CASE: UM 1050
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Cross-Answering Testimony

April 22, 2016

Q. Please state your name, occupation, and business address.

A. My name is Lance Kaufman. I am a Senior Economist for the Public Utility Commission of Oregon (Commission or OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Are you the same Lance Kaufman who previously submitted testimony in this docket?

A. Yes

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to issues raised in the response testimony of Industrial Customers of Northwest Utilities (ICNU) and Noble Americas Energy Solutions LLC (Noble).

Q. Did you prepare exhibits for this docket?

A. Yes. I prepared exhibit Staff/201, consisting of 1 page,
Staff/202, consisting of 2 pages,
Staff/203, consisting of 2 pages,
Staff/204, consisting of 3 pages,
Staff/205, consisting of 3 pages,
Staff/206, consisting of 1 page, and
Staff/207, consisting of 2 pages.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, RESPONSE TO NOBLE

Q. What issue does Noble raise in this docket related to Voluntary Renewable Energy Tariffs (VRET)?

A. Noble notes that the 2017 Protocol does not specifically address the allocation treatment of load associated with VRETs. Noble proposes that the Commission treat VRET load in a similar manner as Direct Access loads.[1]

Q. Do you agree that VRET load should be specifically addressed in the 2017 Protocol?

A. No. VRET load is generally addressed in section IV part A4 of the 2017 Protocol:

> "Costs and benefits associated with Resources acquired in accordance with a Jurisdiction-specific initiative will be assigned on a situs basis to the Jurisdiction adopting the initiative."

Docket UM 1690 is an ongoing proceeding regarding the treatment of VRETs. The specific interstate cost allocation treatment of VRET load should not be finalized until that docket is concluded. The initial guidance given by the Commission to Utilities is that "VRET terms and conditions … must mirror those for direct access."[2] This guidance is consistent with Noble's proposed treatment of VRET load in interstate allocations. PacifiCorp concurs with Staff's position that the treatment of VRET load should be determined in Docket UM 1690.[3]

[1] *See* Noble Solutions/100 Higgins/8.
[2] *See* Order No. 15-405.
[3] *See* Staff/201 Response to OPUC to PAC DR 56.

ISSUE 2, RESPONSE TO ICNU

Q. What issue does ICNU raise regarding SB 1547?

A. ICNU notes that Senate Bill (SB) 1547 will allow PacifiCorp to recover approximately $28.5 million of additional revenues during the term of the 2017 Protocol. These additional revenues relates primarily to truing up actual production tax credits with forecasted production tax credits. ICNU's position is that the revenue associated with SB 1547 reduces the value of the 2017 rate case stay out provision.

Q. Was the SB 1547 revenue included in the analysis presented in your Response Testimony?

A. Yes. I agree that SB 1547 reduces the value of a rate case stay out. However, the analysis in my response testimony includes SB 1547 revenue. Due to the passage of SB 1547, Oregon rates will reflect current production tax credits regardless of when PacifiCorp files for a general rate case. Had SB 1547 not passed, my estimated value of a rate case stay out would have increased by the difference between actual production tax credit revenues and UE 263 forecasted production tax credit revenues.

Q. What issue does ICNU raise regarding caps and floors for the Embedded Cost Differential?

A. ICNU objects to the use of a cap on Oregon's Embedded Cost Differential (ECD). ICNU presents evidence that Oregon's share of the actual ECD may exceed the cap on it in the 2017 Protocol.

Q. Do you find that the likelihood of a high ECD is greater than a low ECD?

A. The ECD has consistently decreased over the last ten years. Many factors are incorporated into the calculation and estimation of the ECD. There is no tractable method of assigning probabilities to ECD outcomes. However, the historic trend for the ECD has been negative.[4] The factors causing the historic decrease in the ECD do not seem likely to reverse.[5]

ICNU's testimony presents ECD estimates[6] that rely on preliminary data generated by PacifiCorp and presented to parties on October 16, 2014.[7] The preliminary ECD estimates presented by ICNU are out of date and no longer accurate. Staff/202 provides an accounting of the difference between the initial ECD estimates and the final ECD estimates.

