Davison Van Cleve PC
Attorneys at Law
TEL (503) 241-7242 • FAX (503) 241-8160 • mail@dvclaw.com
Suite 400
333 SW Taylor
Portland, OR 97204

June 24, 2011

Via Federal Express

Ms. Carol Hulse
Oregon Public Utility Commission
550 Capitol Street, N.E., Suite 215
P.O. Box 2148
Salem OR 97308-2148

Re: 2012 Transition Adjustment Mechanism Schedule 201, Net Power Costs, Cost-Based Supply Service Schedule 205, TAM Adjustment for Other Revenues
Docket No. UE 227

Dear Ms. Hulse:

Enclosed please find an original and six (6) copies of the Highly Confidential Direct Testimony and Exhibits for Donald W. Schoenbeck on behalf of the Industrial Customers of Northwest Utilities in the above-referenced Docket. Confidential copies of the testimony and exhibits on yellow paper are being provided to those parties who have signed the Protective Order, Order No. 10-069, for Docket No. UE 216.

Highly Confidential copies of the testimony and exhibits on green paper are being provided to the Oregon Public Utility Commission and those parties who have reached an informal agreement with PacifiCorp regarding the treatment of information PacifiCorp has claimed to be "Highly Confidential." PacifiCorp provided the underlying alleged "Highly Confidential" information to ICNU pursuant to the terms of an informal agreement under which, inter alia, ICNU would work with PacifiCorp regarding the filing of the material, that all documents would be placed on green paper, and ICNU would not release the information to any party until PacifiCorp's objections regarding the release of the information were resolved. PacifiCorp has informed ICNU that it objects to the release of the allegedly "Highly Confidential" information to the representatives of Noble Americas Energy Solutions. Pursuant to the terms of ICNU and PacifiCorp's informal agreement, ICNU is not providing a copy any Highly Confidential information to Noble Americas Energy Solutions at this time.

ICNU and PacifiCorp are jointly working to develop a modified protective order regarding the treatment of any alleged "Highly Confidential," and have reached an agreement in principle regarding the protective order modifications, but have not finalized a new proposed modified protective order. Any new modified protective order would have to be reviewed by all other parties in this proceeding and approved by the Administrative Law Judge, and the protective order will not be approved by today. Therefore, ICNU is filing any allegedly "Highly Confidential" information consistent with the terms of PacifiCorp and ICNU's informal agreement.

Please also find one (1) CD containing the confidential testimony and exhibits, three (3) CDs containing the confidential workpapers of Donald W. Schoenbeck, & three (3) CDs containing the public workpapers of Donald W. Schoenbeck. All backup workpapers are also being provided concurrently on CD to Staff and PacifiCorp.

Please return one file-stamped copy of the Highly Confidential Direct Testimony in the self-addressed, stamped envelope provided. Thank you for your assistance, and please do not hesitate to contact our office if you have any questions.

Sincerely yours,

<u>/s/ Irion A. Sanger</u>
Irion A. Sanger

Enclosures

cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Direct Testimony and Exhibits of Don Schoenbeck on behalf of the Industrial Customers of Northwest Utilities upon the parties, on the service list, by causing the same to be deposited in the U.S. Mail, postage-prepaid, where paper service has not been waived. Confidential copies have been provided to those parties who have signed the Protective Order, Order No. 10-069, for Docket No. UE 216. Highly Confidential copies of the testimony are being provided to those parties who have been given permission by PacifiCorp.

Dated at Portland, Oregon, this 24th day of June, 2011.

/s/ Sarah A. Kohler
Sarah A. Kohler

(W) PACIFIC POWER & LIGHT
JOELLE STEWARD **(C)**
SENIOR COUNSEL
825 NE MULTNOMAH STE 1800
PORTLAND OR 97232
joelle.steward@pacificorp.com

(W) PACIFIC POWER & LIGHT
JORDAN A WHITE
1407 W. NORTH TEMPLE, STE 320
SALT LAKE CITY UT 84116
jordan.white@pacificorp.com

(W) PACIFICORP
OREGON DOCKETS
825 NE MULTNOMAH ST STE 2000
PORTLAND OR 97232
oregondockets@pacificorp.com

(W) PUBLIC UTILITY COMMISSION OF OREGON
MAURY GALBRAITH **(C)**
PO BOX 2148
SALEM OR 97301
maury.galbraith@state.or.us

(W) RICHARDSON & O'LEARY
GREGORY MARSHALL ADAMS **(C)**
PO BOX 7218
BOISE ID 83702
greg@richardsonandoleary.com

(W) NOBLE AMERICAS ENERGY SOLUTIONS LLC
GREG BASS
gbass@noblesolutions.com

(W) CITIZENS' UTILITY BOARD OF OREGON
GORDON FEIGHNER **(C)**
ROBERT JENKS **(C)**
G. CATRIONA MCCRACKEN **(C)**
610 SW BROADWAY, SUITE 308
PORTLAND OR 97205
gordon@oregoncub.org
bob@oregoncub.org
catriona@oregoncub.org

(W) DEPARTMENT OF JUSTICE
JASON W JONES **(C)**
ASSISTANT ATTORNEY GENERAL
REGULATED UTILITY & BUSINESS SECTION
1162 COURT ST NE
SALEM OR 97301-4096
jason.w.jones@state.or.us

(W) MCDOWELL & RACKNER PC
KATHERINE A MCDOWELL
AMIE JAMIESON **(C)**
520 SW SIXTH AVE - SUITE 830
PORTLAND OR 97204
katherine@mcd-law.com
amie@mcd-law.com

(W) ENERGY STRATEGIES LLC
KEVIN HIGGINS **(C)**
PRINCIPLE215 STATE ST - STE 200
SALT LAKE UT 84111-2322
khiggins@energystrat.com

(W) INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES
MICHAEL EARLY
1300 SW 5TH AVE, STE 1750
PORTLAND OR 97204-2446
mearly@icnu.org

(W) REGULATORY & COGENERATION SERVICES INC
DONALD W. SCHOENBECK
900 WASHINGTON ST STE 780
VANCOUVER WA 98660-3455
dws@r-c-s-inc.com

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 227

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2012 Transition Adjustment Mechanism	)
Schedule 201, Cost-Based Supply Service	)

TESTIMONY OF

DONALD W. SCHOENBECK

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

REDACTED VERSION

June 24, 2011

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 the "Company").

Q. WHAT TOPICS WILL YOUR TESTIMONY ADDRESS?

A. I will discuss select issues related to PacifiCorp's proposal to increase the net power costs ("NPC") allowed under the Transition Adjustment Mechanism ("TAM") by $57.9 million or 17.8%. The average proposed rate increase is approximately 5.2% with a proposed large industrial rate increases of 7.3%. Specifically, I will address the Company's load forecast for 2012, the Company's financial hedging strategy and its impact on the NPC for 2012, the forward price curves used as a starting point for deriving the projected power cost, several aspects of the Company's market sales efforts and how they are reflected in the NPC proposed by the Company, the exclusion of select water years associated with the Bear River hydro system, and the must run designation of certain Gadsby units. In supplemental testimony which will be filed on July 5, 2011, I will address the single issue of converting monthly forward electricity prices into hourly values required for the GRID model.

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

A. The adjustments I recommend the Commission adopt in this testimony will reduce the NPC cost assigned to Oregon by about $63.8 million. The vast majority of this amount is attributable to two adjustments which are related to the Company's system wide projected retail load level used to determine NPC and the Company's hedging strategy associated with gas financial transactions. A brief description of all the adjustments I will address is as follows.

1. <u>Retail Load Forecast</u>

The Company's substantial retail load growth projection has increased system wide NPC by $164 million. My testimony demonstrates that the Company's 7.5% system load growth is unsupported and far above recent actual load growth experienced by the Company. However, if this level of sales is to be used to establish rates in Oregon, there should be a corresponding recognition of the additional margin revenue that will be derived from this sales level. Recognizing this additional revenue would reduce the proposed Oregon increase by $42.6 million.

2. Gas Financial Hedging Strategy

The Company's NPC includes $122.8 million in above market gas hedges for 2012 on a system basis. The Company's hedging strategy is fundamentally flawed by locking in far too much gas far too quickly. I recommend that $64.8 million system wide be disallowed thereby reducing the Oregon NPC by about $16.2 million.

3. Source of Forward Price Curves

The Company uses internally generated highly confidential monthly electricity and gas forward prices to determine NPC. I recommend an independent (or third party) source be used to eliminate any concerns regarding the possibility of gaming, lessen disputes over the highly confidential treatment of the associated prices, and to allow for a more precise tracking of how forward market movements would impact the Company's NPC. Based on a comparative analysis we have done, I recommend using ICE transactional data as the source of the forward prices. I believe this recommendation will have little if any impact on the NPC in this case, while providing the benefits I have just enumerated.

4. Sales Activity - Market Sales Limits

The Company limits or "caps" the amount of possible market sales GRID is allowed to transact each *hour* based upon the *average energy amount sold over the entire on-peak or off-peak monthly period* from the most recent 48 months of sales. These limits are an artificial constraint and as the GRID model does not come close to achieving the total average sales from the 48 month historical period, the caps should be eliminated. The isolated impact of this adjustment would lower the Oregon NPC by about $1.4 million.

