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IDAHO PUBLIC
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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE	)	
APPLICATION OF ROCKY	)	**CASE NO. PAC-E-10-07**
MOUNTAIN POWER FOR	)	
APPROVAL OF CHANGES TO ITS	)	**Direct Testimony of John A. Cupparo**
ELECTRIC SERVICE SCHEDULES	)	
AND A PRICE INCREASE OF $27.7	)	
MILLION, OR APPROXIMATELY	)	
13.7 PERCENT	)	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-10-07

May 2010

Q. Please state your name, business address and present position with Rocky Mountain Power ("Company").

A. My name is John A. Cupparo. My business address is 825 NE Multnomah, Suite 1600, Portland, Oregon 97232. My position is Vice President of Transmission.

Qualifications

Q. Please describe your educational and professional background.

A. I hold a Bachelor of Science degree in Computer Information Systems from Colorado State University. My experience spans 24 years in the energy industry, including oil, gas and electric utilities. The majority of my experience has been in information technology supporting natural gas pipelines, energy commodity trading and end-to-end electric utility operations. I have also provided support for outage management, customer service, transmission scheduling and regulatory issues. I joined PacifiCorp as Chief Information Officer in September 2000 and assumed my current position in August 2006. I am responsible for all aspects of PacifiCorp's main grid transmission investment strategy, customer service, main grid planning, contract administration and tariff management. I am the co-chair of the Northern Tier Transmission Group ("NTTG"), which coordinates transmission planning, transmission expansion, and project reviews with sub-regional and regional planning organizations within the Western Electricity Coordinating Council ("WECC"). I am also an elected class one voting member (transmission owner class) of the WECC Board of Directors. As a member of the WECC Board of Directors, I participate with other WECC members in overseeing WECC's activities, including defining standards and policies to ensure reliability of the western electric grid. I also hold a position on WECC's Transmission Expansion Planning Policy Committee and the Reliability Coordination Committee.

Purpose and Overview of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide information on the Populus to Terminal transmission line, which is the first segment of the Energy Gateway transmission expansion plan to be constructed, and for which the Company is seeking cost recovery in this case. The Populus to Terminal transmission line, and subsequent investments within the Company's long-term, comprehensive transmission expansion plan known as "Energy Gateway," satisfy multiple objectives for efficiently operating a six-state transmission system. The immediate benefit to PacifiCorp's customers in Idaho and elsewhere is a significant investment to enhance reliability and improve transfer capability within the existing system, followed over time by incremental capacity, which is key to unlocking rich resource hubs. Specifically, my testimony:

- Provides an overview of the Company's transmission system;
- Outlines the Company's transmission expansion plan and provides details on the Populus to Terminal line segment of this plan;
- Demonstrates that the Populus to Terminal transmission investment is beneficial to customers; and
- Describes how the Populus to Terminal transmission investment helps satisfy a commitment the Company made as part of the MidAmerican Energy

Holdings Company ("MEHC") transaction.

Company witness Mr. Darrell T. Gerrard provides testimony with additional details and technical information on the Populus to Terminal transmission investment.

Q. What investment related to the Populus to Terminal transmission line is included in the revenue requirement of this rate case?

A. The estimated cost of the Populus to Terminal transmission line to be placed in-service in the test period of this rate case is approximately $802 million. This line is one of the first components of the Company's comprehensive plan related to investment in the transmission system. The Populus to Terminal transmission line is a new double-circuit 345 kilovolt ("kV") transmission line from the Populus substation near Downey, Idaho to the Terminal substation in Salt Lake City, Utah, which will be placed in service in two phases. The first phase from the Ben Lomond substation (near Ogden, Utah) to the Terminal substation was placed in service in March 2010, and the second phase from the Populus substation to the Ben Lomond substation will be in service by November 30, 2010. The testimony of Company witness Mr. Steven R. McDougal describes the revenue requirement calculations associated with this transmission investment.

Overview of PacifiCorp's Transmission System

Q. Please briefly describe PacifiCorp's transmission system.

A. PacifiCorp owns and operates approximately 15,800 miles of transmission lines ranging from 46 kV to 500 kV across multiple western states. As of December 31, 2009, PacifiCorp's total-company net transmission plant in service was approximately $2.2 billion. PacifiCorp is interconnected with more than 80 generation plants and 15 adjacent control areas at approximately 124 points of interconnection. To provide electric service to its retail and wholesale customers, PacifiCorp owns or has interest in generation resources directly interconnected to its transmission system with a system peak capacity of approximately 12,131 MW. This generation capacity includes a diverse mix of resources including coal, hydro, wind power, natural gas simple cycle and combined cycle combustion turbines, and geothermal.

Q. **Please describe the availability of existing transmission capacity on the system.**

A. The Company's 2008 Integrated Resource Plan ("IRP"), which was filed with the Idaho Public Utilities Commission ("Commission") in May 2009 and acknowledged in September 2009, identifies the need for investment in major new transmission facilities to provide ongoing reliability and to meet the forecast loads of PacifiCorp's customers. The IRP analysis is performed by evaluating loads and resource requirements over a twenty-year period.

PacifiCorp's existing transmission system, as well as the transmission grid across the western region, is severely constrained, and numerous regional study groups have identified the pressing need for investment in new transmission infrastructure. These studies are described in more detail later in my testimony.

Additionally, new federal standards that mandate increased transmission system reliability along with PacifiCorp's recent operational experience require additional investments in PacifiCorp's transmission system to ensure the

Company has the capability to provide reliable transmission service under expected operating conditions, and to maintain the transmission system capacity necessary to deliver network load service and contractual point-to-point commitments.

Increasing PacifiCorp's transmission capacity will also provide the opportunity for the Company to make off-system energy purchases or sales, which are used to reduce overall power supply costs. Lastly, additional transmission capacity provides the Company added flexibility in the location and use of generating reserves and flexibility to perform routine maintenance on transmission lines with minimal risk, all of which reduce operating costs to customers.

Q. **Please generally describe how PacifiCorp's transmission expansion plan became a component of IRP.**

A. As part of MEHC's acquisition of PacifiCorp, the Company performed a review of the IRP process. From that review, the Company determined there was a need for a long-term transmission investment strategy to support the long-term resource needs of customers. Historically, IRPs were relatively silent on transmission investments, assuming transmission would follow generation investments. Given the long-term needs of customers and load growth, existing transmission system constraints, the time required, and the challenges associated with designing, permitting and constructing transmission lines, transmission is now a key element of the Company's IRP. This shift in focus is evidenced by the inclusion of Energy Gateway in PacifiCorp's 2008 IRP.

Overview of Energy Gateway Transmission Expansion

Q. Please generally describe Energy Gateway.

A. Energy Gateway is a comprehensive transmission plan based on taking immediate actions while keeping long-term needs in focus. Energy Gateway will enhance reliability, reduce transmission system constraints and improve the flow of electricity to PacifiCorp's customers. The Energy Gateway plan is comprised of eight interrelated and interdependent transmission segments as outlined in Exhibit No. 33. The eight line segments within Energy Gateway are grouped and labeled as part of Gateway Central, Gateway West, Gateway South and the Westside. The Populus to Terminal line segment is within Gateway Central. When fully implemented, Energy Gateway will traverse six states, numerous communities, counties and significant areas of federally-administered lands and will add approximately 2,000 miles of new transmission lines to PacifiCorp's transmission system. Due to the interconnected nature of PacifiCorp's transmission network, investments may be required at other facilities in order to maximize the effectiveness and efficiency of the network. For Energy Gateway, the eight identified transmission segments provide specific capabilities, but they also support other transmission segments to enhance the benefits of Energy Gateway.

Q. Please describe Gateway Central relative to the overall Energy Gateway plan.

A. Gateway Central includes the Populus to Terminal, Mona to Oquirrh and Oquirrh to Terminal transmission lines that will improve reliability and transfer capability to the existing system and also establish the necessary electrical interconnection between Gateway West and Gateway South. The Gateway West and Gateway South segments, when complete, will be the first 500 kV lines to be installed in Wyoming, southeast Idaho and Utah. Gateway Central will provide an essential reliability backbone allowing Gateway West and Gateway South to operate at a higher reliability and at an overall higher capacity than would otherwise be possible without the Gateway Central interconnection. This investment will not only add incremental transmission capacity, but will also strengthen PacifiCorp's overall system while supporting future generation resource development to benefit all PacifiCorp customers.

As described earlier in my testimony, the Populus to Terminal transmission segment is comprised of two smaller sections, which in total extend 135 miles from the new Populus substation near Downey, Idaho, south to the existing Terminal substation near the Salt Lake International Airport west of Salt Lake City, Utah. The Populus to Terminal transmission segment is a key element of the Energy Gateway's Gateway Central. Populus to Terminal is designated as "Segment B" within Gateway Central in Exhibit No. 33.

Populus to Terminal Transmission Investment

Q. Please describe the Populus to Terminal transmission investment in more detail.

A. Exhibit No. 34 is a map of the Populus to Terminal transmission line segment. Ben Lomond to Terminal is the southern section and is highlighted in red on the map. Populus to Ben Lomond is highlighted in yellow, green and blue on the map. Phase I from Ben Lomond to Terminal was the first section of the Populus to Terminal line to be completed and became operational in March 2010. Phase II from Populus to Ben Lomond is scheduled to be complete and in service by November 30, 2010.

Q. **Please describe the findings of the regional transmission studies related to Energy Gateway and specifically the Populus to Terminal segment.**

A. Over the past decade, numerous studies were completed documenting the need for new transmission in the western United States. As early as 2002, the Department of Energy National Transmission Grid Study identified the Wyoming-Idaho interface as a major constrained interface. The study also found that under optimal conditions, the Wyoming-Northern Utah interface is congested during 50 percent or more of the hours during the year.1

In 2004, the Rocky Mountain Area Transmission Study reached similar conclusions and recommended expansion of the 345 kV transmission lines connecting the Company's Bridger substation to points south and west as critically needed improvements.2 In addition, the U.S. Department of Energy's 2006 National Electric Transmission Congestion Study ("DOE Congestion Study") identified several constrained transmission paths in the west as shown in Exhibit No. 35, including lines used to deliver electricity from generation plants in Wyoming to loads in the west.3 Specifically, the DOE Congestion Study

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1 National Transmission Grid Study at pp. 15, 18. A full copy of this report is available at http://www.pi.energy.gov/documents/TransmissionGrid.pdf.
2 Rocky Mountain Area Transmission Study at Chapter 3-2, which shows the Bridger expansion as a critical expansion area from Wyoming to Northern Utah and Wyoming to Idaho. The full report is available at http://psc.state.wy.us/htdocs/subregional/Reports.htm.
3 See DOE Congestion Study at pp. 31-35. The transmission constraints identified in this study were identified by reviewing recent transmission studies such as those conducted by WECC and Seams Steering Group-Western Interconnection. The full report is available at http://nietc.anl.gov/documents/docs/Congestion_Study_2006-9MB.pdf.

illustrated that expansion of the Bridger West transmission facility is critical for relieving congestion from Wyoming to northern Utah, and Wyoming to Idaho.[4]

Similarly, the Western Interconnection 2006 Congestion Assessment Study, which was issued by the DOE Western Congestion Analysis Task Force, identified areas of congestion in the Rocky Mountain States and projected that based on 2005 load and resource forecasts and a production model, many of the paths associated with the various segments of the Energy Gateway Project would be heavily congested.[5]

Reports initiated by the Western Governors' Association ("WGA") also show certain paths in PacifiCorp's service territory (including the Populus to Terminal segment) as constrained.[6]

In addition, the DOE sponsored a study through Idaho National Laboratories to assess the economic impact of not building transmission. While the report focused on assessing the economic impact on the Pacific Northwest, it also provides discussion and support for the "hub and spoke" design which is similar to the Energy Gateway model for connecting resource areas to load. The report also describes the interconnected nature of transmission as being geographically dispersed, yet interdependent.[7]

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4 Such expansion is addressed by the Segment E portion of the Project.

