Direct Testimony
Jacqueline A. Sargent

Before the South Dakota Public Utilities Commission
of the State of South Dakota

In the Matter of the Application of
Black Hills Power, Inc., a South Dakota Corporation

For Authority to Increase Rates
in South Dakota

Docket No. EL09-___

September 29, 2009

## Table of Contents



## Exhibits

NONE

## I. INTRODUCTION AND QUALIFICATIONS

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Jacqueline A. Sargent. My business address is 1140 Plant Street, Rapid City, South Dakota 57702.

**Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A. I am currently employed by Black Hills Service Company, L.L.C. (Service Company), a wholly-owned subsidiary of Black Hills Corporation (Black Hills Corporation), as Director of Generation Dispatch and Power Marketing.

**Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS DOCKET?**

A. I am appearing on behalf of Black Hills Power, Inc.

**Q. WOULD YOU BRIEFLY DESCRIBE YOUR DUTIES AND RESPONSIBILITIES IN YOUR CURRENT POSITION?**

A. I am primarily responsible for ensuring that sufficient resources are available to meet the electric utility customer load obligations of the retail utilities of Black Hills Corporation – Black Hills Power, Inc. ("Black Hills Power"); Cheyenne Light, Fuel & Power Company ("Cheyenne Light"); and Black Hills/Colorado Electric Utility Company, LP ("BHCE") – through the 24 x 7 operations of our generation dispatch and power marketing department. Additionally, I am currently responsible for integrated resource planning for all the retail electric utilities.

**Q. WOULD YOU PLEASE OUTLINE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?**

A. I graduated with honors from the South Dakota School of Mines and Technology with a Bachelor of Science Degree in Electrical Engineering with an emphasis on advanced control systems in May of 1989. In May of 2002, I graduated with a Master of Science Degree in Technology Management, also from the South Dakota School of Mines and Technology. I am a registered Professional Engineer in the state of South Dakota. I have been employed by Black Hills since May of 1988 and have held a number of positions with advancing responsibilities since that time. Initially, I started with Black Hills Power as Customer Service Construction Representative and in 1990 accepted the position of Combustion Turbine Instrumentation and Control Engineer. In 1993, I moved into Black Hills Power's generation department and was the Project Engineer and Start-Up Coordinator for the Neil Simpson II coal-fired power plant project located near Gillette, Wyoming. In this role I reviewed specifications and drawings, supported construction, and organized and led the plant start-up. The project was completed six months ahead of schedule and under budget. Upon completion of this project, I moved into the role of Power Generation and Technical Support Engineer. In 1998, I accepted the position of Planning Coordinator in which I evaluated the generating resources available to best meet Black Hills Power's load obligations. In 2001, I advanced to the position of Manager of Generation Technical Services where I supported the engineering and project needs of both our wholesale generation and retail power supply departments. It was also at this time that I was first introduced to our generation dispatch and power marketing group. In 2003, I was promoted to Director of Generation Support and Resource Planning. In 2004, I was promoted to Director of Wholesale Generation and Power Marketing where I was responsible for the operation and maintenance of our wholesale generation fleet and our Black Hills Power generation dispatch and power marketing group. I became Director of Rates in December of 2005. I assumed my current position as Director of Generation Dispatch and Power Marketing in July 2007.

## II. PURPOSE OF TESTIMONY

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. My testimony starts with an overview of Black Hills Power's native load obligations and wholesale power sales contracts. I then describe reserve requirements, the Company's resource supply portfolio, economic dispatch and the impact of intermittent renewable resources, and the benefits of power marketing. Finally, I explain how Wygen III will enhance our overall supply portfolio.

## III. LOAD OBLIGATIONS AND WHOLESALE POWER SALES

**Q. WHAT LOAD OBLIGATIONS DOES BLACK HILLS POWER HAVE?**

A. Black Hills Power has both retail and wholesale load obligations. Its retail loads are located in South Dakota, Wyoming and Montana. Black Hills Power currently provides capacity and energy to three wholesale customers under long-term contracts known as Power Purchase Agreements or PPAs.

**Q. WHAT ARE THE DIFFERENCES BETWEEN RETAIL AND WHOLESALE LOAD OBLIGATIONS?**

A. Retail load obligations must be served by an electric utility, i.e., the electric utility has a duty to serve these customers. Wholesale load obligations are the result of mutually negotiated contracts between the electric utility and a third party with specified terms.

