BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for a Certificate of Public Convenience and Necessity Authorizing Construction of the Sigurd - Red Butte No. 2 345 kV Transmission Line	: : : : : :	Docket No. 12-035-97

DIRECT TESTIMONY OF

BELA VASTAG

ON BEHALF OF THE

OFFICE OF CONSUMER SERVICES

DECEMBER 21, 2012

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS?

A. My name is Béla Vastag. I am a utility analyst in the Office of Consumer Services (Office). The Office is located in the Heber Wells Building at 160 East 300 South, Salt Lake City, Utah.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address Rocky Mountain Power's (RMP or Company) request for a Certificate of Public Convenience and Necessity (CPCN) for the construction of a second Sigurd to Red Butte 345 kV transmission line (SRB No. 2).

Q. BRIEFLY DESCRIBE THE PROJECT FOR WHICH THE COMPANY IS SEEKING A CPCN?

A. The Company plans to build a 169 mile long high voltage (345 kilovolts) transmission line from its Sigurd substation (near Richfield, UT) to its Red Butte substation (25 miles north of St. George, UT). Construction is expected to begin in April 2013 with the line placed in service in the summer of 2015. The expected cost of the project, including upgrades to other components such as substations, is $380 million. This new line addresses two primary needs:

1. Meeting the growth in the demand for electricity in Southwest Utah – growth which will create peak demand that exceeds the capacity of the existing Sigurd to Red Butte No. 1 345 kV transmission line (SRB No. 1) and the Red Butte substation.
2. Providing electricity service reliability (i.e., redundancy) for Southwest Utah in the event that the SRB No. 1 line is unexpectedly forced out of service.

Q. WHAT LEVEL OF INFORMATION HAS THE COMPANY PROVIDED IN SUPPORT OF THE PROPOSED TRANMISSION PROJECT?

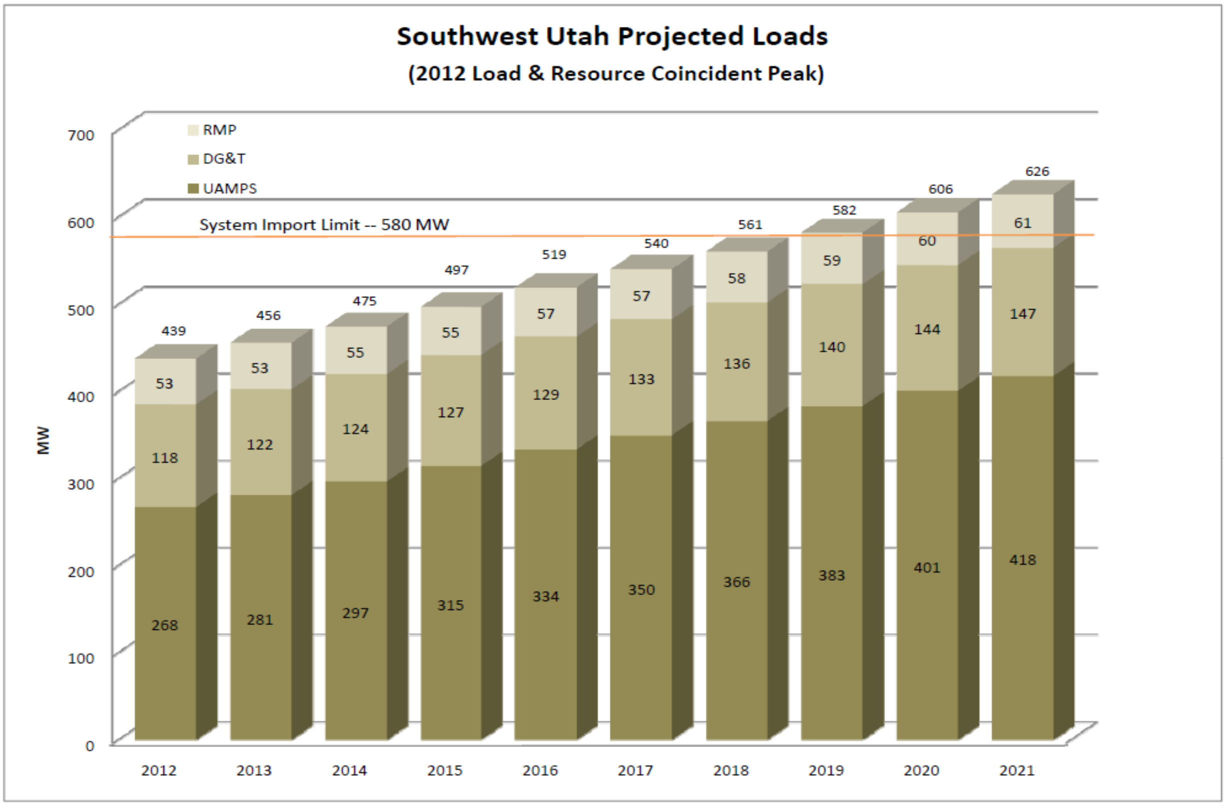
A. The information provided in the Company's application and testimony is at a high level. The Office and other parties have submitted discovery requests and met with Company personnel to better understand the electricity demand and transmission capacity situation in Southwest Utah. The discovery process has verified some of the Company's claims but has also raised some concerns. These concerns include the timing of the transmission investment to meet the growth in electricity demand, the recent loss of transmission service redundancy and the allocation of the $380 million estimated cost between wholesale and retail customers. The Office will address each of these concerns below.

