and Water Access Areas are purchased, managed, and utilized as wildlife habitat and for public hunting. Wildlife use of these areas may be affected by transmission line placement. Thus, we recommend avoidance of these areas.

Several U.S. FWS managed lands are found within the proposed project area including Waubay National Wildlife Refuge and Wetland Management District and Sand Lake National Wildlife Refuge and Wetland Management District. I would encourage you to contact both entities for any information on or concerns regarding U.S. FWS managed lands including grassland and wetland easements that may be in the proposed project area.

- Waubay National Wildlife Refuge; 44401 134A Street; Waubay, SD, 57273; Phone: 605-947-4521
- Sand Lake National Wildlife Refuge; 39650 Sand Lake Drive; Columbia, SD 57433; Phone: 605- 885-6320

Northeastern South Dakota has numerous tracts of these and other types of public lands. The location of these lands can be found online at http://www.sdgfp.info/Wildlife/PublicLands/PubLand.htm.

ENDANGERED OR THREATENED SPECIES

This proposed project location is within the migration route of the 'Aransas National Wildlife Refuge to Wood Buffalo National Park' population of whooping cranes. This species is protected as endangered under both state and federal laws. Placement of power lines in this area could increase the chances of power line strikes and electrocutions. The Endangered Species Act is administered by the U.S. Fish and Wildlife Service (USFWS). As such, I recommend contacting the USFWS Ecological Services Field Office in Pierre, SD for further information (605-224-8693 or southdakotafieldoffice@fws.gov).

The Topeka shiner is a federally endangered species that occupies a high percentage of known historic locations in South Dakota (Shearer 2003). The Topeka shiner is found in the proposed project area. Landscape alterations that occur during construction projects, etc. can cause land erosion and alter the sediment load and water regime of prairie streams affecting habitat available to fish, e.g., Topeka shiners. South Dakota Game, Fish & Parks, in collaboration with the USFWS developed the Topeka Shiner Management Plan (http://stage.sdgfp.info/Wildlife/Diversity/Topeka%20Shiner/TopekaShinerManagementPlan-Revised.pdf). Please contact the USFWS Ecological Services Field Office in Pierre, SD for more information.

The Dakota skipper requires native mid- to tall-grass prairie and is currently found on rolling rangeland with abundant wetlands. Current threats to this species include, but are not limited to, improper land management uses, agricultural cultivation, road construction, and invasive plant species. The Dakota skipper is reduced to scattered populations in fragmented prairies unsuitable for agricultural production, mostly in glacial hills that are too steep or rocky to plow. South Dakota populations are important to the existence of this species. This species is a candidate for listing under the Endangered Species Act (ESA). As such, please contact the USFWS Ecological Services Field Office in Pierre, SD.

Our records indicate bald eagles are nesting in the proposed project area. Migrant bald eagles may also be found in this area in the spring and fall. Please note that the bald eagle is state protected as a threatened species. This species is also protected by the Migratory Bird Treaty Act (MBTA) and the Bald and Golden Eagle Protection Act (BGEPA) which are both administered by the USFWS. The USFWS Ecological Services Field Office in Pierre can provide guidance regarding MBTA and BGEPA.

PRAIRIE GROUSE

Two grassland bird species of management interest to South Dakota Department of Game, Fish and Parks (SDGFP) that may be found in the proposed project area are the sharp-tailed grouse and greater prairie-chicken. The sharp-tailed grouse is a species that prefers grassland habitat (mid- to tall-grasses) with brushy draws and thickets. Deterioration of native grasslands, reduction of nesting and brood rearing cover, and variable climatic factors are limiting factors for this species. The greater prairie-chicken is species prefers tall- to mixed-grass prairies. Loss and fragmentation of tall-grass prairie are considered reason for population declines. These species are known to be area-sensitive, requiring comparatively large tracts of open, contiguous grassland. The lesser prairie chicken, a similar species found in the southern Great Plains, avoids nesting within 400 m of transmission lines or improved roads (Pitman et al. 2005). This information should be considered when determining placement of these structure types as they may also negatively affect greater prairie-chickens.

As outlined above, we have identified potential areas of concern that we would suggest the BSSE project consider when regarding the siting of the proposed transmission line. In sum these include potential impacts to remaining tracts of native prairie, behavior modifications of wetland-dependent species such as water birds and waterfowl, bird strikes and electrocutions, increased probability of invasive plant species establishment, and degradation of public lands managed for wildlife. Species present or likely to be present in the proposed project area have been identified that are protected under specific state or federal statues that significantly contribute to the diversity of the proposed project area.

Because of the potential impacts the placement of the proposed project may have on unique and declining habitats in the region and their associated wildlife species, it is recommended that routing avoid native prairie areas and areas of high wetland concentration. It is also recommended that placement of the proposed project utilize to the maximum extent possible currently disturbed areas (e.g. road ditches, cultivated areas, etc.) or collocated with existing power lines.

The SDGFP appreciates the opportunity to provide comments and we look forward to working with you and providing information as needed. Please send me the information on the upcoming meeting being planned in Pierre at tom.kirschenmann@state.sd.us. If you have any questions on the above comments, please feel free to contact Silka Kempema of my staff at 605-773-2742 or Silka.Kempema@state.sd.us.