**Q. PLEASE DESCRIBE THE WHOLESALE CONTRACTS THAT BLACK HILLS POWER CURRENTLY HAS.**

A. Black Hills Power currently has four wholesale contracts, a firm power sale to the City of Gillette (Gillette), Wyoming; a sale to Montana Dakota Utilities (MDU) for their Sheridan, Wyoming load; and two unit contingent PPAs with the Municipal Energy Agency of Nebraska (MEAN).

**Q. WHAT ARE THE DETAILS OF THE GILLETTE PPA?**

A. Gillette is a municipal electric utility with no generating resources. All of its power supply needs are currently met through PPAs. Black Hills Power provides Gillette with the first 23 MW of firm capacity and associated energy under a long-term PPA that originated in 1985, which has been modified from time-to-time. As noted in the testimony of other witnesses, Black Hills Power and the City of Gillette are negotiating to convert this PPA to a cost of service or similar arrangement, and therefore the assumption of this Application is that only 52% of Wygen III will be included in the cost of service model for the customers of Black Hills Power.

**Q. PLEASE DESCRIBE THE LONG-TERM WHOLESALE CONTRACT WITH MDU.**

A. Black Hills Power entered into an all-requirements ten-year PPA with MDU that began January 1, 1997 and terminated on December 31, 2006. Black Hills Power entered into a new PPA with MDU which commenced on January 1, 2007 and extends for a term of ten years, through December 31, 2016. Pursuant to the 2007 PPA, MDU was given the option to participate in a new generating resource. MDU elected to exercise the option and acquired a twenty-five percent ownership interest in Wygen III. Black Hills Power will continue to provide capacity and associated energy to MDU for its Sheridan load in excess of its Wygen III ownership share. Additionally, Black Hills Power will provide replacement power to MDU when the Wygen III plant is unavailable due to forced or planned outages.

**Q. WHAT TYPE OF WHOLESALE CONTRACTS DOES BLACK HILLS POWER HAVE WITH MEAN?**

A. Black Hills Power previously had a 20 MW PPA with MEAN that was contingent upon the availability of the Neil Simpson II, 80 MW coal-fired power plant. This contract commenced on February 16, 2003 and extended for a term of ten years. This contract has been replaced with a new 20 MW PPA that is contingent upon the availability of the Neil Simpson II plant and Wygen III. This PPA commences with the commercial operation of Wygen III and extends through 2023.

Additionally, Black Hills Power has entered into a five-year, 10 MW unit contingent PPA with MEAN that commences with the commercial operation of Wygen III. It, too, is contingent upon the availability of the Neil Simpson II and Wygen III plants.

**Q. WHY HAS BLACK HILLS POWER ENTERED INTO WHOLESALE CONTRACTS WITH MEAN?**

A. The revenues collected by Black Hills Power under long-term wholesale contracts have been used to offset the costs incurred to serve its retail customers. The revenue from the wholesale contracts has been identified as a revenue credit in the Company's cost of service model. The addition of generating resources to a supply portfolio is "lumpy" and electric utilities grow into them over time. Making wholesale sales to third parties helps utilities offset some of the costs associated with resource additions while allowing the utility to operate facilities at higher load levels which result in greater overall efficiencies, and thus reduce costs for their retail customers.

## IV. RESERVE REQUIREMENTS

**Q. WHAT ARE RESERVE REQUIREMENTS?**

A. There are three types of reserve requirements that impact an electric utility's planning and operations:

- Planning Reserve
- Operating Reserve
- Regulating Reserve

**Q. WHY ARE RESERVE REQUIREMENTS IMPORTANT?**

A. Not only do electric utilities have to plan for ensuring that they have enough generating resources to meet their load obligations, they must plan for additional resources to manage contingency events such as planned maintenance and forced outages that make resources unavailable to meet their load obligations.

**Q. PLEASE EXPLAIN PLANNING RESERVE.**

A. Planning reserve is the amount of capacity that each electric utility must hold in reserve above its annual peak load requirements. A planning reserve margin is a percentage applied to the expected peak load to determine the minimum additional capacity that an electric utility should plan for to ensure that it will meet its peak load obligations in the event of an unforeseen loss of generating resources, extreme weather, or other unexpected conditions.

