Q. Please state your name, business address, and present position.

A. My name is Darrell T. Gerrard. My business address is 825 NE Multnomah Street, Suite 1600, Portland, Oregon 97232. I am currently employed as Vice President – Transmission System Planning for PacifiCorp. I have held my present position since May 2007. The primary duties of my present position include management and oversight of all Main Grid Transmission System Planning requirements for both Rocky Mountain Power and Pacific Power, which are operating units of PacifiCorp (collectively referred to as the "Company").

Q. Please describe your education and business experience.

A. I have a Bachelor of Science degree in Electrical Engineering from the University of Utah. My experience spans more than 30 years in the electric utility business and electric industry in general. I have experience and have been responsible for a number of functional organizations at the Company including: Area Engineering, Area Planning, Region Engineering, T&D Facilities Management, Transmission, Substation and Distribution Engineering, System Protection and Control, T&D Project Management and Delivery, Asset Management, Electronic Communications, Hydro System Engineering, Transmission Grid Operations, and most recently Transmission System Planning. Currently my responsibility is to ensure that proper planning activities are performed as necessary for the Company's bulk transmission system. I am also responsible for the conceptual design and ongoing electrical transmission system planning required to support the Company's Energy Gateway Program.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the purpose and need for the Sigurd to Red Butte No. 2 - 345 kV transmission line (the "Transmission Project" or the "Project") in support of the Company's request for a Certificate of Public Convenience and Necessity ("CPCN").

Q. Please summarize your testimony.

A. In summary, the Transmission Project is necessary to first, improve the overall reliability of the Company's existing transmission system and second it is necessary to meet both short and long term customer demands for energy. The southwest Utah transmission system, including the existing Sigurd to Three Peaks to Red Butte No. 1 – 345 kV transmission line and the Red Butte to Harry Allen 345kV line cannot currently provide adequate and reliable service under all expected operating conditions and expected future customer demands. Additionally, the existing 345kV transmission line between the Sigurd and Red Butte substations represents the sole transmission connection between major southwest Utah load areas, and generation sources expected to serve this customer load. Today loss of this existing line exposes over 120,000 electric customers and over 425 megawatts of demand to loss of supply line outage events. Load growth in southwestern Utah has increased significantly over time and is forecasted to continue to increase beyond the current recession period, further surpassing the capabilities of the existing transmission system. New transmission facilities must be constructed to provide reliable capacity for load service. Without the Project, peak load in southwestern Utah cannot be reliably served during transmission line outages or major substation equipment contingencies. The Project will not only improve reliability and support future electrical load growth in southwestern Utah, but will also improve the ability of Rocky Mountain Power's transmission system to transport energy into southwest and central Utah, and on to high growth urban areas in and around Salt Lake City,along the Wasatch Front, and to Company's eastern control balancing area in general. Due to the interconnected nature of the Company's transmission system, this Project will benefit PacifiCorp's system in a regional context. Utah is currently one of the fastest growing states and projections indicate that it will continue to grow rapidly for decades. Staying ahead of expected future energy demand is therefore critical. Finally, in addition to meeting our customers' future energy requirements, this Project is key to maintaining the Company's compliance with mandated North American Electric Reliability Corporation ("NERC") and Western Electricity Coordinating Council ("WECC") reliability and performance standards during normal system operations and during certain transmission system and generation plant outage conditions.

GENERAL DESCRIPTION OF THE PROJECT

Q. Please describe the Transmission Project.

A. The Project is a component of the Company's long range transmission plan and consists of a new single circuit 345 kV transmission line that will be built between the existing Sigurd substation in Sevier County located approximately six miles northeast of the town of Richfield, Utah, to the Red Butte substation west of State Route 18 and the town of Central in Washington County, Utah. The total length of the Project will be approximately 160 miles, depending on the alternative alignment selected. The precise alignment for the Project has not yet been determined. Because much of the Project will be located on federal land managed by the U.S. Bureau of Land Management of the U.S. Department of Interior ("BLM") as well as the U.S. Forest Service of the U.S. Department of Agriculture (the "USFS"), the ultimate line route decision will be made by the BLM, which has been designated as the lead agency in the federal environmental review process. This decision will be based on an environmental impact statement ("EIS") currently being prepared in accordance with the National Environmental Policy Act ("NEPA"). This process requires, among other things, input by the public, state and federal land and resource agencies, the affected counties and other local jurisdictions. A map showing the EIS study area for the Project is attached hereto as Exhibit RMP___(DTG-1). The Company has been prudent by very actively engaging in the NEPA and permitting process for four years and nine months in order to anticipate the Projects needed in-service date.

Construction of the Project will commence upon approval of the CPCN by the Commission, and issuance of Records of Decision by the BLM and USFS. The duration of construction activities will depend, in part, on the timing of Project authorizations, but in general, the entire Project is expected to require approximately 26 months to complete, with a minimum of 16 months required for heavy construction activities. The Project is designed to meet an in-service date of June 30, 2015.

