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TESTIMONY of

REBECCA E. FREDRICKSON, DAVID W. BOGDON, DAVID L. GILMAN,

DENNIS E. METCALF, AND LARRY A. FURUMASU

Witnesses for Bonneville Power Administration

SUBJECT: TRANSMISSION NETWORK SEGMENT COST ALLOCATION

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Section 1: Introduction and Purpose of Testimony

Q. Please state your name and qualifications.

A. My name is Rebecca E. Fredrickson, and my qualifications are contained in BP-14-Q-BPA-21.

A. My name is David W. Bogdon, and my qualifications are contained in BP-14-Q-BPA-07

A. My name is Dennis E. Metcalf, and my qualifications are contained in BP-14-Q-BPA-47.

A. My name is David L. Gilman, and my qualifications are contained in BP-14-Q-BPA-24.

A. My name is Larry A. Furumasu, and my qualifications are contained in BP-14-Q-BPA-22.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to sponsor the Network segment cost allocation component of the Transmission Rates Study, BP-14-E-BPA-07.

Section 2: Overview of Cost Allocation in Current and Past Rates

Q. Please provide some background on the allocation of BPA's network segment costs.

A. Cost allocation has largely been shaped by settlements of prior rate cases. The FY 1996 rate levels were the result of a settlement between BPA and a majority of rate case parties. Under the settled rates, the Point-to Point (PTP) and Integrated Resource (IR) rates were set equal to each other. The Network Integration Transmission Service (NT)

rate included a base charge, set equal to the PTP and IR rates, and an NT load shaping charge. Network segment costs were allocated to PTP and IR customers based on their contract demand, which is the amount of capacity reserved by the PTP and IR customers in their contracts. Costs were allocated to NT service based on the NT customer's annual non-coincident demand. The NT load shaping charge was calculated to recover the difference between the costs allocated to NT using the annual non-coincident demand method and the revenues recovered from the base charge, which applied to the customer's load on the hour of the month that load on the transmission system peaked (monthly transmission system peak).

Q. Has BPA considered alternative cost allocation methods since the 1996 case?

A. Yes. In the FY 2002-2003 rate case, BPA considered allocating Network segment costs based on the twelve coincident peak (12 CP) method. BPA had performed several tests used for cost allocation purposes and determined that the transmission load pattern supported the use of the 12 CP method. After examining the impact that the 12 CP method would have on rates, however, BPA determined that the rate increase for PTP customers would be too great. Therefore, BPA's Initial Proposal in the 2002 case was to use the one coincident peak (1 CP) method, which resulted in a smaller rate increase than would have resulted from using the 12 CP method. Ultimately, the FY 2002-2003 rate case was resolved through an uncontested settlement that set rate levels for PTP, IR, and NT service. The settlement did not specifically address the cost allocation method for the Network segment.

Q. How have the cost allocation methodologies been addressed in rate cases since 2002?

A. Since the 2002 rate case, transmission rates have been set through settlements that have not explicitly adopted a specific methodology. The FY 2004-2005 rate settlement increased FY 2002-2003 rates by a uniform percentage. The FY 2006-2007 and

FY 2008-2009 rate settlement adjusted the rates by customer class. The FY 2010-2011 and 2012-2013 rate settlements held rates at the FY 2008-2009 levels.

Q. What is the cost allocation method for the current rates?

A. The FY 2012-2013 rates do not reflect any particular cost allocation method. As described above, the current rate levels are based on adjustments made through settlements going back to FY 2002-2003.

Q. Why are you analyzing cost allocation methods for this rate case?

A. Since current rates do not reflect any particular cost allocation method, and we have not examined cost allocation in an Initial Proposal since the 2002 rate case, we wanted to analyze which cost allocation method would be most appropriate for BPA.

Section 3: Consideration of Cost Allocation Methods

Q. What principles guided your consideration of cost allocation methods?

A. Cost causation is one of the primary principles. The underlying theory of cost causation is that costs incurred to benefit a class of service should be allocated to the rates paid by customers for that service. Although the Administrator is not bound to follow FERC ratemaking policies in this context, the FERC standards for cost allocation also provide helpful guidance. We understand that FERC considers a utility's transmission system planning approach when assessing which type of cost allocation method is appropriate for that utility. Therefore, we believe that BPA's planning approach should be considered in determining whether to allocate costs based on coincident peaks (CP) or non-coincident peaks (NCP). For example, if a utility such as BPA plans its system to serve load coincident with the utility's system peak, then the CP method is more appropriate. If a utility such as BPA plans its system to serve each customer's load on the hour of that load's peak (the non-coincident peak), then the NCP method is more appropriate.