Best regards,

Tom Kirschenmann
Chief of Terrestrial Resources

Literature Cited

Avian Power Line Interaction Committee (APLIC). 2006. Suggested Practices for Avian Protections on Power Lines: The State of the Art in 2006. Edison Electric Institute, APLIC and the California energy Commission, Washington, D.C. and Sacramento, CA.

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Shearer, J. S. 2003. Topeka shiner (*Notropis topeka*) management plan for the state of South Dakota. South Dakota Department of Game, Fish and Parks, Pierre, Wildlife Division Report No. 2003-10, 82 pp.

CC: Scott Larson, Field Supervisor, U. S. Fish and Wildlife Service, Ecological Services South Dakota Field Office, Pierre, SD

Connie Mueller, Project Leader, U. S. Fish and Wildlife Service Waubay National Wildlife Refuge and Wetland Management District, Waubay, SD

Harris Hoistad, Project Leader, U. S. Fish and Wildlife Service, Sand Lake National Wildlife Refuge and Wetland Management District, Attention

Casey Mehls, Natural Heritage Database Manager, South Dakota Department of Game, Fish and Parks, Pierre, SD.

SOUTH DAKOTA
Game, Fish & Parks

DEPARTMENT OF GAME, FISH, AND PARKS
Foss Building
523 East Capitol
Pierre, South Dakota 57501-3182

October 31, 2012

Chad Miller
Montana Dakota Utilities Co.
400 North Fourth Street
Bismarck, ND 58501-4092

Dear Mr. Miller,

Thank you for the invitation to the public meetings held in northeast South Dakota to study and discuss corridors for locating future transmission lines related to the Big Stone South to Ellendale project. As you are likely aware, Game, Fish and Parks staff attended two meetings, Aberdeen and Milbank, and shared concerns of transmission lines encountering Game Production Areas.

As I understand, there will be future meetings in early 2013 to further discuss transmission line routes once MDU has had more time to refine locations/routes after receiving the additional input from your public meetings. We look forward to reviewing the refined information and continued dialogue with MDU during this process.

Please feel free to share additional information with us as it develops and the times and locations of future meetings.

Best regards,

Tom Kirschenmann
Terrestrial Resources Chief

Office of Secretary: 605.773.3718 Wildlife Division: 605.223.7660 Parks/Recreation Division: 605.773.3391 FAX: 605.773.6245
TTY: 605.223.7684

South Dakota
Wildlife Division
Department of Game, Fish and Parks

Foss Building
523 East Capitol
Pierre, South Dakota 57501-3182

11 June 2013

Chad Miller, Environmental Scientist
Montana Dakota Utilities
400 North 4th Street
Bismarck, ND 58501

Dear Chad Miller,

This letter is in response to a request dated 6 May 2013 from Montana-Dakota Utilities and Otter Tail Power Company for additional feedback on the preferred route of the proposed 150 to 175 mile long 345 kV transmission line called Big Stone South to Ellendale (BSSE) project. This project is located in northeastern South Dakota.

Based on review of the paper map provided on 6 May 2013 and information found on the project website, the preferred route will not cross or be in close proximity to lands owned and managed by the South Dakota Department of Game, Fish and Parks (SDGFP). Please let us know if this changes.

Prairie grouse and waterbirds are two species groups that are of management concern to the SDGFP. We support your decision to conduct surveys for prairie grouse leks. If a lek is present, we recommend a minimum one-mile buffer be maintained between the lek and the power line. We also recommend that a timing restriction on construction activity be adhered to within a two mile buffer of leks. This means that construction activity would not occur during a three hour period starting at sunrise from 1 March through 30 June. This is to avoid disturbance to birds attending the lek.

In addition, please refer to the information we provided on colonial nesting waterbirds and secretive marshbirds. If colonies of either of these species groups are found along the preferred route, we recommend that a half-mile buffer should be maintained between the colony and the transmission line during construction and that lines are sufficiently marked to reduce bird strikes. The most current published science and technical information on reducing bird collisions with power lines has been summarized and published in an update of "*Mitigating Bird Collisions with Power Lines*" This version was published in 2012 and is available at http://www.aplic.org.

The SDGFP appreciates the opportunity to provide comments. If you have any questions on the above comments, please feel free to contact me at 605-773-2742 or Silka.Kempema@state.sd.us.

Regards,

Silka Kempema

Silka Kempema
Wildlife Biologist

CC: Scott Larson, Field Supervisor, U. S. Fish and Wildlife Service, Ecological Services South Dakota Field Office, Pierre, SD

Connie Mueller, Project Leader, U. S. Fish and Wildlife Service Waubay National Wildlife Refuge and Wetland Management District, Waubay, SD

Harris Hoistad, Project Leader, U. S. Fish and Wildlife Service, Sand Lake National Wildlife Refuge and Wetland Management District, Attention

Casey Mehls, Natural Heritage Database Manager, South Dakota Department of Game, Fish and Parks, Pierre, SD.

Current, Rhonda

From: Miller, Chad <Chad.Miller@mdu.com>
Sent: Friday, August 10, 2012 8:34 AM
To: Hunker, Brian M.; Siedschlag, Emily
Subject: FW: BSSE-SD Emergency Management Comment email

Sincerely,

Chad Miller

From: Miller, Chad
Sent: Friday, August 10, 2012 8:32 AM
To: 'Sarah.Land@state.sd.us'
Subject: RE: Request for Information Big Stone South to Ellendale Transmission Line Project

Sara, thank you for the information. This will be helpful as we develop our routes and start our stakeholder and public meetings. Thanks again, I appreciate it.

