RENEWABLE NORTHWEST PROJECT

UM 1610

RESPONSE TESTIMONY OF

JIMMY LINDSAY

In the Matter of

PUBLIC UTILITY COMMISSION OF OREGON

Staff Investigation Into Qualifying Facility Contracting and Pricing

March 18, 2013

INTRODUCTION

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

A. My name is Jimmy Lindsay. I am employed as Power Systems Analyst at Renewable Northwest Project ("RNP"). My business address is 421 SW Oak Street, Suite 1125, Portland, OR 97204.

Q. Please describe your educational background and work experience.

A. I hold a Bachelor's degree in Physics and a Bachelor's degree in History from Bowdoin College. I received a Fulbright Scholarship to study distributed generation with the Department of Energy Technology at The Royal Institute of Technology in Stockholm, Sweden. I have a pending MSc in Sustainable Energy Engineering from The Royal Institute of Technology. Since returning from Sweden in January 2011, I have worked at RNP as a utility analyst.

Q. What is the purpose of your testimony?

A. My testimony has three parts. First, I explain several general policy reasons why the Oregon Public Utility Commission ("Commission") should retain the core features of its current approach to implementing the Public Utilities Regulatory Policy Act of 1978 ("PURPA"), particularly the 10 MW published rate/standard contract threshold. Second, I address the 10 MW threshold and considerations for preventing aggregated groups of projects from receiving published rates intended for independent 10 MW projects. Third, I address utility-proposed cost adjustments for integration of variable energy resources.

Q. Are your opinions in this case limited to a narrow range of issues?

A. No. My views, and RNP's views more broadly, extend to many of the other issues in the docket. However, these views are likely to align closely with those of other intervenors. Rather than submit overlapping testimony, I have focused on two key themes. My testimony addresses Issue 4A (integration) because integration is a particular focus of my professional attention and expertise. My testimony addresses Issues 5A-C, relating to the standard rate/contract eligibility threshold, for several reasons: (1) retaining the 10 MW threshold is important to Oregon's PURPA implementation continuing to include all competitive renewable resource types, including community scale wind resources; (2) because limiting published rates to single 10 MW projects is key to the integrity of published rates as a policy tool; and (3) because rollback of Oregon's published rate thresholds would send a negative message about the state's intention to encourage renewable resources.

Q. What do you recommend with respect to integration costs?

A. First, because wind integration cost studies are not an appropriate proxy for determining the cost of integrating solar photovoltaic resources, I recommend that the Commission decline to adjust avoided cost rates for integration of solar photovoltaic qualifying facilities ("QFs") until solar penetration motivates utilities to study solar integration costs. Second, I recommend that, if the Commission chooses to reduce avoided cost rates for standard wind QFs to reflect integration costs, it should identify an improved practice for scrutinizing integration studies.

GENERAL PRINCIPLES OF OREGON'S PURPA IMPLEMENTATION

Q. What should be the policy goal of implementing PURPA?

A. The Commission should implement PURPA to encourage competition among resources with diverse characteristics in meeting utilities' generation needs. The Commission should retain the goal it stated in Order No. 05-584: to encourage the economically efficient development of QFs insofar as possible, while ensuring that rates match the utility's avoided cost.

Q. Has the Legislature directed the Commission to encourage development of renewable QFs?

A. Yes. The Oregon Legislature views "community-based renewable energy projects . . . [as] an essential element of Oregon's energy future." ORS 469A.210 sets forth a goal that at least eight percent of retail load by 2025 come from "small-scale renewable energy projects with a generating capacity of 20 megawatts or less." The statute directs "[a]ll agencies . . . [to] establish policies and procedures promoting the goal declared in this section."

Q. Has the Commission promoted that goal to date?

A. Yes. The Commission has committed significant attention to PURPA implementation in the last decade, and has settled many of the core elements of PURPA implementation in a balanced and reasonable manner. UM 1129 produced a 60-page order in 2005 and a 68-page order in 2006. In UM 1396, the Commission tackled details of resource sufficiency, producing orders in 2010 and 2011.