BACKGROUND

Q. What is your general understanding of the standard for the Commission's decision in this case?

A. I am not an attorney but have relied on legal counsel for this response. In *Mulcahy v. Public Service Commission,* 117 P.2d 298 (Utah 1941), the court stated:

> The "convenience" and "necessity" required to support an application for a certificate **are those of the public**, not those of individuals. . . . "Necessity" and "convenience" are not to be construed as synonymous. Convenience is much broader and more inclusive than necessity, but effect must be given to both. **Necessity means reasonably necessary** and not absolutely imperative. . . . It does not mean "necessary" in the ordinary sense of the term. The convenience of the public must not be circumscribed by holding the term "necessity" to mean an essential requisite.
>
> . . .
>
> [I]n determining whether or not the convenience and necessity of the public will be best subserved by the proposed service, the needs and welfare of the people **of the territory or community affected should be considered as a whole**. (117 P.2d at 300, 301; emphasis added)

Q. Has the Commission provided any further guidance in the issuance of a CPCN?

A. Yes. In the Scheduling Order issued in May 2008 that granted a certificate of public convenience and necessity for the Populus – Terminal transmission line project, the Commission was clear that siting of a transmission line is not within the issuance criteria of this type of docket:

> The Commission desires to clarify the purpose of this proceeding. This proceeding is not about the location or siting of the Transmission Line if it is built. The Commission does not have jurisdiction over the siting of transmission lines. **This proceeding is to determine if present or future public convenience and necessity does or will require construction of a transmission line.** (Scheduling Order at page 1; emphasis added).

In its final order in that docket, the Commission reaffirmed that “the Commission does not have jurisdiction over the siting of transmission lines generally nor of this particular facility. . . . Our proceedings are to determine if present or future public convenience and necessity does, or will, require construction of a transmission line.” (Report and Order Granting Certificate and Certificate of Public Need and Necessity, Docket No. 08-035-42, September 4, 2008, at page 2). It is also my understanding that granting of a certificate does not constitute determination of prudency by the Commission.

Q. Recognizing that siting is not an issue here, it may nonetheless be helpful as general background for the Commission to be aware of the proposed route for the Transmission Project. What is the current proposed route for the transmission portion of the Project?

A. A map showing the Company’s proposed route of the Transmission Project is attached as Exhibit RMP___(DTG-2), which, of course, is subject to adjustment based on the outcome of the Final EIS and the Records of Decision from the BLM and USFS. Further, as with any project of this nature, it is also subject to minor route adjustments that may occur during final engineering and design, and working directly with landowners along the transmission line route. The existing Sigurd and Red Butte substations will be upgraded to accommodate the new transmission lines, equipment and termination points.

Q. What is the projected cost of the Project?

A. The projected cost of the Project is approximately $380 million.

STATUS OF ENVIRONMENTAL APPROVAL

Q. What is the current status of the Environmental Impact Statement and approval?

A. The Company filed a right of way permit application with the BLM and the USFS in December 2008, which triggered the need to prepare an EIS in accordance with the requirements of NEPA. The draft EIS was released for public comment in May 2011, with the final EIS scheduled for publication in October 2012. The Company anticipates that the BLM and USFS will issue their respective Records of Decision in December 2012. As noted previously, the BLM has been designated as the lead agency in the EIS process. The Company believes the BLM's decision will result in the issuance of the rights-of-way and authorizations necessary for the Company to begin construction on federally-administered lands. We will, of course, inform the Commission when the environmental approval has been granted, and of any changes to the Company's proposals that may result from that approval process.

Q. What is the current status of the Environmental Assessment and approval?

A. The Company conducted geotechnical soil sampling investigations to identify the geotechnical conditions along each of the alternative routes, to assist in foundation designs, and to facilitate the development of more accurate construction costs. In order to obtain the necessary authorization from the BLM and USFS to conduct these geotechnical investigations, including borehole drilling, an Environmental Assessment ("EA") was required to analyze potential impacts on natural, human and cultural resources along each alternative route as a result of these activities. The BLM, in cooperation with the USFS, state, county and municipal agencies, has completed the EA and issued a Finding of No Significant Impact ("FONSI"). Following the BLM's decision, the Company commenced the geotechnical studies, including borehole drilling activities, in September 2010.

THE PROJECT DECISION—RELIABILITY AND LOAD SERVICE

Q. Customer load growth information is an important factor in determining the need and the timing of transmission projects. What load information was used to determine the Project is needed now?

A. PacifiCorp's Open Access Transmission Tariff ("OATT"),[1] approved by the Federal Energy Regulatory Commission ("FERC"), details the Company's requirements and obligations to provide transmission service. Section 28.2 defines PacifiCorp's responsibilities, which include the requirement to "plan, construct, operate and maintain the system in accordance with good utility practice." Section 31.6 defines the requirement for all network customers to supply annual load and resource updates for inclusion in planning studies. The Company solicits this data annually in order to determine future load and resource requirements for all transmission network customers. The Company's retail loads comprise the bulk of the transmission network customer need in Utah with the exception of southwest Utah where the company provides network transmission service to other utilities who are the major electric service providers in the area. Details regarding those other utilities who are dependent on the Company's transmission system is provided later in my testimony. Section 28.3 states the requirement for PacifiCorp

[1] http://www.oasis.pacificorp.com/oasis/ppw/OATTVol11Baseline_20100908.pdf.

to provide "firm service over the system so that designated resources can be delivered to designated loads." The Project is necessary to meet these requirements and to meet expected and forecasted customer energy demand. Under the Company's OATT it is required to provide adequate and non-discriminatory service to all network customers.