5. **Sales Activity - ISO Charges**

The Company's system-wide NPC includes $4.2 million of California ISO charges with no corresponding benefit as the California market is not modeled in GRID. Either the cost should be eliminated or the corresponding benefit should be imputed into the NPC. I recommend the conservative approach of simply eliminating the cost from the 2012 NPC projection thereby reducing Oregon's NPC by about $1.1 million.

6. **Sales Activity - DC Intertie Charges**

The Company's system-wide NPC includes $4.8 million associated with the DC intertie into Southern California. However, the GRID model does not allow transactions at this market hub as the node is not modeled. As with the ISO charges, this cost should be eliminated from the NPC determination as there is no corresponding benefit. This adjustment would reduce Oregon's NPC by about $1.2 million.

7. **Bear River Hydro Normalization**

In deriving the projected generation from the Bear River system, the Company has eliminated the flood control water years. There is no basis for making such an arbitrary exclusion of select years. As hydro conditions can and do vary from year to year, all years should be included in deriving a normalized hydro generation value. This adjustment will reduce the Oregon NPC by about $0.5 million.

8. **Gadsby Units 4-6 – Wind Integration Costs**

Based on the results of a modeling effort associated with determining the cost of integrating wind resources into the Company's service territory, the Company has proposed in the NPC determination that the Gadsby units 4, 5 and 6 (each about 40 megawatts of capacity) be "blocked on" as must run units in deriving the NPC for 2012.

The operating data provided by the Company shows these units are not operated in this fashion. Further, while it is readily acknowledged that integrating wind resources may impose some additional costs on a system, the precise amount and potential offsetting actions are still being investigated. For both these reasons, the Gadsby units 4-6 should not be modeled as must run at this time. Allowing the units to cycle will reduce the Oregon NPC by about $0.8 million.

Table 1: Combined Adjustments

#	Adjustments	$ (in millions)
1	Retail Load Forecast	$42.6
2	Gas Financial Hedging Strategy	$16.2
3	Source of Forward Price Curves	0
4	Sales Activity – Market Sales Limits	$1.4
5	Sales Activity – ISO Charges	$1.1
6	Sales Activity – DC Intertie Charges	$1.2
7	Bear River Hydro Normalization	$0.5
8	Gadsby Units 4-6	$0.8
	Total	**$63.8**

RETAIL LOAD FORECAST

Q. DOES THE COMPANY'S PROPOSED 2012 NPC REFLECT AN INCREASE IN THE RETAIL LOAD FROM THE LEVEL USED IN THE RECENT UE 216 AND UE 217 PROCEEDINGS?

A. Yes. As noted in the prefiled testimony of Mr. Duvall, the projected system wide retail load level for 2012 is 7.5% greater than the retail loads used to establish the NPC and fixed cost recovery for 2011 in UE 216 and UE 217.

Q. IS THIS PROJECTED GROWTH OCCURING IN A PARTICULAR AREA OR JURISDICTION?

A. No. Confidential Exhibit ICNU/102, Schoenbeck/1 is a retail load comparison by GRID nodal load area for the year 2011 from UE 216/217 and the instant proceeding for 2012 (UE 227). In an industry where energy load growth has generally been measured at a rate of 1-2% for many years, **[Begin C]** [redacted] **[End C]**

Q. HAVE YOU ANALYZED THE COMPANY'S LOAD GROWTH PROJECTION FOR THE OREGON RATE SCHEDULES?

A. Yes. Confidential Exhibit ICNU/102, Schoenbeck/2 is a comparison of the various Oregon rate classes from the UE216/217 proceeding and this instant docket. This page indicates the Company has projected an overall load growth of 7.1% for Oregon with 6.6% for the residential class and 7.6% for the commercial and industrial classes.

Q. WHAT IMPACT DOES THIS SUBSTANTIAL LOAD GROWTH HAVE ON THE PROJECTED NPC?

A. Mr. Duvall correctly noted that with "all else held constant," increases in retail loads result in an increase in NPC for the Company. To gain insight into the cost associated with this load growth, we performed a GRID simulation where every nodal hourly load was reduced by 7.5% to approximate the same load level used to establish rates in the UE 216 proceeding. The system NPC produced by GRID was $164.5 million lower at $26.77 per megawatthour ("MWh") at the sales level as compared to $27.93/MWh under the Company filing. Assuming an Oregon jurisdictional allocation impact of 25% (a value I will use to approximate Oregon impacts throughout the remainder of this testimony), this one singular issue is responsible for a large portion of the Company's proposed increase—roughly $41 million excluding changes due to load variation or $20 million taking into account the reduced load level.

Q. IS SYSTEM WIDE ENERGY LOAD GROWTH OF 7.5% OR OREGON LOAD GROWTH OF 7.1% REALISTIC IN TODAY'S ECONOMIC ENVIRONMENT?

A. No. This value far exceeds the load growth recently experienced by PacifiCorp or that is projected in the Company's March 31, 2011 Integrated Resource Plan ("IRP"). In responses to data requests, the Company has provided energy information for recent time periods. In response to ICNU data request ("DR") 2.7, the Company provided actual and weather normalized system monthly load levels for 2009 and 2010. A summary of this data response is provided as Confidential Exhibit ICNU/102, Schoenbeck/3. This data indicates the Company experienced a 2.2% growth in system loads from 2009 to 2010 based upon weather normalized values. In response to Staff DR 36, the Company provided actual retail sales comparisons for the twelve months ended March 2010 and March 2011. A summary of the Company's data response is provided as Confidential Exhibit ICNU/102, Schoenbeck/4. This page shows a growth rate of just 2.3% for this comparative period on a system basis.

Q. WHAT THEN IS THE EXPLANATION FOR THE 7.5% LOAD GROWTH VALUE BETWEEN UE 216/217 AND THIS FILING?

A. The Company has updated the forecast it had used in the UE 216/217 proceedings. The significance of this update can be seen by reviewing Confidential Exhibit ICNU/102, Schoenbeck/4. The forecast used in UE 216 projected system sales of 54,901 gigawatthours ("GWhs") for 2012 while the updated forecast is projecting 57,247 GWhs, an increase of 4.3%. A comparable increase is indicated for 2011 of 4.5% on a system basis where the updated forecast is projecting 55,531 GWhs as compared to the prior forecast of just 53,153 GWhs. In the Company's recently released IRP, Appendix A, Table A.1 shows system sales projected at 55,553 GWhs in 2011 and 56,789 GWhs for 2012—a value lower than the Company is proposing to use in this case. A copy of the page containing the IRP table is provided as Confidential Exhibit ICNU/102, Schoenbeck/5.

Q. WHAT DOCUMENTATION AND WORKPAPERS HAS THE COMPANY PROVIDED TO SUPPORT THE UPDATED FORECAST?

A. Virtually all the supporting documentation is presented in Confidential Exhibit ICNU/102, Schoenbeck/3-4. While parties have asked for complete documentation and support for the load forecast, very little has been provided by the Company. This is illustrated by Confidential Exhibit ICNU/102, Schoenbeck/6, which is a copy of the Company's narrative response to Staff DR 36. In an abbreviated TAM proceeding, the response from the Company is woefully inadequate. In actuality, I believe using an updated forecast in the context of a TAM only docket—with no associated general rate case docket—is inappropriate.

Q. WHY IS USING AN UPDATED FORECAST INAPPROPRIATE?

A. First of all, examining the reasonableness of a single forecast takes a great deal of time. In this instant case, it would require understanding the fundamental drivers and economic assumptions used to produce three forecasts: 1) the forecast used in the UE 216 proceeding; 2) the forecast done for the IRP; and 3) the forecast the Company has relied on in this docket as all have different retail sales values for 2012. In my view, this effort cannot be adequately performed in a TAM only rate proceeding when there are numerous other matters to examine and the intent is that it be a "stream-lined" process. Second, and probably even more important, is the gaming opportunity that is present in a TAM only proceeding versus a combination TAM and general rate case proceeding ("TAM/GRC") like UE 216 and UE 217. In a TAM/GRC, all costs are examined for reasonableness including retail load levels. The same retail load level is used in both dockets to derive the specific rate charges for recovery of the Company's fixed and variable costs. In a TAM only docket however, the Company has every incentive to increase the retail sales level to drive up NPC resulting in a higher NPC per unit recovery while maintaining the fixed cost recovery at greater per unit charges than would be the case if the higher sales level had simultaneously been reflected in the fixed cost recovery determination. This incentive is just the opposite in a GRC where a lower load forecast produces a higher resulting per unit rate for recovering fixed costs which are substantially greater than the Company's variable costs.

Q. WHAT IS YOUR RECOMMENDATION FOR HOW RETAIL LOAD FORECASTS SHOULD BE ADDRESSED IN A TAM PROCEEDING?

A. If there is a companion GRC docket, I have no objection to allowing the Company to present the most recent retail load level projection. However, if it is a "stand alone" TAM proceeding as is the case now, an alternate method should be used. While my preference would be to use the same load levels as the prior docket, a reasonable alternative is to simply recognize the additional fixed cost revenue recovery from the additional sales to use as an offset to the overall increase allowed for recovery.