Q. What elements have been most significant in encouraging balanced renewable QF development?

A. The most significant factors for encouraging diverse QF resource additions are contract length of at least 20 years, published rates and standard contract availability up to 10 megawatts, and certainty and notice around rate changes. The most significant factors for avoiding excess QF development, relative to utility resource needs, are sufficiency/deficiency pricing and preventing developers from aggregating QFs into large, utility-scale developments. Working together, these key features of Oregon's implementation have produced diverse QF resource additions without overwhelming utility generating portfolios.

Q. How should the Commission approach this docket?

A. The Commission should view this docket as an opportunity to refine certain peripheral mechanics of its PURPA implementation and to address some new issues that have arisen. The Commission need not revisit central tenets of its PURPA implementation policy. Certainly, the Commission should reject the utilities' invitations to dismantle the system created in UM 1129 and UM 1396. In particular, reducing the published rate threshold would set a damaging precedent and fundamentally change PURPA's function of creating a target market for competitive community-scale resources in Oregon.

ELIGIBILITY THRESHOLD AND SINGLE PROJECT DETERMINATION

Q. Should the 10 MW standard contract threshold be retained?

A. Yes. The utilities argue for reducing the standard contract threshold for several reasons: developer sophistication and project costs, mismatch with project-specific avoided cost, and prevention of "disaggregation." The first two reasons were presented in UM 1129, when the Commission established the 10 MW threshold, and are unlikely to have changed significantly. Potential for "disaggregation" was the *sole* reason given by the Idaho Public Utilities Commission ("IPUC") for reducing the published rate threshold for wind and solar resources, yet the IPUC could have used a narrower regulatory approach.

Q. Do you agree that it is important to prevent projects larger than the published rate size threshold from obtaining the published rate?

A. Yes. If larger projects with greater economies of scale are allowed to access published rates, the integrity of published avoided cost rates as a tool to level the playing field for smaller projects may be called into question. In Idaho, where there was effectively no mechanism for regulating the practice of combining several QFs into an aggregated development (and, importantly, where the published rate threshold was much higher than Oregon's and rates were not calibrated to resource sufficiency/deficiency), PURPA resource additions in Idaho Power's service territory added up quickly. The IPUC cited the potential for "disaggregation" as its sole reason for dramatically reducing the published rate threshold for wind and solar QFs, from 10 aMW to 100 kW. The unchecked practice of disaggregation and the extreme response by the IPUC demonstrate the importance of adopting a regulatory mechanism to prevent widespread access to the PURPA published rate by large aggregations of closely related projects.

Q. Must Oregon reduce its PURPA published rate threshold in order to prevent widespread "disaggregation"?

A. No. Reducing the threshold, particularly to 100 kW, is a disproportionate, unnecessarily damaging policy response. A thoughtful regulatory approach to distinguishing single projects from aggregated projects is the right way to accomplish the objective. The 10 MW published rate threshold is significant to accomplishing the Commission's policy goals; it should not be abandoned where other means of preventing widespread "disaggregation" exist.

Q. Do you recommend that the Commission formally adopt the Oregon "partial stipulation" approach for identifying single projects?

A. The Oregon "partial stipulation" approach to single project identification, in combination with other elements of Oregon's PURPA implementation, has effectively prevented widespread disaggregation. There is a significant difference between one or two arguably "disaggregated" projects in Oregon, and the regular practice of project combination in Idaho. Even so, I recommend that the Commission further tighten its single project criteria to prevent additional instances of disaggregation and still preserve the benefits of published rates and standard contracts for community-scale projects.

Q. What is the most important thing for single project criteria to discern in the PURPA context?

A. In the PURPA context, the primary function of the size threshold is to preserve published rates for projects that do not enjoy significant economies of scale (and, as such, are less able to absorb the transaction costs of negotiation). The goal of single project criteria in the PURPA context should be to reveal economic interdependence. Thus, the most important characteristics will be financial in nature—for example, beneficial ownership, financing, cost and revenue sharing, combined purchases of generating equipment, and combined construction contracts.

