SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

CASE NO. EL05-022

IN THE MATTER OF THE APPLICATION BY OTTER TAIL POWER COMPANY

ON BEHALF OF THE BIG STONE II CO-OWNERS

FOR AN ENERGY CONVERSION FACILITY SITING PERMIT FOR THE

CONSTRUCTION OF THE BIG STONE II PROJECT

DIRECT TESTIMONY

OF

GERALD A. TIELKE

OPERATIONS MANAGER

MISSOURI RIVER ENERGY SERVICES

MARCH 15, 2006

BIG STONE II
PARTNERS IN GENERATION

DIRECT TESTIMONY OF GERALD A. TIELKE

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BEFORE THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

DIRECT TESTIMONY OF GERALD A. TIELKE

I. INTRODUCTION

Q: Please state your name and business address.

A: Gerald A. Tielke, Missouri River Energy Services, 3724 West Avera Drive, Sioux Falls, South Dakota.

Q: By whom are you employed and in what capacity?

A: I am the Operations Manager for Missouri River Energy Services (MRES).

Q: What is your educational background?

A: I received a B.S. in electrical engineering in December 1979, with honors, with an emphasis in digital computers and programming, and a mathematics minor, from South Dakota State University. I also received a Masters in Business Administration in December 1992 from the University of South Dakota.

Q: What is your employment history?

A: I joined Missouri River Energy Services in January 1980. At that time I was personally charged with performing all load forecasting. By the early 1990's I advanced to a supervisory role. I also manage the daily scheduling of MRES generation as well as the information systems staff.

Q: What professional organization do you belong to?

A: I am a member of Institute of Electrical and Electronics Engineers and am a registered professional engineer in the State of South Dakota.

Q: What classes or other training have you taken related to resource planning?

A: In my early years on the job I worked closely with the consulting firm staff that had been previously responsible for MRES forecasting, and attended short courses sponsored by the American Public Power Association including "Forecasting Techniques" and the "Residential Energy Conservation Workshop." As my experience grew, I helped the Western Area Power Administration (WAPA) implement their IRP requirements by being a field verifier for their Resource Planning Guide. In more recent years I have had extensive training in locational-market-pricing energy markets, such as now found in the Midwest Independent System Operator (MISO) Energy Market. I have also taken training on energy production software, PROMOD IV, and capacity expansion software, STRATEGIST, both by New Energy Associates.

I am a past chair of the regional Siouxland IEEE section, and a former member of the Upper Midwest Utility Forecasters group. The senior economist on our staff, JP Schumacher, is now a member and immediate past president of that forecasters group.

II. PURPOSE AND SUMMARY

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to describe the present and estimated future demand and energy needs of Missouri River Energy Services' customers to be served by the Big Stone II project and to explain the method employed by MRES to forecast future energy requirements and to plan for selection of additional generation capacity.

Q: Please summarize your testimony.

A: The 2005 total summer capacity ratings of MRES resources were 548 MW. The summer peak demand from 2005 for the MRES member cities was 751 MW, of which MRES was responsible for 352 MW plus transmission losses and 15% planning reserves, or 425 MW.

MRES' forecasts show that member total demand will grow by an average of 1.8% between 2005 and 2014, and by 2011 MRES will have a shortfall of 17 MW of generation capacity. Our planning efforts demonstrate that Big Stone Unit II is a least-cost resource that, along with other planned resources, best matches MRES' resource goals of resource adequacy, minimization of environmental and other risks, and reliability.

Q: What regulations relating to the Big Stone II Unit are covered in your testimony?

A: My testimony provides the information required by ARSD 20:10:22:10. Our staff helped prepare Section 3.1.4.7 and Exhibits 3-16 and 3-17 of the Application, which address MRES' forecasted capacity needs and annual energy requirements, which are incorporated herein by reference.

III. RESOURCE PLANNING

Q: Does MRES engage in resource planning?

A: Yes. MRES prepares an integrated resource plan on a periodic basis. The most recent resource plan was filed with the Minnesota Public Utilities Commission (MPUC) in July 2005, and was the source for the information used in developing the Application in this matter. MRES is also preparing a Supplement to its Minnesota IRP filing which will include additional information regarding our ongoing capacity expansion modeling. MRES also assists its member cities with preparation of the resource plan filings they are required to file with the WAPA on a regular basis.