Q. WHAT IS THE RESULT OF THIS RECOMMENDATION IN THIS PROCEEDING?

A. The compliance filings from the UE 216/217 proceedings have a Commission authorized 2011 base revenue level of $1,106.1 million. Of this amount, $303.3 million was for the recovery of NPC leaving $802.8 million in fixed margin revenue. As indicated by Exhibit PPL/304, Ridenour/1 in this proceeding, the current total base revenue is $1,169.9 million of which $324.5 million is recovery of NPC yielding current margin revenue of $845.4 million. The additional margin revenue amount of $42.6 million ($845.4 – $802.8 = $42.6) should be used to offset the NPC increase in this proceeding.

Q. WHY DO YOU BELIEVE THIS ADJUSTMENT IS WARRANTED?

A. First, as I previously noted, this will eliminate the gaming opportunity of artificially inflating a TAM only forecast to achieve a higher net power cost recovery while maintaining a higher fixed cost rate recovery. Second, the original intent of the TAM was to more accurately determine power costs for rate making procedures in implementing direct access in Oregon. However, PacifiCorp has virtually no direct access customers—having an associated direct access load of just one or two average megawatts ("AMWs"). As the TAM is now just a vehicle to increase power costs to bundled sales customers, it is appropriate to look at their total revenue contribution in a TAM only case and not just the NPC recovery. Finally, to the extent the Company believes the adjustment will not allow sufficient recovery of its current fixed cost, it always has the option to file a GRC with the TAM in order to obtain a higher authorized fixed cost recovery amount from the Commission.

GAS FINANCIAL HEDGING STRATEGY

Q. COULD YOU PLEASE PROVIDE A BRIEF EXPLANATION OF WHY A COMPANY WOULD PURSUE GAS FINANCIAL HEDGING?

A. Yes. Gas financial hedging has been part of the energy industry since at least the mid-1990's. Companies will participate in hedging to manage gas commodity risk thereby reducing price volatility and providing some price certainty. Based on my experience and observation, I believe critical elements of a successful strategy include: 1) recognition that it is highly unlikely that you will be able to "beat the market" through hedging; 2) the diversification principle of portfolio theory should be applied; and 3) the cost and revenue risk should be aligned as closely as possible. These elements form a hedging policy that relies on executing transactions on a programmatic basis, relying on both forward and spot markets for gas transactions (either physical or financial), and not contracting for gas long before it is projected to be needed.

Q. DOES THE COMPANY EXECUTE GAS HEDGES PURSUANT TO A GAS HEDGING STRATEGY?

A. Yes. The Company's proposed 2012 NPC includes the cost associated with **[Begin C]** [redacted] **[End C]** gas financial hedging transactions executed from **[Begin C]** [redacted] **[End C]** with an associated mark-to-market cost of $122.8 million for the entire system. In other words, based upon the forward gas price curves used by the Company when the case was filed, the gas hedges the Company has executed are above the current forward gas prices by $122.8 million. As provided in response to an ICNU data request, **[Begin C]** [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] **[End C]**

Q. CAN YOU PROVIDE EXAMPLES OF OTHER UTILITIES IN THE INDUSTRY THAT HAVE A HEDGING STRATEGY SIMILAR TO THE ONE YOU ARE ADVOCATING?

A. Unfortunately, most utilities declare their hedging strategies to be confidential—just as PacifiCorp has done in this proceeding—so there are only very limited public examples that can be provided.

However, this Commission is well aware of the hedging strategies employed by both NW Natural Gas Company and Avista Utilities. NW Natural uses physical and financial hedges for up to five years but the hedges are very limited as you move away from the prompt contract year. As reported in their 2010 annual report to the Security and Exchange Commission ("SEC"), NW Natural entered the 2010-2011 gas contract year ("prompt year") being only 77% hedged on their projected purchased volumes. For the second year out, NW Natural is only 45% hedged and for the third year out NW Natural has hedged only 5-10% of the forecasted purchase volume. See Exhibit ICNU/103, Schoenbeck/12. While I cannot detail the confidential strategy employed by Avista Utilities ("Avista"), the net result of this strategy can be illustrated by Avista's recent rate filing in Washington for a 2012 test year. The publicly available pro forma power supply Exhibit WGJ-2 indicates a mark-to-market cost associated with physical gas transactions of $4.8 million and a financial hedge mark-to-market credit of $113,000. See Exhibit ICNU/103, Schoenbeck/14. These two values net to a $4.7 million mark-to-market adjustment for 2012. As Avista projected 2012 gas generation is roughly 25% of PacifiCorp's, the Avista mark-to-market value has to be multiplied by a factor of four to be comparable with PacifiCorp's gas need. The difference in 2012 mark-to-market adjustments is substantial as PacifiCorp is seeking recovery of $122.8 million while a comparable Avista value would be only $18.8 million, a difference of $104.0 million.

Q. ARE YOU AWARE OF OTHER PARTIES IN OTHER STATES CHALLENGING PACIFICORP'S GAS HEDGING STRATEGY?

A. Yes. The Company's policy is being challenged by multiple parties in the Company's current Utah general rate case.

Q. WHAT IS YOUR SPECIFIC RECOMMENDATION WITH REGARD TO THE AMOUNT OF PACIFICORP'S MARK TO MARKET GAS COSTS THAT SHOULD BE ALLOWED IN THIS PROCEEDING?

A. Confidential Exhibit ICNU 103, Schoenbeck/15 presents and compares my recommended hedging parameters with PacifiCorp's current values. My recommendation is based on a programmatic hedging policy for all months of the year but it also recognizes the uniqueness of the second quarter (April through June) of each year when abundant hydro is available to displace the vast majority if not all of the gas-fired generation in the Pacific Northwest region. For these months, the hedged target should be substantially lower than all remaining months of the year. Implementing this recommendation reduces PacifiCorp's mark-to-market amount by $64.8 million on a system basis. (It still allows PacifiCorp to recover the substantial sum of $58.0 million attributable to their hedging program.) This lowers the Oregon NPC by about $16.2 million.

<u>**SOURCE OF FORWARD PRICE CURVES**</u>

Q. ARE FORWARD PRICE CURVES USED IN THE DEVELOPMENT OF THE COMPANY'S NPC?

A. Yes. The Company uses forward monthly gas and electricity forward price projections or curves as inputs in developing its NPC. The Company has declared these monthly forward prices to be highly confidential. The monthly forward gas prices are used to determine burner-tip fuel costs, certain contract prices and in the mark-to-market gas hedging calculations. **[Begin HC]** [redacted]

[redacted] [End HC] As with the gas forwards, these prices are used in deriving NPC. In addition, the Company converts most of the forward monthly electricity prices into hourly values required for the GRID model for all the hubs **[Begin HC]** [redacted] **[End HC]** I will address the Company's process of converting the forward monthly electricity prices into the hourly values required by GRID in supplemental testimony to be filed on July 5, 2011.

Q. HOW DOES PACIFICORP DEVELOP ITS FORWARD PRICE CURVES?

A. The Company's SEC 10-K filing describes the sources and method used by the Company to generate their forward price curves:

> PacifiCorp bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent energy brokers, exchanges, direct communication with market participants and actual transactions executed by PacifiCorp. Market price quotations for certain major electricity and natural gas trading hubs are generally readily obtainable for the first six years; therefore, PacifiCorp's forward price curves for those locations and periods reflect observable market quotes. Market price quotations for other electricity and natural gas trading hubs are not as readily obtainable for the first six years. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, PacifiCorp uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on significant unobservable inputs.

PacifiCorp (OR) 2010 10-K at 62 (found at http://www.faqs.org/sec-filings/100301/PACIFICORP-OR-_10-K/).

Q. HAVE YOU DONE ANY ANALYSIS COMPARING PACIFICORP'S INTERNAL MONTHLY PRICE CURVES WITH FORWARD PRICES REPORTED FROM INDEPENDENT OR THIRD PARTY SUPPLIERS?

A. Yes. There are a host of third party providers willing to market or provide forward prices. Our firm has access to forward prices from several sources offering a variety of price points. Recognizing that the development of the NPC for PacifiCorp requires a geographically diverse number of points, we analyzed and compared a sample of PacifiCorp's forward price curves with ICE transactional prices. It has been my experience that ICE prices are recognized as a reputable source of forward prices. For example, a workshop was conducted in California several years ago to evaluate and ascertain third party independent forward price providers that could be used by the investor owned utilities in order to determine short run avoided payments to qualifying facilities. The ICE transactional data was one of four providers chosen and agreed to by all parties to form a pool of providers from which each utility would select three providers. Each of the three investor owned utilities in California uses ICE data as one of the three sources. The comparative analysis we performed was for five trading days in each month of January, February and March of 2011 for many of PacifiCorp's forward price hubs. The analysis was done for **[Begin HC]** [redacted] **[End HC]** and both the on-peak and off-peak prices for **[Begin HC]** [redacted] **[End HC]** ICE does not provide forward price curves for the less liquid hubs of **[Begin HC]** [redacted] **[End HC]** This analysis is provided as Highly Confidential Exhibit ICNU/104. There are two important observations that should be pointed out from this analysis. First, **[Begin HC]** [redacted] **[End HC]** Second, note that in some of the electricity off-peak series, ICE does not provide individual monthly values beyond six or seven months at less liquid hubs. This is not unusual. Most sources generally go from monthly to quarterly to annual reported forward prices as you go out in time. Generally, historic day-ahead reported prices are used to convert a quarterly value into monthly values if this granularity of data is needed. In fact, this is the same approach that must be used on the illiquid hubs where no forward prices are reported at all. Historical relationships are used from more liquid hubs to derive forward prices for less liquid price points. For example, **[Begin HC]** [redacted] **[End HC]** Pages 23-24 of Highly Confidential Exhibit ICNU/104 is a comparison of the resulting price differentials between a less liquid market hub where no forward ICE prices are reported and the comparable differential from the Company's highly confidential forward price curve. These pages illustrate the approach I am recommending for deriving forward monthly prices for less liquid hubs. It is based on the most recent three years of reported day ahead transactions at the less liquid hub as compared to a reference hub. This price differential should be deducted from the 2012 forward price for the reference hub. In this illustration, we have used reported day ahead transactional prices from Platts Megawatt Daily from 2008 – 2010 to derive these adjustment values, but would be willing to consider other available third party sources.