Q. Is a distance criterion also necessary?

A. Distance between projects is not necessarily indicative of economic interdependence. Projects very near one another may be unrelated, while projects 5.1 miles apart may share significant financial details. A distance criterion, however, seems unavoidable as a threshold indicator of when to examine the relatedness of two projects. A distance threshold creates some objectivity and predictability for all involved. I recommend that the Commission retain the five-mile distance criterion from the partial stipulation, but reserve the ability to review and apply financial criteria for more widely spaced projects—perhaps up to 10 miles—where a greater than usual number of characteristics suggest economic interdependence.

Q. Are there criteria to be avoided in distinguishing single projects?

A. A method for distinguishing single projects should not discourage development behaviors that other important policies would encourage. For example, local residents and natural resource agencies may appreciate projects sharing infrastructure and related facilities in order to reduce land impacts. Shared facilities among separate projects should continue to be encouraged as a method of improving the efficiency of the power system. Also, single project criteria should not punish unavoidable similarities across unrelated projects, such as relationships with the same operations and maintenance providers, scheduling or forecasting providers, or renewable energy credit brokers. There are few third party companies providing those services, and all independent QFs will need to contract with some third party to perform some or all of those functions.

INTEGRATION COST ADJUSTMENTS TO QF RATES – SOLAR

Q. Have the utilities performed solar integration cost studies as the foundation for adjusting solar QF rates?

A. No. The utilities have proposed to adjust the avoided cost rates for solar QFs based on the balancing reserve need and cost assumptions from their wind integration studies.

Q. Are wind integration costs predictive of solar integration costs?

A. No. Solar is an entirely different resource with unique integration requirements. Wind integration costs do not accurately reflect the utility cost of solar integration.

Q. How do solar integration requirements differ from wind integration requirements?

A. Integrating solar generation generally requires less balancing reserves than wind generation for four reasons. (1) Solar generation benefits from more accurate generation forecasting than wind generation. (2) Solar generation variability experiences more smoothing due to geographic diversity than occurs for wind facilities. (3) Solar generation is less time correlated than incremental wind generation with existing variable generators. (4) Solar resources only generate during daylight hours. These four factors contribute to solar's reduced integration need relative to wind generation.

Q. Does Bonneville Power Administration ("BPA") charge wind integration rates for solar generators?

A. No. BPA's initial proposal for the FY14-15 rate case does not charge solar generators the wind integration rate. BPA staff used real solar generation data (albeit from only one project) and, by applying the same methodology used to calculate the wind integration rate, determined that the solar integration rate was 18% of the wind integration rate.

Q. Do solar QFs presently impose measurable integration costs?

A. No. Few solar QFs exist on the systems of the utilities represented in this docket. Until these utilities acquire solar generation and forecast data, it is impossible to know how solar forecast errors will correlate with existing system forecast errors. Without this data, utilities cannot accurately estimate solar integration costs.

Q. Should avoided cost rates for solar QFs be adjusted for integration costs at this time?

A. No. Until solar development motivates utilities to perform solar integration cost studies, it is premature to introduce an integration adjustment into the avoided cost calculation for solar QFs.

INTEGRATION COST ADJUSTMENTS TO QF RATES – WIND STUDIES

Q. Have the utilities measured wind integration costs as the foundation for proposing rate adjustments for wind QFs?

A. Yes. The three utilities have developed wind integration studies as a part of their Integrated Resource Plan ("IRP") processes.

Q. Are the wind integration studies designed to measure the cost of wind integration for wind QFs specifically?

A. No. The IRP wind integration studies determine the balancing reserve requirements for the utilities' entire wind fleets, not simply for QF wind projects. For PacifiCorp and PGE, the vast majority of the wind fleet's capacity consists of very large, utility-scale wind projects. After calculating the balancing reserve requirements for the entire wind fleet, the studies calculate the average cost of providing those balancing reserves.

Q. Are gas and market prices a significant variable in determining wind integration costs?

A. Yes. In IRP wind integration studies, the costs associated with using balancing reserves for integration generally are calculated using a test year in which gas and market prices are consistent with the forward price curves assumed for the accompanying IRP. The assumed gas and market prices are a major variable in the resulting wind integration costs.

Q. Are there reasons other than changing gas and market prices why wind integration costs may change substantially from study to study?