Minimum planning reserve margins can vary depending upon the requirements established by various authorities across the country and the unique aspects of different utilities, i.e., the size of a utility's largest hazard. A 15% minimum planning reserve margin is typical, however minimum planning reserve margins can range from 12% to 17.5%. It is important to note that these are minimum requirements and when electric utilities are conducting long-term resource plans, they need to establish a range for planning reserves, both a minimum and a maximum planning reserve margin, so that various resource alternatives may be analyzed. Resource additions tend to be "lumpy" and utilities expect as loads increase over time, or older units are retired, that they will "grow" into the new resource additions.

The minimum planning reserve margin must also account for operating reserve requirements. When identifying resource types to meet planning reserve requirements, it is important to consider the need for operating and regulating reserves, for example quick-start capability and flexible operating parameters.

**Q. WHAT IS OPERATING RESERVE?**

A. The North American Electric Reliability Council (NERC) defines operating reserve as "the capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve."

**Q. WHAT ARE SPINNING AND NON-SPINNING RESERVES?**

A. Spinning reserve is defined by NERC as "generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event." Non-spinning reserve is defined by NERC as "that generating reserve not connected to the system but capable of serving demand within a specified time."

**Q. HOW DOES BLACK HILLS POWER MANAGE OPERATING RESERVE REQUIREMENTS?**

A. Black Hills Power participates in a reserve sharing group, the Rocky Mountain Reserve Group (RMRG), to help minimize the amount of operating reserve that it must carry. Operating reserve is determined based upon a specific utility's system peak demand and a specific utility's largest hazard (the largest potential loss of generating resource on your system). In a reserve sharing group, members support each other's operating reserve requirements. Requirements are first established for the group, and then divided up among the members based on each member's contribution to the total, so that obligations for each member are reduced. Support from a reserve sharing group is only provided for the remainder of the hour in which an event occurs and the next full hour. After that time period, the affected member must have sufficient additional resources, covered by its planning reserve, to meet its load obligations. The amount of operating reserve required may impact the amount and type of planning reserve required.

Black Hills manages spinning reserve requirements by backing down the highest cost resources that are on-line to serve load. In the event of a reserve call, the units that have been backed down are ramped up quickly to meet the spinning reserve requirement and if necessary additional non-spinning reserves are met by bringing quick-start units on-line.

**Q. PLEASE EXPLAIN REGULATING RESERVE.**

A. NERC defines regulating reserve as "the amount of reserve responsive to Automatic Generation Control (AGC), which is sufficient to provide normal regulating margin." Regulating reserve is a part of planning reserve and although it impacts the type of resources needed, it does not impact the amount of resource that is needed to cover a planning reserve margin.

**Q. PLEASE SUMMARIZE THE IMPORTANCE OF MANAGING RESERVE REQUIREMENTS.**

A. To ensure that interruption of supply does not impact a utility's ability to serve its customers, utilities must appropriately manage reserve requirements. NERC has established specific standards requiring that utilities acquire sufficient reserves to support the overall reliability of the bulk transmission system. Failure to comply with these standards could result in significant financial sanctions and would put the interconnected electric system at risk.

As a utility conducts planning studies, reserve requirements are an important consideration not only to ensure that sufficient capacity is available, but also to ensure that its resource supply portfolio consists of a variety of supply-side options to meet both spinning and non-spinning operating reserve requirements.

## V. <u>RESOURCE PORTFOLIO</u>

**Q. PLEASE DESCRIBE THE RESOURCES THAT BLACK HILLS POWER HAS TO SERVE ITS CUSTOMERS.**

A. Black Hills Power's resource supply portfolio consists of base load, intermediate, peaking, super peaking, and renewable resources. The Company owns coal, natural gas and diesel generators which are considered conventional resources. Black Hills Power has a system-firm PPA with PacifiCorp, two Renewable Energy Sales Agreements with Cheyenne Light, and a Surplus Energy Sales arrangement with Cheyenne Light. In addition to these supply-side resources Black Hills has capacity on the Rapid City AC-DC-AC Tie (DC Tie).