5 A full copy of this study is available at http://www.oe.energy.gov/DocumentsandMedia/DOE_Congestion_Study_2006_Western_Analysis.pdf.

6 The full report is available at http://www.westgov.org/wga/initiatives/cdeac/TransmissionReport-final.pdf.

7 See The Cost of Not Building Transmission: Economic Impact of Proposed Transmission Line Projects for the Pacific Northwest Economic Region. Full report is available at http://www.pnwer.org/Portals/0/Presentations/2008%20summit/Cost%20of%20not%20building%20transmission.pdf.

Existing NTTG sub-regional transmission planning studies, conducted in accordance with the Federal Regulatory Energy Commission's ("FERC") Order 890-A, show overall benefits to the region as a result of PacifiCorp's proposed Energy Gateway.

PacifiCorp filed for incentive rates with FERC on July 3, 2008, which is analogous to a need determination. FERC granted the Company incentive rate treatment, and of equal importance, FERC issued a 4-0 decision stating:

> [W]e find that PacifiCorp has adequately demonstrated that the Project (with the exception of segment A) will ensure reliability and reduce transmission congestion... We find that segments B through H of the Project would establish for the first time a backbone of 500 kV transmission lines in PacifiCorp's Wyoming, Idaho and Utah regions. This would provide a platform for integrating and coordinating future regional and sub-regional electric transmission projects being considered in the Pacific Northwest and the Intermountain West, connecting existing and potential generation to loads in an efficient manner, thus reducing the cost of delivered power. Also, the Petition cites the 2006 DOE National Electric Transmission Congestion Study and the 2004 Rocky Mountain Area Transmission Study in stating that that proposed Project will reduce congestion or maintain reliability in the Western Interconnection. Additionally, the project would establish a direct link between PacifiCorp's east and west control areas, providing numerous benefits including increasing transfer capability, reducing the need for curtailments, and reducing transmission congestion.[8]

Commissioner Suedeen Kelly echoed PacifiCorp's Petition in her concurrence stating,

"... while Segments B and C provide a variety of benefits when considered in isolation, they also enable PacifiCorp to achieve the planned transfer capability

8 PacifiCorp, 125 FERC ¶ 61,076 (2008) at p. 10, (Exhibit No. 36).

rating of subsequent segments." [9] A complete copy of the report is provided as Exhibit No. 36.

As noted in Exhibit 33, Segment B is Populus to Terminal and Segment C is Mona to Oquirrh.

Q. What factors does the Company consider before building new transmission?

A. The Company considers several factors before building new transmission facilities including:

- Current and future forecasts for demand and energy required from existing and new resources to new and existing loads. These considerations are addressed in the Company's 2008 IRP including demand-side management and energy conservation programs.
- Alternatives, including building local generation near load, and/or energy market purchases.
- The Company's ability to use existing land rights, existing rights-of-way, and corridors.
- The use of upgrades to increase operability and reliability of existing transmission lines and substations.
- The Company's ability to maximize the capacity and capabilities of existing facilities.

Because prudent transmission investments are typically large scale to maximize efficiencies and gain economies of scale, the benefits are realized over the long term.

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9 Exhibit No. 36, p. 25.

Q. Once the decision is made to invest in new transmission, what is the process for getting it built?

A. Once the decision is made to invest in new transmission, capacity sizing of the transmission line is taken into consideration to balance current and future needs. Constructing long, linear facilities such as transmission lines requires a long lead time and is an extensive process. Siting, permitting and constructing new transmission can take up to seven years and potentially involves acquiring new rights-of-way and permits from local, state and federal agencies. Maximizing the transmission capacity placed in approved corridors is a critical consideration to minimize disruption to communities and landowners. The Company also considers design and routing to minimize the environmental, visual and human impacts.

Q. What land rights and permits were acquired for Populus to Terminal?

A. The Company holds all of the necessary land rights, either in easements or fee ownership, between the Populus substation and the Terminal substation. However, the Company was required to secure numerous permits and approvals from federal and state entities, such as:

- The U.S. Army Corps of Engineers required permits for construction within jurisdictional wetlands.
- The Federal Aviation Administration required aviation permits for construction of Populus to Terminal near Salt Lake International Airport.
- The Utah and Idaho Departments of Transportation required permits from railroad companies for roadway crossings, overhangs and easements.

- The U.S. Bureau of Reclamation required a crossing permit for the Ogden-Brigham canal.
- The Utah Department of Wildlife Resources required a permit for crossing Wildlife and Waterfowl Management Areas, with a separate agreement required for construction within the Legacy Nature Preserve.
- The U.S. Fish & Wildlife Service, U.S. Forest Service and Utah State Historical Preservation Office also required various wildlife & environmental habitat permits.

Q. **What permits were required by local governmental authorities for the construction of Populus to Terminal?**

A. The Company holds a franchise agreement with each municipality and county within the route that grants the necessary rights for the construction of the Populus to Terminal transmission line. In addition, the Company secured conditional use and/or special use permits from all Idaho and Utah cities and counties, based on each community's requirements. The Utah Public Service Commission ("Utah Commission ") and the Idaho Public Utilities Commission ("Idaho Commission") issued Certificates of Public Convenience and Necessity in 2008. The Idaho Commission Order states:

> Thus, Staff believes that the necessity of the Project should be viewed in conjunction with energy resources that are constructed, under way or planned. PacifiCorp elected to undergo a transmission upgrade as part of its preferred resource portfolio of an additional 2,000 MWs of renewable resources by 2013 in the Company's 2007 IRP. A significant portion of these renewable resources will be located in Wyoming. Staff then listed more than 500 MWs of renewable resources that are either under construction or in the final stage of development. In response to a Staff data request, PacifiCorp provided four alternatives that it rejected

> because the Company did not believe that these would provide sufficient capacity for the new resources. Staff agreed that the Project was necessary in order for the Company to continue to provide reliable service from these new resources to growing load centers. 10

In its Order, the Utah Commission noted several parties concurred with the need, including the Division of Public Utilities:

> The Division states it has examined underlying information upon which a need for these additional transmission facilities may be found and concludes it supports RMP's decision to build the Transmission Line and confirms RMP's planned integration and operation of the line with future utility operations and activities. The Division agrees with RMP's conclusions that there is a need for the Transmission Line and the Company's future utility service will be more reliable and efficient with the Transmission Line's addition.11

Q. Please describe the bidding process the Company used to award contracts for the construction of the new transmission.

- The Company initiated a competitive tendering process to receive blind, sealed bids for the project work scope to be delivered on a turnkey, fixed-price, guaranteed completion-date basis using an engineer, procure and construct form of contracting. The competitive tendering process began in October 2007 and provided two separate blind, sealed bidding opportunities. All bid responses were due for submittal in May 2008 and again in July 2008 after the Company provided additional information to bidders allowing a refinement of previously submitted design solutions, and terms and conditions, including price. The Company

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10 In the Matter of the Application of Rocky Mountain Power for a Certificate of Public Convenience and Necessity Authorizing Construction of the Populus-to-Terminal 345 KV Transmission Line Project, Case No. PAC-E-08-03, Order No. 30657 (October 10, 2008) at pp. 3-4.
11 In the Matter of the Application of Rocky Mountain Power for a Certificate of Public Convenience and Necessity Authorizing Construction of the Populus to Terminal 345 KV Transmission Line Project, Docket No. 08-035-42, Report and Order Granting Certificate and Certificate of Public Need and Necessity, (September 4, 2008) at p. 3.

received and evaluated three qualified bids resulting from the May 2008 proposal submissions. During the evaluation period one of the bidders withdrew its participation. The Company received two competing proposals in July 2008 with qualified prices of $609 million and $528 million, respectively. After extensive evaluations of bidder proposals and review of exceptions to work scope and base terms and conditions from each bid proposal, the Company ultimately awarded the contract in October 2008, details of which are provided in Mr. Gerrard's direct testimony. The scope of the bidding process included the Populus to Terminal segment, which includes the sections outlined in Exhibit 34. The bid process is described in more detail in Mr. Gerrard's testimony.

Q. **Why did the Company use the engineer, procure and construct approach?**

A. The engineer, procure and construct ("EPC") solicitation is a common form of contracting for large construction projects like the Populus to Terminal transmission segment and is regarded as a prudent approach for cost control and managing design, procurement and construction risks. This approach: (1) provides certainty relative to schedule and cost outcomes for the benefit of customers; (2) caps potential cost escalations where possible based upon the occurrence of defined risks; and (3) ensures more timely delivery to support system needs and transmission reliability.

Q. **Please explain what you mean concerning capping costs based upon the occurrence of identified risks.**

A. The fixed-price EPC approach has minimal provisions for cost and schedule variances. Where cost and schedule variances were not included in the fixed price for certain contingent aspects of the work scope, these items were identified as risk items and a contingent capped price and schedule allowance was agreed upon prior to contract execution should any of these risk items materialize. Contingent risk items were limited to defined occurrences such as weather delays, environmental impacts and sub-surface ground conditions.

Q. How will the Populus to Terminal transmission line benefit PacifiCorp customers?

A. The Populus to Terminal transmission line and subsequent investments within Energy Gateway satisfy multiple objectives for efficiently operating a six-state transmission system in the long term. The initial benefit to PacifiCorp customers is a significant investment to enhance reliability and improve transfer capability within the existing system. In the future, this investment will also provide benefits of incremental capacity to deliver generation resources within the Company's 2008 IRP.

Reliability is fundamental to effectively and efficiently managing the Company's six-state transmission system. As a federally-regulated transmission provider, the Company must comply with reliability standards mandated by FERC through the North American Electric Reliability Corporation ("NERC") and WECC. By meeting these standards the Company continues to maintain a stable and reliable system during a variety of operating conditions, which minimizes potential outages to all customers and financial impacts of having to deliver higher-cost resources if required. Populus to Terminal increases overall reliability, benefiting all PacifiCorp customers.

Populus to Terminal also increases transfer capability from north to south and south to north across the Company's transmission system. By doing so, the Company addresses a key constraint (Path C), meets an MEHC transaction commitment and improves the Company's ability to import and export lower-cost resources depending on seasonal needs and operating conditions. The benefit to all PacifiCorp customers is the ability of the Company to use the least-cost dispatch of resources to serve loads and manage power costs by selling excess energy off-system or importing lower-cost market energy to serve load. Also, by providing incremental transmission capacity through this transmission segment, the Company has more flexibility in locating reserves on PacifiCorp-owned generation, and making full use of the Northwest Power Pool reserve-sharing program. This program allows the Company to cover reserve requirements without having to build additional generation. Increasing the import capability allows better access to those reserves, thereby reducing costs for all customers. Reliability and transfer capability provide benefits based on the existing system.

Populus to Terminal also establishes incremental capacity to provide long-term benefits to customers. Populus to Terminal is the first step within the Energy Gateway strategy to access resources at their source of production. Benefits will accrue to energy consumers and energy producers by allowing economic resources, new and existing, to be developed and delivered across the Company's service territory.

MEHC Transaction Commitments

Q. Did MEHC and PacifiCorp make specific commitments related to investment in PacifiCorp's transmission system as part of the acquisition approval process?