Q. Why is the transmission system planning approach an important consideration for cost causation and cost allocation?

A. BPA's investment in the transmission system is in large part determined by BPA's obligation to plan the system to satisfy customers' contractual rights and to ensure BPA has the capacity necessary to reliably serve peak loads under a range of projected system conditions. BPA incurs costs based on its transmission system planning. Therefore, BPA's planning approach is an important consideration for cost causation and cost allocation.

Q. What is BPA's planning obligation for PTP and IR service?

A. PTP and IR service are based on contract demand (or reserved capacity), which is the amount of capacity the customer has reserved to deliver energy from point(s) of receipt to point(s) of delivery. To the extent PTP and IR customers have not built their own transmission capacity, such customers are responsible for contracting for sufficient capacity to serve their peak loads and load growth and to deliver generation from their resources. Some customers have contracted for more capacity than their load or generation in order to have flexibility in how they use the system. For example, a PTP customer with several PTP contract reservations for the same point of delivery but different points of receipt has the flexibility to serve its load from any of the points of receipt for which it has a contract reservation. BPA's planning obligation is to ensure that it has sufficient capacity for customers to flexibly use their reserved capacities consistent with their contracts.

Q. What is BPA's planning obligation for NT service?

A. NT service is load-based. NT customers designate load and the resources to serve that load. BPA must plan the transmission system to serve each NT customer's peak loads and forecasted load growth from the customer's designated network resources.

Q. What cost allocation methods did you consider for the FY 2014-2015 rate period?

A. We considered the 1 CP method, the 12 CP method, the three coincident peak (3 CP) method, the 12 non-coincident peak (12 NCP) method, and the annual non-coincident peak (1 NCP) method.

Q. How are costs allocated among Network rates based on each of these methods?

A. All of these methods allocate costs to PTP and IR service based on reserved capacity and to NT service based on forecast NT load. For purposes of allocating costs, we refer to the forecast of PTP and IR customer's reserved capacity and the NT customer's load as the PTP, IR, and NT cost allocation factors. The difference in methodologies relates to which NT load forecast is used.

Q. Why do the methods allocate costs to PTP and IR service based on reserved capacity and to NT service based on forecast load?

A. For PTP and IR service, BPA's planning obligation is defined by the amount of reserved capacity in the PTP and IR customers' contracts. For NT service, BPA's planning obligation is defined by the NT customers' designated load.

Q. How do the methodologies differ with respect to forecast NT load?

A. Under the 1 CP method, the customer's NT load forecast that is used to allocate cost is its NT load during the hour of the year in which the load on the transmission provider's system is highest (the annual transmission system peak). A load forecast is determined for each year of a two-year rate period, and the average of the two is used for the rate calculation.

Under the 12 CP method, the customer's load forecast is based on its load during the hour of each month in which the load on the transmission provider's system is highest (the monthly transmission system peak). The average of the monthly load forecasts is used for the rate calculation.

Under the 3 CP method, the load forecast is the load during the hour of the monthly transmission system peak for the three consecutive months in which load on the transmission provider's system is highest. The average of the monthly forecasts is used for the rate calculation.

Under the 12 NCP method, the load forecast is the customer's hourly load at its network load points of delivery on the hour of the month in which the sum of the customer's load at all of its points of delivery is highest. The average of the customer's monthly load forecast for the rate period is used for the rate calculation.

Under the 1 NCP method, the load forecast is the customer's hourly load at its network load points of delivery on the hour of the year in which the sum of the customer's load at all of its points of delivery is highest. A load forecast is determined for each year of a two year rate-period, and the average of the two is used for the rate calculation.

Section 4: Consideration of BPA's Transmission System Planning Approach

Q. What is BPA's transmission system planning approach?

A. BPA plans the transmission system so that it can be reliably operated to meet the demands placed on it, including customers' forecast highest hourly system demands (the non-coincident peak load) and the transmission of energy to transmission systems adjacent to BPA's system (off-system). BPA also plans the system to meet mandatory NERC and WECC transmission planning standards (NERC and WECC are the national and regional organizations, respectively, that set reliability standards), such as the mandatory NERC Transmission Planning (TPL) standards.