Q: Please explain how MRES' integrated resource planning process works.

A: The integrated resource planning process requires a combined analysis of forecasted energy requirements, demand-side management programs, and supply-side generation capability to determine how projected energy requirements are going to be best met in the future.

IV. FORECASTING

Q: Please describe the process by which MRES forecasts future power and energy demands of its customers.

A: The MRES load forecasts are based upon a short-term monthly time-series forecast blended into a long-term annual econometric forecast. The resulting blended forecast predicts the aggregate total usage for each member city for each month of the forecast horizon. MRES then obtains the monthly MRES demand and energy sales for each of its member by subtracting the allocated amounts of demand and energy they purchase form other suppliers. MRES performs both long-term and short-term load forecasts for each of its member cities. The short-term forecasts cover a time range covering the remainder of the current year, plus the next calendar year, and are usually completed twice a year. The long-term load forecasts cover the time range of one year to at least 15 years into the future, and are completed about once every other year. The results of the short-term and long-term forecasts are combined into a single load forecast for power-supply planning purposes. The forecasts are adjusted for the addition of transmission losses between MRES resources and the member city locations; and to remove the portion of the member loads that are served by other suppliers.

Q: What are the sources of information for your forecasts?

A: The MRES load forecasts use a variety of sources. A primary driver is the historic metered load of the cities, which is obtained from billing meters located at the main substations of each member city. This metered demand and energy data is used on a monthly and annual basis in the load forecasts. Demographic data includes county-level historic and forecasted census data obtained from Woods & Poole Economics, Inc., an independent firm based in Washington D.C. that specializes in long-term county economic and demographic projections. Historic weather data, in the form of monthly and annual cooling and heating degree days, were obtained from the National Oceanic and Atmospheric Administration (NOAA) for seven weather stations in the region. The future years of the forecasts were based on the 30-year normals (1970-2000) published by NOAA. The gross domestic price deflator, and the national industrial production index, are each variables that were used in the long-term forecast models for some of the member cities and were obtained from the Economy.com web site. Finally, the historic prices of alternative fuels, which include natural gas, fuel oil, and propane, were obtained from the Energy Information Administration (EIA) and the Minnesota Department of Commerce. Forecasted alternative fuel prices were obtained from the 2004 EIA Annual Energy Outlook Table 14 for the West North Central Region.

Q: Do you review other forecasts in conducting your own?

A: Yes. We are aware of the forecasts that other regional utilities use and make publicly available, as they do in resource plan filings for instance. We are members of the Upper Midwest Utility Forecasters group, an informal association of economists that develop load forecasts for utilities in the region. Also, the MRES forecasting process has been through the review and comment process several times over the years as part of the Minnesota IRP process.

Q: What are the present capacity and energy requirements for MRES' members?

A: The latest figures available at the time of the July 2005 Resource Plan filing were for calendar year 2004. The figures showed that the peak demand of the MRES member cities was 723 MW and their energy use for the year was 3,897,707 MWhr. The cities obtain, on average, just over half of their supply from allocations of power and energy they receive from WAPA. One city, Marshall, Minnesota, also receives an allocation from the Heartland Consumers Power District (HCPD). These allocations are fixed and do not increase over time. MRES is responsible for the growth portion of the member city loads.

The MRES share of these amounts, including wheeling losses, was 327 MW and 1,589,880 MWhr in 2004. MRES is a summer peaking system and reached its peak demand in July 2004.

Q: Explain the difference between peak demand and energy use.

A: The peak demand is the largest amount of electricity demanded by MRES' municipal members during any particular hour, and it is expressed in terms of megawatts. This is the generation capacity that must be available for MRES to satisfy the peak demand. The energy use, on the other hand, is the amount of electricity used over a time period such as a year, so it is expressed in terms of megawatt hours.

Q: What is predicted to be the rate of growth for MRES over the next fifteen years?

A: The table below, from the July 2005 Resource Plan filing, shows the forecasted total energy requirements of the MRES members. Also shown is the portion that is to be supplied by MRES, after subtracting the portion to be supplied to our members by WAPA and by HCPD. As the table shows, MRES has a robust rate of growth, and one that is generally higher than typical for other regional utilities. Over the 10-year period 2006-2015, the MRES energy requirements are projected to grow at an average rate of 3.6%.