Southwest Utah Load Growth

Q. WHAT INFORMATION DID THE COMPANY PROVIDE ON LOAD GROWTH IN SOUTHWEST UTAH?

A. Company witness Darrell T. Gerrard provided a forecast of load growth in his direct testimony. This information is reproduced below.[1]

[1] Direct Testimony of Darrell T. Gerrard, Exhibit G – SW Utah Projected Customer Demand Forecast 9-17-2012.pptx



Q. PLEASE EXPLAIN THE INFORMATION PRESENTED IN THIS CHART?

A. This chart shows the loads served by the existing SRB No. 1 line. The loads are broken out by three entities: the Utah Associated Municipal Power Systems (UAMPS), Deseret Generation and Transmission (DG&T) and Rocky Mountain Power (RMP). In 2012, the total load was divided among the three as follows – UAMPS 61%, DG&T 27% and RMP 12%. From 2012 to 2021, the chart shows significantly different rates of load growth among these three entities: UAMPS 150 MW growth or an average of 5.1% annually, DG&T 29 MW growth or 2.5% annually and RMP only 8 MW growth or 1.6% annually. The chart indicates the share of loads in 2021 to be: UAMPS 67%, DG&T 23% and RMP 10%. It is important to note that RMP's relative share of total load is forecasted to decline between 2012 and 2021 and only 8 MW of the projected growth over the next decade is for RMP in its Southwest Utah service territory.

Q. DO YOU QUESTION ANY OF THESE LOAD GROWTH FORECASTS?

A. Yes, the projected average annual growth rate for UAMPS of 5.1% appears to be high. This forecast was provided by UAMPS and not generated by the Company.

