BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1050

In the Matter of PacifiCorp's Petition for Approval of Amendments to Revised Protocol Allocation Methodology	)

DIRECT TESTIMONY OF DONALD W. SCHOENBECK

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

REDACTED VERSION

January 27, 2011

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Donald W. Schoenbeck. I am a member of Regulatory & Cogeneration Services, Inc. ("RCS"), a utility rate and economic consulting firm. My business address is 900 Washington Street, Suite 780, Vancouver, WA 98660.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I've been involved in the electric and gas utility industries for almost 40 years. For the majority of this time, I have provided consulting services for large industrial customers addressing regulatory and contractual matters. I have appeared before the Oregon Public Utility Commission (the "Commission" or "OPUC") on many occasions since 1984. A further description of my educational background and work experience can be found in Exhibit ICNU/101 in this proceeding.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am testifying on behalf of the Industrial Customers of Northwest Utilities ("ICNU"). ICNU is a non-profit trade association whose members are large industrial customers served by electric utilities throughout the Pacific Northwest, including PacifiCorp (or "Company").

Q. WHAT TOPICS WILL YOUR TESTIMONY ADDRESS?

A. I will discuss PacifiCorp's application to modify the manner in which it allocates prudently incurred system costs in its jurisdictional allocation study to Oregon. According to PacifiCorp's analysis submitted in this docket, it is estimated the proposed changes will increase costs allocated to Oregon by [redacted] million over the period 2012 to 2016, as compared to the current allocation methodology. Consistent with PacifiCorp's prefiled testimony, I will refer to the current jurisdictional allocation method as the Revised Protocol and the proposed allocation method as the 2010 Protocol.

Q. PLEASE BRIEFLY SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS ADDRESSED IN THIS TESTIMONY.

A. PacifiCorp's application for the adoption of the 2010 Protocol is the result of discussions initiated due to the belief of the Public Service Commission of Utah ("Utah Commission") that the state will not realize the benefit that had been projected under the Revised Protocol at the time it had agreed to this allocation method. PacifiCorp's proposed 2010 Protocol is essentially a "rolled-in" allocation method, with two adjustments that were converted to levelized fixed dollar amounts. The purported intent of the two adjustments is to recognize and retain a known hydro-related cost/benefit for Oregon and also directly assign the substantial cost related to the removal of the Klamath dams to the states of Oregon and California. The Company is proposing to use the 2010 Protocol in any rate filing submitted through December 31, 2016. For the applicable period, the Oregon levelized hydro benefit is $6.85 million per year, while the Klamath dam removal charge is $11.5 million per year. The net result of these adjustments is that Oregon ratepayers will be paying $4.6 million more each year under the 2010 Protocol than a rolled-in approach, or about $23 million over the period of 2012-2016.

ICNU believes modifications to any jurisdictional allocation method should be based on cost causation. Under the 2010 Protocol, the two adjustments were determined based upon projected data of select resource costs and expected generation over the term of the proposal. As such, the proposed values will undoubtedly not be reflective of the actual costs and generation over this time period. Further, analysis of the projected growth in peak demands and energy consumption indicates revisions are warranted in the manner in which demand related system costs are allocated and fixed production related costs are classified in the jurisdictional allocation study.

The sensitivity analysis I have performed indicates changing the manner in which the system costs are classified and allocated would reduce the costs assigned to Oregon by about [redacted] million per year, or over [redacted] million during the period from 2012-2016, using only a rolled-in method. As a result of this analysis, I recommend the Commission not adopt the 2010 Protocol for Oregon and keep the current method in place temporarily. Instead, the Commission should enter into a multi-state collaborative process to review and examine all system cost elements with the goal of achieving an allocation method that appropriately follows the principles of cost causation. My analysis in this case indicates that an appropriate rolled-in allocation method is more consistent with cost causation principles than either the Revised Protocol or the 2010 Protocol. However, if the Commission feels compelled to modify the jurisdictional allocation method at this time, any change should be founded upon cost causation, as illustrated by the ICNU sensitivity analysis. Based upon this analysis, the fixed cost demand classification percentage should be changed from 75% to 50% under the 2010 Protocol.

