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March 18, 2013

Via Electronic Filing and U.S. Mail

Public Utility Commission of Oregon
Attention: Filing Center
PO Box 2148
Salem, OR 97308-2148

Re: INVESTIGATION INTO QUALIFYING FACILITY CONTRACTING AND PRICING
OPUC Docket No. UM 1610

Attention Filing Center:

Enclosed for filing in the above-captioned docket are an original and five copies of the *Direct Testimony and Exhibits of Bill Eddie on behalf of OneEnergy, Inc.*

An extra copy of this cover letter is enclosed. Please date stamp the extra copy and return it to me in the envelope provided.

Thank you in advance for your assistance.

Sincerely,

Ken Kaufmann

Ken Kaufmann

cc: UM 1610 Service List

Enclosures

Docket No. UM 1610
Exhibit OneEnergy/100
Witness: Bill Eddie

BEFORE THE PUBLIC UTILITY COMMISSION
OF THE STATE OF OREGON

ONEENERGY, INC.

Direct Testimony of Bill Eddie

March 18, 2013

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I. About the Witness

Q. Please briefly introduce yourself and OneEnergy.

A. My name is Bill Eddie. I am President and one of the founders of OneEnergy, Inc. OneEnergy is a Washington corporation with headquarters in Seattle and an office in Portland. We develop renewable energy projects, and plan to develop solar photovoltaic projects under 5 MW in Oregon. We also provide renewable energy credits ("RECs") to customers around the country, including numerous investor-owned and public utilities in the West.

Q. What is your background?

A. I am involved in all business activities at OneEnergy. I directly handle our REC trading business. In our project development business, I am primarily involved in power and REC sales. Prior to OneEnergy, I was the Director of Origination and Procurement at Bonneville Environmental Foundation ("BEF") from mid-2007 to early 2010. In that role, I managed the wholesale side of BEF's REC and carbon offset business. Earlier in my career, I practiced environmental and energy law. I represented environmental groups, clean energy advocates, and private developers in a wide array of proceedings, including numerous cases before the Idaho Public Utilities Commission. I represented NW Energy Coalition in cases involving ratemaking and demand side management. I represented Renewable Northwest Project (a party to this case) in cases involving net metering and PURPA qualifying facility contracts. Idaho Power Company invited me to serve on the company's Integrated Resource Plan Advisory Council for the 2004 and 2006 Integrated

Resource Plan ("IRP") cycles, which I did as a representative of the environmental community.

Q. What is OneEnergy's experience with PURPA qualifying facilities in the Northwest?

A. We have been involved with numerous projects in a variety of roles. Threemile Canyon Farms retained OneEnergy to help develop the new 4.8 megawatt dairy digester located at Threemile's dairy facilities near Boardman. For this project, we principally managed interconnection and power sales matters with PacifiCorp. We also handled incentives applications and some permitting matters for the project. That project declared commercial operations in December 2012. We handled the environmental credit marketing for the Roseburg Landfill Gas project in Douglas County (a 1.6 MW project), and had a minor role in that project's financing.

OneEnergy purchases renewable energy credits from the PaTu Wind Farm near Wasco, Oregon, and the Finley Bioenergy project near Boardman, Oregon. In Idaho, we purchase RECs from the "Double A" Dairy digester, and from numerous Idaho wind projects. Because we have a financial relationship with these projects as a REC purchaser, we have become intimately aware of the factors that influence their success.

Q. Why is OneEnergy involved in this proceeding?

A. OneEnergy intends to develop solar photovoltaic projects in Oregon. We believe this case directly impacts our business interests in this state.

II. Summary and Policy Position

Q. Can you please summarize your testimony?

A. Yes. Overall, Oregon's QF framework adopted in UM 1129 has worked quite well to foster the development of new, small scale non-utility owned renewable energy projects under 10 MW in size. These projects include diverse resources such as methane digester projects, landfill gas-to-energy projects, small hydropower facilities, as well as family owned wind projects. A partial listing of projects utilizing the standard contract process in Oregon would include: Threemile Canyon Farms digester, Stahlbush Island Farms digester, Finley Bioenergy landfill gas project, Dry Creek landfill gas project, Roseburg landfill gas project, Juniper Ridge hydroelectric project, PaTu wind farm, and Lime wind farm.

The utility proposals to substantially reduce the size threshold for standard contract eligibility, and reduce contract length, would effectively prevent projects from going forward. Given the near absence of unintended consequences of the Commission's 10 MW standard avoided cost rate contracts, I believe the Commission should adopt only narrow policy changes intended to foster the development of distributed renewable energy projects, while preventing unintended consequences. The changes I recommend to the standard contract for QFs would better recognize the benefits of distributed generation and foster its development.

Q. Is that all you plan to testify about?

A. No. I will also describe and recommend the following minor modifications to how avoided costs are calculated and updated: The renewable avoided cost and the CCCT-based avoided cost methodologies should be updated by including capacity deferral benefits as permitted by 18 CFR §292.304(e)(2)(vii). The renewable avoided cost methodology should include costs associated with new transmission necessitated by construction of the IRP renewable resource. The gas-based avoided cost methodology should be updated to include the cost of gas supply infrastructure expansions and electricity transmission expansions necessary to fully utilize the proxy resource. Regarding solar integration, we oppose imposition of a solar integration charge until the costs have been studied and subjected to public scrutiny. With respect to regular updates to avoided costs, we propose an unbiased structure that takes into account easily measured factors that significantly impact the calculated rates.

Q. From your perspective, what are the key policies the Commission should consider in this case?

A. UM 1610 is an important opportunity for the Commission to reduce barriers that hamper development of small, distributed generation. By distributed generation ("DG") I mean projects that connect at distribution voltage and are sized to primarily serve load on the substation or distribution circuit to which the project connects. Minor changes to Oregon's PURPA framework adopted in UM 1129 would significantly aid the development of DG.

DG has unique benefits compared to other forms of generation but a variety of factors hinder its development.[1] DG has lower associated system (line and transformation) losses than larger projects. DG requires less new investment for

[1] See OPUC Staff, *Distributed Generation in Oregon: Overview, Regulatory Barriers and Recommendations*, presented at the Commission's February 25, 2005, public meeting (http://www.oregon.gov/puc/electric_gas/dg_report.pdf).

transmission and distribution (T&D) than do larger projects interconnected at transmission voltages. And DG reduces certain risks to system reliability, both because it can be dispersed throughout the system and because it can be developed in small increments with short lead times. In addition, DG resources add to the diversity of our energy supply mix.

In recognition of these and other benefits, the Commission has in the past urged the utilitiies to aggressively pursue development of distributed generation[2], and the utilities have pledged their cooperation.[3] The Commission and other state agencies also have a mandate, under Section 24 of SB 838, to implement policies and procedures promoting that statute's goal of serving at least 8% of Oregon's retail electric load from small-scale renewable energy projects of 20 MW capacity or less.[4]

Now is an opportune time to move forward on this shared goal of encouraging distributed generation development while Oregon's investor owned utility customers can benefit from federal tax incentives. The federal business energy investment tax credit offers a federal tax credit of 30% for many small renewable qualifying facilities, including solar photovoltaics. This important federal incentive (with respect to solar PV) is scheduled to shrink to 10% in 2017. Thus, there is a roughly four-year window of relative stability in the federal incentive for solar PV.

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[2] *See In the matter of PacifiCorp 2008 Integrated Resource Plan*, OPUC Docket No. LC 47, Order No. 10-066, 25 (2010) ("We continue to encourage the Company to pursue all types of distributed generation resources and account for all potential benefits.").

[3] *See* PacifiCorp 2011 Integrated Resource Plan, p. 274 ("PacifCorp 2011 IRP") ("PacifiCorp will continue to participate with regulators and advocates in legislative and other regulatory activities that help provide tax or other incentives to renewable and distributed generation resources,").

[4] ORS 469A.210 (2012).

DG projects typically cost more to construct (on a dollars-per-kW basis) than larger projects using the same type of equipment, due mainly to higher fixed overhead costs and less economies of scale for equipment procurement. In order for DG to be attractive to develop compared to larger capacity alternatives, its unique benefits must be given an economic value. The Commission's current PURPA standard cost framework does not account for the unique values of DG and, unless such values are recognized, an opportunity to capture cost effective renewable DG resources will be missed.

Q. Please summarize your recommendations with respect to DG.

A. OneEnergy urges the Commission, in this proceeding, to recognize the unique values and regulatory challenges faced by DG and to address this issue with respect to distributed generation QFs 3 megawatts and smaller that are directly interconnected to the purchasing utility's distribution system. Three changes to the standard contract are warranted for DG, and will make DG financeable to a similar degree as larger QFs. First, the standard avoided cost rate should be adjusted (increased) to account for avoided system losses. Second, DG QFs should have the option to elect fixed prices for up to a 25-year term. And third, DG QFs should have the option to select a levelized pricing structure.

With these changes, Oregon is likely to capture a significant amount of renewable DG that otherwise would not be developed.

Q. Have you prepared an exhibit that summarizes OneEnergy's proposals in the same format as the Issues List in the Commission's December 21, 2012 Order?

A. Yes. Please refer to Exhibit OneEnergy/116 for a comprehensive list of OneEnergy's positions in the Issues List format.

III. Global Issues (applicable to all projects utilizing the standard contract system)

Q. Should the Commission change the 10 MW cap for the standard contract? [Issues List 5(A)]

A. OneEnergy is not recommending a change to the existing 10 MW eligibility cap. However OneEnergy recommends that DG QFs (those smaller than 3 MW and connecting at distribution voltage to the purchasing utility) be paid for avoided system losses, and receive two other simple options in the standard contract. I explain these options in Section VI.

Q. Does OneEnergy agree that disaggregation is an important issue to address in this investigation? [Issues List 5(B)]

A. Yes. Disaggregation of a large project into smaller projects for the purpose of obtaining the standard published avoided cost subverts the intent of standard rates and should be avoided.

The Dispute Resolution paragraph in the Partial Stipulation adopted in UM 1129 (and included with PacifiCorp's Direct Testimony)[5] already allows the IOU to refer a dispute with a QF regarding eligibility to the Commission for resolution – an

[5] Exhibit PAC/202, Griswold/19 (Feb. 4, 2013) ("Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to the standard rates and standard contract. Any dispute concerning a QF's entitlement to the standard rates and standard contract shall be presented to the Commission for resolution.").

important feature that safeguards standard rates from abuse. One easy way to improve the existing rule is for the utilities to utilize the dispute resolution rights they already have.

Q. What changes to the existing Partial Stipulation does OneEnergy recommend? [Issues List 5(B)]

A. OneEnergy supports PacifiCorp's proposal to allow only independent family or community-based projects to have common passive investors. (PAC/200, Griswold/25 (Feb. 4, 2013)). OneEnergy also believes that guidance from the Commission regarding what constitutes a passive investor would assist the utilities in making an initial determination. While determining ownership interests is fairly straightforward, developers and utilities may have different opinions about what constitutes a passive investor.

Q. Does OneEnergy agree with the utilities that QFs should not be allowed to share infrastructure? [Issues List 5(B)]

A. No. OneEnergy disagrees with PGE's and PacifiCorp's proposal to prohibit shared infrastructure among QFs seeking a standard contract. (PGE/100, Macfarlane-Morton/10 (Feb. 4, 2013); PAC/200, Griswold/26 (Feb. 4, 2013).) Shared infrastructure does not by itself prove disaggregation; furthermore unnecessary duplication of energy infrastructure is bad public policy because it increases overall system costs.