Q. ON WHAT BASIS DO YOU SUGGEST THAT THE 5.1% APPEARS TO BE HIGH?

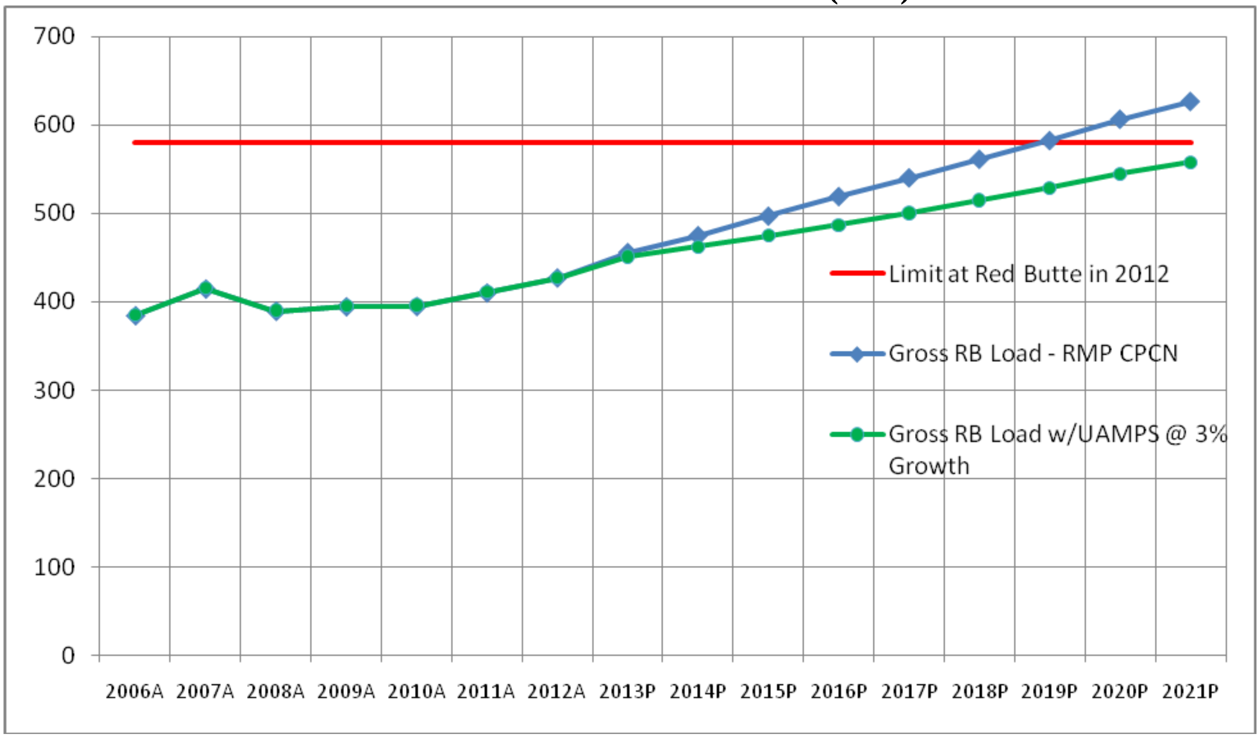
A. First, the growth rate provided by UAMPS of 5.1% per year is more than twice the growth rate of the other two load entities, DG&T 2.5% and RMP 1.6%. Second, the Governor's Office of Planning and Budget (GOPB) projects population for Washington County, UT to grow from 138,751 in 2010 to 179,396 in 2020.[2] This is an average annual growth rate of 2.6% for Washington County which is the location of the city of St. George, the major load center of the county and a member of UAMPS. Without specific supporting information from UAMPS, its 5.1% growth rate is not consistent with other forecasts for the region.

Q. ASSUMING A GROWTH RATE FOR UAMPS THAT IS SIMILAR TO THAT OF DG&T AND RMP AND MORE IN LINE WITH THE GOPB PROJECTIONS, HOW DOES THAT AFFECT THE LOAD FORECAST FOR SOUTHWEST UTAH?

A. If an average annual rate of growth of 3% instead of 5.1% is used for UAMPS loads starting in 2013, the load picture for SW Utah changes as shown in Chart 1 below.

[2] Governor's Office of Planning & Budget, Demographic and Economic Projections, 2012 Baseline Projections, Population by Age and Area, http://www.governor.state.ut.us/dea/ERG/ERG2012/Population%20by%20Age%20and%20Area.xlsx

Chart 1 – Southwest Utah Loads – (MW)[3]