II. PACIFICORP'S PROPOSAL

Q. PLEASE BRIEFLY EXPLAIN THE HISTORY OF THE REVISED PROTOCOL AND HOW IT HAS FUNCTIONED FOR OREGON.

A. The Revised Protocol was the result of negotiations that started in 2002. The final form of the Revised Protocol was adopted by the Commission in January 2005, replacing the then current cost allocation method referred to as the Modified Accord. At the time the Commission adopted the Revised Protocol, ICNU supported an alternate allocation methodology assigning a larger portion of hydro resources to Oregon. In its order adopting the Revised Protocol, the Commission directed the Company to keep track of and report the results of two alternate cost allocation methods in annual reports and general rate case dockets. These methods were the then current Modified Accord and the Hybrid Method, which was to be developed by the Company and interested parties pursuant to Commission directives.

As the Revised Protocol has been in place a relatively brief period of time, a comparative analysis of how it has functioned in rate proceedings is rather limited. In the UE 179 proceeding, under the Revised Protocol, the Company filed for a $112 million increase. The Company determined the Modified Accord would have resulted in an Oregon increase request of $129 million, while the Hybrid Method would have produced an increase request of $158 million. In the UE 210 proceeding, the Company sought a $113 million increase under the Revised Protocol (including the associated TAM increase). The Company determined the Modified Accord would have produced a request of $116 million, while the Hybrid Method would have produced a request of only $91 million. In the UE 217 proceeding, the Company sought a $200 million increase under the Revised Protocol (including the associated TAM increase). The Company determined the Modified Accord would have produced a request of $242 million, while the Hybrid Method would have produced a request of $199 million. A comparison of the three allocation methods for this relatively brief period indicates inconsistent results. The Hybrid Method produced results that were $46 million greater than the Revised Protocol in UE 179, but were $21 million less than the Revised Protocol in the very next proceeding. In UE 217, the results of the two methods were quite close being within $2 million. As compared to the Modified Accord, the Revised Protocol produced significantly lower requests in two of the dockets ($17 million less in UE 179 and $42 million less in UE 217), but comparable results in the third proceeding (within $3 million). Summing the requests for the three dockets for each method indicates the Revised Protocol produced requests that were $23 million lower than the Hybrid Method and $62 million less than the Modified Accord.

Another aspect of the Revised Protocol was the establishment of a "multi-state process" standing committee ("MSP Committee") to address and consider questions of interpretation or possible changes to the Revised Protocol. The MSP Committee is composed of one representative from each state employing the Revised Protocol. Importantly, however, any proposed modification coming from the MSP Committee must be formally approved by each state commission that had previously approved the Revised Protocol in order for the change to become effective.

Q. HAVE YOU VERIFIED THE ACCURACY OF PACIFICORP'S COST ESTIMATES UNDER THE VARIOUS COST ALLOCATION METHODS?

A. No. I have simply used PacifiCorp's data included in its filings and I have not independently verified the accuracy of the data. Analyzing PacifiCorp's past comparisons of the various allocation methods would be time consuming and is outside the scope of my testimony. I refer to these comparisons in my testimony for illustrative purposes.

Q. IS THE COMPANY'S PROPOSED 2010 PROTOCOL THE RESULT OF MSP COMMITTEE DELIBERATIONS?

A. Yes. In November 2008, Utah parties raised the concern that the continued use of the Revised Protocol may not be equitable for Utah compared to the expectations created when the Utah Commission agreed to adopt the Revised Protocol. At that time, Utah parties believed near-term costs increases would be offset by long-term cost savings as compared to a rolled-in benchmark. The Company agreed to undertake a comparative analysis of the Revised Protocol and other cost allocation methods including a rolled-in method as a result of the November 2008 discussion. Based on the results of this study, Utah parties sought modifications to the Revised Protocol at a MSP Committee meeting in September 2009. From that time until July 2010, the MSP Committee worked on proposed modifications to the Revised Protocol resulting in the Company's 2010 Protocol submitted to the Commission in this docket.

Q. HOW IS THE 2010 PROTOCOL DIFFERENT FROM THE REVISED PROTOCOL?

A. The 2010 Protocol is basically a rolled-in method with just two adjustments that are fixed for the 2012 to 2016 period. The use of the term "rolled-in" refers to the manner in which costs are assigned to all jurisdictions based on allocation factors reflecting contributions from all jurisdictions and all months. For several resource cost categories, this is different from the Revised Protocol that used seasonal allocation factors or jurisdictional specific assignments for certain resources. The purported intent of the two adjustments to the rolled-in result is to maintain a "hydro endowment" for Oregon and to implement the Klamath Hydroelectric Settlement Agreement ("KHSA").