A. Yes. The regulatory commissions in all six states in the Company's service territory approved the Company's capital commitments specifically in transmission and distribution as part of the acquisition of the Company by MEHC. MEHC made specific commitments and developed plans for a significant capital expansion program across the system to support future demands and growth of its customers. As part of the acquisition approval process, MEHC committed to increase transfer capacity on a constrained path known as Path C by 300 MW.[12] Populus to Terminal improves the capacity on Path C and has a planned increase in transfer capacity of 1,400 MW when combined with other segments of Energy Gateway. As such, the Populus to Terminal transmission segment will significantly improve a point of constraint on the system that currently affects numerous transmission customers, will strengthen reliability and will enable the Company to achieve the planned transfer capability rating of subsequent Energy Gateway segments.

Conclusion

Q. Please summarize your conclusions.

A. New transmission is essential to enhance transmission system reliability, provide capacity to integrate resources for the long-term benefit of customers and meet load growth. Populus to Terminal is the first step to increase transmission

12 See Order No. 29998 at Page 6 (Commitment No. 34).

capacity within PacifiCorp's six-state transmission system. This investment and subsequent investments in Energy Gateway are prudent, cost effective and beneficial to customers.

Q. Is the inclusion of Populus to Terminal in Idaho rates in the public interest and if so, why?

A. Yes. The Populus to Terminal and subsequent investments within Energy Gateway satisfy multiple objectives for efficiently operating a six-state transmission system. The initial benefit to PacifiCorp's customers is enhanced reliability and improved transfer capability within the existing system. In the future, it will also provide incremental capacity for delivery of resources within the Company's 2008 IRP, which is a key to unlocking rich resource hubs for the benefit of all PacifiCorp customers and ultimately the western interconnect.

Q. Does this conclude your direct testimony?

A. Yes.

Case No. PAC-E-10-07
Exhibit No. 33
Witness: John A. Cupparo

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

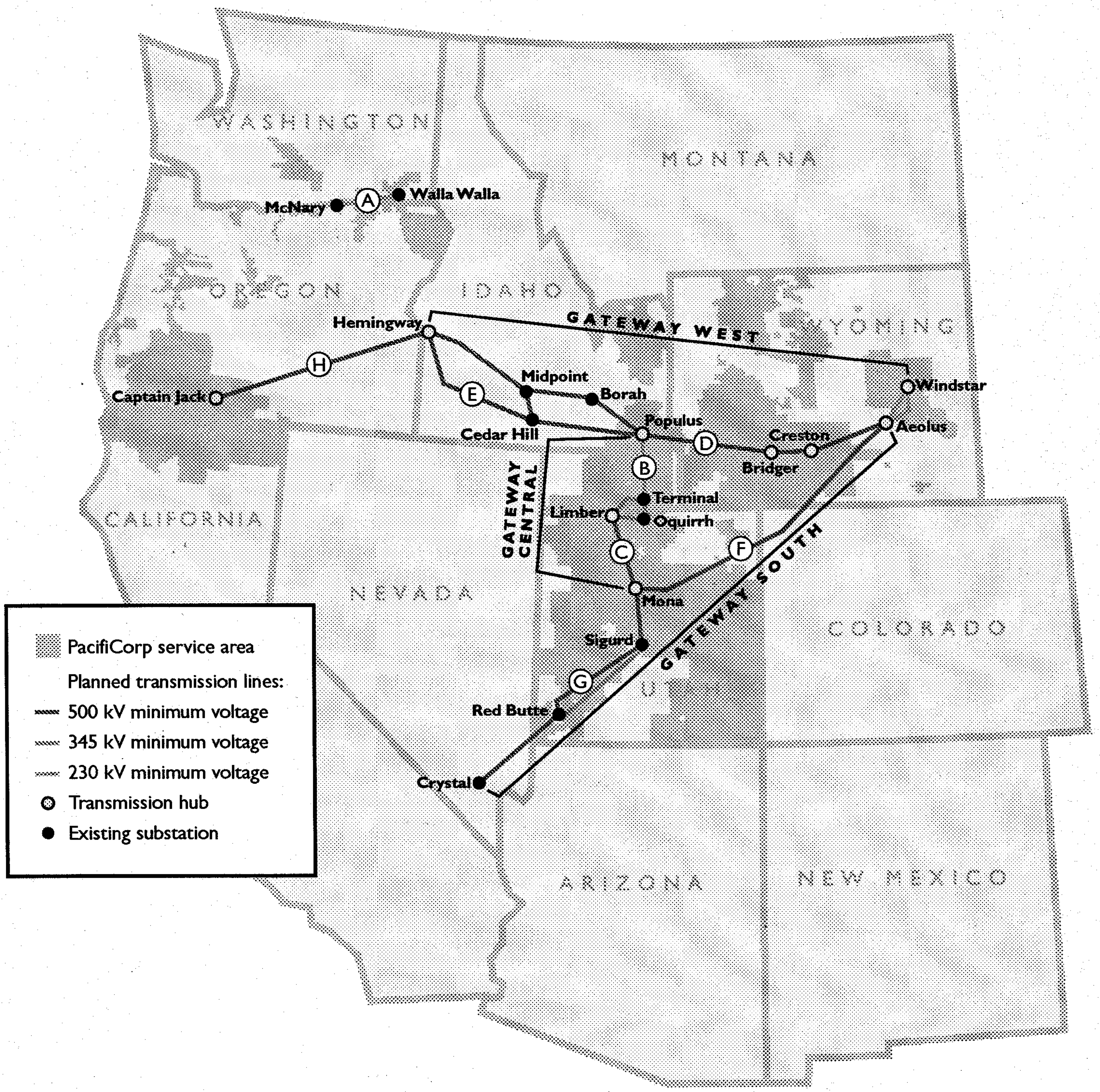
ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of John A. Cupparo

Gateway Map

May 2010

Rocky Mountain Power
Exhibit No. 33 Page 1 of 1
Case No. PAC-E-10-07
Witness: John A. Cupparo



This map is for general reference only and reflects the expansion necessary to construct Energy Gateway to its full capacity of 6000 MW. It may not reflect the final routes or construction sequence.

Case No. PAC-E-10-07
Exhibit No. 34
Witness: John A. Cupparo

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of John A. Cupparo

Populus to Terminal Map

May 2010

Case No. PAC-E-10-07
Exhibit No. 35
Witness: John A. Cupparo

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

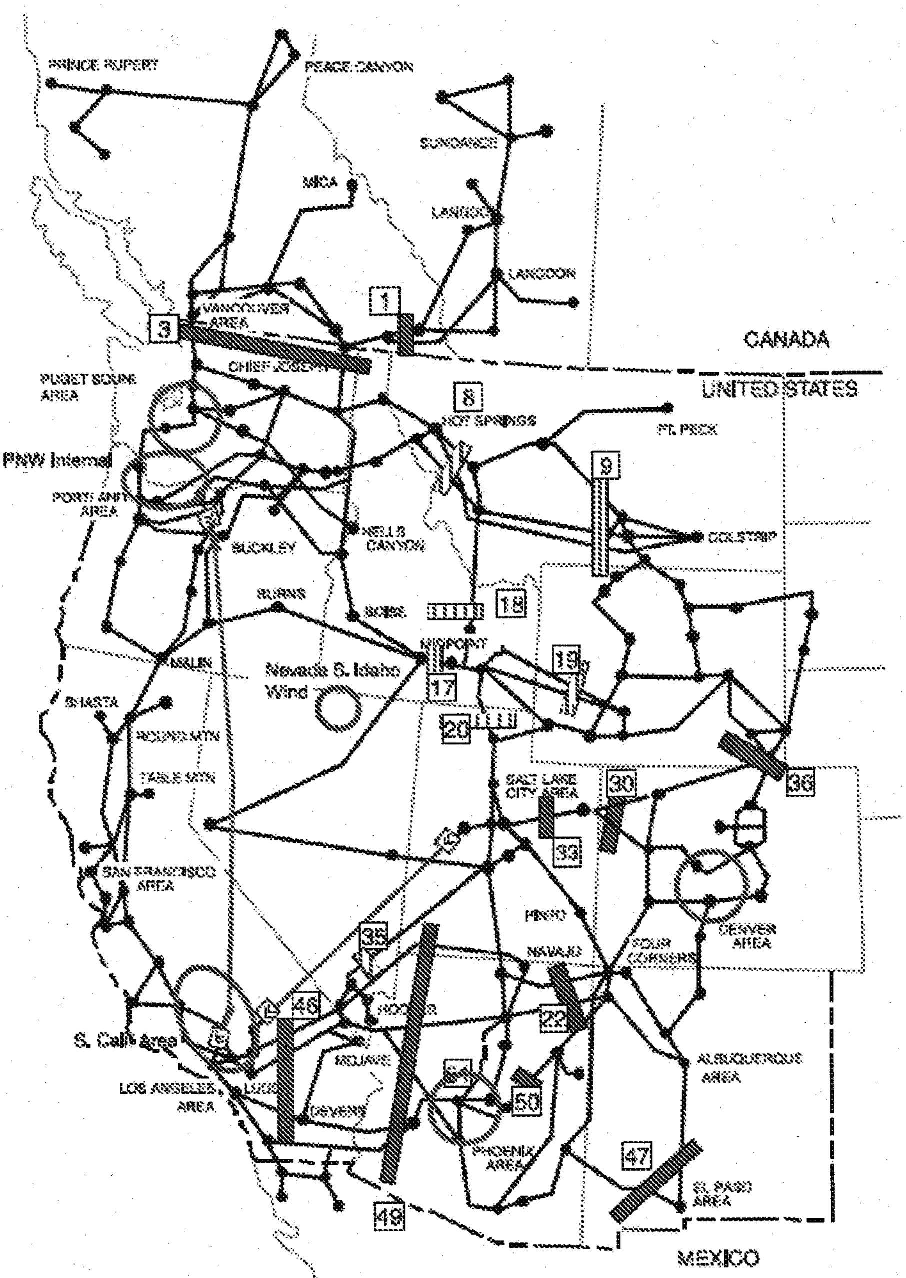
ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of John A. Cupparo

DOE Congestion on Western Paths Map

May 2010

Figure 4-1. Congestion on Western Transmission Paths



Congested Transmission Paths

Transmission line (or lines). Solid red or hashed bars "bundle" the lines they cross or touch into a numbered transmission path.

The number alongside each bar is the WECC number for that path.

Congestion on the path, based on current or near-term conditions.

Subregional areas with significant existing congestion.

Congestion that would result from future development of generation capacity in the Rocky Mountain area.

Based on historical and existing modeling studies. Not all of WECC's 67 catalogued paths are shown.

Case No. PAC-E-10-07
Exhibit No. 36
Witness: John A. Cupparo

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of John A. Cupparo

Incentive Rate Order

May 2010

125 FERC ¶ 61,076
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
and Jon Wellinghoff.

PacifiCorp Docket No. EL08-75-000

ORDER ON PETITION FOR DECLARATORY ORDER

(Issued October 21, 2008)

1. On July 3, 2008, PacifiCorp filed a petition for declaratory order (Petition) pursuant to section 219 of the Federal Power Act (FPA)[1] and Order No. 679[2] seeking incentive rate treatment for its Energy Gateway Transmission Expansion Project (Project). The Project, described by PacifiCorp as eight interdependent line segments, will expand PacifiCorp's transmission network by 2,000 miles of extra-high voltage (EHV) transmission lines. PacifiCorp seeks a 250 basis point adder to its base return on equity (ROE) and recovery of prudently-incurred abandonment costs if the Project is cancelled due to factors beyond its control. For the reasons discussed below, we will grant in part, and deny in part, PacifiCorp's Petition and grant in part, and deny in part, the requested incentive rate treatment for its Project.