Q. WHAT DOES THIS CHART INDICATE?

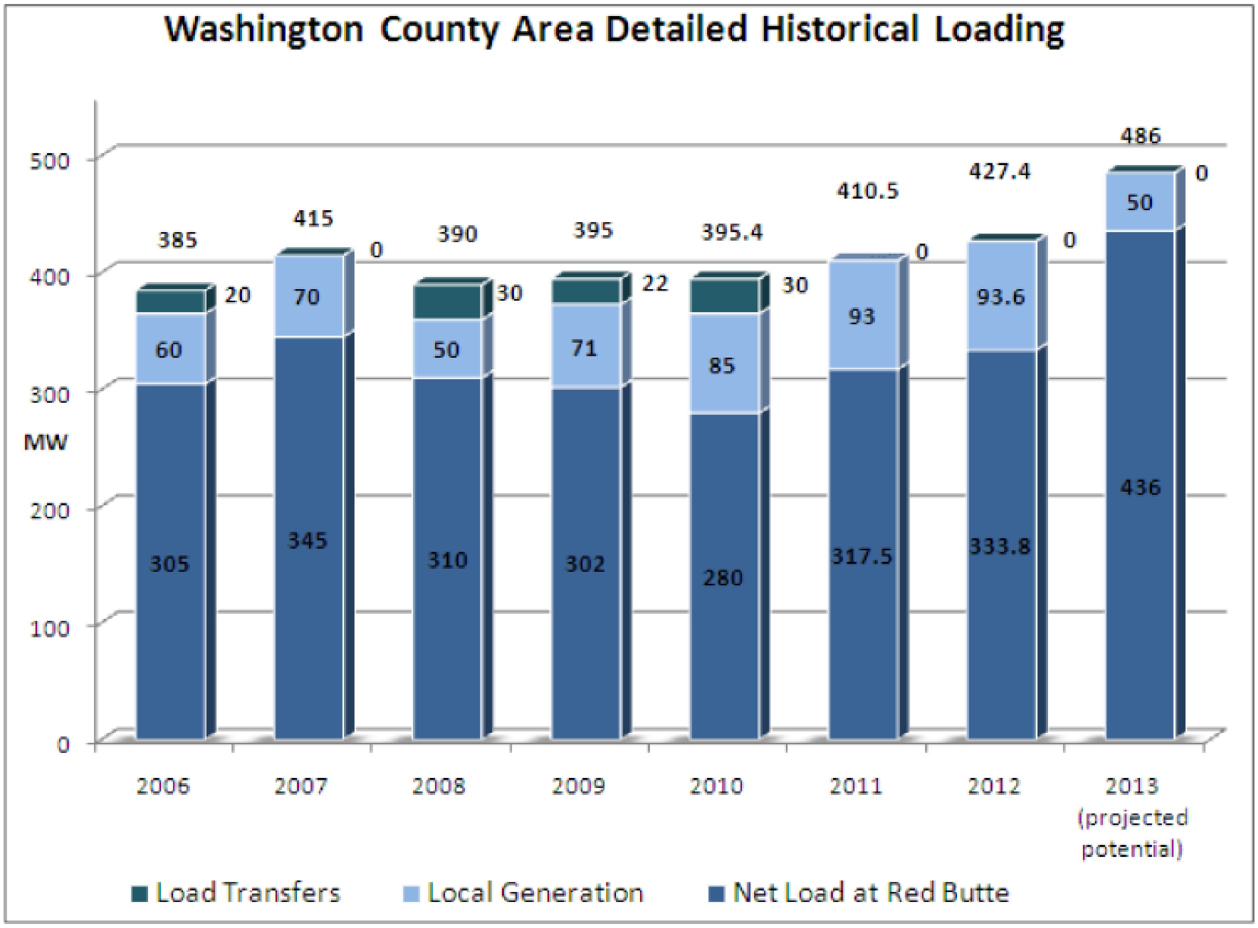
A. With the UAMPS load growth at 3% annually, the 580 MW limit at Red Butte is not exceeded until after 2021 versus 2019 using the Company's projections. This delays the need for SRB No. 2 Line by at least three more years – until 2022. This is seven years after the proposed in-service date of 2015 for SRB No. 2.