Q. DOES THE REVISED PROTOCOL CURRENTLY HAVE A HYDRO ENDOWMENT BENEFIT FOR OREGON?

A. Yes. The Revised Protocol does have a hydro endowment based on a cost differential calculation for utility owned hydroelectric resources and certain Mid-Columbia contractual resources. This embedded cost differential ("ECD") is calculated as the per unit difference between owned or contracted for resource costs and the costs of all other resources, exclusive of the qualifying facility ("QF") contracts, multiplied by the expected generation from the hydro resources.

Q. IS THE SAME CALCULATION USED TO DETERMINE THE 2010 PROTOCOL HYDRO ENDOWMENT?

A. No. While the same hydro resources are used in the calculation, the per unit cost of other resources used in the ECD are only pre-2005 resources as listed in Exhibit PPL/205. The import of this change is shown by comparing columns m and n of confidential Exhibit ICNU/102. Column m shows the estimated per unit cost of resources under the Revised Protocol, while column n shows the estimated per unit cost of the pre-2005 portfolio. The projected pre-2005 resources have a per unit cost that is [redacted] per megawatt hour ("MWh") lower than the projected costs of all resources. Since the cost of this subset of resources is lower than the more expansive Revised Protocol portfolio of resources, the result is a substantially lower hydro endowment credit for 2012 to 2016 of about [redacted] million under the 2010 Protocol excluding the levelizing step or $5.6 million per year. With the levelizing adjustment applied to the hydro endowment, the 2012-2016 hydro credit is $33 million or $6.85 million per year. Under the Revised Protocol calculation, the Oregon hydro endowment would be [redacted] million or [redacted] million per year for the period of 2012 to 2016.

Q. WHY SHOULD THE COMMISSION BE WILLING TO CONSIDER THIS DETRIMENTAL CHANGE?

A. This change should not be considered in isolation but as part of the entire proposal. However, as the hydro endowment has been a critical element of prior methods, it is important for the Commission to have a good understanding of this modification within the 2010 Protocol.

Q. CAN YOU PROVIDE AN EXAMPLE OF A FAVORABLE CHANGE FOR OREGON UNDER THE 2010 PROTOCOL?

A. Yes. Under the Revised Protocol, an ECD was determined comparing each state's QF contract portfolio to the other resource costs with any premium assigned to each state. When this was adopted, Oregon parties felt the near term cost increase from this allocation would eventually lead to a long term benefit from having below average QF costs. Under the 2010 Protocol, existing QF contract costs are proposed to be allocated on a system basis. The change in treatment of QF contracts will reduce Oregon's net cost assignment by about [redacted] million over the period of 2012 to 2016. Isolating the impact of these two changes together—the hydro endowment other cost calculation and QF contract allocation—results in an increase, over 2012 to 2016, to Oregon of about [redacted] million under the 2010 Protocol, excluding the levelizing calculation, and [redacted] million with the levelizing calculation.

Q. PLEASE EXPLAIN THE SECOND ADJUSTMENT PROPOSED AS PART OF THE 2010 PROTOCOL.

A. The second adjustment relates to how costs related to the KHSA are treated under the 2010 Protocol. The proposal is to directly assign the cost of dam removal to the states of Oregon and California. As compared to a rolled-in allocation, this approach increases the costs to Oregon by [redacted] million for the period of 2012 to 2016.

Q. EARLIER YOU STATED THE TWO ADJUSTMENTS ARE FIXED FOR THE 2012 TO 2016 PERIOD. PLEASE EXPLAIN WHAT YOU MEAN.

A. During the MSP Committee deliberations with regard to the 2010 Protocol, financial modeling was done to assess the impact of various changes to the Revised Protocol for each state as well as indicating the results under the Modified Accord and a rolled-in approach. This modeling exercise indicated annual variations in the hydro endowment calculation with an Oregon credit value as low as just $1.6 million in 2013 and as high as $12.5 million in 2011. As part of this process, the MSP Committee agreed to do a present value levelization of the two adjustments leaving the values as equal and fixed amounts as set forth in PPL/101, Kelly/54. In other words, while the jurisdictional revenue requirement will undoubtedly vary from the projections used in formulating the 2010 Protocol, the amount of each of the two adjustments will not. If the 2010 Protocol is approved by all states, in each Oregon rate filing, the Company will determine the Oregon revenue requirement based on a rolled-in allocation method using its most current cost projections, plus an $11,496,000 surcharge for the KHSA, minus a credit of $6,851,000 for the ECD hydro adjustment. Put another way, the Oregon revenue requirement will be based upon a rolled-in cost allocation method, plus an additional $4,645,000.