Sincerely,

Chad Miller

From: Sarah.Land@state.sd.us [mailto:Sarah.Land@state.sd.us]
Sent: Thursday, August 09, 2012 4:09 PM
To: Miller, Chad
Subject: Re: Request for Information Big Stone South to Ellendale Transmission Line Project

Chad,

Jon Nesladek forwarded me your letter requesting information on issues for the Montana-Dakota Utilities Co. and Otter Tail Power Company proposed Big Stone South to Ellendale 345kV Transmission Line project in North Dakota and South Dakota. I would like to point you to the local floodplain administrators to ensure that any routes and alternatives comply with the floodplain ordinance that are in place in those counties that are included in your study area. They will be able to determine if the proposal meets the standards of their floodplain ordinances. If it is to go through a city I can give you those contacts as well, since cities also have their own floodplain ordinances in addition to the county.

Brown County
Gary Vetter
(605) 626-7144
gvetter@brown.sd.us

Spink County
Larry Tebben
(605) 472-4591
Ltebben.spinkem@nrctv.com

Beadle County
Tom Moeding
(605) 353-8421

Tomm.bcmgmt@midconetwork.com

Marshall County
JoAnn Goldsmith
(605) 448-5291
mcdirector@venturecomm.net

Day County
Rick Tobin
(605) 380-1275
Ricktobin99@yahoo.com

Clark County
David Paulson
(605) 532-3751
clarkdoe@itctel.com

Roberts County
Scott Currence
(605)698-3205
roberteq@venturecomm.net

Codington County
Luke Muller
(605) 882-6300
Planning.codcoext@midconetwork.com

Hamlin County
David Schaefer
(605) 783-7831
hamcoem@itctel.com

Grant County
Krista Atyeo-Gortmaker
(605) 432-6532
Krista.atyeo-gortmaker@state.sd.us

Deuel County
Jodi Theisen
(605) 874-8562
dczoning@itctel.com

Thank you,

Sarah Land, MPA
NFIP Coordinator
SD Office of Emergency Management
118 W. Capitol Avenue
Pierre, SD 57501
(605) 773-3231 (P)
(605) 773-3580 (F)

SOUTH DAKOTA
STATE HISTORICAL SOCIETY
DEPARTMENT OF TOURISM

August 13, 2012

Mr. Chad Miller
Montana-Dakota Utilities Co.
400 North 4th Street
Bismarck, ND 58501

Dear Mr. Miller:

On August 1, 2012, the South Dakota Office of the State Historic Preservation Officer (SHPO) received a request for information from Montana-Dakota Utilities Co. and Otter Tail Power Company concerning the proposed Big Stone South to Ellendale 345-kV Transmission Line Project.

A brief review of our records indicates there are a number of known properties and surveys in Brown, Clark, Codington, Day, Deuel, Grant, Hamlin, Marshall, Roberts and Spink Counties, which have been identified as the study area. Given the size of the study area it is difficult to provide useful information concerning the potential impacts of the project to cultural resources or historic properties.

However, once the route alternatives are established, I would like to provide the following recommendations.

- Complete a records search for the routes to determine if they contain known cultural resources or historic properties. A record search can be obtained at the Archaeological Research Center at (605) 395-1936.
- An on-the-ground survey should be conducted by a qualified archaeologist to relocate known archaeology properties and identify any new archaeology properties that might be impacted. Resources located in the project area should be evaluated for listing on the National Register of Historic Places and avoided during construction activities.
- A reconnaissance level survey should be conducted by an architectural historian to identify structures or building that may be visually impacted by the project. Resources located in the project area should be evaluated for listing on the National Register of Historic Places and avoided during construction activities.
- Contact American Indian tribes in South Dakota and the surrounding states concerning the effects of the project on properties of religious and cultural significance. For your convenience I have enclosed a list of Tribal Chairmen and Tribal Historic Preservation Officers.

Please note that South Dakota Codified Law 34-27-26 prohibits knowingly disturbing human skeletal remains or funerary objects except by a law enforcement officer, coroner or other official designated by law in performance of official duties.

Should you require additional information, please contact Paige Olson at (605) 773-6004. Your concern for the non-renewable cultural heritage of South Dakota is appreciated.

Sincerely,

Jay D. Vogt
State Historic Preservation Officer

P. Olson

Paige Olson
Review and Compliance Coordinator

SOUTH DAKOTA
STATE HISTORICAL SOCIETY
DEPARTMENT OF TOURISM

July 30, 2013

Mr. Alan Stanfill
HDR Engineering, Inc.
701 Xenia Ave. South Suite 600
Minneapolis, MN 55416

Dear Mr. Stanfill:

Thank you for the opportunity to comment on the document entitled "Level I Records Search for the Big Stone South to Ellendale 345 kV Transmission Line Project, Brown, Day and Grant Counties, South Dakota".

The Level I Records Search indicates there are a number of known cultural resources within the project areas defined as "South Dakota Study Area" (2-mile-wide) and the "South Dakota Option Area" (500-feet-wide). Given this information, I would like to reiterate my original recommendations submitted to Mr. Chad Miller of Montana-Dakota Utilities Company on August 12, 2012, so they may be taken into consideration during the development of the finale Level III survey methodology.

- An on-the-ground survey should be conducted by a qualified archaeologist to relocate known archaeology properties and identify any new archaeology properties that might be impacted. Resources located in the project area should be evaluated for listing on the National Register of Historic Places and avoided during construction activities.