Q. Do you recommend any changes to how the eligibility cap is applied? [Issues List 5(C)]

A. I am aware of one area where Commission clarification would be helpful: how to calculate the nameplate capacity of PV solar QFs. In Order No. 05-584 at page 40 the Commission found that "[d]esign capacity, as defined by the manufacturer's nameplate capacity for a QF project, will continue to be the measure of eligibility for standard contracts." I assume that this means, in the case of a PV solar installation, the peak AC capacity flowing onto the IOU's system at the point of interconnection, but others might read the Commission's statement to mean the rated DC capacity of the panels. If the DC definition were used, solar PV QFs would effectively be downrated compared to other types of QFs. For example, a PV facility with 1 MW DC capacity will never generate 1 MW AC power at any time, due to inverter losses. A statement from the Commission clarifying that nameplate capacity means AC output, in the case of PV solar projects, would avoid the possibility of future disputes regarding this point.

Q. Should the resource technology affect the size of the cap for the standard contract or the criteria for determining whether a QF is a "single QF"? [Issues List 5(C)]

A. No. Allowing only independent family or community-based projects to have common passive investors and clarifying the definition of a passive investor will effectively address the perceived problems with disaggregation under the current rules. There is no reason to have discriminatory size caps for standard rates when the non-discriminatory fix I explained above will work.

Q. Can a QF receive Oregon's Renewable Avoided Cost price if the QF owner will sell the RECs in another state? [Issues List 5(D)].

A. Yes. During the sufficiency period all RECs should stay with the QF, and there is no policy basis to restrict where the QF can sell the RECs.

Q. How often should avoided costs be updated? [Issues List 3(A)]

A. I believe an annual update of all inputs to the standard and negotiated contracts is appropriate, and suggest the update occur shortly after the U.S. Energy Information Association releases each Annual Energy Outlook (typically this report is issued in April of each year). Increasing the frequency of updates will improve the accuracy of avoided costs while also providing certainty to all parties.

Q. Should QFs be credited for deferring capacity investment? [Issues List 4(C)]

A. Yes, the avoided cost should take into account the value of capacity investment deferred in accordance with 18 C.F.R. § 292.304(e)(2)(vii).

> Clause (vii) refers to the fact that the lead time associated with addition of capacity from qualifying facilities may be less than the lead time that would have been required if the purchasing utility had constructed it own generating unit. Such reduced lead time might produce savings in the utility's total power production costs, by permitting utilities to avoid the "lumpiness," and temporary excess capacity associated therewith, which normally occur when utilities bring on line large generating units. In addition, reduced lead time provides the utility with greater flexibility with which it can accommodate changes in forecasts of peak demand.[6]

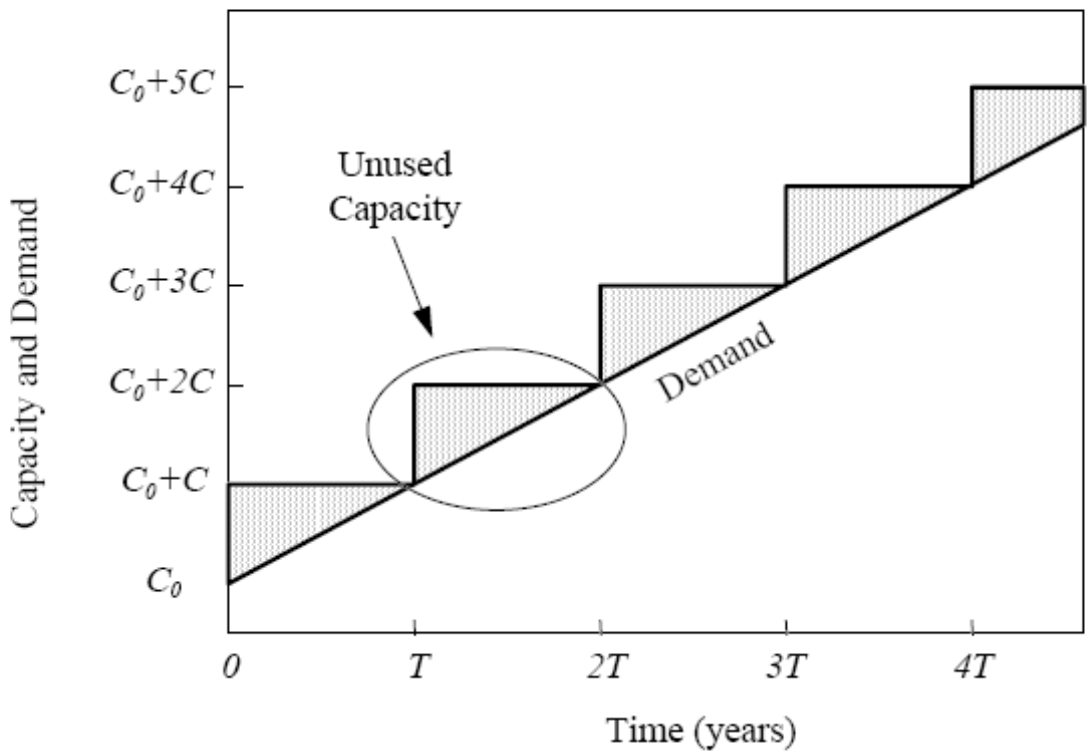
FERC rule 292.304(e)(2) requires that lumpiness be accounted for in avoided cost rates "to the extent practicable".

The United States Department of Energy, in a 2007 study of the benefits of Distributed Generation mandated by the Energy Policy Act of 2005, concluded that "there can be economic benefits related to generation investment deferral that are

[6] *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC Stats. & Regs. ¶ 30,128, 12,227 (1980), order on reh'g, Order No. 69-A, FERC Stats. & Regs. ¶ 30,160 (1980).

directly attributable to DG."[7] The figure below, excerpted from the United States DOE report, illustrates the source of savings: by adding DG in small increments to match load growth as opposed to large single additions triggered at the first need for additional capacity, periods of excess, unneeded capacity can be minimized.

Distributed Generation Can Reduce Unused Capacity[8]



[7] *The Potential Benefits of Distributed Generation and Rate-Related Issues that may Impede Their Expansion*, United States Department of Energy, p. 3-15 (February 2007) (http://www.ferc.gov/legal/fed-sta/exp-study.pdf).

[8] *Id.* at 3-16 (excerpted from Hoff, T. E., Wenger, H. J. and B. K. Farmer, 1996, "Distributed Generation: An Alternative to Electric Utility Investments in System Capacity" Energy Policy 24(2): 137-147).

Q. Has the Commission previously considered crediting QFs for deferring capacity investment? [Issues List 4(C)]

A. Yes. In UM 1129, Staff and ODOE identified "advantages to incremental capacity added by QFs, rather than lumpy capacity being added by new utility plant."[9] However, the Commission was not presented with a "definitive method" for incorporating lumpiness in UM 1129.[10] Therefore, the Commission did not require a specific adjustment, but directed parties to incorporate a lumpiness adjustment in negotiated contracts if the could establish a "practical and reasonable" way to do so.[11]

Q. Is there now a practical and reasonable way to value lumpiness? [Issues List 4(C)]

A. Yes. It appears that lumpiness benefits can be calculated using the same approach PacifiCorp used in its 2011 IRP to evaluate deferred capacity benefits of energy efficiency demand side management, or "DSM". PacifiCorp uses the term "resource deferral benefit" to describe the value, in $/MWh, of deferred capital recovery and fixed operations and maintenance ("O&M") costs. [12] "Deferred capital recovery" is the savings attributed to postponing the time when the cost of a new CCCT resource is added to the rate base. "Deferred fixed O&M" is the additional savings from the associated postponement of fixed O&M costs of a new CCCT.

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[9] *In the Matter of PUC of Oregon Staff's Investigation Related to Electric Utility Purchases from Qualifying Facilities*, OPUC Docket No. UM 1129, Order No. 05-584, 23 (2005).

[10] *In the Matter of PUC of Oregon Staff's Investigation Related to Electric Utility Purchases from Qualifying Facilities*, OPUC Docket No. UM 1129, Order No. 07-360, 22 (2007).

[11] *Id.*

[12] PacifiCorp 2011 IRP Addendum, 13 (attached as Exhibit OneEnergy/101).

Q. How does PacifiCorp calculate these resource deferral benefits? [Issues List 4(C)] [Issues List 4(C)]

A. The resource capacity deferral benefit is calculated in two steps:

1. <u>Fixed Cost Deferral Benefit Determination</u>
Fixed cost benefits are obtained by calculating the differences in annual fixed and capital recovery costs (millions of 2010 dollars) between the base portfolio and the portfolio with the Class 2 DSM program addition. The stream of annual benefits is then converted into net present value (NPV) using the 2011 IRP discount rate (7.17 percent).

2. <u>Levelized Value Calculation</u>
The fixed cost resource deferral benefit value obtained from step 1 is divided by the Class 2 DSM program energy in megawatt-hours (also converted to a NPV) to yield a value in dollars per megawatt-hour-year ($/MWH-yr).[13]

Further details of PacifiCorp's modeling approach are explained in "Chapter 2 - Class 2 DSM Decrement Study" in its 2011 IRP Addendum.[14]

Q. What value did PacifiCorp calculate for resource deferral benefits of Class 2 DSM? [Issues List 4(C)]

A. PacifiCorp used a levelized capacity resource deferral value of $16.69/MWh for all of its Class 2 (non-dispatchable energy efficiency) DSM resources.[15]

Q. Is this the same value that should apply to QFs? [Issues List 4(C)]

A. Differences in the coincident peak capacity factor between Class 2 DSM and QF generation might result in a lower value for QFs that do not tend to generate during system peak hours.

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[13] *Id*.

[14] *Id*. at 13.

[15] *Id*. at 16.

Q. How does PacifiCorp plan to act based on its Class 2 DSM benefits model? [Issues List 4(C)]

A. Based in part on its calculated resource deferral benefits, PacifiCorp plans to make Class 2 DSM a major part of its resource portfolio. Action Item 6 in its 2011 IRP Action Plan is "Acquire up to 1,200 MW of cost-effective Class 2 programs by 2020, equivalent to about 4,533 GWh. This includes programs in Oregon acquired through the Energy Trust of Oregon."[16] That action item was revised in 2012 to "Acquire at least 900 MW and up to 1,800 MW of cost-effective Class 2 programs by 2020, equivalent to at least 4,533 GWh and up to 9,066 GWh. Acquire at least 520 MW and up to 1000 MW of cost-effective Class 2 DSM by 2016."[17]

Q. Do you think PacifiCorp's Class 2 DSM Decrement Study results can be applied to QFs? [Issues List 4(C)]

A. I believe the same benefits of Class 2 DSM recognized by PacifiCorp are also provided by QFs. I do not have enough information about the parameters of the study to know whether its findings can be directly applied to QFs. Some adjustment to the study parameters may be needed. I see no reason why re-running the study with QFs would not be feasible. The types of energy efficiency modeled in the study (lighting, cooling, whole house, etc.) are likely no less complex, and may be quite analogous to, load shapes of QFs. This suggests that the System Optimizer model is capable of modeling QF output to produce values for the benefits of capacity resource deferral of clean, non-fuel resources.

[16] PacifiCorp 2011 IRP, p. 16.

[17] PacifiCorp 2011 IRP Update, p. 7 (2012).

Q. Do you have a specific recommendation regarding lumpiness? [Issues List 4(C)]

A. Yes. In 2006, the Commission declined to include resource deferral benefits in avoided costs because of the lack of a definitive method for calculating those benefits. In 2007, the U.S. DOE concluded that such benefits can be calculated. In 2011, PacifiCorp developed a definitive method and then used it to help justify investment in up to 1,800 MW of DSM by 2020. In recognition of these changes since the Commission last addressed this issue, I propose that the utilities be directed to study the capacity investment deferral benefits of wind, solar, and baseload QFs using the same model or methodology PacifiCorp used to model energy efficiency Class 2 DSM, and that resource deferral benefits be added to both the renewable avoided cost and the CCCT-based avoided cost.

Q. Do you have any other proposals regarding how the seven factors of 18 C.F.R. § 292.304(e)(2) should be taken into account? [Issues List 4(C)]

A. Yes. QFs eligible for the standard contract should have the option to volunteer to be curtailed up to 100 hours/year (with compensation), at any time upon 1-hour notice. This would give the utility the ability to dispatch the qualifying facility downward, which is a cognizable value under factor (i).