Q. HOW WILL THE OREGON REVENUE REQUIREMENT BE DETERMINED IN FILINGS SUBMITTED AFTER JANUARY 1, 2017?

A. At this point, it is not known. The Company's testimony simply states it anticipates a process similar to that used in formulating the 2010 Protocol, or the 2010 Protocol may be extended.

III. ICNU ASSESSMENT OF PACIFICORP'S FILING

Q. DO YOU HAVE ANY CONCERNS REGARDING THE 2010 PROTOCOL AS IT WOULD APPLY TO OREGON?

A. Yes. Some of my concerns include: 1) the overarching manner that it was initiated based on projected benefits from a 2004 forecast not materializing; 2) the substantial dilution in the hydro benefit to Oregon; and 3) no cost crediting for the funds collected under the KHSA from other states. The bottom line result for Oregon from the proposed changes is quite revealing: the 2010 Protocol produces a higher revenue requirement for Oregon than a rolled-in approach. Under the 2010 Protocol, the hydro endowment has become a very real cost for Oregon. In addition, I believe other aspects of the Revised Protocol which are now part of the 2010 Protocol should be re-examined and changed.

Q. WHY DO YOU OBJECT TO THE MANNER IN WHICH THE PROPOSED CHANGES WERE INITIATED?

A. The instant filing arose from the fact that alternate cost allocation methods did not comport with prior projections from 2004 which indicated a future benefit to Utah as compared to a rolled-in method. While the 2004 projections indicated a modest benefit from adopting the Revised Protocol for Utah for 2012 to 2016 (ranging from [redacted]% to [redacted]%), updated results indicate a modest cost (ranging from [redacted]% to [redacted]%). This is simply not the primary measure to judge the reasonableness of a cost allocation approach. It is important to remember that Utah has not set rates based solely on the Revised Protocol. Utah adopted the Revised Protocol based on a change that included rate caps.

Instead of simply mechanically changing the manner in which costs are allocated, judgment should be exercised to determine if a particular allocation method should be modified or changed. For example consider the situation where select resources are only run to serve a sharp, short system peak in the summer months. A party could advocate using cost causation theory that the cost of these peaking resources should be allocated using the peak loads when the resources are required (a seasonal approach). However, another party could assert the resources are available throughout the year and loads from all months should be used to allocate the costs of the resources (a rolled-in method). Both allocation methods can be modeled and compared with the different results clearly quantified. But this type of analysis does not address the real issue: which method should be used? The mere fact that different methods produce different results or are closer to stale expectations cannot be the only basis used to justify a change in allocation methodology. The appropriate analysis is to show why the proposed change is a superior method than the current procedure. In reviewing the MSP Committee documents, they are devoid of this type of analysis. Changes to the jurisdictional allocation method should be based on cost causation arguments showing why the specific change is warranted and appropriate.

Q. WHAT ARE YOUR CONCERNS WITH THE MANNER IN WHICH THE 2010 HYDRO ENDOWMENT CALCULATION IS DONE?

A. Confidential Exhibit ICNU/102 presents some additional detail supporting the ECD Hydro adjustment set forth in Exhibit PPL/206. As can be seen from this summary exhibit, the ECD hydro adjustment is the result of projections of resource costs for the west side hydro resources (column e), the Mid-C contracts (column g) and the cost of the 2005 resources, although only the per unit cost is shown for this last category (column n). Similarly, the expected capability has been projected as set forth for the west side resources (column e) and the Mid-C resources (column h) over the period of time the 2010 Protocol is proposed to be in place. Relying on projections from 2010 to quantify select cost responsibility for many years out is contrary to the rate setting process. It is not at all unusual to have a formula rate in place for many years to establish a method for deriving cost responsibility. However, fixing values today that will not change regardless of actual cost or generation levels for many years should be given careful consideration. Indeed, intense scrutiny should have been done by the MSP Committee to understand the cost projections and any issues that may cause the cost projection to deviate from a simple singular point forecast presented to participants. For example, the anomaly of the per unit cost of the west side resources being higher in 2013 than the pre-2005 cost should have been questioned and explained. The foundation of ratemaking is that it be based upon known and measurable costs. Establishing a fixed hydro endowment now based upon projections going six years out is contrary to this rate making tenet.