Q. What specific reliability standards and criteria require the Project and its timing to completion?

A. PacifiCorp plans, designs, and operates its transmission system to meet or exceed NERC Standards for Bulk Electric Systems and WECC Regional standards and criteria. The NERC standards are federal law stated in 18 CFR Part 40 (Mandatory Reliability Standards for Bulk-Power Systems). The WECC standards and criteria are deemed necessary for the WECC Region to meet or exceed NERC standards. There are currently more than 100 approved NERC standards with which the Company must comply. The Project and its respective in-service date timing are required to maintain compliance with the following:

- NERC TPL-001 System Performance Under Normal Conditions[2]
- NERC TPL-002 System Performance Following Loss of a Single BES Element[3]
- NERC TPL-003 System Performance Following Loss of Two or More BES Elements[4]
- NERC TPL-004 System Performance Following Extreme BES Events[5]

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[2] NERC TPL-001 can be found at: http://www.nerc.com/files/TPL-001-0.pdf.
[3] NERC TPL-002 can be found at: http://www.nerc.com/files/TPL-002-0.pdf.
[4] NERC TPL-003 can be found at: http://www.nerc.com/files/TPL-003-0.pdf.

- TPL 001-WECC-1-CR System Performance Criteria Normal Conditions[6]
- TPL 002-WECC-1-CR System Performance Criteria Following Loss of a Single BES Element
- TPL 003-WECC-1-CR System Performance Criteria Following Loss of Two or More BES
- TPL 003-WECC-1-CR System Performance Criteria Following Extreme BES Events
- NERC TOP-002 [Normal Operations Planning](http://www.nerc.com/files/TPL-002-0.pdf)[7]
- NERC TOP-004 [Transmission Operations](http://www.nerc.com/files/TPL-004-0.pdf)[8]
- NERC TOP-007 [Reporting SOL and IROL Violations](http://www.nerc.com/files/TOP-007-0.pdf)[9]

The above-referenced standards dictate the minimum levels of transmission system reliability, redundancy, and performance required for transmission facilities. The Company must have adequate transmission system capacity to serve customers in advance of the expected demand and must be proactive in doing so.

Q. Please discuss further how these standards and criteria influence the timing of the Project.

A. These mandatory standards require the Company to have a forward-looking transmission plan of action to reliably serve current and anticipated customer demands under all expected operating conditions, including normal system

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[5] NERC TPL-004 can be found at: http://www.nerc.com/files/TPL-004-0.pdf.
[6] TPL 001-WECC-1-CR – TPL 004-WECC -1-CR can be found at: http://www.wecc.biz/Standards/WECC%20Criteria/TPL-001%20thru%20004-WECC-1-CR%20-%20System%20Performance%20Criteria.pdf.
[7] NERC TPL-002 can be found at: http://www.nerc.com/files/TPL-002-0.pdf.
[8] NERC TPL-004 can be found at: http://www.nerc.com/files/TPL-004-0.pdf.
[9] NERC TOP-007 can be found at: http://www.nerc.com/files/TOP-007-0.pdf.

operations (all system elements in service) and during system contingencies (where elements of the transmission system are out of service), both planned or otherwise. NERC Transmission Planning Standard TPL 002 states:

> **A. Introduction**
> **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that *meet specified performance requirements with sufficient lead time*, and continue to be modified or upgraded as <u>*necessary to meet present and future system needs.*</u>
>
> **B. Requirements**
> **R1.** The Planning Authority and Transmission Planner shall each demonstrate through valid assessment that its portion of the interconnected transmission *system is planned such that the Network can be operated to supply projected customer demands and projected Firm (nonrecallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions* as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:
>
> > **R1.1.** Be made annually.
> > **R1.2.** Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
>
> **R2.** When System simulations indicate an *inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1*, the Planning Authority and Transmission Planner shall each:
>
> > **R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
> > ***R2.1.1.*** *Including a schedule for implementation.*
> > ***R2.1.2.*** *Including a discussion of expected required in-service dates of facilities.*
> > ***R2.1.3.*** *Consider lead times necessary to implement plans.*

(Emphasis added)

The Company is required to have both short-term and long-term transmission plans to reliably meet all expected current and forecasted customer electrical demands. The requirement to have such plans and prudently meet current and forecasted customer demand is not optional for the Company. Projects of this size require multi-year planning, permitting and construction processes, and the Company must anticipate the need for adequate lead times and schedules for implementation of the Project.

Q. Is the Transmission Project included in the Company's IRP plans currently under development and scheduled for release in early 2013?

A. Yes: The timing of the Project CPCN and timeline for the Company to enter into a contract for construction are key in the Company's decision to include the Project in its current IRP planning cycle analysis for 2013. Utah Report and Order under Docket No. 11-2035-01 issued March 22, 2012 page 10, the Commission stated the Company's "*existing system should represent only facilities which have already received a certificate of convenience and necessity (if required) or for which the Company has a binding contract in place. All other facilities should be included in core or sensitivity cases as options.*" The Project is necessary to reliably deliver existing and future network resources to existing and future network loads. In addition, the Company anticipates this regulatory proceeding to approve a CPCN for the Project will be concluded before the Company publishes its final 2013 IRP.

Q. Has the Company entered into a binding contract for design and construction of the Project?

A. The Company has competitively bid the Project as a part of its Engineer, Procure, and Construct ("EPC") strategy used in effective delivery of transmission projects of this size and scope. The Company expects to complete bid evaluations and to award contracts for the Project in November, 2012. The Company fully recognizes that its efforts in the EPC bidding process and subsequent award of construction contracts necessary for the Project is occurring in a parallel track with this CPCN proceeding however, the contract timing and award is necessary in order to preserve the design and construction durations and timelines necessary to efficiently place the Project in-service by June 2015. In recognition of this timeline requirement, the Company has structured and negotiated contract terms that allow termination of these contracts, by the Company, in the event the CPCN is not issued or in the event the Record of Decision and Notice-to-Proceed are not received from the BLM as lead agency in the NEPA process.