Forecasted Energy Sales – Typical Weather
Includes Wheeling Losses
July 2005 Resource Plan

Year	Member Load (MWH)	City Growth Rate	MRES Portion (MWH)	MRES Growth Rate
2006	4,143		1,897	
2007	4,220	1.85%	1,974	4.04%
2008	4,297	1.82%	2,046	3.63%
2009	4,368	1.64%	2,121	3.71%
2010	4,440	1.66%	2,194	3.41%
2011	4,520	1.80%	2,292	4.46%
2012	4,598	1.73%	2,365	3.20%
2013	4,678	1.73%	2,450	3.58%
2014	4754	1.64%	2,527	3.14%
2015	4,830	1.59%	2,602	2.99%
2016	4,908	1.62%	2,885	10.85%
2017	4,985	1.58%	3,174	10.04%
2018	5,054	1.37%	3,243	2.16%
2019	5,120	1.31%	3,309	2.04%
2020	5,190	1.37%	3,374	1.97%

The reason for the large jumps in energy consumption for years 2016 and 2017 is because of the expiration of the HCPD portion of the supply for Marshall, Minnesota in July 2016. MRES currently supplies the portion of the Marshall load supplement to both WAPA and HCPD; the MRES share will take a step increase in July 2016 due to the expiration of the HCPD portion of the supply.

Q: What is predicted to be the capacity needs of MRES' members over the next fifteen years?

A: The table below shows the forecasted total demand, or capacity, requirements of the MRES members as reported in the July 2005 Resource Plan filing. Also shown is the portion that is the responsibility of MRES, after subtracting the portions that are the responsibility of WAPA and HCPD. The last column shows the total MRES planning reserve responsibility, including the 15% capacity planning reserve margin required by MAPP.

MRES Projected Capacity Requirements
July 2005 Resource Plan

Summer Values in MW:					Winter Values in MW:					Peak Load Respons-ibility[4]	
Sea-son	Total Load + Wheel	Supplied by HCPD[1]	WAPA Seas. Max[2]	MRES Require-ments[3]	Season	Total Load + Wheel	Supplied by HCPD[1]	WAPA Seas. Max[2]	MRES Require-ments[3]	Year	MW
2006	802	60	349	405	2005-06	726	57	307	373	2006	466
2007	817	60	349	421	2006-07	739	57	307	387	2007	484
2008	833	60	349	437	2007-08	753	57	307	400	2008	502
2009	847	60	349	451	2008-09	765	57	307	413	2009	519
2010	861	60	349	466	2009-10	778	57	305	428	2010	536
2011	877	60	345	486	2010-11	792	57	304	444	2011	559
2012	892	60	345	502	2011-12	806	57	304	458	2012	577
2013	908	60	345	218	2012-13	820	57	304	473	2013	596
2014	924	60	345	534	2013-14	833	57	304	486	2014	614
2015	939	60	345	550	2014-15	846	57	304	500	2015	632
2016	955	0	345	628	2015-16	859	57	304	514	2016	722
2017	969	0	345	643	2016-17	873	0	304	586	2017	739
2018	983	0	345	657	2017-18	885	0	304	599	2018	755
2019	996	0	345	670	2018-19	897	0	304	611	2019	771
2020	1010	0	345	685	2019-20	909	0	304	623	2020	787
					2020-21	922	0	304	637		

1. Portion of Marshall, MN power supplied by HCPD.
2. Seasonal maximum WAPA supply.
3. Total Load minus the amounts supplied by HCPD and WAPA, plus 5% typical bulk transmission system losses, minus 2% typical peak load diversity between members.
4. The summer MRES requirement plus 15% as long as MRES is summer peaking.

Q: What is predicted to be the total peak demand requirements of MRES' customers over the next fifteen years?

The table below shows, for the summer seasons, the total amount of capacity supplied by current MRES resources, compared to the MRES peak load responsibility forecasted for each year, as reported in the July 2005 Resource Plan filing. The shortfall beginning in 2011 is the forecasted capacity requirement for new resources.