Q. WHY DO YOU DISAGREE WITH THE MANNER IN WHICH THE KHSA IS TREATED UNDER THE 2010 PROTOCOL?

A. The KHSA requires the Company to implement a rate surcharge in Oregon and California to help fund the removal of certain dams including hydro generation facilities. The 2010 Protocol converts this source of revenue ([redacted] million per year) to a cost that is directly assigned to only Oregon and California. The Klamath hydroelectric resources have been in place for many, many years. During this time, the costs were allocated not only to Oregon and California but also to Washington and Wyoming under the jurisdictional studies and the associated generation served the system load. To now assign the cost of removal to just Oregon and California allows other states to escape the removal cost even though they had benefitted from the existence of these facilities for many years. This "singled out" treatment is also contrary to a rolled-in methodology.

The 2010 Protocol should treat the Klamath dam removal costs as any other cost item. The costs should be included in jurisdictional studies when they are being incurred and are known and measurable. It is my understanding that early customer funding of the dam removal costs under the KHSA is placed in two trust accounts. Funds from these trust accounts should be used to pay for the proportionate share of allocated dam removal costs when they are needed and can be used. Under the 2010 Protocol, the net impact on Oregon rate payers from treating this cost as situs to Oregon is an [redacted] million increase in revenue requirement each year under the 2010 Protocol as compared to a rolled-in method.

Q. WHAT CONCERNS DO YOU HAVE WITH ASPECTS OF THE REVISED PROTOCOL THAT HAVE BEEN CARRIED OVER TO THE 2010 PROTOCOL?

A. My concerns go to the manner in which production-related costs are classified in the 2010 Protocol and how demand-related costs are allocated to the various states. The methods that are being used are no longer appropriate and reflective of why the costs are being incurred.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THIS TO BE THE CASE.

A. The merger of Pacific Power & Light and Utah Power & Light occurred over 20 years ago. At that time, the fixed cost classification percentages of 75% demand-related and 25% energy-related were agreed upon in order to share the merger benefits. Under the Revised Protocol and the 2010 Protocol, all resource fixed costs are still classified using the same percentages. (All other resource costs—primarily fuel—are considered as being energy-related). As these classification percentages were put in place many years ago, I believe they need to be re-evaluated based on cost causation principles.

This analysis should consider for example the causal connection between maintenance expense and plant operations. Maintenance expense is generally dictated by the operating hours of a resource and the number of times it starts up and shuts down. For this reason, it is not at all unusual to see maintenance expense classified as being energy related. Another evaluation alternative would be to simply acknowledge that resources supply both capacity and energy as a joint product. The difficulty then becomes determining how the costs should be assigned to each category.

These types of classification debates have occurred for even more years than the existence of the merged company, and there are a variety of established methods that could be selected. These include the use of a: 1) peak and average; 2) average and excess; 3) equivalent peaker; and 4) the peak credit method. The first three approaches are used to classify just the fixed production related costs while the peak credit method is generally used to classify all production-related costs. The following table shows how the three fixed cost methods compare to the 2010 Protocol percentages. The peak and average and average and excess values were derived using the 2011 load levels from the Company's jurisdictional allocation spreadsheet models. I derived the equivalent peaker percentage using the capital costs of single cycle plants and combined cycle plants from the Company's 2008 Update Integrated Resource Plan ("2008 IRP Update"). As is presented in the table, any of these methods produces a demand-related percentage much lower than the current value contained in the 2010 Protocol.

Fixed Cost Demand Classification Comparison

Method	**1 CP**	**12 CP**
2010 Protocol	75%	75%
Peak and Average	[redacted]	[redacted]
Average and Excess	[redacted]	[redacted]
Equivalent Peaker	[redacted]	[redacted]

Q. HOW WOULD STATE JURISDICTIONAL REVENUE REQIREMENTS BE ALTERED FROM CHANGING THE FIXED COST PERCENTAGE?

A. The change would be a function of the energy usage or intensity of each state. If a state uses more energy per megawatt of jurisdictional peak as compared to the entire system, that state would experience an increase in its assigned cost responsibility. Conversely, a less energy intensive state would see a reduction in its cost responsibility. Confidential Exhibit ICNU/103 shows the jurisdictional load factors I have calculated based upon the

Company's projected twelve coincident peaks and energy sales. A load factor is a measure of energy intensity since it is calculated as the average energy usage divided by the peak usage. As can be seen from this exhibit, the load factor for Oregon is [redacted]

Q. WHY HAVE YOU PRESENTED THE RESULTS IN THE ABOVE TABLE USING BOTH A SINGLE COINCIDENT PEAK AND A TWELVE COINCIDENT PEAK DEMAND ALLOCATION FACTOR?