- A reconnaissance level survey should be conducted by an architectural historian to identify structures or building that may be visually impacted by the project. Resources located in the project area should be evaluated for listing on the National Register of Historic Places and avoided during construction activities.

I appreciate your company, on behalf of Montana-Dakota Utilities Company and Otter Tail Power Company, taking into consideration my recommendation to contact American Indian tribes in South Dakota and the surrounding states concerning the effects of the project on properties that may be of religious and cultural significance. I understand from our meeting on May 30, 2013, that your company is working with the Standing Rock Sioux and Sisseton-Wahpeton Oyate Tribal Historic Preservation Officers. I encourage your company to continue working toward a final plan to identify properties important to American Indian tribes.

Please note that South Dakota Codified Law 34-27-26 prohibits knowingly disturbing human skeletal remains or funerary objects except by a law enforcement officer, coroner or other official designated by law in performance of official duties.

900 GOVERNORS DR • PIERRE • SD 57501 • P {605 • 773 • 3458} F {605 • 773 • 6041} • HISTORY.SD.GOV
DEPARTMENT OF TOURISM {TOURISM.SD.GOV}

I look forward to reviewing the final Level III field survey methodology being developed by your company to identify cultural resources within the project corridor.

Should you require additional information, please contact Paige Olson at (605) 773-6004. Your concern for the non-renewable cultural heritage of South Dakota is appreciated.

Sincerely,

Jay D. Vogt
State Historic Preservation Officer

P. Olson
Paige Olson
Review and Compliance Coordinator

Cc: Mr. Henry Ford, Montana-Dakota Utilities Co.
Mr. Dean Pawlowki, Otter Tail Power Company
Ms. Wasté Win Young, Standing Rock Sioux Tribe
Ms. Dianne Desrosiers, Sisseton-Wahpeton Oyate

APPENDIX D

SOUTH DAKOTA SOIL SERIES INFORMATION

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Soil Associations

Big Stone South to Ellendale 345-kV Project

Association	Acres in ROW	Percent of ROW	Series	Parent Material	Drainage	Slope (percent)
ABERDEEN-HARMONY-BEOTIA (SD146)	94.9	3.39%	Aberdeen	glacial lacustrine sediments on lake plains	moderately well drained	0 to 2
			Harmony	lacustrine sediments on lake plains	moderately well drained	0 to 2
			Beotia	silty glaciolacustrine deposits on lake plains	well drained or moderately well drained	0 to 6
BARNES-KRANZBURG-BROOKINGS (SD126)	194.8	6.96%	Barnes	loamy till	well drained	0 to 25
			Kranzburg	loess overlying glacial till on uplands	well drained	0 to 9
			Brookings	loess overlying glacial till on footslopes and in swales	moderately well drained	0 to 6
BARNES-SVEA-TONKA (SD149)	474.2	16.96%	Barnes	loamy till	well drained	0 to 25
			Svea	calcareous till and local alluvium from the till	well or moderately well drained	0 to 25
			Tonka	local alluvium over till or glaciolacustrine deposits in closed basins and depressions on till and glacial lake plains	poorly drained, slowly permeable	0 to 1
BEARDEN-GREAT BEND-OVERLY (SD145)	304.6	10.89%	Bearden	calcareous silt loam and silty clay loam lacustrine sediments	somewhat poorly drained, moderately to slowly permeable soils	0 to 3
			Great Bend	glaciolacustrine sediments on lake plains	well drained soils	0 to 15
			Overly	calcareous sediments	well drained or moderately well drained	0 to 15
EGAN-HUNTIMER-WORTHING (SD119)	75.2	2.69%	Egan	silty sediments overlying glacial till on uplands	well drained	0 to 15
			Huntimer	clayey glaciolacustrine sediments on uplands	well drained	0 to 6
			Worthing	clayey alluvial sediments in upland depressions on till plains	poorly and very poorly drained	0 to 1
FORDVILLE-RENSHAW-SOUTHAM (SD128)	276.8	9.90%	Fordville	loamy sediments over sand and gravel on outwash plains and terraces	well drained	0 to 9
			Renshaw	loamy sediments and the underlying sand and gravel on outwash plains and terraces	somewhat excessively drained	0 to 25
			Southam	local alluvium from glacial drift	very poorly drained, slowly permeable	0 to 1
FORMAN-AASTAD-BARNES (SD137)	54.0	1.93%	Forman	calcareous till	well drained, moderately slowly permeable	0 to 30
			Aastad	calcareous till on moraines and till plains	moderately well drained	0 to 6
			Barnes	loamy till	well drained	0 to 25
FORMAN-AASTAD-BUSE (SD135)	192.6	6.89%	Forman	calcareous till	well drained, moderately slowly permeable	0 to 30
			Aastad	calcareous till on moraines and till plains	moderately well drained	0 to 6
			Buse	loamy glacial till on moraines	well drained	3 to 60
FORMAN-BUSE-SOUTHAM (SD134)	446.4	15.96%	Forman	calcareous till	well drained, moderately slowly permeable	0 to 30
			Buse	loamy glacial till on moraines	well drained	3 to 60
			Southam	local alluvium from glacial drift	very poorly drained, slowly permeable	0 to 1
HEIMDAL-SISSETON-SVEA (SD138)	32.9	1.18%	Heimdal	calcareous glacial till on glacial till plains and moraines	well drained, moderately permeable	0 to 40
			Sisseton	calcareous, stratified, loamy and silty glacial drift on uplands	well drained	2 to 40
			Svea	calcareous till and local alluvium from the till	well or moderately well drained	0 to 25
LUDDEN-LAMOURE-LADELLE (SD139)	67.0	2.40%	Ludden	clayey alluvium	poorly or very poorly drained, slowly permeable	0 to 1
			Lamoure	silty alluvium on flood plains	somewhat poorly drained or poorly drained	0 to 2
			LaDelle	alluvium on terraces and flood plains	moderately well drained	0 to 9
LUDDEN-RYAN-LADELLE (SD152)	86.5	3.09%	Ludden	clayey alluvium	poorly or very poorly drained, slowly permeable	0 to 1
			Ryan	alkaline clayey sediments	poorly drained, very slowly permeable	0 to 1
			LaDelle	alluvium on terraces and flood plains	moderately well drained	0 to 9
PEEVER-FORMAN-TONKA (SD136)	237.6	8.50%	Peever	glacial till on uplands	well drained	0 to 9
			Forman	calcareous till	well drained, moderately slowly permeable	0 to 30
			Tonka	local alluvium over till or glaciolacustrine deposits in closed basins and depressions on till and glacial lake plains	poorly drained, slowly permeable	0 to 1
POINSETT-WAUBAY-SINAI (SD130)	114.3	4.09%	Poinsett	silty glacial drift on uplands	well drained	0 to 15
			Waubay	silty glacial drift	moderately well drained	0 to 6
			Sinai	glaciolacustrine sediments on uplands	moderately well drained and well drained	0 to 9
VIENNA-LISMORE-KRANZBURG (SD111)	144.7	5.17%	Vienna	silty and loamy loess over loamy glacial till on uplands	well drained soils	0 to 15
			Lismore	silty sediments over glacial till on uplands	moderately well drained	0 to 6
			Kranzburg	loess overlying glacial till on uplands	well drained	0 to 9