Q. WHAT CONCLUSION AND RECOMMENDATIONS DO YOU HAVE FROM HAVING PERFORMED YOUR COMPARATIVE ANALYSIS?

A. **[Begin C]** [redacted] **[End C]** I recommend that ICE prices be used where ever possible instead of the Company's prices. In my view this will provide several benefits to the TAM process. First, it results in a more transparent TAM procedure because the data is readily available from ICE so it can be obtained without going through the Company's highly confidential discovery process. ICNU extended considerable consultant and attorney resources just to gain access to information related to forward price curves in this case. I have been informed that these disputes over access to this information are not unique to this case. Second, as the prices are provided by an independent party, it reduces the potential for gaming by PacifiCorp manipulating the final curves used to establish the TAM rates. Third, forward prices change from day to day. By using ICE data for the forward prices, any party can monitor the forward price movement throughout the TAM process. This will eliminate some "surprises" that could otherwise occur when the final curves are employed in the final update. I know from experience that this last point has been very useful in past Puget Sound Energy ("PSE") proceedings where the tracking of Kiodex forward prices (the third party supplier used by PSE for forward gas and electricity prices in its filings) has provided a before the fact understanding of the ultimate rate increase authorized by the Washington Commission in PSE proceedings.

SALES ACTIVITY

Q. IN WHAT ELECTRICITY MARKETS DOES PACIFICORP SELL POWER?

A. PacifiCorp transacts a substantial amount of sales at many trading points. These include the Mid-C and PV major trading hubs, as well as FC, COB, Mead, Mona and the California market ("CAISO").

Q. HAS PACIFICORP MODELLED ALL THESE TRADING HUBS IN GRID?

A. No. GRID does include Mid-C, PV, COB, Mead and Mona but it does not model any transactions with the CAISO.

Q. HOW DOES PACIFICORP MODEL TRADING TRANSACTIONS AT THE HUBS IT HAS INCLUDED IN GRID?

A. PacifiCorp converts the monthly electricity forward prices into three typical hourly price curves (weekdays, Sundays/holidays and Saturday) at each trading hub. GRID then uses these hourly prices to make balancing purchases or balancing sales depending upon the incremental generating costs and available transmission capacity for each hour to minimize overall system costs. GRID has been structured as an hourly dispatch model. Accordingly, all the balancing transactions at these hubs—whether a purchase or a sale-are akin to a real-time spot market purchase or sale.

Q. IS THIS THE MANNER IN WHICH PACIFICORP ACTUALLY BUYS AND SELLS POWER?

A. No. In actuality, the vast majority of the Company's purchase and sales activity is done in the day ahead ("DA") market and not the spot market modeled by GRID. Confidential Exhibit ICNU/105, Schoenbeck/9 compares the spot market and forward markets transactions the Company did over the 48 month period of July 2006 through June 2010 with the GRID produced transactions for 2012. **[Begin C]** [redacted] **[End C]**

SALES ACTIVITY – MARKET CAPS

Q. HAS PACIFICORP'S MODELING IMPOSED CONSTRAINTS ON THE AMOUNT OF SALES TRANSACTIONS PRODUCED BY GRID?

A. Yes. First, as I previously noted, PacifiCorp has excluded the more lucrative southern California market from the GRID model all together. In addition to this, PacifiCorp has imposed monthly on-peak and off-peak hourly sales caps at each trading hub. (No purchase caps are imposed.) These hourly limits cap the amount of power that can be sold at each hub. Confidential Exhibit ICNU/105, Schoenbeck/1 presents the Company's hourly caps used to constrain GRID sales.

Q. HOW WERE THE CAPS DETERMINED?

A. The caps were derived from averaging the historical sales levels actually achieved by the Company over the 48 month period of July 2006 through June 2010 and include a reduction for the firm short term market sales exogenously input into GRID for 2012. Obviously, then there were many, many hours in the historical period when the actual hourly sales amount exceeded the average sales value for that time interval. Accordingly, the caps can act as a constraint on the GRID sales transactions.

Q. HAVE YOU ANALYZED THE IMPACT OF THE COMPANY CAPS ON THE NPC?

A. Yes. Confidential Exhibit ICNU/105, Schoenbeck/1 is color coded to show the time periods when a Company cap constrains the GRID spot sales transactions. Values with a red background represent time periods when the cap was a constraint for *every hour* of the time interval. Values denoted with a blue background represent periods where the cap was reached at least one hour of the time period. **[Begin C]** [redacted] **[End C]**

Confidential Exhibit ICNU/105, Schoenbeck/2-3, and 5 present the GRID spot sales results both with and without the Company's caps. Page 5 of the exhibit shows that eliminating the caps **[Begin C]** [redacted] **[End C]** Page 4 of this exhibit compares the GRID produced sales levels both with and without the caps to the historic level for all the trading hubs. **[Begin C]** [redacted] **[End C]** For this reason, I recommend all the caps be removed in order to more properly determine the NPC for 2012.

Q. WHAT REASONS HAVE BEEN PROVIDED BY THE COMPANY FOR WHY THE CAPS SHOULD BE IMPOSED?

A. It appears the Company may be concerned about market liquidity and the possibility of too much resulting coal generation. However, I don't believe these concerns are warranted. First of all, Confidential Exhibit ICNU/105, Schoenbeck/6 presents the sources of supplying the additional sales made under the uncapped GRID run. This page shows that **[Begin C]** [redacted] **[End C]** Further, Confidential Exhibit/105, Schoenbeck/7 presents the GRID dispatched coal generation with and without the caps along with historical generation as reported in FERC Form 1 reports. The increase in coal generation from eliminating the caps is increased by only **[Begin C]** [redacted] **[End C]** and well within the historical operations for all plants shown on this page. In no instance is the uncapped level greater than the historical maximum for each plant.

I compiled Confidential Exhibit ICNU/105, Schoenbeck/8 to address the Company's potential concern with market liquidity at the various trading hubs. It shows PacifiCorp's transactions as a percent of the total transaction by quarter for the years 2008, 2009 and 2010. This exhibit was compiled from a Platts Megawatt Daily report which used FERC Electric Quarterly Reports ("EQRs") which must be submitted to FERC indicating all sales activity. This exhibit page shows that for the six hubs modeled by GRID, PacifiCorp's activity represents a small percentage of the market. Thus none of the reasons put forth by the Company justify imposing the caps.

Q. WHAT IS THE IMPACT ON NPC FROM ELIMINATING THE CAPS?

A. System wide net power costs are reduced by $5.5 million. Therefore Oregon's NPC responsibility is reduced by about $1.4 million. I recommend this adjustment be made by the Commission in order to more accurately determine the Company's NPC.

SALES ACTIVITY – ISO CHARGES

Q. DOES THE COMPANY'S NPC DETERMINATION INCLUDE CHARGES OR COSTS ASSOCIATED WITH THE MARKETS THAT ARE NOT MODELLED IN GRID?

A. Yes. The transmission costs include two line items associated with the CAISO market that is not modeled in GRID. The costs are $1.6 million for service fees and $2.6 million for wheeling charges for a total of $4.2 million. These costs were imposed by the CAISO for the spot market opportunity transactions undertaken by PacifiCorp for the historical period from July 2009 through June 2010.

Q. SHOULD THESE COSTS BE ALLOWED IN PACIFICORP'S NPC FOR 2012?

A. No. It is inappropriate to impose the cost associated with transactions when the offsetting revenue has not been included. PacifiCorp would have not entered into these spot sales unless there was a clear profit margin at the time of the transaction. Ratepayer equity requires that the cost of these sales be removed from the 2012 NPC. For Oregon, this will reduce the NPC responsibility by about $1.1 million.

Q. HAVE OTHER COMMISSIONS AGREED WITH THE REMOVAL OF THESE COSTS?

A. Yes. In a recent case before the Idaho commission, Mr. Mark Widmer proposed this same adjustment and it was adopted by that commission. Re Rocky Mountain Power, Idaho Public Utility Commission Docket No. ID PAC-E-10-07, Order No. 32196 at 31-32 (Feb. 28, 2011).