I. Background

2. According to PacifiCorp, the Project is one of the most ambitious electric infrastructure projects planned in the western United States in the past two decades. The Project will enlarge and expand PacifiCorp's system-wide transmission network by adding approximately 2,000 miles of new EHV transmission lines in the six-state region including California, Idaho, Oregon, Utah, Washington, and Wyoming, and deliver up to 3,000 MW of capacity from location-constrained renewable resources in Wyoming to distant load centers; its estimated cost exceeds $6 billion. PacifiCorp claims that the Project will provide its customers with substantial economic, reliability and

[1] 16 U.S.C. § 824s (2006).

[2] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222, *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

environmental benefits, including reducing transmission congestion and the future cost of delivered power throughout the six-state service territory.

3. According to PacifiCorp, the Project is a backbone transmission project providing a platform for integrating and coordinating future regional and sub-regional electric transmission projects being considered in the Pacific Northwest and the Intermountain West. Its configuration is described as a "hub and spoke" design which is characterized by PacifiCorp as major EHV transmission lines that connect areas with a strong potential for generation resource development (hubs) to an enhanced transmission system (spokes) for delivery to customers throughout the western United States. Under the Project, hubs are planned for western Wyoming, south central Wyoming, southwestern Idaho, south central Utah, and southern Oregon. From the hubs, power will be collected and moved in different directions to permit PacifiCorp to efficiently deliver power from a variety of generation sources to load. According to PacifiCorp, the additional transmission infrastructure and the "hub and spoke" design will provide flexibility, improve efficiency and enable development of clean and renewable energy resources and will ensure that PacifiCorp's system will be capable of meeting future regional needs.[3]

4. PacifiCorp states that each of the eight interrelated line segments has been assigned one of four priority classifications for construction.[4] PacifiCorp explains that most of the segments are dependent on the development of other segments and the priority levels have been established to ensure the most prudent approach to deliver completion of the Project. Four segments comprise Priority One of the Project (segments A, B, C and G). According to PacifiCorp, these segments are being built to enhance the base load service and reliability of PacifiCorp's transmission system. PacifiCorp anticipates that these segments will be among the earliest portions of the Project to be placed into service, and it has begun the preliminary permitting and contracting work to get these segments on-line between 2010 and 2014.[5]

[3] PacifiCorp Petition at 8 and 9.

[4] According to PacifiCorp, the priority classification assigned to each segment is driven by efficiency and cost-effective development and construction of the Project; therefore, PacifiCorp clustered segments offering similar general benefits and asset in-service dates.

[5] Segment A is a 230 kV segment which will extend approximately 56 miles between Walla Walla, Washington and Umatilla, Oregon and cost roughly $108 million. Segment B is a double circuit 345 kV line that will be constructed in two segments. The line will run from a new substation near Downey, Idaho 135 miles south to an existing substation near Salt Lake City, Utah; the estimated cost is $800 million. Segment C extends north from central Utah running 86 miles north to two future substations. It is a

(continued...)

5. Two segments comprise Priority Two (segments D and E). PacifiCorp states that the two segments are designed to enhance the resource adequacy of the region by connecting transmission-constrained wind resources in Wyoming to westward load centers.[6] Two segments comprise Priority Three of the Project (segments E and H). PacifiCorp states that these segments are intended to integrate its two control areas within the Project footprint, and to provide a means for transmitting renewable energy supplies.[7] Priority Four consists of segment F which is intended to provide back-up system reliability, as well as rating support for PacifiCorp's newly enhanced system.[8]

6. The application states that three of the segments may be upsized from a single-circuit to a double-circuit system.[9] PacifiCorp states that it is actively working with potential equity partners to determine the interest and commitment to pursue a double-circuit configuration for these segments.

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double circuit line which will have one segment constructed at 500 kV and the other at 345 kV and is expected to cost $425 million. The segment G transmission line is approximately 280 miles and will connect an existing substation in central Utah to another substation north of Las Vegas, Nevada. The lines are planned as a single circuit 345 kV line, and could be upsized to include a 500 kV line configuration. The estimated cost is $754 million.

[6] The two portions of segment D will consist of roughly 300 miles of new transmission line running from eastern Wyoming to western Wyoming and is estimated to cost approximately $880 million. PacifiCorp states that the segment will consist of two single circuit 230 kV lines, and a double circuit 500 kV/230 kV line. The 230 kV segment of the line could be upsized to 500 kV. Segment E, also comprised of two sections both single-circuit 500 kV lines, will run from a planned generation resource hub near Rock Springs, Wyoming, across Idaho to a point southwest of Boise, Idaho and cost an estimated $1.02 billion.

[7] Segment E continues the single circuit, 500 kV, Priority Two line running to western Idaho. Segment H, single circuit 500 kV line, will run 375 miles from an existing substation in western Idaho to a Bonneville Power Administration substation in northern California. The cost is estimated at $786 million.

[8] Segment F which is also a single circuit, 500 kV line extends approximately 395 miles from a new substation in southeastern Wyoming to central Utah. Segment F is expected to cost $764 million.

[9] PacifiCorp Petition at n.9 and Cupparo Affidavit at 10-12.

A. Requested Incentives

7. PacifiCorp requests a 250 basis point adder to its base ROE for the revenue requirement associated with the capital costs of its Project, not to exceed the upper end of the zone of reasonableness as determined in a future proceeding under FPA section 205. PacifiCorp asserts that the ROE adder is necessary to compensate it for the unusual and significant project risks.

8. PacifiCorp also requests authorization to recover all prudently-incurred development and construction costs if the Project is cancelled or abandoned, in whole or in part, as a result of its inability to obtain necessary approvals, or as a result of any action or inaction by a governmental authority, or regulatory agency, for any reason outside PacifiCorp's control.

9. PacifiCorp states that it qualifies for the rate incentives because of the scope and magnitude of the Project, because it is intended to respond to regional needs in Idaho, Oregon, Utah, Washington, and Wyoming, and because it will improve reliability, reduce congestion, provide transmission access for renewable resources, provide transmission for forecasted load growth and will deploy advanced transmission technologies. As the Project will directly link PacifiCorp's east and west control areas, it will minimize congestion and relieve loading along paths between Wyoming and areas west and south, and, by adding interconnections and increasing transfer capacity, the Project will reduce the need for curtailments and improve access to generation resources needed to meet system demand and reserve obligations.[10]

10. PacifiCorp asserts that it is entitled to a rebuttable presumption of eligibility for the requested incentives under Order No. 679 because nearly all segments of the Project (except segments A and C) were planned and approved under a Fast Track Process developed in 2007 by the planning committee of the Northern Tier Transmission Group (NTTG), prior to finalizing requirements for the NTTG's planning process required by Order No. 890.[11] Additionally, PacifiCorp states that NTTG's 2007 Annual Report

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[10] *See* PacifiCorp Petition, Cupparo Affidavit at 19.

[11] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (March 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007), *order on reh'g and clarification*, Order No. 890-A, 73 Fed. Reg. 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g and clarification*, Order No. 890-B, 123 FERC ¶ 61,299 (2008). According to PacifiCorp, the Fast Track provided a forum for stakeholder input and participation in the identification of Fast Track projects critical to relieving areas of congestion and improving reliability. *See* PacifiCorp Petition, Cupparo Affidavit at 15-16.

identified the need for all of PacifiCorp's proposed segments (except segment A) to increase transmission capacity in order to reduce congestion and improve reliability.[12] PacifiCorp states that following the NTTG planning committee approval of the 2007 Annual Report and Fast Track recommendations, the Project (with the exception of segments A and C) was submitted for Western Electricity Coordinating Council (WECC) regional planning review.[13]

11. In the event that the Commission determines PacifiCorp is not entitled to that rebuttable presumption, PacifiCorp argues in the alternative that the benefits from constructing the Project nevertheless satisfy the eligibility criteria of Order No. 679. PacifiCorp contends that the Project, once completed, will result in increased reliability[14] and a reduction in congestion. Specifically, PacifiCorp points out that the Project will: (1) establish a 500 kV backbone; (2) reduce curtailments resulting from overscheduled use; (3) provide additional access to resources and reserves; (4) increase the diversity of the available resource mix; (5) connect its two control areas (Pacific Power and Rocky Mountain Power) to better serve network load; and (6) help satisfy state renewable portfolio requirements. The Petition references numerous transmission studies identifying constrained paths and interfaces and other areas critical for relieving congestion in the region; PacifiCorp states that the Project is its response to these findings, as well as responding to the projected demands on its available capacity due to growth of its network load obligation. PacifiCorp also highlights that the Project will enable it to link remote renewable resources to load centers throughout the West.

12. At this time, PacifiCorp is not seeking to change its rates under FPA section 205, but states that it will make a subsequent section 205 rate filing in the future to implement the incentive rate treatment. PacifiCorp also explains that it will ask state regulators to include the Project's investment in retail electric rates; to the extent that the recovery of all of the transmission investment is permitted in its retail rate base, "PacifiCorp will compensate its retail customers by crediting the transmission-related revenues, inclusive of any incentives granted by the Commission, against its retail revenue requirement."[15]

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[12] According to the Petition, the Fast Track process relied on studies previously done within the region to identify congested transmission that impedes efficient and reliable operation of the grid.

[13] *See* PacifiCorp Petition, Cupparo Affidavit at 17.

[14] PacifiCorp states that, by adding critical EHV infrastructure to the bulk power transmission system, the Project will provide contingency capacity throughout the system, thereby enhancing reliability within the NTTG footprint and the broader region.

[15] PacifiCorp Petition at 4.

PacifiCorp expects that the requested incentives will be an important consideration in obtaining state regulator support for including the reliability and future growth elements of the Project in retail rates.

B. Risks and Challenges

13. PacifiCorp states that its approach to this Project is a significant departure from past approaches to the development of major transmission projects. It notes that historically such projects were built when associated generation resources were sited; however, PacifiCorp notes that with the current uncertainty of conventional generating technology, the time required to permit and construct major transmission and the inability of many renewable resource developers to finance major transmission investments, transmission must be sited "ahead" of specific generation resources to best position utilities to meet future forecasted load growth. PacifiCorp asserts that with this approach, PacifiCorp faces greater risks for transmission investment.

14. PacifiCorp explains that it faces significant financial and regulatory risks in pursuing this Project. PacifiCorp cites the estimated $6 billion cost, comparing that to the average $111 million that it spent on capital expenditures annually between 2002 and 2007, and noting that the total cost is more than three times its current transmission rate base of $1.8 billion. In addition, PacifiCorp states that, since the Project would constitute the backbone for a future 500 kV infrastructure in the Project footprint, it would be "responsible for ensuring that the underlying system . . . can withstand technical and regulatory scrutiny, including the protection of neighboring electrical systems."[16] According to PacifiCorp, this factor has made it difficult to enlist additional partners in the Project. Its financial risk is also affected by the fact that it will be siting transmission lines ahead of new generation resources, as noted above, and the fact that development costs are likely to increase over time.

15. PacifiCorp asserts that its Project faces significant regulatory risks because it must garner approval of various state and federal authorities, including six states, the Bureau of Land Management and the United States Forest Service. PacifiCorp also notes that tribal issues and federal land management are implicated in the construction and development of the Project. PacifiCorp also states that large portions of the Project are expected to traverse federally-administered lands, as well as through routes that are not situated on existing rights-of-way. PacifiCorp anticipates that proceedings will be contested and prolonged, and recognizes the risk of siting delays and potential re-routing that may increase the overall cost. This, according to PacifiCorp, equates to added authorization complexities on a scale unlike previous transmission projects for which the Commission has granted requested rate incentives.

[16] PacifiCorp Petition at 31.