Q. Do utilities have a right to curtail a QF under the existing standard power purchase agreement? [Issues List 4(C)]

A. Generally not. Utilities cannot curtail a QF unilaterally except under very limited circumstances because PURPA requires a utility to purchase all net output from a QF. However QFs have the right to opt-in to a voluntary curtailment program.

Allowing QFs who are willing to agree to be curtailed to do so will improve flexibility in system operations and correspondingly lower system costs. Utilities could model this resource capability in the PDDRR model and determine its value.

Q. How should QFs opting-in to this option be compensated? [Issues List 4(C)]

A. This is an issue we plan to explore with the Utilities during the April 2 settlement conference. I am hopeful that we can reach a mutually beneficial settlement of this opportunity. One simple solution would have the QF be paid for the estimated lost power sales, and that would be reasonable solution for solar PV QFs. However, there may be other consequences to curtailment for some QF project types.

Q Should the avoided cost methodology be the same for all three electric utilities operating in Oregon? [Issues List 1(A)(ii)]

A. Generally, yes. However, I agree that only PGE and PacifiCorp should offer a Renewable Avoided Cost to QFs because they are subject to the full requirements of Oregon' Renewable Portfolio Standard ("RPS").

Q. Do you support PacifiCorp's proposal to use market prices from a single market hub (like PGE) rather than blended market prices to calculate standard avoided cost prices during the sufficiency period? [Issues List 1(A)(ii)]

A. No, at least not at this time. The issue of which indices PacifiCorp should use for its market index price was settled in UM 1129. If PacifiCorp were to prepare a table like the Pricing Option 1 table on page 5 of its Schedule 37, showing the annual avoided cost rates based on (a) Mid-C index only; and (b) the current blended index, and file those tables along with its supporting calculations, then perhaps we could support its proposal. As proposed, there is not enough information to evaluate the economic magnitude of the change it proposes.

Q. What is Section 24 of SB 838[18] and how does it affect this proceeding? [Issues List 1(A); 5(A)]

A. Section 24 of SB 838 (Oregon's law establishing renewable portfolio standards) declares a goal that by 2025 at least 8% of Oregon's retail electrical load be served by small-scale renewable energy projects of 20 MW capacity or less. I think it is very relevant because few proceedings directly affect the viability of small-scale renewable energy development in Oregon more than this proceeding.

Q. Are the utilities on a pace to achieve the goal set forth in Section 24? [Issues List 1(A); 5(A)]

A. Because the Commission has not implemented Section 24 through a rulemaking, there currently is no rule governing how to calculate what fraction of Oregon's retail electric load is currently served by community renewable energy. However, I analyzed renewable generators under 20 MW located in Oregon which are certified as RPS-eligible in either Oregon or California (or both). *See* Exhibit OneEnergy/102. I made conservative assumptions about the likely capacity factors for each resource type to calculate an estimated annual energy production from these projects in aggregate. Under my assumptions, Oregon as a whole currently gets about 3.5%

[18] SB 838 § 24 was codified as ORS 469A.210 and now reads: "Goal for community-based renewable energy projects. The Legislative Assembly finds that community-based renewable energy projects, including but not limited to marine renewable energy resources that are either developed in accordance with the Territorial Sea Plan adopted pursuant to ORS 196.471 or located on structures adjacent to the coastal shorelands, are an essential element of Oregon's energy future, and declares that it is the goal of the State of Oregon that by 2025 at least eight percent of Oregon's retail electrical load comes from small-scale renewable energy projects with a generating capacity of 20 megawatts or less. All agencies of the executive department as defined in ORS 174.112 shall establish policies and procedures promoting the goal declared in this section."

of its energy from projects under 20 MW. I offer this by way of example—the Commission could well determine it is more appropriate to use different assumptions.

Q. Are the utilities out of compliance with the statute? [Issues List 1(A); 5(A)]

A. No. First, I do not perceive the statute to create an RPS-type compliance requirement for the utilities. Rather, it is a statewide goal to be implemented through the state agencies' policies and procedures. Second, the 8% target is for 2025, which is still many years away. A utility that is not meeting the goal today has 12 years more to meet it. It may add (or subtract) many community-based renewable energy projects to its system before 2025.

Q. Why do you mention Section 24 in your testimony? [Issues List 1(A); 5(A)]

A. Because I believe the legislature wanted the Commission to establish policies encouraging the development of more small renewable energy projects. Qualifying facilities can provide much of that development, particularly if the Commission adopts policies and procedures in this proceeding that facilitate development of small QFs.

Q. What policies and procedures encouraging the development of small community based renewable energy projects do you recommend the Commission adopt? [Issues List 1(A); 5(A)]

A. I recommend that the Commission give careful consideration to the proposed changes in support of distributed generation 3 MW and under discussed in Section VI, below.

IV. Renewable Avoided Cost Calculation

Q. Do have recommendations for improving the accuracy of the renewable avoided cost prices? [Issues List 2(A)]

A. Yes. First, the renewable avoided cost calculation should be adjusted to reflect the cost of transmission service to the utility's Oregon service territory. PacifiCorp's proposed renewable avoided cost does not include transmission costs. Second, the renewable avoided cost should factor in the existence of the federal production tax credit ("PTC"), or changes in the value of the credit, during regular adjustments in the future.

Q. Why should the cost of transmission be included in the renewable avoided cost calculation? [Issues List 2(A)]

A. A remote wind project that has not secured transmission to a utility's territory in Oregon is simply not an avoided resource in Oregon.

Q. Why should the renewable avoided costs be adjusted to account for the changes in the PTC? [Issues List 2(A)]

A. The PTC is a valuable federal incentive for wind projects, currently equating to 2.2 cents per kilowatt-hour of production. The PTC impacts not only the price at which wind projects can sell their energy, but also whether the projects are economical to be built at all. PGE and PacifiCorp assume the PTC will exist for the proxy future wind projects used in calculating the renewable avoided cost. However, the existence of the PTC in the future is not assured. The PTC is currently set to expire at the end of 2013. In general, it would be poor planning to assume any federal tax incentive will exist indefinitely into the future. It is possible the PTC could expire, or could be changed to a different amount of tax credit, or could be replaced with an entirely different structure.

The PTC's history shows cycles of expiration and renewal. For example, the PTC was expired in 2000, 2002, and 2004, leading to precipitous drops in wind installations in those years. At times, the PTC has expired for short periods only to be renewed days or weeks later.

Q. How should an adjustment for the PTC be implemented? [Issues List 2(A)]

A. At each regular avoided cost update cycle, the renewable avoided cost should be adjusted to account for whether the PTC exists. If the PTC has been continuously expired for more than 3 months prior to the update, then the renewable avoided cost should be increased by the value of the PTC. Likewise, if the PTC's value has changed (either up or down), the renewable avoided cost should be adjusted to reflect the actual PTC value.

By requiring the PTC to be expired continuously for 3 months prior to the update, it is less likely that QFs would be able to take advantage of short-term expirations of the PTC (such as occurred this year during the ongoing federal budget disputes).

Q. Do you have any concerns about how RECs will be allocated for projects electing the renewable avoided cost prices? [Issues List 2(A)]

A. I do have one narrow concern relating to the role of the Energy Trust of Oregon. I am aware that when the Energy Trust of Oregon provides incentives to renewable projects, it normally takes ownership of all or a portion of the RECs the project will produce in the future. The Energy Trust then retires those RECs for RPS compliance on behalf of the utility purchasing the project's power.

Under the utilities' proposed renewable avoided cost structure, the project will retain its RECs during an initial period of "RPS Sufficiency" (i.e. when the utility has satisfied its RPS obligations ahead of the next step-up in obligations). After the RPS Sufficiency is over (i.e. when the utility expects to acquire its next large renewable asset for the purpose of RPS compliance), the utility will own the RECs. OneEnergy does not object to that proposed allocation of RECs under the renewable avoided cost methodology, however we are concerned about projects' ability to obtain an Energy Trust incentive agreement.

Specifically, we are concerned Energy Trust will not support a project if the project's RECs may be sold off by the utility to third parties for other RPS obligations in other states, or to voluntary buyers. We simply believe the Commission should protect the role of Energy Trust of Oregon in supporting projects that use the renewable avoided cost method.

We have raised this issue with several other parties in this docket, as well as the Energy Trust, and hope to identify a solution prior to hearings.

V. Non-Renewable (CCCT SAR) Avoided Cost Calculation

Q. Do you have recommendations for improving the accuracy of the non-renewable avoided cost prices? [Issues List 1(A)(i)]

A. Yes, I have two recommendations for updating the CCCT proxy model and one recommendation regarding an integration charge for solar QFs. I generally support the avoided cost methodologies approved by the Commission in UM 1129.

However, changed circumstances require that the CCCT proxy be updated in order to accurately reflect the utility's avoided cost of purchase from QFs. First, the CCCT proxy should be made to account for the cost of expanding firm natural gas pipeline capacity or storage capacity. A flaw of the CCCT proxy is that it assumes sufficient gas supply capacity exists. Several reports in 2012 warn that regional gas infrastructure has reached its limits and is unable to support planned gas-fired generators without expansion. The cost of a major pipeline is substantial. The avoided cost rate runs the risk of substantially underestimating the cost of CCCT proxy unless this potential cost is accounted for.

Second, the capacity component should account for the cost to transmit power from the proxy resource to the system, including any necessary transmission upgrades. Another flaw of the CCCT proxy is that it assumes sufficient transmission capacity to transmit CCCT proxy output to the system. Regional transmission has become increasingly constrained since UM 1129 such that a new CCCT would likely trigger substantial transmission upgrades in order to deliver output to Oregon. These upgrade costs should be factored into the CCCT proxy model.

Last, no integration cost should be imposed on solar QFs until solar integration has been studied and subjected to a public review process. I explain each of these three recommendations in turn below.

V(a) Natural Gas Supply Infrastructure

Q. Should avoided cost rates account for the cost of gas infrastructure needed to ensure adequate gas supply to the proxy CCCT? [Issues List 1(A)(i)]

A. Yes. It is axiomatic that a CCCT relied upon for its firm capacity must have a dependable gas supply. The Commission recently recognized this in Order No. 12-398 by requiring participants in a PGE RFP to prove access to adequate gas.[19] In the past, it may have been reasonable to assume that sufficient capacity existed to provide fuel to a new CCCT. The assumption is no longer valid. The consensus appears to be that the regional gas infrastructure cannot accommodate more gas-fired generation. As explained below, the need for new infrastructure is probable and the costs are significant. An avoided cost based on forecasted need for CCCTs should account for this. It is fair and consistent with PURPA that QFs avoiding these costs be paid rates that reflect the avoided costs.

Q. What evidence is there that future CCCTs will require major gas infrastructure upgrades? [Issues List 1(A)(i)]

A. According to independent reports released in 2012 by the Northwest Gas Association ("NGA") and the Bonneville Power Administration ("BPA"), the regional gas infrastructure cannot support forecasted new gas-fired generation. The NGA reports that "[u]nder the base and high cases, peak day demand could begin to stress the [gas] system, approaching or exceeding the region's infrastructure capacity within the forecast horizon."[20] BPA reports that "[a]ccording to the experts, the current [gas] infrastructure does not necessarily have incremental firm capacity available in certain areas to serve new generating

[19] *In the Matter of Portland General Electric Co. Request for Proposals for Capacity and Baseload Resources*, OPUC Docket No. UM 1535, Order No. 12-398, 2 (2012) (requiring for flexible capacity product RFP to demonstrate one of three specified solutions to adequate gas service).

