  

Integrated Resource Plan

2008-2027

CHEYENNE LIGHT, FUEL & POWER

and

BLACK HILLS POWER

– Subsidiaries of Black Hills Corporation –

  

Cheyenne Light Fuel & Power

Black Hills Corporation™

Black Hills Power

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Preface

Black Hills Corporation is an integrated energy company headquartered in Rapid City, South Dakota, with a 125-year history of providing retail electric services through Black Hills Power and its predecessor companies. The Company grew over the years, adding other energy businesses to diversify our revenue sources, including a coal mine (1956), oil and gas operations (1985), energy marketing (1997) and independent power production (2000). This diversified energy strategy has worked well, as the coal mine provides very low cost fuel to our utility power plants. We developed expertise in planning, constructing and operating power plants gave us the ability to establish power plants in other regions to serve native loads of other utilities.

In 2005, the Company's retail footprint expanded with the acquisition of CLF&P. This successful expansion included a goal to self-build power generation to serve its customers reliably and economically for decades to come and to eliminate potential power delivery and economic uncertainties that can result from merchant market conditions and tenuous power purchase contract renewals. To meet the growing needs of our customers, the Wygen II power plant is under construction with a schedule to be in commercial operation January 1, 2008.

BHC is proud of its history of innovation. Through our continued perfection of technical and business practices, we have been able to hold down costs for our customers while advancing safeguards for the environment. In the 1960s, for example, we were the first in North America to utilize air-cooled condensing technology in power plants. This innovation reduces water consumption by more than 90 percent compared to conventional coal-fired plants, and we employ this technology in four existing power plants in Wyoming, with the fifth coming on line in 2008. In 2003, our Wygen I power plant was nominated for the prestigious U.S. Environmental Protection Agency's Clean Air Award. This nomination stemmed from our application of best available control technology that reduced emissions of NOx, SOx and particulates to levels below the strict standards of the Wyoming Department of Environmental Quality and well below federal mandates. Wygen II represents another milestone, as this plant is expected to be the first in the Nation to substantially reduce mercury emissions when it goes into service.

We believe in resource conservation, environmental stewardship and providing value-priced electric service.

Our commitment to service extends to our customers and their communities. We set high standards for our customer service, reliability and safety and we do so economically. Because of our responsiveness, BHP has attained a 98 percent customer satisfaction level, according to a 2006 independent survey. Our customer satisfaction numbers are improving in Cheyenne, with a 90 percent customer approval rating there. These figures compared very favorably to a national customer satisfaction level of 74 percent, according to the Edison Electric Institute. Our employees, too, are dedicated to our communities. In their free time, hundreds of employees provide thousands of volunteer hours in civic, charitable, and other worthy causes.

We believe in resource conservation, environmental stewardship and providing value-priced electric service. It is in that spirit that we submit this IRP so that we might continue our tradition of providing reliable and economical energy to our customers in the decades to come.

Summary

Black Hills Corporation (BHC) conducted this integrated resource plan (IRP) to provide a road map for defining the system upgrades, modifications, and additions required to ensure reliable and least cost electric service to Black Hills Power (BHP) and Cheyenne Light, Fuel & Power (CLF&P) utility customers now and for the future. A full range of practicable resource alternatives, including renewable resources, were examined with the emphasis on determining the most robust plan that balances risk, reliability, and cost under a variety of possible future scenarios.

…this IRP confirms the selection of the coal-fired Wygen III as the next least-cost resource addition.

The final plan meets these important objectives:

- Ensure a reasonable level of price stability for its customers
- Generate and provide safe, reliable electricity service while complying with all environmental standards
- Manage and minimize risk
- Continually evaluate renewables for our energy supply portfolio, being mindful of the impact on customer rates.

After updating all of the assumptions and performing the analyses, the resources selected and the action plan developed in this IRP are consistent with the IRP developed in 2005. The 2005 IRP determined that subsequent to building Wygen II for operation in 2008, the next resource of choice is Wygen III in the 2009-2011 time frame. After conducting a comprehensive planning analysis that considered a broad range of generation alternatives and global climate change scenarios, this IRP confirms the selection of the coal-fired Wygen III as the next least-cost resource addition in 2010 to provide reliable, low cost service to customers of the combined BHP and CLF&P systems.

Action Plan

The action plan provides a template for the actions that should be taken over the next several years. BHC should continue to monitor market conditions and regulatory developments so that the items in the action plan can be adapted to address actual conditions as they occur.

- Build Wygen III for commercial operation in 2010.
- Continue to examine resource alternatives for development in the 2012-2014 time frame.
- Seek opportunities to develop economic renewable resources – particularly wind and biomass.
- Actively participate in and influence, to the extent possible, the Congressional efforts to tax or cap emissions of carbon dioxide (CO_2) in order to mitigate customer rate impacts.
- Work with equipment manufacturers to develop cost effective carbon capture and carbon sequestration technologies for existing generation resources.
- Actively review development of future load growth, especially in the Cheyenne, Wyoming area.
- Monitor transmission developments in the Western U.S.
- Continue to examine transmission alternatives for direct connection between the BHP and CLF&P service territories.

BHC has two investor-owned utility subsidiaries: BHP, an electric utility, and CLF&P, an electric and gas utility.

BHP is a small electric utility with a service obligation of approximately 65,000 customers in a 9,300-square mile area of western South Dakota, northeastern Wyoming, and southeastern Montana. BHP's service territory includes approximately 2,600 customers in Wyoming, incorporating the towns of Newcastle, Osage, and Upton. BHP's 2006 total customer load was 2,280,000 MWh with a peak demand of 415 MW. This load includes service obligations to BHP native load customers and two wholesale electric customers, the City of Gillette, Wyoming and the Montana-Dakota Utilities (MDU) Sheridan Service Territory in Wyoming.

CLF&P serves approximately 39,000 electric customers and 33,000 natural gas customers in Cheyenne and a large portion of Laramie County, Wyoming, including natural gas service to Pine Bluffs, Burns, and Carpenter in eastern Laramie County. Its 2006 peak electric load was 163 MW. All of the electric requirements for CLF&P through December 31, 2007, will be procured through an all-requirements contract with Public Service Company of Colorado (a subsidiary of Xcel Energy). After this contract terminates, CLF&P will assume the full obligation to serve the CLF&P load. The Wygen II coal-fired unit is expected to be completed on schedule and in commercial operation by January 1, 2008, in order to meet the electricity requirements of CLF&P customers.

The Planning Environment

The electric utility industry and BHC face many external influences including climate change, renewable portfolio standards, volatile electricity and natural gas markets, and transmission constraints. Decision making for future resource additions has to include the significant uncertainty stemming from these external influences. This is one of the most difficult times in the history of the utility industry to make choices about future resource additions. Reflecting a long-standing corporate commitment to meet customer needs in an environmentally-friendly manner, BHC has served as a leader in examining new and innovative technologies at its generating facilities. This demonstrated proactive stance will be beneficial in addressing the many external influences confronting BHC over the planning horizon.

Reflecting a long-standing corporate commitment to meet customer needs in an environmentally-friendly manner, BHC has served as a leader in examining new and innovative technologies.

BHC is proud of its environmental record, achievements and cooperation with regulatory authorities. Over the decades, we have employed cutting edge technologies for its coal-fired power plants. Lack of water in the Gillette, Wyoming area led BHC to become a pioneer in the installation and operation of air-cooled condensers. More recently BHP partnered with Babcock & Wilcox, the Energy & Environmental Research Center of the University of North Dakota, Optimal Air Testing, and the University of Wyoming on studies examining methods of controlling mercury emissions on coal-fired generation.

BHC was the first adopter of low NOx burners which were retrofitted on Neil Simpson I to control nitrous oxide emissions. BHC recently agreed to test burn enhanced coal produced by Evergreen Energy Inc. Independent consultants retained by Evergreen monitored the associated emission impacts, in order to assist in the understanding of the environmental and operational merits of that process. BHC has striven to ensure that its plants use the best available control technologies and produce the lowest level of emissions possible. The company will continue to investigate carbon capture and sequestration as these appear to be the cost effective mitigation technologies most likely to reduce CO_2 emissions. In addition, a portion of the BHC generating units, including Neil Simpson II and all of the Wygen units can be retrofitted with carbon capture equipment.

Assumptions

A wide variety of data assumptions are included in our IRP modeling. Critical assumptions include coal price forecasts, gas price forecasts, market price forecasts, financial parameters, planning reserves, emissions costs, and CO_2 tax projections. The Global Energy Decisions (GED), Power Market Advisory Service: Electricity and Fuel Price Outlook – WECC, Spring 2007 (WECC 2007 Spring Reference Case), a leading provider of resource planning information and software, was used for the long-term gas and electric price forecasts. The WECC 2007 Spring Reference Case assumes that carbon legislation will be implemented by 2012 and will include a carbon emissions cost of \$2.30 per ton of CO_2 starting in 2012 and increasing to \$24.60 by 2027 (which represents a levelized cost of $10.65/ton). The assumed planning reserve margin is 15%. Peak demand and energy forecasts were developed for BHP, CLF&P, the City of Gillette, and the MDU Sheridan Service Territory. These major assumptions create a realistic scenario under which we concluded that coal-fired resources are best-suited to accommodate load growth in a cost effective manner.

Sensitivities

In addition to base case forecasting, we evaluated our model with certain variation in our assumptions, enabling us to understand how changes in modeling can affect outcomes different from the base case. This sensitivity analysis gives us both confidence in our conclusions and a better understanding of how our performance may change as conditions change. To balance risk, reliability and cost, we performed several sensitivity analyses, including:

- Alternative capacity expansion plans
- Stress test scenarios
- Risk analysis

Resources

This IRP, like others, focuses on supply-side factors to meet future load requirements. However, both BHP and CLF&P utilize a standard slate of DSM programs. DSM programs readily assess all classes of customers – residential, commercial, and industrial. These programs involve strategies for institutionalizing load reduction through training of trade allies, encouraging both the construction of energy efficient buildings and the usage of energy efficient appliances. The penetration of the DSM programs is assumed to be reflected in the historical data used to derive the load forecasts and thus it is propagated into the future at the same level of penetration as a percentage of total load.

BHP's and CLF&P's existing supply-side resources are all assumed to remain in operation throughout the study period except the three Osage units which are assumed to be retired as of December 31, 2012 and the Colstrip power purchase agreement (PPA) terminates in 2023. The Neil Simpson Combustion Turbine II converts to utility ownership after contract expiration in June of 2012. The life of the Ben French steam station will be extended throughout the study period by means of equipment upgrades in 2009 which are assumed to cost approximately $10 million in 2007 dollars.

For the IRP process, new resources are selected to ensure that the system satisfies applicable operating and planning reserve criteria.

BHP will provide power to MDU's Sheridan Service Territory throughout the study period as well as to the City of Gillette, Wyoming. A 20 MW unit contingent sale to the Municipal Energy Agency of Nebraska (MEAN) will terminate in February 2013, the current expiration date. For purposes of this IRP, it has also been assumed that 60 MW of Wygen I will continue, per the existing contract terms, to be available to CLF&P throughout the planning horizon. This assumption will be reexamined when the next IRP is performed.

Because the peak demand and energy requirements of its customers continue to grow throughout the 2008-2027 forecast period, BHC will consider the addition of new supply-side resources, conventional and renewable, self-built or otherwise procured through a Request for Proposals (RFP). Conventional resources examined in the IRP included coal, natural gas combined cycle, integrated gasification combined cycle (IGCC), combustion turbine, and purchased power. The renewable resources that were considered in the IRP include solar, wind, and biomass.

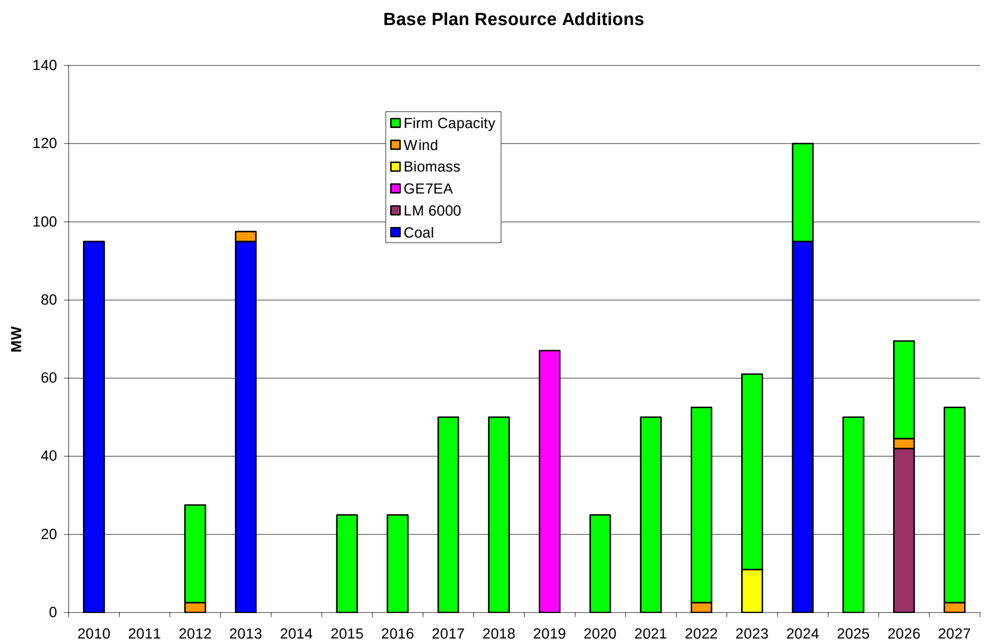
Base Plan

For the IRP process, new resources are selected to ensure that the system satisfies applicable operating and planning reserve criteria. No resources were screened out of consideration in the modeling process. Thus all potential conventional and renewable resources were examined. The combination of resources that provides the lowest present value of revenue requirements (PVRR) to the BHP and CLF&P customers while satisfying the reliability criteria was selected and is referred to as the Base Plan. For purposes of the IRP, no transmission costs have been added to the various cases as all were assumed to require the same level of purchased transmission service.

The resources added in the Base Plan include pulverized coal units in 2010, 2013, and 2024; wind energy resources in the form of new 25 MW PPA's in each of 2012, 2013, 2022, 2026, and 2027; peaking resources in 2019 and 2026; and a biomass facility in 2023. In addition, purchased power in the market is utilized in the months of July and August in many of the years in lieu of building any additional resources (6 x 16, up to two 25 MW blocks). These resource additions are all reflected on Figure ES-1.

Today, utilities must plan for the future electricity needs of customers in an environment of significant uncertainty.

Figure ES-1



This IRP promotes a diversified portfolio of power generation assets, including the use of cost-effective renewable resources.

Financial Risk Analysis

Today, utilities must plan for the future electricity needs of customers in an environment of significant uncertainty. Thus, the analysis conducted in the preparation of this IRP examined uncertainty under a variety of possible future conditions. Stress test scenarios were developed to determine effects on the preferred resource mix based on conditions different than the Base Plan assumptions. Stress tests were performed to determine the best portfolio of new generation additions under lower gas price assumptions (15% lower than the Base Plan) as well as significantly higher CO_2 tax forecasts (approximately five times Base Plan assumptions with a levelized cost of \$63.26/ton) (the Very High CO_2 Tax Plan). In both cases, the preferred portfolio included the addition of a combustion turbine instead of Wygen III. A plan was also developed that did not allow any new coal resources after Wygen II (the No Coal Plan) to determine what would be selected for capacity expansion if coal were not an option.

Other stress tests were performed such as lower gas prices, no CO_2 taxes, and higher construction costs for Wygen III. The results of these stress tests led to portfolio additions that either did not materially differ from the Base Plan or were similar to either the No Coal Plan or the Very High CO_2 Tax Plan.

To achieve the objective of this IRP, i.e., determining the most robust plan that balances risk, reliability, and cost under a variety of possible future conditions stochastic risk analysis was performed for each of the Base Plan, the No Coal Plan, and the Very High CO_2 Tax Plan. This analysis determined the present value revenue requirement (PVRR) for each under a wide range of sensitivities.

GED's Strategic Planning model uses a structural approach to forecast prices that captures the uncertainties in regional electric demand, resources, and transmission. The model generates regional forward price curves across multiple scenarios. Scenarios are driven by a wide range of market drivers and take into account statistical distributions, correlations, and volatilities. The uncertainties examined in this IRP include those shown in Table ES-1 which shows the minimum and maximum values used for the uncertainty variables.

Table ES-1

Ranges for Uncertainty Variables

Variable	Minimum	Maximum
Mid-Term Peak	.82	1.14
Mid-Term Energy	.92	1.09
Long-Term Demand	.91	1.10
Mid-Term Gas Price	.75	2.10
Mid-Term Oil Price	.86	1.16
Long-Term Gas and Oil Price	.82	1.18
Mid-Term Coal Unit Availability	.88	1.10
Mid-Term Nuclear Unit Availability	.94	1.06
Mid-Term Gas Unit Availability	.85	1.16
Mid-Term Hydro Output	.82	1.17
Long-Term Pulverized Coal Capital[2]	1.00	1.20
Long-Term CT Capital	1.00	1.08
Long-Term CC Capital	1.00	1.12
Long-Term IGCC Capital	1.00	1.30

This table shows a summary of the uncertainty variables and the multipliers used to establish their minimum and maximum values for the risk analysis.

…there is a 70% probability that the Base Plan will have a lower PVRR than either of the other two cases for all possible futures.

The results of the stochastic analysis show that the expected PVRR, the cost that would be expected in a deterministic analysis, for the Base Plan is significantly lower than for the other two cases as shown in Table ES-2. The probable cost shown for each scenario is the mean cost developed through the stochastic analysis. The probable cost for the Base Plan is lower than the probable cost for the other cases. However, the risk associated with the Base Plan (which is the difference between the expected cost and the probable cost) is more significant than for either of the other two cases because of the potential exposure that would result in the Base Plan from a high CO_2 tax.

Table ES-2

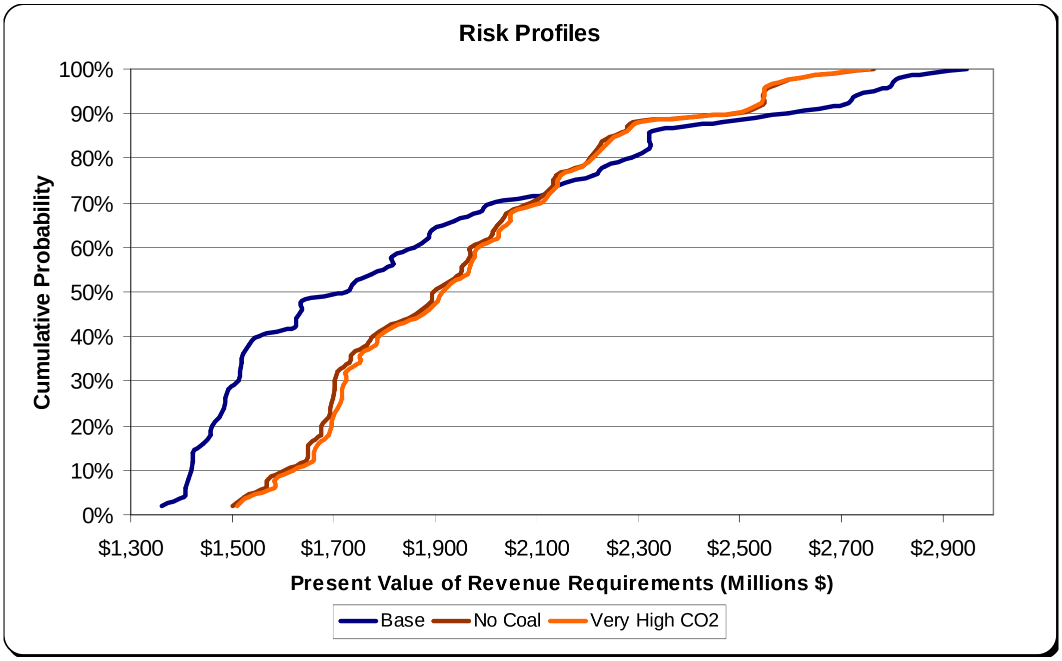
Expected and Probable Costs for All Scenarios – PVRR (2008-2027) (millions of dollars)

	Base Plan	No Coal	Very High CO_2 Tax
Expected Cost	$1,685.20	$1,856.34	$1,867.84
Probable Cost	$1,865.59	$1,957.19	$1,968.12
Difference	$180.39	$100.85	$100.28

This table summarizes the present value revenue requirement under different assumptions, and shows that the risk associated with the base plan is more significant than for the other two cases.

The risk profiles for the Base Plan, No Coal Plan, and Very High CO_2 Tax Plan are shown on Figure ES-2. As demonstrated by this figure, there is a 70% probability that the Base Plan will have a lower PVRR than either of the other two cases for all possible futures.

Figure ES-2



The stress test results show that there is a 72% probability that the Base Plan will have a lower PVRR than either of the other two cases.

This IRP demonstrates the long-term value of the addition of coal-fired, baseload power plants supplemented by the cost-effective use of gas-fired and renewable power sources.

The Base Plan meets the objective of the IRP to determine the most robust plan that balances risk, reliability, and cost over a wide range of possible future conditions. The decisions reached in the Base Plan in this IRP reflect comprehensive planning analysis that examines a number of potential decisions and selects the resources that meet the objectives. The comprehensive global warming analysis considered a broad range of CO_2 taxes, with the Wygen III unit being determined to be the resource of choice, in the 2010 time frame.

Conclusion

This IRP demonstrates the long-term value of the addition of coal-fired, baseload power plants supplemented by the cost-effective use of gas-fired and renewable power sources. It defines the system upgrades, modification and additions that area required to ensure reliable, least cost electric service to BHP and CLF&P customers now and into the future.

This plan meets the objectives of the Company to:

- Ensure a reasonable level of price stability for its customers
- Generate and provide safe, reliable electricity service while complying with all environmental standards
- Manage and minimize risk, and
- Continually evaluate renewables for our energy supply portfolio, being mindful of the impact on customer rates.

Introduction

Company Situation

Black Hills Corporation (BHC) is a diversified energy company headquartered in Rapid City, South Dakota. BHC has two investor-owned utility subsidiaries: Black Hills Power, Inc. (BHP), an electric utility, and Cheyenne Light, Fuel & Power Company (CLF&P), an electric and gas utility.

BHP is a small electric utility with a service obligation of approximately 65,000 customers in a 9,300-square mile area of western South Dakota, northeastern Wyoming, and southeastern Montana. BHP's service territory includes approximately 2,600 customers in Wyoming, incorporating the towns of Newcastle, Osage, and Upton. BHP's 2006 total customer load was 2,280,000 MWh with a peak demand of 415 MW. This load includes service obligations to BHP native load customers and two wholesale electric customers, the City of Gillette, Wyoming and the Montana-Dakota Utilities (MDU) Sheridan Service Territory in and around Sheridan, Wyoming.

This IRP was developed to provide a road map for defining the appropriate system upgrades, modifications, and additions required to ensure reliable and least cost electric service.

CLF&P serves approximately 39,000 electric customers and 33,000 natural gas customers in Cheyenne and a large portion of Laramie County, Wyoming, including natural gas service to Pine Bluffs, Burns, and Carpenter in eastern Laramie County. Its 2006 peak electric load was 163 MW. All of the electric requirements for CLF&P through December 31, 2007, will be procured through an all-requirements contract with Public Service Company of Colorado (part of Xcel Energy). After this contract terminates, BHC will assume the full obligation to serve the CLF&P load.

BHC completed an IRP filed with the Wyoming Public Service Commission on March 31, 2005. Since that IRP was completed several important changes have occurred in the electric utility industry:

- Natural gas prices have continued to exhibit extreme volatility, and in 2006, reached historically high prices.
- The April 2, 2007, U.S. Supreme Court decision directed the EPA to reconsider its position as to whether carbon dioxide (CO_2) is a pollutant that should be regulated. U.S. Congressional action is also expected with regard to reducing CO_2 emissions.
- Many utilities around the country (primarily in the Midwest and Eastern U.S.) are in the initial stages of licensing nuclear power plants.
- The public expects utilities to seriously examine renewable energy resources and offer renewable energy rates. CLF&P has such a renewable energy premium program tariff in place.

This IRP addresses resource needs of the combined CLF&P and BHP systems for the planning horizon of 2008-2027.

Objectives

This IRP was developed to provide a road map for defining the appropriate system upgrades, modifications, and additions required to ensure reliable and least cost electric service to BHP and CLF&P utility customers now and for the future. The IRP examined the needs of the BHP and CLF&P customers with a thorough consideration of generation, including renewable energy, purchased power, transmission, and interconnection issues.

Prudent utility practices were employed in the preparation of the IRP and a full range of practicable resource alternatives, including renewables, were evaluated. Comprehensive modeling was undertaken using GED Capacity Expansion and Strategic Planning *powered by MIDAS Gold*® software modules (see Appendix B). The GED modeling included: 1) a screening of resources, 2) optimization of resource selection using linear programming techniques, 3) in-depth modeling of resource portfolios using production costing models, and 4) risk analysis using stochastic techniques. However, no rate analysis has been conducted as such is beyond the scope of a standard IRP.