Q. Are you aware of any reason the ECD could be lower than anticipated?

A. Yes, the Qualified Facilities (QF) contracts used to forecast the ECD include only active contracts.[8] I understand that PacifiCorp is involved in several new Utah QF contracts that have not become active yet. Utah QF tariff pays lower energy prices than the forecasted cost of all other generation. New Utah QFs appear to cost less than $32 per MWh,[9] while the forecasted cost of all other

[4] *See* Staff/202 Response to OPUC to PAC DR 30.
[5] *See* Staff/203 Response to OPUC to PAC DR 32.
[6] *See* ICNU/100 Mullins/3.
[7] *See* Staff/204 Response to OPUC to PAC DR 52 and 53.
[8] *See* Staff205 Response to OPUC to PAC DR 55.
[9] *See* Staff/206 QF prices for Utah.

generation is $48.[10] Adding these QFs would, therefore, decrease the cost of all other generation and decrease the ECD.

Under the 2017 Protocol QF contracts are treated as rolled in. Existing Oregon QF contracts are about twice as expensive as existing Utah QFs.[11] However, new Oregon QF contracts appear to have prices on par with other PacifiCorp states.

Q. Should the Commission reject the ECD cap and floor, as proposed by ICNU?

A. No. While there is a possibility that removing the cap would benefit Oregon customers, there is also a possibility that removing the floor would harm Oregon customers. There is not sufficient evidence to weigh either outcome as the more likely scenario.

Q. Does Staff believe that any portion of the 2017 Protocol should be viewed as precedential?

A. No. The 2017 Protocol should not be viewed as precedential. ICNU raises concern that the 2017 Protocol does not provide Oregon with a full hydro endowment and that this sets a precedent for future interstate allocations.[12] Staff disagrees on both counts. The 2017 Protocol provides Oregon with the full historic hydro endowment, but for the limited term of the 2017 Protocol and in context of the all aspects of the settlement, provides for a cap and floor on the operation of the ECD which reduces risks to Oregon customers that the

[10] *See* Staff/207 Response to OPUC to PAC DR 48.
[11] *See* Staff/207 Response to OPUC to PAC DR 48.
[12] *See* ICNU/100 Mullins/18.

ECD will be lower than the floor and reduces risk to PacifiCorp if the ECD is higher than the cap.

Furthermore, the 2017 Protocol is agreed to by stipulation, and as such does not represent any precedent for future negotiations. Staff fully intends to continue pursuing a fair allocation of merger benefits as outlined in the original approval of the merger by the Commission. The size of the merger benefits and the fair allocation of these benefits are in no way affected by the 2017 Protocol.

Finally, once the 2017 Protocol ends the default allocation method is the Revised Protocol. The Revised Protocol contains a dynamic ECD with no caps and floors.

Q. What issue does ICNU raise regarding the Klamath Dam?

A. ICNU notes that Oregon customers pay a disproportionate share of the Klamath Dam removal costs and that these costs are not capped in the same manner as the ECD. Staff agrees that Oregon customers are paying a substantial portion of the Klamath Dam removal costs. Staff also agrees Oregon customers should be justly compensated for these costs.

Staff finds that the 2017 Protocol is sufficient short term compensation. Staff anticipates including the system benefits associated with the dam removal in the analysis of future allocation agreements. There is no need to specifically address Klamath Dam removal benefits in the 2017 Protocol because the 2017 Protocol will not be in effect when these benefits materialize.

Q. Does this conclude your cross-answering testimony?

A. Yes.

CASE: UM 1050
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Exhibits in Support
Of Cross-Answering Testimony

April 22, 2016

OPUC Data Request 56

Please refer to Nobel Solutions/100 Higgins/4 at lines 10 through 16. What is PacifiCorp's understanding of the treatment of VERT load in allocation factors under the 2017 Protocol.