Q. ARE THERE ANY OTHER FACTORS WHICH MAY ALSO MITIGATE LOAD GROWTH AND DELAY THE NEED FOR THE SRB NO. 2 LINE?

A. Yes, there is local generation in the SW Utah region which helps reduce the peak demand served by the high voltage transmission system. For example, the city of St. George has its 80 MW Millcreek Generation Facility. This facility utilizes two 40 MW generators powered by natural gas fired turbines. As shown in the chart below, local generation

[3] 2006A refers to 2006 actual coincident peak loads while 2013P refers to 2013 projected loads. 2006 to 2012 actual load data obtained from the PacifiCorp 2012 Southwest Utah Post-Peak Report, page 13.

contributed 93.6 MW in 2012, which lowered the peak load at the Red Butte substation and on the SRB No. 1 line to 333.8 MW.[4]



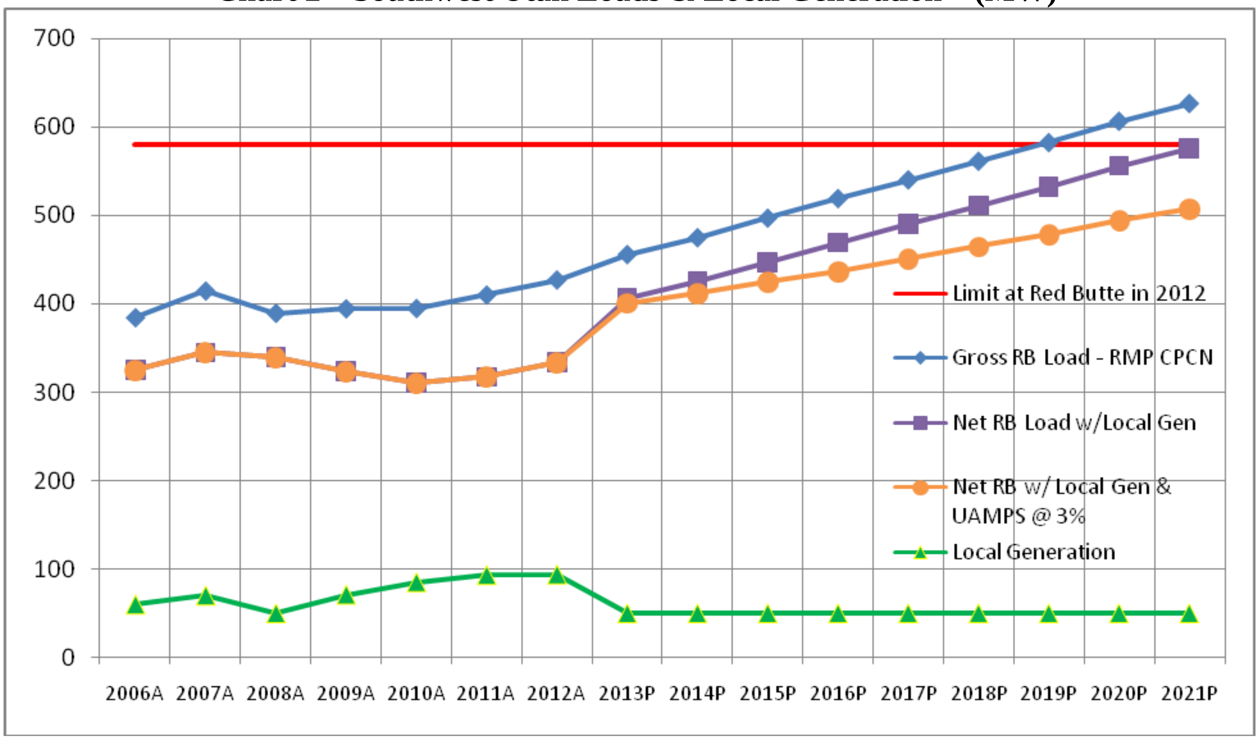
Q. HOW MIGHT THE AVAILABILITY OF LOCAL GENERATION AND A LOWER GROWTH RATE FOR UAMPS LOADS AFFECT THE TIMING OF THE NEED FOR THE SRB NO. 2 LINE?