The final plan meets the objectives of the company:

- Ensure a reasonable level of price stability for its customers
- Generate and provide safe, reliable electricity service while complying with all environmental standards
- Manage and minimize risk
- Continually evaluate renewables for our energy supply portfolio, being mindful of the impact on customer rates.

The Planning Environment

The electric utility industry and Black Hills Corporation face many external influences due to regulatory and legislative actions or potential actions. The uncertainty stemming from these external influences makes this one of the most difficult times in the history of the utility industry to make choices about future resources. Reflecting a long-standing corporate commitment to meet customer needs in an environmentally-friendly manner, BHC has served as a leader in examining new and innovative technologies at its generating facilities. This demonstrated proactive stance will be beneficial in addressing the many external influences confronting BHC over the planning horizon. These external influences include climate change, renewable portfolio standards, volatile electricity and natural gas markets, and transmission constraints.

Over the years, BHC has implemented cutting edge technologies for its coal-fired power plants.

Innovative Technologies

Over the years, BHC has implemented cutting edge technologies for its coal-fired power plants. Lack of water in the Gillette, Wyoming area led BHC to become a pioneer in the installation and operation of air-cooled condensers. BHC has partnered with Babcock & Wilcox, the Energy & Environmental Research Center of the University of North Dakota, Optimal Air Testing, and the University of Wyoming on studies examining methods of controlling mercury emissions when coal is used as a combustion fuel. BHC was the first adopter of low NO_x burners which were retrofitted on Neil Simpson I in the early 1990s to control nitrous oxide emissions. Since that time, each of Neil Simpson II, Wygen I, and Wygen II have been equipped with the latest design low NO_x burners. And, BHC agreed to test burn coal produced by Kfuels in order to assist in the understanding of the environmental and operational merits of that process. BHC has striven to ensure that its plants use the best available control technologies and comply with all permit emission limits.

Climate Change

The belief that the temperature of the earth is warming above normal levels and that human activity is causing this warming is termed “global climate change” or “global warming.” Greenhouse gases are generally identified as the cause of global warming with CO_2 as the major contributor. Although the U.S. was not a signatory to the Kyoto Protocol and the U.S. Congress has yet to act on ways to manage or reduce CO_2 emissions, it is generally believed that some legislation will eventually be enacted. The electric utility industry, with its heavy reliance on fossil fuel to produce electricity, is one of the primary producers of CO_2 emissions in the U.S.

The assumptions made for this IRP include CO_2 taxes reflecting the belief that such a nationwide CO_2 control mechanism will be enacted. However, much uncertainty exists about the date at which such legislation will be enacted and the form that it will take (cap and trade, a tax on emissions, or a command and control approach). Regardless, it is important to recognize that a portion of the BHC generating units, including Neil Simpson II and all of the Wygen units can be retrofitted with carbon capture equipment.

BHC is aware that geological formations in Wyoming are conducive for carbon sequestration and is monitoring related developments. Captured carbon could be injected into the ground to enhance oil recovery or injected specifically to remove it from the atmosphere. BHC also participates in Colorado tree planting programs to reduce CO_2 levels in the atmosphere.

Renewable Portfolio Standards

BHC has taken several proactive steps to increase its utilization of renewable energy.

Renewable portfolio standards (RPS) are statutes enacted by state legislatures or through voter referenda that mandate a minimum amount of renewable energy be included in utility resource portfolios by a date certain, often with the required percentage increasing over time. RPS have primarily, but not exclusively, been enacted as a result of state-based electric restructuring efforts. As of early 2007, twenty-three states and the District of Columbia have enacted an RPS.[1] Some of the states allow or encourage a trading mechanism for the exchange of renewable energy credits among the state's utilities to facilitate compliance with the RPS.[2] The U.S. Congress has been lobbied to establish a national RPS, but to date no legislation has been enacted. Wyoming, South Dakota, and Montana have not enacted an RPS.

BHC has taken several proactive steps to increase its utilization of renewable energy. Wind resource analyses of BHP's service territory in South Dakota were undertaken in the early 1990s. CLF&P has established a Renewable Premium Program whereby customers can voluntarily sign up to pay a green power premium to support production of renewable energy through the purchase of renewable energy credits. CLF&P entered into a 20 year, 30-MW wind energy power purchase agreement (PPA) for purchase of wind energy at the Happy Jack facility outside of Cheyenne, Wyoming, which will begin operation in September 2008. A meteorological data tower has been in operation north of Belle Fourche, South Dakota, since 2006 gathering wind data to determine what size wind energy resource could be built in this area. Thus, BHC is well positioned in the event that any of the three states in which it currently operates enacts an RPS.

Electricity and Natural Gas Markets

BHC participates in the electricity markets on an hourly basis. Price fluctuations occur and have occurred historically due to classic economic supply and demand – prices are higher during on-peak periods and lower during off-peak periods, except in unusual circumstances. The price of electricity in BHC's market is currently driven, and will be driven over the planning horizon, by the price of natural gas and the ability of neighboring utilities to ensure adequate generation and transmission resources.

We are working to ensure that transmission constraints will not preclude its customers from benefiting from generation resources located throughout its service territory.

Natural gas prices have exhibited significant volatility since 2003. Important factors driving this volatility are the increased use of natural gas resources (combustion turbines and combined cycle units) in the U.S. pipeline constraints and the reality that new natural gas developments for production facilities produce lower quantities and lower gas quality than did developments in the 20th century. Although some forecasters predict greater natural gas price stability and increased liquid natural gas (LNG) imports in the future, much uncertainty exists as to whether or not such developments will actually occur. Thus, it is prudent for utility planners to examine high and low gas price forecasts in their planning analyses.

The current regulatory environment has not been conducive to construction of new power plants or transmission lines. Further constraints on the construction of both of these types of resources will limit the availability of power that can be purchased during on-peak periods and serve to drive up purchased power prices even more.

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[1] " States with Renewables Portfolio Standards," www.pewclimate.org/what_s_being_done/in_the_states/rps.cfm, April 2007.
[2] "Renewable Portfolio Standards," www.newrules.org/electricity/rps.html.

Transmission Constraints

Transmission additions across t`he U.S. have historically occurred in conjunction with the construction of generating resources. As most utilities throughout the U.S. stopped building additional resources themselves over the past twenty years, construction of transmission also slowed or stopped. Thus, the backlog of needed transmission projects has grown at the same time that consumer resistance to those projects has increased. With the Energy Policy Act of 2005, the federal government has been empowered to designate transmission corridors of national interest. However, the pace of transmission additions is still very slow, the permitting process long, and environmental resistance strong. We are working to ensure that transmission constraints will not preclude its customers from benefiting from generation resources located throughout its service territory.

Conclusion

These external influences, when combined, make the current environment one of the most difficult in the history of the utility industry.

Assumptions

A wide variety of data assumptions must be made for integrated resource plan (IRP) modeling. Critical assumptions described in the following paragraphs include coal price forecasts, gas price forecasts, market price forecasts, financial parameters, planning reserves, emissions costs, and CO_2 taxes. GED, *Power Market Advisory Service: Electricity and Fuel Price Outlook – WECC, Spring 2007* (WECC 2007 Spring Reference Case)[3] was used for the long-term gas and electric price forecasts. The load and energy forecast is described in its own section of the report that follows this one.

Coal Price Forecasts

BHC's ownership of the coal reserves provides supply security over the planning horizon and greater confidence in forecasted coal prices.

BHC's coal-fired generation facilities are fueled by coal from the Wyodak coal mine, located in Gillette, Wyoming. All of the coal-fired generation is located at the mouth of the Wyodak mine with the exception of the Ben French and Osage facilities which are in close enough proximity to the Wyodak mine for coal to be delivered by truck. The coal is mined by Wyodak Resources Development Corporation (WRDC), a subsidiary of Black Hills Corporation. WRDC has 250-300 million tons of coal reserves that can be economically mined. Thus, coal resources are adequate to supply projected coal requirements for 40 to 50 years, assuming current production levels. BHC's ownership of the coal reserves provides supply security over the planning horizon and greater confidence in forecasted coal prices. Location of the power plants at the mine mouth renders transportation costs and escalation in transportation costs irrelevant. This position is very beneficial for BHC's customers as current market conditions are such that few utilities are able to obtain long-term coal supply contracts from mines in the Powder River Basin or long-term transportation agreements.

Gas Price Forecasts

BHC used the natural gas price forecasts from the WECC 2007 Spring Reference Case. The Henry Hub values were adjusted by the basis differential to more accurately reflect the price of gas as actually delivered to BHP generating facilities. The Henry Hub gas prices are shown monthly in Table 1. The gas price forecasts reflecting the basis differentials are set forth in Figure 1.

[3] *Power Market Advisory Service: Electricity and Fuel Price Outlook – WECC, Spring 2007*. This document describes issues in markets around the U.S. (e.g., nuclear, transmission, and climate change) and provides forecasts of fuels including natural gas and coal, and electricity market prices.

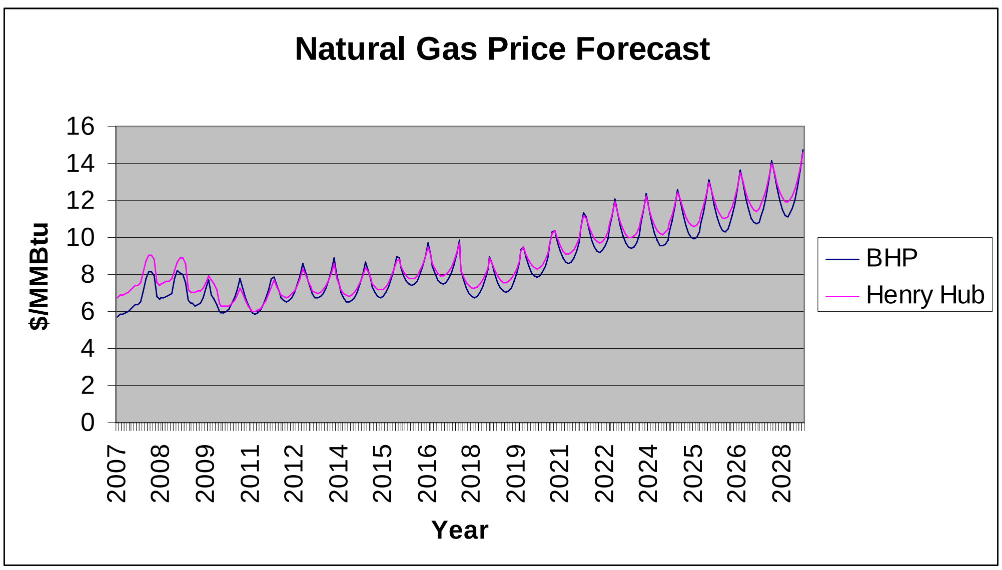
Table 1

Monthly Henry Hub Natural Gas Prices ($/MMBtu)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2007	6.72	6.86	6.90	6.95	7.05	7.17	7.29	7.38	7.42	7.53	8.15	8.76
2008	9.07	9.06	8.84	7.55	7.43	7.48	7.54	7.60	7.66	7.75	8.21	8.66
2009	8.90	8.90	8.59	7.22	7.06	7.06	7.07	7.09	7.12	7.23	7.58	7.94
2010	7.72	7.51	7.19	6.46	6.31	6.27	6.28	6.32	6.43	6.61	6.91	7.27
2011	6.94	6.59	6.28	6.11	6.02	5.99	6.04	6.16	6.34	6.61	6.94	7.35
2012	7.68	7.33	7.07	6.88	6.78	6.75	6.80	6.93	7.14	7.44	7.81	8.27
2013	7.97	7.61	7.34	7.14	7.03	7.00	7.06	7.19	7.42	7.72	8.11	8.59
2014	7.77	7.43	7.16	6.97	6.86	6.83	6.89	7.02	7.23	7.53	7.91	8.38
2015	8.14	7.78	7.50	7.30	7.18	7.15	7.21	7.35	7.57	7.89	8.28	8.77
2016	8.82	8.43	8.12	7.91	7.79	7.75	7.81	7.96	8.21	8.55	8.98	9.51
2017	9.02	8.62	8.31	8.09	7.96	7.93	7.99	8.14	8.39	8.74	9.18	9.72
2018	8.25	7.88	7.59	7.39	7.28	7.25	7.30	7.45	7.68	7.99	8.40	8.89
2019	8.59	8.21	7.91	7.70	7.58	7.55	7.61	7.76	8.00	8.33	8.75	9.26
2020	9.47	9.04	8.72	8.49	8.35	8.32	8.38	8.55	8.81	9.17	9.64	10.20
2021	10.35	9.89	9.53	9.28	9.14	9.10	9.17	9.35	9.64	10.03	10.54	11.16
2022	11.07	10.58	10.20	9.93	9.77	9.73	9.81	10.00	10.30	10.73	11.27	11.93
2023	11.35	10.84	10.45	10.17	10.02	9.97	10.05	10.25	10.56	10.99	11.55	12.23
2024	11.58	11.06	10.66	10.38	10.22	10.18	10.26	10.45	10.78	11.22	11.79	12.48
2025	12.06	11.52	11.11	10.82	10.65	10.60	10.68	10.89	11.23	11.69	12.28	13.00
2026	12.53	11.97	11.54	11.24	11.06	11.01	11.10	11.31	11.66	12.14	12.76	13.50
2027	13.02	12.44	11.99	11.67	11.49	11.44	11.53	11.75	12.12	12.61	13.25	14.03

Source: GED

Figure 1



Henry Hub prices gradually rise at an average rate of about 1.53 percent annually in real dollars and are on an average about 30 percent higher as compared to the forecast from Fall 2006. (WECC 2007 Spring Reference Case report Page 5-27). To more accurately reflect gas a delivered to BHP, we adjusted the HH values by the basis differential.

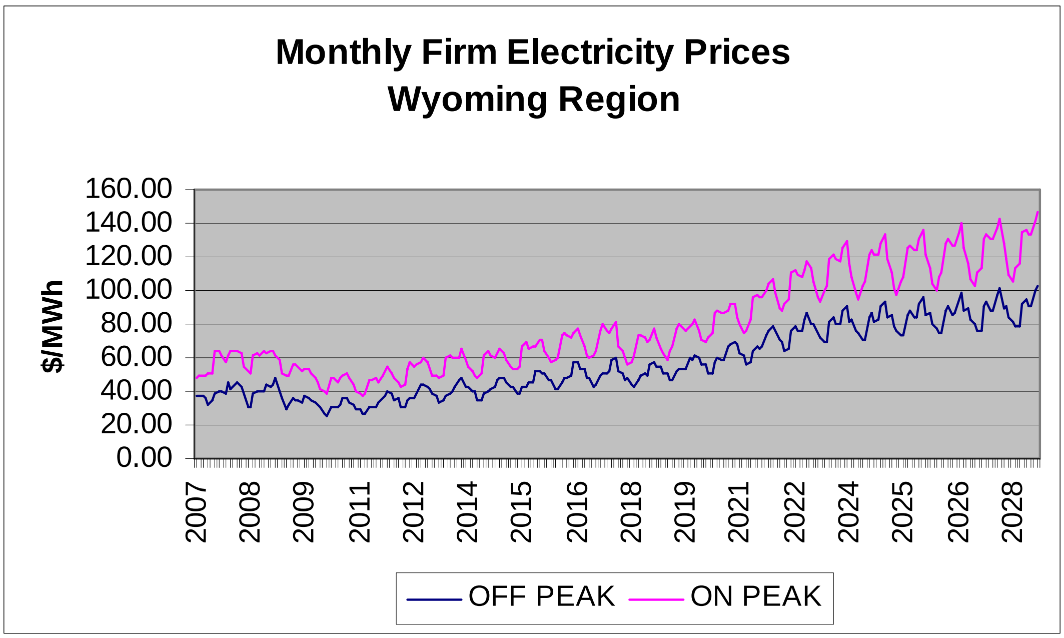
Market Price Forecast

BHP will sell surplus energy when market conditions make this possible. Prices for surplus energy vary significantly between the on-peak and off-peak periods primarily due to utilization of peaking generation at the margin during on-peak and base load generation at the margin during off-peak. During the on-peak hours, natural gas is almost always the fuel at the margin. Thus, projections of on-peak prices – both for economy energy purchases and for surplus sales – are linked to the projected price of natural gas. For off-peak periods, coal is more likely to be the fuel at the margin and thus the price projections for off-peak energy and surplus sales are significantly lower than the projections for the on-peak prices.

BHP will purchase energy when it is a cost effective displacement of gas-fired units and during periods of forced or scheduled plant outages. Prices for economic energy, comparable to prices for surplus sales, vary significantly between on-peak and off-peak periods as well. In addition, BHP assumes that it is possible to purchase up to 50 MW during the peak period months of July and August for six days a week, sixteen hours a day.

Electricity price estimates for the Wyoming region came from the WECC 2007 Spring Reference Case, and are the basis on which BHP's surplus sales and economy energy are priced and are as shown in Figure 2.

Figure 2



The WECC 2007 Spring Reference Case analysis of energy market prices employs many assumptions including gas prices and the number of fuel types of the new power plants that are projected to be built in each region.

Financial Parameters

BHC used a discount rate of 7.76% to examine the present value of revenue requirements (PVRR). Levelized fixed charge rates applied to the capital costs for new technologies examined in the IRP included 11.31% for coal and integrated gasification combined cycle (IGCC), 11.96% for combustion turbine, 11.96% for combined cycle, and 12% for solar. The book and tax lives assumed for the supply-side resources considered in the IRP are shown in Table 2.

Table 2
Book and Tax Life Assumptions

Technology	Tax Life (years)	Book Life (years)
Coal	20	40
LMS-100 Simple Cycle Combustion Turbine	15	30
LM-6000 Simple Cycle Combustion Turbine	15	30
Frame 7EA Simple Cycle Combustion Turbine	15	30
Combined Cycle (new plant)	20	30
Combined Cycle (Gillette conversion)	20	35
IGCC	20	40
Biomass	7	20
Solar	5	20
Wind	5	25

The annual escalation rates used in the analysis include 2.5% for variable operating and maintenance costs (O&M), 2.5% for fixed O&M, and 3.0% for construction.

Planning Reserves

Planning reserve margin is defined as the additional capacity required in excess of a utilities peak forecasted demand to ensure resource adequacy for a reliable generation portfolio. As new resources are added to the supply portfolio there will be times when there will be excess energy available to be sold to the market. It is assumed that revenues from the sales of excess energy are credited back to the cost of the portfolio. To constrain the model from overbuilding resources, the reserve margin is capped at 25%. Historically across the country, the level of planning reserve margin has generally varied from 15 to 20%. A minimum planning reserve margin of 15% was used in this Resource Plan, which is consistent with what other utilities use in the western region and is generally regarded as prudent industry practice. The maximum planning reserve margin was capped at 25% in an effort to assure that the size of the units when added to a system the size of BHP and CLF&P can be reasonably optimized.

A minimum planning reserve margin of 15% was used in this Resource Plan…

As a member of the Rocky Mountain Reserve Group (RMRG), BHC has reduced its reserve requirements by committing to its pro rata share of required reserves among the entire RMRG. The pro rata share is at a level that requires the group to cover the group's largest single contingency. BHC must also carry spinning reserves. Currently, the spinning reserve total requirement for a combination of BHP and CLF&P is 12 MW, which represents half of the operational reserve the companies are required to carry. Membership in the RMRG reduces the amount that the combined companies are required to carry in total and as spinning reserve.

Emissions Costs

Costs for emissions allowances for sulfur dioxide (SO_2), nitrous oxides (NO_x), and mercury (Hg) were input into the IRP model. Emissions, and their associated costs, were modeled for each of SO_2, NO_x, and Hg for all new units. The Clean Air Interstate Rule (CAIR) increases the cost of SO_2 compliance in 2010 and 2015. CAIR also places annual and seasonal (April through September) NO_x emission limits on generating units in the Eastern U.S. beginning in 2009. For IRP modeling purposes, it was assumed, per the WECC 2007 Spring Reference Case, that some annual NO_x emission limit would be placed on generating units in the Western U.S. beginning in 2012. The Clean Air Mercury Rule (CAMR) affects mercury emissions starting in 2010. The values used are shown in Table 3.

Table 3

Emissions Costs

Year	SO_2 ($/ton)	NO_x ($/ton)	Hg (000 $/ton)
2007	460	0	0
2008	472	0	0
2009	483	0	0
2010	495	0	13,468
2011	508	0	13,804
2012	520	545	14,149
2013	513	559	14,503
2014	515	573	14,866
2015	507	587	15,237
2016	500	602	15,618
2017	492	617	16,009
2018	484	632	16,409
2019	477	648	16,819
2020	471	664	17,240
2021	465	681	17,671
2022	458	698	18,112
2023	451	715	18,565
2024	446	733	19,029
2025	440	751	19,505
2026	433	770	19,993
2027	352	789	20,493

Source: WECC 2007 Spring Reference Case

In 2006, Global Energy developed a proprietary Emission Forecast Model (EFM) to simulate emission control decisions and results simultaneously in the three cap-and-trade markets (SO_2, NO_X, Hg).

Carbon Dioxide Taxes

The U.S. Supreme Court's, April 2, 2007, decision that the Environmental Protection Agency has the authority to regulate CO_2 and other greenhouse gases as pollutants means that, electric utilities in the U.S. that burn fossil fuels must seriously contemplate, in their planning, the impact of a "carbon tax" or a "cap and trade" program for carbon emissions.

Because of this action, BHC in its IRP decided to use the WECC 2007 Spring Reference Case assumptions for its Base Plan, which include a CO_2 tax starting in 2012 at a level of $2/ton (in 2007 dollars) escalating at one dollar per ton per year until 2026. This pattern results in the $/ton costs for CO_2 taxes as shown in Table 4. The level of CO_2 taxes assumed in the High CO_2 Case are also shown in Table 4.

Table 4

Carbon Dioxide Taxes

Year	$/ton WECC 2007 Spring Reference Case	$/ton (High CO_2 tax case)
2007	0.0	0.0
2008	0.0	0.0
2009	0.0	0.0
2010	0.0	0.0
2011	0.0	0.0
2012	2.3	26.67
2013	3.5	28.73
2014	4.8	30.95
2015	6.1	33.34
2016	7.5	35.91
2017	9.0	38.68
2018	10.5	41.66
2019	12.1	44.88
2020	13.8	48.34
2021	15.5	52.07
2022	17.4	56.09
2023	19.3	60.41
2024	21.3	65.07
2025	23.4	70.09
2026	24.0	75.50
2027	24.6	81.33

National greenhouse gas regulation has a great potential to reshape the electric generation fuel mix as well as electricity and fuel prices, especially for natural gas.

Load Forecast

Load forecasts were developed for the BHP system; CLF&P; City of Gillette, Wyoming; and the MDU Sheridan Service Territory. These load forecasts were then combined for the IRP – the energy was summed across the systems and coincident peaks were determined. Key assumptions and factors associated with the forecasts are provided in the paragraphs below.

BHP

The BHP load forecast of peak demands and annual energy for 2008-2027 is shown in Table 5. It reflects an annual trended growth rate of approximately 1.58% with load additions that were known at the time.[4] The load shape is based on historical data. Figures 3 and 4 show the peak demand and energy forecast for BHP, not including the 20 MW sale to the Municipal Energy Authority of Nebraska (MEAN), the City of Gillette or the MDU Sheridan Service Territory. The forecasted peak demand and energy includes losses incurred to serve load.