16. Finally, PacifiCorp states that there will be uncommon technology-related risks because it contemplates investing in several advanced transmission technologies that have not been widely deployed.[17] PacifiCorp believes that there is added risk because there is uncertainty as to how these technologies will perform within this Project, and it notes that these novel technologies "must be designed, constructed and tested to ensure they meet the requirements of the Project."[18]

C. Technology Statement

17. PacifiCorp included an advanced technologies statement in its Petition as required by Order No. 679.[19] Subject to further study and final engineering, PacifiCorp states that it intends to utilize several types of advanced technologies in connection with various segments. PacifiCorp has not, in most cases, designated the specific segments on which the advanced technologies will be used. According to PacifiCorp, the technologies meet the standard set forth in Order No. 679, and in section 1223 of the Energy Policy Act of 2005 (EPAct 2005),[20] as they mitigate congestion and enhance grid reliability by increasing the capacity, efficiency and reliability of an existing or new transmission facility. PacifiCorp's advanced technologies fall into the categories of advanced conductor technology, enhanced power device monitoring, fiber optic technologies, power electronics and other technologies.[21]

18. PacifiCorp intends to utilize Trapezoidal Conductor technology which involves the use of Aluminum Conductor Steel Supported/Trapezoidal Wire. According to PacifiCorp, this advanced conductor design will increase transmission capacity, and reduce the sag of the transmission lines as well as avoid energy losses. PacifiCorp intends to use this technology on 500 kV lines, anticipated to be used on segments C, D, E, and G.[22]

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[17] As further discussed below, PacifiCorp plans on utilizing trapezoidal conductors, and fiber optic shield wires in addition to other innovative technologies. PacifiCorp Petition at 35.

[18] *Id.*

[19] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 302.

[20] Pub. L. No. 109-58, § 1223, 119 Stat. 594, 953 (2005).

[21] PacifiCorp Petition at 42.

[22] *Id.* at 23, Cupparo Affidavit at 24. PacifiCorp also asserts that an estimated 6,000 to 120,000 metric tons of carbon dioxide could be avoided annually, as a result of applying this technology.

19. PacifiCorp states that it is planning to use Static VAR Compensators (SVCs) which are electrical devices used to automatically match impedance to regular voltage and improve both dynamic and transient network stability. PacifiCorp is evaluating the installation of SVCs on several segments of the Project in order to support the required dynamic voltage regulation and "firming up" of the system, and also improve reliability, power quality, contingency recovery, create operational benefits and help maximize the overall total transfer capability.[23]

20. PacifiCorp plans to use fiber optic technology in order to shield phase conductors from direct lightning strikes, provide high-capacity, high-speed communication channels and reliably detect short circuits. PacifiCorp states that the installation of the fiber optic technology can also create additional latent capacity bandwidth, which could also provide an alternate secure communication path that could be used for national security and regional development purposes. PacifiCorp states that this technology has the potential to be used throughout the Project.[24]

21. PacifiCorp also intends to use phase shifters to improve and/or increase stability limits of transmission lines when the maximum power transfer is reached. PacifiCorp states that phase shifters help provide operational and seasonal flexibility, and that it is pursuing targeted applications of this technology to reduce overall system losses by eliminating circulating currents, and helping to protect neighboring transmission systems.[25]

22. In addition, PacifiCorp intends to employ Special Protection Schemes (SPS) to respond to system events and disturbance data that could potentially cause undue stress on its system as necessary to maximize grid total transfer capability, to improve long-term reliability and reduce negative impacts to the interconnected systems, as well as to benefit the interim ratings of the lines.[26]

23. Finally, PacifiCorp states that it is evaluating the use of advanced monitors in transformers at the new substations that will provide notification when the affected equipment is near failure. This technology, while not required by reliability standards, helps protect high-cost investments and improve reliability by providing for early detection of potential issues.

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[23] PacifiCorp Petition at 45.

[24] *Id.*

[25] *Id.* at 46.

[26] *Id.* at 47.

II. Notice of Filing and Responsive Pleadings

24. Notice of PacifiCorp's filing was published in the *Federal Register*, 73 Fed. Reg. 41,064 (2008), with interventions and protests due on or before July 24, 2008. Timely motions to intervene raising no substantive issues were filed by Horizon Wind Energy LLC, Arizona Public Service Company, the Transmission Agency of Northern California, and the Utah Division of Public Utilities. Timely motions to intervene and protests were filed by the Bonneville Power Administration (Bonneville), Industrial Customers of Northwest Utilities (Industrial Customers), and the Utah Municipal Power Agency (UMPA). Utah Associated Municipal Power Systems (Utah Systems) filed a timely motion to intervene and comments. On August 6, 2008, PacifiCorp filed a motion for leave to answer and an answer. On September 5, 2008, UMPA responded to PacifiCorp's answer.

25. Bonneville claims that PacifiCorp cannot establish a rebuttable presumption, as provided under Order No. 679, by satisfying the threshold criteria for eligibility for transmission incentive treatment under FPA section 219 with a showing, in pertinent part, that a transmission project results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion. Bonneville notes that PacifiCorp claims to meet this condition by virtue of its participation in the NTTG planning process. However, Bonneville contends that the Project was announced in May of 2007, while NTTG did not start its planning process until later that year. Thus, according to Bonneville, the Project could not have originated from the NTTG planning process.

26. Protesters argue that the requested 250 basis point ROE adder is too high. Bonneville asserts that, although some ROE adder would be appropriate, PacifiCorp's requested incentive is 100 basis points higher than any previously approved by the Commission. UMPA similarly argues that PacifiCorp has failed to justify such a large adder, calling the 250 basis point incentive rate adder "unprecedented."[27] UMPA also alleges that the risks attributable to the Project are reduced as a result of PacifiCorp's recovery of abandoned plant costs; thus, the proposed level of ROE adder is not warranted.[28] Utah Systems note that, although the Project may be larger than any for which incentives were previously granted, "an incentive return on equity generates dollars based on a percentage of the total equity investment."[29] According to Utah

[27] UMPA July 24, 2008 Protest at 9.

[28] *Id.* at 10 ("the abandoned plant rate incentive eliminates PacifiCorp's exposure to the very risks PacifiCorp relies on to justify its extraordinary 250 basis point adder").

[29] Utah Systems July 24, 2008 Comments at 4.

Systems, since a ROE on a large investment yields a greater number of dollars than the same ROE on a smaller investment, it is unclear why a greater percentage return is appropriate for a larger project. Bonneville and Industrial Customers contend that the large scope of the Project, which PacifiCorp relies on to justify such a large adder, was artificially created by virtue of PacifiCorp bundling a number of individual, smaller, projects together into one package.

27. As such, Bonneville and Industrial Customers argue that PacifiCorp has failed to demonstrate a nexus between the incentives sought and the investment being made. Industrial Customers contends that since PacifiCorp already planned certain transmission investments included in the Project, the ROE adder is not tailored to its actual risks and challenges. Further, it asserts that the scope and effects of the Project are not as large as PacifiCorp claims because it "is not one large transmission investment, but a series of eight separate and often unrelated transmission projects."[30] Bonneville urges the Commission to analyze each of the segments individually to determine if each is related to the other segments and whether there is a nexus for each to the requested incentive rate. In particular, Industrial Customers and Bonneville claim that segment A is a local transmission project, separately planned and operationally unrelated to the other segments.[31] They also question whether transmission that has been planned for some time for PacifiCorp to meet its load service obligations through routine investments warrants incentive rate treatment.[32]

28. UMPA similarly argues that PacifiCorp should not receive incentive rate treatment for transmission investments needed to serve the needs of existing customers.[33] UMPA suggests that the system upgrades proposed by PacifiCorp are "the kinds of routine investments made in the ordinary course of expanding the system to account for load growth."[34] Stating that PacifiCorp is required to maintain its system in order to serve load and respond to anticipated load growth, UMPA asserts that "current customers should not be forced to pay additional incentive rates in order to cause the transmission

[30] Industrial Customers July 24, 2008 Protest at 5.

[31] *Id.* at 6; Bonneville July 24, 2008 Protest at 5.

[32] Bonneville July 24, 2008 Protest at 4; Industrial Customers July 24, 2008 Protest at 7.

[33] UMPA July 24, 2008 Protest at 5-7.

[34] *Id.* at 6.

provider to provide for the basic transmission service that the provider is obligated to provide . . ."[35] Bonneville and Industrial Customers make similar arguments.[36]

29. All four protesters assert that segments A, B, and C were requirements stemming from Mid-American Energy Holding Company's (MidAmerican) acquisition of PacifiCorp. According to Utah Systems, MidAmerican and PacifiCorp already received a construction incentive (merger approval), and further incentives now may be unnecessary. Bonneville and UMPA cite Commission precedent for rejecting a request for incentive rate treatment where a project had been ordered by the Commission in another proceeding.[37] As the Commission in *Westar* denied incentives when the applicant failed to offer evidence that conditions had changed since its prior commitments, UMPA asserts that PacifiCorp has also failed to provide any evidence that circumstances have changed since it committed to build segments A, B, and C as part of its merger with MidAmerican.

30. More generally, protesters claim that granting incentive rate treatment to PacifiCorp will not serve to promote new investment. Industrial Customers contend that PacifiCorp has not identified any regulatory and technology risks that other utilities would not have to face when making routine transmission investments, and that incentive rate treatment in this case would simply give PacifiCorp higher returns on investments it was already planning to make. Utah Systems state that investors may not stand to gain much from the requested incentives, because PacifiCorp plans that the additional revenues generated by the ROE will be used to reduce the transmission rates that otherwise would be paid by its retail customers. Utah Systems suggest that "the increased revenue credits to PacifiCorp's retail jurisdictions is the price of securing state approvals,"[38] and is concerned that the Commission in Order No. 679 did not envision retail rate relief as a valid reason for granting incentives at the federal level.

31. UMPA also raises concerns about the proposed credit to retail customers. UMPA believes that, as a result of the crediting mechanism, only PacifiCorp's wholesale

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[35] *Id.*

[36] *See* Bonneville July 24, 2008 Protest at 5 (routine investment necessary to meet wind generation interconnection requests); Industrial Customers July 24, 2008 Protest at 7 (normal and routine transmission investments related to system reliability and load growth).

[37] Bonneville July 24, 2008 Protest at 5-6 and UMPA July 24, 2008 Protest at 7-8 (citing *Westar Energy Inc.* (*Westar*), 122 FERC ¶ 61,268, at P 49-52 (2008)).

[38] Utah Systems July 24, 2008 Comments at 4-5.

customers would pay the proposed incentive rate. UMPA suggests that PacifiCorp has requested a higher incentive rate than necessary, given that it will only be recovered on ten percent of its transmission revenue requirement,[39] and concludes that the retail credit is preferential and unduly discriminatory.

32. Bonneville and UMPA request that the Commission set this case for hearing to determine a just and reasonable incentive rate treatment for the various segments of the Project[40] and to properly tailor any approved incentives to encourage investment without discriminating against wholesale customers.[41]

33. Finally, Bonneville does not object to PacifiCorp's requested incentive for recovery of prudently incurred development and construction costs if the Project is cancelled or abandoned "as a result of any action or inaction by a governmental authority."[42] But, Bonneville requests clarification that the clause "action or inaction by a governmental authority" does not include actions or inactions by Bonneville. Bonneville asserts that that provision should protect PacifiCorp from things such as denial of easements and regulatory approvals, but that action or inaction by Bonneville should not trigger cost recovery under that incentive.