A. I have presented both results for two reasons. First, while the peak and average and average and excess method generally call for using the single system peak ("1 CP") to derive the percentages, I recognize other individuals may argue for using all twelve peaks ("12 CP"), as are currently used in the Revised Protocol and the 2010 Protocol. The second reason for presenting these results is because I believe the use of a simple average 12 CP demand allocation factor needs to be re-visited if the Revised Protocol is to be changed.

Q. WHY?

A. As is the case with respect to the classification percentages, the 12 CP allocation factor has been in place for some time. The appropriateness of this allocation approach is premised on having similar monthly peaks or reliability requirements across most months. An examination of recent years shows there have been several months close to the peak value but the summer peak has been greater than the highest winter peak. Going forward, the Company is projecting even greater dominance of the summer peak to all other months. This is shown in Confidential Exhibit ICNU/104. The top half of the exhibit shows the Company's projected coincident peak demand growth from 2009 to

2019 for each state. Note that the July and August growth is about [redacted] MWs above the projected winter peak growth. This exhibit also shows the projected growth divided between the western maintenance area ("WMA") and the eastern maintenance area ("EMA"). This grouping shows that almost [redacted]% of the peak growth is projected to occur in the EMA, making it the preferred location for new resource additions.

The bottom half of the exhibit shows each month's peak as a percent of the summer peak. Note that the projected growth translates into the summer peak months becoming much greater than the winter peaks over the planning horizon. As resources must be planned well in advance of the anticipated commercial operation date, the Company's projected summer growth is dictating the new resources that are being planned today. It is also important to recognize that the resources being added today are generally much more reliable than prior technologies. It is not unusual for combined cycle plants to achieve equivalent availabilities well in excess of 90%. This demand growth coupled with much greater reliability of new resource additions indicates the simple average 12 CP demand allocation factor proposed in the 2010 Protocol is inappropriate for the very period of time when it will be in place.

Q. HAVE YOU REVIEWED ANY OTHER ANALYSIS SUGGESTING THE DOMINANCE OF THE COMPANY'S SUMMER SEASON?

A. Yes. As part of their 2011 Integrated Resource Plan ("2011 IRP") process, the Company produced a stochastic loss of load study which was posted on their website in November 2010. Studies such as this are conducted to aid in understanding the level of reliability of a system given the anticipated loads and resource availability. These studies indicate to what extent the available resources are insufficient to serve the expected load level. The resulting loss of load probability ("LOLP") can be used as a measure of resource adequacy. The most common LOLP reliability standard is a one day in ten year occurrence (0.027%) which PacifiCorp has adopted for its IRP portfolio development. LOLP values above this criterion indicate additional resources are required while LOLP values below this amount indicate the resources used in the analysis are sufficient.

PacifiCorp's LOLP study indicated the loss of load hours ("LOLH") that would be expected to occur for five different planning reserve margins (8.3%, 10.2%, 12.8%, 15.5% and 18.3%) using 2014 loads. The following tables present the LOLH for each of the planning reserve margins segregated into summer (April through September) and winter (October through March) seasons and the percentage split between seasons.

LOLH by Season
Hours

	Winter	Summer	
PRM	Oct – Mar	Apr-Sep	Total
8.3%	1.0	19.0	20.0
10.2%	0.4	12.0	12.3
12.8%	0.3	6.5	6.9
15.5%	0.0	2.2	2.2
18.3%	0.0	0.8	0.8

LOLH by Season
Percent

	Winter	Summer	
PRM	Oct – Mar	Apr-Sep	Total
8.3%	5%	95%	100%
10.2%	3%	97%	100%
12.8%	5%	95%	100%
15.5%	2%	98%	100%
18.3%	1%	99%	100%

Under every planning reserve margin, the vast majority of expected hours of unserved load are within the summer season. Based on the results of this analysis, PacifiCorp has proposed an increase in the planning reserve margin used in its 2011 IRP to 13% from the prior value used of 12%. The LOLP analysis provides additional confirmation that the summer peak loads are far more critical for the Company than the months of October through March with additional resources required in the summer months in order to achieve the targeted reliability level.