Q. Has the Transmission Project been included in previous IRP modeling and analysis?

A. Yes. The 2008 Integrated Resource Plan ("IRP"), updated March 31, 2010, and 2008 IRP Update Errata dated June 16, 2010, include the Project as part of the modeled transmission topology for the purpose of selecting the Company's preferred portfolio of future supply-side and demand-side resources. The 2008 IRP describes what the Company calls the "Energy Gateway Transmission Expansion." (2008 IRP, at pages 60-66). The Sigurd to Red Butte Transmission Project is an integral part of the Energy Gateway Transmission Expansion. Energy Gateway is designed to use "a 'hub and spoke' concept to most efficiently integrate transmission lines and collection points with resources and loads centers aimed at serving the Company's customers while keeping in sight Regional and Sub Regional needs." (2008 IRP, at page 61). The "2008 IRP Action Plan

Update" consisted of 21 Action Items, one of which was to "Permit and construct a 345 kV line between Sigurd and Red Butte." (2008 IRP, Table 6.1, at pages 56 thru 66; the Sigurd to Red Butte project is identified as item 12 on page 64).

The Populus to Terminal transmission project (CPCN approved in Report and Order, Docket No. 08-035-42, September 4, 2008) and the approved Mona to Oquirrh transmission project (CPCN approved in Report and Order, Docket No. 09-035-54, July 16, 2010) are also part of the Energy Gateway Transmission Expansion. The Company's success in providing low-cost energy depends on its ability to reliably acquire and transmit power from numerous sources to load centers. In addition, these coordinated projects represent a long-term effort by the Company to deliver network resources to loads, to support retail load growth, and improve reliability of the power grid, all of which is beneficial to the Company's customers as a whole.

Further the Project was incorporated as part of a transmission expansion option included in the 2007 IRP capacity expansion optimization model. This analysis helped support the decision to include the Project as part of the Company's preferred portfolio. (2007 IRP, pg. 231)

Q. How does this Project meet the requirements of the current IRP in light of the current recession?

A. The 2011 IRP recognizes that, at least in the near term, load growth will not be as vibrant as had been forecast in the 2007 IRP, an issue I discuss further below.

For many years, Utah has been a high-growth state. Indeed, based on the recently released 2010 census, Utah's population increased by 23.8 percent over the last decade, the third highest growth rate in the country.[10] The Company is unaware of any data or other projections that suggest that this will change in any substantial way (particularly given Utah's natural population growth, which I discuss in detail below). When the recession ends, Utah will continue to be attractive to business and industrial growth and electricity will be essential to meet Utah's above-average population growth.

With respect to Washington County, according to U.S. Census Bureau information there were 90,345 residents in 2000 and the 2007 projected population was 133,447, resulting in a 47.7 percent increase from 2000 to 2007. This growth translated into significant increases in electrical demand in the area of the Washington County, consistently maintaining growth rates from 10 – 20 percent annually from 2001 to 2007. Since 2007, the estimated population growth was drastically reduced through 2011 but is beginning to increase. This was confirmed with the 2010 census which reported a total population of 138,115. Census estimates for future population growth in Washington County is expected to reach 141,666 in 2011 and will continue at the current modest growth levels.[11]

Utah has not been as hard hit by the recession as other states and the country as a whole. The seasonally adjusted national unemployment rate for November 2010, according the Bureau of Labor Statistics ("BLS"), was 9.8 percent.[12] The BLS reported that Utah's unemployment rate for the same period

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[10] *See* http://2010.census.gov/2010census/data/apportionment-pop-text.php.
[11] http://quickfacts.census.gov/qfd/states/49/49053.html.
[12] http://data.bls.gov/PDQ/servlet/SurveyOutputServlet?data_tool=latest_numbers&series_id=LNS14000000

was 7.5 percent,[13] the sixteenth lowest unemployment rate of the fifty states.[14]

Of course, the long-range planning represented by the IRP requires the Company to look far beyond the current recession to assure that the electricity needs of Utah are met on a much longer time line. Thus, while demand has been affected by the recession and the 2011 IRP Update dated March 30, 2012 has scaled-back its estimate of future customer peak load demand, the Company's network load obligation in Utah is still expected to grow during the next ten years at an average annual energy demand growth rate of about 2.5 percent. (2011 IRP Update, at page 28 Table 3.2) The Company must ensure that, not only are there adequate supplies of electricity to meet ongoing customer demands for energy, but also that the transmission system has the capacity and reliability to deliver this increased demand for electricity to customers. At the same time, adequate transmission capability is essential for the Company to maintain its obligation to provide reliable and safe electricity to all of its customers. Without increased reliability and new capacity gained by the Project, the Company will not be able to reliably meet customer energy needs.

UTAH POPULATION GROWTH

Q. Are the energy demand growth estimates in the Company's 2011 IRP and estimates from other Network customers served by the Company consistent with other data sources?

A. Yes. While I am not an expert on population growth drivers in our service areas, I reviewed a new state study of Utah's economy, the 2010 Economic Report to the

[13] http://www.bls.gov/eag/eag.ut.htm.
[14] http://www.bls.gov/web/laumstrk.htm.

Governor ("2010 Report").[15] I have attached a portion of the "Demographics" section of the Report as Exhibit RMP___(DTG-3).