[20] Northwest Gas Association, "2012 Gas Outlook: Natural Gas Supply, Demand, Capacity and Prices in the Pacific Northwest", p. 13, 2012 (attached as Exhibit OneEnergy/103) (http://www.pnucc.org/sites/default/files/NWGA%20Outlook%202012.pdf).

resources. Nor is the natural gas infrastructure currently adequate to satisfy the significant growth in demand that is projected to be needed to balance regional electricity loads with gas-fired peaking facilities."[21] Idaho Power's 2011 IRP projected that gas transport costs will double to reflect "the cost of adding additional pipeline capacity for delivery to Idaho Power's service area."[22] In 2011, PGE stated that it had no more gas storage available for purposes of its RFP.[23] PacifiCorp has also acknowledged that new natural gas plants may require construction of additional pipeline capacity at additional cost.[24] In short, the evidence uniformly indicates that major upgrades of gas infrastructure will be triggered by forecasted new CCCTs.

Q. Are the costs of new gas infrastructure significant enough to be worth factoring into avoided costs? [Issues List 1(A)(i)]

A. Likely, yes. Although I have no way of knowing which regional infrastructure upgrades will happen, an example provides a sense of the magnitude of upgrade costs. The Ruby Pipeline, the most recent major pipeline project in the West, brings natural gas 687 miles from Opal, Wyoming to Malin, Oregon. It was completed in 2011 at a cost of $3,712,000,000.[25] I am not aware that the utilities have a uniform way of studying and allocating these costs.

[21] Bonneville Power Administration, "The Role of Natural Gas in the Northwest's Electric Power Supply", p. 8, August 2012 (attached as Exhibit OneEnergy/102).

[22] Idaho Power 2011 Integrated Resource Plan, p. 95 (2011) ("Idaho Power 2011 IRP").

[23] *In the Matter of Portland General Electric Co. Request for Proposals for Capacity and Baseload Resources*, OPUC Docket No. UM 1535, Order No. 11-371, 4 (2011),

[24] PacifiCorp 2011 IRP, p. 277 (2011) ("In selecting a gas-fired resource, the implicit assumption is made that natural gas transportation infrastructure exists or will be built.").

[25] Ruby Pipeline LLC, "Statement of Actual Cost of Facilities Constructed", FERC Docket No. CP09-54-000 (January 30, 2012) (attached as Exhibit OneEnergy/105).

Q. If a utility needs new gas infrastructure to supply a new CCCT, who bears the cost of constructing the new capacity? [Issues List 1(A)(i)]

A. Gas customers (i.e., the CCCT owner) needing new service generally bear the cost to expand natural gas facilities needed to provide new service. According to a 2011 NERC report:

> In general, pipelines also react to load growth. FERC will generally not authorize new pipeline capacity unless customers have already committed to it (Firm delivery contracts), and pipelines are prohibited from charging the cost of new capacity to their existing customer base.[26]

The costs of constructing new wholesale natural gas pipelines are not socialized among system users but rather are assigned directly to the subscribers.[27]

Q. How do gas customers pay the costs of new gas infrastructure when they are responsible for the costs? [Issues List 1(A)(i)]

A. One form of arrangement is for the utility to enter into a long-term gas service contract in which the utility's service payment reimburses the pipeline company for construction costs.[28] Thus, the utility requiring the upgrade would be responsible for the incremental cost of that upgrade.

For example, PGE's planned Carty CCCT and PacifiCorp's Lake Side 2 CCCT have incurred or will incur expensive gas infrastructure costs triggered by

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[26] North American Electric Reliability Corp., "2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States", p. 83, December 2011 (excerpt attached as Exhibit OneEnergy/106; full report available at http://www.nerc.com/files/Gas_Electric_Interdependencies_Phase_I.pdf).

[27] *Id*.

[28] Bridges, Allison, VP and General Manager, Williams Northwest Pipeline, proceedings of Plugging into Natural Gas, Portland, Oregon January 25, 2012. p. 10 (attached as Exhibit OneEnergy/107).

the location of the CCCT. The 24-mile pipeline whose sole purpose is to serve the Carty CCCT is projected to cost $54,300,000.[29] PacifiCorp's Lake Side 2 triggered a projected $33,400,000 in gas infrastructure upgrades, $24,500,000 of which the pipeline company attributes solely to the new CCCT.[30] Major costs of the Lake Side 2 upgrade include a new compressor package and replacement of 0.9 miles of pipeline. According to the public filings, cited above, PGE and PacifiCorp have or will enter into long-term delivery contracts with the pipeline company in exchange for the upgrades.[31]

This is not to say other potential payment arrangements do not exist. However, given the evidence, utilities should have the burden of demonstrating they will not bear incremental costs of new infrastructure.

Q. Do the utilities' avoided cost rate methodologies account for the cost of new gas infrastructure that NWGA and BPA and others predict will be needed? [Issues List 1(A)(i)]

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[29] Gas Transmission Northwest LLC, "Abbreviated Application for Certificate of Public Convenience and Necessity", FERC Docket No. CP12-494-000, 1-4 (July 31, 2012) (attached as Exhibit OneEnergy/108).

[30] Questar Pipeline Co., "Abbreviated Application of Questar Pipeline Company to Modify Existing Pipeline Facilities", FERC Docket No. CP12-524-000, 3-4 (September 1, 2012) (estimated project cost of $19.7 million) (attached as Exhibit OneEnergy/109); *In the Matter of the Application of Questar Gas Company to Provide Natural Gas Transportation Service to the Lake Side Power Plant Facility*, Utah PSC Docket No. 12-057-04, unnumbered Order, 2-3 (June 20, 2012) (estimated project cost of $13.7 million, $4.8 million of which due solely to Lake Side expansion) (attached as Exhibit OneEnergy/110).

[31] Lake Side 2: Questar Pipeline Co., "Abbreviated Application of Questar Pipeline Company to Modify Existing Pipeline Facilities", FERC Docket No. CP12-524-000, 12 (noting PacifiCorp signed a precedent agreement for firm transportation service with a 30-year term) (OneEnergy/109); Utah PSC Docket No. 12-057-04, unnumbered Order, 1 (noting PacifiCorp entered into an agreement for firm transportation for a confidential period of years) (OneEnergy/110).

[31] Carty: Gas Transmission Northwest LLC, "Abbreviated Application for Certificate of Public Convenience and Necessity", FERC Docket No. CP12-494-000, 3-4 (noting PGE entered into a precedent agreement with a 30-year term) (OneEnergy/108).

A. I have reviewed the avoided cost work papers provided by the three utilities and found no clear indication that the costs of new gas infrastructure are accounted for in the avoided cost methodologies.

PacifiCorp, bases its avoided cost on a blend of a west side CCCT and SCCT described in its 2011 IRP.[32] Gas transportation is an itemized cost in IRP Table 6.4, and Table 9 of PacifiCorp's avoided cost worksheet lists the "Burner tip West Side Gas Fuel Cost".[33] However, the IRP bases gas transport rates on current existing tariff rates and explicitly admits that it assumes sufficient capacity exists:

> The result of this is that <u>the 2011 IRP assumes that the economics of a new natural gas fired generator reflect the current cost of service for existing natural gas transportation facilities</u>; whereas, the cost of any new natural gas transportation capacity is dependent on the volumetric size of the new capacity, and prevailing costs of construction, maintenance, and operations (e.g. steel, labor, financing).[34]

This assumption that sufficient gas capacity will exist is not valid given the NWGA and BPA reports in 2012. The assumption is not predictive of PacifiCorp's true avoided cost to construct and operate the CCCT proxy.

Idaho Power says the need for new infrastructure will double gas transport costs. Idaho Power's work papers provided in response to CREA DR 2.7 include a "East-Side Delivery" cost. OneEnergy intends to clarify with Idaho Power

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[32] *See* Appendix 2 to PacifiCorp's avoided cost worksheet provided in response to REC Data Request 2.28 (attached as Exhibit OneEnergy/111).

[33] *See* Appendix 1 to PacifiCorp Response to REC Data Request 2.28 (attached as Exhibit OneEnergy/112).

[34] PacifiCorp 2011 IRP, p. 277.

whether the projected doubling in gas transport costs are reflected in Idaho Power's avoided cost methodology.

PGE appears to use its system-average gas transportation rate in its avoided cost rate methodology, which in effect dilutes the actual cost of expanding gas infrastructure. According to PGE's 2012 update to its IRP, since its 2009 it has expanded its transport capacity.[35] The expansion increased PGE's fixed gas transportation cost from $0.38 per dekatherm/day on NW Pipeline (NWP) and $0.43 per dekatherm/day on Gas Transmission Northwest (GTN) to $0.41 and $0.46 respectively.[36] Presumably the gas transport rates used by PGE in its avoided cost rate worksheet are based on these IRP numbers, although they do not match exactly. (The worksheet uses $0.380 dekatherm/day on NWP and $0.468 dekatherm/day on GTN.[37])

Q. What is wrong with PGE's analysis on gas transportation costs?

A. PGE's system-average gas transportation rate does not accurately reflect PGE's avoided cost for the CCCT proxy because it dilutes the cost of new gas infrastructure with pre-existing transportation rights acquired when pipeline and storage capacity may have been plentiful. The true avoided cost is the marginal cost of the next increment of gas transportation required for a planned CCCT, including any new infrastructure needed. At a time when the next increment of gas transportation may be significantly more expensive, it is important to get this price right.

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[35] PGE 2012 Update to PGE 2009 Integrated Resource Plan , p, 24 ("2012 Update to PGE 2009 IRP").

[36] *Id.*; PGE 2009 IRP, 79.

[37] PGE response to Data Requet No. 003 from CREA, Attachment A, worksheet "O&M- Fuel Trans." (attached as Exhibit OneEnergy/113).

The lack of uniformity in the utility's methods for quantifying gas transport costs, and the lack of consideration for the regional constraints identified by the NWGA and BPA, strongly suggest that the avoided cost rates proposed by the utilities fail to account for the future costs of obtaining adequate delivery for a CCCT.

Q. Do you advocate for a particular type of gas transport or storage capacity for a CCCTs? [Issues List 1(A)(i)]

A. No. A number of adequate supply solutions may exist for any given CCCT, including a combination of transport service and storage. The Commission recognized this in PGE's recent RFP when it adopted the independent evaluator's recommendation of three solutions for RFP participants to demonstrate adequate gas supply for a flexible capacity product.[38]

Q. How do you recommend addressing potential costs of new gas infrastructure for purposes of avoided cost rates? [Issues List 1(A)(i)]

A. I recommend that the Commission direct the utilities to study the potential costs and propose an adjustment with supporting documentation. Utilities' studies should justify assumptions regarding the availability of sufficient pipeline capacity and/or storage in the future in light of the NWGA and BPA reports. The utilities' proposals should account for the potential of other gas users acquiring remaining capacity in the regional system before the utilities have need. The proposals should identify the marginal cost of firm gas transport service to the CCCT proxy (including major regional infrastructure, storage capacity, and the lateral directly

[38] OPUC Order No. 12-398, 2.

servicing the proxy), not the utility's system-average gas transport cost. The proposals should clearly identify which costs are capital costs paid during construction and which become fixed gas transport costs.

Given the current strain on regional infrastructure and the magnitude of the expense of new gas infrastructure, it is time to revisit the assumptions made in UM 1129 regarding gas supply. Without these measure, we run the risk of an avoided cost that grossly underestimates the cost of a new CCCT.

Q. Are there other reasons why firm rights to natural gas should be considered? [Issues List 1(A)(i)]

A. Increased regional dependency of natural gas has serious implications for electricity reliability. The region experienced a gas constraint brought on by a cold snap in December 2009.[39] The low temperatures simultaneously drove demand up and caused a series of failures in gas transport infrastructure. Gas-fired generators with firm capacity remained online, but Puget Sound Energy switched all of its gas-fired generators with alternate-fuel capability to oil. NW Natural lost service to 329 gas customers.

Texas's gas shortage in February 2011 had more serious consequences.[40] Again, cold weather caused outages at several generators during a four-day period. At the peak of rolling blackouts, 1.3 million customers were out of service. The gas shortage was exacerbated by loss of electricity to pumping units and compressors.

[39] Bonneville Power Administration, "The Role of Natural Gas in the Northwest's Electric Power Supply", p. 10-11, (OneEnergy/104).