A. Yes. Wind integration study methodology has changed dramatically from study to study often resulting in large changes to the calculated reserve requirements and resulting wind integration cost estimates. (For example, PacifiCorp's change from use of synthetic wind data to use of real wind data improved the company's 2013 study methodology considerably.) Furthermore, as market conditions evolve, there will be continued changes in the appropriate study assumptions regarding scheduling periods, imbalance market opportunities, operational improvements in the power system, wind penetration and diversity assumptions, and the portfolio of available balancing resources. Substantial revisions to integration costs will continue as utilities are able to rely on an expanding suite of tools to lower wind integration costs.

Q. Are you aware of any regulatory mandate that utilities update their wind integration studies with every IRP?

A. In the past several years, general utility practice has been to update wind integration studies in the beginning of each IRP cycle, but I am not aware of a specific regulatory requirement to do so.

Q. Do IRP wind integration studies provide an adequate foundation for establishing integration adjustments to PURPA avoided cost rates?

A. Two significant procedural improvements are needed before the Commission could reasonably rely on IRP wind integration studies as a foundation for integration adjustments to PURPA avoided cost rates: (1) Regular, consistent updates to ensure both that gas and market prices are consistent with assumptions used to generate avoided cost rates and that study methodologies and assumptions are current; and (2) a more rigorous standard of review for wind integration studies and a forum for Commission approval of their specific results.

Q. How frequently should utilities update wind integration cost studies to support adjustments to PURPA rates?

A. The Commission should require utilities to update wind integration cost results on the same timelines that it has selected for other significant elements of the avoided cost rate. Integration study methodologies and assumptions should be reviewed and updated with every two-year IRP cycle and associated gas and market prices should be no more than two years old. If the Commission considers a PURPA-specific update too burdensome, then the wind integration cost should be demonstrated to be consistent with the last yearly power cost rate case filing.

Q. Do IRPs provide a sufficient forum for scrutiny and specific Commission approval of wind integration studies?

A. Generally, no. IRPs can provide a good forum for learning about utility wind integration studies, and the Commission has increasingly required Technical Review Committees to sign off on study methodology. However, major problems with wind integration studies have prompted the Commission to direct utilities to make improvements to the studies and/or to the associated process in the next IRP cycle. That direction has not identified the appropriate wind integration cost for the intervening time period. This type of result in an IRP would not produce adequate justification for a PURPA rate adjustment. In addition, even where studies do not contain major methodological flaws, studies are scrutinized in IRPs only for their effect on long-term resource planning. Within the IRP, a compelling demonstration that the wind integration cost does not accurately reflect the cost of integrating QFs would not be likely to garner significant Commission attention unless it affected the utility's preferred portfolio selection. Yet, flawed wind integration cost estimates may alter prospects for QF development long before they change the preferred portfolio selection.

Q. Are rate cases a better source for scrutinizing and approving wind integration costs to be used for PURPA avoided cost adjustments?

A. Not always. Like IRPs, rate cases can be a good forum to gain information about the foundation for wind integration cost estimates. However, even if questions were raised about wind integration costs in annual power cost adjustment cases, those cases frequently may be settled without rulings on specific issues. Eventually, it may be possible for the Commission to set PURPA integration adjustments equivalent to the specific wind integration tariffs approved by the Federal Energy Regulatory Commission ("FERC") for application to merchant wind facilities, but few utilities have as yet secured wind integration tariffs through FERC.

Q. For the present, what do you recommend as the most appropriate forum for settling wind integration cost adjustments to PURPA rates?

A. I recommend that if IRP review identifies significant problems with a wind integration study then the acknowledgment order should address the treatment of wind integration cost adjustments for PURPA rates. If wind integration costs used in IRPs do not accurately reflect present wind integration costs, the Commission should identify a cost other than the utility-proposed cost as an integration adjustment for QFs. Otherwise, a PURPA-specific docket or tariff filing will have to be identified as the forum for establishing QF wind integration adjustments, which would be an additional administrative burden on all parties.

Q. Can you give some concrete examples to illustrate your recommendation for regular updates and specific approval of PURPA integration cost adjustments?