Population growth is a combination of two factors: (1) natural growth (births minus deaths) and (2) net migration (the number of people moving into the state minus people moving out of the state). Based on the 2010 Report, in both factors, growth in Utah is vibrant. Utah has one of the highest fertility rates in the country (the fertility rate in the United States is 2.06, while the rate in Utah is 2.47). (*See* page 49, Table 15 of Exhibit RMP___(DTG-3)). At the same time,

> "Utah's life expectancy has been consistently higher than the national average. Life expectancy in Utah rose from 77.7 years in 1990 to 78.6 years in 2000. Nationally, life expectancy rose from 75.4 years in 1990 to 77.0 years in 2000." (Exhibit RMP___(DTG-3), at page 41).

In combination, a high birth rate and a higher than average life expectancy produces a strong rate of natural growth. In terms of net migration, Utah has consistently experienced positive net in-migration for nearly two decades (and with the economic problems experienced by California and Nevada one can reasonably expect this to continue). The year 2009 "marked the 19th consecutive year with net in-migration" to Utah (Exhibit RMP___(DTG-3), at page 44). The combination of these factors, and a stronger than average economy, produces strong and continued population growth. In the last decade of the twentieth century, Utah added about 510,000 new residents. (Exhibit RMP___(DTG-3), see Figure 29). Through 2009, Utah has added nearly 554,000 more residents since 2000.

[15] The 2010 Report is available online at http://www.governor.utah.gov/dea/ERG/2010ERG.pdf.

In summary, the 2010 Report projects strong population growth for Utah: The State's population "was projected to be 2.9 million in 2010, 3.7 million in 2020, 4.4 million in 2030, 5.2 million in 2040, 6.0 million in 2050, and 6.8 million in 2060." (*See* Exhibit RMP___(DTG-3), at page 25).

This increase in population will result in additional residential, municipal, and industrial electrical demands to accommodate the increased population's needs. Despite conservation efforts by the Company and the public, it is clear that additional transmission capacity is necessary for the Company to meet reliability and customer demand growth over the foreseeable future.

CURRENT TRANSMISSION SITUATION IN SOUTHWEST UTAH

Q. Please describe the current situation of the southwest Utah transmission system and how the Sigurd to Red Butte Transmission Project fits into that situation.

A. The existing transmission system serves customer loads in southwestern Utah and additionally it provides transmission capacity necessary for firm point to point energy transfers to and from Utah and Nevada through the Company's WECC rated transmission Path TOT2C. This system is currently comprised of one 111 mile long 345kV transmission line connected between the Sigurd and Red Butte substations and one 148 mile long 345kv line from Red Butte Substation to Harry Allen substation in Nevada. Rocky Mountain Power must increase the capacity of the system consisting of one extra high voltage transmission path between the existing Sigurd and Red Butte substations. This will be accomplished by construction of the Company's Sigurd to Red Butte Transmission Project.

This single existing transmission line between Sigurd and Red Butte substation does not have the available capacity to reliably serve current and expected future customer demand. Exhibit RMP___(DTG-4) shows the existing system serving southwest Utah today. The Project, when completed, will add a second transmission line between Sigurd and Red Butte substations improving reliability and increasing the existing transmission system's capacity to meet the current and projected customer demands in southwest Utah and meet firm point to point energy transfers across TOT 2C. The Project will also provide an increased level of system redundancy as required by mandatory reliability standards substantially improving the Company's ability to provide reliable electrical service to its customers for many years. Exhibit RMP___(DTG-5) shows the system configuration after completion of the Project.

Under its Open Access Transmission Tariff, the Company has to maintain transmission service contract obligations for firm point to point transmission service into and out of southwestern Utah. In addition to meeting customer demand served from Red Butte substation, another secondary benefit of this Project is the capacity of the WECC Path TOT2C in the southbound direction will increase incrementally by 200MW above today's capacity from Red Butte substation to Harry Allen substation for a total system planned capacity of 600MW (see Exhibit RMP___(DTG-5). This new transmission capacity can be used by the Company to make off-system sales during periods of surplus energy or to import energy during emergency conditions resulting from transmission or generation contingencies. In addition, under its OATT, the Company's ability to offer additional firm transmission services to third parties in the Region will be increased by the Project. All of the above provide benefits to all of the Company's customers, including those in Utah by reducing their overall energy costs.

Furthermore, the Project provides improved access to existing and new generation sources, and would provide options to access other energy resources, including renewable resources. While the proposed Project is needed independent of, and would be built regardless of, any new generation project or other proposed transmission lines known in the area, the resulting increase in capacity added to the existing transmission system allows flexibility for future generation and interconnected transmission facilities.

Q. What analysis or studies did the Company perform to determine the Project is needed and the timeline for the Project?

A. The Company performs annual reliability assessments, required under mandatory reliability planning standard TPL 002 section B. Requirement (R1.), to determine that its transmission system complies with minimum mandatory system performance standards. This performance standard requires that during loss of any single transmission system element ("N-1 single contingencies") that firm service is maintained, no system overloads exist and there is no loss of customer demand. As part of this assessment the Company conducts a review of the forecasted peak energy demands in the area. Exhibit RMP___(DTG-6), Southwest Utah Customer Demand Forecast, is a histogram of forecasted peak customer demand served from the Company's Red Butte substation connected to the Company's only 345kV extra high voltage transmission source servicing the area. The exhibit depicts very significant increases with customer energy demand over the next ten years. Exhibit RMP___(DTG-6) shows the limit on the existing system serving the area based on the two most severe system outages the Company must consider. The first limit is the outage of the existing Sigurd to Red Butte 345kV line, 580MW representing the existing northbound limit of the Red Butte to Harry Allen line, and the second is the loss of Red Butte Substation voltage support equipment.