III. Discussion

A. Procedural Matters

34. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2008), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

35. Rule 213(a) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a) (2008), prohibits an answer to a protest, unless otherwise permitted by the decisional authority. We are not persuaded to accept PacifiCorp's answer and UMPA's response and will, therefore, reject them.

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[39] *See* UMPA July 24, 2008 Protest at 11 (noting that PacifiCorp states it receives over ninety percent of its recovery on transmission investment through native load and retail ratemaking processes.)

[40] Bonneville July 24, 2008 Protest at 7.

[41] UMPA July 24, 2008 Protest at 2.

[42] Bonneville July 24, 2008 Protest at 6 (citing PacifiCorp July 3, 2008 Petition at 4).

B. Section 219 Requirement

36. In EPAct 2005, Congress addressed incentive-based rate treatments for new transmission construction.[43] Specifically, section 1241 of EPAct 2005 added a new section 219 to the FPA directing the Commission to establish, by rule, incentive-based (including performance-based) rate treatments for electric transmission. The Commission issued Order No. 679, which set forth processes by which a public utility could seek transmission rate incentives pursuant to section 219, including the incentives requested here by Petitioners.

37. Order No. 679 provided that a public utility may file a petition for declaratory order or FPA section 205 filing to obtain incentive rate treatment for transmission infrastructure investment that satisfies the requirements of FPA section 219. The applicant must demonstrate that the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion.[44] Order No. 679 also established a rebuttable presumption that a project satisfies these threshold criteria for eligibility for transmission incentive treatment under section 219 if: (1) a transmission project results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission; or (2) a project has received construction approval from an appropriate state commission or state siting authority.[45] Order No. 679-A clarified the operation of this rebuttable presumption by noting that the authorities and/or processes on which it is based (i.e., a regional planning process, a state commission, or siting authority) must, in fact, consider whether the project ensures reliability or reduces the cost of delivered power by reducing congestion.[46]

38. PacifiCorp asserts that the Project meets the rebuttable presumption under Order No. 679 since, "[v]irtually all segments of the Project were planned, coordinated and approved under the auspices of the … NTTG planning process." However, PacifiCorp also acknowledges that the NTTG formal planning process had not been fully developed when "Fast Track" review occurred, and further that certain portions of the Project were

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[43] *See* Pub L. No. 109-58, 119 Stat 594, 961 (2005).

[44] *See* 18 C.F.R. § 35.35(d) (2008).

[45] *See id.*; Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 47.

[46] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 49.

not subject to any regional planning process review at all.[47] Under those circumstances, we find that the Project is not eligible for the rebuttable presumption of relying on a regional planning process.

39. Nevertheless, we find that PacifiCorp has adequately demonstrated that the Project (with the exception of segment A) will ensure reliability and reduce transmission congestion, and therefore meets the requirements of FPA section 219 for incentive rate treatment. We find that segments B through H of the Project would establish for the first time a backbone of 500 kV transmission lines in PacifiCorp's Wyoming, Idaho and Utah regions.[48] This would provide PacifiCorp a platform for integrating and coordinating future regional and sub-regional electric transmission projects being considered in the Pacific Northwest and the Intermountain West, connecting existing and potential generation to loads in an efficient manner, thus reducing the cost of delivered power.[49] Also, the Petition cites the 2006 DOE National Electric Transmission Congestion Study and the 2004 Rocky Mountain Area Transmission Study in stating that the proposed Project will reduce congestion or maintain reliability in the Western Interconnection.[50] Additionally, the Project would establish a direct link between PacifiCorp's east and west control areas, providing numerous benefits including increasing transfer capability, reducing the need for curtailments, and reducing transmission congestion.[51]

40. With regard to segment A, which is a 230 kV segment connecting existing power substations at Walla Walla, Wallula and McNary, Washington and extending to Umatilla, Oregon, we conclude that PacifiCorp has not provided sufficient evidence to meet the requirements of FPA section 219 for incentive rate treatment and therefore, we decline to grant any incentive for this segment. In support of segment A, the Petition merely states that it "could be used to link existing and future sources of renewable resources to better benefit system power transfers."[52] There are no congestion studies or reliability assessments in the record to support a finding that segment A will either ensure reliability or reduce the cost of delivered power by reducing congestion, as required by our regulations to qualify for incentive rates. Accordingly, PacifiCorp has met the

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[47] *See* PacifiCorp Petition, Cupparo Affidavit at 15-16.

[48] *Id.* at 20 & n.41.

[49] *Id.* at 3, Cupparo Affidavit at 4, 7, and 19.

[50] *Id.* at 21-23, Cupparo Affidavit at 22.

[51] *See id.*, Cupparo Affidavit at 39.

[52] PacifiCorp Petition at 10. *See also* Cupparo Affidavit at 8-9.

requirements of FPA section 219 for segments B through H of the Project; however, we will deny incentive rate treatment for segment A of the Project, without prejudice to PacifiCorp re-filing with the required support for that portion of the Project.

C. Incentives and the Commission's Nexus Requirement

41. In addition to satisfying the section 219 requirement of ensuring reliability or reducing the cost of delivered power by reducing congestion, an applicant must demonstrate that there is a nexus between the incentive sought and the investment being made. In Order No. 679-A, the Commission clarified that the nexus test is met when an applicant demonstrates that the total package of incentives requested is "tailored to address the demonstrable risks or challenges faced by the applicant."[53] As part of our evaluation of whether the incentives requested are tailored to address the demonstrable risks or challenges faced by the applicant, the Commission has found the question of whether a project is "routine" to be particularly probative. In *BG&E*,[54] the Commission clarified how it will evaluate projects to determine whether they are routine and the effect this evaluation has on an applicant's request for incentives. Specifically, to determine whether a project is not routine, the Commission stated that it will consider all relevant factors presented by the applicant. For example, an applicant may present evidence on: (1) the scope of the project (e.g., dollar investment, increase in transfer capability, involvement of multiple entities or jurisdictions, size, effect on region); (2) the effect of the project (e.g., ensuring reliability or reducing congestion costs); and (3) the challenges or risks faced by the project (e.g., siting, internal competition for financing with other projects, long lead times, regulatory and political risks, specific financing challenges, other impediments).[55]

42. The Project is an enormous undertaking by PacifiCorp to construct approximately 2,000 miles of new EHV transmission lines throughout six states (including 230 kV, 345 kV and 500 kV transmission lines). The Project will provide the first backbone 500 kV "superhighway" in this part of the Western Interconnection and may facilitate the addition of future 500 kV transmission lines in the area. The Project will improve transfer capacity; for example, segment B, when combined with the other segments of the Project, will increase transfer capacity by 1,400 MW, and significantly mitigate a

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[53] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 40.

[54] *Baltimore Gas and Electric Company*, 120 FERC ¶ 61,084, at P 52-55 (2007) (*BG&E*).

[55] This list provides some examples of evidence that may help inform the Commission whether a project is routine in nature, but is not intended to be exhaustive.

transmission constraint on the system.[56] The Bridger Expansion project (part of segment E) will increase transfer capacity by a significant amount.[57] In addition, the Project will relieve several other points of congestion within the PacifiCorp control areas.[58] Also, the Project will directly link PacifiCorp's east and west control areas, enabling PacifiCorp to make efficient use of resources to meet its load and reserve obligations, as well as minimize congestion and relieve loading along paths between Wyoming and areas west and south.[59] The Project will provide substantial benefits in terms of ensuring reliability in the region and will also reduce congestion costs.

43. Moreover, PacifiCorp faces significant risks and challenges in pursuing this Project. The Petition enumerates considerable siting, construction, regulatory, financing, and technology risks. Namely, the configuration of the Project[60] and the siting of its transmission facilities ahead of the siting for specific generation resources may lead to additional costs, delays, or modifications down the road. PacifiCorp notes that currently no 500 kV infrastructure exists within the Project footprint in Idaho, Utah and Wyoming; therefore, as the first entity to construct a new 500 kV system, it will be responsible for mitigating any impacts caused on the existing transmission system. PacifiCorp explains that the new 500 kV transmission system should not cause any overloads on the underlying lower voltage transmission system. It cites the need to mitigate possible overloads as the reason to construct a redundant transmission system, which effectively raises the costs and risks of incorporating a new higher voltage class of transmission in the area.[61]

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[56] *See* PacifiCorp Petition, Cupparo Affidavit at 9.

[57] *Id.* at Exhibit 4, p. IV.

[58] *See id.* at 22.

[59] *See id.* at Exhibit 5, p. 35.

[60] As noted above, PacifiCorp will employ a "hub and spoke" configuration that is characterized by major EHV transmission lines that connect areas with strong potential for generation resource development (hubs) to an enhanced transmission system (spokes) for delivery of capacity and energy to customers throughout the region.

[61] *See* PacifiCorp Petition at n.41.

44. We also find that the Project faces significant risks related to the magnitude of the financial investment required (estimated at $6 billion),[62] which represents more than a 330 percent increase in PacifiCorp's existing transmission rate base,[63] and the regulatory risks involved. There are significant siting issues because the individual segments must be approved by numerous states and several federal authorities, including the Bureau of Land Management and the United States Forest Service. Further, tribal issues and federal land management issues are implicated in the construction and development of the Project.

45. Further, PacifiCorp states that the Project will also facilitate the delivery of remote renewable resources, accommodating up to 3,000 MW of capacity from location-constrained renewable resources in Wyoming to distant load centers. We find that, in addition to the other bases discussed above, construction or enhancement of transmission facilities designed to provide access to these types of remote resources is not routine.

46. We do not agree with protesters' assertions that the large scope of the Project is an artificial creation of combining several individual, smaller projects, nor that the Commission should analyze each of the segments individually to determine whether there is a nexus for each. We conclude that each segment of this Project (with the exception of segment A, as discussed above) will improve PacifiCorp's transmission operations and, among other things, increase transfer capability. Moreover, even if we were to find that each segment is a separate project, which we do not, the Commission has held that an applicant "may present evidence that a group of projects, when considered in the aggregate, are not routine."[64] Hence, consistent with Commission precedent, we consider, and conclude that the Project as a whole satisfies the nexus requirement.

47. Similarly, Bonneville and Industrial Customers' objections that transmission already planned to meet PacifiCorp's load service obligations should not receive incentive rate treatment are not persuasive. We explained in Order No. 679 that "[i]nclusion of a facility in a plan does not mean that a project can or will get built," and that even in such instances the granting of incentives may help to secure financing.[65]

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[62] This cost estimate reflects a single circuit configuration. However; we note that PacifiCorp seeks equity partners to upsize segments D, E and F from a single circuit to double circuit configuration, and that could significantly increase the Project costs. *Id.* at n.9.

[63] *Id.* at 7, Cupparo Affidavit at 7, 29-30.

[64] *BG&E*, 120 FERC ¶ 61,084 at P 53.

[65] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 35.

Additionally, PacifiCorp has provided ample evidence that by adding the additional transmission capability, the Project will ensure reliability and provide other benefits, as well as serve to meet load service obligations.

48. Regarding protesters' claims that PacifiCorp is already obligated to build certain segments as a result of its merger with MidAmerican, and that it should not receive incentive rate treatment consistent with *Westar*, we find that this case is distinguishable. In *Westar*, the Commission found that the petitioner had not explained why it required incentives to encourage investment in its project when the Commission had already directed it to increase transfer capability on the transmission line as part of mitigation requirements in another proceeding. The Commission explained that projects an entity is required to build may not necessarily qualify for incentives because there is that obligation and a high assurance of recovery of the related costs.[66] With respect to PacifiCorp, the record does not indicate that this Commission required the parties to construct any transmission as a condition for approval of the MidAmerican/PacifiCorp merger.[67] The parties apparently made commitments to build segments A, B, and C in proceedings before various state commissions, but PacifiCorp asserts that "Segments B and C represent significant expansions, of the original transaction commitments."[68] As such, the circumstances have changed since PacifiCorp entered into those transaction commitments. These distinctions, in conjunction with the manner in which segments B and C are integrated with the Project as a whole, lead us to conclude that incentives are warranted to encourage investment for these segments.