**Q. WHAT ARE THE CONVENTIONAL RESOURCES IN BLACK HILLS POWER'S RESOURCE PORTFOLIO?**

A. Black Hills Power's conventional resources are listed in Table JAS-1 below:

**Table JAS – 1 Conventional Resources**

| Resource Type | Net Capacity (MW) | In Service Date |
|---|---|---|
| ***Base Load – Coal*** | | |
| Ben French | 22 | 1960 |
| Neil Simpson I | 18 | 1969 |
| Neil Simpson II | 80 | 1995 |
| Osage[1] (1,2 & 3) | 33 | 1946-1948 |
| Wygen III | 52[2] | 2010 |
| Wyodak | 67[3] | 1978 |
| Subtotal | 272 | |
| | | |
| ***Intermediate – Natural Gas*** | | |
| Lange CT | 38 | 2002 |
| Neil Simpson CT#1 | 38 | 2000 |
| Subtotal | 76 | |
| | | |
| ***Peaking – Natural Gas/Diesel*** | | |
| Ben French CTs[4] (1-4) | 80 | 1977-1978 |
| | | |
| ***Super Peaking - Diesel*** | | |
| Ben French Diesels[5] (1-5) | 10 | 1965 |
| | | |
| Total | 438 | |
| Note 1 – each unit is rated 11 MW<br>Note 2 – BHP share of 100 MW unit<br>Note 3 – BHP share of 335 MW unit<br>Note 4 – each unit is rated 20 MW<br>Note 5 – each unit is rated 2 MW | | |

**Q. WHAT IS THE DIFFERENCE BETWEEN BASE LOAD, INTERMEDIATE, PEAKING AND SUPER PEAKING RESOURCES?**

A. Resource type designations are based on the overall costs of the various resource types. Base load resources typically have higher initial installed costs (capital costs) and lower fuel-related costs. Intermediate resources have medium installed costs and medium fuel-related costs. Peaking resources have lower installed costs and higher fuel-related costs, and super peaking resources typically have the lowest installed costs and the highest fuel-related costs.

Resources are utilized, or dispatched, based upon their fuel costs. Because base load resources typically have the lowest fuel-related costs they are operated at very high output levels, full load output, or base loaded. Intermediate resources typically have the next highest fuel-related costs and as load increases and once all of the base load resources have been fully dispatched, intermediate resources are turned on. As load continues to grow, peaking resources are operated. Finally, when loads reach the highest peak levels, super peaking resources are utilized.

Base load resources are always needed and are therefore operated at very high capacity factors, while super peaking resources are run very little and typically have very low capacity factors.

**Q. PLEASE DESCRIBE BLACK HILLS POWER'S SYSTEM FIRM PPA WITH PACIFICORP.**

A. The PacifiCorp PPA is for 50 MW of system firm capacity and up to an 80 percent load factor of the associated energy. The capacity pricing is based upon

PacifiCorp's annual levelized fixed costs of the Colstrip coal-fired facilities as adjusted for capital improvements and other specified fixed annual charges. The PPA energy cost tracks changes in the operating cost of PacifiCorp's share of the Colstrip coal-fired facilities. It is therefore referred to by Black Hills Power as the "Colstrip Contract." The Colstrip Contract expires in 2023. There is also a PacifiCorp transmission agreement associated with the Colstrip Contract, a firm point-to-point transmission service agreement to deliver the Colstrip Contract energy to the Black Hills Power system.

**Q. WHAT RENEWABLE ENERGY SALES AGREEMENTS DOES BLACK HILLS POWER HAVE WITH CHEYENNE LIGHT?**

A. Cheyenne Light has two PPAs to purchase wind energy. One PPA is for 29.4 MW of wind energy and associated renewable energy credits (RECs) from Happy Jack Windpower, LLC (Happy Jack) and the other is for 29.4 MW of wind energy and associated RECs from Silver Sage Windpower, LLC (Silver Sage). Black Hills Power has subsequently entered into two Renewable Energy Sales Agreements (RESAs) with Cheyenne Light in which 50% of the Happy Jack wind energy is sold to Black Hills Power and 66.67% of the Silver Sage wind energy is sold to Black Hills Power. Black Hills Power pays Cheyenne Light the same rate, without markup, that Cheyenne Light pays under its respective PPAs with Happy Jack and Silver Sage.

**Q. WHY DID BLACK HILLS POWER AGREE TO PURCHASE WIND ENERGY AND THE ASSOCIATED RECS FROM CHEYENNE LIGHT?**

A. This arrangement allows both Black Hills Power and Cheyenne Light customers to benefit through the coordination of generation and sharing of wholesale renewable energy generated by third-party suppliers at a market price. Happy Jack and Silver Sage are located in Cheyenne, Wyoming and the average capacity factor of the facilities is expected to be greater than 35%. Additionally, the facilities are located within Western Area Power Administrations (Western) control area and Western is able to provide cost effective regulation service to help manage the intermittent nature of wind resources.