Response to OPUC Data Request 56

In UM 1690, the Commission deferred for future consideration the issue of whether it is in the public interest for utilities to offer VRET. Any determination regarding VRET or the treatment of VRET loads should be addressed within the context of a proceeding specifically addressing that issue.

CASE: UM 1050
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support
Of Cross-Answering Testimony

April 22, 2016

OPUC Data Request 30

Referring to PAC/100, Dalley/17, please provide the values of the Oregon ECD used to establish rates, as approved by the Public Utility Commission of Oregon, by year, through 2017. The first year would be the effective date of tariffs filed in the first use of Revised Protocol. For each year, identify whether the allocation methodology was Revised Protocol or 2010 Protocol. Where no new rates pursuant to a PacifiCorp general rate occurred, assume the most recent Commission-adopted ECD value escalated by the change in kWh sales to Oregon retail customers.

Response to OPUC Data Request 30

Please see Attachment OPUC 30.

TABLE 1
Oregon ECD Values by General Rate Case

Docket No.	Test Period	Rates Effective	MWh sales to Oregon retail customers	Oregon ECD Value (reduction to Rev. Req.)	Method
UE-170	12/31/2006	10/4/2005	13,617,171	$ (12,824,741)	Revised Protocol
UE-179	12/31/2007	1/1/2007	13,577,546	$ (20,989,570)	Revised Protocol
UE-210	12/31/2010	2/2/2010	13,392,810	$ (13,062,546)	Revised Protocol
UE-217	12/31/2011	1/1/2011	12,774,660	$ (15,465,663)	Revised Protocol
UE 246	12/31/2013	1/1/2013	13,097,740	$ (5,419,206)	2010 Protocol
UE 263	12/31/2014	1/1/2014	13,168,971	$ (8,792,171)	2010 Protocol

TABLE 2
Oregon ECD Values by Calendar Year

Year	OR ECD Value Adjusted by change in MWh	Method	Actual MWh[(1)]	Note	OPUC 32 % Change
2006	$ (12,824,741)	Revised Protocol	13,744,192		
2007	(20,989,570)	Revised Protocol	13,844,112		**64%**
2008	(21,210,049)	Revised Protocol	13,720,167		1%
2009	(20,301,211)	Revised Protocol	13,132,266		-4%
2010	(13,723,131)	Revised Protocol	12,894,307	(2)	**-32%**
2011	(15,465,663)	Revised Protocol	12,879,781		**13%**
2012	(15,473,422)	Revised Protocol	12,781,069		0%
2013	(5,419,206)	2010 Protocol	12,818,351		**-65%**
2014	(8,792,171)	2010 Protocol	12,965,548		**62%**
2015	(8,587,532)	2010 Protocol	12,862,461	(3)	-2%
2016	(8,712,867)	2010 Protocol	13,050,189	(4), (5)	1%
2017	(8,541,358)	2010 Protocol	12,793,302	(4), (5)	-2%

Table 2 Footnotes:

1) Temperature normalized

2) Rates from Docket No. UE-210 were effective 2/2/2010. The amount shown for 2010 is calculated as one month (January) of the UE-179 ECD amount, the remainder is based on the ECD from Docket No. UE-210

3) CY 2015 load at sales as shown is preliminary.

4) CY 2016 and 2017 are assumed to be held at the ECD level set in the Company's most recent general rate case, Docket No. UE-263

5) Actual MWh shown for CY 2016 and 2017 represents the forecasted load at sales

CASE: UM 1050
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Exhibits in Support
Of Cross-Answering Testimony

April 22, 2016

OPUC Data Request 32

For any year by which the ECD changes by more than a plus or minus ten percent from the prior year's value, please explain the factors, and the relative impact of these factors, that caused the ECD value to change.