A. Yes, I can provide examples from my experience with the wind integration studies of Idaho Power, PGE, and PacifiCorp. In particular, I can explain why neither Idaho Power's nor PGE's present wind integration studies would be appropriate foundations for wind integration adjustments to avoided cost rates today.

Q. Why is Idaho Power's wind integration study insufficient to form the foundation for PURPA avoided cost rate adjustments?

A. Idaho Power's wind integration study was developed largely without stakeholder or Technical Review Committee ("TRC") participation. The company shared its nearly completed study with a TRC following the Commission's IRP acknowledgment order (Order No. 12-177) directing Idaho Power to "form a wind integration study technical review committee that is fully engaged in the process." However, Idaho Power has not elicited any written feedback from the TRC, shared TRC feedback with stakeholders, nor incorporated TRC suggestions into the wind integration study that it now presents to the Commission for acknowledgment as part of its IRP Update in LC 53.

Even more significant are the study's major methodological flaws. Idaho Power calculates wind's balancing reserve requirements based on the day-ahead forecast errors; wind integration reserve requirements should be based on hour-ahead schedule errors. Hour ahead schedule errors are much smaller than day-ahead errors, and are the standard for measuring integration reserve requirements. Another significant limitation is Idaho Power's reliance on synthetic data to determine the wind integration reserve requirement. Synthetic data tends to be overly correlated with the remaining wind generation data, thereby overestimating the wind integration balancing requirements.

Q. How would you propose that the Commission address those issues with Idaho Power's wind integration cost study in setting avoided cost rates?

A. The Commission soon will consider whether to acknowledged Idaho Power's IRP Update, which includes its wind integration study, in LC 53. I recommend that the Commission do so with an eye to whether the study reasonably justifies a specific cost adjustment for QF rates. If not, I recommend that the Commission direct ongoing improvements to the study, but also that the Commission identify an appropriate discount to the utility proposal or other alternative for use in PURPA avoided cost rates until the utility produces a better-supported study. For example, the Commission could direct Idaho Power to continue using its existing rate adjustment ($6.50/MWh) until it has met higher methodological and procedural standards for its study.

Q. Why is PGE's wind integration study insufficient to form the foundation for PURPA avoided cost rate adjustments?

A. As with Idaho Power, there are procedural and methodological reasons why PGE's wind integration cost study is presently insufficient to form the foundation for avoided cost rate adjustments. First, PGE's wind integration study was presented in November 2011 and discussed at a Commission public meeting in

January 2012, but PGE did not seek or receive acknowledgment of the study. Although RNP considered the study to be a vast improvement over PGE's previous efforts, PGE discussed the study as a "base case" and RNP cautioned that its conservative assumptions did not warrant using the study for ratemaking or IRP use. Moreover, PGE's study uses gas and market prices that are now significantly out of step with those used to generate avoided cost rates. With regard to the methodology, a primary concern was PGE's assumption that the majority of its generators would not be able to provide balancing reserves. However, PGE's response to RNP-03 makes it clear that this study assumption is incorrect and that the lower cost balancing reserves are available to integrate wind. Finally, RNP encouraged PGE to model intrahour scheduling practices, as the utility currently practices with BPA.

Q. What do you propose PGE use for wind integration cost adjustments?

A. The Commission should address the above concerns in its review of PGE's next IRP to be filed in November 2013. If a wind integration adjustment to the PURPA avoided cost tariff is required before the IRP is acknowledged, then I recommend that the Commission direct PGE to use BPA's wind integration cost to adjust avoided cost rates.

Q. What lessons do you draw from PacifiCorp's wind integration study?

A. In the most recent IRP cycle, PacifiCorp has developed a wind integration study that contains major methodological improvements. PacifiCorp's study also demonstrates that gas and market price assumptions have a dramatic effect on wind integration cost results. The evolution of PacifiCorp's wind integration study demonstrates that achieving higher standards for wind integration studies can make a major difference for PURPA avoided cost rate adjustments.