**Q. PLEASE EXPLAIN THE SURPLUS ENERGY SALES ARRANGEMENT BETWEEN BLACK HILLS POWER AND CHEYENNE LIGHT.**

A. Cheyenne Light's loads and resources are dispatched under a Generation Dispatch and Energy Management Agreement (GDEMA) in place with Black Hills Power. Cheyenne Light has excess or surplus energy beyond what it needs to serve its customer load obligations. Under the GDEMA, Black Hills Power accepts this surplus energy from Cheyenne Light at a predetermined rate, much like a put. If this set energy price fits within its economic dispatch parameters, Black Hills Power will use this energy to serve its customers. If not, Black Hills Power takes the energy to the market. Cheyenne Light customers benefit because it keeps their least cost resources fully loaded and Black Hills Power customers benefit from having additional access to economic energy.

**Q. HOW DOES THE DC TIE FIT INTO THE BLACK HILLS POWER RESOURCE SUPPLY PORTFOLIO?**

A. The United States is separated into three separate electrical interconnects, the western interconnect, the eastern interconnect and ERCOT, or Texas. The only physical means to transfer energy between these interconnects is with the use of AC-DC-AC ties which take alternating current (AC) from one interconnect, convert it to direct current (DC) and then convert the DC back to AC at the same frequency as the second interconnect, basically compensating for the inherent frequency variations which occur between interconnects. Black Hills Power's load is located within the western interconnect. The DC Tie provides Black Hills Power access to additional energy markets within the eastern interconnect.

**Q. DOES BLACK HILLS POWER HAVE ANY ADDITIONAL RESOURCES THAT IT CAN UTILIZE TO MEET ITS LOAD OBLIGATIONS?**

A. Yes, Black Hills Power has a Reserve Capacity and Integration Agreement (RCIA) with PacifiCorp. The RCIA allows Black Hills Power to count the Ben French combustion turbine capacity as 100 MW. This is important because the output of these units is reduced at higher ambient temperatures. Those higher temperatures occur in the summer months of June, July and August coinciding with Black Hills Power's peak load periods. The RCIA agreement gives Black Hills Power the right to call on PacifiCorp for any of the 100 MW that cannot be generated by the Ben French combustion turbines to meet operating reserve requirements. This agreement terminates on June 30, 2012.

## VI. ECONOMIC DISPATCH

**Q. WHAT IS ECONOMIC DISPATCH?**

A. Economic dispatch is the methodology of meeting load obligations with resources with the lowest dispatch cost. Dispatch costs are determined based upon resource efficiency and fuel supply costs. Resource efficiency, or heat rate, is measured in Btu/kWh and fuel costs in $/mmBtu. As an example, if one resource has a heat rate of 12,000 Btu/kWh and a fuel supply cost of $1.00 per mmBtu, then its dispatch cost is $12/MWh or $0.012/kWh. If another resource has a heat rate of 10,000 Btu/kWh and a fuel supply cost of $3.00 per mmBtu, then its dispatch cost is $30/MWh or $0.03/kWh. Under economic dispatch, the first resource would be fully utilized to serve load before turning on the next resource so that customers are served with the least cost resources. Additionally, using the example above, if energy can be purchased in the market for less than $30/MWh that energy would be purchased before the $30/MWh resource is dispatched.

**Q. ARE THERE ANY OTHER FACTORS THAT IMPACT ECONOMIC DISPATCH?**

A. Yes. Examples of other factors that may impact economic dispatch include: loss of a low cost resource due to a forced outage, integrating intermittent resources such as wind, requirements to purchase blocks of energy to meet capacity shortfalls, and must run directives from reliability coordinators or transmission providers.

Forced outages are unplanned events that cause a generating unit to trip off-line, removing it from the supply portfolio. When a low cost unit trips, it typically is replaced with a higher cost resource, which then increases the average system dispatch costs.

Intermittent resources such as wind are not dispatchable and energy by contract must be taken when it is available. If such energy is at a higher cost than other resources, lower cost resources need to be backed down in order to make room for the wind and the result is that the overall average system dispatch costs increase.