Response to OPUC Data Request 32

Please see Attachment OPUC 30 for the year-over-year embedded cost differential (ECD) change percentages.

For the change between CY 2006 and CY 2007 (UE-170 to UE-179)
The change in the ECD was primarily due to an increase in embedded cost of the All Other Generation Resources, mostly driven by an increase in purchased power, adding approximately $5-8 million to the value of the Oregon ECD. Also, favorable Oregon QF pricing added another $3.0 million to the value of the Oregon ECD.

For the change between CY 2009 and CY 2010 (UE-179 to UE-210)
The main reason for the change between the Oregon dynamic ECDs was due to a decrease in the Grant Reasonable credit, causing a reduction to Oregon's ECD benefit of approximately $6.6 million.

For the change between CY 2010 and CY 2011 (UE-210 to UE-217)
The main reason for the change between the Oregon dynamic ECDs was due to favorable Oregon QF pricing, increasing Oregon's ECD benefit by approximately $1.3 million. Also, variances in the Mid-C contract differential and an increase in the Grant Reasonable credit contributed an additional $0.6 million to Oregon's ECD benefit.

For the change between CY 2012 and CY 2013 (UE-217 to UE-246)
Docket UE-246 was the first general rate case that used the 2010 Protocol. The change in the west hydro differential component was due to higher west hydro embedded costs (particularly increased operations and maintenance costs and hydro relicensing) combined with a lower west hydro MWh output. These items reduced Oregon's ECD benefit by approximately $8.5 million.

The change in the Mid-C component was due to a decrease in the Grant Reasonable portion along with termination of some Mid-C contracts affecting the $/MWh differential and the Mid-C factor. These changes in the Mid-C component decreased Oregon's benefit by approximately $16 million.

These decreases were partially offset by the benefit Oregon received from eliminating the QF differential component in the 2010 Protocol ECD calculation. The value of the QF component under the Revised Protocol in Docket No. UE-217 was about $15.5 million.

For the change between CY 2013 and CY 2014 (UE-246 to UE-263)
The change in the west hydro differential component was due to higher All Other Generation (pre-2005) Resource embedded costs, primarily increased steam operations and maintenance costs and depreciation expense. These items increased Oregon's ECD benefit by approximately $3.0 million.

CASE: UM 1050
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 204

Exhibits in Support
Of Cross-Answering Testimony

April 22, 2016

OPUC Data Request 52 Confidential

Please confirm that at the time the file "2014 MSP Foundational Update Study_CONF.xlsx" was prepared, PacifiCorp forecasted Oregon's share of the ECD under Revised Protocol ranged between [redacted] and [redacted] for 2017 through 2019. If not confirmed, please explain what the referenced data represent.

Response to OPUC Data Request 52

The referenced numbers represent Oregon's share of the ECD under Revised Protocol that was calculated in the 2014 MSP Foundational Study Update, which were prepared with the sole purpose of studying allocations. As such, these numbers were forecasted using general assumptions, which were agreed to by the MSP Broad Review Workgroup, and were never intended to represent a true revenue requirement.

The confidential information is designated as confidential under the protective order in these proceedings and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 53

Please provide a narrative explaining why the values in"2014 MSP Foundational Update Study_CONF.xlsx" sheet "Attachment E-5" differ from the values provided in response to OPUC to PacifiCorp DR 31. Please identify the specific factors driving the different results.

Response to OPUC Data Request 53

The MSP foundational studies are not indicative of the future Oregon Dynamic ECD levels. The foundational studies were prepared by the Company and provided to the MSP participants in the summer of 2014. The explicit purpose of the data was to study allocations, not predict revenue requirement at a level commensurate with a proceeding used to actually set rates. Many simplifying assumptions were used to project the data from actual 2013 levels to 2017, 2018 and 2019. As such, the results of the studies are, quite simply, not comparable to the data the Company would use in a rate proceeding. Additionally, the MSP foundational studies are based on outdated data and assumptions.