A. As you can see from Chart 2 below, the combination of these two reductions to peak load can delay the need for SRB No. 2 well past 2021. The projections are conservative as they only assume 50 MW of local generation is dispatched to meet forecasted peak loads from

[4] PacifiCorp 2012 Southwest Utah Post-Peak Report, September 2012, see pages 6 and 13. Note: The 2013 projected load of 486 MW is an “extreme weather projected potential” and does not compare to the Company’s 2013 projection in its CPCN testimony (Gerrard Exhibit G).

2013 through 2021, which is the smallest actual amount of actual local generation contributed in any year from 2006 to 2012.

Chart 2 – Southwest Utah Loads & Local Generation – (MW)



Q. CAN THE COMPANY RELY ON THIS LOCAL GENERATION?

A. No, the Company indicates that it has attempted to complete local generation agreements but has not been successful.[5] However, the charts above show that local generation has been dispatched every year from 2006 to 2012 to meet peak load requirements and has been increasing in recent years.

[5] Response to OCS Data Request 2.5.

Q. PLEASE STATE THE OFFICE'S CONCERN REGARDING THE TIMING OF THIS LINE.

A. The Office is concerned that the Company has not adequately justified the timing of the need for the SRB No. 2 line. Delaying the construction of a $380 million project by even a couple of years would be a benefit to ratepayers.

Transmission Service Redundancy

Q. THE COMPANY STATES THAT THE SRB NO. 2 LINE WILL PROVIDE AN INCREASED LEVEL OF SYSTEM REDUNDANCY AS REQUIRED BY MANDATORY RELIABILITY STANDARDS.[6] WHAT SPECIFIC STANDARD IS THE COMPANY REFERRING TO IN THIS STATEMENT?

A. The Company is referring to North American Electric Reliability Corporation (NERC) standard TPL-002, System Performance Following Loss of a Single BES Element. In this case, the BES or Bulk Electric System element that the NERC standard addresses is the SRB No. 1 line. The Company claims that the SRB No. 2 line is needed to provide redundancy and comply with NERC TPL-002.

Q. WHAT DID THE COMPANY'S MOST RECENT TPL ASSESSMENT CONCLUDE REGARDING THE SRB NO. 1 LINE?

A. PacifiCorp's 2011 TPL Assessment concluded that no deficiencies were found for TPL-002 for 2012 because the analysis assumed that service can be provided from the NV Energy system.[7] That is, service can be provided to Southwest Utah from the south, via the Harry Allen substation in Nevada. For 2016 and 2021, the assessment also found no deficiencies because the SRB No. 2 line was assumed to be in place.

[6] Direct Testimony of Darrell T. Gerrard – Errata, Page 19, Lines 431 – 432.
[7] Response to OCS Data Request 1.2.

Q. HAVE CIRCUMSTANCES CHANGED REGARDING COMPLIANCE WITH NERC STANDARD TPL-002 SINCE THE COMPANY COMPLETED ITS 2011 TPL ASSESSMENT?

A. Yes, the Company asserts they are no longer compliant in 2012 because back-up service is no longer available from the NV Energy system.[8] NV Energy filed a request with the Federal Energy Regulatory Commission (FERC) in 2011 to cancel an interconnection agreement with UAMPS that previously provided transmission service to supply backup energy in the event that an outage occurred on the SRB No. 1 line. On November 17, 2011, the FERC accepted NV Energy's request and the UAMPS agreement was cancelled effective April 19, 2012.[9]

Q. WHAT ARE THE OFFICE'S CONCERNS ON THIS ISSUE OF TRANSMISSION REDUNDANCY?

A. The Office is concerned that the cancellation of one agreement between UAMPS and NV Energy appears to have placed the electricity supply for the region in jeopardy. With the UAMPS loss of the NV Energy agreement and the lack of agreements to operate local generation during peak periods, the redundancy that the SRB No. 2 line will provide becomes evident. However, along with the redundancy that the construction of the SRB No. 2 line provides comes the important economic question of how the costs of the project will be divided up between wholesale and retail customers.