Q. What is the Company's plan to address customer demand in excess of the system limits until such time the Project can be completed and placed in service?

A. The Company has worked jointly with other interconnected transmission providers and load serving entities in the area to develop temporary emergency system operating procedures in the event customer demand exceeds system capabilities. These procedures include dispatching local "non-firm" generation if it is available or demand reduction by customer load shedding, or both actions if necessary. These procedures are intended only to provide temporary system relief during periods of excess demand and will remain in place until the Project can be completed and placed in service.

Q. What are the impacts to the system and the Company if the Project is not completed?

A. If the Project is not completed, customer energy demand will push the system over its established reliability limits and customer demand will be interrupted. The Company is subject to inquiry or investigation and exposed to fines and sanctions that may be imposed by FERC, NERC and/or WECC for any noncompliance. WECC, in conjunction with NERC, has established minimum reliability standards and criteria for the Bulk Electric System. The Company must meet all NERC and WECC transmission system reliability standards and performance criteria. These criteria require the Company to have a forward looking plan to reliably serve current and anticipated future customer demand under normal conditions and during system contingencies where elements of the transmission system are out of service, planned or otherwise.

The WECC and NERC mandatory standards and criteria establish the minimum requirements for System Planning, Operation, and Maintenance with which all transmission providers in the United States must comply. These standards and criteria require that transmission providers evaluate all expected customer demand levels and operating conditions and plan adequate redundancy in the system to meet minimum levels of system reliability and performance. It is the Company's responsibility as a transmission provider, based on operational history and experience, to plan, design, site and construct transmission projects to meet system performance requirements and manage reliability, risks and costs. The Project is required to reliably serve customers in Utah including those in areas of southwest Utah served from the Red Butte substation.

Q. What are the impacts to customers if the Project is not constructed or it is delayed for any reason?

A. Without the Project, existing and future forecasted customer energy demand in southwestern Utah cannot be reliably served and the Company's firm point-to-point transmission service contract obligations may not be met. In addition, the Company would not be in compliance with the requirement to meet customer energy demand under the requirements of its OATT sections 28 and 31 which I discussed earlier in my testimony. The generation resources assigned to serve the designated network customer load centers served from the Red Butte Substation are all located north of the Company's Sigurd and Red Butte Substations. If the transmission system does not have adequate capacity to reliably serve customer demand or the existing Sigurd to Red Butte transmission line is out of service, for any reason, these designated generation resources cannot be reliably delivered to customer load centers served from the Red Butte Substation.

Q. What is the result if the existing transmission system is out of service for some reason?

A. When the single 345kV transmission line existing today between Sigurd and Red Butte is out of service, planned or otherwise, the entire southwest Utah load (more than 120,000 customers) is subject to being served exclusively from Nevada Energy's system via a single transmission line connected from the Company's Red Butte Substation to Nevada Energy's 345kV Harry Allen substation. Nevada Energy and their interconnected system are under no obligation to meet customer demand or to supply energy to southwest Utah customers in the event of inadequate system capacity or during outages of the Company's existing Sigurd to Red Butte line. An adequate supply of energy, along with available firm transmission service from Nevada to deliver energy to southwest Utah is currently not available or economic under all current and future expected levels of customer demand.

In summary, the Project provides new incremental transmission capacity that is required in the short term and long-term to deliver network generation to network load centers in southwest Utah. The Project also provides increased transmission capacity allowing the Company to meet its current and future load service requirements, as well as enabling the Company to comply with mandatory WECC and NERC reliability performance standards and requirements therein.

Q. What is the estimated cost to obtain backup supply from Nevada Energy in order to mitigate risk and potential impacts to southwest Utah customers during outages of the Company's existing Sigurd to Red Butte line?

A. The Company has estimated, based on the limited capacity of the transmission system between Harry Allen and Red Butte Substations, that the cost of obtaining 580MW of firm transmission wheeling services from Nevada Energy would amount to a NPV cost of $104 million over twenty years. The cost of this transmission service is expected to increase substantially as Nevada Energy has some significant transmission investments currently under construction and is planning to consolidate from two into one balancing area. The Company estimates the NPV cost of securing a firm energy option at Mead Hub over the same period would cost $465 million dollars over the same 20 year period. Using 20-year timeframe, the Company anticipates a third Sigurd to Red Butte transmission line will be needed in addition to the Project within the next 20 to 25 years.

Q. Does the Project, when constructed, eliminate the higher cost to customers than to purchase of back up firm transmission service and firm energy from Nevada?

A. Yes. The project provides a second transmission path from the Company's and other network customers' designated generation resources to the Company's and other customer network load centers served at the Red Butte substation and, therefore is a lower cost alternative than reliance on transmission service and energy supply from Nevada.

Q. Are there other reliability benefits that result from the Project in addition to eliminating backup service from Nevada?

A. Yes. The project provides improved reliability to customers during normal system operation and during system outages, both planned and unplanned. The Company conducted an analysis of these system operational and reliability benefits and estimated the NPV of having the second line in-service was $65.2 million over the same 20 year period.

Q. Have there been instances where the Company's only existing transmission Sigurd to Red Butte line was out of service and customer demand was interrupted?