To prepare the MSP foundational studies, the Company used calendar year 2013 actual data from the Company's accounting system, and then forecasted the data out through the study horizon of 2027 using assumptions from the Company's 2013 business plan, 2014 IRP Update, 2010 Depreciation Study depreciation rates, 2013 load forecasts, and many other assumptions. Together, these outdated assumptions and data produce a result that does not reflect the true cost of providing electricity in today's conditions.

The MSP foundational studies used prices and assumptions from the 2013-2014 timeframe to estimate the costs and production levels. The following are examples of items that do not reflect current operating and cost conditions as a result of the outdated assumptions:

- All other company owned generation production: The production levels associated with the Company's 'All Other (non-west hydro) Generation Resources' was too low. This results in the ECD being overstated by approximately $3 million.

- West-hydro production: The production levels associated with the Company's west hydro facilities was too high. This results in the ECD being overstated by approximately $1 million to $1.6 million.

- Other Generation O&M: The MSP foundational study applied general escalation factors to the CY 2013 actual data in order to forecast future O&M. This resulted in Other Generation O&M in 2017-2019 being overstated. This results in the ECD being overstated by approximately $1 million.

- Mid-Columbia (Mid-C) Factor: In 2019, the MSP foundational study assumed the Douglas Wells contract would expire, which caused Oregon's Mid-C factor to increase from approximately 44 percent to 86 percent. This results in the MSP Foundational Study Revised Protocol ECD being overstated by approximately $4.5 million in 2019. The contract has since been renewed, which was reflected in the Company's Fall 2015 business plan used to produce the updated ECD forecasts discussed in OPUC 31.

CASE: UM 1050
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 205

Exhibits in Support
Of Cross-Answering Testimony

April 22, 2016

OPUC Data Request 55

Please provide all work papers used to aggregate QF costs from the contract level to the level used in the work papers provided in response to DR 48. For each contract, please state whether the project is operational, or if it represents an executed contract not yet in commercial operation. For those contracts not yet in commercial operation, please provide the contracted commercial operation date.

Response to OPUC Data Request 55

Please refer to Confidential Attachment OPUC 55-1, which provides the work paper supporting the aggregated qualifying facility (QF) projected values for calendar year 2016, and Confidential Attachment OPUC 55 -2, which provides the work paper supporting the aggregated QF projected values for calendar years 2017, 2018 and 2019. All of the QF resources listed in the attachments are operational.

The confidential attachments are designated as confidential under the protective order in these proceedings and may only be disclosed to qualified persons as defined in that order.

Staff/205
Kaufman/2-3

Page 2 and 3 are confidential.

You must have signed the Protective Order No: 10-365 in this docket to view these pages.

CASE: UM 1050
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 206

Exhibits in Support
Of Cross-Answering Testimony

April 22, 2016

ELECTRIC SERVICE SCHEDULE NO. 37 - Continued

Base Load Facility

Volumetric Winter and Summer Energy Prices for On-Peak and Off-Peak hours ¢/kWh

Non-Levelized Prices

Deliveries During	On Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh)	
Calendar Year	Winter	Summer	Winter	Summer
2015	2.383	3.163	2.036	2.365
2016	2.449	3.353	2.100	2.436
2017	2.569	3.303	2.242	2.481
2018	2.912	3.452	2.442	2.563
2019	2.994	3.750	2.541	2.735
2020	3.000	3.877	2.530	2.838
2021	3.421	4.166	2.806	3.047
2022	3.717	4.554	3.032	3.330
2023	4.037	4.692	3.368	3.562
2024	4.189	4.993	3.360	3.680
2025	4.387	5.192	3.629	3.846
2026	4.556	5.269	3.810	3.990
2027	4.778	5.081	4.007	3.848
2028	6.449	6.449	3.584	3.584
2029	6.598	6.598	3.676	3.676
2030	6.729	6.729	3.748	3.748
2031	7.026	7.026	3.983	3.983
2032	7.188	7.188	4.081	4.081
2033	7.306	7.306	4.134	4.134