CONCLUSION

Q. Please summarize your testimony.

A. I recommend that the Commission retain the central elements of its existing PURPA implementation. In particular, a strong regulatory control can eliminate potential for "disaggregation" as a basis for lowering the published rate/standard contract cap. With regard to integration cost adjustments, I recommend that the Commission reject adjustments for solar QFs at this time and that it establish a well-defined process for approving wind integration cost adjustments.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I served the foregoing REPLY TESTIMONY OF JIMMY LINDSAY upon the following parties on the service list, via electronic mail, on March 18, 2013:

RENEWABLE NORTHWEST PROJECT

By: /s/ Megan Walseth Decker
Megan Walseth Decker, OSB No. 034878
megan@rnp.org

(W) PUBLIC UTILITY COMMISSION OF OREGON
BRITTANY ANDRUS
ADAM BLESS
P.O. Box 2148
Salem OR 97308-2148
brittany.andrus@state.or.us
adam.bless@state.or.us

(W) IDAHO POWER COMPANY
DONOVAN E WALKER
REGULATORY DOCKETS
PO BOX 70
BOISE ID 83707-0070
dwalker@idahopower.com
dockets@idahopower.com

(W) PUC STAFF - DEPARTMENT OF JUSTICE
STEPHANIE S ANDRUS, AAG
BUSINESS ACTIVITIES SECTION
1162 COURT ST NE
SALEM OR 97301-4096
stephanie.andrus@doj.state.or.us

(W) OREGON DEPARTMENT OF JUSTICE
RENEE M FRANCE
NATURAL RESOURCES SECTION
1162 COURT ST NE
SALEM OR 97301-4096
renee.m.france@doj.state.or.us

(W) PORTLAND GENERAL ELECTRIC
RANDY DAHLGREN - 1WTC0702
J. RICHARD GEORGE - 1WTC1301
121 SW SALMON ST
PORTLAND OR 97204
pge.opuc.filings@pgn.com
richard.george@pgn.com

(W) ESLER STEPHENS & BUCKLEY
JOHN W STEPHENS
888 SW FIFTH AVE STE 700
PORTLAND OR 97204-2021
stephens@eslerstephens.com;
mec@eslerstephens.com

(W) MCDOWELL RACKNER & GIBSON PC
LISA F RACKNER
ADAM LOWNEY
419 SW 11TH AVE., SUITE 400
PORTLAND OR 97205
dockets@mcd-law.com
adam@mcd-law.com

(W) THOMAS H. NELSON
ATTORNEY AT LAW
PO BOX 1211
WELCHES OR 97067-1211
nelson@thnelson.com

(W) OREGON DEPARTMENT OF ENERGY
MATT KRUMENAUR
KACIA BROCKMAN
625 MARION ST NE
SALEM OR 97301
matt.krumenauer@state.or.us
kacia.brockman@state.or.us

(W) THOMAS NELSON
PO BOX 1211
WELCHES OR 97067-1211
nelson@thnelson.com

(W) RICHARDSON & O'LEARY
GREGORY M ADAMS

(W) PACIFICORP
R BRYCE DALLEY
825 NE MULTNOMAH ST., STE 2000
PORTLAND OR 97232
bryce.dalley@pacificorp.com
oregondockets@pacificorp.com

MARY WIENCKE
825 NE MULTNOMAH ST, STE 1800
PORTLAND OR 97232-2149
mary.wiencke@pacificorp.com

(W) CLEANTECH LAW PARTNERS
DIANE HENKELS
6228 SW HOOD
PORTLAND OR 97239
dhenkels@cleantechlawpartners.com

(W) OREGON SOLAR ENERGY INDUSTRIES ASSOCIATION
GLENN MONTGOMERY
PO BOX 14927
PORTLAND OR 97293
glenn@oseia.org

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

(W) ANNALA, CAREY, BAKER, ET AL., PC
WILL CAREY
PO BOX 325
HOOD RIVER OR 97031
wcarey@hoodriverattorneys.com

(W) CABLE HUSTON BENEDICT HAAGENSEN & LLOYD LLP
RICHARD LORENZ
1001 SW FIFTH AVE - STE 2000
PORTLAND OR 97204-1136
rlorenz@cablehuston.com