Table 5

BHP Peak Demand and Energy Forecast 2008-2027

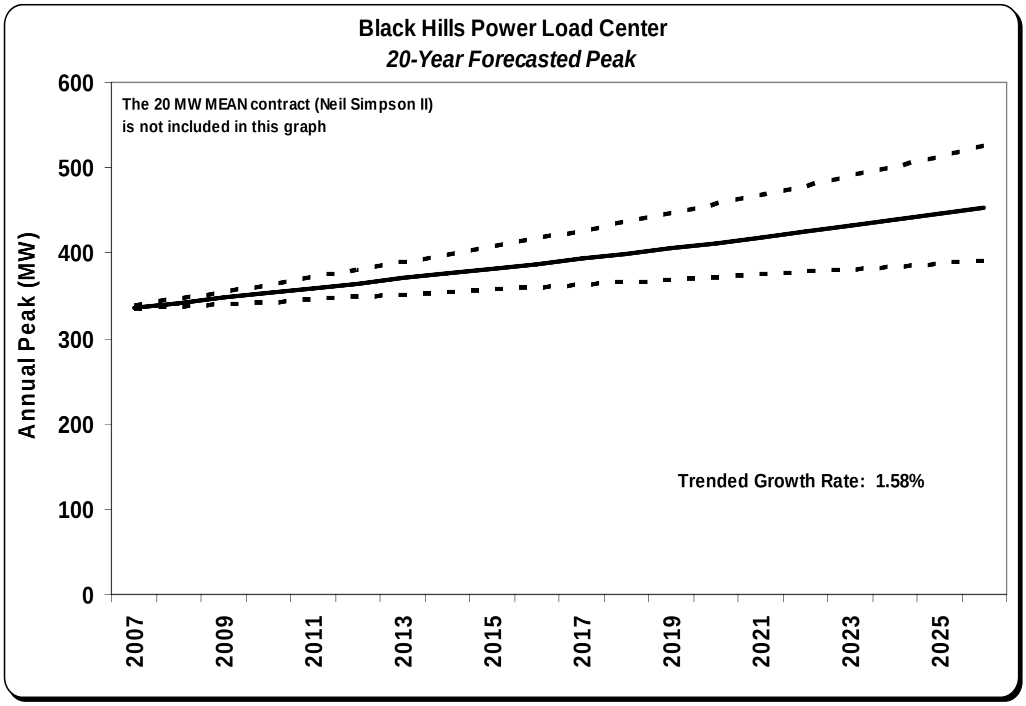
Year	Peak Demand (MW)	Growth in Peak Demand (%)	Annual Energy (MWh)	Growth in Annual Energy (%)	Load Factor (%)
2008	342		1,745,692		58.3
2009	348	1.75	1,772,494	1.54	58.2
2010	353	1.44	1,799,841	1.54	58.3
2011	359	1.70	1,827,968	1.56	58.2
2012	364	1.39	1,856,885	1.58	58.2
2013	370	1.65	1,886,262	1.58	58.2
2014	376	1.62	1,916,109	1.58	58.2
2015	381	1.33	1,946,384	1.58	58.3
2016	387	1.57	1,977,139	1.58	58.3
2017	393	1.55	2,008,379	1.58	58.3
2018	399	1.53	2,040,114	1.58	58.3
2019	405	1.50	2,072,349	1.58	58.4
2020	412	1.73	2,105,095	1.58	58.4
2021	418	1.46	2,138,357	1.58	58.4
2022	425	1.67	2,172,145	1.58	58.4
2023	431	1.41	2,206,467	1.58	58.4
2024	438	1.62	2,241,331	1.58	58.4
2025	445	1.60	2,276,746	1.58	58.4
2026	452	1.57	2,312,721	1.58	58.4
2027	459	1.55	2,349,263	1.58	58.4

BHP forecasted peak and energy reflecting an annual trended growth rate of 1.58%. The load shape for 2005 was used in the deterministic case and samples from the 2000-2005 load shapes were randomly drawn for the stochastic price trajectories.

[4] Since the load forecast was completed, potential load additions in BHP's service territory that have arisen include DUSEL, Wal-Mart, and an ethanol plant.

Figure 3

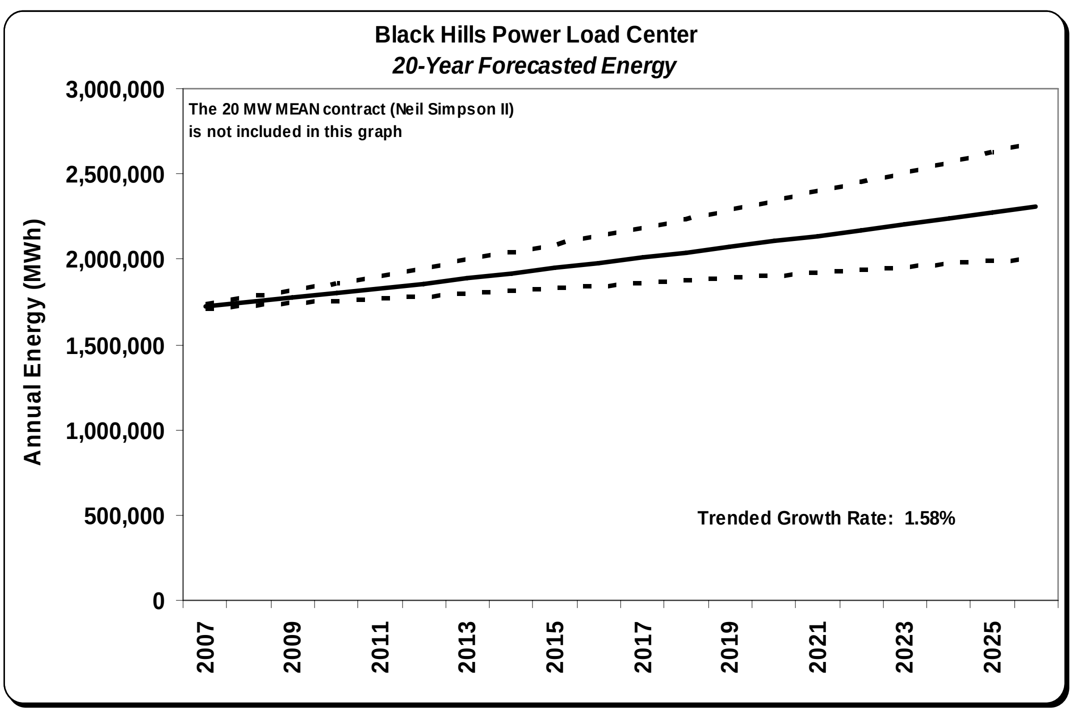
Black Hills Power Peak Demand Forecast



This diagram represents an 80% confidence that the actual BHP peak will fall within these confidence bands.

Figure 4

Black Hills Power Energy Forecast



This diagram represents an 80% confidence that the actual BHP energy will fall within these confidence bands.

CLF&P

The CLF&P forecast represents a trended forecast growth rate of 2.5% as well as known load additions. The load shapes used in the modeling for forecasting have been modified to reflect the historical load losses associated with Dyno Nobel and Trilegiant and the load gain associated with Lowes. The forecast also incorporates known load additions including the Wal-Mart distribution center, the forecast increase in Dyno Nobel load, and the Trilegiant office complex expansion. For modeling purposes, the peak demand and annual energy values shown in Table 6 and Figures 5 and 6 have been increased by 5% to reflect the losses that need to be provided to the Western Area Power Administration under the Network Integration Transmission System agreement (NITS).

Table 6

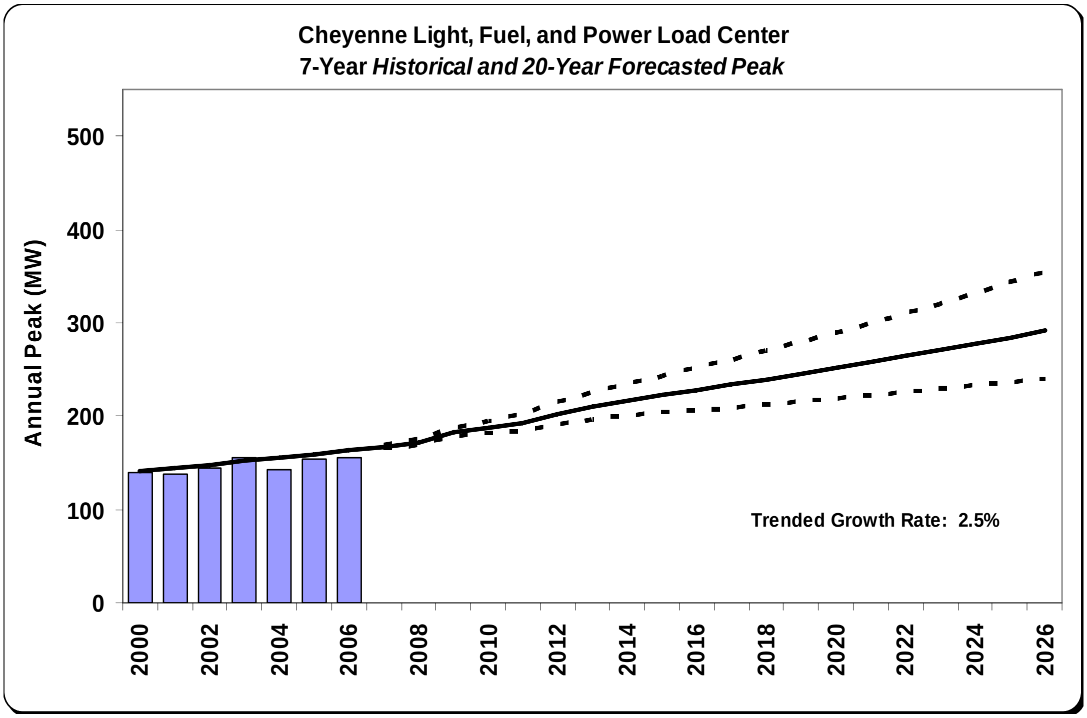
CLF&P Peak Demand and Energy Forecast 2008-2027

Year	Peak Demand (MW)	Growth in Peak Demand (%)	Annual Energy (MWh)	Growth in Annual Energy (%)	Load Factor (%)
2008	171		1,055,923		70.3
2009	184	7.60	1,156,917	9.56	72.0
2010	188	2.17	1,190,876	2.94	72.2
2011	192	2.13	1,223,790	2.76	72.7
2012	202	5.21	1,279,220	4.53	72.2
2013	210	3.96	1,324,391	3.53	71.9
2014	217	3.33	1,372,416	3.63	72.1
2015	222	2.30	1,407,920	2.59	72.3
2016	228	2.70	1,443,118	2.50	72.3
2017	233	2.19	1,479,196	2.50	72.3
2018	239	2.58	1,516,176	2.50	72.3
2019	245	2.51	1,554,080	2.50	72.3
2020	251	2.45	1,592,932	2.50	72.3
2021	258	2.79	1,632,755	2.50	72.3
2022	264	2.33	1,673,574	2.50	72.3
2023	271	2.65	1,715,414	2.50	72.3
2024	278	2.58	1,758,299	2.50	72.3
2025	284	2.16	1,802,257	2.50	72.3
2026	292	2.82	1,847,313	2.50	72.3
2027	299	2.40	1,893,496	2.50	72.3

CLF&P forecasted peak and energy reflecting an annual trended growth rate of 2.5%. The load shape for 2005 was used in the deterministic case and samples from the 2000-2005 load shapes were randomly drawn for the stochastic price trajectories. Additional load gains include a Wal-Mart Distribution Center, Dyno Nobel, Trilegent Building, and NCAR.

Figure 5

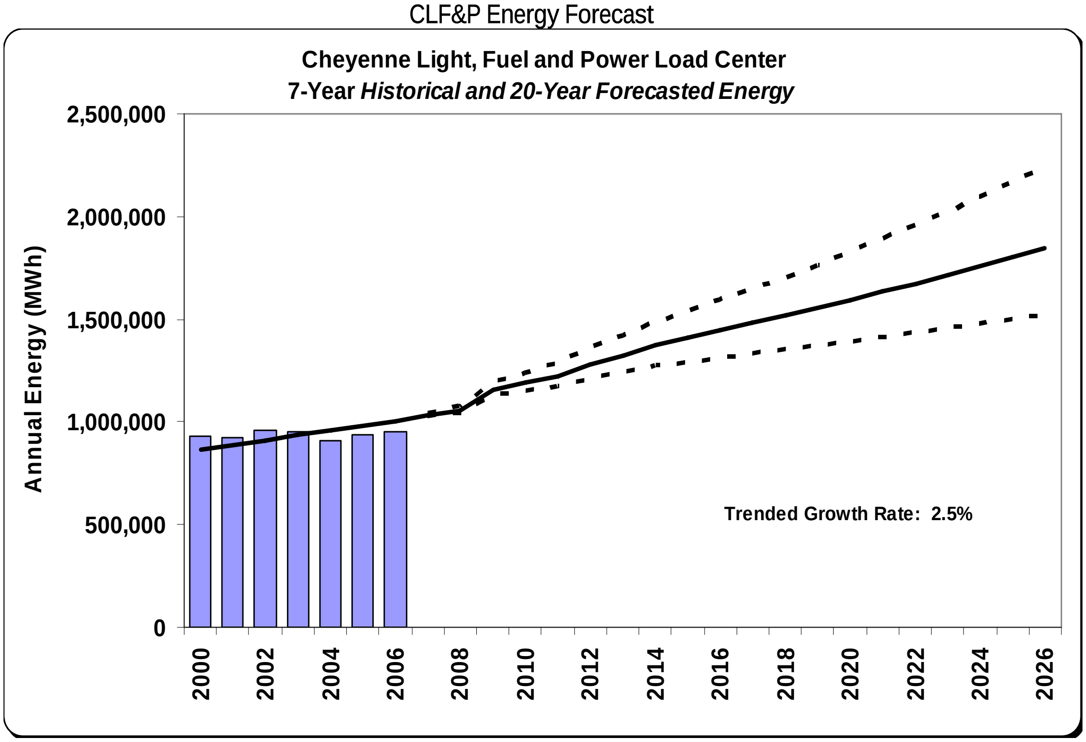
CLF&P Peak Demand Forecast



This diagram represents an 80% confidence that the actual CLF&P peak will fall within these confidence bands.

Figure 6

CLF&P Energy Forecast



This diagram represents an 80% confidence that the actual CLF&P energy will fall within these confidence bands.

City of Gillette, Wyoming

The City of Gillette, Wyoming procures power to supply its electricity needs from BHP and from MEAN. The BHP contract with the City of Gillette for 23 MW continues into perpetuity unless either party gives a seven-year written notice to terminate. For all years of the planning horizon, the 23 MW load is at a 100% load factor. This means the annual energy for a non-leap year (8,760 hours) is 201,480 MWh and in a leap year (8,784 hours), the annual energy total will be 202,030 MWh.

MDU Sheridan Service Territory

The MDU Sheridan Service Territory's forecast was provided by Montana-Dakota Utilities for the years 2008-2027. The peak demand and energy forecast for the MDU Sheridan Service Territory used in the IRP is shown on Table 7 and on Figures 7 and 8.

Table 7

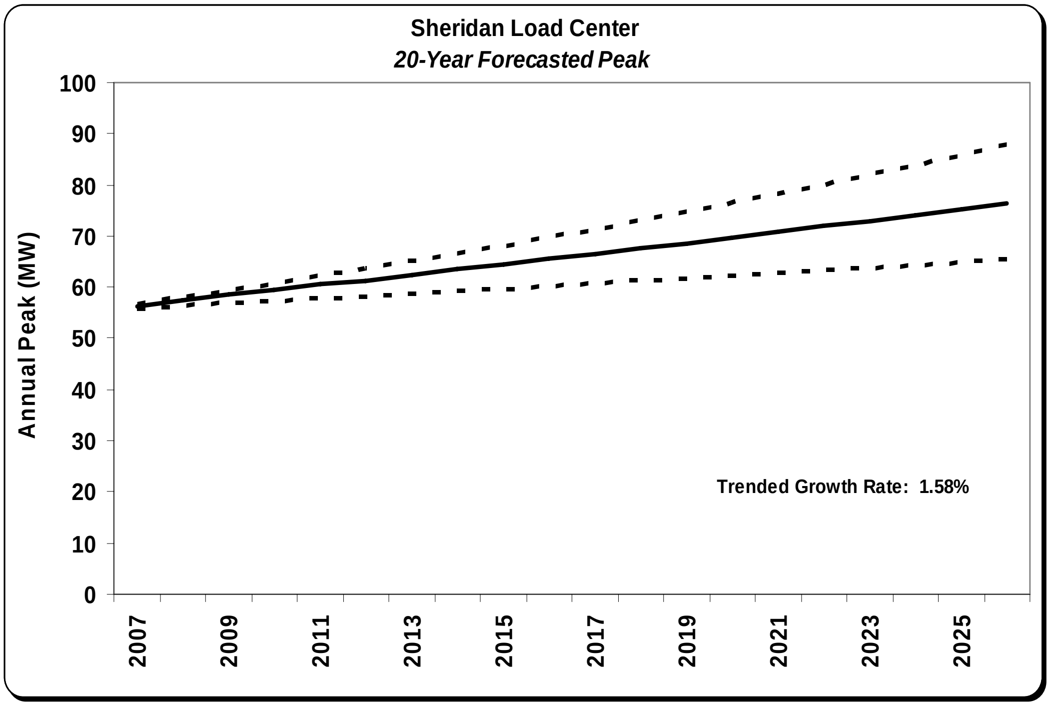
MDU Sheridan Service Territory Peak Demand and Energy Forecast 2008-2027

Year	Peak Demand (MW)	Growth in Peak Demand (%)	Annual Energy (MWh)	Growth in Annual Energy (%)	Load Factor (%)
2008	58		286,924		57.0
2009	59	1.72	292,328	1.88	56.9
2010	60	1.69	297,514	1.77	57.1
2011	61	1.67	302,523	1.68	57.0
2012	61	0.00	307,269	1.57	57.2
2013	62	1.64	312,087	1.57	57.2
2014	64	3.23	316,974	1.57	57.0
2015	65	1.56	321,980	1.58	57.0
2016	66	1.54	327,066	1.58	57.0
2017	67	1.52	332,231	1.58	57.0
2018	68	1.49	337,479	1.58	57.1
2019	69	1.47	342,809	1.58	57.0
2020	70	1.45	348,223	1.58	57.0
2021	71	1.43	353,723	1.58	57.0
2022	72	1.41	359,310	1.58	57.0
2023	73	1.39	364,985	1.58	57.1
2024	74	1.37	370,750	1.58	57.1
2025	75	1.35	376,606	1.58	57.1
2026	77	2.67	382,554	1.58	57.1
2027	78	1.30	388,597	1.58	57.1

MDU Sheridan Service Territory forecasted peak and energy reflecting an annual trended growth rate of 1.58%. The load shape for 2005 was used in the deterministic case and samples from the 2000-2005 load shapes were randomly drawn for the stochastic price trajectories.

Figure 7

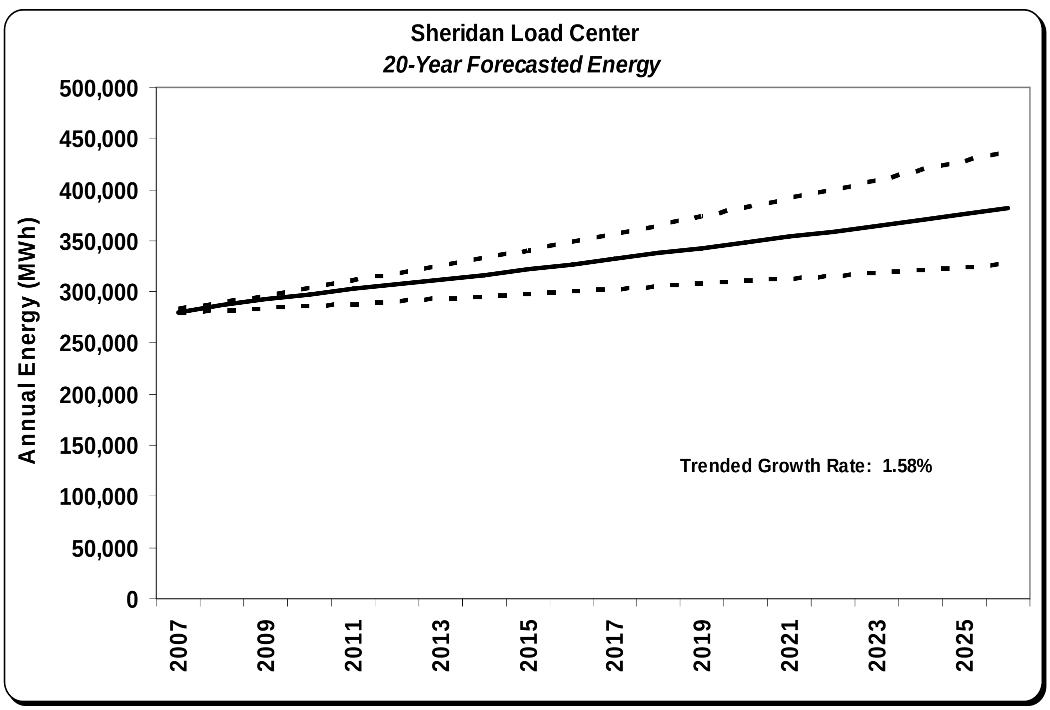
MDU Sheridan Service Territory Peak Demand Forecast



This diagram represents an 80% confidence that the actual MDU Sheridan Service Territory peak will fall within these confidence bands.

Figure 8

MDU Sheridan Service Territory Energy Forecast



This diagram represents an 80% confidence that the actual MDU Sheridan Service Territory energy will fall within these confidence bands.

Combined System

The 2005 IRP demonstrated that the least cost plan for BHP and CLF&P customers was a plan that considered and planned for the combined system. Therefore, this IRP only analyzes the resource requirements for the combined BHP and CLF&P system. The load forecasts for BHP, CLF&P, the City of Gillette and the MDU Sheridan Service Territory were combined into one load forecast as shown in Table 8. Figures 9 and 10 reflect the combined system load excluding the 23 MW associated with the City of Gillette. The peak demand in the resulting load forecast is obtained by summing loads across all hours of the year for each system. The resulting peak demand is called the coincident peak demand and reflects the fact that all systems do not peak on the same hour of the year. As shown on Figure 11, the historical average peak coincidence factor is 98.3%. The peak demand for the combined system has been obtained by forecasting the peak demand for each individual system, summing the resulting peaks, and then multiplying the total by 0.983.

The energy is summed across all components to obtain the total annual energy. The trended forecast represents a projected annual growth rate of 1.92%. The load factor increases moderately over the forecast horizon. For modeling purposes, the 2005 hourly load shape was used, because it was an accurate representation of expected future load shapes.

Table 8

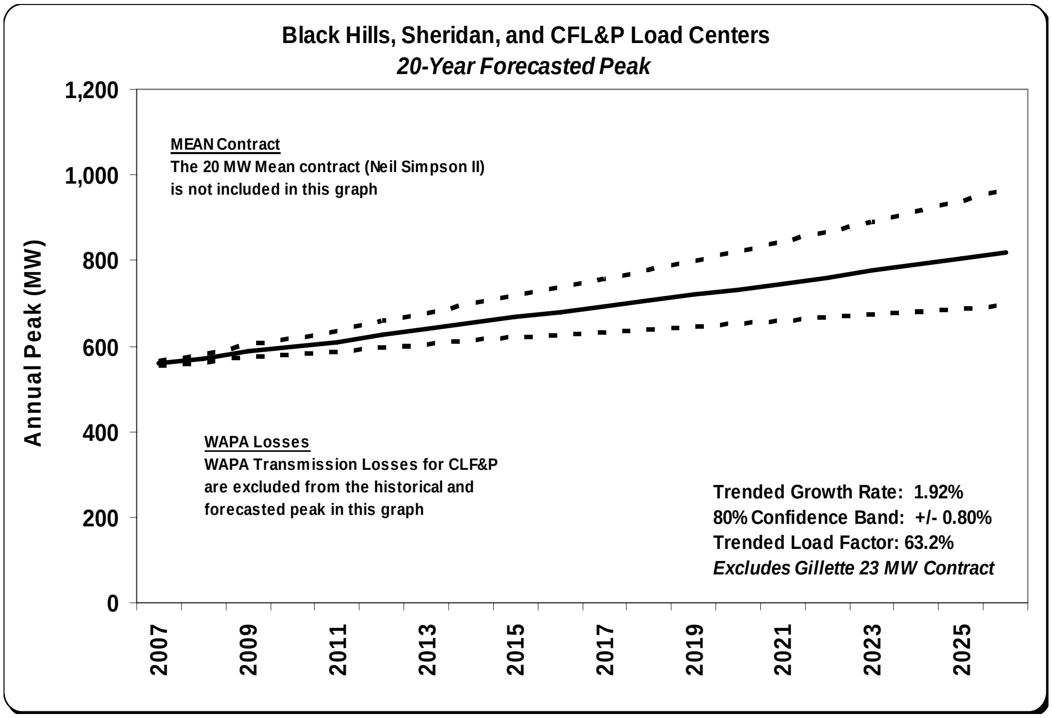
Combined System Peak Demand and Energy Forecast 2008-2027

Year	Peak Demand (MW)	Growth in Peak Demand (%)	Annual Energy (MWh)	Growth in Annual Energy (%)	Load Factor (%)
2008	583		3,290,021		64.2
2009	604	3.60	3,423,130	4.05	64.7
2010	615	1.82	3,489,712	1.95	64.8
2011	625	1.63	3,555,763	1.89	64.9
2012	643	2.88	3,644,856	2.51	64.5
2013	656	2.02	3,724,220	2.18	64.8
2014	671	2.29	3,806,979	2.22	64.8
2015	682	1.64	3,877,764	1.86	64.9
2016	695	1.91	3,948,800	1.83	64.7
2017	708	1.87	4,021,287	1.84	64.8
2018	721	1.84	4,095,245	1.84	64.8
2019	734	1.80	4,170,713	1.84	64.9
2020	747	1.77	4,247,717	1.85	64.7
2021	761	1.87	4,326,305	1.85	64.9
2022	774	1.71	4,406,494	1.85	65.0
2023	789	1.94	4,488,327	1.86	64.9
2024	803	1.77	4,571,844	1.86	64.8
2025	818	1.87	4,657,069	1.86	65.0
2026	833	1.83	4,744,043	1.87	65.0
2027	849	1.92	4,832,810	1.87	65.0

The combined system forecasted peak and energy reflecting an annual trended growth rate of 1.58%. The load shape for 2005 was used in the deterministic case and samples from the 2000-2005 load shapes were randomly drawn for the stochastic price trajectories.