MRES Future Capacity Needs – Summer
July 2005 Resource Plan

	Current Summer Resources in MW:								
Season	LRS Base	LRS Peaking	Exira	WPP	Municipal\1	Interruptible Load	Total Resources	Peak Load Responsibility	Short-fall
2006	271.8	8	100	51.2	117.3	3.7	554	466	
2007	271.8	8	100	51.2	117.3	3.7	554	484	
2008	271.8	8	100	51.2	117.3	3.7	554	502	
2009	271.8	8	100	51.2	107.3	3.7	544	519	
2010	271.8	8	100	51.2	107.3	3.7	544	536	
2011	271.8	8	100	51.2	107.3	3.7	544	559	17
2012	271.8	8	100	51.2	107.3	3.7	544	577	35
2013	271.8	8	100	51.2	107.3	3.7	544	596	54
2014	271.8	8	100	51.2	107.3	3.7	544	614	72
2015	271.8	8	100	51.2	107.3	3.7	544	632	90
2016	271.8	8	100	51.2	107.3	3.7	544	722	180
2017	271.8	8	100	51.2	107.3	3.7	544	739	197
2018	271.8	8	100	51.2	107.3	3.7	544	755	213
2019	271.8	8	100	51.2	107.3	3.7	544	771	229
2020	271.8	8	100	51.2	107.3	3.7	544	787	245

1 Assuming the municipal capacity contracts will be reduced by about 10 MW effective January 2009.

V. GENERATION RESOURCES

Q: What are MRES' existing generation resources?

A: As of the summer of 2005, MRES resources had a total summer capacity rating of 548 MW accredited in MAPP. Its resource mix was about 50% baseload and 50% peaking capacity, plus a small amount of non-accredited wind and interruptible energy.

MRES has baseload capacity from its 272 MW share of the Laramie River Station (LRS) located near Wheatland, Wyoming. MRES currently has no intermediate resources.

MRES has the following peaking resources totaling 280 MW: 100 MW from Exira units 1 and 2, located near Brayton, Iowa; 52 MW from the Watertown Peaking Plant, Watertown, South Dakota; various municipal capacity units totaling 120 MW; and 8 MW of additional capacity from LRS when fuel oil is added to the coal mix.

Besides these amounts of accredited capacity, MRES has about 5 MW of wind generation and about 4 MW of interruptible load with backup generation that is owned by customers at the retail level and which MRES has rights to call on if needed.

Q: Is MRES' cost of generation resources accurately represented as part of Exhibit 3-3 to the Application?

A: Yes. MRES receives energy from only one base-load resource, LRS. LRS has one of the lowest production costs of any coal unit in the country. As a result, it makes economic sense to produce energy from this base-load unit at a very high capacity factor, usually exceeding 90% of the plant's capability each year.

All other MRES generation, except wind, is from peaking resources utilizing natural gas or fuel oil. These peaking units have a very high production cost; it makes economic sense to produce energy from them only in hours when market prices are high enough to justify their use, or for reliability purposes. These units have an average production of less than 10% of capability each year for MRES.

Q: Does MRES purchase any power under purchase power agreements?

A: Yes. MRES does not own any generation resources. It purchases all of its long-term power and energy supply through the Western Minnesota Municipal Power Agency (WMMPA), which is the owner of the resources that MRES controls. WMMPA has given MRES exclusive rights to the output of its resources; MRES is responsible for all costs of WMMPA.

Also, as explained above, the MRES members purchase power and energy from both MRES and from WAPA. In the case of one member, they also purchase power from HCPD until July 2016. The WAPA power allocations do not increase and in fact may decrease by up to 1%

every five years, causing a corresponding increase in MRES requirements. A 1% decrease in the WAPA allocations is modeled in 2011 and in 2016 in the July 2005 Resource Plan filing.

Q: Are MRES' existing generation resources sufficient to meet its forecasted demand and energy requirements?

A: No. As calculated in the July 2005 Resource Plan filing, in 2011 the projected deficit is 17 MW. By 2015, the deficit grows to 90 MW and by 2020 it jumps to 245 MW. These are consistent with the deficit amounts shown in the Application in this matter.

Since July 2005, the MRES integrated planning process has continued to move forward. A new short-term forecast has been completed, showing a slightly higher load growth, in part due to a new soybean plant installation in a North Dakota member community. It also appeared that the municipal capacity that is available for MRES to call on would be reduced by 20 MW in 2009 instead of by 10 MW, as originally predicted. Combined with this was a unique opportunity to obtain a surplus combustion turbine on the market nearly identical to the two already at the Exira site, and a window of opportunity while transmission was available at that site. Thus, MRES is adding a third combustion turbine to increase the Exira station accreditation by 40 MW to take advantage of these opportunities as well as to cover the increased load growth and reduced municipal capacity.