APPENDIX H

PRELIMINARY TRANSMISSION STRUCTURE TYPICAL DRAWINGS

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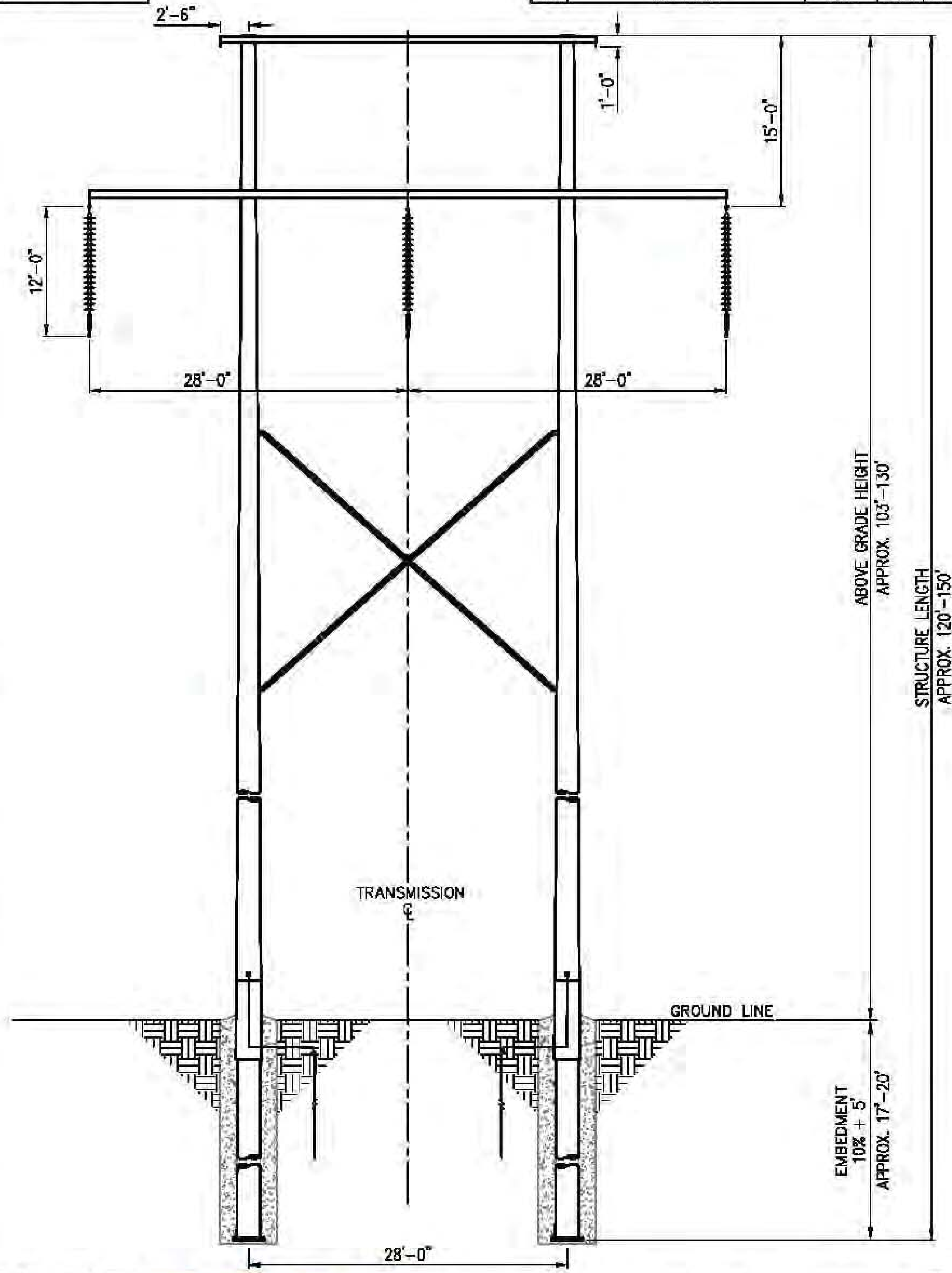
REV	REVISIONS	DATE	DRN	DSGN	CKD	APPD
C	PRELIMINARY DIMS: ADDITIONAL DIMS	08/05/13	JFH	KMW	DJF	
B	PRELIMINARY DIMS: MINOR REVISIONS	08/02/13	JFH	KMW	DJF	
A	PRELIMINARY APPOXIMATE DIMENSIONS	07/29/13	JFH	SMH	DJF	