Figure 9

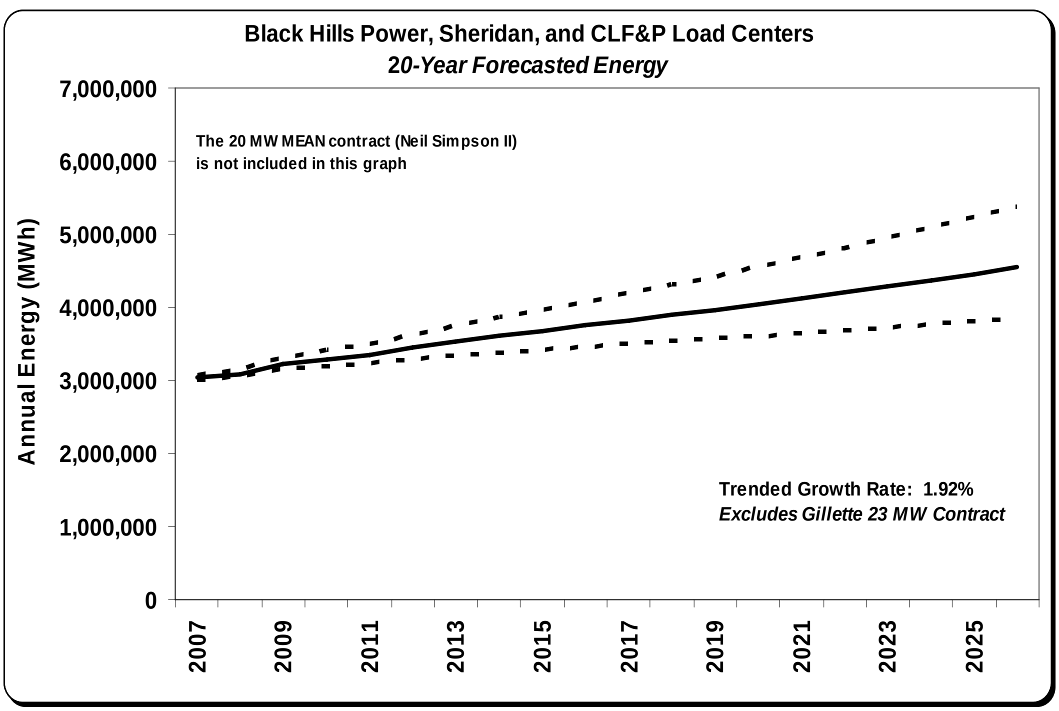
Combined System Peak Demand Forecast (*excluding City of Gillette)



This diagram represents an 80% confidence that the actual combined system peak will fall within these confidence bands.

Figure 10

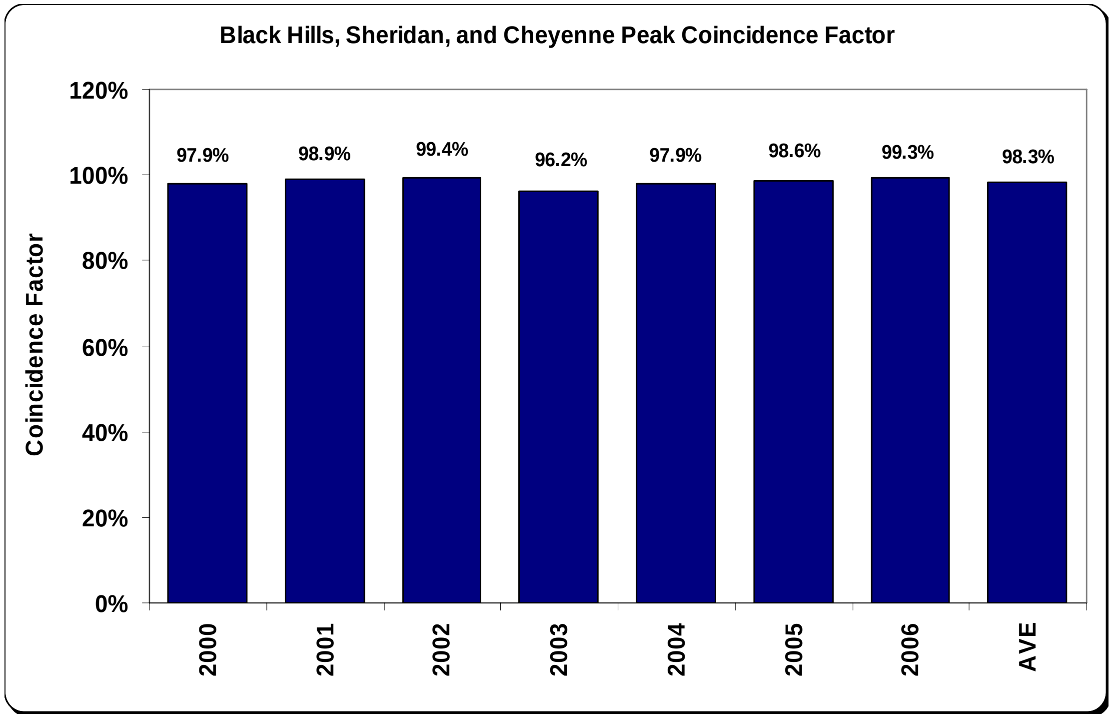
Combined System Energy Forecast (*excluding City of Gillette)



* The 23 MW Gillette load was excluded because it is a 100% load factor with no growth or peaking obligation.

This diagram represents an 80% confidence that the actual combined system energy will fall within these confidence bands.

Figure 11



Comparing the peaks of the combined system from 2000-2006, the resulting average coincidence factor is 98.3%

Demand-Side Management

Demand-side management (DSM) programs generally promote conservation and/or energy efficiency and are designed to encourage consumers to modify their level and pattern of electricity usage. DSM includes only energy and load-shape modifying activities undertaken in response to utility-administered programs. DSM does not include energy or load-shape changes arising from the normal operation of the marketplace or from government-mandated energy-efficiency standards. For this IRP, the penetration of the DSM programs is assumed to be reflected in the historical data used to derive the load forecasts and thus it is propagated into the future at the same level of penetration as a percentage of total load.

Historical DSM Programs at BHP

BHP has extensive DSM experience related to rate applications, energy efficient product research, and energy efficiency rebates.

- At one point, the commercial program included rebates for energy efficient lighting and motors. These lighting and motor rebates were eventually phased out as higher efficiency levels within the marketplace became standard.
- BHP offers rebates for electrical equipment that is efficient, can be controlled, and is not the standard for typical installations.
- The first geothermal heat pumps (also known as ground source heat pumps) installed in the Black Hills were installed at BHP employees' homes. BHP gained valuable knowledge regarding the sizing and installation of the ground loops associated with the geothermal unit.
- The Large Demand Curtailable (LDC) rate tariff is available to customers owning generators that provide up to 400 hours of annual operation to BHP. These LDC customers are asked by phone to run their generator. A limited number of customers participate in the LDC program and BHP has gained approximately 2.5 MW of curtailable load through the LDC program.
- The Demand Controller program has been very successful and continues to be an attractive alternative for customers looking at total electric homes.

…the penetration of the DSM programs is assumed to be reflected in the historical data used to derive the load forecasts and thus it is propagated into the future at the same level of penetration as a percentage of total load.

Existing DSM Programs at BHP

BHP's primary DSM programs involve long-term relationships with customers and trade allies in the building industry that include sponsorship programs and participation in trade organizations. In 2006, BHP extended approximately $175,000 in customer rebates and incentives:

▪ Demand Controller Program	$39,905
▪ Air Source Heat Pumps	$72,916
▪ Geothermal Heat Pumps	$6,305
▪ Electric Heating (with Demand Controller)	$14,268
▪ Electric Water Heating	$41,788

General DSM activities at BHP in 2006 had costs that totaled approximately $231,000:

▪ Energy Audits	$2,106
▪ Heat Loss Analysis	$22,061
▪ Rate Comparisons	$5,452
▪ General DSM	$8,384
▪ Key Customer Accounts	$157,537
▪ Trade Ally Program	$35,564

DSM programs at BHP include:

Residential Programs

- Trade Ally Programs
- Trade Ally Advertising Program
- Trade Ally Events
- Demand Controller Program
- Comfort-Cove Heat Program
- Heat Pump Program
- Electric Water Heater Program

Commercial and Industrial Programs

- Water Heaters
- HVAC/Heat Pumps
- Power Factor Correction
- Energy Management Rate Options
- Load Monitoring

Residential Programs

Trade Ally Programs

BHP creates working relationships with builders; heating and air conditioning, plumbing, and electrical contractors; and home improvement centers to promote the use of energy efficient appliances and building techniques. By virtue of these relationships, BHP is able to effectively access those groups of customers that are directly involved with energy efficiency initiatives.

Through the Trade Ally Advertising Program, BHP will reimburse up to 50% of the cost (up to a ceiling amount) of the money its trade allies use to advertise:

- Demand Control Systems
- Electric Resistance Heat (with demand controller)
- Electric Heat Pumps
- Geothermal Systems
- Energy Efficient Electric Water Heaters
- Energy Efficient Motors

BHP offers a series of training opportunities for its trade allies that include:

- Training for realtors, appraisers, and home inspectors on how to recognize and sell energy efficient homes.
- Demand Controller Installer Certification classes for electricians.
- The annual Electro-Technology Expo to inform professionals in the building industry about new electric technologies and standards for residential and commercial applications.
- Energy management workshops to educate electricians, HVAC contractors, engineers, and key account personnel about applications using energy efficient equipment.
- Sponsorship of the annual Energy Conservation Awareness Day, in conjunction with area home improvement centers, to raise awareness among customers on the need to weatherize their homes and conserve energy during the winter season.

…the interactions with the groups involved – builders, contractors, retail home improvement centers, realtors, appraisers, home inspectors – increase the effectiveness of a range of energy efficiency initiatives through direct customer contact.

This program and the interactions with the groups involved – builders, contractors, retail home improvement centers, realtors, appraisers, home inspectors – increase the effectiveness of a range of energy efficiency initiatives through direct customer contact and education.

Demand Controller Program

The purpose of the Demand Controller Program is to reduce the residential customer's peak demand. An energy management system is installed which monitors the customer's total load and automatically sheds customer loads during peak periods. Customers with a demand controller installed take service under the Residential Demand Service tariff, which includes a demand and energy charge. New demand controller systems strongly encourage customers to shift their electricity usage to off-peak periods. The program is targeted towards customers who use at least 1,200 kWh per month or who spend $120 or more per month on their electric bill.

BHP estimates that its Demand Controller Program provides a system peak demand reduction of 1.8 MW (0.5 kW per customer) in the summer and a 7.4 MW (2.0 kW per customer) demand reduction in the winter based on the present number of 3,723 Residential Demand Service customers (3,627 in South Dakota and 96 in Wyoming).

Comfort-Cove Heat Program

BHP's Comfort-Cove Heat program promotes energy efficient radiant products to residential customers, small business customers, and area contractors. Residential customers who install Comfort-Cove heating systems are eligible for a rebate if they also install a demand controller. Customers realize energy savings with radiant heat through individual space heat control and lower thermostat settings.

Heat Pump Program

BHP provides rebates for residential customers who install efficient electric air source heat pumps or, geothermal heat pump systems. BHP promotes the installation of heat pumps to both single family and multi-family residential units. The rebates are offered to promote energy efficiency. The coefficient of performance (COP) for air source heat pumps approach 2.0 and geothermal system COPs are 3.0 or greater.

ASAP Program

The ASAP program provides single family residential customers the opportunity to purchase service agreements for their appliances. The ASAP program covers forced air heating systems, central air conditioning, electric heat pumps, geothermal heat pumps, and water heaters. Proper maintenance reduces energy waste, insures optimum performance and prolongs the life of the system. BHP had 186 customers enrolled in the program as of December 31, 2006.

Electric Water Heater Program

BHP offers cash rebates and incentives for customers to install electric water heaters. Larger incentives are provided to customers who also install a demand controller to provide greater rate savings to the customer and to provide a potential reduced load to BHP.

Other Customer Programs

Other customer programs include a range of customer assistance, energy conservation, and energy assistance programs.

- BHP became an ENERGY STAR® partner in late 2006. As a partner, the company promotes the cost savings and conservation attributes of ENERGY STAR® products to its customers through several avenues. ENERGY STAR® is a voluntary labeling program introduced by the U.S. Environmental Protection Agency in 1992 to identify and promote energy-efficient products to reduce greenhouse gas emissions. ENERGY STAR® is now on major appliances, office equipment, and home electronics as well as new homes and commercial and industrial buildings.
- BHP offers free Heat Loss/Gain Analyses of existing or new home construction to determine cost savings specific to HVAC equipment.
- Communications mechanisms provide all classes of customers with information including BHP's web site, a residential customer monthly newsletter, and business and commercial customer newsletters.

Commercial and Industrial Programs

BHP offers a variety of DSM programs and rate options for commercial and industrial (C&I) customers. Energy management rate options are primarily designed to encourage shifting load to off-peak periods or to encourage the installation of geothermal heat pump systems.

- On an annual basis, account managers contact the top 300 Key Accounts to discuss energy issues important to the customers. Energy management is always one of the topics covered in these annual review meetings.
- The heat pump rebates program is BHP's most successful C&I DSM program. During the last five years, 58 air source heat pumps (totaling 185 tons) and 259 geothermal/water source heat pumps (totaling 742 tons) have been installed within BHP's system. The rebates over the five year period total $93,822.
- The General Service Large and Industrial Contract Service tariffs allow qualified customers to use up to 150% of on-peak demands during off-peak periods for no additional charge.
- The Energy Storage rate structure promotes the use of qualified energy storage and geothermal heat pump systems. Several large commercial structures have installed geothermal heat pump or ice storage cooling systems as a result. This rate is also used as an alternative to interruptible type rates. It is often a better fit for both customers and BHP.
- BHP's largest customer shifts about 1-2 MW from on-peak to off-peak periods under the Industrial Contract Service tariff. Several other customers shift less than 200 kW to off-peak periods under the General Service Large tariff.
- Permanent and temporary interval metering is used for billing and load monitoring purposes. Customers are able to reduce their peak demand, turn off unnecessary equipment and improve their power factor through information derived from the data.
- Customers receive reports from BHP when there is a significant drop in their power factor. This service allows the customer to correct the problem before incurring significant costs or causing increased demands to BHP's electrical system.

Energy management rate options are primarily designed to encourage shifting load to off-peak periods or to encourage the installation of geothermal heat pump systems.

BHP's C&I DSM incentives, qualifying criteria, and technical services are shown on Table 9.

Table 9

BHP Commercial and Industrial DSM Programs

Program	Incentive/Service	Qualifying Criteria
Water Heaters	$1.00/gallon	30 gallon minimum tank size. Minimum electric capacity of not more than 4,500 watts @ 240 volts. Maximum Rebate of $800 per customer.
HVAC – Heat Pumps	Replacement Heat Pump Installation	
	$50/ton – Air Source or Water Source	SEER ≥ 13, $800 max. per customer
	New Heat Pump Installation	
	$150/ton – Air Source Heat Pumps	SEER ≥ 13, $2,500 max. per customer
	$150/ton – Water/Geo Source Heat Pumps	SEER ≥ 13, $2,500 max. per customer
	$125/ton – Geothermal loop fields.	$7,500 max. per customer
Power Factor Correction	Account analysis and rate savings	Customer request
Energy Management Rate Options	Account analysis, rate comparisons and technical assistance	Terms and conditions of each rate option are detailed under the appropriate rate schedule
Load Monitoring	Energy use, power factor, and peak demand profiles and motor starting current measurements	Customer request

BHP offers a variety of DSM programs and rate options for commercial and industrial customers.

Existing DSM Programs at CLF&P

The DSM programs at CLF&P are under development. Most of the initial programs are aimed at eduction and public awareness campaigns. Alliances with industry, trade, education, government, and consumer groups are being established in the Cheyenne, Wyoming area.

Specific programs include:

- Energy Assistance and Resource Partners
    - Low Income Energy Assistance Program (LIEAP)
    - Energy SHARE of Wyoming
    - Wyoming Business Council
    - Wyoming Energy Conservation Improvement Program (WYECIP)
    - Wyoming Energy Council
    - Wyoming Energy Savers Program
    - Senior Tax Rebates
    - Tax Credits
- Key Customer Account Program
- Trade Ally Relations Program
- Energy Awareness and Education
- ENERGY STAR® Program
- Communications Mechanisms

Energy Assistance and Resource Partners

CLF&P promotes federal, state, and local energy assistance programs and resource agencies through many means. These programs and resource agencies/partners include:

Low Income Energy Assistant Program (LIEAP). This federally funded program helps income-eligible participants pay their utility bills and weatherize their homes. CLF&P provides applications at its business office.

ENERGY SHARE of Wyoming. This program supports people in sudden hardship circumstances with heating-related emergencies and is funded by voluntary donations from CLF&P customers, employees, and shareholders.

Wyoming Business Council. The Wyoming Business Council administers the State Energy Program which works to increase the opportunities for alternative or renewable energy use in Wyoming using domestic fuels and resources.

Wyoming Energy Conservation Improvement Program (WYECIP). This program encourages facility owners to implement energy conservation measures which are funded through guaranteed energy savings.

Wyoming Energy Council. The Wyoming Energy Council co-sponsors the Home Performance with ENERGY STAR® program with CLF&P. This program offers a comprehensive whole-house approach to making energy efficient home improvements.

Wyoming Energy Savers Program. This program was established by the Wyoming Community Development Authority in 2006 to provide loans to homeowners. The loans are to be used for weatherization upgrades and the installation of energy efficient equipment including windows, insulation, proper ducting, and heating and cooling.

Senior Tax Rebates. Qualifying senior citizens are eligible for a tax rebate for energy assistance.

Tax Credits. Tax credits are available for home builders who improve building envelopes or who meet the ENERGY STAR® standards. Manufacturers of energy efficient clothes washers, dishwashers, and refrigerators are eligible for tax credits. Certain commercial buildings are eligible for tax credits related to the energy efficiency of the building envelope, lighting, or heating and cooling. Tax credits are available for qualified solar water heating and photovoltaic systems. Specific qualified fuel cells and microturbine systems are eligible for tax credits.

Key Customer Account Program

CLF&P has assigned specific employees to become liaisons for key commercial and industrial customers. Through this program, customers are offered services that help communicate ways to manage energy usage, reduce power quality problems, learn about a variety of energy technologies, and understand their energy usage and billing. A variety of educational opportunities are provided by CLF&P for the key customers.

Trade Ally Relations Program

Trade Ally Programs include the Trade Ally Advertising Program, Trade Ally Training and Technology Events, and a Trade Ally Contact List on the web. Through the advertising program, CLF&P reimburses up to a certain level of advertising costs for energy management systems, ENERGY STAR® rated lighting, ENERGY STAR® rated heating and cooling systems, ENERGY STAR® rated water heaters, energy audits to ENERGY STAR® standards, and energy efficient motors. Training and technology events include realtor training, Energy Efficient Technology Expo, Power Quality and Gas Safety Training, and Energy Conservation Awareness Day. In addition, CLF&P maintains a listing of trade ally contacts on a portion of its web site.

Energy Awareness and Education

Energy Awareness and Education activities sponsored by CLF&P include energy conservation radio messages, the Cheyenne Home & Garden Show, "Be Energy Smart" education programs for school-aged children, Energy Conservation Awareness Day, and the Energy Weatherization Day.

ENERGY STAR® Program

CLF&P became an ENERGY STAR® partner in late 2006. As a partner, the company will promote the cost savings and conservation attributes of ENERGY STAR® products to its customers through a variety of avenues. ENERGY STAR® is a voluntary labeling program introduced by the U.S. Environmental Protection Agency in 1992 to identify and promote energy-efficient products to reduce greenhouse gas emissions. ENERGY STAR® is now on major appliance, office equipment, and home electronics as well as new homes and commercial and industrial buildings. The two major ongoing ENERGY STAR® programs include "Change a Light, Save the World" and "Home Performance with ENERGY STAR®" which the Company participates.

Communications Mechanisms

Communications mechanisms provide all customers with information including the CLF&P web site and a residential customer monthly newsletter.

Other Customer Programs

Renewable Premium Program

Beginning in 2006, CLF&P introduced a way for residential and business customers to support renewable energy resources through the Renewable Premium Program. Customers subscribe to one or more renewable energy credits for which they pay a prescribed amount per credit.

As conservation and energy efficiency appear to be an alternative means of reducing future CO_2 emissions, utilities and regulators believe that utilities should not be penalized financially for undertaking DSM programs.

Future Considerations for DSM

Many investor-owned utilities are currently discussing new means to handle expenses associated with DSM programs. As conservation and energy efficiency appear to be an alternative means of reducing future CO_2 emissions, utilities and regulators believe that utilities should not be penalized financially for undertaking DSM programs. To this end, some states and some utilities are taking steps to ensure a return of and return on capital for DSM programs, similar to the way in which other capital investments are treated. BHC will be monitoring the activity of other larger utilities across the country in an effort to identify the most cost effective DSM program that can be implemented for BHP and CLFP customers. BHC is aware that PacifiCorp has taken some initial steps in this area.

Supply-Side Resources

Existing Resources

The resources available to BHP and CLF&P to meet customer obligations include coal-fired and natural-gas fired generating plants, diesel units, and long-term purchase power agreements as shown on Table 10.

Table 10
2007 BHP and CLF&P Supply-Side Resources

Power Plant	Fuel Type	State	Total Capacity (MW)	Interest (%)	BHP & CLF&P Capacity (MW)	Average Net Capacity (MW)*	Start Date
Ben French	Coal	SD	25.0	100	25.0	22.0	1960
Neil Simpson I	Coal	WY	21.8	100	21.8	16.0	1969
Neil Simpson II	Coal	WY	90.0	100	90.0	81.0	1995
Osage	Coal	WY	34.5	100	34.5	33.0	1948
Wyodak	Coal	WY	362.0	20	72.4	67.0	1978
Ben French Diesels 1-5	Diesel	SD	10.0	100	10.0	10.0	1965
Ben French CTs 1-4**	Gas/Oil	SD	100.0	100	100.0	100.0	1977-1979
Lange CT	Gas	SD	40.0	100	40.0	40.0	2002
Neil Simpson CT I	Gas	WY	40.0	100	40.0	39.0	2000
Total Installed Capacity					433.7	408	
Long Term Power Purchases	Type		Capacity (MW)		Start Date	End Date	Term
PacifiCorp PPA (Colstrip)	Firm		50.0		1983	2023	40
Wygen I	Firm		60.0		2003	2013	10
Neil Simpson CT II	Firm		40.0		2001	2011	10
Capacity Summary			Capacity (MW)				
Total Coal			219.0				
Total Combustion Turbine			179.0				
Total Purchase			150.0				
Total Other			10.0				
TOTAL			553.0				

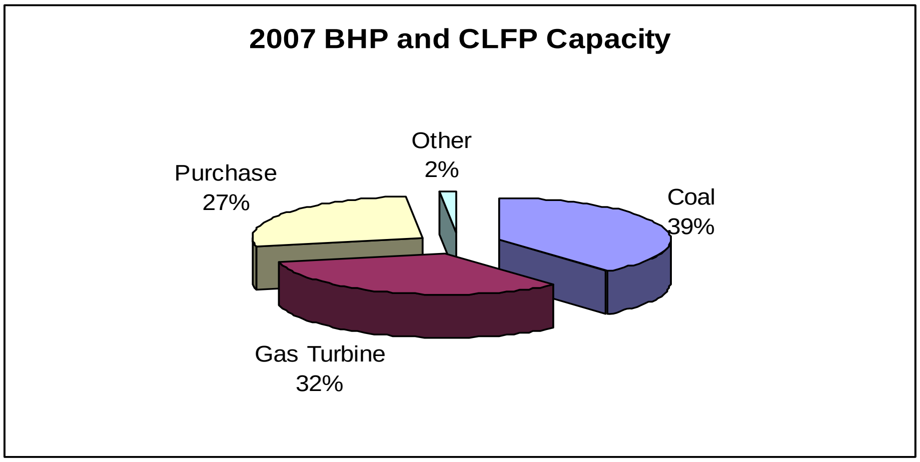
* The values shown on this table are demonstrated historical summer capacity.

** Under terms of the RCIA with PacifiCorp, these units will be rated at 76 MW total (summer value) as of 7/1/2012.

The base plan assumes the listed supply side resources taking into account the refurbishment of Ben French, retirement of Osage, conversion of the agreement with PacifiCorp, and termination dates for the contracts.

As illustrated on both Table 10 and Figure 12, coal accounts for about 39% of the total existing capacity and combustion turbines for 32%. Of the purchases, 110 MW out of the total of 150 MW are coal with the remainder being natural gas.

Figure 12



Coal accounts for about 39% of the total existing capacity and combustion turbines for about 32%. Of the purchases, 110 MW out of the total of 150 MW are coal with the remainder being natural gas.

For purposes of this IRP, BHC has assumed that the three Osage units will all retire as of December 31, 2012. In the 2005 IRP, Ben French was assumed to retire at the end of 2013. BHC has performed studies that examined the cost-effectiveness of spending approximately $10 million (in 2007 dollars) to replace the steam turbine at Ben French and extend the life of the unit for approximately 15 years. Because the economics of this rehabilitation are quite favorable, for the purposes of the IRP, it has been assumed that Ben French will be in operation throughout the planning horizon with the upgrades performed in 2009. Capacity under the Reserve Capacity Integration Agreement (RCIA) from PacifiCorp will no longer be available as of 7/1/2012. At that time, the equivalent capacity available from the Ben French CTs will be changed to 76 MW.