49. Finally, we address concerns raised by Utah Systems that investors may not stand to gain much from undertaking the risks associated with this investment. Because the additional revenues generated by the ROE adder will be used to reduce the transmission rates of PacifiCorp's retail customers, Utah Systems suggest that the increased revenue credits are the price of securing state approvals, which was not identified as a reason for granting incentives in Order No. 679. There is no evidence in the record regarding the impact of the requested incentives on state commission approval, nor is there any reason to believe the incentives will not attract investors to the Project. We therefore dismiss these claims by Utah Systems as speculative.

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[66] *Westar*, 122 FERC ¶ 61,268 at 49-50, citing Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 94.

[67] *See MidAmerican Energy Holdings Co.,* 113 FERC ¶ 61,298 (2005), *reh'g denied*, 118 FERC ¶ 61,003 (2007).

[68] PacifiCorp Petition at n.32.

50. Accordingly, for the reasons discussed above, we find that PacifiCorp's Project is not routine in nature, and, therefore, meets the nexus requirement to be eligible for incentives under Order No. 679.

D. Requested Incentives

1. ROE Adder

51. PacifiCorp's Project is unparalleled in terms of its size, cost, siting risk, regulatory and financial risk, technology-related risks, and other factors. In addition to the numerous risks and challenges associated with this Project, PacifiCorp will require an enormous investment (well in excess of $5 billion, even without the estimated $108 million needed to construct segment A), thereby presenting financing challenges not faced by the ordinary transmission investment. It is also important to recognize that PacifiCorp has voluntarily proposed to invest a large amount of capital to build backbone 500 kV transmission facilities through large portions of its system, which will ensure reliability and/or reduce congestion costs and facilitate the construction of additional high voltage facilities throughout the region. This, together with the vast size of the Project (roughly 2,000 miles of transmission lines, even excluding segment A) and the extended period of time for completion (through 2014) is the type of infrastructure development envisioned by EPAct 2005 and Order No. 679. All of these factors support the request for an incentive ROE adder, which PacifiCorp believes will attract capital for the Project, when added to the base ROE to be determined in a future rate case.

52. We also do not agree with Utah Systems' objection that, since a ROE on a large investment yields a greater number of dollars than the same ROE on a smaller investment, a greater percentage return is not appropriate for a larger project. In Order No. 679, the Commission permitted, when justified, an incentive-based ROE to all public utilities for new investments in transmission facilities that benefit consumers by ensuring reliability or reducing congestion costs.[69] The Commission concluded that ROE incentives encourage investment, and the granting of ROE incentives could make transmission projects more attractive and, therefore, more likely.[70] In evaluating these incentives, the Commission considered "the appropriateness of a higher ROE as a

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[69] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 91.

[70] *Id. See also Commonwealth Edison Co.*, 124 FERC ¶ 61,231, at P 29 (2008) ("A higher ROE encourages new transmission investment because it provides a longer term higher return on equity after the project comes on line, only for that new investment, and makes that transmission project more attractive as an investment.").

mechanism for increasing investment in new capacity."[71] In this instance, we find that PacifiCorp's incentive rate adder is justified based on the requirements of Order No. 679.

53. Accordingly, as discussed further below, we grant a 200 basis point incentive for the Project, to be added to the base ROE determined in a future PacifiCorp section 205 filing. Our grant of the incentive ROE adder will be bound by the upper end of the zone of reasonableness.

2. <u>Recovery of Abandoned Plant Costs</u>

54. PacifiCorp requests recovery of all prudently-incurred development and construction costs in the event the Project is cancelled or abandoned as a result of its inability to obtain necessary approvals, or as a result of any action or inaction by a governmental authority or regulatory agency, for reasons beyond PacifiCorp's control. In Order No. 679, we found that this incentive is an effective means to encourage transmission development by reducing the risk of non-recovery of costs.[72] Consistent with Order No. 679, PacifiCorp has shown a nexus between the recovery of prudently-incurred costs associated with abandoned transmission projects and its planned investment. Thus, we will grant the request for the recovery of prudently-incurred development and construction costs if the Project is cancelled or abandoned, in whole or in part, as a result of PacifiCorp's inability to obtain necessary approvals, or as a result of any action or inaction by a governmental authority or regulatory agency, for any reason determined to be outside PacifiCorp's control in subsequent section 205 filings.[73]

55. We find that this incentive will be an effective means to encourage the completion of the Project. For example, besides its scope and size, this Project requires timely approvals from multiple jurisdictions, along with various federal approvals. Dependence upon approval by multiple jurisdictions introduces a significant element of risk to this Project that is not faced by utilities building transmission facilities within a single jurisdiction. Granting the request for an abandonment incentive will help to ameliorate these risks and help ensure completion of the Project.

56. Regarding Bonneville's request for clarification regarding whether its actions could be construed as those of a "governmental authority" and thus potentially trigger PacifiCorp's ability to recover abandoned plant costs, we dismiss this request as premature. We will address any request for recovery of abandonment costs in the context

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[71] *See id.* P 85.

[72] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 163.

[73] *Id.* P 165-66.

of the required filing under FPA section 205. In that proceeding, PacifiCorp will bear the burden of demonstrating that the Project was cancelled or abandoned as a result of its inability to obtain necessary approvals, or as a result of any action or inaction by a governmental authority, or regulatory agency, for reasons outside PacifiCorp's control.

3. Total Package of Incentives

57. As noted earlier, in Order No. 679-A, the Commission clarified that its nexus test is met when an applicant demonstrates that the total package of incentives requested is tailored to address the demonstrable risks or challenges faced by the applicant. The Commission noted that this nexus test is fact-specific and requires the Commission to review each application on a case-by-case basis. Consistent with Order No. 679,[74] the Commission has, in prior cases, approved multiple rate incentives for particular projects.[75] This is consistent with our interpretation of FPA section 219 as authorizing the Commission to approve more than one incentive rate treatment for an applicant proposing a new transmission project, as long as each incentive is justified by a showing that it satisfies the requirements of the FPA section 219 and that there is a nexus between the incentives being proposed and the investment being made.

58. PacifiCorp states that the total package of incentives that it has requested is necessary to compensate it for the substantial risks posed by the Project. It also asserts that the overall risks associated with building the Project are not fully mitigated by an abandonment incentive, and argues that reducing its requested ROE adder because it has been granted an abandonment incentive "would misalign the scope of PacifiCorp's risks with its narrowly tailored incentive package."[76]

59. We find that PacifiCorp has shown, consistent with Order No. 679-A, that multiple incentives are justified to address the demonstrable risks or challenges faced by the Project.[77] An ROE adder and abandoned plant costs incentive rate treatment are not mutually exclusive, and PacifiCorp has explained why it is seeking each incentive and

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[74] Order No. 679, FERC Stats. & Regs. ¶ 31, 222 at P 55.

[75] *See, e.g.*, *Allegheny Energy, Inc.*, 116 FERC ¶ 61,058, at P 60, 122 (2006) (approving ROE at the upper end of the zone of reasonableness and 100 percent abandoned plant recovery); *Duquesne Light Co.*, 118 FERC ¶ 61,087, at P 55 (2007) (granting an enhanced ROE, 100 percent CWIP, and 100 percent abandoned plant recovery).

[76] PacifiCorp Petition at 39.

[77] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 21, 27.

how each is relevant to the proposed Project. As discussed above, PacifiCorp faces significant risks and challenges in pursuing this Project. We find here that granting the ROE incentive, together with abandoned plant recovery, will encourage greater participation from potential equity partners. Due to the number of approvals needed, the cost of the Project construction, the fact that transmission construction will precede siting of new generation, and other factors cited, PacifiCorp is exposed to greater risks of project failure which results in increased risks to debt. The two incentives sought by PacifiCorp serve different purposes; thus, we reject protestors' arguments that the total package of incentives is unwarranted, and find that PacifiCorp has shown a nexus for the total package of incentives. However, we will approve a 200 basis point adder rather than the 250 basis point adder requested by PacifiCorp. A 200 basis point adder is a significant increase in the return on equity that will be earned on this ambitious infrastructure investment; we find that such adder is just and reasonable under the circumstances presented by PacifiCorp's application.

4. Other Issues

60. In Order No. 890, the Commission required transmission providers to open their transmission planning process to customers, coordinate with customers regarding future system plans, and share necessary planning information with customers.[78] The Commission identified important benefits stemming from that requirement, finding that an open, transparent, and coordinated transmission planning process would increase the ability of customers to access new generating resources, including renewable resources, and would promote efficient utilization of transmission.[79] Such potential benefits are particularly important with respect to the development of new backbone transmission facilities like the Project. PacifiCorp indicates in the Petition that it is continuing to explore the proper size and exact location of some segments of the Project.[80] To the extent that such aspects of the Project remain under consideration, the Commission expects that PacifiCorp will address them as appropriate through the transmission planning process required by Order No. 890.[81]

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[78] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 3.

[79] *Id.* P 3, 5.

[80] *See, e.g.*, PacifiCorp Petition at 13, n.23 (regarding the section of segment E that is intended to connect the Populus substation to the Hemingway substation) and Cupparo Affidavit at 12 (regarding possible upsizing of segment G).

[81] In July 2008, the Commission accepted PacifiCorp's Order No. 890 transmission planning compliance filing, as well as comparable filings submitted by other

(continued...)

61. UMPA raises concerns about the proposed credit to retail customers. UMPA believes that, as a result of the crediting mechanism, only PacifiCorp's wholesale customers would pay the proposed incentive rate. UMPA suggests that PacifiCorp has requested a higher incentive rate than necessary, given that it will only be recovered on ten percent of its transmission revenue requirement, and concludes that the retail credit is preferential and unduly discriminatory.

62. We find that UMPA's assertion is beyond the scope of this proceeding. Any future proposal by PacifiCorp to provide a credit to its retail customers is a matter for state commission approval. We also disagree that the requested incentive is higher than necessary, as discussed above. To the extent that UMPA is concerned about the equities of rate allocation between wholesale and retail customers, this issue is properly raised when PacifiCorp files under FPA section 205 to recover costs associated with the Project.

63. Finally, we deny protestors' requests that we set this matter for hearing. In general, the Commission sets matters for a trial-type evidentiary hearing only to resolve material issues of law and fact. In this case, however, since PacifiCorp has satisfied the requirements of Order No. 679, except for segment A, we conclude that setting this matter for hearing is not appropriate.

<u>The Commission orders</u>:

The petition for declaratory order is hereby granted in part, and denied in part, as discussed in the body of this order.

By the Commission. Commissioners Kelly and Wellinghoff concurring with separate statements attached.
Commissioner Moeller not participating.

(S E A L)

Kimberly D. Bose,
Secretary.

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transmission providers in the region and the related NTTG Agreements, subject to modifications and further compliance filings. *Idaho Power Co.*, 124 FERC ¶ 61,053 (2008).

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PacifiCorp Docket No. EL08-75-000

(Issued October 21, 2008)

KELLY, Commissioner, *concurring:*

This order addresses a petition for declaratory order seeking incentive rate treatment filed by PacifiCorp. PacifiCorp requests two transmission rate incentives for its extra-high voltage (EHV) transmission project: a 250 basis point adder to its base return on equity (ROE) and recovery of prudently-incurred abandonment costs if the Project is cancelled due to factors beyond its control.