Q. Please describe BPA's transmission planning process.

A. BPA conducts several planning processes, such as Network Open Season cluster studies, reliability compliance studies, and interconnection studies. The Network Open Season cluster studies identify upgrades to the transmission system needed to accommodate new transmission service requests for which BPA does not have available transfer capability. The reliability planning studies cover a ten-year planning horizon and identify upgrades to the transmission system needed to mitigate potential system deficiencies (such as a transmission line loaded beyond its rated limit) and to maintain compliance with NERC and WECC transmission planning standards. The interconnection studies identify upgrades to the system to accommodate new generation interconnection requests. BPA also studies the available transfer capability on the system to determine whether BPA has the capacity to offer service to new transmission service requests.

Q. Please describe how the planning studies are done.

A. BPA uses simulation models, such as power flow studies (analysis of the flow of energy on the transmission system under a variety of scenarios), to test whether the system or a particular area of the system can reliably serve load, transfer energy off-system, and meet mandatory NERC and WECC standards throughout the year under a range of forecast generation, load, and system conditions (such as a transmission line outage). The power flows on the transmission system depend upon the load levels at that location, the generation dispatch ("dispatch" refers to the use of given resources to serve load at any given time; for example, wind generation on the east side of the system displacing hydro and thermal generation on the west side), the loading (amount of power) on the interties (for example, loading on the California-Oregon intertie is typically higher during the spring and summer season), and the transmission facility conditions (for example, transmission outages). If the models indicate potential deficiencies in system

performance that affect the ability of the system to reliably serve load or transfer energy under the simulated conditions, BPA may reinforce the transmission system. BPA performs planning studies for each season of the year.

Q. What areas of the transmission system does BPA study?

A. For planning purposes, BPA has divided the transmission system into 24 areas based on population centers and geographic location. These areas include, for example, Seattle, Olympic Peninsula, Portland, Central Oregon, northern Idaho, southeast Idaho/northwest Wyoming, and the Tri-Cities (which includes the cities of Kennewick, Pasco, and Richland in southeastern Washington). BPA conducts power flow studies for each area.

Q. Which load forecast does BPA use in its planning studies?

A. For the power flow study for a particular area during a particular season, BPA uses the non-coincident peak load forecast for each customer during the season being studied. The load forecast is the customer's load on the hour in which the sum of the customer's loads at all of its points of delivery is highest for the season. The load forecast is based on customer peak load levels that have a fifty percent probability of occurring. This load forecast serves as a reasonable base-point assumption for peak load.

Q. Do loads peak at the same time of the year in each area studied?

A. No. BPA's large transmission system covers a geographically diverse territory. As a result, loads peak at different times on different parts of the system. The total load on BPA's system typically peaks in December, January, or February (the winter months), depending on weather conditions for the year. Loads in the Seattle and Olympic Peninsula areas typically peak on an hour during these months, but not necessarily on the same hour of the month as the transmission system peak. Loads in southeast Idaho and northwest Wyoming also typically peak during the winter, but not necessarily during the same hour as the transmission system peak, the Seattle peak, or the Olympic Peninsula

peak. Loads in the Tri-Cities region, on the other hand, typically peak during an hour in the summer months, which are considered an off-peak time period for the system as a whole. For Portland and Central Oregon, the load may peak twice; once during the winter months and a second time, at a similar level, during the summer months.

Q. Why does BPA plan to serve non-coincident peak load as opposed to coincident peak load?

A. As indicated above, BPA must comply with mandatory NERC reliability standards. NERC Standard TPL-001-0.1 requires transmission planners, such as BPA, to plan its transmission system so that the system can be operated to supply projected customer demands and projected firm transmission services at all demand levels over a range of forecast system demands under various system conditions, such as the outage of a transmission facility. BPA applies this standard by planning to serve each customer's forecast peak demand, not just the customer's load on the hour of the year or month during which loads peak on BPA's system. If BPA planned the system to serve loads coincident with its annual system peak or a single seasonal system peak, but not the forecast peak load for each customer, BPA would be at risk of having insufficient facilities to serve each location's forecast peak loads and might be at risk of violating the mandatory NERC TPL Reliability Standards. By using non-coincident peak load assumptions in planning studies rather than coincident peak, BPA maintains adequate facilities to serve peak loads for each customer across BPA's diverse system.