In addition to its generating assets, BHP has capacity rights on the Rapid City DC Tie Station. Currently, BHP has 50 MW of capacity from East-to-West and 90 MW of capacity from West-to-East. This will change in 2008 such that BHP will have 70 MW of capacity in both directions.

BHP currently has the following Power Sales Agreements in place that terminate as shown:

- MDU Sheridan Service Territory. System firm capacity and energy to serve Montana-Dakota Utilities' (MDU) retail customers in the MDU Sheridan Service Territory up to 55 MW. MDU may purchase additional capacity and energy from BHP at adjusted rates to serve requirements above 55 MW. The contract terminates at the end of 2016, although for purposes of this IRP, the contract has been modeled as being in existence throughout the entire planning period.
- City of Gillette, Wyoming. System firm capacity and energy to serve the City of Gillette retail customers up to 23 MW. The initial period of the contract terminates on December 31, 2012 followed immediately by evergreen provisions that extend the contract into perpetuity. Either during the initial period (up to December 31, 2012) or during any subsequent year, either party can terminate the contract upon seven years written notice. For purposes of the IRP, BHP has modeled the Gillette contract as being in existence throughout the entire planning period.
- Municipal Energy Agency of Nebraska (MEAN). MEAN purchases 20 MW of unit contingent capacity and energy from the Neil Simpson II coal plant. The power is delivered at the Stegall West 230-kV bus. The contract commenced February 16, 2003 and extends for a term of ten years.

Committed Resources

CLF&P has made commitments for new resources over the planning horizon. The 95 MW (net) Wygen II unit is scheduled for commercial operation on January 1, 2008. CLF&P has signed a PPA with Tierra Energy (soon to be Duke Energy) to take 30 MW of wind from a facility west of Cheyenne, Wyoming.

New – Conventional Resources

A variety of conventional supply-side resources were examined and considered in preparing the IRP. These include coal, natural gas-fired combined cycle, natural gas-fired simple cycle combustion turbine, and integrated gasification combined cycle (IGCC). A brief description of each type of resource and the cost and other parameters used for modeling are described below.

Coal. New pulverized coal-fired units were assumed to be located on or near the Wyodak plant site. Each new unit is rated at 95 MW (net) at the time of the summer system peak. Data used for modeling new coal-fired units are shown in Table 11.

Table 11

Coal-Fired Power Plant Performance Parameters

Parameter	Wygen III and Future Coal Units
Earliest feasible year of installation	2010
Size, MW (net)	95
Full load heat rate, Btu/kWh	12,500
Capital cost, $/kW (2006 $)	2,320
Fixed O&M, $/kW-year	31.6
Variable O&M, $/MWh	3.18
Equivalent Forced Outage Rate, %	1.81
Construction time, months	30

Operating parameters derived from the uprate design of the Wygen II generating facility.

Combined Cycle. In a combustion turbine combined cycle facility, the hot exhaust gases from the combustion turbine pass through a heat recovery steam generator (HRSG). The steam generated by the HRSG is expanded through a steam turbine which, in turn, drives an additional generator. Combustion turbine combined cycle systems typically burn natural gas and are available in a wide variety of sizes and configurations. If BHC were to install a combined cycle facility, an important consideration with regard to siting the facility is accessibility to and availability from natural gas pipelines. Parameters used to model a combined cycle facility (using two LM 6000s) as a resource are shown on Table 12.

Table 12

Combined Cycle Performance Parameters (2 x 1 LM 6000)

Parameter	Value
Size, MW (net)	120
Full load heat rate, Btu/kWh	7,375
Capital cost, $/kW (2006 $)	1,176
Fixed O&M, $/kW-year	8.29
Variable O&M, $/MWh	2.83
Equivalent Forced Outage Rate, %	2

Operating parameters were derived from the Washington Group's Engineering study of the GE LM6000 2X1 combined cycle generation facility.

Combustion Turbine. Combustion turbines typically burn natural gas and/or No. 2 fuel oil and are available in a wide variety of sizes and configurations. Combustion turbines are generally used for peaking and reserve purposes because of their relatively low capital costs, higher full load heat rate, and the higher cost of fuel when compared to conventional baseload capacity. Combustion turbines have the added benefit of providing quick-start capability in certain configurations. In this analysis, four different options were modeled for combustion turbines: LMS-100, LM-6000, a Frame 7EA, and the conversion of the Neil Simpson Combustion Turbine II from a merchant facility to a regulated asset. Parameters used to model each of these CT options are shown on Table 13.

Table 13
Combustion Turbine Performance Parameters

Parameter	LMS-100	LM-6000	Frame 7EA
Size, MW (net)	89.6	41.8	66.9
Full load heat rate, Btu/kWh	9,550	10,850	14,646
Capital cost, $/kW (2006 $)	592	660	587
Fixed O&M, $/kW-year	14.63	19.51	14.63
Variable O&M, $/MWh	4	4.78	3.02
Equivalent Forced Outage Rate, %	2	2	2

Operating parameters were derived from the Washington Group's Engineering study of the GE LMS100, LM-6000, and Frame 7EA.

Integrated Gasification Combined Cycle. Integrated gasification combined cycle (IGCC) is the least mature of the coal-fired power generation technologies. There are commercial-scale units in North America that have demonstrated several years of successful operation, however, none has employed carbon capture technology. There are at least 15 suppliers of commercial gasification, but three main gasification technologies have emerged in the industry. The main gasification technologies are offered by GE Energy (originally known as the Chevron/Texaco process), Shell, and ConocoPhillips (E Gas). These are all entrained-flow, slagging gasifiers.

An IGCC unit is comprised of four major subsystems: gasification, oxygen supply, gas cleanup, and the power block. The gasifier reacts coal, oxygen from an air separation unit (ASU), and steam at high pressure (400 to 1000 psi) to produce a medium Btu fuel gas (200-300 Btu/scf). Carbon monoxide (CO) and H_2 are the primary combustibles in the gasifier product. Slag is removed from the gasifier through a slag tap, and the remaining fly ash is removed by a particulate control system positioned in the raw gas stream. Fly ash is typically recycled back to the coal feed to maximize carbon utilization.

Emissions control for IGCC plants is generally done in the raw gas stream and at the combustion turbine combustor rather than the flue gas. The volumetric flow of raw gas is much smaller than that of flue gas at this point, reducing the size of the gas cleanup systems. Also, the partial pressures of pollutants are much higher than in flue gas, making the absorption processes more efficient.

The parameters used to model IGCC in this IRP are contained in Table 14. These parameters represent participation (assumed that BHC could participate in up to 50 MW, available in 25 MW blocks) in a larger IGCC unit (500 MW) owned by a utility other than BHC.

Table 14

IGCC Performance Parameters

Parameter	Value
Size, MW (net)	25
Full load heat rate, Btu/kWh	9,000
Capital cost, $/kW (2006 $)	2,732
Fixed O&M, $/kW-year	22.17
Variable O&M, $/MWh	10.15
Equivalent Forced Outage Rate, %	2.3

Operating parameters were derived from the Washington Group's Engineering study of an IGCC. The parameters listed represent participation up to 50 MW, in 25 MW blocks, of a 500 MW facility.

Purchased Power. A purchased power product was modeled as available in two 25 MW blocks during the months of July and August. The product is assumed to be available in a 6 x 16 product (six days per week – Monday through Saturday – 16 hours per day – 6 am through 10 pm). The product is priced at the market price of power at Mid-C plus $6.00 per MWh.

New – Renewable Resources

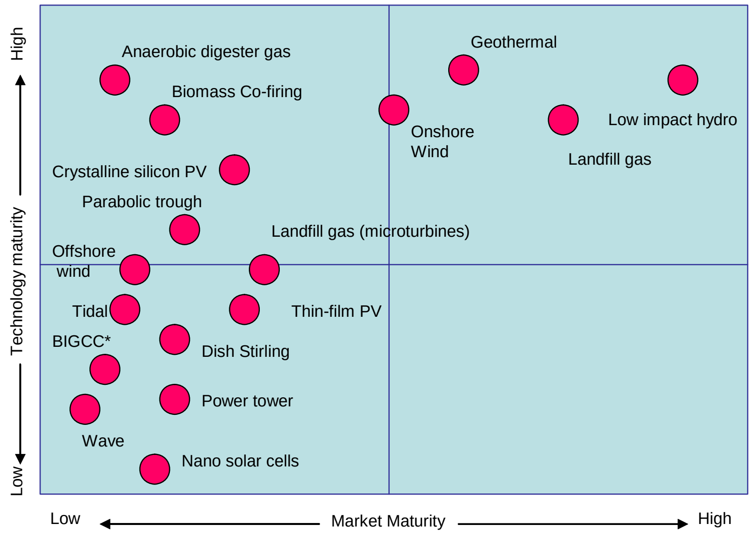
Renewable resources are appearing in more electric utilities' resource portfolios due to two primary drivers: 1) renewable energy portfolio standards have been enacted in some states requiring or strongly encouraging utilities to install a minimum percentage of renewables by a date certain, and 2) the costs for many renewable technologies have become more cost competitive. Renewable portfolio standards (RPS) are statutes enacted by state legislatures or through voter referenda that mandate a minimum amount of renewable energy be included in utility resource portfolios by a date certain often with the required percentage increasing over time. RPS have primarily, but not exclusively, been enacted as a result of state-based electric restructuring efforts. As of early 2007, twenty-three states and the District of Columbia have now enacted an RPS.[5] Some of the states allow or encourage a trading mechanism for the exchange of renewable energy credits among the state's utilities to facilitate compliance with the RPS.[6] In the West, the Western Governor's Association and the California Energy Commission in collaboration with the Western Regional Air Partnership have developed the Western Renewable Energy Generation Information System (WREGIS) to track renewable energy generation and ownership of renewable energy certificates in eleven Western states, two Canadian provinces, and northern Baja California.[7]

Some of the renewable technologies have reached a commercial state as demonstrated in Figure 13 and some have reached market maturity. Figure 13 shows that both biomass and wind are technologically mature although the primary drivers for wind technology development remain the federal production tax credits and renewable portfolio standards enacted by states.

[5] " States with Renewables Portfolio Standards," www.pewclimate.org/what_s_being_done/in_the_states/rps.cfm, April 2007.
[6] "Renewable Portfolio Standards," www.newrules.org/electricity/rps.html.
[7] "Briefs," *Electric Utility Week*, August 23, 2004, p. 5. The Western Electric Coordinating Council agreed to be the home for the electronic tracking system (an accounting system and database) known as WREGIS.

Figure 13 [8]

Renewable Energy Technology Status



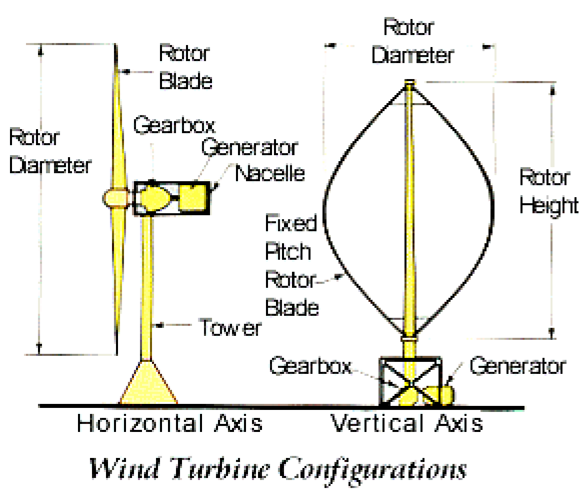
*Biomass integrated gasification combined cycle
Source: Navigant Consulting

Biomass and wind are technologically mature although the primary drivers for wind technology development remain the federal production tax credits and renewable portfolio standards enacted by states.

Three categories of renewable resources were modeled in the course of the preparation of this IRP: wind, solar, and wood waste (a form of biomass).

Wind. Wind energy systems for utility applications transform the kinetic energy of the wind into electrical energy. Wind electric turbines are either vertical-axis (egg-beater-style) or horizontal-axis (propeller-style) machines. Horizontal-axis turbines are the most common today, constituting almost all of the utility-scale (greater than 100 kW) applications. Figure 14 shows these two wind turbine configurations.

Figure 14



Horizontal axis wind turbine configurations are the most common today, constituting almost all of the utility-scale applications.

[8] Schimmoller, Brian K., "Renewables Get Into the Mix," *Power Engineering*, January 2004, pp. 22-30.

Turbine subsystems include:

- A rotor, or blades, that convert the wind's energy into rotational shaft energy
- A nacelle (enclosure) containing a drive train, usually including a gearbox (not all turbines require a gearbox) and a generator
- A tower to support the rotor and drive train
- Electronic equipment such as controls, electrical cables, ground support equipment, and interconnection equipment.[9]

The American Wind Energy Association (AWEA) reports that 11,603 MW of wind energy capacity was installed in the U.S. as of the end of 2006. The top ten states as reported by AWEA are shown in Table 15.

Table 15
Installed Wind Energy Capacity in the U.S. (2006)

State	Installed Capacity (MW)
Texas	2,768
California	2,361
Iowa	936
Minnesota	895
Washington	818
Oklahoma	535
New Mexico	497
Oregon	439
New York	370
Kansas	364

This table shows the top ten states by wind capacity, in MW, as reported by AWEA.

Wyoming has 288 MW of wind generation installed (Table 16). South Dakota has 44 MW of wind generation installed (Table 17), with the most significant wind generation at Basin Electric Power Cooperative's (Basin) Highmore wind farm totaling 40.5 MW and consisting of 27 1.5-MW wind turbines owned by FPL Energy. Basin also owns two turbines at the Chamberlain (Prairie Winds) site totaling 2.6 MW. Montana has 146 MW of wind generation installed (Table 18). Wind energy for utility generation purposes is generally installed in areas that have Class 4 winds or better.[10]

[9] Figure and general information from web site of the American Wind Energy Association www.awea.org.
[10] Power Technologies 2003 Databook, National Renewable Energy Laboratory, July 2003, accessed at www.nrel.gov/analysis/power_databook/.

Table 16

Existing and Proposed Wind Energy Projects in Wyoming[11]

Existing Project	Owner	Date Online	MW	Power Purchaser
Medicine Bow	Platte River Power Authority (PRPA)	1996	0.065	PRPA
Medicine Bow	PRPA	1998	1.2	PRPA
Foote Creek Rim I	PacifiCorp, Eugene Water & Elec. (EWEB)	1999	41.4	PacifiCorp, EWEB
Foote Creek Rim II	Caithness	1999	1.8	Bonneville Power Administration (BPA)
Foote Creek Rim III	Caithness	1999	24.75	Public Service Company of Colorado
Foote Creek Rim IV	Caithness	2000	16.8	BPA
Medicine Bow	PRPA	1999	3.3	PRPA
Medicine Bow	PRPA	2000	1.32	PRPA
Rock River I	Shell Wind Energy	2001	50	PacifiCorp
Wyoming Wind Energy Center	FPL Energy	2003	144	PPM Energy
Clipper Windpower Test Turbine	Clipper Windpower	2005	2.5	PRPA
F.E. Warren Air Force Base	F. E. Warren Air Force Base	2005	1.32	F. E. Warren Air Force Base
Planned Project	**Developer**	**Date Online**	**MW**	**Utility Purchaser**
Bridger Butte Wind Project	Mountain Wind Power, LLC	NA	201	NA

TABLES 16, 17 & 18: Wyoming, South Dakota and Montana have a combined installed wind generation of 478 MW. For BH, wind resources will be purchased through a PPA in 25 MW blocks.

Table 17

Existing and Proposed Wind Energy Projects in South Dakota[12]

Existing Project	Owner	Date Online	MW	Power Purchaser
Chamberlain (Prairie Winds)	Basin Electric	2001	2.6	Basin Electric, East River Co-op
Howard County	City of Howard	2001	0.216	City of Howard
Gary	EMS-DES	2002	0.09	EMS-DES
Canova	City of Howard	2002	0.108	City of Howard
Rosebud Sioux	Rosebud	2003	0.75	Rosebud Tribe
Highmore	FPL Energy	2003	40.5	Basin Electric
Planned Project	Developer	Date Online	MW	Utility Purchaser
Minn-Dakota Wind Power Project (SD portion)	PPM Energy	Under construction	49.5	NA
Pine Ridge Reservation	Invenergy	NA	200-400	NA
Java Wind Farm	Northern SD	NA	30	NA

[11] Wind Project Data Base – Wyoming, American Wind Energy Association, www.awea.org/projects/wyoming.html. The Happy Jack project is not shown on the AWEA listing.

[12] Wind Project Data Base – South Dakota, American Wind Energy Association, www.awea.org/projects/southdakota.html. The Happy Jack project is not shown on the AWEA listing.

Table 18
Existing and Proposed Wind Energy Projects in Montana[13]

Existing Project	Owner	Date Online	MW	Power Purchaser
Blackfeet Reservation	Blackfeet Nation	1996	0.1	Glacier Electric Cooperative
Martinsdale Wind Farm	Martinsdale Hutterite Colony	2005	0.715	Martinsdale Hutterite Colony
Judith Gap	Invenergy Wiud	2005	135	Northwestern
Horseshoe Bend	Exergy/United Materials	2006	9	Idaho Power

Planned Project	Developer	Date Online	MW	Utility Purchaser
Fort Peck	Tribes and Community College	NA	0.66	NA
NA	Wind Hunter LLC	NA	Up to 500	NA

BHC issued a Request for Proposals (RFP) in early 2006 seeking renewable energy. The Happy Jack wind facility, a 30 MW wind facility located near the Happy Jack substation outside of Cheyenne, Wyoming, will enter commercial operation by the end of 2008.

In addition, BHC, in cooperation with South Dakota State University, has set up a meteorological data tower north of Belle Fourche, South Dakota to monitor wind data. Data have been collected from the tower since mid-2006. To date, the data indicate an average wind speed at the Belle Fourche site of 16-17 mph, which is comparable to the wind speed data at Happy Jack. After a year of data are collected, BHC intends to hire a wind consultant to perform a feasibility analysis for a 20 MW wind energy facility.

For purposes of this IRP, BHC modeled wind energy as a resource that would be procured through a power purchase agreement (PPA). Wind was assumed to be available in 25 MW blocks at a cost of $42/MWh, escalating over time. The wind resource was assumed to generate energy with a pattern close in characteristics to that expected from Happy Jack. Although wind energy resources often present regulating challenges to utility operators, BHC will rely on WAPA to regulate new wind generation, therefore, no regulating constraints were captured or modeled in the course of conducting this IRP.

Solar. A 10 MW solar photovoltaic generation facility was modeled as one of the renewable options considered by BHC during the IRP process. A photovoltaic (PV) or solar cell is made of semiconducting material, typically wafer-based crystalline silicon technology, configured such that when sunlight hits the cells, the electrons flow through the material and produce electricity. Usually, about 40 solar cells are combined to form a module. Modules can be characterized as flat plate or concentrator systems. About 10 modules make up a flat plate PV array. Approximately 10-20 arrays would be required to provide enough electricity for a typical household. For this analysis, characteristics and costs were modeled for a 10 MW PV flat plate thin film facility which included a capital cost of $7912/kW (2006 dollars) (which does not include land or start-up costs), fixed O&M of $22.44/kW, and no variable O&M costs.

[13] Wind Project Data Base – Montana, American Wind Energy Association, www.awea.org/projects/montana.html. The Happy Jack project is not shown on the AWEA listing.

Biomass. Biomass energy is the generation of electric power from resources including urban waste wood, as well as crop and forest residues. Of most interest to BHC is biomass consisting of urban waste wood in conjunction with forest wood waste (sometimes referred to as forest slash). Such biomass feedstocks can either be co-fired with coal in an existing coal-fired boiler or combusted in boilers designed and built specifically for the biomass fuel itself. More than 75% of the installed biomass facilities in the U.S. are associated with the forest products industry with 95% of that capacity comprised of wood-fired systems. Of the approximately 1,000 wood-fired plants in the U.S., about two-thirds provide power and heat for on-site uses only, and does not to feed into the electricity grid.

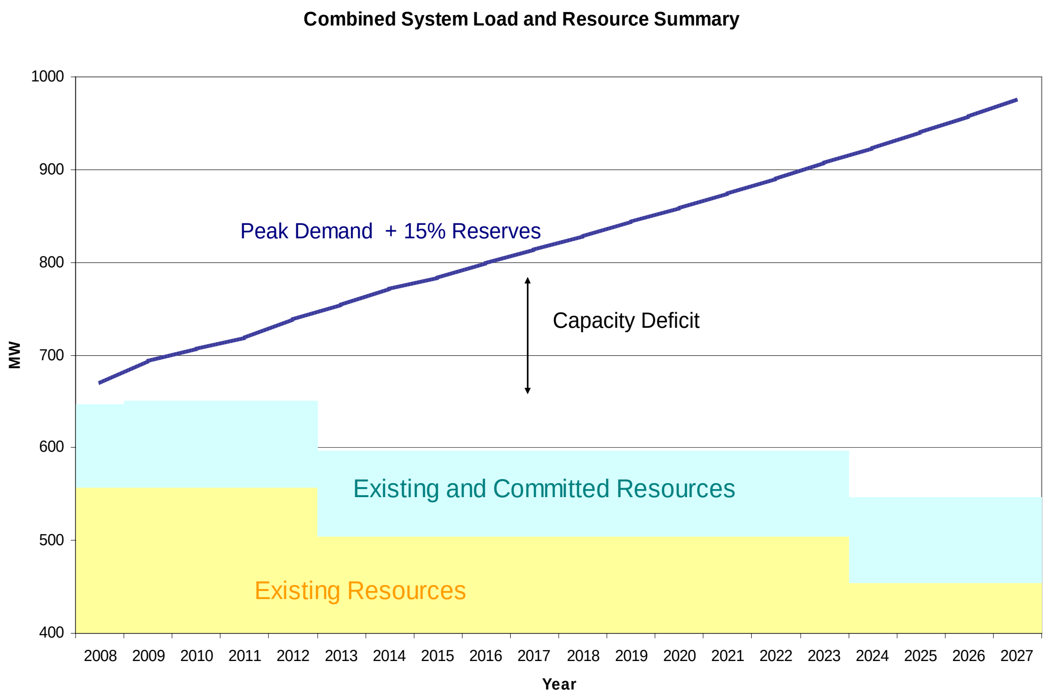
Biomass in the form of a wood waste facility was assumed to be procured by BHC through a PPA. Biomass would be available in blocks of 11 MW, generating electricity with a heat rate of 10,430 Btu/kWh. Biomass was priced at 5.9 cents/kW (in 2006 \$); half of the cost escalates over time. The facility is assumed to be base loaded for a minimum of 8,400 hours per year.

Resource Need Assessment

As described in the Load Forecast section of this report, the combined system is expected to experience a growth in load of just under 2% per year. In addition, on January 1, 2008, all of the energy requirements of CLF&P become its own responsibility. Over the planning horizon, several units retire and contracts for resources with third parties expire. The totality of the requirements for new resources, incorporating the need for planning reserves of 15% and including the committed resources of Wygen II and Happy Jack but not any other future resources, are shown on Figure 15 and in Appendix C. The capacity deficit is reflected as the distance between the two lines. That deficit grows to over 400 MW by 2027.

For BHC's IRP process, new resources are selected to ensure that the system satisfies applicable operating and planning reserve criteria. No resources were screened out of consideration in the modeling process.

Figure 15



The gap between demand and resources widens throughout the planning period.

Base Plan

For BHC's IRP process, new resources are selected to ensure that the system satisfies applicable operating and planning reserve criteria. No resources were screened out of consideration in the modeling process. Thus all potential conventional and renewable resources were examined. The combination of resources that provides the lowest PVRR to the BHC customers while satisfying the reliability criteria was selected and is referred to as the Base Plan.