SALES ACTIVITY – DC INTERTIE

Q. ARE THERE ANY OTHER COSTS THAT HAVE BEEN INCLUDED IN THE NPC CALCULATION WHERE THERE IS NO CORRESPONDING BENEFIT?

A. Yes. The Company has included $4.8 million associated with its contract with the Bonneville Power Administration ("BPA") for rights to 200 MWs of DC intertie capacity. PacifiCorp entered into this agreement to enable a long-term sales agreement with Southern California Edison ("SCE") many years ago but this contract terminated in 2002. However, the term of the transmission contract was not tied or linked to the SCE agreement. Consequently, the transmission agreement will extend for many years to come. The capacity of this wheeling agreement is seldom used by PacifiCorp. In response to an ICNU data request, PacifiCorp provided the transactions over this line for the period of July 2009 through June 2010. All of the **[Begin C]** [redacted] **[End C]** This extraordinary low level of activity does not justify the inclusion of the substantial wheeling costs in the NPC determination.

Q. HAVE ANY COMMISSIONS DISALLOWED THE DC INTERTIE EXPENSE FOR NOT BEING USED AND USEFUL?

A. Yes. In a recent Washington proceeding, the Washington commission disallowed recovery of the DC intertie wheeling expense. The order stated:

> PacifiCorp's evidence and arguments focus on whether the contract was prudent when it was executed. However, we do not need to answer that question in this Order. Even if we assume that the contract was prudent at its inception the Company has an ongoing obligation to manage the resource under contract to provide a benefit to the Company and its ratepayers. PacifiCorp has failed to demonstrate that it does so.

> Both Staff and ICNU testify that the contract is not expected to be used during the rate year to support the West Control Area, and thus no benefits are likely to materialize from the transmission capacity under the contract. The parties based their conclusions on the Company's failure to use the DC intertie capacity during the test year. As to its future use, they point to the absence of NOB contracts in the Company's GRID model as further support for their conclusion that the contract's capacity will not be used during the rate year.
>
> We find Staff's and ICNU's testimony and arguments to be compelling. Generally, for a resource to be included in rates, it must be found to be used and useful. This is not to say that every component of the Company's system has to be used to provide service at all times. However, the testimony here raises serious doubt as to the continued usefulness of the DC intertie capacity – doubt that PacifiCorp fails to address, much less resolve.
>
> There is a point when facilities or even contracts such as this have no demonstrated or foreseeable need. It is at this point that such capacity should be retired or written off the books. We are not convinced that now is the time for such action, and we accept the Company's rationale that the DC Intertie capacity could be useful in the future. The Company, however, must do more than state that the facility might be used at some unspecified time to justify including this resource in rates.

WUTC v. PacifiCorp, WUTC Docket No. UE 100749, Order 06 at ¶¶148-151 (Mar. 25, 2011). I recommend the Commission use this same reasoning in this proceeding. No benefit from the DC intertie is included in the NPC determination. As with the CAISO fees and charges, the DC intertie costs should not be included in NPC.

BEAR RIVER HYDRO NORMALIZATION

Q. HOW IS THE EXPECTED HYDRO GENERATION DETERMINED FOR RATEMAKING PURPOSES IN THE PACIFIC NORTHWEST?

A. Hydro generation is dependent upon water availability from rain or snow melt. In the Pacific Northwest where there is limited hydro storage capability, the annual hydro generation can vary substantially from year to year due to swings in yearly precipitation. Consequently, for normalized ratemaking a large number of water years are typically used to capture an expected (or median) amount of generation from hydro facilities. It has been my experience that a large number of years—typically at least 40—are used to for ratemaking purposes.

Q. HAS PACIFICORP USED A LARGE NUMBER OF WATER YEARS TO DERIVE THE EXPECTED GENERATION FROM HYDRO FACILITIES IN THIS PROCEEDING?

A. For the most part it has, but there is one notable exception. For the Bear River hydro system, the Company has eliminated what it terms are flood control years. As the Company starts with only 30 water years for this system, the elimination of the 11 flood control years results in an expected generation amount from these facilities based on only 19 years of record.

Q. ARE YOU FAMILIAR WITH ANY ARGUMENTS FOR EXCLUDING SELECT WATER YEARS OF RECORD IN DERIVING NORMALIZED HYDRO GENERATION?

A. Yes. In Washington several years ago the staff introduced the concept of "filtering" (eliminating) select water years beyond two standard deviations from the mean (both high and low) to determine a normalized or base power cost hydro amount for utilities that had annual power adjustments with true-up provisions. The logic behind the staff adjustment was that the true-up adjustment mechanism would capture the costs or benefits resulting from those extraordinary high and low water years that were more than two standard deviations from the average. The Washington commission has made it clear that even in the case of a utility with an adjustment mechanism, there must be a strong statistical basis to eliminate water years. See WUTC v. Puget Sound Energy, Docket No. UE-090704, Order 11 at 43 (April 2, 2010).

Q. WHAT REASONING HAS THE COMPANY PROVIDED FOR ELIMINATING THE FLOOD CONTROL YEARS?

A. The company's prefiled testimony does not address the issue. There is simply a sentence stating it has eliminated the years as it had done in the UE 216 filing. See PPL/100, Duvall/5, lines 17-19.

Q. WHAT IS YOUR UNDERSTANDING ON WHY THE COMPANY PROPOSED TO ELIMINATE THE FLOOD CONTROL YEARS?

A. I believe the basis was the belief that the Bear River system had experienced a prolonged drought condition that was expected to continue.

Q. IS THIS IN FACT THE CASE?

A. No. The company announced on May 5, 2011 that this system is likely to be in a flood control situation so there is no drought condition today. See Exhibit ICNU/106. Further it would be inappropriate to establish normalized NPC based on near term hydro conditions unless there was an annual true-up mechanism in place. This is not the case for PacifiCorp, where no such mechanism exists. PacifiCorp's NPC should be determined based on a large number of water years as is done in all rate setting proceeding in the Pacific Northwest. Proposals to selectively eliminated particular years of record are inappropriate as no one can predict the precipitation that will fall. Moreover, the Company's adjustment just eliminated high water years. This is most inappropriate since it is asymmetric by not also eliminating or adjusting for low water years.

Q. WHAT IMPACT DOES THIS HAVE ON PACIFICORP'S NPC?

A. Including all water years reduces NPC by about $2.0 million on a system basis or $0.5 million for Oregon.

GADSBY UNIT 4-6

Q. HAS THE COMPANY MODIFIED THE MANNER IN WHICH IT HAS CALCULATED THE COST OF INTEGRATING WIND RESOURCES IN DETERMINING THE NPC IN THIS PROCEEDING?

A. Yes. Based on the results of a wind integration study undertaken by the Company, the Company is proposing to capture wind integrations costs through two methods. First, the Company is assuming a balancing charge of $0.70/MWh applied to its wind generation. Second, the Company has modeled Currant Creek and the Gadsby units 4, 5 and 6 as being "blocked on" or must run. This means these units are modeled as being on even when it would be uneconomic to operate. The stated reason for this was due to a "need to continue to committing its gas units to be able to quickly respond to the magnitude of changes." Currant Creek is a combined cycle plant ("CCCT") so the uneconomic penalty from operating it when it would otherwise be displaced is not too great. However, the three Gadsby units are relatively inefficient and at 40 MWs per unit, the uneconomic penalty is far greater from modeling these units as must run.

Q. DOES THE COMPANY OPERATE THE GADSBY UNITS 4-6 AS MUST RUN FACILITIES?

A. No. Confidential Exhibit ICNU/107 presents a table I prepared showing the number of hours each month when the Gadsby units were not running. This exhibit shows these units are not blocked on to provide operating reserves as has been assumed in the NPC.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO HOW THE COMPANY HAS TAKEN INTO ACCOUNT WIND INTEGRATION COSTS IN ITS NPC?

A. For purposes of this proceeding, I recommend the Commission accept the Company's proposed balancing charge of $0.70/MWh and the blocking on of the Currant Creek plant. However, the three Gadsby units should not be designated as must run.

Q. WHY?

A. While it can be acknowledged that the addition of wind resources is likely to result in some additional costs, a precise value is difficult to quantify. Further, there are numerous on-going investigations and analysis under way to ascertain how wind can be most efficiently integrated into the regional power system. Until all this work is completed, I believe it is premature to impute a substantial cost associated with wind integration. At this point, the Company's proposed cost of $0.70/MWh coupled with Currant Creek providing additional reserves is appropriate. Going beyond this, by assuming the Gadsby units will be blocked on when they have yet to operate in this manner is not reasonable. I am aware that certain parties have raised other concerns with PacifiCorp's modeling of wind integration costs in other proceedings. ICNU reserves the right to raise other concerns with PacifiCorp's wind integration costs in future proceedings or reply testimony in this case.