Q. How do the planning studies consider the transmission of energy over the Network transmission facilities and interties to adjacent transmission systems?

A. As discussed above, the NERC TPL standards require BPA to supply its customers' demands, which include the transmission of energy over BPA's system to adjacent transmission systems (referred to as "energy transfers"). A significant amount of energy

is transferred across Network transmission facilities to serve load off of BPA's system. Energy transfers significantly affect power flows on BPA's system. For example, energy transferred from Canada to California usually flows in a north-to-south direction in the summer and typically causes high flows on the South of Allston flowgate (a flowgate is set of transmission lines that are studied together) and the California-Oregon intertie. For studies of energy transfers, BPA's main objective is to test the reliability of the system to transfer large amounts of energy over the Network and interties to adjacent transmission systems.

Q. When do energy transfers typically peak?

A. Although loads typically peak during the summer or winter months, energy transfers may peak during the winter, spring, and summer months. For example, during the late spring and summer, generation on BPA's system typically exceeds the amount of load on the system. Some of the excess hydro generation serves load on BPA's system because it displaces thermal generating units that would otherwise serve the load. Some of the excess generation is marketed to serve load off of BPA's system. Historically, transmitting the excess hydro generation to adjacent transmission systems causes flows over north-to-south transmission lines, such as the South of Allston flowgate and the California-Oregon intertie, to be high during the late spring and summer months. During the winter months, east-to-west flows over the Cross-Cascades North and South flowgates tend to be high due to peak loads in the major load centers west of the Cascades. During other periods when excess wind generation is being transmitted, different east-to-west flowgates are affected, such as West of McNary, West of Slatt, and West of John Day.

Q. What are BPA's other planning considerations?

A. To meet the NERC TPL standards, BPA also considers the operational flexibility of the system, such as the system's ability to reliably meet demands during normal conditions (all lines in service) and during transmission contingencies (transmission facility or generation outages). Outages affect the availability of transmission capacity to serve load and transmit energy off-system. To mitigate this, BPA schedules a large amount of transmission line maintenance work and plans its transmission outages for periods when load and energy transfers are lower (referred to as off-peak periods).

Q. When does BPA reinforce the transmission system?

BPA may reinforce the transmission system if facilities are needed to meet mandatory reliability standards, BPA's contractual obligations, or new requests for transmission or interconnection service. For example, BPA may need to add or upgrade facilities, such as transmission lines and transformers, to serve an NT customer's load growth. BPA may also reinforce the transmission system to meet new requests for transmission service identified in the Network Open Season process. For example, BPA is reinforcing the transmission system by adding facilities such as the McNary-John Day transmission line to accommodate new transmission service requests.

Q. Based on your analysis, which cost allocation method is most consistent with cost causation, as reflected in BPA's transmission planning approach?

A. The 12 NCP method is most consistent with BPA's planning approach, because BPA plans the transmission system to meet the demands under a range of system conditions throughout the year. As indicated above, the demands on BPA's system peak at different times of the year. Most of the load on BPA's system peaks during the winter months, but some peaks during the summer months. Energy transfers on BPA's system typically peak during the winter, spring, and summer months, depending on the type of generation

transferred. BPA schedules most of its maintenance work and transmission facility outages during off-peak periods, when loads and energy transfers are lower. Because BPA's planning processes and system investments consider the demands on the system throughout the year, not during just one month or season, the 12 NCP method is most consistent with BPA's planning processes and with cost causation.

Q. Why are you proposing to forecast NT load using the 12 NCP method even though BPA's planning studies use non-coincident peak load forecasts for each season?

A. Although the customer's non-coincident peak load for each season is an important consideration in BPA's planning studies, it is not the only consideration. BPA also plans the system for energy transfers and operational flexibility. These demands cause loading on the transmission system to peak at different times of the year. Costs should be allocated based on when the demands on the system occur. Therefore, we analyzed our system demand profile to determine whether costs should be allocated based on the NT customers' 12 monthly non-coincident peak loads or the NT customers' non-coincident peak load for a single season or month.

We understand that FERC favors allocating costs based on the 12 monthly peaks if the transmission provider's load curve is relatively flat. A flat load curve indicates that transmission capacity is built to meet customer demands from month to month and not the demands during a single season or month. When considered as a whole, the demands on BPA's system do not vary significantly from month to month, because the load and energy transfers peak at different times of the year. As a result, we propose to allocate costs to NT customers based on the 12 monthly non-coincident peaks.