Cost Allocation

Q. IS COST ALLOCATION DETERMINATION INCLUDED WITHIN THE SCOPE OF THIS CPCN PROCEEDING?

A. No. In its Scheduling Order and Notice of Hearing, the Commission clearly indicated the scope of this proceeding by stating: **"This proceeding is to determine if present or**

[8] See response to OCS Data Request 2.4.
[9] FERC Docket No. ER11-4215-000.

future public convenience and necessity does or will require construction of a transmission line."[10] (Emphasis in original)

Q. WHAT CONSIDERATIONS RELATED TO THE SRB NO. 2 TRANSMISSION PROJECT REQUIRE THE OFFICE TO RAISE THE ISSUE OF COST ALLOCATION IN THIS CPCN PROCEEDING?

A. This proposed transmission project is mainly being built to meet the forecasted load growth and reliability requirements of UAMPS and DG&T. These entities are wholesale transmission customers of PacifiCorp and are the primary beneficiaries of the project. Thus, the costs of the project should appropriately follow benefits and be allocated accordingly.

Q. IS THE PRINCIPLE THAT COSTS SHOULD FOLLOW BENEFITS CONSISTENT WITH FERC ORDER 1000?

A. Yes. In discussing regional and interregional cost allocation methods in Order 1000, the FERC set forth two main principles: 1) costs must be allocated in a way that is roughly commensurate with benefits; and 2) there must be no involuntary allocation of costs to non-beneficiaries. The FERC recently reaffirmed these guiding principles in its Order No. 1000-B on October 18, 2012.[11]

Q. ARE THESE FERC PRINCIPLES SIMILAR TO RATEMAKING PRINCIPLES USED BY THE COMMISISON WHEN DETERMINING COST RESPONSIBILITY IN RATE PROCEEDINGS?

A. Yes. In rate proceedings, <u>cost causation</u> and <u>fairness</u> are two primary principles relied on by the Commission in allocating costs to customers. In the case of the SRB No. 2

[10] Scheduling Order and Notice of Hearing, Docket No. 12-035-97, October 18, 2012, page 2.
[11] FERC Docket No. RM10-23-002, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Section 66, page 52. http://www.ferc.gov/whats-new/comm-meet/2012/101812/E-1.pdf.

transmission project, PacifiCorp's wholesale customers are the primary "cost causers" and beneficiaries of this $380 million investment, and costs should be allocated accordingly.

Q. WHAT IS THE OFFICE'S POSITION ON THE COST ALLOCATION ISSUE RELATED TO THE SRB NO. 2 TRANSMISSION PROJECT?

A. The Office recognizes that cost allocation issues are normally not raised in a CPCN proceeding and reserved for rate proceedings. However, it must be noted that this proposed new transmission line will largely be constructed to serve the growing load and reliability requirements of UAMPS' and DG&T's customers in Southwest Utah. By contrast, RMP's retail loads in Southwest Utah are only forecasted to increase by a total of 8 MWs by 2021.

Consequently, the Office recommends that the Commission clearly indicate in its CPCN Order that all issues pertaining to cost allocation will be addressed the first time the Company seeks to recover any costs associated with the project. A key issue that must be examined by the Commission is the appropriateness of using the existing revenue credit method as a means to fairly compensate RMP's retail customers for a significant transmission investment that primarily benefits PacifiCorp's wholesale customers.

Conclusion

Q. WHAT IS THE OFFICE'S POSITION IN THIS CASE?

A. Given the parameters established by the Commission that "this proceeding is to determine if present or future public convenience and necessity does or will require construction of a transmission line", the Office does not oppose the granting of a CPCN in this case. However, the concerns raised by the Office in this testimony may be of issue in a future proceeding in which the Company requests cost recovery for these facilities. Therefore, the Office recommends that the Commission, in its order on this CPCN Application, specify that cost recovery and cost allocation issues have yet to be resolved and will be addressed in a future rate proceeding.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.