DSGN	PEI	07/29/13
DRN	PEI	07/29/13
CKD	PEI	07/29/13
SCALE: N.T.S.		

FOR 8.5x11 DWG ONLY

FILE

BSS+E Big Stone South to Ellendale

OTTER TAIL POWER CO. & MONTANA-DAKOTA UTIL. CO.

PRELIMINARY H-FRAME TANGENT
345kV TRANSMISSION LINE

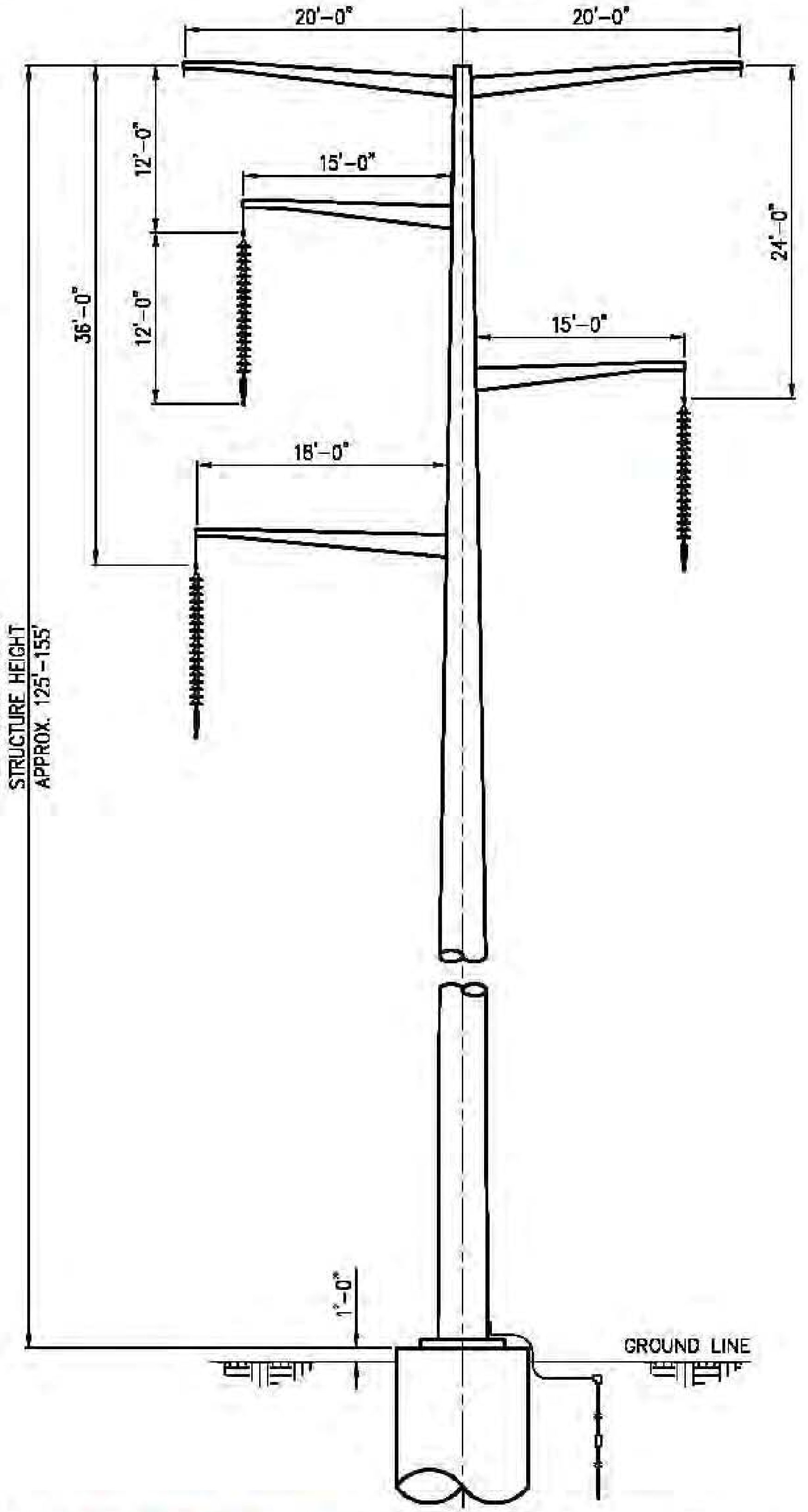
BIG STONE SOUTH TO ELLENDALE

JOB NUMBER: 127156

REV: C

DRAWING NUMBER: APP-STR01

REV	REVISIONS	DATE	DRN	DSGN	CKD	APPD
B	PRELIMINARY DIMS: MINOR REVISIONS	08/02/13	JFH	SMH	DJF	
A	PRELIMINARY APPOXIMATE DIMENSIONS	07/29/13	JFH	SMH	DJF	



DSGN	PEI	07/29/13
DRN	PEI	07/29/13
CKD	PEI	07/29/13
SCALE: N.T.S.		