If, during peak periods, there is not enough capacity to meet the sum of the load obligations plus a minimum reserve margin, additional firm blocks of energy must be purchased from the market. A firm block of energy is just that, so many MWh each hour for a specified period of time. Firm blocks of energy cannot be dispatched, so room has to be made for that energy every hour. If the load does not materialize, other lower cost resources may need to be backed down such that the firm energy can be utilized. This series of events increases the average system dispatch cost. This typically happens during periods when new resources are being constructed or if there is a catastrophic failure of one of the generating units.

Finally, must run generation is generation that must be on line regardless of the load level, usually to support operation of the system in specific locations. The must run generation may not be the lowest cost resources available. Reliability coordinators and transmission operators are responsible for the reliable operation of electric transmission systems. Depending on certain loading conditions, line outages or other events the integrity of the transmission system may require that generating units be operating at various locations within the transmission system. If these resources have a high dispatch cost, they will increase the overall system average dispatch costs.

**Q. HOW DOES BLACK HILLS POWER EMPLOY ECONOMIC DISPATCH TO SERVE ITS CUSTOMERS?**

A. Black Hills Power's generation dispatch and power marketing department looks at annual, seasonal, monthly and day-ahead load forecasts and resource availability to meet load obligations. On an hour-by-hour basis, resources are matched with load obligations. If Black Hills Power's customer loads can be served more economically from purchased power than from using generating resources, then purchases are arranged with counterparties that can deliver to Black Hills Power's transmission system. If excess resources are available and access to markets can be obtained, any of the excess may be sold for the prevailing market price. Black Hills Power's electric load is primarily served by its coal-fired generating facilities in South Dakota and Wyoming and by the 50 MW Colstrip Contract. As the Company's most economical generation, the costs of these resources are attributed first – after the costs of renewable resources – to the utility customer load. Loads above this capacity are served by economy market purchases or the use of combustion turbine and diesel resources – whichever is the most cost-effective.

**Q. YOU PREVIOUSLY MENTIONED VARIOUS FACTORS THAT IMPACT ECONOMIC DISPATCH, HOW DOES BLACK HILLS POWER PLAN TO MANAGE THESE IMPACTS GOING FORWARD?**

A. Non-dispatchable intermittent resources such as wind are the most difficult to manage. Utilities cannot control these resources and are required to accept the energy they generate whenever it is available. The two Renewable Energy Sales Agreements that Black Hills Power has with Cheyenne Light support Black Hills Power's ability to help meet the State of South Dakota's objective of achieving a target of a ten percent (10%) renewable energy portfolio by 2015. Therefore, to ensure economic dispatch of other resources, Black Hills Power will treat renewable energy as zero cost energy for purpose of dispatch and the associated energy will be the first resource attributed to serving load.

**Q. HOW WILL THIS IMPACT CUSTOMERS?**

A. Renewable energy is often not a least cost energy resource and therefore this method of economic dispatch may increase costs for customers. However, it will promote the use of renewable resources by allowing utilities to recoup their costs and further support South Dakota's objective to achieve a ten percent renewable energy goal.

**Q. ARE THERE ADDITIONAL IMPACTS TO ECONOMIC DISPATCH THAT BLACK HILLS POWER PLANS TO ADDRESS?**

A. Yes, additional impacts to economic dispatch that Black Hills Power plans to address include block energy purchases and must run generation requirements.

When available, block energy purchases can help a utility to delay, for a short period of time, constructing the next needed resource addition. However, this energy must be purchased in blocks of firm energy. These blocks of firm energy are not dispatchable and the utility must incorporate them into its supply portfolio as a specific amount of energy for a specific time period. If a utility has a capacity deficit, it must acquire this type of energy or it must construct a capacity resource to meet its deficit. If not, it would put the bulk electric system at risk, be subject to load shedding as required by the other interconnected utilities, and face substantial sanctions by NERC.

Black Hills Power is changing its economic dispatch methodology as follows: block energy purchases will be dispatched by Black Hills Power to serve load after renewable resources. This supports the economic dispatch of remaining resources after renewable resources and block energy purchases have been fully utilized to serve load.

**Q. WHAT WILL THE IMPACT BE TO CUSTOMERS FOR THESE CHANGES TO BLACK HILLS POWER'S DISPATCH METHODOLOGY?**

A. Block energy purchases to meet customer loads and minimum reserve requirements are purchased six to twelve months prior to the actual need to ensure that sufficient resources have been secured to meet load obligations plus a minimum reserve margin. Therefore, when the time comes to receive the energy from block purchases, the market price of economy energy may be lower than what was paid for the block energy or it may be significantly higher. If the block energy is not dispatched to load it may negatively impact how the remaining resources can be economically dispatched with a resulting increase in costs to serve customers.