[40] *Id*. at 11-12

New England is perhaps the U.S. region most reliant on natural gas. A New York Times article entitled "In New England, a Natural Gas Trap" reported that "a vulnerability heightened by a shortage of natural gas pipeline capacity" caused electricity prices to be four to eight times higher than normal for extended periods during cold weather.[41] ISO New England vice-president and chief operating officer Vamsi Chadalvada warned that pipeline capacity is inadequate to keep prices steady.[42] ISO New England considers reliability to be intertwined with price stability.

V(b) Cost of Electricity Transmission System Upgrades

Q. Do you think the CCCT proxy continues to adequately address the cost of building transmission to bring its output to the system? [Issues List 1(A)(i)]

A. No. Currently, the system upgrades necessary to bring the CCCT proxy output onto the system are not accounted for in the current avoided cost methodology. It may have been reasonable to ignore these costs during UM 1129, but the regional transmission system is increasingly congested. The Commission recognized the necessity of accounting for the cost of transmission to bring output to load in PGE's recent RFP. The Commission agreed that if PGE needed to build a transmission line to bring the capacity from its benchmark resource to its

[41] "In New England, a Natural Gas Trap", New York Times (February 15, 2013) (The article quotes a natural gas energy consultant as saying, "[w]e are sticking a lot of straws into this soft drink.") (attached as Exhibit OneEnergy/114).

[42] *Id*.

system, the costs should be properly allocated.[43] QFs should be on a level playing field with the CCCT proxy.

Q. Do QFs currently pay for system upgrades needed to bring their output to the system? [Issues List 1(A)(i)]

A. Yes. Costs of system upgrades necessitated by a QF are directly assigned to the QF during the interconnection process under OAR 860-082-0035(4). Because QFs bear the costs of bringing their output to the utility's load, they should be compared to a CCCT proxy that include the cost of bringing the proxy's output to the utility's load.

V(c) No Solar Integration until Studied

Q. Should the standard CCCT-based avoided cost rates be adjusted by a solar integration charge? [Issues List 4(A)]

A. Not until a solar integration charge has been studied by the utilities and subjected to public scrutiny. I note that none of the utilities proposed a specific solar integration charge for standard rates in their testimony. By contrast, wind integration charges have been subjected to extensive study and public scrutiny through the IRP process and through the utilities' testimony in this proceeding.

Q. Can a solar integration charge be approximated from a wind integration charge? [Issues List 4(A)]

A. No. Wind integration costs are not a good indication of solar integration costs. For starters, solar generation only occurs during daytime hours; nighttime

[43] OPUC Order No. 11-371, 5-6 (2011); *but see* OPUC Order No. 12-215, 2-3 (2012) (directing that the cost of the transmission line need not be included because PGE said it did not need the line and would use BPA transmission).

production is always zero. In short hand, an integration charge should value the utility's cost of integrating an unpredicted change in generation output. There can be no integration cost of solar during nighttime hours, since it is a perfectly predictable resource. Furthermore solar generation, unlike wind, has a strong positive correlation with summer loads. I would anticipate this clear difference in generation profile between wind and solar would lead to significantly lower integration costs for solar as compared to wind. In any event, we simply do not have adequate information to set a solar integration charge until it has been studied in Oregon and subjected to public scrutiny. Especially when the aggregate amount of solar production on utility systems in Oregon is so tiny, it is inappropriate to impose an integration charge at this time.[44] I recommend the Commission direct the utilities to study solar integration costs during the next IRP cycle, just as wind integration costs have been studied.

VI. Proposed Changes for Small Distributed Generation

Q. What changes do you propose to aid small distributed generation QFs? [Issues List 4(C)]

A. OneEnergy urges the Commission to recognize the unique values and regulatory challenges faced by DG and to address this issue with respect to distributed generation QFs 3 MW and smaller that are directly interconnected to the purchasing utility's distribution system. Three changes to the standard contract are warranted for DG, and will make DG financeable to a similar degree as larger

[44] PacifiCorp and PGE testified in May 2012 that "[a]t this time there is a small amount of solar capacity in the Joint Utilities resource mixes and a solar integration study seems premature given the considerable time and resources that would be required to complete such a study." Joint Testimony/100, Brown-Macfarlane/4, OPUC Docket No. 1559 (May 10, 2012).

QFs: First, the standard avoided cost rate should be adjusted (increased) to account for avoided system losses. Second, DG QFs should have the option to elect fixed prices for up to a 25-year term. And third, DG QFs should have the option to select a levelized price schedule. These changes should apply whether the QF elects the renewable- or CCCT-based avoided cost.

Q. Why provide these changes only for projects under 3 MW? [Issues List 4(C)]

A. Three megawatts is a reasonable size estimate for projects that primarily serve local load, and therefore prevent system losses (especially transmission losses). In my experience, most substations have peak loads larger than 3 MW. So long as the substation serving the circuit where the DG QF is interconnected has load in excess of the DG QF output, the DG QF output will serve local load. While there likely will be instances where DG QF output will exceed local loads during certain times, such instances are likely to be uncommon compared to the fraction of time DG QF output is serving local load only.

There are other regulatory examples where 3 MW is used as a threshold to identify small projects. The standard QF contract system in Oregon has less onerous credit requirements for projects 3 MW and under. The Oregon interconnection rules identify 3 MW projects as a threshold for projects that may not need to pay for data acquisition and telemetry equipment. OAR 860-082-0070(3). Also, California recently adopted a standard contract system for QFs under 3 MW, using a renewable avoided cost methodology (*see* California PUC decision D.12-05-035).

Q. What is the first term you propose to add for DG QFs seeking a standard contract? [Issues List 4(C)]

A. First, I propose that the standard published avoided cost (renewable or gas) be increased by 3.9% for DG QFs to account for average avoided transmission system losses compared to non-DG QFs.

Q. Why is this adjustment warranted? [Issues List 4(C)]

A. This adjustment better represents the IOU's avoided cost for DG QF energy than does the existing methodology because, as a general rule, generation from a DG QF (e.g. under 3 MW generator interconnected to the distribution system) serves local load and, therefore, does not incur losses on the transmission system. Since DG QF losses are lower than QFs whose net output generally flows across the transmission grid, the rate for DG QFs should be adjusted upward.

Q. How did you arrive at 3.9%? [Issues List 4(C)]

A. That figure is a conservative estimate of that portion of the utilities' total avoided system losses attributable to transmission losses (as opposed to distribution losses). Generation by DG QFs clearly avoids transmission system losses. While many DG QFs will also result in avoided distribution system losses, these will vary based on the specific location of the QF on the utility's system. In Docket No. UM 1559, PacifiCorp, PGE, and Idaho Power recently estimated their average avoided system losses associated with rooftop solar PV to be 9.18 percent, 6.14 percent, and 10.9 percent, respectively. (Joint-Testimony/102, Brown-Macfarlane/3; Joint-Testimony/101, Brown-Macfarlane/1; Idaho Power/200, Allphin/5, Docket No. UM 1559 (May 10, 2012)). In a recent filing with Washington's Utilities and

Transportation Commission, PacifiCorp reported a similar rate of line losses (9%) associated with the installation of energy efficiency measures identified in the IRP. In that report, PacifiCorp attributed 3.9% to transmission losses, with the balance attributable to distribution losses.[45] In other words, from its two recent filings it appears that PacifiCorp has embraced 3.9% as the assumed average avoided transmission system losses attributable to small scale PV solar and DSM. In Docket No. UM 1559, the parties reached consensus on using average losses as a reasonable compromise. (Order No. 12-396 at 5). Until a better number is calculated by the utilities and applied uniformly when evaluating resources, I think 3.9% is an acceptable value for use with the standard avoided cost for DG QFs. This number should be applied to all utilities, unless PGE and Idaho Power justify using a more accurate number for their respective systems. Alternatively, if the utilities have the existing capability to calculate these values and are willing to do so (at no or nominal cost to the QF) then the losses could be modeled on a project specific basis.

Q. Would adding 3.9% to contract price for DG QFs effectively value all of DG's benefits? [Issues List 4(C)]

A. No. 3.9% is a conservative, well-supported estimate of only one benefit (avoided transmission losses) provided by DG QFs. As noted above, DG QFs also are likely to reduce distribution system losses, which are not accounted for in the 3.9% figure. DG QFs add to the diversity of our energy resources (both locational diversity and fuel-type diversity), and therefore lower risks for ratepayers. This diversity benefit is

[45] *PacifiCorp's Ten-Year Conservation Potential and 2012-2013 Biennial Conservation Target for its Washington Service Area*, pp. A3-6, A3-9 (attached as Exhibit OneEnergy/115).

not accounted for in the 3.9% figure. DG QFs can also provide voltage support on distribution lines, and potentially avoid transmission and distribution investments. Again, these benefits are not captured in the 3.9% figure. For these reasons, DG QFs arguably should be paid still more for their power, but I acknowledge the other listed benefits are case-by-case and harder to measure.

Q. What is the second option you propose to add for DG QFs seeking a standard contract? [Issues List 6(I)]

A. I propose that DG QFs be allowed to sign fixed-price contracts up to twenty-five years in length.

Q. Why? [Issues List 6(I)]

A. Because I believe that, without the BETC or other comparable program, and without a more robust green tags market, DG QFs will not be financeable based on a 15-year fixed avoided cost standard contract in the near future. Since Oregon's BETC program has been eliminated, and the market value of RECs has dropped to under $3/MWh for near-term vintages (and to around $1/MWh for spot transactions), I do not believe it is possible for my company to obtain project financing for DG projects based on the current avoided cost prices and contract length.

Q. Why is contract length important for renewable energy investors? [Issues List 6(I)]

A. In general, renewable energy project investors seek "bond-like" returns on their investments. They seek low risk, long periods of revenue certainty, and returns that are commensurate with that investment profile. On a sliding scale, investors will tend to accept slower and lower returns on their investment if the project has longer terms of contracted revenues. This is particularly true for solar PV, which has very long product warrantees (for example, 25 years is a typical warranty length for solar panels), and few other operational risks. Based on my experience in the renewable energy business, I believe that a power purchase agreement with a fixed price for 25 years is significantly more financeable than one with 15 years of fixed prices.

In Docket No. UM 1129, the Commission found that contract length should be the term minimally necessary to ensure that most QF projects can be financed.[46] The term of contract minimally necessary to finance a project typically will be longer for DG QFs than for larger QFs, therefore giving DG QFs the option of a longer term is consistent with the Commission's finding in UM 1129.

Q. Does extending the contract term for DG QFs increase risk that the customer will overpay? [Issues List 6(I)]

A. I don't think so. There is a greater likelihood that the contract rate will be different from the market price in the outer years of a fixed price contract. However no one knows if the contract price will be higher or lower than the future market price.

Q. Does extending the contract term for DG QFs increase the risk that the QF will default? [Issues List 6(I)]

A. No. More than ever before, DG QFs are comprised of mature technology, which is likely to perform well over a longer term. For example, most PV panel manufacturers now offer warranties of up to 25 years. Because most DG QFs are unfueled, they are immune from the risk of rising fuel costs. Finally, DG QFs are

[46] Order No. 05-584, 19.

unlikely to incur regulatory costs, such as a carbon tax, that would threaten their ability to fulfill a long-term sales obligation.

Q. Is a 25-year term typical of other resources procured by the utilities? [Issues List 6(I)]

A. Yes. Last August, PGE signed a 25-year power purchase agreement with the 5 MW "Outback" solar PV facility.[47] Idaho Power recently signed an Idaho 25-year power purchase agreement with Interconnect Solar, a 20 MW QF.[48] In its 2011 IRP, PacifiCorp assumes a service life of 30 years for rooftop solar (p. 122), 25 years for wind (p. 115), and 40 years for a combined cycle combustion turbine (p. 115).

Q. What is the third option you propose to add for DG QFs seeking a standard contract? [Issues List 1(B)]

A. I propose that the Commission permit DG QFs to elect levelized pricing for the term of their standard contract. Levelized prices would be of great assistance to DG QFs, since cash flows will be stronger in early years.