The combination of increased load projections, reduced municipal capacity, and new Exira capacity resulted in no change to 2011 being the first year of a capacity deficit.

VI. DSM AND CONSERVATION PLANNING

Q: Does MRES consider the effects of demand-side management and conservation measures as part of its resource planning?

A: Yes. MRES has a long history of supporting the efforts of its members in evaluating and implementing DSM and energy conservation programs. MRES is a not-for-profit joint-action agency efficiently serving 60 member municipalities, 57 of whom have long-term power supply contracts with MRES. As such, each MRES member-city owns and operates its local, municipal electric utility. The citizens of each of those cities determine democratically how their utility is managed and operated. Although MRES provides supplemental power supply and additional energy-related services, including information and programs on conservation, and demand-side resources, the ultimate decision as to how each municipal utility is operated and how programs are implemented rests with each individual municipal utility and its customer-owners.

Even though MRES does not directly control DSM, given its vertical dis-integration, there is a long history of DSM and conservation activities within the MRES membership. Many of the members have used load management hardware to shave their peak demands since the 1970's. The members in Iowa and Minnesota have a minimum spending requirement each year, to be spent on energy conservation activities. Also, all members are required to undergo an Integrated Resource Planning process and reporting requirement to avoid losing part of the their WAPA power allocation. Taken together, there is a significant amount of ongoing DSM and conservation activity that is reflected in the actual loads of the members and thus implicitly included in the load forecast used in the July 2005 Resource Plan filing. Our best estimate is that DSM and conservation efforts among MRES members have reduced generation capacity requirements by approximately 57 MW as of 2005.

Q: Please explain MRES' ongoing DSM efforts.

A: MRES currently is implementing capacity expansion modeling which will supplement the production cost modeling originally utilized for the July 2005 Resource Plan filing. As part of this additional modeling, MRES will develop potential DSM additions to allow the capacity expansion model to analyze the direct impact of various levels of additional DSM on supply-side choices, and will allow DSM, and renewables, to compete directly against supply-side resources in developing the optimal resource mix. We intend to file the results of this capacity expansion modeling April 1 as part of a supplemental filing with the Minnesota Public Utilities Commission and can have the results available for this proceeding if necessary. MRES will be working with its board and its members to determine the implementation plan for any additional DSM programs that are selected in the IRP modeling effort.

VII. SELECTION OF BIG STONE II

Q: What are the results of the MRES' resource planning activities?

A: Due to both growth in demand and the addition of new municipalities as members, MRES resource needs continue to grow. In its July 2005 Resource Plan, MRES has identified the need for significant additional capacity beginning in 2011. Resource needs will also increase notably when MRES assumes the HCPD share of load for Marshall, Minnesota in July 2016. In addition, MRES will lose the ability of calling on 10 MW of member generation capacity beginning in 2009. In order to determine the best resource mix to meet this capacity shortfall and to serve MRES members and its customers, MRES analyzed a variety of generation resources. This analysis resulted in an optimal plan (the "Preferred Alternative") that indicated the need for a mix of baseload, peaking, and renewable generation. Specifically, the analysis confirmed that the combination of investment in a supercritical pulverized coal plant through participation by MRES in the proposed Big Stone Unit II project, along with a combination of 180 MW of combustion turbine ("CT") peaking units, and 40 MW of wind energy, would best fill the expected capacity gap and would meet the MRES goal of providing cost-effective and reliable energy for the long-term.

The MRES Preferred Alternative was one that was slightly more expensive than the least-cost optimal plan, in that it also included renewable resources to meet Minnesota's 10% renewable energy objective (MN REO). The MN REO provides that each electric utility serving in Minnesota must make a good faith effort to provide 10% of its power supply from renewable resources by 2015.

The MRES Preferred Alternative included renewable resources (in the form of wind units), baseload capacity (from new coal supply), and peaking units (from new combustion turbines). The following are the resources that MRES should add, based on the MRES Preferred Alternative:

MRES Preferred Alternative Capacity Expansion Plan – July 2005 Resource Plan			
Year	Unit	Accredited MW	Unit Type
2007	Wind	6	Wind (40 MW nameplate)
2011	BSP II	145	Coal, including 40 MW for Hutchinson, MN
2016	CT	90	Combustion Turbine
2018	CT	45	Combustion Turbine
2020	CT	45	Combustion Turbine

When calculating the alternatives, coal units were considered in 15 MW increments, to reduce the difficulties in calculating any more precisely than that. While the Preferred

Alternative recommended 145 MW of BSP II, the final 150 MW ownership in BSP II for MRES was determined after discussions with the other Applicants.