Q. WHAT IMPACT DOES YOUR RECOMMENDATION HAVE ON PACIFCORP'S NPC?

A. The NPC is lowered by $3.0 million or about $0.8 million for Oregon's allocated share.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

OREGON PUBLIC UTILITY COMMISSION, Complainant, v. PACIFICORP D/B/A PACIFIC POWER & LIGHT COMPANY, Respondent.	)	Docket No. UE 227

EXHIBIT ICNU/101

QUALIFICATIONS OF DONALD W. SCHOENBECK

June 24, 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. UE 227

EXHIBIT ICNU/102

RETAIL LOAD FORECAST EXHIBIT

REDACTED VERSION

June 24, 2011

[ENTIRE PAGE IS CONFIDENTIAL]

Comparison of Oregon Sales - UE 216/217 versus UE 227

Line No.	Description	Schedule No.	UE 217 MWh	UE 227 MWh	Difference Amount	Difference Percent
	(1)	(2)	(3)	(4)	(5)	(6)
	Residential					
1	Residential	4	5,306,840	5,657,949	351,109	6.6%
2	**Total Residential**		5,306,840	5,657,949	351,109	6.6%
	Commercial & Industrial					
3	Gen. Svc. < 31 kW	23	1,013,838	1,046,565	32,727	3.2%
4	Gen. Svc. 31 - 200 kW	28	2,011,827	2,047,124	35,297	1.8%
5	Gen. Svc. 201 - 999 kW	30	1,386,076	1,306,684	(79,392)	-5.7%
6	Large General Service >= 1,000 kW	48	2,349,055	3,069,679	720,624	30.7%
7	Partial Req. Svc. >= 1,000 kW	47	381,991	239,380	(142,611)	-37.3%
8	Agricultural Pumping Service	41	149,120	148,303	(817)	-0.5%
9	Agricultural Pumping - Other	33	127,459	122,259	(5,200)	-4.1%
10	**Total Commercial & Industrial**		7,419,366	7,979,994	560,628	7.6%
	Lighting					
11	Outdoor Area Lighting Service	15	10,138	10,059	(79)	-0.8%
12	Street Lighting Service	50	10,594	9,690	(904)	-8.5%
13	Street Lighting Service HPS	51	16,563	17,902	1,339	8.1%
14	Street Lighting Service	52	1,061	927	(134)	-12.6%
15	Street Lighting Service	53	9,250	9,408	158	1.7%
16	Recreational Field Lighting	54	847	993	146	17.2%
17	**Total Public Street Lighting**		48,453	48,979	526	1.1%
18	**Total Sales to Ultimate Consumers**		12,774,659	13,686,922	912,263	7.1%

Summary of PacifiCorp's Response to ICNU 2.7 1st Supplemental
System Load at input

UE 199

	Forecast	Actual	Variance	Weather Normalized Actual	Variance
Jan-09	5,292,551	5,275,416	-0.32%	5,164,549	-2.42%
Feb-09	4,688,523	4,586,053	-2.19%	4,485,041	-4.34%
Mar-09	4,832,329	4,708,878	-2.55%	4,630,464	-4.18%
Apr-09	4,323,591	4,262,774	-1.41%	4,249,664	-1.71%
May-09	4,667,303	4,439,688	-4.88%	4,432,225	-5.04%
Jun-09	5,039,779	4,357,530	-13.54%	4,552,875	-9.66%
Jul-09	5,778,551	5,332,419	-7.72%	5,231,143	-9.47%
Aug-09	5,496,849	5,022,337	-8.63%	5,055,131	-8.04%
Sep-09	4,703,912	4,605,347	-2.10%	4,457,300	-5.24%
Oct-09	4,736,389	4,554,317	-3.84%	4,573,723	-3.43%
Nov-09	5,043,253	4,750,760	-5.80%	4,756,443	-5.69%
Dec-09	5,588,675	5,492,584	-1.72%	5,291,869	-5.31%
Total:	60,191,705	57,388,102	-4.66%	56,880,428	-5.50%

UE 207

	Forecast	Actual	Variance	Weather Normalized Actual	Variance
Jan-10	5,222,663	5,103,878	-2.27%	5,215,225	-0.14%
Feb-10	4,691,696	4,517,802	-3.71%	4,592,393	-2.12%
Mar-10	4,735,034	4,670,231	-1.37%	4,688,761	-0.98%
Apr-10	4,495,315	4,381,813	-2.52%	4,353,004	-3.17%
May-10	4,559,608	4,414,761	-3.18%	4,514,156	-1.00%
Jun-10	4,838,202	4,596,811	-4.99%	4,681,347	-3.24%
Jul-10	5,398,855	5,501,070	1.89%	5,483,080	1.56%
Aug-10	5,357,125	5,242,765	-2.13%	5,280,707	-1.43%
Sep-10	4,729,459	4,577,712	-3.21%	4,594,621	-2.85%
Oct-10	4,610,488	4,547,544	-1.37%	4,581,061	-0.64%
Nov-10	4,709,268	4,867,007	3.35%	4,798,857	1.90%
Dec-10	5,326,617	5,279,736	-0.88%	5,370,890	0.83%
Total:	58,674,331	57,701,130	-1.66%	58,154,103	-0.89%
			2009 to 2010 Growth>>>		**2.24%**

UE 216

	Forecast	Actual	
Jan-11	5,167,771	5,277,616	Preliminary Data
Feb-11	4,630,158	NA	
Mar-11	4,704,001	NA	
Apr-11	4,417,805	NA	
May-11	4,542,765	NA	
Jun-11	4,784,314	NA	
Jul-11	5,386,528	NA	
Aug-11	5,308,226	NA	
Sep-11	4,653,855	NA	
Oct-11	4,535,531	NA	
Nov-11	4,650,846	NA	
Dec-11	5,245,484	NA	
	58,027,282		

UE 227

	Forecast	Actual	
Jan-12	5,414,133	NA	
Feb-12	4,976,521	NA	
Mar-12	5,149,465	NA	
Apr-12	4,833,958	NA	
May-12	5,005,441	NA	
Jun-12	5,092,584	NA	
Jul-12	5,748,224	NA	
Aug-12	5,594,992	NA	
Sep-12	4,937,167	NA	
Oct-12	5,024,611	NA	
Nov-12	5,084,370	NA	
Dec-12	5,507,231	NA	
	62,368,697		3.6%

REDACTED
ICNU/102
Schoenbeck/4

Summary of PacifiCorp Attachment to OPUC Question 36

Total Company

Actual Retail Sales over two years				UE 216			UE 227		
	April 2009 through March 2010	April 2010 through March 2011	Year over year growth for actual	2011	2012	Year over year growth for UE 216	2011	2012	Year over year growth for UE 227
Residential	15,892,918	15,974,898	0.5%	15,733,922	15,991,588	1.6%	16,264,040	16,512,864	1.5%
Commercial	16,033,991	16,280,963	1.5%	16,398,542	16,887,798	3.0%	16,940,620	17,690,174	4.4%
Industrial	18,745,869	19,619,103	4.7%	19,082,896	20,082,754	5.2%	20,465,220	21,164,452	3.4%
Irrigation	1,240,759	1,268,412	2.2%	1,357,020	1,357,190	0.0%	1,284,530	1,300,540	1.2%
Public Authority	432,182	429,590	-0.6%	438,660	439,820	0.3%	436,140	437,310	0.3%
Lighting	144,115	144,978	0.6%	141,480	141,900	0.3%	140,880	141,350	0.3%
Total	52,489,834	53,717,944	2.3%	53,152,520	54,901,050	3.3%	55,531,430	57,246,690	3.1%
						Change in the Forecast>>>:	4.5%	4.3%	

Oregon

Actual Retail Sales over two years				UE 216			UE 227		
	April 2009 through March 2010	April 2010 through March 2011	Year over year growth for actual	UE 216 2011	UE 216 2012	Year over year growth for UE 216	UE 227 2011	UE 227 2012	Year over year growth for UE 227
Residential	5,554,770	5,533,085	-0.4%	5,309,420	5,370,202	1.1%	5618364	5,660,392	0.7%
Commercial*	4,898,745	4,915,291	0.3%	4,886,460	4,951,922	1.3%	5136614	5,388,272	4.9%
Industrial	2,385,806	2,249,625	-5.7%	2,256,190	2,488,736	10.3%	2295492	2,318,456	1.0%
Irrigation	240,293	208,437	-13.3%	285,110	285,130	0.0%	265760	281,860	6.1%
Public Authority									
Lighting	37,507	37,335	-0.5%	37,480	37,590	0.3%	37840	37,940	0.3%
Total	13,117,121	12,943,773	-1.3%	12,774,660	13,133,580	2.8%	13,354,070	13,686,920	2.5%
						Change in the Forecast>>>:	4.5%	4.2%	

* Positive outlook due to future growth by data centers

Utah

Actual Retail Sales over two years				UE 216			UE 227		
	April 2009 through March 2010	April 2010 through March 2011	Year over year growth for actual	2011	2012	Year over year growth for UE 216	2011	2012	Year over year growth for UE 227
Residential	6,535,481	6,626,101	1.4%	6,657,920	6,803,328	2.2%	6,781,442	6,926,240	2.1%
Commercial	7,508,926	7,684,172	2.3%	7,864,240	8,217,408	4.5%	8,108,892	8,525,520	5.1%
Industrial	7,369,866	7,725,613	4.8%	7,403,840	7,761,624	4.8%	8,379,906	8,710,750	3.9%
Irrigation	201,890	211,344	4.7%	188,260	188,280	0.0%	187,650	187,440	-0.1%
Public Authority	432,182	429,590	-0.6%	438,660	439,820	0.3%	436,140	437,310	0.3%
Lighting	79,140	79,850	0.9%	76,220	76,450	0.3%	76,610	76,840	0.3%
Total	22,127,486	22,756,671	2.8%	22,629,140	23,486,910	3.8%	23,970,640	24,864,100	3.7%
						Change in the Forecast>>>:	5.9%	5.9%	