Levelized Prices (Nominal)

	On Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh)	
	Winter	Summer	Winter	Summer
15-year (2016-2030) Nominal Levelized	3.831	4.471	2.962	3.153

(continued)

CASE: UM 1050
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 207

Exhibits in Support
Of Cross-Answering Testimony

April 22, 2016

OPUC Data Request 48

Please refer to the response to OPUC to PacifiCorp DR 31. Please provide all work papers used to estimate the QF component of the difference between the Revised Protocol and 2017 Protocol dynamic ECD.

Response to OPUC Data Request 48

Please refer to Attachment OPUC 48.

Attachment OPUC 48

Staff/207
Kaufman/2

Qualified Facilities

Account	Description	Amount	Mwh	$/Mwh
555	Utah Annual Qualified Facilities Costs	28,752,568	417,769	68.82
555	Oregon Annual Qualified Facilities Costs	13,502,335	105,984	127.40
555	Idaho Annual Qualified Facilities Costs	4,724,761	76,543	61.73
555	WYU Annual Qualified Facilities Costs	-	-	-
555	WYP Annual Qualified Facilities Costs	-	-	-
555	California Annual Qualified Facilities Costs	5,000,266	33,296	150.18
555	Washington Annual Qualified Facilities Costs	-	-	-
	Total Qualified Facilities Costs	51,979,931	633,591	82.04

All Other Generation Resources
(Excl. West Hydro, Mid C, and QF)

Account	Description	Amount	Mwh	$/Mwh
500 - 514	Steam Operation & Maintenance Expense	1,206,453,437		
535 - 545	East Hydro Operation & Maintenance Expense	8,934,613		
546 - 554	Other Generation Operation & Maintenance Expense	390,039,867		
555	Other Purchased Power Contracts	572,246,208		
40910	Production Tax Credits	(109,645,408)		
4118	SO2 Emission Allowances	(681,154)		
	James River	0		
	REC Revenue	(9,121,092)		
403SP	Steam Depreciation Expense	210,584,274		
403HP	East Hydro Depreciation Expense	6,776,861		
403OP	Other Generation Depreciation Expense	128,758,946		
403MP	Mining Depreciation Expense	0		
404IP	East Hydro Relicensing Amortization	322,530		
406	Amortization of Plant Acquisition Costs	4,750,825		
	Total All Other Operating Expenses	**2,409,419,906**		
310 - 316	Steam Electric Plant in Service	7,080,890,202		
330 - 336	East Hydro Electric Plant in Service	164,774,232		
302 & 186M	East Hydro Relicensing	9,769,805		
340 - 346	Other Electric Plant in Service	4,097,565,955		
399	Mining	175,889,819		
108SP	Steam Accumulated Depreciation Reserve	(2,856,521,745)		
108OP	Other Generation Accumulated Depreciation Reserve	(947,715,255)		
108MP	Other Accumulated Depreciation Reserve	(3,007,478)		
108HP	East Hydro Accumulated Depreciation Reserve	(62,089,249)		
111IP	East Hydro Relicensing Accumulated Reserve	(5,479,529)		
114	Electric Plant Acquisition Adjustment	143,167,971		
115	Accumulated Provision Acquisition Adjustment	(114,057,313)		
151	Fuel Stock	171,902,328		
253.16 - 253.19	Joint Owner WC Deposit	(5,413,275)		
253.98	SO2 Emission Allowances	(430,756)		
154	Materials & Supplies	121,041,493		
154	East Hydro Materials & Supplies			
	Total Net Rate Base	**7,970,287,205**		
	Pre-tax Return	10.74%		
	Rate Base Revenue Requirement	**856,061,817**		
	Annual Embedded Cost			
	All Other Generation Resources	**3,265,481,724**	68,129,102	47.93