A. Yes. As recent as May 31, 2011, the single 345kV line from Red Butte substation to Nevada Energy's Harry Allen substation was taken out of service to facilitate construction at Harry Allen. At approximately 9 a.m., a system fault occurred on the only remaining transmission line serving Red Butte substation resulting in that substation and all customers in southwest Utah being disconnected from the generation supply. The customer demand in the area was low that particular day, at approximately 120 megawatts (28 percent of the peak customer demand in 2012). The transmission system outage lasted approximately nine minutes before the faulted line was restored. More than 120,000 customers were impacted, with some taking 2.5 hours or more to recover from the event.

Q. Would the Project, if it had been in-service at the time, have prevented such a widespread outage in the area and reduced impacts to customers?

A. Yes. The Project would have provided increased capacity and reliability to Red Butte substation as it is a second transmission line to the Red Butte substation connecting to generation sources connected to Sigurd substation. Consequently customers would not have experienced loss of electrical supply during the event.

ALTERNATIVES AND RATIONALE FOR THE PROJECT

Q. Were alternatives to the Project considered?

A. Yes. Long term alternatives to constructing a new transmission line are limited. Nonetheless, alternatives to constructing a new transmission line were given serious consideration by the Company, but none fully met the purpose and need of the Project long-term. The alternatives considered by the Company included: (1) electric load and demand-side management and energy conservation, (2) new generation facilities, both of which are part of the Company's IRP process, and (3) obtaining additional capacity from the existing transmission system upgrades and alternative transmission technologies. As a result of the resource portfolio modeling conducted for the 2011 IRP Update and based on the load and resource data provided by other network customers the Company concluded that additional transmission capability in Utah was the best option.

Q. What other actions has the Company taken to provide the needed system reliability and capacity before proceeding with this Project?

A. As I discussed in alternative (3) above, the Company has completed projects to add major equipment to the existing Three Peaks substation in 2009 to help improve the 345 kV system operation and reliability for serving the general area. In 2011 the Company completed an additional project adding major equipment to the existing Red Butte substation in 2009 and 2010 that improved voltage support and overall reliability of the system in the general area. In 2011 additional facilities were added to the Harry Allen substation. These projects, along with the special transmission emergency operating procedures which I discussed earlier in my testimony, are required in order to serve customers and delay this project until the summer of 2015.

Q. Please describe further why the Project was selected?

A. The Project was selected based on several factors:

- The Project is needed to transport energy produced from network designated generation resources, both the Company's and third parties', which are remote from the network load centers served from the Red Butte substation.
- The Project is necessary for the Company to maintain its contract obligations to continue to provide reliable firm transmission services both native load services and point-to-point services.

- As stated previously, reliability benefits are provided by developing redundant transmission paths between the Sigurd and Red Butte substations in the event of unscheduled or planned outages. The Project satisfies not only the immediate need to serve customers but also the long term load growth requirement in addition to improving the reliability of the system for the Company's customers generally.
- Strengthening the transmission system between the Sigurd and Red Butte substations allows the Company greater opportunity to take advantage of economic power transfers, sales, and purchases between Utah and Nevada.
- Currently transmission line and station maintenance windows are limited because the system is highly utilized. When completed, this Project will improve the Company's ability to perform required maintenance without significant operational impacts to the system, and it will reduce impacts to customers during planned and forced system outages.
- The Project provides an opportunity for developing southwest municipalities to incorporate both short- and long-term transmission infrastructure needs into their planning processes.

Q. Describe how the Project will benefit the Company's customers.

A. The Transmission Project will provide a reliable and adequate supply of electricity to meet existing and future customer energy demands. Without the increased transmission capacity provided by the Project, the Company would be faced with an increased and unacceptable risk of not being able to meet its load service obligations current and future. The Project will enhance the Company's ability to provide safe, reliable and efficient service to all customers including those in southwest Utah. Further, in order to provide low-cost energy, the Company must have the ability to acquire power from numerous generation sources in order to negotiate the most competitive pricing. By adding transmission capacity the Company has increased its ability and options to obtain additional generation sources at competitive pricing. The Project will result in a stronger interconnection with other parts of the system providing better transmission system access to the other sources of generation. The Project, especially when complemented with other projects, such as the Populus to Terminal project and the Mona to Oquirrh transmission project which is now under construction and is anticipated to be complete by May 2013, will greatly strengthen the Company's transmission capacity and flexibility. Generally, the addition of the Project is integral in strengthening the Western grid's transmission infrastructure, which is necessary based upon the Company's customers' near-term and long-term load growth projections, and the contingencies and restrictions occurring on the system during outage conditions. The Project has undergone WECC's Three Phase Ratings Process, and has been approved by WECC for Phase 3-"Construction Phase" status as part of the overall Energy Gateway Transmission Expansion Project. This WECC approval is necessary as it allows the company to interconnect the Project to the wider transmission system in the area and to reliably operate the Project at its approved ratings. The Project is widely regarded as a necessary interconnection point to support the long-term transmission expansion planning established in the WECC Region plans[16] and in the most recent Northern Tier Transmission Group sub-regional plan. http://nttg.biz/site/index.php?option=com_docman&task=cat_view&gid=308&Itemid=31

OTHER BENEFITS

Q. Will the Transmission Project provide increased transmission system capacity and improved reliability for the Company's wholesale transmission customers?

A. Yes. Utah Associated Municipal Power Systems ("UAMPS"), Utah Municipal Power Agency ("UMPA"), and Deseret Generation & Transmission, Inc. ("DG&T") rely on Utah-based generation and are transmission dependent utilities that depend the Company's transmission system to serve loads throughout the state including those in southwest Utah. The Project and the Energy Gateway Project overall will enable the Company to continue to meet these requirements as well as its contractual OATT service obligations to PacifiCorp Energy, UAMPS, UMPA, and DG&T. The Project's added transfer capacity is essential to the future reliable electrical service to these entities. The customer demand served by the Project for each of those respective entities is depicted in Exhibit RMP___(DTG-6).