It is appropriate to consider Segments B through H of PacifiCorp's EHV petition as a single, integrated transmission project. In applying the project-based criteria that I have relied upon in previous transmission incentives proceedings to determine whether PacifiCorp's EHV transmission project warrants incentive rate treatment,[1] I conclude that it does. Thus I concur with the decision to grant the requested incentives, as modified in the order.[2] I take this opportunity to present my reasons for doing so.

PacifiCorp's objective in undertaking this EHV transmission project, among other things, is to establish a 500 kV backbone throughout 6 western states, efficiently integrate wind resources into the grid, and connect PacifiCorp's Rocky Mountain Power and Pacific Power control areas. The overall project is comprised of eight segments, which PacifiCorp has organized into four priority groups. Intervening parties argued that the various segments are not necessarily interrelated and should be analyzed on an individual basis. In a recent transmission incentives case, I warned against evaluating disparate transmission projects as a single, integrated transmission project.[3] However, for the reasons

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[1] *American Electric Power Service Corporation*, 118 FERC ¶ 61,041 (2007).

[2] The order denies incentive rate treatment to Segment A. I concur with this decision. PacifiCorp has neither demonstrated it is an integrated segment of the overall project nor shown it to merit incentives on an individual basis.

[3] *Pepco Holdings, Inc.*, 124 FERC ¶ 61,176 (2008). See separate statement (continued...)

listed below, I am satisfied that Segments B through H comprise a single integrated project. In this case, I assessed the merits of each project individually and determined that, with the exception of Segment A, all segments would be eligible for some form of incentive rate treatment. However, I also considered whether these segments are an integrated whole. I find that Segments B through H are interrelated because they satisfy the overarching goals of building an EHV transmission backbone across six states and bringing renewable resources to load centers. When considered in the aggregate, PacifiCorp's EHV transmission project represents an exceptional undertaking, larger than any other project the Commission has yet seen (within the context of incentives applications) as measured across any number of metrics, including total estimated costs, total line miles and geographic footprint. For example, while Segments B and C provide a variety of benefits when considered in isolation, they also enable PacifiCorp to achieve the planned transfer capability rating of subsequent segments.[4] Though Segment G is geographically separate from other parts of this transmission proposal, it is a piece of Gateway South, which is designed to provide access to resources from Wyoming to parts of Utah and Nevada. Because the 500 kV infrastructure proposed by PacifiCorp is so much larger in voltage terms than the exiting transmission infrastructure in parts of Idaho, Utah, and Wyoming, PacifiCorp must construct Segments, D, E, and F to provide a fully redundant transmission system. Finally, PacifiCorp is building Segment H to provide for the integration of PacifiCorp's east and west control areas, and to further support delivery of renewable energy.

It is appropriate to grant PacifiCorp's request for incentive rate treatment, as modified by the order. In absolute terms, as well as relative to PacifiCorp's current transmission plant in service, the financial undertaking here is significant. The total estimated cost of Segments B through H is $5.5 billion, representing over 3 times PacifiCorp's already large $1.8 billion transmission plant in service. The Project adds roughly approximately 2,000 miles of new EHV transmission infrastructure across 6 states—Nevada, Idaho, Oregon, Utah, Washington, and Wyoming—and the estimated time to completion for the final segments is 2014. While PacifiCorp's home territory is in most of these states, coordinating regulatory approvals across a large number of authorities will require significant effort and resource commitment. Finally, I believe that the EHV transmission project will produce an array of public interest benefits. It will create an EHV backbone transmission system that connects existing and future resources,

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of Commissioner Kelly issued August 27, 2008.

[4] PacifiCorp July 3, 2008 Petition for Declaratory Order, Docket No. EL08-75-000, Appendix A at 10.

including renewables, with consuming areas. PacifiCorp's project will facilitate delivery of as many as 3,000 MW from location-constrained renewable resources in Wyoming. Moreover, once this backbone has been installed, it should facilitate the addition of future 500 kV infrastructure at a lower cost.

I concur with the specific incentives approved in this order—recovery of prudently-incurred abandonment costs and a 200 basis point ROE adder. I have previously approved the abandoned plant incentive for projects that I believe to be eligible for incentives. In this case such treatment is supported by the long construction period, large cost, both in absolute terms and as a percentage of current rate plant in service, and risks associated with the regulatory processes.

With respect to an incentive ROE adder, PacifiCorp asserts that the overall risks associated with building the project are not fully mitigated by an abandonment incentive. While I have previously stated that basis point adders to ROE may be used to overcome either financial or non-financial impediments to transmission expansion,[5] I have approved ROE adders in a limited number of proceedings and those adders were well below 200 basis points. In this case, I agree with the order and support an ROE adder of 200 basis points for Segments B through H. Order No. 679-A states "the most compelling case for incentive ROEs are new projects that present special risks or challenges, not routine investments made in the ordinary course."[6] PacifiCorp's EHV transmission project meets this standard.

There are several features of PacifiCorp's project that subject PacifiCorp to risks and challenges not seen in the ordinary course of business. PacifiCorp will be installing Segments B through H over the course of the next five and half years at an estimated cost of $5.5 billion. While I generally prefer approving recovery of 100 percent of prudently incurred Construction Work In Progress (CWIP) incentive to mitigate some of the risks of constructing a project over a long development schedule, PacifiCorp asserts that CWIP does not provide significant protection in this case. As noted above, the abandoned plant incentive is not sufficient to address such risk alone and therefore an ROE adder is appropriate. PacifiCorp will also be deploying an assortment of advanced technologies.

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[5] *Bangor Hydro-Electric Company*, 117 FERC ¶ 61,129 (2006) (*Opinion No. 489*).

[6] *Promoting Transmission Investment through Pricing Reform*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236, at P 60 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

I believe that PacifiCorp's EHV transmission project provides public interest benefits that, on balance, contribute to the appropriateness of the ROE adder. The geographic and financial scope of the overall project when combined with PacifiCorp's decision to undertake transmission development ahead of generation creates significant financial risk that merits an incentive ROE adder. Rather than embark upon an incremental, small-scale expansion of its transmission system, PacifiCorp elected to construct this wide-ranging EHV transmission project. As PacifiCorp notes, this represents a departure from convention and presents novel investment risks. An incentive ROE adder is appropriate here as I do not believe that other incentives discussed in Order 679 address this circumstance. It is significant that establishing a "first-of-its-kind energy superhighway" connecting Wyoming, Idaho, Utah and Oregon will offer benefits to future developers of EHV transmission lines as they will likely face fewer engineering and system reliability obstacles.

There are also opportunities for third party equity partnership at various points in the overall project. Segments D and E appear to be on course to be jointly-owned with Idaho Power, and there are further opportunities for third party equity partnership on other segments. Segments F, G, and H are sufficiently flexible to allow for "upsizing" (i.e. from a single circuit to a double-circuit system or from 230 kV to 500 kV) or reconfiguration, depending on participation of potential equity partners. PacifiCorp states that it is "actively working with potential equity partners to determine the interest and commitment to such an upsize."[7] Approval of incentives here offers PacifiCorp an appropriate incentive to progress with development of all project segments and provides certainty with respect to approved incentives that should promote equity partnerships. In instances where the Commission can support joint ownership and "upsizing" of infrastructure, I believe that incentive rate treatment is appropriate. In future proceedings, I would support approval of a minimum level of incentives (e.g. a minimum ROE adder) and condition further incentives, such as supplemental ROE basis points, on completing equity partnership arrangements and commitments to upsizing transmission infrastructure.

Accordingly, I respectfully concur with this order.

Suedeen G. Kelly

[7] PacifiCorp July 3, 2008 Petition for Declaratory Order, Docket No. EL08-75-000, at 5 n.9.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PacifiCorp Docket No. EL08-75-000

(Issued October 21, 2008)

WELLINGHOFF, Commissioner, concurring:

In today's order, the Commission approves a 200 basis point incentive ROE adder for PacifiCorp in connection with its Energy Gateway Transmission Expansion Project. I agree with that decision. I write separately to highlight important characteristics of this project that I believe warrant this significant incentive ROE adder.

I have dissented from numerous orders in which I felt that the majority undermined the nexus requirement that is an essential component of Order No. 679 and inappropriately granted incentive ROE adders.[1] By contrast, I agree that this project satisfies the nexus requirement. It is noteworthy that this project is, as described in today's order, "the first backbone 500 kV 'superhighway' in this part of the Western Interconnection and may facilitate the addition of future 500 kV transmission lines in the area."[2] At least as important, I believe that this project is a non-routine investment worthy of the significant incentive ROE adder granted here because it will use advanced technologies that will benefit all users of the grid and ultimate consumers, and because it will significantly increase the availability of renewable energy resources.

With respect to the use of advanced technologies, PacifiCorp provides substantial detail in its required technology statement and accompanying testimony. For example, PacifiCorp describes its plans concerning advanced conductor technology, Static VAR Compensators, and phase shifters, among other technologies.[3] PacifiCorp Witness John Cupparo states that "[r]eliance on novel technologies inherently posts increased risks in the form of added uncertainty as to how they will perform within the context of this large

[1] *See, e.g.*, *Commonwealth Edison Co.*, 122 FERC ¶ 61,037 (2008) (dissent in part of Commissioner Wellinghoff); *Virginia Elec. and Power Co.*, 124 FERC ¶ 61,207 (2008) (dissent of Commissioner Wellinghoff); *Duquesne Light Co.*, 125 FERC ¶ 61,028 (2008) (dissent in part of Commissioner Wellinghoff).

[2] *PacifiCorp*, 125 FERC ¶ 61,076 at P 42 (2008).

[3] PacifiCorp Petition at 41-48 and Cupparo Affidavit at 24-29.

project."[4] While recognizing such risks and challenges, PacifiCorp also states that it "is committed to optimizing the technology that will be utilized by the Project."[5]

As I have discussed previously, I believe that consideration of advanced technologies and their associated risks and challenges is an appropriate component of the nexus analysis that the Commission conducts in evaluating applications for incentives under Order No. 679.[6] Consistent with such consideration, today's order accounts for technology-related risks in evaluating PacifiCorp's incentives request.[7]

With respect to increasing the availability of renewable energy resources, PacifiCorp states that this project will facilitate the delivery of up to 3,000 MW of capacity from location-constrained renewable resources in Wyoming to distant load centers.[8] I agree with the statement in today's order that construction or enhancement of transmission facilities designed to provide access to these types of remote resources is not routine.[9] I have stated previously that amid heightened concerns about climate change and dependence on foreign oil, it is essential that our country take steps to accelerate the integration of clean, reliable, domestic renewable energy resources into our energy portfolio.[10] In light of the broad and substantial benefits associated with increasing the availability of renewable energy resources, I continue to believe that it is appropriate for the Commission to provide investment incentives in this area. I also note that in granting such incentives, it remains important for the Commission to promote the use of intelligent and efficient technologies that optimize operation of the facilities at issue.

For these reasons, I concur with today's order.

Jon Wellinghoff
Commissioner

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[4] Cupparo Affidavit at 32.

[5] PacifiCorp Petition at 42.

[6] *See, e.g., Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188 (2008) (dissent in part of Commissioner Wellinghoff at 1-4); *Northeast Utilities Service Co.*, 124 FERC ¶ 61,044 (2008) (dissent of Commissioner Wellinghoff at 2-3).

[7] *PacifiCorp*, 125 FERC ¶ 61,076 at P 43, 51 (2008)

[8] *Id.* P 45.

[9] *Id.*

[10] *See Southern California Edison Co.*, 121 FERC ¶ 61,168 (2007) (concurrence of Commissioner Wellinghoff at 2).