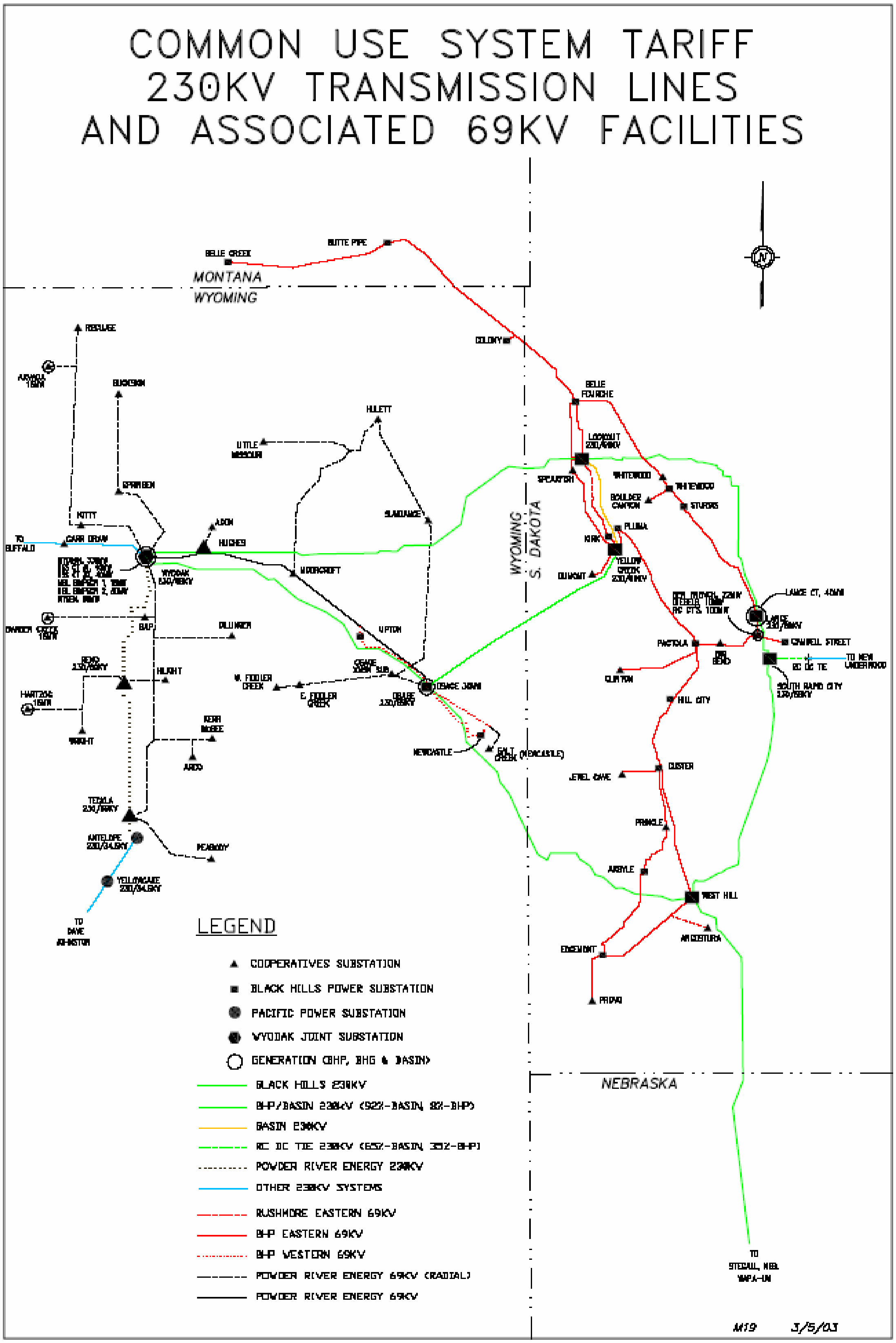
The modeling for the Base Plan was performed by GED using the Strategic Planning *powered by MIDAS Gold®* software and its Markets, Portfolio, Capacity Expansion, Financial and Risk Modules (see Appendix B). The Markets module generates electric market price forecasts by hour for the planning horizon for the markets of interest, reflecting transmission constraints. The Portfolio module uses the market price forecasts generated by the Markets module to perform specific deterministic analyses. The Capacity Expansion module is an optimization module that performs screening of resource alternatives as well as an optimized set of resources. The Financial module is capable of modeling the financial parameters of a utility system and generating bottom-line financial statements. The Risk module performs stochastic analysis on specified production and financial variables.

Transmission

For purposes of the IRP, no transmission costs have been added to the various cases as all were assumed to require the same level of purchased transmission service. Transmission constraints are recognized but not priced in the analysis.

BHP. BHP, Basin Electric Power Cooperative (Basin) and Powder River Energy Corporation (PRECorp) are parties to a Federal Energy Regulatory Commission (FERC) approved joint open access transmission tariff (OATT) which governs high voltage (230-kV) transmission assets in parts of Nebraska, South Dakota, and Wyoming. The transmission assets governed by the FERC-approved OATT is referred to as the Common Use System (CUS). The CUS includes 642 miles of high voltage lines of which BHP owns 447 miles, BHP jointly owns 43 miles with Basin Electric Power Cooperative (Basin), Powder River Energy Corporation (PRECorp) owns 60 miles, and Basin owns 92 miles. BHP and Basin completed construction of a jointly-owned AC-DC-AC transmission tie that was placed into commercial operation in October 2003. The tie provides an interconnection between the Western and Eastern transmission grids, making available access to both the Western Electricity Coordinating Council (WECC) and the Mid-Continent Area Power Pool (MAPP) regions. BHP owns 35% of the tie which has a total capacity of 400 MW – 200 MW West to East and 200 MW East to West. BHP has firm transmission access on the PacifiCorp transmission system for two transmission service agreements: 1) a firm point-to-point used to deliver power to the Black Hills system and 2) a network integration transmission services agreement used to deliver MDU's Sheridan Service Territory loads. A map of the CUS transmission system is shown on Figure 16.

Figure 16

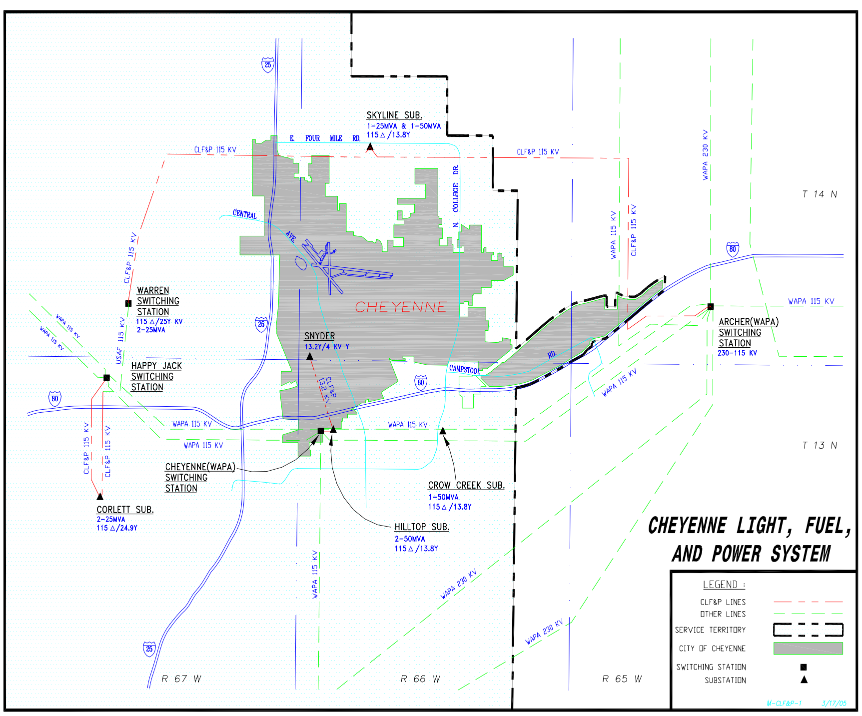

COMMON USE SYSTEM TARIFF
230KV TRANSMISSION LINES
AND ASSOCIATED 69KV FACILITIES
MONTANA
WYOMING
S. DAKOTA
NEBRASKA
LEGEND
COOPERATIVES SUBSTATION
BLACK HILLS POWER SUBSTATION
PACIFIC POWER SUBSTATION
WYODAK JOINT SUBSTATION
GENERATION (BHP, BHG & BASIN)
BLACK HILLS 230KV
BHP/BASIN 230KV (92%-BASIN, 8%-BHP)
BASIN 230KV
RC DC TIE 230KV (65%-BASIN, 35%-BHP)
POWDER RIVER ENERGY 230KV
OTHER 230KV SYSTEMS
RUSHMORE EASTERN 69KV
BHP EASTERN 69KV
BHP WESTERN 69KV
POWDER RIVER ENERGY 69KV (RADIAL)
POWDER RIVER ENERGY 69KV
M19 3/5/03

The ability of BHP, and the rest of the members of the common use system, to transmit power outside of its service territory is constrained in many cases by circumstances out of the company's control. Utilities within the western U.S. belong on a voluntary basis to the WECC. The Technical Studies Subcommittee of WECC and other committees and subcommittees examine the capability of the transmission system and determine how much power can be safely sent along various transmission lines under a range of system conditions, including conditions when one or more contingencies have occurred with a contingency usually denoting the outage of a major generating unit or transmission facility. Power flows outside of BHP's territory and on lines owned by others can significantly affect the ability of the company to send or receive power. Of particular interest and concern to BHC, particularly as it pertains to the most economic, safe, and reliable means of serving its Wyoming customers both in the Cheyenne area and in northeastern Wyoming, are transmission paths denoted by the WECC as TOT 3, TOT 4A, TOT 4B, TOT 5 and TOT 7. More information on these transmission paths and their constraints are provided in Appendix A.

The transmission limitations described in Appendix A currently constrain BHP's ability to transmit power outside of its service territory and also restrict the manner in which BHP and CLF&P can exchange power. If transmission access were increased, it is possible that the price of market power available to BHP and CLF&P would increase. It is also expected that additional energy would be available to purchase during the peak months of July and August.

CLF&P. CLF&P owns only limited transmission facilities. CLF&P owns two 115-kV transmission line segments that total 25.5 miles in length that are situated wholly within, and are operated by, Western Area Power Administration's (WAPA) Rocky Mountain Region control area. CLF&P also owns limited transmission facilities in two WAPA transmission substations and a switching station. CLF&P uses these transmission facilities to interconnect its distribution system with the WAPA transmission system. Although its transmission facilities operate at transmission voltage (115 kV), they effectively serve only as an extension of CLF&P's distribution system, enabling CLF&P to interconnect its system with the WAPA system. The CLF&P service territory and transmission facilities are shown on Figure 17.

Figure 17
CLF&P Service Territory and Transmission Facilities



CLF&P owns limited transmission facilities to interconnect its distribution system with the WAPA transmission system

Results

The resources added in the Base Plan to meet BHP's and CLF&P's objectives in conducting this IRP are shown in Table 19 and Figure 18. Pulverized coal units are added in 2010, 2013, and 2024. Wind energy resources in the form of new 25 MW purchased power agreements are shown in each of 2012, 2013, 2022, 2026, and 2027. The Neil Simpson Combustion Turbine II converts to utility ownership in 2012. Peaking resources are added in 2019 and 2026 and a biomass facility is added in 2023. In addition, purchased power in the market is utilized in the months of July and August in many of the years as noted in lieu of building any additional resources. No cost or resource allocation between BHP and CLF&P was performed as part of the preparation of the IRP.

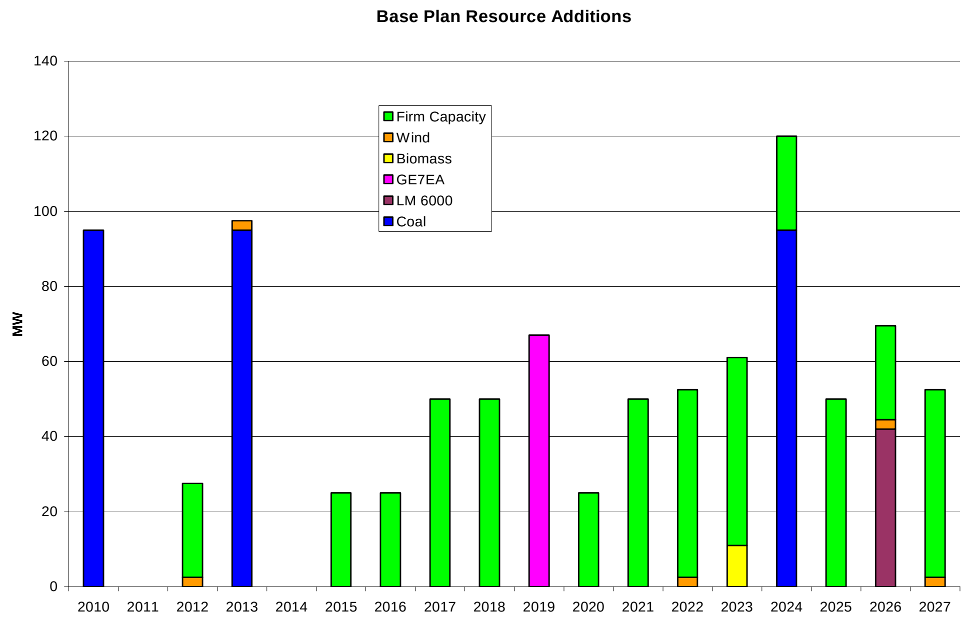
Table 19
Base Plan Resource Additions

Year	Resource Addition	MW
2008	Wygen II, Happy Jack	90 3
2009		
2010	Wygen III	95
2011		
2012	Wind PPA	2.5*
2013	Wygen IV, Wind PPA	95 2.5
2014		
2015		
2016		
2017		
2018		
2019	Frame 7EA	67
2020		
2021		
2022	Wind PPA	2.5
2023	Biomass	11
2024	Wygen V	95
2025		
2026	Wind PPA, LM 6000	2.5 42
2027	Wind PPA	2.5

* 10% of the 25 MW Wind PPA counts toward planning reserves.

Wygen II and Happy Jack are shown as resource additions but were considered committed resources in the study.

Figure 18



This table shows a summary of the uncertainty variables and the multipliers used to establish their minimum and maximum values for the risk analysis.

Risk Analysis

Utilities must plan for the future customer needs for electricity in an environment of significant uncertainty. Thus, the analysis conducted in the preparation of this IRP examined uncertainty under a variety of possible future conditions. Expansion plans were developed for scenarios in which various resources other than those selected in the Base Plan needed to be included or excluded in the resource mix. Stress test scenarios were examined looking at effects on the resource mix of different conditions than the Base Plan assumptions. A specific analysis was conducted comparing the installation of a combustion turbine instead of Wygen III in 2010. Stochastic risk analysis was conducted to look at the expected net present value and sensitivity of the Base Plan to a wide variety of parameters that can impact future electricity requirements. These analyses are all documented in this section.

Scenarios

Optimal resource plans were developed for three scenarios in addition to the Base Plan. The underlying assumptions for all four of these cases are:

Base Plan

- Wygen II comes on line in 2008
- Osage 1-3 retire December 31, 2012
- MEAN contract (20 MW) expires February 2013
- Happy Jack wind contract begins September 1, 2008
- Wygen I contract modeled as 60 MW through the entire study period
- Neil Simpson Combustion Turbine II PPA expires December 2011
- Neil Simpson Combustion Turbine II converts to ownership in 2012
- Colstrip PPA expires December 2023
- 50 MW of firm purchase is available each July and August as a 6 x 16 product
- WECC Spring 2007 Reference Case gas prices and emission costs.

No Coal Option

- Same assumptions as listed above for Base Plan
- No coal-fired units in the form of Wygen or similar units are available after Wygen II
- LMS-100 assumed to be built in 2010.

Carbon Dioxide Tax

- Same assumptions as listed above for Base Plan
- Used stringent “Kyoto-like” CO_2 tax instead of WECC Spring 2007 Reference Case assumptions.

Force on Biomass PPA in 2010

- Same assumptions as listed above for Base Plan
- Force on 11 MW Biomass PPA in 2010.

The optimal builds that results from the models runs with these assumptions are shown on Table 20.

Table 20
Optimal Expansion Plans*

Year	Base	No Coal	CO_2 Tax	Biomass 2010
2010	95 MW Wygen III	90 MW LMS-100	67 MW 7EA	11 MW Biomass PPA 25 MW Wind PPA
2011		25 MW Wind PPA	25 MW Wind PPA	95 MW Wygen III 25 MW Wind PPA
2012	25 MW Wind PPA	25 MW Wind PPA	25 MW Wind PPA	25 MW Wind PPA
2013	95 MW Wygen IV 25 MW Wind PPA	90 MW LMS-100 25 MW Wind PPA	90 MW LMS-100 25 MW Wind PPA	
2014				
2015				
2016			90 MW LMS-100	
2017				95 MW Wygen IV
2018		11 MW Biomass PPA		
2019	67 MW 7EA	90 MW LMS-100		
2020				
2021				
2022	25 MW Wind PPA		11 MW Biomass PPA 25 MW Wind PPA	
2023	11 MW Biomass PPA	25 MW Wind PPA	90 MW LMS-100	
2024	95 MW Wygen V	90 MW LMS-100		95 MW Wygen V
2025			42 MW LM-6000	
2026	42 MW LM-6000 25 MW Wind PPA			42 MW LM-6000 25 MW Wind PPA
2027	25 MW Wind PPA	42 MW LM-6000		

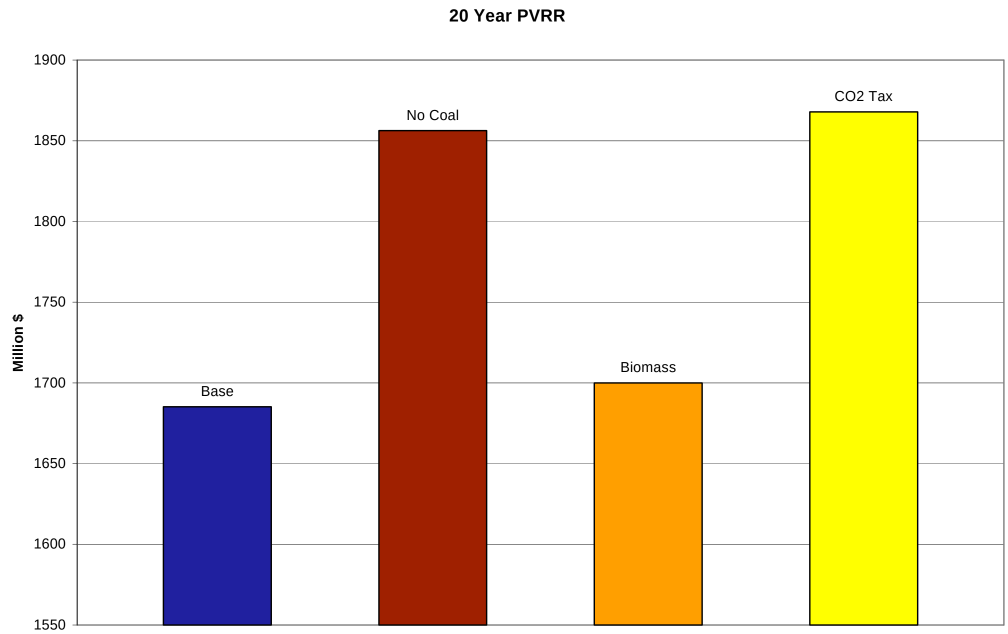
*For all plans, 10% of the wind capacity installed counts toward reserve margins.
Thus for each 25 MW of Wind PPA, 2.5 MW of reserves are counted.

…in cases where coal cannot be built or the tax on CO_2 is prohibitive, no additional Wygen units past Wygen II are part of the optimal expansion plan.

As would be expected, in cases where coal cannot be built or the tax on CO_2 is prohibitive, no additional Wygen units past Wygen II are part of the optimal expansion plan. With a biomass PPA required as a resource in 2010, Wygen III is delayed a year but is still part of the optimal resource plan, as are Wygen IV and V (although the installation of Wygen IV is delayed).

The PVRR projected for each of these scenarios is shown in Figure 19.

Figure 19
All Scenarios – Deterministic PVRR 2008-2027



Comparison of the base plan to the other scenarios confirm the reasonableness of the base plan.

Stress Test Scenarios

Stress test scenarios were run to determine whether the conditions examined needed to be examined in greater detail in the IRP. The results of these stress tests are as shown below.

Double CO_2 Tax

- Same assumptions as base plan
- Used two times higher CO_2 tax than WECC Spring 2007 Reference Case
- GED recalculated market prices to account for higher CO_2 tax
- GED recalculated new 6x16 product pricing to account for higher CO_2 tax

Outcome: Build Wygen III in 2010.

Increase Wygen Unit Capital Costs

- Same assumptions as base plan
- Increase Wygen III capital costs by 15%

Outcome: Build Wygen III in 2010.

Low Gas Prices

- Same assumptions as base plan
- Decreased gas prices by 15%
- GED recalculated market prices to account for lower gas prices
- GED recalculated new 6x16 product pricing to account for lower gas prices

Outcome: Build 7EA and Wind in 2010. Wygen III built in 2013.

Very Low Gas Prices

- Same assumptions as base plan
- Decreased gas prices by 30%
- GED recalculated market prices to account for lower gas prices
- GED recalculated new 6x16 product pricing to account for lower gas prices

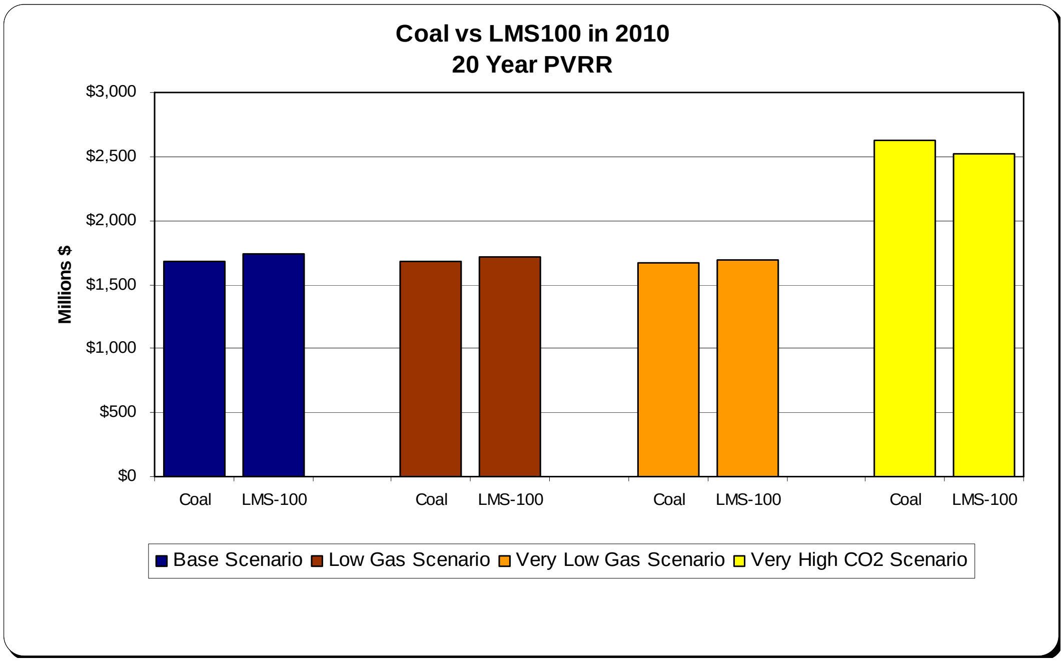
Outcome: Build LMS-100 instead of Wygen III. Did not build any future Wygen units.

These results confirmed the reasonableness of the Base Plan and the use of the assumptions selected as documented in the IRP for the risk analysis.

Wygen III versus a Combustion Turbine

In order to examine the specific decision regarding the 2010 resource, independent deterministic analysis was conducted comparing the economics of two sets of expansion plans. In one series of runs the 2010 resource is Wygen III. In the second set, the 2010 resource is an LMS-100 combustion turbine. Each series of runs included the Base Plan, low gas scenario, very low gas scenario, and a very high CO_2 tax scenario. The results of these analyses are shown on Figure 20. Because the building of Wygen III results in lower PVRR in each of the scenarios (including the low gas and very low gas) except in the very high CO_2 tax scenario, the prudent 2010 resource selection is demonstrated to be Wygen III.

Figure 20



An independent deterministic analysis comparing Wygen III to an LMS 100 expansion plan resulted in a lower PVRR for each of the scenarios.

Stochastic Analysis

GED's Strategic Planning model uses a structural approach to forecasting prices that captures the uncertainties in regional electric demand, resources, and transmission. Regional forward price curves are generated across multiple scenarios using a stratified Monte Carlo sampling program. Scenarios are driven by a wide range of market drivers that take into account statistical distributions, correlations, and volatilities.

The uncertainty drivers developed for the specific Wyoming market prices are also used when evaluating the resource mix. During the evaluations, the prices and associated uncertainties provide sufficient information about the market to allow for proper evaluation of alternatives. For example, high gas prices would generally result in high on-peak prices. The following uncertainties were examined in the IRP and resulted in 50 future scenarios for price development and portfolio evaluation:

- Demand
  - Mid-Term Peak by region
  - Mid-Term Energy by region
  - Reference Load Shape Year
  - Long-Term Demand (to consider uncertainty in the rate of long-term load growth)

- Fuel Prices
  - Mid-term Gas Price
  - Mid-Term Oil Price
  - Long-Term Gas and Oil Price (to consider the price uncertainty in the long-term supply/demand)
- Supply
  - Mid-Term Coal Unit Availability by region
  - Mid-Term Nuclear Unit Availability by region
  - Mid-Term Gas Unit Availability by region
  - Mid-Term Hydro Output by region
- Capital Cost
  - Long-Term Pulverized Coal Capital Cost
  - Long-Term Combustion Turbine Capital Cost
  - Long-Term Combined Cycle Capital Cost
  - Long-Term Integration Gasification Combined Cycle Capital Cost

The range of values for each of these parameters is developed using either uniform distributions or standard deviations for two related variables that are then correlated. The ranges for the variables considered (with 1.0 being the middle) are shown in Table 21.