Q. What conditions would you place on a DG's ability to elect this option? [Issues List 1(B)]

A. I believe that a DG QF electing levelized prices should be required to have warranties for its primary energy conversion equipment (e.g., the solar panels) equal to or greater than the length of levelization. Its site lease (if applicable) should match or exceed the term of the power purchase agreement. The DG QF

[47] "*Smart Energy Capital, BELECTRIC and Obsidian Finance Partner to Build Northwest's Largest Solar Power Plant -- 5.7 MW renewable energy plant expected to be complete October 2012; output to serve customers of Portland General Electric under 25-year contract*"; Bloomberg Business Wire (September 21, 2012) (http://www.bloomberg.com/article/2012-09-21/as4wB_FjBDCM.html).

[48] *In the Matter of the Application of Idaho Power Co. for Firm Energy Sales Agreement with Interconnect Solar Dev. LLC*, Idaho PUC Case No. IPC-E-11-10, Order No. 32384, 1 (2011).

also should meet the currently existing insurance and creditworthiness requirements in the standard contract (for QFs under 3 MW).

Q. Should the DG QF post security if using your proposed levelized pricing structure? [Issues List 1(B)]

A. No. While this may be a reasonable requirement of larger generators, it would be a burden on DG QFs without a commensurate benefit to IOU's customers. I am aware that there have been instances in the past of QFs receiving levelized payments defaulting before the end of the contract and leaving the utility with uncollectable damages. However the amount of such losses, when limited to QFs 3 MW and smaller with insurance, equipment warranties, and no fuel risk is in line with many other risks a utility passes on to its customers. I understand that DSM measures financed by utilities sometimes do not produce their expected benefits due to actions by the load owner. To my knowledge, the utilities have never required that DSM participants post security as a condition of their participation in a program, even though it is assumed that some will default and will be unable to pay any resulting damages to the utility.

Q. How should your recommended options for 3 MW DG be implemented? [Issues List 1(B)]

A. Each of the options, above, can be implemented as a simple "check the box" option in the standard power purchase agreement. PacifiCorp already uses this approach, in Section 10 of its standard (Schedule 37) power purchase agreement. Section 10 allows the QF to elect which type of security it will post. QFs under 3 MW that meet the creditworthiness requirements can elect not to post any security. QFs over 3

MW and QFs under 3 MW that do not meet the creditworthiness requirements must elect to post some form of security. In this fashion, one standard contract accommodates the different needs of QFs over and under 3 MW. The options I propose, above, could be implemented in a similar fashion.

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(correlates to list in December 21, 2012 Order)

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Direct Testimony of Bill Eddie

Excerpts From PacifiCorp 2011 IRP Addendum

CHAPTER 2 – CLASS 2 DSM DECREMENT STUDY

This section presents the methodology and results of the energy efficiency (Class 2 demand-side management) decrement study. For this analysis, the 2011 IRP preferred portfolio was used to calculate the decrement value ("avoided cost") of various types of Class 2 DSM resources. PacifiCorp will use these decrement values when evaluating the cost-effectiveness of current programs and potential new programs between IRP cycles.

The Class 2 DSM decrement study was enhanced for the 2011 IRP. To align with the resource costs applied for resource portfolio development using the System Optimizer capacity expansion model, cost credits were applied to the Class 2 DSM decrement values reflecting (1) a transmission and distribution (T&D) investment deferral benefit, (2) a generation capacity investment deferral benefit, and (3) a stochastic risk reduction benefit associated with clean, no-fuel resources.[7] Decrement values for two new energy efficiency load shapes were also estimated: residential water heating and "plug" loads (i.e., energy consumed by electronic devices plugged into sockets.)

Modeling Approach

To determine the Class 2 DSM decrement values, PacifiCorp defined 17 shaped Class 2 DSM resources, each at 100 megawatts at the time of peak load, and available starting in 2011 and for the duration of the 20-year IRP study period. In contrast, the valuation study for the 2008 IRP focused on 13 resources. The added resources consist of residential water heating and plug loads for both east and west control areas. Adding these new energy efficiency resources to the analysis is intended to provide a refined valuation for energy savings and further aid in developing program initiatives for such applications as showerheads, heat pump water heaters, and consumer electronics.

Consistent with prior valuation studies, PacifiCorp first determined the system production cost with and without each Class 2 DSM resources using the PaR production cost model in Monte Carlo stochastics mode. The difference in production cost (stochastic mean PVRR) for the two runs indicates the system value attributable to the DSM resource through lower spot market transaction activity and resource re-optimization with the DSM resource in the portfolio. The cost credits mentioned above are then added separately outside of the model, thereby increasing Class 2 DSM decrement values. The resource deferral benefit, as a new step for deriving the decrement values value, is described below. The PaR decrement values were determined for three CO_2 tax scenarios: zero, medium (starting at $19/ton and escalating to $39/ton by 2030), and low-to-very high (starting as $12/ton and escalating to $93/ton by 2030).

[7] Refer to Volume 1, page 147 of the 2011 IRP for a summary of the T&D investment deferral and stochastic risk reduction cost credits applied to the System Optimizer energy efficiency resource options.

Generation Resource Capacity Deferral Benefit Methodology

PacifiCorp used the System Optimizer model to determine the generation resource capacity deferral benefit. The approach is similar to the stochastic production cost difference method, except that only the fixed cost benefit of adding each 100-megawatt Class 2 DSM resource is calculated. This is accomplished by running System Optimizer with a base resource portfolio that excludes each 100-megawatt Class 2 DSM program, and then comparing the fixed portfolio costs against the cost of the same portfolio derived by System Optimizer that includes the DSM program at zero cost. The simulation period is 20 years. As a simplifying assumption, PacifiCorp applied the East "system" load shape for the generic DSM program, which has a capacity planning contribution of 93 percent and a capacity factor of 69 percent. The resource deferral fixed cost benefit is comprised of the deferred capital recovery and fixed operation and maintenance costs of a "next best alternative" resource—a combined-cycle combustion turbine (CCCT). The difference in the portfolio fixed cost represents the resource deferral benefit of the DSM program. (Note that System Optimizer's production cost benefits were not taken into account to avoid double-counting the benefit extracted from stochastic PaR model results.)

Since a 100-megawatt Class 2 DSM is not sufficiently large enough to defer a CCCT, System Optimizer was configured to allow fractional CCCT unit sizes for both the base portfolio and each of the 17 Class 2 DSM resource portfolios. Deferral of CCCT capacity can begin starting in 2015, the year after the Lake Side 2 CCCT is planned to be in service. Note that each Class 2 DSM resource can also defer front office transactions (a market resource representing a range of forward firm market purchase products).

The resource capacity deferral benefit is calculated in two steps:

1. Fixed Cost Deferral Benefit Determination
   Fixed cost benefits are obtained by calculating the differences in annual fixed and capital recovery costs (millions of 2010 dollars) between the base portfolio and the portfolio with the Class 2 DSM program addition. The stream of annual benefits is then converted into a net present value (NPV) using the 2011 IRP discount rate (7.17 percent).
2. Levelized Value Calculation
   The fixed cost resource deferral benefit value obtained from step 1 is divided by the Class 2 DSM program energy in megawatt-hours (also converted to a NPV) to yield a value in dollars per megawatt-hour-year ($/MWh-yr).

This value, along with the T&D investment deferral credit and stochastic risk reduction credit, are added to the PaR model decrement values to yield the final adjusted values.

Class 2 DSM Decrement Value Results

Table 7 reports the NPV levelized avoided costs by DSM resource and CO_2 tax scenario for 2011 through 2030, along with a breakdown of the three cost credits (capacity deferral, T&D investment deferral, and stochastic risk reduction). Tables 8, 9, and 10 report the annual nominal-dollar avoided costs, in $/MWh, for each CO_2 tax scenario. Figures 6 through 11 graphically show the avoided annual cost trends for the three CO_2 tax scenarios by east and west location, along with average annual forward market prices for the relevant location (Palo Verde (PV) for the east and Mid-Columbia (Mid-C) for the west.)

Consistent with the results for the 2008 IRP, the residential air conditioning decrements produce the highest value for both the east and west locations. The water heating (new), plug loads (new), and system load shapes provide the lowest avoided costs. Much of their end use shapes reduce loads during a greater percentage of off-peak hours than the other shapes and during all seasons, not just the summer.

Table 7 – Levelized Class 2 DSM Avoided Costs by Carbon Dioxide Tax Scenario, 20-Year Net Present Value (2011-2030)

Resource	Location	Load Factor	Total Avoided Costs by Carbon Dioxide Tax Scenario, Including all Cost Credits ($/MWh)			Cost Credit Components ($/MWh)			
			Low to Very High	Medium	None	Capacity Resource Deferral	T&D Investment Deferral	Stochastic Risk Reduction	Total Credit
Residential Cooling	East	10%	114.94	116.46	101.55	16.69	11.80	14.98	43.47
Residential Lighting	East	48%	91.17	91.71	78.49	16.69	2.35	14.98	34.02
Residential Whole House	East	35%	94.37	94.89	81.48	16.69	3.23	14.98	34.91
Commercial Cooling	East	20%	102.05	102.96	88.88	16.69	1.91	14.98	33.58
Commercial Lighting	East	48%	93.27	93.59	79.91	16.69	1.97	14.98	33.64
Water Heating	East	57%	90.57	90.95	77.72	16.69	5.83	14.98	37.50
Plug Loads	East	59%	90.16	90.49	77.40	16.69	2.33	14.98	34.00
System Load Shape	East	69%	90.31	90.72	77.53	16.69	1.62	14.98	33.29
Residential Cooling	West	7%	111.17	123.03	112.04	16.69	16.63	14.98	48.30
Residential Heating	West	25%	90.44	99.31	88.69	16.69	5.59	14.98	37.26
Residential Lighting	West	48%	88.82	97.81	88.02	16.69	2.48	14.98	34.15
Commercial Cooling	West	16%	96.04	106.31	96.43	16.69	2.60	14.98	34.27
Residential Whole House	West	49%	88.81	97.96	87.86	16.69	2.03	14.98	33.70
Commercial Lighting	West	48%	89.40	98.56	88.86	16.69	2.20	14.98	33.87
Water Heating	West	56%	87.35	96.12	86.53	16.69	7.11	14.98	38.79
Plug Loads	West	59%	87.61	96.35	86.72	16.69	2.46	14.98	34.13
System Load Shape	West	71%	87.38	96.26	86.54	16.69	1.75	14.98	33.42

Table 8 – Annual Nominal Class 2 DSM Avoided Costs, No CO_2 Tax Scenario, 2011-2030

		Avoided Cost Values (Nominal $/MWh)									
Resource	Actual Load Factor	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
EAST											
Residential Cooling	10%	92.59	93.45	98.67	96.34	101.80	98.22	96.60	97.05	98.60	97.21
Residential Lighting	48%	68.52	71.88	75.53	76.95	79.37	77.68	77.26	75.56	75.80	77.67
Residential Whole House	35%	71.53	74.73	78.69	79.45	81.63	80.27	79.94	77.98	78.73	80.67
Commercial Cooling	20%	78.04	80.13	85.32	84.93	89.12	86.45	85.23	85.02	86.60	87.68
Commercial Lighting	48%	69.01	72.91	77.14	77.66	80.19	78.99	78.08	77.13	78.32	79.02
Water Heating	57%	67.18	70.81	74.26	75.81	78.05	76.78	76.36	74.80	75.40	77.29
Plug Loads	59%	67.15	70.61	74.11	75.52	77.67	76.22	76.17	74.64	75.42	76.54
System Load Shape	69%	67.17	70.50	74.01	75.23	77.42	76.31	75.89	74.81	75.50	76.78
WEST											
Residential Cooling	7%	87.50	93.55	98.82	103.91	110.65	110.55	108.64	109.64	113.62	115.96
Residential Heating	25%	70.91	76.58	81.06	84.69	85.77	85.61	85.78	86.51	89.45	91.47
Residential Lighting	48%	69.00	74.09	78.90	83.43	86.40	85.48	84.82	86.34	88.94	90.75
Commercial Cooling	16%	74.58	79.96	84.81	89.76	94.93	94.49	93.23	95.07	97.84	100.16
Residential Whole House	49%	68.87	74.32	78.88	83.14	85.81	85.12	84.74	86.14	88.73	90.75
Commercial Lighting	48%	68.94	74.78	79.90	84.42	87.23	86.57	86.08	87.13	89.46	91.68
Water Heating	56%	67.78	72.97	77.56	82.04	84.79	84.09	83.45	84.93	87.26	89.23
Plug Loads	59%	68.10	73.23	77.85	82.15	84.81	84.20	83.75	85.01	87.57	89.47
System Load Shape	71%	67.69	72.87	77.49	82.00	84.66	84.11	83.54	84.90	87.31	89.41