Q. How is the load curve measured?

A. FERC uses three tests to measure the flatness of the load demand curve. The tests are typically performed using the utility's native load (load that the transmission provider is

obligated to serve), NT load, PTP reserved capacity, and legacy contract rights (transmission contracts executed before FERC issued Order No. 888, which included a tariff to be used for new transmission contracts) over a five-year period.

Under what is called the low-to-annual peak test, the lowest monthly peak of the year is compared to the highest monthly peak. FERC considers a ratio of 66 percent or higher as indicative of a flat demand curve.

Under the average-to-annual peak test, the average of the 12 monthly peaks is compared to the highest monthly peak of the year. FERC considers a ratio of 81 percent or higher to indicate a flat demand curve.

Finally, under the on-and-off peak test, the peak load during the peak period as a percentage of the annual peak is compared to the average of the monthly peaks during the off-peak period as a percentage of the annual peak. The peak period is the peak month for the 1 CP method or the peak three months for the 3 CP method. The off-peak period is the other months of the year. FERC considers a 19 percentage point or less difference between these two figures to indicate a flat demand curve.

Q. How did BPA perform the tests?

A. BPA performed the three tests using two sets of data for FY 2006-2011: (1) the current Network segment billing factors, which for NT service is the customer's load coincident with the monthly transmission system peak and for the PTP, IR and FPT service is the reserved capacity; and (2) monthly transmission peak load, which represents all flows on the system during the peak hour of the month, including load served under PTP, IR, FPT, and NT service as well as intra- and inter-regional energy transfers over the interties and the Network transmission facilities. The results of the tests are provided in Appendices 1 and 2 to this testimony. The main difference between the two sets of data is that billing factors for PTP, FPT, and IR service are reserved capacity, while the monthly

transmission peak load reflects actual flows and also includes the transmission of energy across BPA's system to serve off-system loads.

Q. Why did you use both the Network segment billing factors and the monthly transmission peak load for the tests?

A. Both sets of data provide useful information. We understand that FERC performs the tests using NT load, PTP reserved capacity, and legacy contract rights (on the basis of load or reserved capacity), rather than actual use of the system. Therefore, we used the Network segment billing factor data because it is more consistent with the FERC method. BPA's customers have more reserved capacity than load on the system, particularly during their off peak months, and there is a high volume of energy transfers over the transmission system that is not used to serve load on the system. We wanted to see if the test results would be significantly different based on actual demand patterns on the system, regardless of service type. The monthly transmission peak load reflects actual demand patterns on the system.

Q. What were the test results?

Using the Network segment billing factor data, the result for the low-to-annual peak test is 91 percent. For the average-to-annual peak test, the result is 94 percent. For the on-and-off peak test, the result is 6 percent. *See* Appendix 1. Using the monthly transmission peak load data, the result for the low-to-annual peak test is 88 percent. For the average-to-annual peak test, the result is 94 percent. For the on-and-off peak test, the result is 7 percent. *See* Appendix 2. Under both sets of data, the test results are within the FERC ranges for a flat demand curve. The results for the low-to-annual peak test are within the FERC range of 66 percent or higher. The results for the average-to-annual peak test are within the FERC range of 81 percent or higher. The results for the on-and-off peak test are within the FERC range of 19 percent or lower. These test results

indicate that the load curve on BPA's system is relatively flat throughout the 12 months of the year.

Q. Based on your analysis, which cost allocation method does BPA's load curve support?

A. A load curve that is relatively flat throughout the year indicates that the monthly peaks do not vary significantly from month to month. Under this scenario, the costs incurred to serve load are also relatively constant from month to month, so it would be consistent for the utility to allocate costs based on the average peak load during the 12 months. If the load curve indicates a sharp peak during a single month or season, on the other hand, the costs incurred to serve load during the peak period are significantly higher than during the off-peak periods. Thus, costs are reasonably allocated based on the load during the peak period. Applying this logic to the NCP methods, BPA's flat load curve supports allocating costs on the basis of the non-coincident peak load averaged over all months of the rate period as opposed to a single month. As described above, we propose the 12 NCP method instead of a coincident peak method because BPA plans to serve non-coincident peak load, transmit energy off-system, and maintain operational flexibility throughout the year and not just during a single month or season.