## VII. BENEFITS OF POWER MARKETING

**Q. WHAT IS THE BENEFIT OF HAVING THE GENERATION DISPATCH AND POWER MARKETING DEPARTMENT?**

A. Black Hills Power's customers experience two primary benefits related to having the generation dispatch and power marketing department. First, the department is able to keep resources fully loaded so that they operate at optimum efficiency, which results in overall lower costs. Second, this group has market presence and knowledge and therefore has the ability to secure the least cost, most economical resources for serving load. Being engaged in the market, having a market presence, equates to getting the best market prices, which provides benefits to Black Hills Power's customers.

**Q. ARE BLACK HILLS POWER'S GENERATION FACILITIES UTILIZED IN CONJUNCTION WITH POWER MARKETING ACTIVITIES?**

A. Yes, when load is less than the resources available, any excess energy is sold into the market if such is economically feasible. As stated previously, this allows facilities to be fully loaded and thus operated more efficiently which results in an overall lower cost per kWh to our customers. For example, the previous resource described with a heat rate of 12,000 Btu/kWh at full load may have a part load heat rate of 16,000 Btu/kWh – a difference of 4,000 Btu/kWh. At a fuel cost of

$1/mmBtu, that increase in heat rate equates to a $4/MWh increase in dispatch cost for that unit.

**Q. ARE YOU ABLE TO TRACK WHICH ENERGY IS USED TO SERVE LOAD OBLIGATIONS AND WHICH ENERGY IS USED TO SERVE POWER MARKETING ACTIVITY?**

A. Yes. Black Hills Power has systems and procedures to track the cost of all sales and resource dispatching to monitor our performance and economic decisions for serving both native customer load and generating power marketing margins. These systems and procedures assure Black Hills Power's management that customer loads are served first and with the most economical resources and that any power marketing sales are not made at the expense of Black Hills Power's utility customers. This assurance is accomplished primarily through the accounting and scheduling system that serves the utility. The system identifies the lowest cost energy that is being purchased or utilized, on an hourly basis (24 hours per day, 7 days per week), and attributes that cost to the utility customers.

**Q. WOULD YOU GIVE AN EXAMPLE?**

A. Assume that at a specific time of day, Black Hills Power is utilizing its coal-fired resources and its combustion turbines, is receiving energy from its Colstrip Contract, and is also purchasing energy from the market. If the resource with the lowest dispatch cost at that point in time is the coal-fired generator source, that cost is attributed to the utility customers. As the aggregate of resources necessary to serve the Black Hills Power retail and firm wholesale contracts is totaled, the combined most economical blend is assigned to the customer load cost first and any cost above the cost to serve customer load is assigned to any ongoing short-term power marketing sales.

**Q. WHY DOES BLACK HILLS POWER HAVE THAT PRACTICE?**

A. Black Hills Power is a utility company with its primary mission to serve its utility customers as efficiently, reliably, and economically as possible, while still maintaining an acceptable return on its investment.

**Q. DOES THE GENERATION DISPATCH AND POWER MARKETING DEPARTMENT PROVIDE DISPATCH AND POWER MARKETING SERVICES FOR OTHER UTILITY AFFILIATES?**

A. Yes, in addition to providing services to Black Hills Power, the generation dispatch and power marketing department provides dispatch and marketing services to Cheyenne Light, Black Hills Wyoming and Black Hills Colorado Electric. The same group of people is responsible for managing the loads and resources for all three of Black Hills Corporation's electric utilities so that these efforts are not duplicated. Additionally, this group will provide similar services to MDU for dispatching its share of Wygen III. The costs for these services are then shared by all of the parties based on a capacity ratio share of resources that the department manages for each party. This amounts to significant cost savings for all parties. Rather than each party having to staff and manage separate dispatch centers, each pays a portion of the costs associated with one department.

## VII. CLOSING

**Q. HOW WILL THE ADDITION OF WYGEN III BENEFIT BLACK HILLS POWER'S CUSTOMERS?**

A. Wygen III provides needed capacity to assure customer load obligations will be met now and into the future. When combined with existing resources, Wygen III's low dispatch cost will help stabilize customer rates over the long-term by minimizing the cost impacts associated with volatile natural gas markets.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes, it does.