CITIZENS UTILITY BOARD OF OREGON	
CITIZENS' UTILITY BOARD OF OREGON	610 SW BROADWAY, STE 400 PORTLAND OR 97205 dockets@oregoncub.org
MICHAEL GOETZ **(C)** CITIZENS' UTILITY BOARD OF OREGON	610 SW BROADWAY STE 400 PORTLAND OR 97206 mike@oregoncub.org
ROBERT JENKS **(C)** CITIZENS' UTILITY BOARD OF OREGON	610 SW BROADWAY, STE 400 PORTLAND OR 97205 bob@oregoncub.org
ICNU UM 1050	
JESSE E COWELL **(C)** DAVISON VAN CLEVE	333 SW TAYLOR ST., SUITE 400 PORTLAND OR 97204 jec@dvclaw.com
BRADLEY MULLINS **(C)** MOUNTAIN WEST ANALYTICS	333 SW TAYLOR STE 400 PORTLAND OR 97204 brmullins@mwanalytics.com
NIPPC UM 1050	
ROBERT D KAHN NORTHWEST & INTERMOUTAIN POWER PRODUCERS COALITION	PO BOX 504 MERCER ISLAND WA 98040 rkahn@nippc.org
IRION A SANGER **(C)** SANGER LAW PC	1117 SE 53RD AVE PORTLAND OR 97215 irion@sanger-law.com
NOBLE AMERICAS ENERGY SOLUTIONS	
GREGORY M. ADAMS **(C)** RICHARDSON ADAMS, PLLC	PO BOX 7218 BOISE ID 83702 greg@richardsonadams.com
GREG BASS NOBLE AMERICAS ENERGY SOLUTIONS, LLC	401 WEST A ST., STE. 500 SAN DIEGO CA 92101 gbass@noblesolutions.com
KEVIN HIGGINS **(C)** ENERGY STRATEGIES LLC	215 STATE ST - STE 200 SALT LAKE CITY UT 84111-2322 khiggins@energystrat.com
NW ENERGY COALITION	
WENDY GERLITZ NW ENERGY COALITION	1205 SE FLAVEL PORTLAND OR 97202 wendy@nwenergy.org
PACIFICORP UM 1050	
PACIFICORP, DBA PACIFIC POWER	825 NE MULTNOMAH ST, STE 2000 PORTLAND OR 97232 oregondockets@pacificorp.com
R. BRYCE DALLEY PACIFIC POWER	825 NE MULTNOMAH ST., STE 2000 PORTLAND OR 97232 bryce.dalley@pacificorp.com

MATTHEW MCVEE PACIFICORP	825 NE MULTNOMAH PORTLAND OR 97232 matthew.mcvee@pacificorp.com
PGE UM 1050	
PATRICK G HAGER PORTLAND GENERAL ELECTRIC	121 SW SALMON ST 1WTC0702 PORTLAND OR 97204 pge.opuc.filings@pgn.com; patrick.hager@pgn.com
V. DENISE SAUNDERS PORTLAND GENERAL ELECTRIC	121 SW SALMON ST 1WTC1301 PORTLAND OR 97204 denise.saunders@pgn.com
STAFF UM 1050	
MARC HELLMAN **(C)** PUBLIC UTILITY COMMISSION OF OREGON	PO BOX 1088 SALEM OR 97308-1088 marc.hellman@state.or.us
JASON W JONES **(C)** PUC STAFF--DEPARTMENT OF JUSTICE	BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301-4096 jason.w.jones@state.or.us
LANCE KAUFMAN **(C)** PUBLIC UTILITY COMMISSION OF OREGON	PO BOX 1088 SALEM OR 97308-1088 lance.kaufman@state.or.us

CERTIFICATE OF SERVICE

UM 1050

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 22nd day of April, 2016 at Salem, Oregon

Kay Barnes

Kay Barnes
Public Utility Commission
201 High Street SE Suite 100
Salem, Oregon 97301-3612
Telephone: (503) 378-5763