Section 5: Initial Proposal and Effect on Network Segment Revenues

Q. What method are you proposing to use to allocate costs for the Network segment for FY 2014-2015?

A. We propose to allocate Network segment costs based on the 12 NCP method.

Q. *What is the current NT billing factor?*

A. The current NT rate includes two charges: the NT base charge, set equal to the Network segment unit cost, and the NT load shaping charge, which recovers the difference between the costs allocated to NT service and costs recovered under the base charge. For

both of these charges, the billing factor is the NT customer's load on the hour of the monthly transmission system peak.

Q. What is the proposed NT billing factor for the FY 2014-2015 rates?

A. We proposed to change the NT billing factor to the NT customer's highest hourly load during the month. The reason for this change is discussed further in section 3 of Bogdon *et al*., BP-14-E-BPA-30. The NT customer's highest hourly load during the month is higher than (or in some cases equal to) the NT customer's load on the hour of the monthly transmission system peak. Thus, the forecast of NT load based on the proposed NT billing factor is higher than the forecast based on the current NT billing factor. If BPA applied the current rate to the forecast based on the proposed NT billing factor, the effect would be a revenue increase for NT customers because the same rate is applied to a higher amount of load.

Q. How did you compare the rate effect of the 12 NCP allocation method versus the 1 CP allocation method without including the effect of changing the NT billing factor?

A. We compared the revenues that would be recovered from NT, PTP, and IR service under current rates, rates calculated under the 1 CP method, and rates calculated under the 12 NCP method, with both the current and proposed billing factors. By comparing the revenues in this way, the unit of measure for NT, PTP, and IR service (the billing factors) is held constant for each calculation and only the rate changes. The result is the rate effect of the 12 NCP method.

Q. Can you explain why changing the billing factor changes the rate impacts?

A. In general, we can determine the difference between two cost allocation methods by comparing the rate under one method to the rate under the other method. In this case, however, this comparison does not show the different rate impacts of the two methods because the units to which they apply are different. As an analogy, if a gas station owner

sold gasoline for a dollar a gallon, but then changed the unit of measure to a liter while keeping the price the same, the effect is a rate increase because the same price is being charged for a smaller quantity. If the owner also increases the price, then the overall rate increase will be due to two factors: the higher price and the smaller unit of measurement.

In this case, comparing the rate under the 12 NCP method to the current rate does not accurately indicate the effect of changing cost allocation methods because, in addition to using a different NT load forecast to allocate costs, we also propose to change the NT billing factor. The different NT billing factor contributes to the overall rate impact.

Q. How did you compare the revenues?

A. First, we calculated the revenues recovered under the current rates and current billing factors. For PTP and IR service, the billing factor is the reserved capacity. For NT service, it is the NT customer's load on the hour of the monthly transmission system peak.

Next, we calculated the revenues recovered by applying a rate based on the FY 2014-2015 network revenue requirement and the 1 CP cost allocation method to the same billing factor. We then calculated the percentage difference between these two results to determine the percentage change in revenues attributable to the FY 2014-2015 revenue requirements using a 1 CP cost allocation methodology. Then we calculated the revenues recovered by applying the current rate to the forecast of NT, PTP, and IR service using the proposed billing factors. For PTP and IR service, the billing factor remains the reserved capacity. For NT service, it is the NT customer's highest hourly load during the month.

Next, we calculated the revenues recovered by applying a rate based on the FY 2014-2015 network revenue requirement and the 12 NCP cost allocation method to the same billing factor. Then we calculated the percentage difference between these two

results to determine the percentage change in revenues attributable to a change in the cost allocation methodology to 12 NCP. Finally, we subtracted revenues calculated using the 12 NCP method from the revenues calculated using the 1 CP method to determine the percentage difference in revenues between the two cost allocations. The results of our analysis are included in Appendix 3.

Q. What is the difference in revenue impact between the 1 CP cost allocation method and the 12 NCP cost allocation method for NT service?

A. As indicated in Table 1 of Appendix 3, using projected FY 2014-2015 Network revenue requirements and a 1 CP cost allocation methodology increases NT revenues by 14.02 percent over the revenues generated by current rates. Use of the 12 NCP method decreases NT revenues generated by current rates by 5.02 percent; this difference in revenue between current rates and the 12 NCP cost allocation methodology is attributable to the different cost allocation methodology.