Table 21

Ranges for Uncertainty Variables

Variable	Minimum	Maximum
Mid-Term Peak	.82	1.14
Mid-Term Energy	.92	1.09
Reference Load Shape	NA	NA
Long-Term Demand[1]	.91	1.10
Mid-Term Gas Price	.75	2.10
Mid-Term Oil Price	.86	1.16
Long-Term Gas and Oil Price	.82	1.18
Mid-Term Coal Unit Availability	.88	1.10
Mid-Term Nuclear Unit Availability	.94	1.06
Mid-Term Gas Unit Availability	.85	1.16
Mid-Term Hydro Output	.82	1.17
Long-Term Pulverized Coal Capital[2]	1.00	1.20
Long-Term CT Capital[2]	1.00	1.08
Long-Term CC Capital[2]	1.00	1.12
Long-Term IGCC Capital[2]	1.00	1.30

[1] Base Plan average long-term growth rate is 2.1%.

[2] Capital cost uncertainty only looks at potentially higher costs. Expected values are coal – 1.10, CT – 1.04, CC – 1.06, and IGCC – 1.15.

This table shows a summary of the uncertainty variables and the multipliers used to establish their minimum and maximum values for the risk analysis.

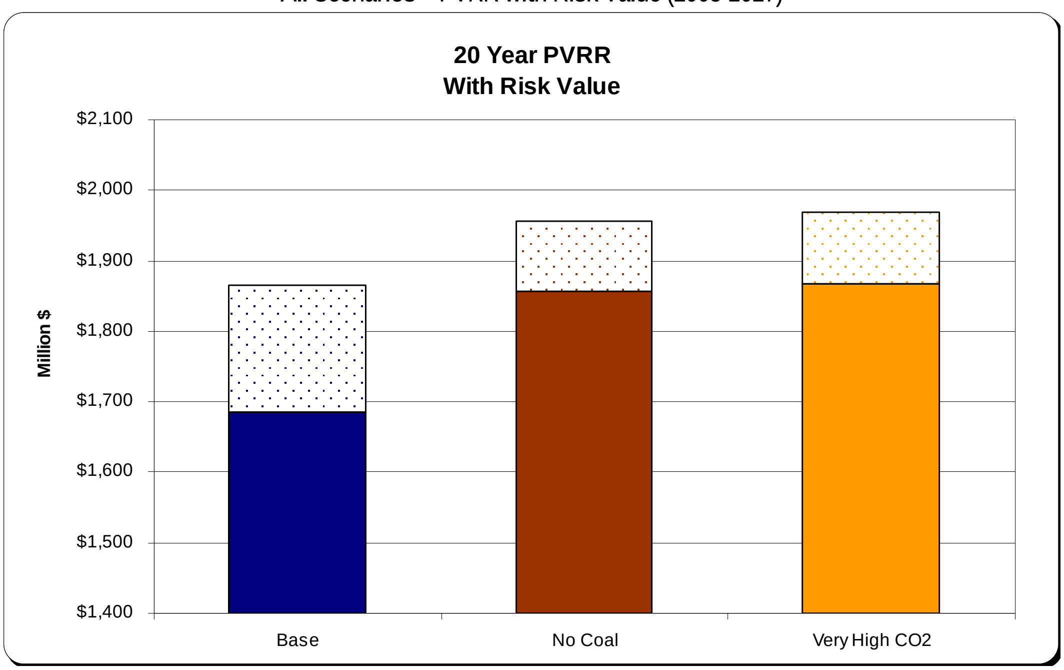
Risk profiles were created using stochastic analysis for each of the base plans, the no coal option, and the Very High CO_2 Tax scenario, all described previously in the scenarios portion of this report section. The results of the stochastic analysis show that the expected PVRR, the cost that would be expected in a deterministic analysis, for the Base Plan is significantly lower than for the other two cases (Table 22, Figures 21 and 22). Figure 23 shows that there is a 70% chance that the Base Plan will have a lower PVRR than either of the other two plans examined. The probable cost shown for each scenario is the mean cost developed through the stochastic analysis. The probable cost for the Base Plan is lower than the probable cost for the other cases. However, the risk associated with the Base Plan (which is the difference between the expected cost and the probable cost) is more significant than for either of the other two cases because of the potential exposure that would result in the Base Plan from a high CO_2 tax.

Table 22
Expected and Probable Costs for All Scenarios – PVRR (2008-2027) (millions of dollars)

	Base Plan	No Coal	Very High CO_2 Tax
Expected Cost	$1,685.20	$1,856.34	$1,867.84
Probable Cost	$1,865.59	$1,957.19	$1,968.12
Difference	$180.39	$100.85	$100.28

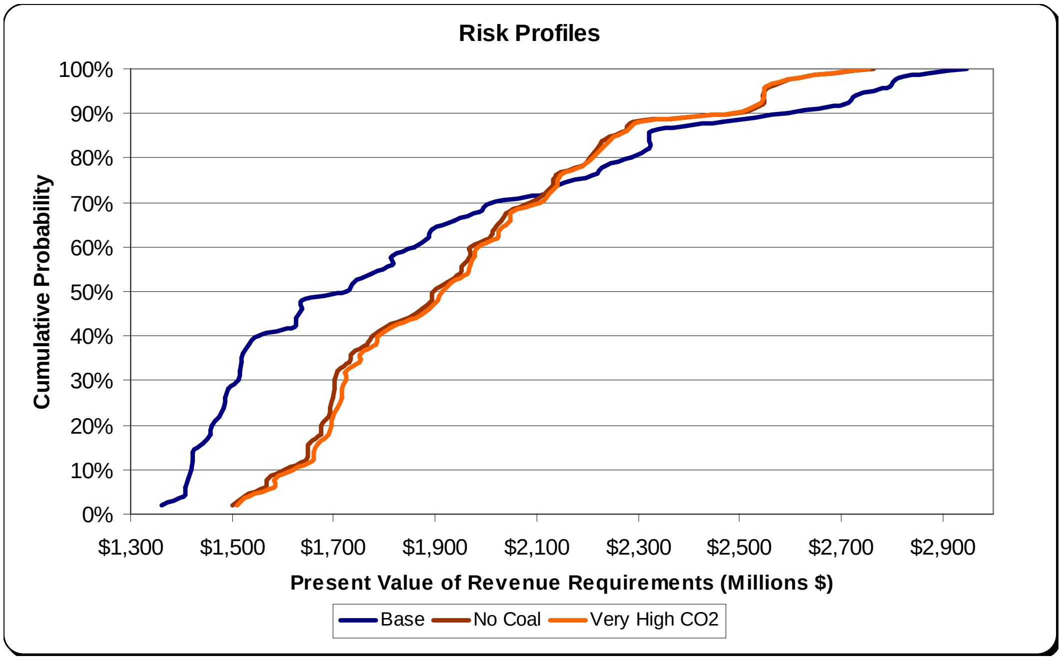
A potential high CO_2 tax increases the risk associated with the Base Plan.

Figure 21
All Scenarios – PVRR with Risk Value (2008-2027)



Comparison of the individual 20-year PVRR for each scenario showing that the probable cost of the Base Plan is still lower than the other cases.

Figure 22

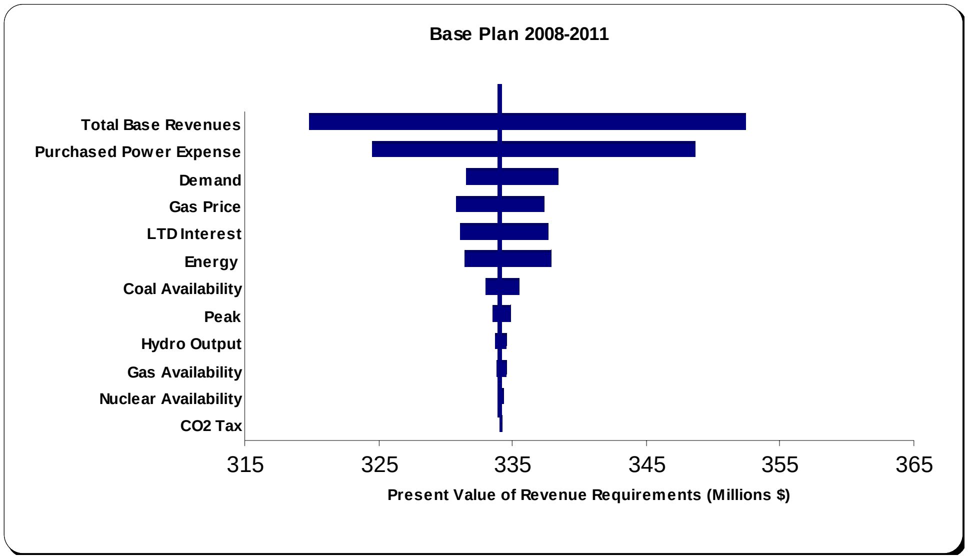


The stress test results show that there is a 72% probability that the Base Plan will have a lower PVRR than either of the other two cases.

Sensitivity Drivers

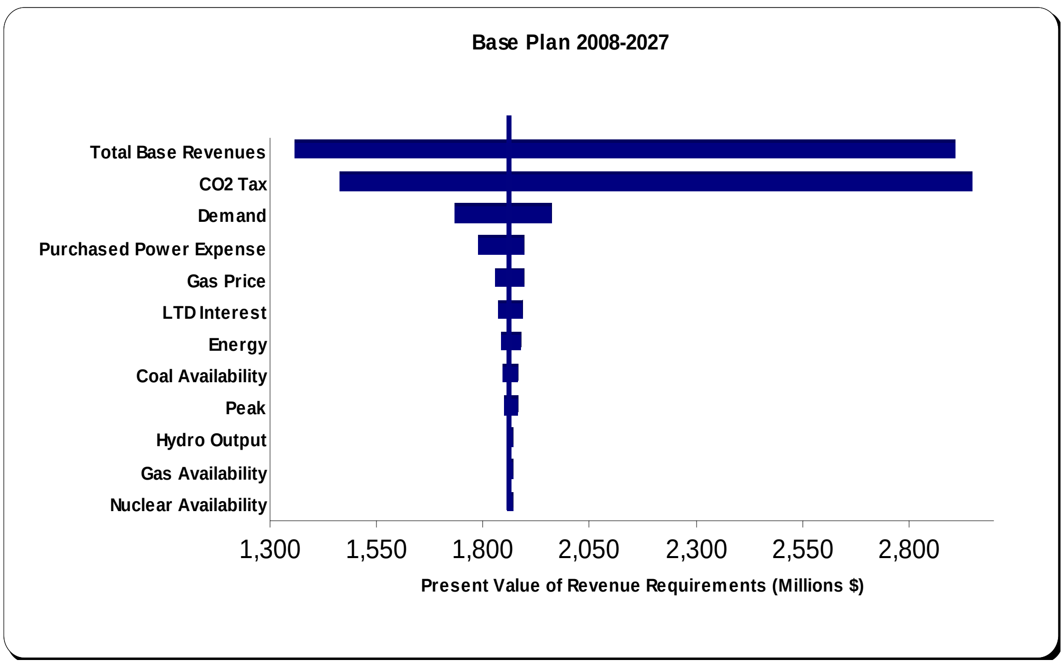
The magnitude of the influence that any specific driving factor has in determining PVRR can be represented in what is called a "tornado chart." The values on this chart are determined through regression analysis and identify the contribution of each variable to the total risk. The CO_2 tax is the primary risk driver in this IRP. Figures 23 and 24 show the risk drivers for the Base Plan in the years without a CO_2 tax (Figure 23 2008-2011) and for all of the years of the planning horizon (Figure 24 – tax effective in 2012) . The tornado charts for the no coal and very high CO_2 tax case show very similar results. For those years in which a CO_2 tax has not been implemented, the primary risk driver is the price of purchased power, followed by the peak demand forecast, and then the price of natural gas.

Figure 23
Base Plan – Tornado Chart (without CO_2 Tax)



For Figures 23 & 24, the primary driver for the entire length of the study is CO_2 followed by demand and purchased power for all three cases.

Figure 24
Base Plan – Tornado Chart



Conclusions and Recommendations

… this IRP confirms the selection of the coal-fired Wygen III as the least-cost resource addition in 2010 to provide reliable, low cost service to customers of the combined BHP and CLF&P systems.

BHC conducted this IRP to provide a road map to define the system upgrades, modifications, and additions that may be required to ensure reliable and least cost electric service to BHP's and CLF&P's customers now and into the future. A full range of practicable resource alternatives, including renewables, were examined with the emphasis on determining the most robust plan that balances risk, reliability, and cost under a variety of possible future scenarios.

The final plan meets the objectives of the company:

- Ensure a reasonable level of price stability for its customers
- Generate and provide safe, reliable electricity service while complying with all environmental standards
- Manage and minimize risk
- Continually evaluate renewables for our energy supply portfolio, being mindful of the impact on customer rates.

After updating all of the assumptions and performing the analyses, the resources selected and the action plan developed in this IRP remain consistent with the IRP developed in 2005. The 2005 IRP determined that subsequent to building Wygen II for operation in 2008, the next resource of choice is Wygen III in the 2009-2011 time frame. After conducting a comprehensive planning analysis that considered a broad range of generation alternatives and global climate change scenarios, this IRP confirms the selection of the coal-fired Wygen III as the least-cost resource addition in 2010 to provide reliable, low cost service to customers of the combined BHP and CLF&P systems.

Action Plan

- The action plan provides a template for the actions that should be taken over the next several years. BHC should continue to monitor market conditions and regulatory developments so that the items in the action plan can be adapted to address actual conditions as they occur.
- Build Wygen III for commercial operation in 2010.
- Continue to examine resource alternatives for development in the 2012-2013 time frame.
- Seek opportunities to develop economic renewable resources – particularly wind and biomass.
- Actively participate in and influence, to the extent possible, the Congressional efforts to tax or cap emissions of CO_2 in order to mitigate customer rate impacts.
- Work with equipment manufacturers to develop carbon capture and carbon sequestration technologies for existing generation resources.
- Actively review development of future load growth, especially in the Cheyenne, Wyoming area. Monitor transmission developments in the Western U.S.
- Monitor transmission developments in the Western U.S.
- Continue to examine transmission alternatives for direct connection between the BHP and CLF&P service territories.

Appendix A

Transmission Paths

TOT 3 is located at the border between northeast Colorado, southeast Wyoming, and southwest Nebraska. This area is a bottleneck that limits flows of power from Wyoming south into the Denver area of Colorado. Historically, the flows have all been north to south (coming down to the Denver area from Wyoming and Nebraska). The rating of the lines can vary significantly based on local generation levels and DC tie levels and direction from a low of 843 MW to a high of 1,605 MW. Under certain conditions when TOT 3 is loaded to its limit, constraints result on TOT 5. The transfer capability of the path is divided between the Western Area Power Administration, Missouri Basin Power Project, Xcel Energy, and Tri-State Generation and Transmission. The rating limits for this area were first identified and established in 1981 and were most recently revised in 1999.[14]

TOT 4A is located in southwest Wyoming where flows are all northeast to southwest across the path. Constraints in the area can limit the flows to a minimum of 0 MW. Maximum flow is 810 MW. The typical real-time rating is around 650 MW. PacifiCorp has the entire transfer capability of the path. Flows from BHP's Wyodak facility and to Cheyenne can be limited by conditions at TOT 4A. The rating limits for this area were initially identified and established in 1991.[15]

TOT 4B is located in northwest Wyoming where flows have historically been southeast to northwest across the path. Dependent on the flow levels on TOT 4A, constraints in the area can limit the flows to a minimum of 0 MW. Maximum flow is 680 MW. The typical real-time rating is around 475 MW. PacifiCorp and the Western Area Power Administration share the transfer capability on this path. Flows from BHP's facilities in the Gillette area can be limited by conditions at TOT 4B. The flows on TOTs 4A and 4B are interdependent and flows on one limit the flows allowable on the other. The rating limits for this area were initially identified and established in 1991.[16]

TOT 5 is located in west-central Colorado where the flows have historically all been west to east across the path – with power moving into the Denver area. The transfer limit is 1675 MW from west to east. The transfer capability of the path is divided between the Western Area Power Administration, Platte River Power Authority, Tri-State Generation and Transmission, and Xcel Energy. The rating limits for this area were initially identified and established in 1987-88.[17]

TOT7 is located in north-central Colorado where flows have historically been north to south across the path. The transfer limit is 890 MW from north to south. This path is primarily affected by Wyoming to Colorado power exchanges. The rating limit for this path was established in December 1995. The transfer capability of the path is divided between Public Service Company of Colorado and Platte River Power Authority.[18]

As noted above, the rating limits and issues for the transmission system in Wyoming and Colorado have been identified and known for fifteen to twenty years. Solutions to the issues include the construction of new transmission lines and most of the solutions have also been known and identified for many years. However, utilities have been reluctant to invest in new transmission infrastructure

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[14] Western Electricity Coordinating Council, "WECC 2004 Path Rating Catalog," Prepared by the Technical Studies Subcommittee, March 2004.
[15] Ibid.
[16] Ibid.
[17] Ibid.
[18] Western Electricity Coordinating Council, "WECC 2005 Path Rating Catalog," Prepared by the Technical Studies Subcommittee, March 2005.

throughout the U.S. In the West, the Western Governors' Association has been proactive in examining issues relative to the electric utility infrastructure starting with the issuance in August 2001 of a report titled *Conceptual Plans for Electricity Transmission in the West.* This report showed that new transmission and generation infrastructure located remotely from customers could provide benefits for customers throughout the West. However, this study was conceptual in nature and did not identify specific projects and thus did not examine financial viability, needed permitting, or where to site facilities.[19]

On August 22, 2003, the Governors of Wyoming and Utah announced the formation of the Rocky Mountain Area Transmission Study (RMATS) to overcome the transmission bottlenecks and congestion that had developed because of the lack of investment in new transmission infrastructure. The states involved in RMATS include Colorado, Idaho, Montana, Utah, and Wyoming. RMATS intends to see projects through from planning and project definition through approvals, contracting, siting, and financing, to engineering and construction.[20] The work of the RMATS project to date has identified three transmission projects (Recommendation 1) to be pursued into Phase II that includes three transmission projects within the Rocky Mountain region. These projects include a Montana System Upgrade, a Bridger Expansion, and a Wyoming to Colorado Project.[21]

- Montana System Upgrade will enable exports from the Rocky Mountain region to the Pacific Northwest. No new transmission lines are required. Equipment to be installed consists of series compensation, a new autotransformer, and two new substations. This project will increase transfer capacity by 500 MW. There are limited siting requirements. The project could be completed in two years. Cost: $72 million.
- The Bridger Expansion project involves the construction of two new 345-kV lines. The transfer capacity is expected to increase by 1350 MW. Both the new transmission lines and the new substation sites could have siting requirements. The project could be completed in five years. Capital cost: $580 million.
- The Wyoming to Colorado Project involves the addition of a new 345-kV line from northeastern Wyoming across the constrained path between Wyoming and Colorado to Denver (TOT 3), the addition of series compensation, and additional substation interconnections. The capacity is expected to increase by 500 MW. Congestion would be reduced from 73% to below 30%. The project could be completed in five years. Capital cost: $318 million.

The Bridger Expansion project, as announced by PacifiCorp on May 30, 2007, will result in the building of more than 1,200 miles of 500-kV transmission lines originating in Wyoming and connecting into Utah, Idaho, Oregon, and the desert southwest. The total cost of this project is now estimated to total over $4 billion.[22]

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[19] Rocky Mountain Area Transmission Study: Connecting the region today for the energy needs of the future, September 2004, p. 1-5.

[20] Ibid., pp. 1-5 – 1-6. Three other sub-regional transmission planning processes are also underway in the WECC. These include the Southwest Area Transmission (SWAT) formerly the Central Arizona Transmission Study (CATS) including Arizona, New Mexico, and parts of Colorado and Nevada; Southwest Transmission Expansion Plan (STEP) examining Arizona, Southern California, and Southern Nevada; and the Northwest Transmission Advisory Committee (NTAC) exploring transmission in the Pacific Northwest (Washington, Oregon, northern California, northern Nevada, and portions of Idaho and Montana). In March 2004, a state-specific group, the Montana Transmission Advisory Group (MTAG) was formed to address issues within the state. Ibid., pp 1-8 and 2-6.

[21] Ibid., p. 3-1 – 3-4.

[22] "Rocky Mountain Power to construct transmission lines through West," May 30, 2007, www.pacificorp.com/Press-Release/Press_Release74823.html.

Recent additional studies conducted on transmission in the area include the Eastern Wyoming Joint Queue Study/TOT3 WECC Phase Two Study for the Western Area Power Administration and Basin and a study examining the Wyoming-Colorado Project Intertie Study completed in June 2007 which was conducted for Trans-Elect and the Wyoming Infrastructure Authority. The 2006 Basin study examined transmission system modifications between the Dave Johnson substation (in Wyoming) and Ault substation (in Colorado).

In addition to the WECC Paths described above, the Wyodak area has been, and currently is, stability constrained. As with any stability-constrained areas, the addition of generating facilities will further weaken stability. Wyodak area stability constraints may require the addition of transmission facilities to allow interconnection of new generation within the Wyodak area.

Appendix B

Software used for Analysis

Strategic Planning *powered by MIDAS Gold®* was utilized to measure and analyze the consumer value of competition.

Strategic Planning includes multiple modules for an enterprise-wide strategic solution. These modules are:

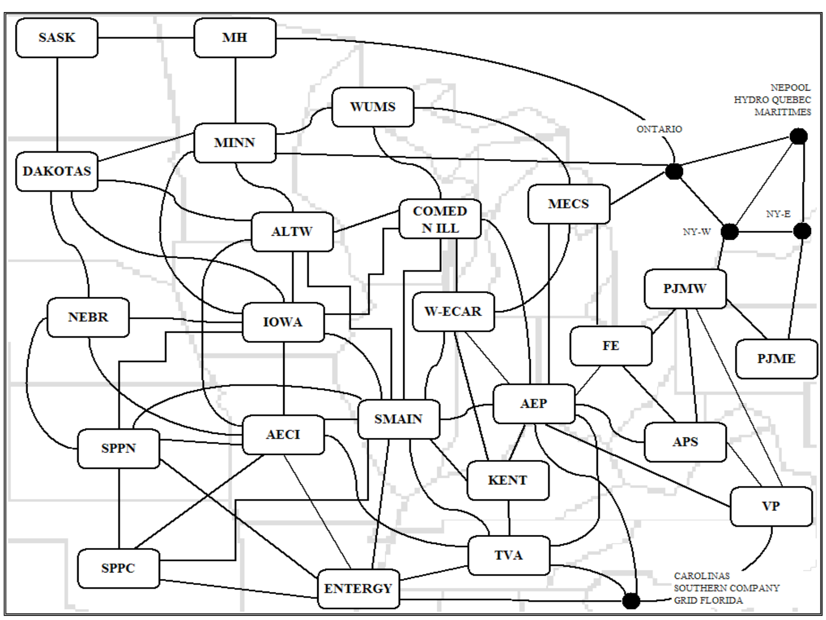
- **Markets**
- **Portfolio**
- **Financial**
- **Risk**

Strategic Planning is an integrated, fast, multi-scenario zonal market model capable of capturing many aspects of regional electricity market pricing, resource operation, asset and customer value. The markets and portfolio modules are hourly, multi-market, chronologically correct market production modules used to derive market prices, evaluate power contracts, and develop regional or utility-specific resource plans. The financial and risk modules provide full financial results and statements and decision making tools necessary to value customers, portfolios and business unit profitability.

Markets Module

Generates zonal electric market price forecasts for single and multi-market systems by hour and chronologically correct for 30 years. Prices may be generated for energy only, bid- or ICAP-based bidding processes. Prices generated reflect trading between transaction groups where transaction group may be best defined as an aggregated collection of control areas where congestion is limited and market prices are similar. Trading is limited by transmission paths and constraints quantities.

Sample Topology



SOURCE: Global Energy

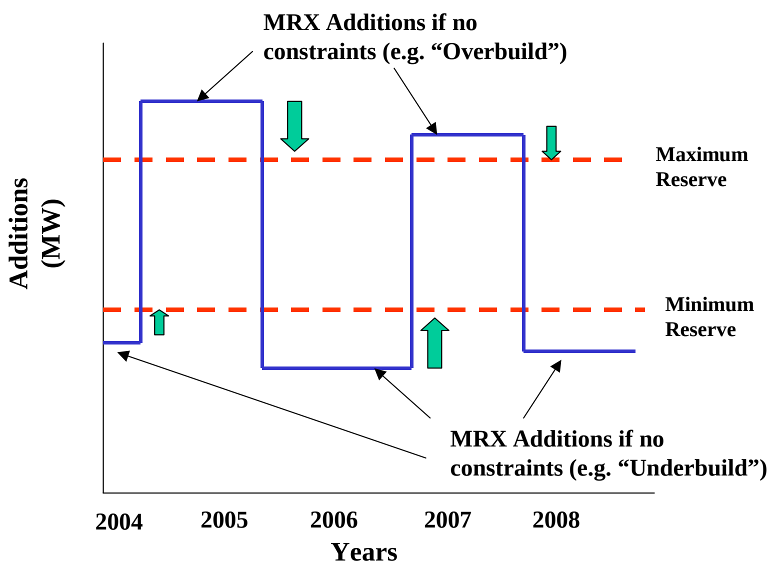
The database is populated with Global Energy Intelligence – Market Ops information. Operational information provided for over 10,000 generating units

- Load forecasts by zone (where zone may be best defined as utility level) and historical hourly load profiles
- Transmission capabilities
- Coal price forecast by plant with delivery adders from basin
- Gas price forecast from Henry Hub with basis and delivery adders

When running the simulation in markets module, the main process of the simulation is to determine hourly market prices. Plant outages are based on a unit derate and maintenance outages may be specified as a number of weeks per year or scheduled.