FOR 8.5x11 DWG ONLY

BSS+E
Big Stone South to Ellendale

OTTER TAIL POWER CO. & MONTANA-DAKOTA UTIL. CO.

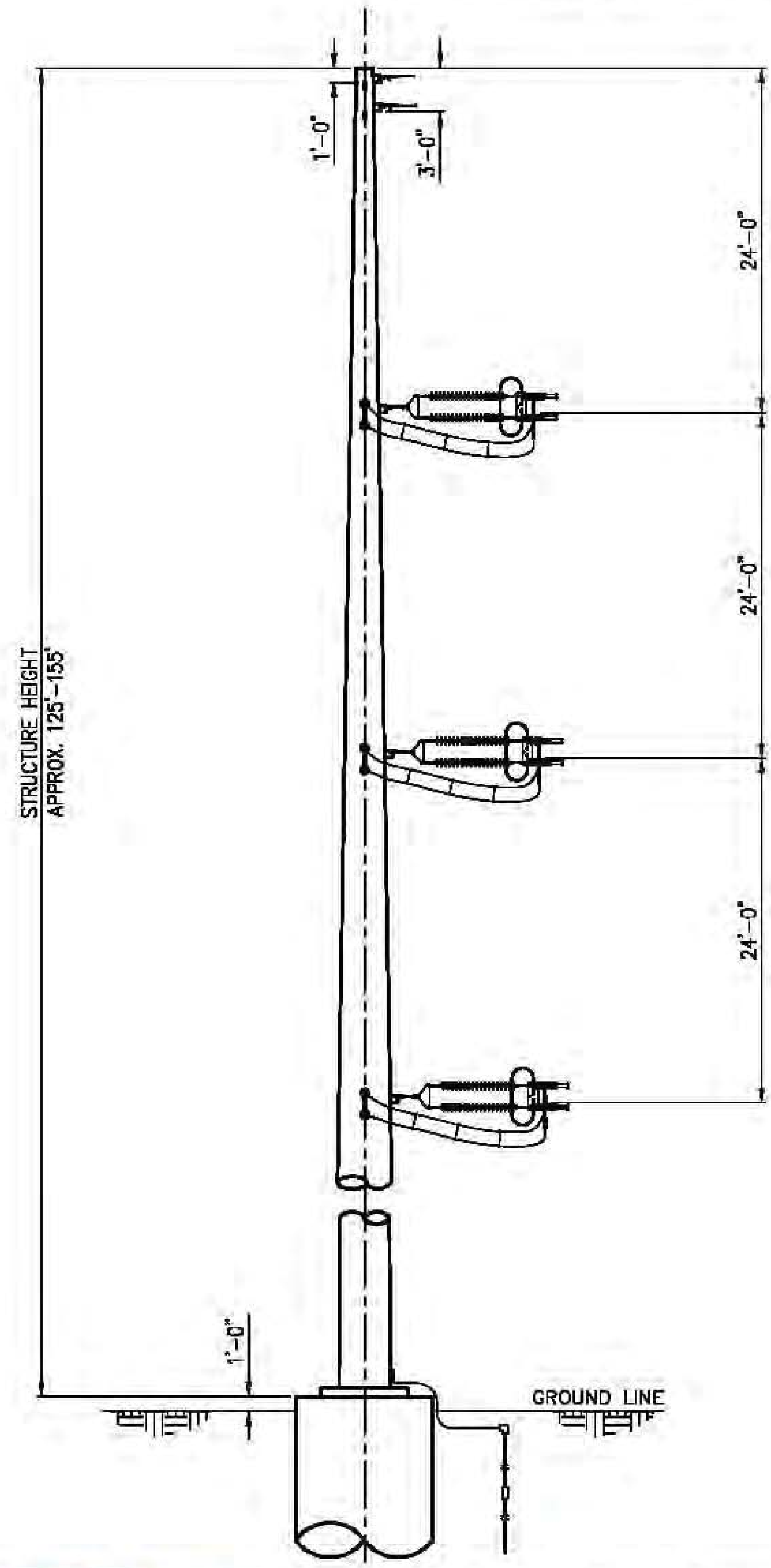
PRELIMINARY DELTA TANGENT
345kV TRANSMISSION LINE

BIG STONE SOUTH TO ELLENDALE

JOB NUMBER: 127156
REV: B
DRAWING NUMBER: APP-STR02

006977

REV	REVISIONS	DATE	DRN	DSGN	CKD	APPD
B	PRELIMINARY DIMS: MINOR REVISIONS	06/02/13	JFH	SMH	DJF	
A	PRELIMINARY APPOXIMATE DIMENSIONS	07/29/13	JFH	SMH	DJF	



DSGN	PEI	07/29/13
DRN	PEI	07/29/13
CKD	PEI	07/29/13
SCALE: N.T.S.		