Wyoming

Actual Retail Sales over two years				UE 216			UE 227		
	April 2009 through March 2010	April 2010 through March 2011	Year over year growth for actual	UE 216 2011	UE 216 2012	Year over year growth for UE 216	UE 227 2011	UE 227 2012	Year over year growth for UE 227
Residential	1,065,780	1,068,112	0.2%	1,054,546	1,065,134	1.0%	1,098,858	1,123,898	2.3%
Commercial	1,485,154	1,543,460	3.9%	1,500,376	1,530,154	2.0%	1,533,948	1,571,088	2.4%
Industrial	6,765,472	7,115,539	5.2%	6,958,358	7,327,902	5.3%	7,243,804	7,547,494	4.2%
Irrigation	19,625	21,425	9.2%	19,200	19,310	0.6%	22,970	23,090	0.5%
Public Authority					0				
Lighting	11,627	11,821	1.7%	12,910	12,950	0.3%	11,580	11,630	0.4%
Total	9,347,659	9,760,357	4.4%	9,545,390	9,955,450	4.3%	9,911,160	10,277,200	3.7%
						Change in the Forecast>>>:	3.8%	3.2%	

Washington

Actual Retail Sales over two years				UE 216			UE 227		
	April 2009 through March 2010	April 2010 through March 2011	Year over year growth for actual	UE 216 2011	UE 216 2012	Year over year growth for UE 216	UE 227 2011	UE 227 2012	Year over year growth for UE 227
Residential	1,626,258	1,630,054	0.2%	1,607,898	1,627,938	1.2%	1639452	1,653,850	0.9%
Commercial	1,431,397	1,429,150	-0.2%	1,457,408	1,471,968	1.0%	1445652	1,473,300	1.9%
Industrial	812,284	812,072	0.0%	792,934	801,764	1.1%	843366	858,700	1.8%
Irrigation	168,794	153,988	-8.8%	158,850	158,860	0.0%	160220	160,230	0.0%
Public Authority									
Lighting	10,875	10,963	0.8%	9,870	9,900	0.3%	9810	9,840	0.3%
Total	4,049,608	4,036,227	-0.3%	4,026,960	4,070,430	1.1%	4,098,500	4,155,920	1.4%
						Change in the Forecast>>>:	1.8%	2.1%	

Idaho

Actual Retail Sales over two years				UE 216			UE 227		
	April 2009 through March 2010	April 2010 through March 2011	Year over year growth for actual	UE 216 2011	UE 216 2012	Year over year growth for UE 216	UE 227 2011	UE 227 2012	Year over year growth for UE 227
Residential	709,660	711,573	0.3%	707,422	723,724	2.3%	728642	748,938	2.8%
Commercial	416,899	420,475	0.9%	411,012	426,304	3.7%	428482	443,558	3.5%
Industrial	1,363,902	1,668,935	22.4%	1,619,676	1,645,652	1.6%	1662976	1,686,504	1.4%
Irrigation	518,568	580,790	12.0%	607,470	607,460	0.0%	549980	549,920	0.0%
Public Authority									
Lighting	2,603	2,640	1.4%	2,520	2,530	0.4%	2580	2,640	2.3%
Total	3,011,632	3,384,414	12.4%	3,348,100	3,405,670	1.7%	3,372,660	3,431,560	1.7%
						Change in the Forecast>>>:	0.7%	0.8%	

California

Actual Retail Sales over two years				UE 216			UE 227		
	April 2009 through March 2010	April 2010 through March 2011	Year over year growth for actual	UE 216 2011	UE 216 2012	Year over year growth for UE 216	UE 227 2011	UE 227 2012	Year over year growth for UE 227
Residential	400,969	405,974	1.2%	396,716	401,262	1.1%	397282	399,546	0.6%
Commercial	292,871	288,414	-1.5%	279,046	290,042	3.9%	287032	288,436	0.5%
Industrial	48,538	47,318	-2.5%	51,898	57,076	10.0%	39676	42,548	7.2%
Irrigation	91,588	92,428	0.9%	98,130	98,150	0.0%	97950	98,000	0.1%
Public Authority									
Lighting	2,363	2,368	0.2%	2,480	2,480	0.0%	2460	2,460	0.0%
Total	836,329	836,502	0.0%	828,270	849,010	2.5%	824,400	830,990	0.8%
						Change in the Forecast>>>:	-0.5%	-2.1%	

APPENDIX A – LOAD FORECAST DETAILS

Introduction

This appendix reviews the load forecast used during the 2011 Integrated Resource Plan and scenario development for case sensitivities to varying levels in the load forecast. The load forecasting review starts with the final system level retail sales forecast reflecting the chosen Class 2 DSM efficiencies from the 2011 IRP preferred portfolio. The next section elaborates the methodology for long-range load forecasting and provides an overview of the modeling involved. For the state level summaries, retail sales at the customer meter are discussed at the state-level reflecting the chosen Class 2 DSM efficiencies from the 2011 IRP preferred portfolio. Finally, the system level and state level load forecast at the generation as used in the 2011 IRP modeling are discussed.

Load Forecast

Table A.1 shows the final retail sales values at the customer meter for the total system as well as individual state level after the load reduction impacts of Class 2 DSM programs included in the 2011 IRP preferred portfolio.

Table A.1 – System Annual Sales forecast (in Gigawatt-hours) 2011 through 2020

System Retail Sales – Gigawatt-hours (GWh)							
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Other	**Total**
2011	16,272	16,949	20,469	1,285	141	436	**55,553**
2012	16,522	17,699	20,688	1,301	141	437	**56,789**
2013	16,454	18,004	21,524	1,302	141	436	**57,861**
2014	16,567	18,247	22,233	1,302	141	436	**58,927**
2015	16,715	18,529	22,629	1,302	141	436	**59,752**
2016	16,896	18,973	23,050	1,302	142	437	**60,801**
2017	16,953	19,190	23,250	1,302	141	436	**61,273**
2018	17,078	19,452	23,553	1,302	141	436	**61,963**
2019	17,215	19,723	23,842	1,302	141	436	**62,660**
2020	17,335	20,036	24,202	1,303	142	437	**63,454**
Average Annual Growth Rate							
2011-20	**0.7%**	**1.9%**	**1.9%**	**0.2%**	**0.1%**	**0.0%**	**1.5%**

Methodology Overview

PacifiCorp estimates total load by starting with customer class sales forecasts in each state and then adds line losses to the customer class forecasts to determine the total load required at the generators to meet customer demands. Forecasts are based on statistical and econometric modeling techniques and customer-specific sales forecast for large customers. These models

OPUC Data Request 36

The TAM filing states that total company forecast load is forecast to be 7.5% greater than in UE 216. Please provide a complete breakdown of the UE 216 loads, the most recent actual loads, and the forecast UE 227 loads, by customer class and by jurisdiction or state. Include a detailed narrative that explains any load growth, by customer class, of greater than 1% and provide backup documentation that supports the company assertions.

Response to OPUC Data Request 36

The comparison of 2011 and 2012 TAM forecasts from UE 216 and UE 227 is not a meaningful comparison for assessing load growth. The two forecasts were developed approximately a year apart, with the UE 227 forecast being informed by an additional year's worth of actual data including usage and economic trends than were available at the time the UE 216 forecast was developed. In addition, the 7.5% increase is comparing a more recent forecast of 2012 calendar year with a year older forecast of 2011. It would make more sense to compare year over year growth under one particular forecast.

Please refer to Attachment OPUC 36 for a complete breakdown of retail sales by class by state for UE 216 (2011 and 2012), most recent weather normalized actual for 24 months, UE 227 (2011 and 2012), and the percentage change associated for year over year growth.

In general, the total Company sales growth is attributable to stronger actual retail sales in the recent past, positive outlook (new growth and expansion) into the future by data centers, and growth from new and existing industrial customers.

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

OREGON PUBLIC UTILITY COMMISSION, Complainant, v. PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY, Respondent.	)	Docket No. UE 227

EXHIBIT ICNU/103

NATURAL GAS HEDGES

REDACTED VERSION

June 24, 2011

[PAGES 1-10 and 15 ARE CONFIDENTIAL]

NWN 10-K 12/31/2010

Section 1: 10-K (FORM 10-K)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2010

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to__________

Commission file number 1-15973

NW Natural

NORTHWEST NATURAL GAS COMPANY
(Exact name of registrant as specified in its charter)

Oregon	**93-0256722**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

220 N.W. Second Avenue, Portland, Oregon 97209
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: **(503) 226-4211**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes [X] No [ ]

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes [ ] No [X]

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [X] No [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes [X] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer [X]	Accelerated Filer [ ]
Non-accelerated filer [ ]	Smaller Reporting Company [ ]

2011 Outlook

In 2011, we intend to remain focused on improving our core businesses, enhancing our strategic position, advancing business development projects related to our primary business segments, and strengthening our organizational effectiveness. The following is a brief summary of management's plans and objectives in these four areas. For further information, see "Issues, Challenges and Performance Measures," and "Strategic Opportunities," below.

Business improvements. We continue to develop, integrate, consolidate and streamline operations using recently acquired new technology, which include an enterprise resource planning system, an automated dispatching system and an automated meter reading system. These and other new technologies support our operating model.

Strategic position. We remain committed to creating shareholder value while balancing the interests of our customers, employees and the communities we serve. To create value, we anticipate and respond to business challenges and opportunities that lie ahead, including finding innovative solutions to economic and environmental challenges as well as regulatory, workforce and business development challenges and opportunities, such as the potential investment in long-term gas reserves on behalf of our utility customers.