Q. What is the difference in revenue impact between the 1 CP cost allocation method and the 12 NCP cost allocation method for PTP service?

A. As indicated in Table 2 of Appendix 3, using projected FY 2014-2015 Network revenue requirements and a 1 CP cost allocation methodology increases revenues by 16.49 percent. Use of the 12 NCP method increases revenues by 18.64 percent. The difference between the two is 2.15 percent (18.64 percent minus 16.49 percent). Thus, for PTP service, the revenues under the 12 NCP method are 2.15 percent higher than the revenues under the 1 CP method.

Q. What is the difference in revenue impact between the 1 CP cost allocation method and the 12 NCP cost allocation method for IR service?

A. The current IR rate, the FY 2014-2015 IR rate calculated under a 1 CP cost allocation methodology, and the proposed FY 2014-2015 IR rate (calculated using a 12 NCP cost

allocation methodology) are identical to their PTP counterparts. Thus, the rate impact of using the 12NCP method for the transmission portion of IR service is identical to that for PTP. *See* Appendix 3 Tables 2 and 3.

Q. Why are revenues higher for PTP and IR service under the 12 NCP method but lower for NT service?

A. The main reason is the elimination of the load shaping charge from the NT rate, which is discussed in section 3 of Bogdon *et al*, BP-14-E-BPA-30. The current NT load shaping charge is higher than the proposed increase to the unit cost (the proposed NT rate is set equal to the Network unit cost). Thus, the revenues recovered from NT customers are lower under the proposed rate.

Q. Does this conclude your testimony?

A. Yes.

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Appendix 1: Tests Using Network Segment Billing Factor Data

Fiscal Year	(A) Annual Peak (MW)	(B) Average of 12 Monthly Peaks (MW)	(C) Average of 11 off-peak Monthly Peaks (MW)	(D) Minimum Peak (MW)	(E) Low to Annual Test (D) / (A)	(F) Average to Annual Test (B) / (A)	(G) On and Off Peak Test 1 - (C) / (A)
2006	28,255	27,536	27,471	26,606	94%	97%	3%
2007	31,844	29,988	29,820	28,713	90%	94%	6%
2008	31,594	30,203	30,076	29,222	92%	96%	5%
2009	33,457	30,978	30,753	29,376	88%	93%	8%
2010	35,505	31,913	31,586	30,892	87%	90%	11%
2011	33,949	32,389	32,247	31,559	93%	94%	5%
Data based on Network Integration load at transmission system peak plus LT PTP and Legacy FPT and IR reserved capacity (billing factors)				**Average over 6years:**	**91%**	**94%**	**6%**

Appendix 2: Tests Using Monthly Transmission Peak Load Data

Fiscal Year	(A) Annual Peak (MW)	(B) Average of 12 Monthly Peaks (MW)	(C) Average of 11 off-peak Monthly Peaks (MW)	(D) Minimum Peak (MW)	(E) Low to Annual Test (D) / (A)	(F) Average to Annual Test (B) / (A)	(G) On and Off Peak Test 1 - (C) / (A)
2006	21,108,551	20,306,527	20,233,616	19,238,393	91%	96%	4%
2007	24,805,173	23,235,907	23,093,246	21,709,897	88%	94%	7%
2008	25,543,711	24,183,302	24,059,628	23,209,556	91%	95%	6%
2009	27,478,409	25,006,420	24,781,693	23,417,659	85%	91%	10%
2010	30,164,296	28,192,960	28,013,748	24,941,993	83%	93%	7%
2011	30,830,855	29,303,951	29,165,141	28,494,123	92%	95%	5%
				Average over 6years:	**88%**	**94%**	**7%**

Data based on TTSL

Appendix 3: Analysis of Revenue Impacts

Table 1: Analysis of NT Revenue Under the 1CP and 12NCP Cost Allocation Methodologies