Taken together, the recent dominance of the summer loads and the results of the LOLP analysis suggests the 12 CP demand allocation factor is not appropriate for assigning system resource costs to each jurisdiction. Alternative methods such as using the summer peak months or a weighted 12 CP approach should be considered if the Revised Protocol is to be changed to more accurately reflect cost causation.

Q. HAVE YOU PERFORMED ANY SENSITIVITY ANALYSIS TO ESTIMATE THE IMPACT ON THE OREGON REVENUE REQUIREMENT FROM MODIFYING THE FIXED COST CLASSIFCATION PERCENTAGE?

A. Yes. Confidential Exhibit ICNU/105 summarizes the results of a series of sensitivities I performed using the Company's spreadsheet model. I simply lowered the demand related fixed cost classification percentage in five percent (5%) increments down to fifty percent (50%). As shown by the exhibit, each 5% increment had a significant impact on the Oregon revenue requirement. At the 50% value—near the upper range of the three fixed cost methods I discussed—the result is an [redacted] million reduction for the 2012 to 2016 period (line 10) or an average of [redacted] million per year (line 15) for Oregon. This is a substantial sum.

Q. HAVE YOU DONE A SENSITIVITY ANALYSIS WITH REGARD TO THE 12 CP PEAK DEMAND ALLOCATION FACTOR?

A. Yes. Confidential Exhibit ICNU/106 compares the results of the 12 CP method with a summer peak approach using the peak demands of July and August. ("2 CP"). While I am not as yet convinced this is the most appropriate method, it does result in a substantial reduction in the Oregon revenue requirement of [redacted] million over the 2012 to 2016 period (line 16) or an average of [redacted] million per year (line 17). For me, this analysis does indicate however that the demand allocation approach is very sensitive and warrants careful consideration given current circumstances.

Q. ARE YOUR CLASSIFICATION AND DEMAND ALLOCATION SENSITIVITY RESULTS ADDITIVE TO ASCERTAIN THE AFFECT ON OREGON IF BOTH METHODS WERE CHANGED?

A. No, they are not, as the demand allocation sensitivity was performed using a fixed-cost demand classification percentage of seventy-five percent (75%). To illustrate the impact of both changes, I performed a sensitivity analysis using a 50% classification percentage coupled with a 2 CP allocation factor. Confidential Exhibit ICNU/107 compares the results of this sensitivity with a straight rolled-in method using the Company's 75% demand-related classification percentage and 12 CP allocation factor. For Oregon, implementing these changes would lower the cost responsibility by [redacted] million for the 2012-2016 period, or almost [redacted] million per year.

IV. ICNU RECOMMENDATIONS

Q. BASED UPON YOUR REVIEW AND ANALYSIS OF THE COMPANY'S FILING, WHAT RECOMMENDATIONS DO YOU HAVE FOR THE COMMISSION?

A. I recommend the Commission not adopt the 2010 Protocol at this time. ICNU recommends that any change to the existing jurisdictional allocation method should be based upon cost causation. Changes should not be adopted simply to achieve a forecast that was projected years ago, as the instant filing attempts to do. Instead, ICNU recommends the Commission and interested parties participate in a multistate collaborative to review all aspects of how system costs are allocated based on cost causation with the goal of achieving an allocation method that can be in place for a long period of time.

Q. IF THE COMMISSION FEELS COMPELLED TO ADOPT THE CHANGES CONTAINED IN THE 2010 PROTOCOL AT THIS TIME, WHAT WOULD YOU RECOMMEND?

A. Under those conditions, I recommend the Commission adopt one more change to the 2010 Protocol. The Commission should approve the use of a 50% demand-related fixed cost classification percentage for system costs. The current 75% value is dated and I have shown the value to be far outside a reasonable range.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

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OREGON PUBLIC UTILITY COMMISSION,	)
	)
Complainant,	)
	)
v.	)
	)
PACIFICORP D/B/A PACIFIC POWER & LIGHT COMPANY,	)
	)
Respondent.	)

EXHIBIT ICNU/101

QUALIFICATIONS OF DONALD W. SCHOENBECK

January 27, 2011

QUALIFICATIONS AND BACKGROUND OF DONALD W. SCHOENBECK

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Donald W. Schoenbeck, 900 Washington Street, Suite 780, Vancouver, Washington 98660.