		Avoided Cost Values (Nominal $/MWh)									
Resource	Actual Load Factor	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
EAST											
Residential Cooling	10%	102.98	105.51	106.53	109.80	108.14	103.44	102.23	123.84	127.89	137.29
Residential Lighting	48%	79.83	81.78	82.95	82.03	83.11	82.89	81.40	91.99	93.97	100.83
Residential Whole House	35%	82.57	84.72	85.49	86.08	86.83	86.64	83.04	96.68	98.67	106.22
Commercial Cooling	20%	90.70	92.79	94.83	96.95	95.40	93.63	91.82	107.39	110.82	118.31
Commercial Lighting	48%	80.99	83.36	84.90	84.92	85.20	84.32	82.21	94.02	97.11	104.06

		Avoided Cost Values (Nominal $/MWh)									
Resource	**Actual Load Factor**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Water Heating	57%	79.38	81.02	82.00	82.11	83.18	82.88	80.68	92.25	93.94	100.95
Plug Loads	59%	78.87	80.54	81.88	81.80	82.29	82.16	80.79	91.57	93.24	100.38
System Load Shape	69%	78.74	80.98	82.21	82.41	82.97	82.52	80.69	92.46	94.55	101.68
WEST											
Residential Cooling	7%	120.27	123.27	124.84	125.63	125.40	129.01	133.33	138.61	138.61	143.17
Residential Heating	25%	92.80	95.16	97.02	98.79	99.22	104.26	103.19	107.04	108.91	111.73
Residential Lighting	48%	93.08	95.64	97.17	99.10	98.70	102.28	103.77	108.10	109.58	112.83
Commercial Cooling	16%	103.11	105.94	107.30	108.81	108.76	111.45	114.54	119.99	120.88	124.49
Residential Whole House	49%	92.90	95.35	96.83	98.67	98.66	102.84	103.53	107.85	109.37	112.47
Commercial Lighting	48%	93.73	96.29	98.04	99.81	99.82	103.61	104.89	109.10	110.91	114.12
Water Heating	56%	91.56	93.78	95.40	97.39	97.37	100.54	101.92	106.01	107.97	110.79
Plug Loads	59%	91.64	94.06	95.52	97.55	97.30	100.76	102.00	106.38	108.17	110.99
System Load Shape	71%	91.59	93.94	95.49	97.36	97.34	100.84	101.95	106.36	108.06	110.84

Table 9 – Annual Nominal Class 2 DSM Avoided Costs, Low to Very High CO_2 Tax Scenario, 2011-2030

		Avoided Cost Values (Nominal $/MWh)									
Resource	**Actual Load Factor**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
EAST											
Residential Cooling	10%	89.02	91.10	92.33	92.16	103.87	104.22	101.20	107.09	108.23	107.72
Residential Lighting	48%	66.01	69.58	70.80	71.90	82.56	83.19	84.43	84.44	85.99	88.06
Residential Whole House	35%	68.62	72.05	73.32	74.41	85.38	85.61	86.07	86.87	88.69	90.57
Commercial Cooling	20%	74.91	78.03	79.48	80.02	92.09	92.05	92.18	94.33	95.64	97.16
Commercial Lighting	48%	66.77	70.07	71.87	72.75	83.71	84.70	85.82	85.88	87.70	90.14
Water Heating	57%	64.81	68.17	69.37	70.79	81.39	82.33	83.15	83.56	85.45	87.50
Plug Loads	59%	64.77	68.02	69.74	70.70	80.96	82.08	83.29	83.18	84.54	87.26
System Load Shape	69%	64.92	67.96	69.35	70.61	81.02	82.00	82.79	83.20	84.55	86.87
WEST											
Residential Cooling	7%	81.27	85.07	86.47	88.00	97.88	100.55	101.45	105.26	108.10	110.90
Residential Heating	25%	65.81	69.58	71.51	72.85	78.56	80.34	82.14	84.17	86.31	89.79

		Avoided Cost Values (Nominal $/MWh)									
Resource	**Actual Load Factor**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Residential Lighting	48%	63.51	66.58	68.62	69.88	77.33	78.88	80.28	82.87	85.31	88.27
Commercial Cooling	16%	69.05	71.80	73.84	75.16	84.02	86.47	87.30	90.75	93.15	95.89
Residential Whole House	49%	63.50	66.85	68.74	69.99	77.15	78.85	80.42	82.88	85.08	88.07
Commercial Lighting	48%	63.63	66.80	68.84	70.10	77.71	79.31	80.95	83.31	85.71	89.06
Water Heating	56%	62.41	65.52	67.55	68.75	75.92	77.70	79.10	81.50	83.84	86.53
Plug Loads	59%	62.69	65.88	67.74	69.05	76.15	77.70	79.31	81.75	84.10	86.86
System Load Shape	71%	62.33	65.60	67.45	68.71	75.84	77.58	79.08	81.44	83.94	86.53

		Avoided Cost Values (Nominal $/MWh)									
Resource	**Actual Load Factor**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
EAST											
Residential Cooling	10%	115.85	123.61	128.08	137.47	142.06	143.42	154.90	180.57	195.11	218.30
Residential Lighting	48%	92.62	98.32	101.69	107.97	114.59	120.87	127.13	145.77	155.11	173.70
Residential Whole House	35%	95.44	101.09	105.17	112.72	118.69	125.05	131.36	153.26	162.52	182.70
Commercial Cooling	20%	104.73	109.14	114.83	123.93	130.80	133.09	140.06	163.32	172.93	200.70
Commercial Lighting	48%	94.91	100.06	105.47	111.87	117.96	124.03	130.47	151.20	162.60	182.58
Water Heating	57%	92.12	96.97	101.95	108.16	114.88	121.02	127.93	146.87	156.64	177.16
Plug Loads	59%	91.66	96.70	101.49	107.16	114.32	120.32	126.73	145.55	154.26	175.57
System Load Shape	69%	91.99	96.97	102.03	107.61	114.12	121.03	127.26	146.11	156.69	177.64
WEST											
Residential Cooling	7%	115.53	122.06	127.58	133.97	141.79	152.37	157.59	170.65	179.22	189.63
Residential Heating	25%	91.99	96.35	102.37	109.15	116.02	131.46	131.07	138.81	148.06	156.39
Residential Lighting	48%	90.78	96.25	101.85	108.30	115.04	127.27	130.17	139.61	148.59	156.89
Commercial Cooling	16%	99.30	104.81	110.54	116.53	123.95	133.70	138.61	150.45	159.46	167.57
Residential Whole House	49%	90.98	95.99	101.64	108.18	115.27	127.79	129.88	139.27	148.30	156.82
Commercial Lighting	48%	91.70	96.89	102.75	109.04	115.95	128.63	131.20	140.77	150.07	158.85
Water Heating	56%	89.26	94.46	100.05	106.42	113.45	125.22	127.93	136.94	146.45	154.84
Plug Loads	59%	89.49	94.60	100.50	106.75	113.61	125.58	128.42	137.40	146.68	155.09
System Load Shape	71%	89.51	94.43	100.23	106.42	113.37	125.63	128.18	137.32	146.53	155.10

Table 10 – Annual Nominal Class 2 DSM Avoided Costs, Medium CO_2 Tax Scenario, 2011-2030

		Avoided Cost Values (Nominal $/MWh)									
Resource	Actual Load Factor	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
EAST											
Residential Cooling	10%	92.01	91.50	95.47	90.41	116.85	114.75	113.45	116.39	118.93	120.59
Residential Lighting	48%	66.61	69.53	71.34	70.94	92.99	93.51	93.38	93.64	94.83	97.91
Residential Whole House	35%	69.58	72.28	74.46	73.30	95.62	95.85	95.98	96.54	97.25	101.50
Commercial Cooling	20%	76.46	77.82	81.97	78.94	103.42	103.58	102.17	102.89	105.32	109.07
Commercial Lighting	48%	67.25	70.38	73.04	71.88	93.98	95.26	95.04	95.71	96.77	100.30
Water Heating	57%	65.18	68.06	69.97	69.89	91.92	92.64	92.97	92.54	93.96	97.41
Plug Loads	59%	65.16	67.97	70.05	69.56	91.40	92.10	92.42	92.15	94.08	96.67
System Load Shape	69%	65.12	68.04	70.00	69.38	91.26	92.30	92.18	92.08	94.11	97.25
WEST											
Residential Cooling	7%	85.37	92.78	94.94	97.51	122.94	126.87	122.17	124.77	130.24	132.77
Residential Heating	25%	71.42	77.64	79.39	81.76	97.95	99.54	99.23	100.19	104.18	106.21
Residential Lighting	48%	66.78	72.50	74.85	76.94	97.90	99.53	97.51	99.69	103.47	106.07
Commercial Cooling	16%	71.77	78.06	80.78	83.07	107.22	109.27	105.19	108.42	112.10	116.03
Residential Whole House	49%	67.45	73.49	75.67	77.80	97.76	99.54	97.56	99.55	103.43	106.03
Commercial Lighting	48%	67.07	73.49	75.70	78.00	98.68	100.19	97.82	100.18	103.92	107.07
Water Heating	56%	65.47	71.34	73.54	75.71	96.26	97.73	95.86	98.04	101.70	104.37
Plug Loads	59%	65.86	71.77	73.90	75.96	96.54	97.84	96.18	98.14	101.85	104.85
System Load Shape	71%	65.66	71.57	73.79	75.85	96.25	97.78	96.04	98.12	101.86	104.56

		Avoided Cost Values (Nominal $/MWh)									
Resource	Actual Load Factor	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
EAST											
Residential Cooling	10%	125.57	131.25	133.34	142.19	141.47	131.18	130.37	153.07	158.43	171.00
Residential Lighting	48%	101.70	104.18	106.66	109.14	110.57	108.57	107.94	118.67	123.53	130.43
Residential Whole House	35%	104.62	107.48	110.95	114.02	114.98	111.90	110.68	123.55	128.44	136.13
Commercial Cooling	20%	114.81	117.06	121.00	125.42	125.90	119.41	117.43	135.09	140.99	152.28

		Avoided Cost Values (Nominal $/MWh)									
Resource	**Actual Load Factor**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Commercial Lighting	48%	104.02	105.75	110.04	112.67	114.01	110.31	109.83	121.35	126.81	136.27
Water Heating	57%	101.05	103.59	106.94	109.61	111.00	108.15	107.17	118.92	122.52	131.34
Plug Loads	59%	100.36	102.51	106.08	108.83	109.89	107.38	106.80	117.64	121.95	130.47
System Load Shape	69%	100.75	102.91	106.59	109.26	109.93	107.93	107.42	118.90	123.86	131.88
WEST											
Residential Cooling	7%	135.63	140.77	146.35	152.81	150.62	149.83	147.88	158.04	160.17	168.14
Residential Heating	25%	108.12	111.39	116.14	120.47	120.99	123.05	119.50	123.79	127.27	131.90
Residential Lighting	48%	108.09	111.69	117.11	121.96	121.47	121.70	119.29	125.50	129.29	133.97
Commercial Cooling	16%	117.95	122.18	128.59	133.56	132.06	130.80	128.51	137.31	140.79	146.76
Residential Whole House	49%	107.89	111.61	116.71	121.52	121.45	121.57	119.04	125.02	128.36	133.51
Commercial Lighting	48%	108.95	112.32	117.74	122.87	122.05	122.48	120.08	126.55	130.75	135.41
Water Heating	56%	106.22	109.93	114.91	120.15	119.37	119.33	116.97	123.06	126.97	131.66
Plug Loads	59%	106.36	110.07	115.23	119.84	119.50	119.33	117.21	123.24	127.08	131.90
System Load Shape	71%	106.46	109.92	115.12	119.93	119.67	119.41	117.23	123.11	127.20	131.91