FOR 8.5x11 DWG ONLY

FILE

BSS+E Big Stone South to Ellendale

OTTER TAIL POWER CO. & MONTANA-DAKOTA UTIL. CO.

PRELIMINARY MONOPOLE DEADEND
345kV TRANSMISSION LINE

BIG STONE SOUTH TO ELLENDALE

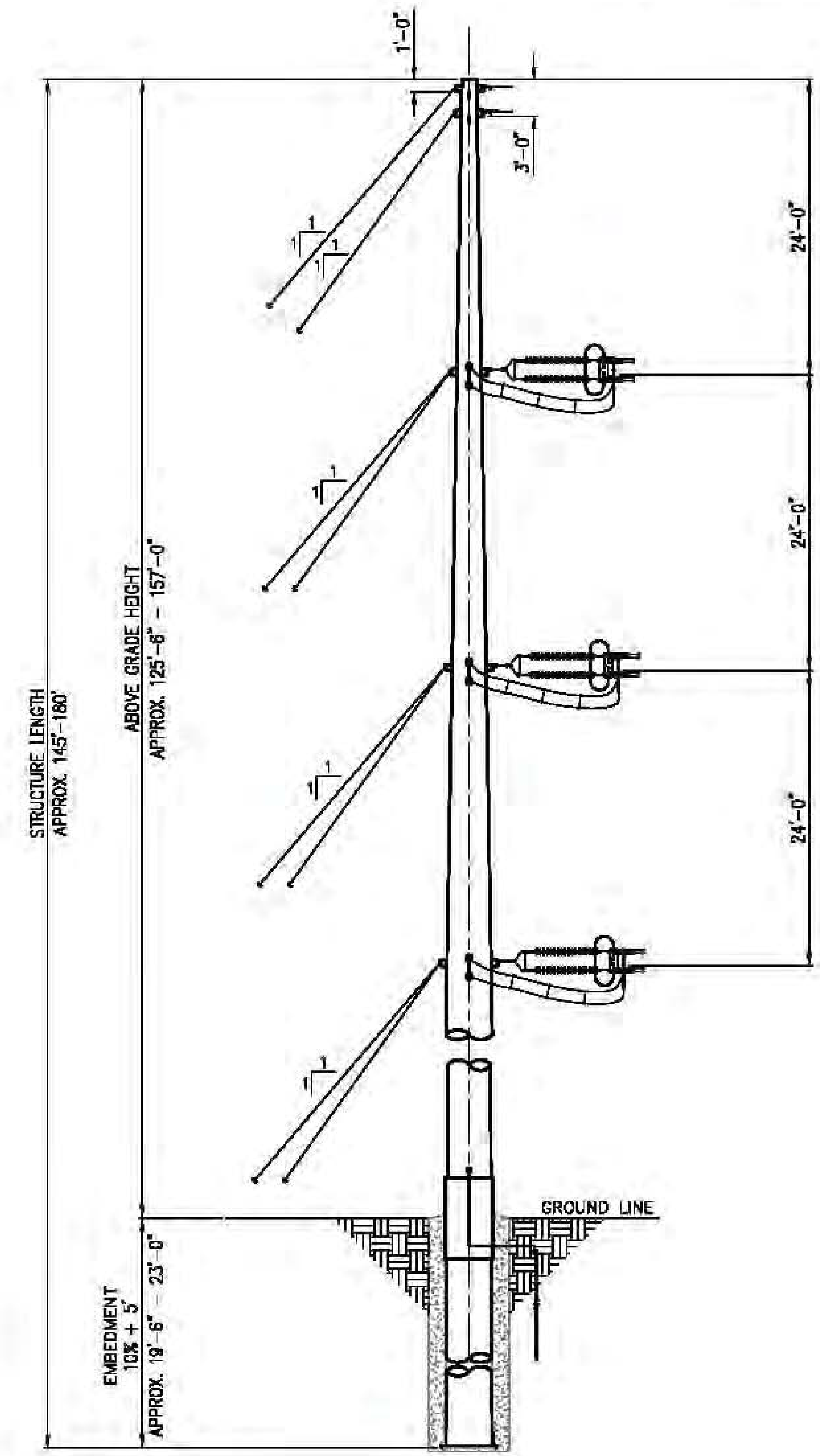
JOB NUMBER: 127156

REV: B

DRAWING NUMBER: APP-STR03

006978

REV	REVISIONS	DATE	DRN	DSGN	CKD	APPD
C	PRELIMINARY DIMS: ADDITIONAL DIMS	08/05/13	JFH	KMW	DJF	
B	PRELIMINARY DIMS: MINOR REVISIONS	08/02/13	JFH	KMW	DJF	
A	PRELIMINARY APPOXIMATE DIMENSIONS	07/29/13	JFH	SMH	DJF	



DSGN	PEI	07/29/13
DRN	PEI	07/29/13
CKD	PEI	07/29/13
SCALE: N.T.S.		

FOR 8.5x11 DWG ONLY

Big Stone South to Ellendale

OTTER TAIL POWER CO. & MONTANA-DAKOTA UTIL. CO.

PRELIMINARY GUYED MONOPOLE DEADEND
345kV TRANSMISSION LINE

BIG STONE SOUTH TO ELLENDALE

JOB NUMBER: 127156

REV: C

DRAWING NUMBER: APP-STR04

006979