The market based resource expansion algorithm builds resources by planning region based on user-defined profitability and/or minimum and maximum reserve margin requirements in determining prices. In addition, strategic retirements are made of non-profitable units based on user-defined parameters.

MRX Decision Basis



SOURCE: Global Energy

The markets module simulation process performs the following steps to determine price:

Hourly loads are summed for all customers within each Transaction Group.

- For each Transaction Group in each hour, all available hydro power is used to meet firm power sales commitments.
- For each Transaction Group and Day Type, the model calculates production cost data for each dispatchable thermal unit and develops a dispatch order.
- The model calculates a probabilistic supply curve for each Transaction Group considering forced and planned outages.
- Depending on the relative sum of marginal energy cost + transmission cost + scarcity cost between regions, the model determines the hourly transactions that would likely occur among Transaction Groups.
- The model records and reports details about the generation, emissions, costs, revenues, etc. associated with these hourly transactions.

Portfolio Module

Once the price trajectories have been completed in the markets module, the portfolio module may be used to perform utility or region specific portfolio analyses. Simulation times are faster and it allows for more detailed operational characteristics for a utility specific fleet. The generation fleet is dispatched competitively against pre-solved market prices from the markets module or other external sources. Native load may also be used for non-merchant/regulated entities with a requirement to serve.

Operates generation fleet based on unit commitment logic which allows for plant specific parameters of:

- Ramp rates
- Minimum/maximum run times
- Start up costs

The decision to commit a unit may be based on one day, three day, seven day and month criteria. Forced outages may be based on monte-carlo or frequency duration with the capability to perform detailed maintenance scheduling. Resources may be de-committed based on transmission export constraints.

Portfolio module has the capability to operate a generation fleet against single or multiple markets to show interface with other zones. In addition, physical, financial and fuel derivatives with pre-defined or user-defined strike periods, unit contingency, replacement policies, or load following for full requirement contracts are active.

Capacity Expansion Module

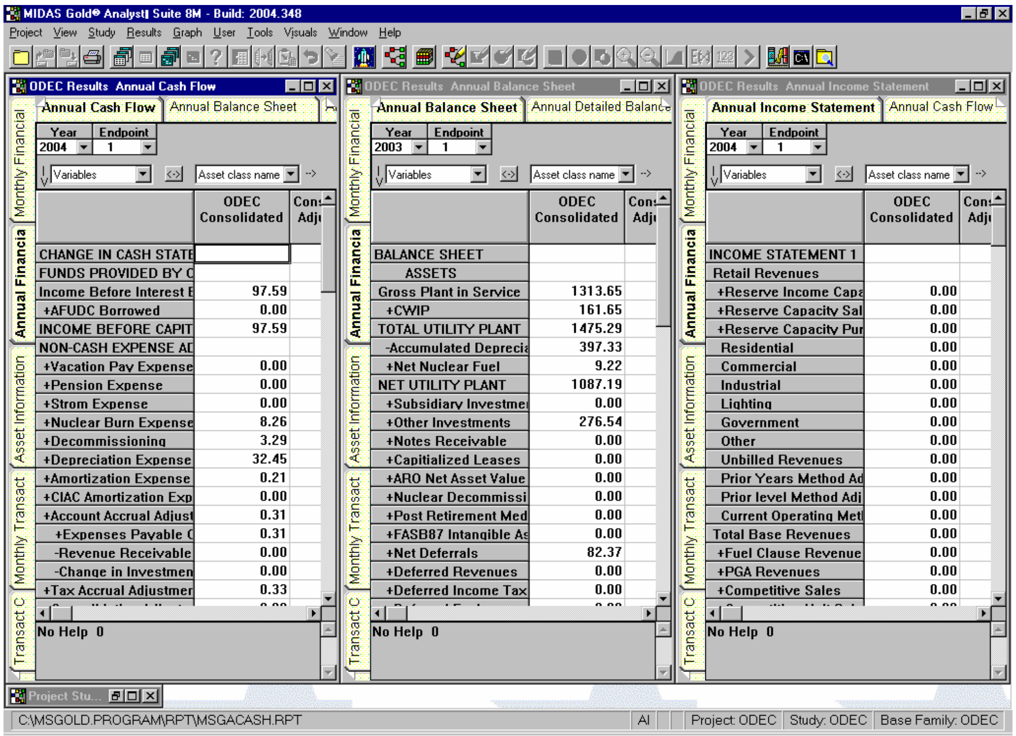
Capacity Expansion automates screening and evaluation of generation capacity expansion, transmission upgrades, strategic retirement, and other resource alternatives. It is a detailed and fast economic optimization model that simultaneously considers resource expansion investments and external market transactions. With Capacity Expansion, the optimal resource expansion strategy is determined based on an objective function subject to a set of constraints. The typical criterion for evaluation is the expected PVRR subject to meeting load plus reserves, and various resource planning constraints.

- Develop long-term resource expansion plans with type, size, location, and timing of capital projects over a 30-year horizon
- Access significant production and costing detail in results
- Include a complete range of technologies, including renewables, DSM, retirements, and transmission upgrades, today and in the future
- Consider interactions with external markets and between internal regions

Financial Module

The financial module allows the user the ability to model other financial aspects regarding costs exterior to the operation of units and other valuable information that is necessary to properly evaluate the economics of a generation fleet. The financial module produces bottom-line financial statements to evaluate profitability and earnings impacts.

Sample Reports



Source: Global Energy

Risk Module

Risk module provides users the capability to perform stochastic analyses on all other modules and review results numerically and graphically. Stochastics may be performed on both production and financial variables providing flexibility not available in other models.

Strategic Planning has the functionality of developing probabilistic price series by using a four-factor structural approach to forecast prices that captures the uncertainties in regional electric demand, resources and transmission. Using a Latin Hypercube-based stratified sampling program, Strategic Planning generates regional forward price curves across multiple scenarios. Scenarios are driven by variations in a host of market price "drivers" (e.g. demand, fuel price, availability, hydro year, capital expansion cost, transmission availability, market electricity price, reserve margin, emission price, electricity price and/or weather) and takes into account statistical distributions, correlations, and volatilities for three time periods (i.e. Short-Term hourly, Mid-Term monthly, and Long-Term annual) for each transact group. By allowing these uncertainties to vary over a range of possible values a range or distribution of forecasted prices are developed.

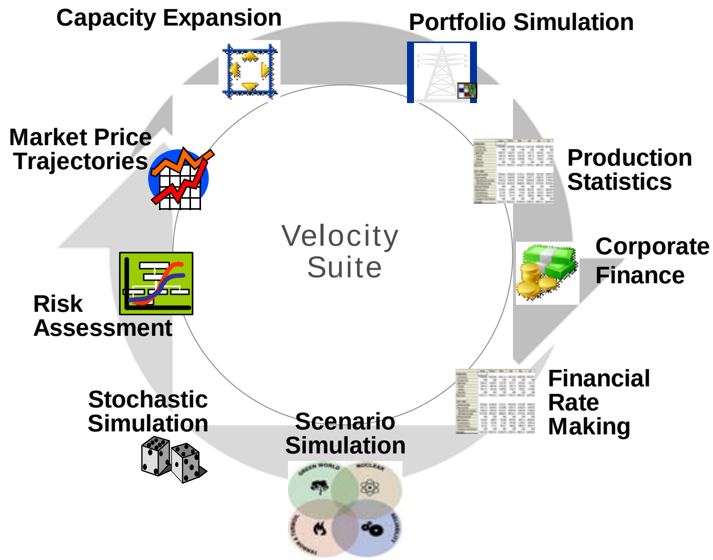
Overview of Process

Strategic Planning
Enterprise-Wide Portfolio Analysis

Strategic Planning

Challenge
Enterprise-wide solution

Best Practice
Strategic Planning combines zonal market price trajectories, portfolio analysis, corporate finance, capacity expansion, and risk assessment within a single model.



SOURCE: Global Energy

Appendix C

Combined BHP/CLF&P
Load and Resources Balance - Base
MW

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
PEAK DEMAND	583	604	615	625	643	656	671	682	695	708	721	734	747	761	774	789	803	818	833	849
EXISTING RESOURCES																				
Ben French Steam	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
Neil Simpson I	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Neil Simpson II	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81
Osage 1	11	11	11	11	11															
Osage 2	11	11	11	11	11															
Osage 3	11	11	11	11	11															
Wyodak	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67
Ben French Diesels	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Ben French CTs	100	100	100	100	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76
Lange CT	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Neil Simpson CT 1	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Wygen I	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Neil Simpson CT II	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
TOTAL EXISTING BHP/CLFP CAPACITY	507	507	507	507	483	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450
COMMITTED RESOURCES																				
Wygen II	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Happy Jack		3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
TOTAL COMMITTED RESOURCES	90	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93
TOTAL EXISTING + COMMITTED RESOURCES	597	600	600	600	576	543	543	543	543	543	543	543	543	543	543	543	543	543	543	543
PURCHASE																				
Colstrip	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	0	0	0	0
SALES																				
MEAN	20	20	20	20	20															
TOTAL RESOURCES	627	630	630	630	606	593	593	593	593	593	593	593	593	593	593	593	543	543	543	543
DESIRED PLANNING RESERVE (15%)	87	91	92	94	96	98	101	102	104	106	108	110	112	114	116	118	120	123	125	127
PEAK PLUS RESERVES	670	695	707	719	739	754	772	784	799	814	829	844	859	875	890	907	923	941	958	976
CAPACITY DEFICIT	(43)	(65)	(77)	(89)	(133)	(161)	(179)	(191)	(206)	(221)	(236)	(251)	(266)	(282)	(297)	(314)	(380)	(398)	(415)	(433)
Resource Additions																				
Wygen III			95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Block Purchase	25	50			25			25	25	50	50		25	50	50	50	25	50	25	50
Wind PPA					2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Wygen IV						95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Wind PPA						2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Combustion Turbine												67	67	67	67	67	67	67	67	67
Wind PPA															2.5	2.5	2.5	2.5	2.5	2.5
Biomass																11	11	11	11	11
Wygen V																	95	95	95	95
Wind PPA																		2.5	2.5	2.5
Combustion Turbine																		42	42	42
Wind PPA																			2.5	2.5
Total Resources	652	680	725	725	728.5	788	788	813	813	838	838	855	880	905	907.5	918.5	938.5	1008	985.5	1010.5
Net Reserves % of Total Obligation	11.84	12.58	17.89	16.00	13.30	20.12	17.44	19.21	16.98	18.36	16.23	16.49	17.80	18.92	17.25	16.41	16.87	23.23	18.31	19.02

Abbreviations

AC – Alternating current
ASAP – Appliance service and protection program
ASU – Air separation unit
AWEA – American Wind Energy Association
Basin – Basin Electric Power Cooperative
BHC – Black Hills Corporation
BHP – Black Hills Power
BIGCC – Biomass integrated gasification combined cycle
BPA – Bonneville Power Administration
Btu – British Thermal Unit
CAIR – Clean Air Interstate Rule
CAMR – Clean Air Mercury Rule
CC – Combined Cycle
C&I – Commercial and Industrial
CLF&P – Cheyenne Light, Fuel & Power
CO – Carbon monoide
CO_2 – Carbon dioxide
COP – Coefficient of Performance
CT – Combustion Turbine
CUS – Common Use System
DC – Direct current
DSM – Demand-Side Management
DUSEL – Deep Underground Science and Engineering Laboratory.
EWEB – Eugene Water & Electricity Board
FERC – Federal Energy Regulatory Commission
GED – Global Energy Decisions
Hg - Mercury
HRSG – Heat Recovery Steam Generator
HVAC – heating, ventilation, and air conditioning
IGCC – Integrated gasification combined cycle
IRP – Integrated Resource Planning or Integrated Resource Plan
kV – kilovolt
kVA – kilovolt ampere
kW – kilowatt
kWh – kilowatt-hour
LDC – Large Demand Curtailable
LIEAP – Low Income Energy Assistance Program
LNG –Liquid Natural Gas
MAPP – Mid-Continent Area Power Pool
MDU – Montana-Dakota Utilities
MEAN – Municipal Energy Agency of Nebraska
MMBtu – Millions of British Thermal Units
MW – Megawatt
MWh – Megawatt-hour
NITS – Network Integration Transmission System
NO_x – Nitrous Oxides
NPV – Net Present Value
NS – Neil Simpson
O&M – Operating and Maintenance
PPA – Power Purchase Agreement

PRB – Powder River Basin
PRECorp – Powder River Energy Corporation
PRPA – Platte River Power Authority
PV – Photovoltaics
PVRR – Present Value of Revenue Requirements
RCIA – Reserve Capacity Integration Agreement
RFP – Request for Proposal
RMATS – Rocky Mountain Area Transmission Study
RMRG – Rocky Mountain Reserve Group
RPS – Renewable Portfolio Standards or Renewable Energy Portfolio Standards
scf – Standard cubic foot
SEER – Seasonal energy efficiency ratio
SO_2 – Sulfur dioxide
UPS – Uninterruptible Power Supplies
WAPA – Western Area Power Administration
WECC – Western Electricity Coordinating Council
WRDC – Wyodak Resources Development Corporation
WREGIS – Western Renewable Energy Generation Information System
WYECIP – Wyoming Energy Conservation Improvement Program

Glossary[23]

Base Load Generation – Those generating facilities within a utility system that are operated to the greatest extent possible to maximize system mechanical and thermal efficiency and minimize system operating costs.

Base Load Unit/Station – Units or plants that are designed for nearly continuous operation at or near full capacity to provide all or part of the base load. An electric generation station normally operated to meet all, or part, of the minimum load demand of a power company's system over a given amount of time.

Biomass – A variety of organic fuel sources that can either be processed into synthetic fuels or burned directly to produce steam or electricity.

British Thermal Unit (Btu) – The standard unit for measuring quantity of heat energy, such as the heat content of fuel. It is the amount of heat energy necessary to raise the temperature of one pound of water one degree Fahrenheit.

Capacity – The maximum load that a generating unit, generating station, or other electrical apparatus can carry under specified conditions for a given period of time without exceeding approved limits of temperature and stress. For purposes of an IRP, the capacity of a generating unit is the maximum load available for dispatch, subject to forced outages, at the discretion of the operator.

Capacity Factor – The ratio of the average operating load of an electric power generating unit for a period of time to the capacity rating of the unit during that period.

Carbon Dioxide (CO_2) – A colorless, odorless, nonpoisonous gas normally part of the ambient air; fossil fuel combustion produces significant quantities of CO_2.

Coal – A black or brownish solid combustible substance formed by the partial decomposition of vegetable matter without free access of air and under the influence of moisture and often intense pressure and temperature. The rank of coal (anthracite, bituminous, sub bituminous, and lignite) is determined by its heating value.

Combined Cycle – An electrical generation device powered by fossil fuel (natural gas) that combines a combustion turbine with a steam turbine to produce electrical generation.

Combustion Turbine – An electric generating unit in which the prime mover is a gas turbine engine.

Commercial Sector – Business establishments that are not engaged in transportation or in manufacturing or other types of industrial activity (agriculture, mining, or construction).

Common Use System – The high voltage (230 kV) system in parts of Montana, Nebraska, South Dakota and Wyoming included within the construct of a joint open access transmission tariff. The parties to the tariff are BHP, Basin, and PRECorp.

Consumer Price Index (CPI) – Average change in prices over time in a fixed market basket of goods and services. The Bureau of Labor Statistics publishes CPIs for two population groups: (1) A CPI for all Urban Consumers (CPI-U) which covers approximately 80% of the total populations and (2) a CPI for Urban Wage Earners and Clerical Workers (CPI-W) which covers 32% of the total population.

Control Area – The geographical area in which a utility is responsible for balancing generation and load.

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[23] Sources include: www.blackhillspower.com/glossary.htm. www.ferc.gov/help/glossary.asp. Appendix M, PacifiCorp 2003 Integrated Resource Plan. www.mge.com/about/electric/glossary.htm. www.fsec.ucf.edu/pvt/Resources/glossry.htm.

Demand – The rate at which electric energy is delivered to or by a system, part of a system, or a piece of equipment. It is expressed in kilowatts or other suitable unit at a given instant or averaged over any designated period of time. The primary source of "demand" is the power-consuming equipment of the customers.

Demand Forecast – An estimate of the level of energy or capacity that is likely to be needed at some time in the future.

Demand-Side Management (DSM) – The planning, implementation, and monitoring of utility activities designed to influence customer use of electricity in ways that will produce desired changes in a utility's load shape (i.e., changes in the time pattern and magnitude of a utility's load). Utility programs falling under the umbrella of DSM include: load management, customer generation, and innovative rates. DSM includes only those activities that involve a deliberate intervention by the utility to alter the load shape. These changes must produce benefits to both the utility and its customers.

Dispatch, Dispatching – The operating control of an integrated electric system to: 1) assign generation to specific generating plants and other sources of supply to effect the most reliable and economic supply as the total of the significant area loads rises or falls, 2) control operations and maintenance of high-voltage lines, substations, and equipment, including administration of safety procedures, 3) operate the interconnection, and 4) schedule energy transactions with other interconnected electric utilities.

Economic Dispatch – The start-up, shutdown, and allocation of load to individual generating units to affect the most economical production of electricity for customers.

Electric Power Generation – The large-scale production of electricity in a central plant. A power plant consists of one or more units. Each unit includes an individual turbine generator. Turbine generators (turbines directly connected to electric generators) use steam, wind, hot gas, or falling water to generate power.

Electric Space Heating – Space heating of a dwelling or business establishment or other structure using permanently installed electric heating as the principal source of space heating throughout the entire premises.

Energy Efficiency Ratio (EER) – A figure of merit of air conditioning or refrigeration performance. The relative efficiency of an appliance in converting primary energy (e.g., electricity) to useful work (such as for cooling in the case of air conditioners) at the rated condition. EER (Btu/kWh) is the Btu per hour output provided by the unit, divided by the watts of electric power input. The larger the EER, the more efficient the unit.

Firm Transmission – Transmission service that may not be interrupted for any reason, except during an emergency when continued delivery of power is not possible.

Fixed Costs – Costs that do not change or vary with usage, output, or production.

Fossil Fuel Plant – A plant using coal, oil, gas, and other fossil fuel as its source of energy.

Generation – The act of producing electrical energy from other forms of energy such as thermal, mechanical, chemical, or nuclear; also, the amount of electric energy produced usually expressed in kilowatt-hours (kWh) or megawatt-hours (MWh).

Green Power, Green Pricing – Optional service choices that feature renewable fuels such as wind or solar, priced at some form of premium.

Green Tags – A currency used in the energy trade to represent the environmental benefits of renewable energy generation. Green tags are also called tradable renewable energy certificates or renewable energy credits.

Grid – The layout of the electrical transmission system or synchronized transmission network.

Heat Rate – A measure of generating station thermal efficiency, generally expressed in Btu per net kilowatt-hour. It is computed by dividing the total Btu content of fuel burned for electric generation by the resulting net kilowatt-hour generation.

Heavy Load Hours (HLH) – The time of day on a system that would be considered peak demand. Actual hours vary by individual power system.

Industrial Sector – Manufacturing industries, which make up the largest part of the sector, along with mining, construction, agriculture, fisheries, and forestry.

Interruptible Demand – The magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted by direct control of the system operator, remote tripping, or by action of the customer at the direct request of the system operator.

Kilo – A prefix used to denote 1,000 units (thousand).

Kilowatt (kW) – One kilowatt equals 1,000 watts.

Kilowatt-hour (kWh) – The basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour. One kilowatt-hour equals 1,000 watt-hours.

Light Load Hours (LLH) – The time of day on a system that would be considered off-peak demand. Actual hours vary by individual power system.

Load – Any electrical device that uses power supplied by the source.

Load Curve – A curve on a chart showing power (kilowatts) supplied, plotted against time of occurrence, and illustrating the varying magnitude of the load during the period covered.

Load Factor – The ratio of the average load in kilowatts supplied during a designated period to the peak or maximum load in kilowatts occurring in that period. Load factor, in percent, also may be derived by multiplying the kilowatt-hours in the period by 100 and dividing by the product of the maximum demand in kilowatts and the number of hours in the period.

Load Management – The management of load patterns in order to better utilize the facilities of the system. Generally, load management attempts to shift load from peak use periods to other periods of the day or year.

Load Profile – Graphical depiction of the quantity of electricity used over a specified time period.

Load Shape – The variation in the magnitude of the power load over a daily, weekly, monthly, or annual period.

Mega – A prefix used to denote 1,000,000 units (million).

Megawatt (MW) – One megawatt equals one million watts.

Megawatt-hour (MWh) – The basic unit of electric energy equal to one megawatt of power supplied to or taken from an electric circuit steadily for one hour. One megawatt-hour equals 1,000 kilowatt-hours.

Mid-Columbia – Trading hub for electricity located in central Washington near the mid-Columbia hydro projects.

Natural Gas – A naturally occurring combustible mixture of gases recovered from the earth from wells. It is composed predominantly of methane, but contains other light hydrocarbons and impurities.

Net Present Value – The discounted stream of year-by-year costs back to a common date.

Non-firm Transmission – Transmission service that may be interrupted in favor of Firm Transmission schedules or for other reasons.

Non-spinning Reserve – Off-line generating capacity that can be brought on-line within ten minutes.

Peak Demand – The greatest demand on an electric system during a prescribed demand interval in a calendar year.

Power Factor – The ratio of real power (kW) to apparent power (kVA) at any given point and time in an electric circuit. Generally, it is expressed as a percentage ratio.

Present Value of Revenue Requirements (PVRR) – The sum of year-by-year revenue requirements, discounted at an after-tax cost of capital to a common date. The PVRR takes into account the time value of money such that different projections of costs of various timing and magnitude can be evaluated on a comparable basis.

Production – The act or process of generating electric energy.

Production Tax Credit (PTC) – Tax credit available to renewable energy options as determined by the U.S. Congress.

Reliability – The guarantee of system performance at all times and under all reasonable conditions to assure constancy, quality, adequacy, and economy of electricity. It is also the assurance of a continuous supply of electricity for customers at the proper voltage and frequency.

Renewable Energy – Any source of energy that is continually available or that can be renewed or replaced. Examples include wind, solar, geothermal, hydro, photovoltaic, wood, and waste. Nonrenewable energy sources include coal, oil, and gas which all exist in finite amounts.

Renewable Energy Credit – see Green Tags.

Renewable Portfolio Standards – Statutes that require electricity suppliers to include renewables as a certain percentage of their power generation mix.

Reserve Margin – The difference between net system capability and system maximum load requirements (peak load or peak demand).

Residential Electric Service – A customer, sales, and revenue classification covering electric energy supplied for residential (household) purposes.

Seasonal Energy Efficiency Ratio (SEER) – Standard measurement of the overall efficiency of a heat pump or air conditioner during the cooling season. It is the total season heat removed (Btu) divided by the total electrical energy input (watt-hours) during the same period. The larger the SEER, the more efficient the unit.

Service Area – Territory in which a utility system is required or has the right to supply electric service to ultimate customers.

Standard cubic foot (scf) – A standard cubic foot is a measure of quantity of natural gas equal to a cubic foot of volume at 60ºF and 14.7 pounds per square inch (psia) or 1 atmosphere.

Stochastic- A stochastic process is one whose behavior is non-deterministic in that a state does not fully determine its next state.

Sub bituminous Coal – A dull black coal ranking between lignite and bituminous, it is mined chiefly in Montana and Wyoming.

Summer Peak – The greatest load on an electric system during any prescribed demand interval in the summer (or cooling) season, usually between June 1 and September 30.

Thermal – A term used to identify a type of electric generating station, capacity, capability, or output in which the source of energy for the prime mover is heat.

Transmission – The act or process of transporting electric energy in bulk from a source or sources of supply to other principal parts of the system or to other utility systems.

Transmission Access – The ability of third parties to make use of transmission facilities owned by others (wheeling utilities) to deliver power to another utility.

Transmission Grid – An interconnected system of electric transmission lines that allows power to move from any point to another over multiple paths.

Turbine – A part in some electric generators that is spun by a force of energy (e.g., air, water, steam, or a combustion engine) in order to turn the generator. It generally consists of a series of curved vanes emanating from an axis that is turned by forcing a fluid past the vanes.

Variable Costs – Costs that change or vary with usage, output, or production. Example: fuel costs.

Watt – The electrical unit of real power or rate of doing work. The rate of energy transfer equivalent to one ampere flowing due to an electric pressure of one volt at unity power factor. One watt is equivalent to approximately 1/746 horsepower, or one joule per second.

Wheeling – The transmission of electricity by an entity that does not own or directly use the power it is transmitting.

Wholesale Sales – Energy supplied to other utilities, municipals, Federal and state electric agencies, and power marketers for resale ultimately to customers.

Winter Peak – The greatest load on an electric system during any prescribed demand interval in the winter (or heating) season, usually between December 1 of a calendar year and March 31 of the next calendar year.

Black Hills Corporation

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