PETER J RICHARDSON
PO BOX 7218
BOISE ID 83702
greg@richardsonandoleary.com
peter@richardsonandoleary.com

(W) RENEWABLE ENERGY COALITION
JOHN LOWE
12050 SW TREMONT ST
PORTLAND OR 97225-5430
jravenesanmarcos@yahoo.com

(W) ONE ENERGY RENEWABLES
BILL EDDIE
206 NE 28TH AVE
PORTLAND OR 97232
bill@oneenergyrenewables.com

(W) OREGONIANS FOR RENEWABLE ENERGY POLICY
KATHLEEN NEWMAN
1553 NE GREENSWORD DR
HILLSBORO OR 97214
kathleenoipl@frontier.com;
k.a.newman@frontier.com

MARK PETE PENGILLY
PO BOX 10221
PORTLAND OR 97296
mpengilly@gmail.com

(W) LOYD FERY
11022 RAINWATER LANE SE
AUMSVILLE OR 97325
dlchain@wvi.com

(W) ASSOCIATION OF OR COUNTIES
MIKE MCARTHUR
PO BOX 12729
SALEM OR 97309
mmcarthur@aocweb.org

(W) CITY OF PORTLAND - PLANNING & SUSTAINABILITY
DAVID TOOZE
1900 SW 4TH STE 7100
PORTLAND OR 97201
david.tooze@portlandoregon.gov

(W) CLEANTECH LAW PARTNERS PC
DIANE HENKELS
6228 SW HOOD
PORTLAND OR 97239
dhenkels@cleantechlawpartners.com

(W) COLUMBIA ENERGY PARTNERS LLC
PETER BLOOD
317 COLUMBIA ST
VANCOUVER WA 98660
pblood@columbiaenergypartners.com

(W) ENERGY TRUST OF OREGON
ELAINE PRAUSE
JOHN M VOLKMAN
421 SW OAK ST #300
PORTLAND OR 97204-1817
elaine.prause@energytrust.org
john.volkman@energytrust.org

(W) EXELON BUSINESS SERVICES COMPANY, LLC
PAUL D ACKERMAN
100 CONSTELLATION WAY STE 500C
BALTIMORE MD 21202
paul.ackerman@constellation.com

(W) EXELON WIND, LLC
JOHN HARVEY
4601 WESTOWN PARKWAY, STE 300
WEST DES MOINES IA 50266
john.harvey@exeloncorp.com

(W) LOVINGER KAUFMANN LLP
KENNETH KAUFMANN
JEFFREY S LOVINGER
825 NE MULTNOMAH STE 925
PORTLAND OR 97232-2150
kaufmann@lklaw.com
lovinger@lklaw.com

(W) NORTHWEST ENERGY SYSTEMS
DAREN ANDERSON
1800 NE 8TH ST., STE 320
BELLEVUE WA 98004-1600
da@thenescogroup.com

(W) RENEWABLE ENERGY COALITION
JOHN LOWE
12050 SW TREMONT ST
PORTLAND OR 97225-5430
jravenesanmarcos@yahoo.com

(W) ROUSH HYDRO INC.
TONI ROUSH
366 E WATER
STAYTON OR 97383
tmroush@wvi.com

(W) SMALL BUSINESS UTILITY ADVOCATES
JAMES BIRKELUND
548 MARKET ST STE 11200
SAN FRANCISCO CA 94104
james@utilityadvocates.org

(W) STOLL BERNE
DAVID A LOKTING
209 SW OAK STREET, SUITE 500
PORTLAND OR 97204
dlokting@stollberne.com

(W) DAVISON VAN CLEVE PC
MELINDA J DAVISON
BRADLEY VAN CLEVE
IRION A SANGER
333 SW TAYLOR, SUITE 400
PORTLAND OR 97204
mjd@dvclaw.com
bvc@dvclaw.com
ias@dvclaw.com
mail@dvclaw.com

(W) CITIZENS' UTILITY BOARD OF OREGON
ROBERT JENKS
G. CATRIONA MCCRACKEN
610 SW BROADWAY, STE 400
PORTLAND OR 97205
dockets@oregoncub.org
bob@oregoncub.org
catriona@oregoncub.org