Business development. We continue to focus on the development of our underground gas storage businesses, the natural gas infrastructure investment in Palomar and key utility initiatives.

Organizational effectiveness. Our employees are our most valued resource. We intend to support our employees with a positive and safe work environment, on-going training opportunities, continued refinement of our organizational structure and new technologies to achieve goals and facilitate improvements.

Issues, Challenges and Performance Measures

Economic weakness. Ongoing weakness in local and U.S. economies has continued to impact utility customer growth, business demand for natural gas and gas storage prices. Most recently, our utility's annual customer growth rate increased slightly to 0.9 percent at December 31, 2010, compared to 0.8 percent in 2009 and 1.6 percent in 2008. We are still faced with 10 to 11 percent unemployment rates in Oregon and southwest Washington and a sluggish business environment. However, despite these challenges we believe we are well positioned to continue adding utility customers due to lower natural gas prices, our relatively low market penetration, our efforts to convert homes to natural gas, and the potential for environmental initiatives that could favor natural gas use in our region.

Managing gas prices and supplies. Our gas acquisition strategy is designed to secure sufficient supplies of natural gas to meet the needs of our utility customers and to hedge gas prices to effectively manage costs, reduce price volatility and maintain a competitive advantage. With recent success in new drilling technologies and substantial new supplies from shale gas formations around the U.S. and in Canada, the supply of North American natural gas has increased dramatically, which has contributed to lower and more stable gas prices. We entered the 2010-11 gas contract year, which began November 1, 2010, hedged on gas commodity prices at approximately 77 percent of our forecasted purchase volumes. In addition, we are currently hedged at approximately 45 percent for the 2011-12 gas contract year and between 5 and 10 percent for the 2012-13 gas contract year. Our Purchased Gas Adjustment (PGA) mechanism, along with our gas price hedging strategies and gas supplies in storage, enable us to reduce earnings risk exposure and secure lower gas costs for customers. These lower gas prices, coupled with good customer service and energy efficiency programs for customers, can help strengthen natural gas' competitive price advantage compared to other fuels. In addition to hedging gas prices over the next few years, we are evaluating and developing other gas acquisition strategies to potentially manage gas price volatility for customers beyond three years, including possible investment in long-term gas reserves. Although stable gas prices provide opportunities to manage costs for our distribution customers, they present challenges for our gas storage business by lowering the value of, and reducing demand for, storage services and limiting Gill Ranch's ability to contract for longer terms at favorable prices.

REDACTED
ICNU/103
Schoenbeck/13

Exhibit No. ___ (WGJ-2)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-110876

EXHIBIT NO._____(WGJ-2)

WILLIAM G. JOHNSON

REPRESENTING AVISTA CORPORATION

Avista Corp.
Power Supply Pro forma - Washington Jurisdiction
System Numbers - Jan 2010 - Dec 2010 Actual and Jan 2012 - Dec 2012 Pro Forma
2010 Loads with Energy Efficiency Load Adjustment

Line No.		Jan 10 - Dec 10 Actuals	Adjustment	Jan 12 - Dec 12 Pro forma
	555 PURCHASED POWER			
1	Modeled Short-Term Market Purchases	$0	$16,924	$16,924
2	Actual ST Market Purchases - Physical	159,193	-147,924	11,269
3	Actual ST Purchases - Financial M-to-M	0	12,326	12,326
4	Rocky Reach	2,172	-2,172	0
5	Rocky Reach/Rock Island Purchase	0	11,384	11,384
6	Wells - Avista Share	1,400	499	1,899
7	Wells - Colville Tribe's Share	9,496	-9,496	0
8	Priest Rapids Project	5,609	785	6,394
9	Wanapum	-1,228	1,228	0
10	Grant Displacement	5,653	-5,653	0
11	Douglas Settlement	334	246	580
12	Lancaster Capacity Payment	21,475	578	22,053
13	Lancaster Variable O&M Payments	2,689	-223	2,466
14	Lancaster BPA Reserves	824	-824	0
15	WNP-3	13,920	1,284	15,204
16	Deer Lake-IP&L	6	0	6
17	Small Power	1,079	13	1,092
18	Stimson	1,964	402	2,366
19	Spokane-Upriver	2,055	884	2,939
20	Black Creek Index Purchase	234	-234	0
21	Non-Monetary	90	-90	0
22	Contract A	6,789	-6,789	0
23	Contract B	6,745	-6,745	0
24	Contract C	6,658	-6,658	0
25	Contract D	7,556	-7,556	0
26	Clearwater Paper Co-Gen Purchase	18,720	-18,720	0
27	Ancillary Services	631	-631	0
28	Stateline Wind Purchase	3,016	-3,016	0
29	Total Account 555	277,080	-170,177	106,903
	557 OTHER EXPENSES			
30	Broker Commission Fees	366	0	366
31	REC Purchases (SMUD)	349	1	350
32	EIA REC Purchase	0	725	725
33	Natural Gas Fuel Purchases	119,116	-119,116	0
34	Total Account 557	119,831	-118,390	1,441
	501 THERMAL FUEL EXPENSE			
35	Kettle Falls - Wood Fuel	10,551	1,534	12,085
36	Kettle Falls - Start-up Gas	30	0	30
37	Colstrip - Coal	15,984	3,803	19,787
38	Colstrip - Oil	139	0	139
39	Total Account 501	26,704	5,336	32,040
	547 OTHER FUEL EXPENSE			
40	Coyote Springs Gas	53,491	-15,894	37,597
41	Coyote Springs 2 Gas Transportation	7,891	-58	7,833
42	Lancaster Gas	46,902	-6,544	40,358
43	Lancaster Gas Transportation	5,837	956	6,793
44	Lancaster Gas Transportation Optimization	0	-409	-409
45	Actual Physical Gas Transactions M-to-M	0	4,800	4,800
46	Actual Financial Gas Transactions M-to-M	0	-113	-113
47	Gas Transportation for BP, NE and KFCT	32	0	32
48	Rathdrum Gas	545	-544	1
49	Northeast CT Gas	62	-62	0
50	Boulder Park Gas	505	-472	33

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

OREGON PUBLIC UTILITY COMMISSION,	)	
Complainant,	)	
v.	)	Docket No. UE 227
PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY,	)	
Respondent.	)	

EXHIBIT ICNU/104

FORWARD SOURCE COMPARISON

REDACTED VERSION (ENTIRE EXHIBIT IS HIGHLY CONFIDENTIAL)

June 24, 2011

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

OREGON PUBLIC UTILITY COMMISSION, Complainant, v. PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY, Respondent.	))))))))))))	Docket No. UE 227

EXHIBIT ICNU/105

SALES ACTIVITY

REDACTED VERSION (ENTIRE EXHIBIT IS CONFIDENTIAL)

June 24, 2011

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

OREGON PUBLIC UTILITY COMMISSION, Complainant, v. PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY, Respondent.	Docket No. UE 227

EXHIBIT ICNU/106

May 5, 2011 Rocky Mountain Power Press Release

June 24, 2011

Bear River Managers Note Flooding Potential is High

May 05, 2011

SALT LAKE CITY — Managers of the Bear River system in northern Utah and southeastern Idaho have been closely monitoring spring runoff conditions in the Bear River basin. They conclude that the potential for flooding is high all along the Bear River below Bear Lake, including the area between Wardboro and Bern in Bear Lake County, Idaho.

"Based on runoff forecasts, we believe there will be localized flooding of the Bear River into its historic flood plain," said Connely Baldwin, Rocky Mountain Power hydrologist. "There are many variable factors, that could influence the extent of flooding, including how rapidly snow melts and the possibility of a local heavy rain storm. However, people with property along or near the river should take all prudent measures to address the risks. These conditions could rival or perhaps exceed those of 1983-84."

Local emergency management officials have been notified of the current situation and are kept informed of changing local conditions. The Bear River hydroelectric projects have tested emergency operating plans that include provisions for contacting the National Weather Service and local public safety officials in the case of impending high runoff events or more serious emergencies. Rocky Mountain Power urges residents in proximity to the Bear River to monitor these information sources until the threat of spring runoff subsides.

The Bear River hydro system has been operated by Rocky Mountain Power or its predecessor companies since development began in 1909. Its primary goals are to provide irrigation water for some 150,000 acres of farm land, reduce the impacts of flooding, generate hydroelectric power, provide recreational opportunities and enhance fish and wildlife habitat.

About Rocky Mountain Power
Rocky Mountain Power is headquartered in Salt Lake City and provides electric service to more than 1 million customers in Utah, Wyoming and Idaho. As part of PacifiCorp, one of the lowest-cost electricity producers in the United States, Rocky Mountain Power and Pacific Power provide approximately 1.7 million customers in six western states with reliable, efficient energy. The company works to meet growing electricity demand while protecting and enhancing the environment. Visit www.rockymountainpower.net.

Media inquiries: 800-775-7950

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

OREGON PUBLIC UTILITY COMMISSION,	)	
Complainant,	)	
v.	)	Docket No. UE 227
PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY,	)	
Respondent.	)	

EXHIBIT ICNU/107

GADSBY UNITS – HOURS OF NON-OPERATION

REDACTED VERSION (ENTIRE EXHIBIT IS CONFIDENTIAL)

June 24, 2011