(A) Product	(B) Rate ($/kW-yr)	(C) Billing Factor (MWs/Yr)	(D) Average Revenue/Yr (B) x (C) ($000)[1]	(E) Rate ($/kW-yr)	(F) Billing Factor MWs/Yr	(G) Average Revenue/Yr (E) x (F) ($000)[1]	(H) Percentage Increase (Decrease)
	Cost Allocation At Current Rates			**Assumes 1CP NT Cost Allocation At Proposed Rates**			
NT Base Rate	15.576[2]	6,421[3]	100,107	18.144	6,421[3]	116,507	16.49%
NT Load Shaping	4.404[4]	6,552[5]	28,854	4.644	6,552[5]	30,427	5.45%
Total			128,871			146,933	14.02%
	Cost Allocation At Current Rates			**Assumes 12NCP NT Cost Allocation At Proposed Rates**			
NT Base Rate	15.576[2]	7,434[6]	115,795	18.480[7]	7,434[6]	137,383	18.64%
NT Load Shaping	4.404[4]	6,552[5]	28,854	0[8]	6,552[5]	0[8]	(100.00%)
Total			144,469			137,383	(5.02%)
Difference between revenue impacts							19.04%

Witnesses: Rebecca E. Fredrickson, David W. Bogdon, David L. Gilman, Dennis E. Metcalf, and Larry A. Furumasu

[1] Values in this column may not extend due to rounding
[2] Current rate of $1.298/kW-month * 12
[3] Documentation, BP-14-E-BPA-07A, Table 4, line 55, column O
[4] Current rate of $0.367/wK-month times 12
[5] Documentation, BP-14-E-BPA-07A, Table 4, line 54, column O
[6] Documentation, BP-14-E-BPA-07A, Table 4, line 59, column O
[7] Documentation, BP-14-E-BPA-07A, Table 7, line 27 * 12
[8] Documentation, BP-14-E-BPA-07A, Table 7, line 48

Appendix 3: Analysis of Revenue Impacts

Table 2: Analysis of PTP Revenue Under the 1CP and 12NCP Cost Allocation Methodologies

(A) Product	(B) Rate ($/kW-yr)	(C) Billing Factor (MWs/Yr)	(D) Average Revenue/Yr (B) x (C) ($000)[1]	(E) Rate ($/kW-yr)	(F) Billing Factor MWs/Yr	(G) Average Revenue/Yr (E) x (F) ($000)[1]	(H) Percentage Increase (Decrease)
	Cost Allocation At Current Rates			**Assumes 1CP NT Cost Allocation At Proposed Rates**			
PTP, Long Term	15.576[2]	24,780[3]	385,981	18.144	24,780[3]	449,617	16.49%
PTP, Short Term	15.576[2]	1,617	25,191	18.144	1,617	29,344	16.49%
Total			411,172			478,962	16.49%
	Cost Allocation At Current Rates			**Assumes 12NCP NT Cost Allocation At Proposed Rates**			
PTP, Long Term	15.576[2]	24,780[3]	385,981	18.480[4]	24,780[3]	457,944	18.64%
PTP, Short Term	15.576[2]	1,617	25,191	18.480[4]	1,617	29,888	18.64%
Total			411,172			487,831	18.64%
Difference between revenue impacts							2.15%

[1] Values in this column may not extend due to rounding
[2] Current rate of $1.298/kW-month times 12
[3] Documentation, BP-14-E-BPA-07A, Table 4, line 51, column O
[4] Documentation, BP-14-E-BPA-07A, Table 7, line 27 * 12

Appendix 3: Analysis of Revenue Impacts

Table 3: Analysis of IR Revenue Under the 1CP and 12NCP Cost Allocation Methodologies

(A) Product	(B) Rate ($/kW-yr)	(C) Billing Factor (MWs/Yr)	(D) Average Revenue/Yr (B) x (C) ($000)[1]	(E) Rate ($/kW-yr)	(F) Billing Factor MWs/Yr	(G) Average Revenue/Yr (E) x (F) ($000)	(H) Percentage Increase (Decrease)
	Cost Allocation At Current Rates			**Assumes 1CP NT Cost Allocation At Proposed Rates**			
Transmission Portion of IR	15.576[2]	669[3]	10,419	18.144	669[3]	12,137	16.49%
	Cost Allocation At Current Rates			**Assumes 12NCP NT Cost Allocation At Proposed Rates**			
Transmission Portion of IR	15.576[2]	669[3]	10,419	18.480[4]	669[3]	12,362	18.64%
Difference between revenue impacts							2.15%

[1] Values in this column may not extend due to rounding
[2] Current rate of $1.298/kW-month * 12
[3] Documentation, BP-14-E-BPA-07A, Table 4, line 50
[4] Documentation, BP-14-E-BPA-07A, Table 7, line 27 *12