Q. PLEASE STATE YOUR OCCUPATION.

A. I am a consultant in the field of public utility regulation and I am a member of Regulatory & Cogeneration Services, Inc. ("RCS").

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I have a Bachelor of Science Degree in Electrical Engineering from the University of Kansas and a Master of Science Degree in Engineering Management from the University of Missouri.

From June of 1972 until June of 1980, I was employed by Union Electric Company in the Transmission and Distribution, Rates, and Corporate Planning functions. In the Transmission and Distribution function, I had various areas of responsibility, including load management, budget proposals and special studies. While in the Rates function, I worked on rate design studies, filings and exhibits for several regulatory jurisdictions. In Corporate Planning, I was responsible for the development and maintenance of computer models used to simulate the Company's financial and economic operations.

In June of 1980, I joined the consulting firm of Drazen-Brubaker & Associates, Inc. Since that time, I have participated in the analysis of various utilities for power cost forecasts, avoided cost pricing, contract negotiations for gas and electric services, siting and licensing proceedings, and rate case purposes including revenue requirement determination, class cost-of-service and rate design.

In April 1988, I formed RCS. RCS provides consulting services in the field of public utility regulation to many clients, including large industrial and institutional customers. We also assist in the negotiation of contracts for utility services for large users. In general, we are engaged in regulatory consulting, rate work, feasibility, economic and cost-of-service studies, design of rates for utility service and contract negotiations.

Q. IN WHICH JURISDICTIONS HAVE YOU TESTIFIED AS AN EXPERT WITNESS REGARDING UTILITY COST AND RATE MATTERS?

A. I have testified as an expert witness in rate proceedings before commissions in the states of Alaska, Arizona, California, Delaware, Idaho, Illinois, Maryland, Montana, Nevada, North Carolina, Ohio, Oregon, Washington, Wisconsin and Wyoming. In addition, I have presented testimony before the Bonneville Power Administration, the National Energy Board of Canada, the Federal Energy Regulatory Commission, publicly-owned utility boards and in court proceedings in the states of Washington, Oregon and California.

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

OREGON PUBLIC UTILITY COMMISSION, Complainant, v. PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY, Respondent.	)	Docket No. UM 1050

EXHIBIT ICNU/102

EMBEDDED COST DIFFERENTIAL ALLOCATION DETAIL

REDACTED VERSION

January 27, 2011

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

OREGON PUBLIC UTILITY COMMISSION, Complainant, v. PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY, Respondent.	))))))))))))	Docket No. UM 1050

EXHIBIT ICNU/103

COMPARISON OF JURISDICTIONAL LOAD FACTORS

REDACTED VERSION

January 27, 2011

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

OREGON PUBLIC UTILITY COMMISSION, Complainant, v. PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY, Respondent.	)	Docket No. UM 1050

EXHIBIT ICNU/104

2009-2019 PEAK LOAD GROWTH - MWs

REDACTED VERSION

January 27, 2011

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

OREGON PUBLIC UTILITY COMMISSION, Complainant, v. PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY, Respondent.	))))))))))))	Docket No. UM 1050

EXHIBIT ICNU/105

FIXED COST CLASSIFICATION SENSITIVITY –
ROLLED-IN ALLOCATION METHOD

REDACTED VERSION

January 27, 2011

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

OREGON PUBLIC UTILITY COMMISSION,	)	
Complainant,	)	
v.	)	Docket No. UM 1050
PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY,	)	
Respondent.	)	

EXHIBIT ICNU/106

PEAK DEMAND ALLOCATION FACTOR SENSITIVITY
ROLLED-IN METHOD

CONFIDENTIAL SUBJECT TO GENERAL PROTECTIVE ORDER

January 27, 2011

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

OREGON PUBLIC UTILITY COMMISSION, Complainant, v. PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY, Respondent.	)	Docket No. UM 1050

EXHIBIT ICNU/107

FIXED COST CLASSIFICATION AND PEAK DEMAND SENSITIVITY ROLLED-IN METHOD

REDACTED VERSION

January 27, 2011