[16] http://www.wecc.biz/committees/BOD/TEPPC/SCG/Shared%20Documents/Forms/AllItems.aspx.

Q. Will the Transmission Project provide other benefits to customers and the public overall?

A. Yes. As has been seen in the West and other parts of the country, the transmission grid can be affected in its entirety by what happens on an individual transmission line or path. For example, the transmission system between southern and northern Utah is comprised of several individual transmission lines or line segments. A single outage on any of the individual lines or line segments due to storm, fire, or other external human interference can and does cause significant reductions in transmission capacity and can negatively impact the Company's ability to serve customers. In the event of a line outage, the redundancy provided by the Project will allow the Company to continue to meet native load service obligations and continue to meet other contractual obligations to third parties. Strengthening this path and increasing system redundancy with the new transmission line will benefit all customers due to these factors.

Q. Are there other benefits you see from this Project?

A. Yes. While this Project provides the next necessary increment of transmission capacity in the area, it also supports and complements other future transmission investments that are currently proposed by the Company and other utilities in the region. The Energy Gateway Project, which includes this Project, positions the Company to be strongly interconnected to other regional projects currently being planned and provides options for access to additional resources.

Q. Would the Company still proceed with this Project even if other segments of Energy Gateway are delayed or not completed?

A**.** Yes. The Project is required to reliably serve existing and future customer demand and must be constructed even if other Energy Gateway segments are not completed. Further the benefits I have stated above related to the project are independent of benefits provided by other Energy Gateway segments.

Q. Please explain why a CPCN is necessary now for a project that is not scheduled for completion until June 2015.

A. Because of the economics of building transmission lines, additional transmission facilities typically come in large blocks rather than small increments. The Company is an essential service provider and as such develops its long-range plans to meet customer service requirements. The Company is required by NERC and WECC to plan in advance of our growing customers' demand for electrical energy. As part of this process, the Company plans segments of transmission projects, such as the Sigurd to Red Butte 345 kV Project, in increments which are standard in the industry and because large infrastructure additions like the Project require long lead times in order to meet anticipated energy demands. These large additions are complex and require long range project planning to incorporate siting, permitting, the NEPA process, design, material ordering, and logistics, and because of the physical length of the Project and related environmental and terrain considerations, construction will require multiple years. Scheduling and planning and constructing infrastructure projects in this manner helps reduce overall project costs and thus costs to our customers.

STATUS OF PERMITS FROM LOCAL GOVERNMENT ENTITIES

Q. What is the current status with regard to obtaining the necessary permits from local government entities?

A. The Company has filed a right-of-way permit application with the BLM and USFS. As noted, these filings triggered the need to conduct the EIS as part of the federal process. The draft EIS was published for public review and comment in May, 2011, with the issuance of a final EIS scheduled in October 2012. It is anticipated that the Records of Decision for the Project will be issued by both the BLM and USFS in late December 2012. The Company believes the BLM's decision (as the lead agency in the EIS process) will result in the issuance of rights-of-way and authorizations necessary for the Company to begin construction on federally-administered lands located along the transmission route. The Company has or will receive the required consents, franchises, and permits from all of the local governmental entities having jurisdiction over the proposed alignments for the Project. The Company has obtained conditional use permits from the following local governmental entities: Beaver County, Iron County, Millard County, Sevier County, Washington County, and Richfield.

In addition to the conditional use permits, the Company is in the process of obtaining the required consents and permits from the State of Utah which will be obtained once the final transmission line alignment has been identified. Additionally, any permits and approvals required from State agencies for actual construction and operation of the Project will be obtained in the ordinary course of development. These required consents and permits may include, but may not be limited to, stream alternation permits from the Utah Department of Natural Resources, highway encroachment permits from the Utah Department of Transportation, storm water permits from the Utah Department of Environmental Quality, right of way grants from the Utah School and Institutional Trust Lands Administration, and approvals from the State Historic Preservation Office of Utah.

Based on the current routing plan, these are the only permits, franchises and consents required for the Project. Should a routing change resulting from the environmental approval process require any additional local consents, franchises, or permits, the Company will immediately seek such approval. As required by Utah Code Ann. 54-4-25(4)(a), the Company will provide notice to the Commission in such event.

RATE TREATMENT AND PRUDENCE REVIEW

Q. Is the Company seeking a prudence finding or a determination of rate treatment for the cost of the Transmission Project at this time?

A. No, not at this time. A request for cost recovery will be made in a future general rate case or major plant addition filing. The appropriate prudence review will be made in that proceeding.

Q. How does the Company plan to recover the cost of the Project when it is completed?

A. The Company plans to include the total Project cost as part of its FERC transmission rate base with rates established under a formula approved by the FERC. Under this rate all network customers are charged for use of PacifiCorp's total transmission system based on each network customer's respective energy demand on the system.

CONCLUSION AND RECOMMENDATION

Q. What do you recommend?

A. I recommend that the Commission find and conclude that the Project is needed in order for the Company to provide efficient and reliable service to its customers in southwest Utah and throughout the state, and that the Project is in the public interest. Based on those findings and conclusions, I recommend that the Commission grant the Company a CPCN for the Project.

Q. Does this conclude your direct testimony?

A. Yes.