Q: What is the Hutchinson Purchased Power Agreement referenced in the footnote in the table above?

In early 2005, MRES entered into a purchased power agreement (PPA) with the city of Hutchinson, Minnesota. Under the PPA, MRES is obligated to finance and supply 40 MW of Big Stone II resource to Hutchinson should Big Stone II be built. Thus, 40 MW has been added to any Big Stone II requirements for MRES, representing the portion that will be resold to Hutchinson. Hutchinson has just recently become a MRES member.

Q: Has MRES projected what sources of generation might be available to meet the forecasted demand for power and energy?

A: Yes. The following table shows how much energy was forecasted to be produced from each class of resources under the Preferred Alternative.

Energy Production Forecast, GWH (Excluding Hutchinson Portion of Big Stone II)						
Year	LRS	Big Stone II	Exira	Future Wind	Other Resources	Total Production
2006	1,497	-	45.2	-	432	1,974
2007	1,653	-	43.9	140.2	221	2,059
2008	1,699	-	49.4	140.2	243	2,131
2009	1,556	-	57.1	140.2	451	2,204
2010	1,731	-	67.3	140.2	342	2,281
2011	1,758	242.6	30.7	140.2	217	2,388
2012	1,566	469.1	28.7	140.2	258	2,462
2013	1,734	438.0	33.9	140.2	201	2,547
2014	1,811	454.6	40.5	140.2	190	2,636
2015	1,633	540.9	46.4	140.2	352	2,712
2016	1,878	534.4	56.8	140.2	398	3,007

2017	2,007	630.7	61.5	140.2	480	3,319
2018	1,790	683.3	61.5	140.2	712	3,386
2019	1,975	661.4	60.9	140.2	622	3,460
2020	2,028	666.2	62.0	140.2	634	3,531

Q: How will Big Stone II meet projected customer demands for power and energy?

A: MRES would utilize Big Stone II for meeting both its capacity reserve obligations and its energy supply to its member cities. The proposed timing of the Big Stone II addition is ideal for MRES because it is proposed just when MRES needs to add additional resources. Big Stone II is ideally located on the transmission system relative to the MRES loads, in that it is central to the MRES load region, and it is located within the MISO market region. Almost half of the MRES load is located within MISO, but currently all of the large MRES generating resources are located outside of the MISO region. Thus MRES would be able to deliver energy from Big Stone II directly into the MISO region for delivery to our load points rather than paying "pancaked" rates for transmission wheeling, or service.

Q: Is Big Stone II projected to meet all the demand that is anticipated by 2020?

A: No. In terms of capacity obligations, additional capacity would be needed by 2016. In terms of energy supply, MRES has only a single base-load resource, which is its 272 MW share of the LRS. The forecasted MRES loads will greatly exceed 272 MW during the next several years. Adding 105 MW of base-load supply from Big Stone Unit II to the 272 MW of LRS, at full output, would still only be enough to serve the MRES loads about 55% of the hours in 2017, decreasing to 45% of the hours in 2020. By the time plant outages are taken into account, those units would be able to serve the loads even less of the time.

Q: What resources will be available to meet future power and energy requirements if Big Stone Unit II is not constructed?

A: If Big Stone II is not approved, MRES will still need to find additional capacity by 2011. The optimal plan, calculated without Big Stone II and adjusted for the MN REO, is shown below.

MRES Expansion Plan Without Big Stone II			
Year	Unit	Accredited MW	Unit Type
2007	Wind	6	Renewable – Wind (40 MW nameplate)
2011	CT	45	Combustion Turbine
2013	CT	45	Combustion Turbine
2014	coal	60	Coal
2016	CT	45	Combustion Turbine
2018	CT	45	Combustion Turbine
2020	CT	45	Combustion Turbine

This assumes, among other things, that MRES successfully joins a partnership for another coal unit in the 2014-2015 timeframe.

Q: Does this conclude your testimony?

A: Yes.