Figure 6 – East Class 2 DSM Nominal Avoided Cost Trends, Low to Very High CO_2 Tax Scenario

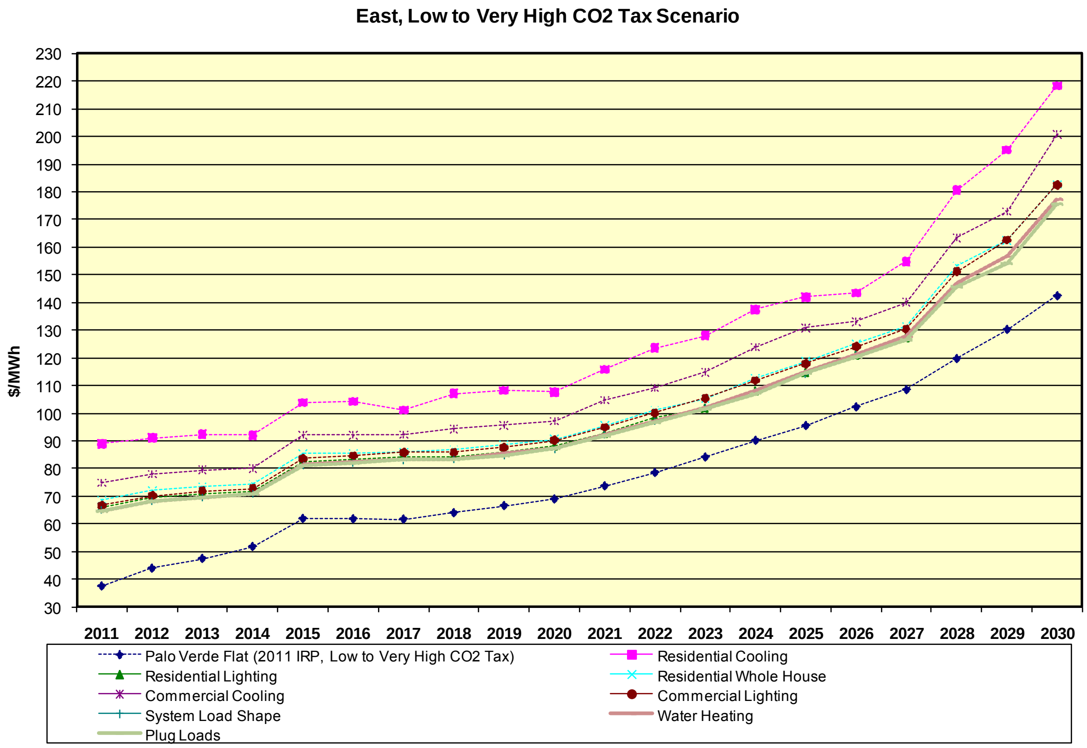


Figure 7 – West Class 2 DSM Nominal Avoided Cost Trends, Low to Very High CO_2 Tax Scenario

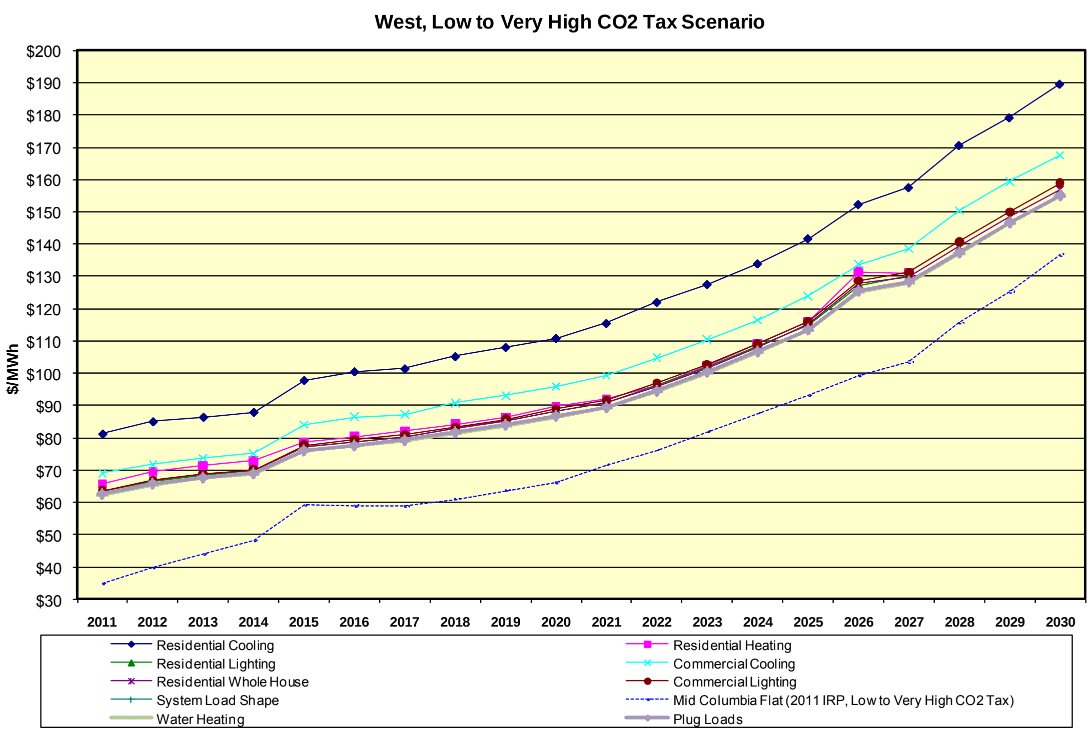


Figure 8 – East Class 2 DSM Nominal Avoided Cost Trends, Medium CO_2 Tax Scenario

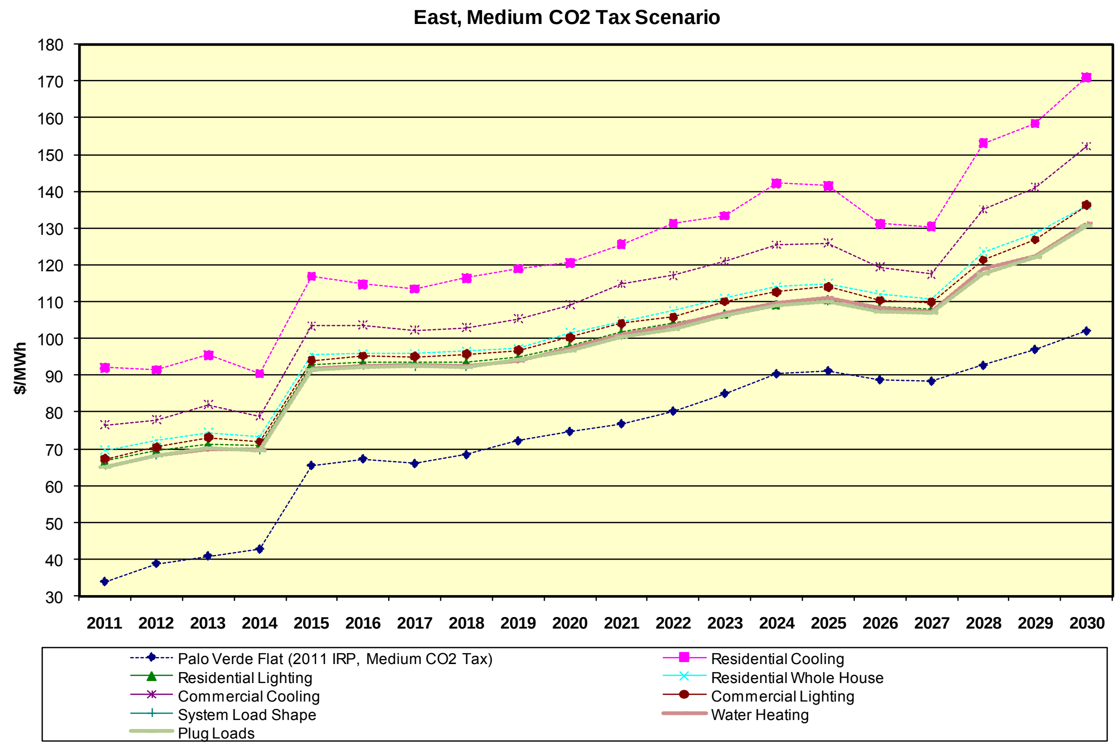


Figure 9 – West Class 2 DSM Nominal Avoided Cost Trends, Medium CO_2 Tax Scenario

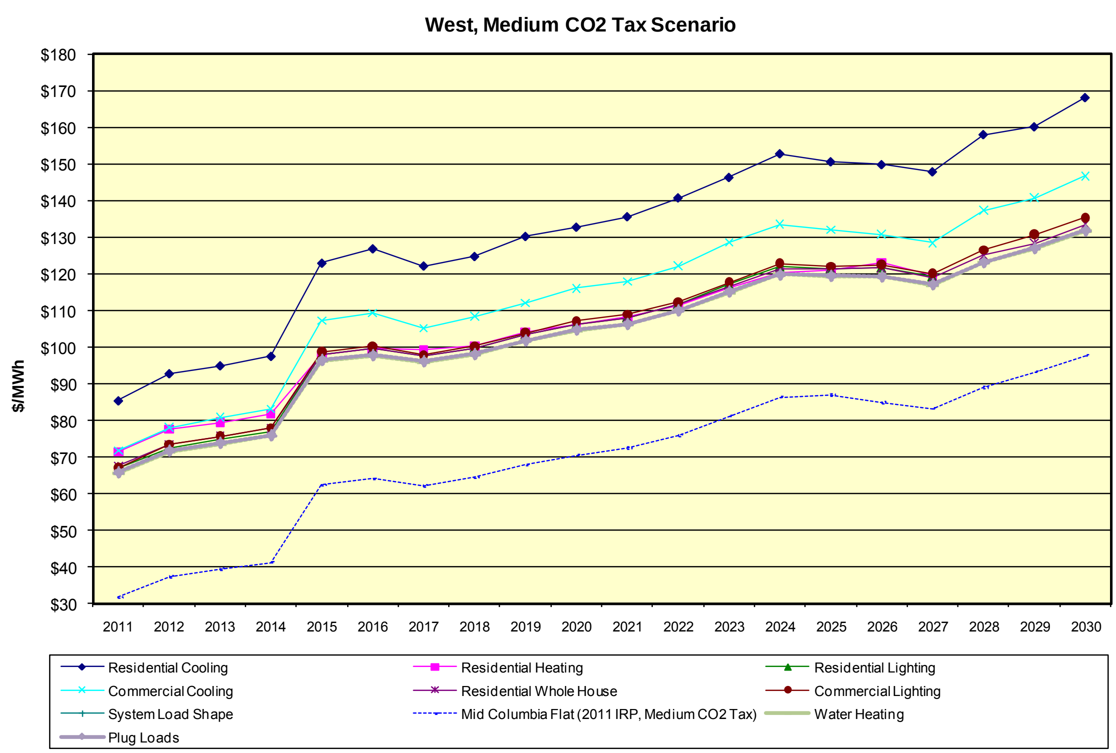


Figure 10 – East Class 2 DSM Nominal Avoided Cost Trends, No CO_2 Tax Scenario

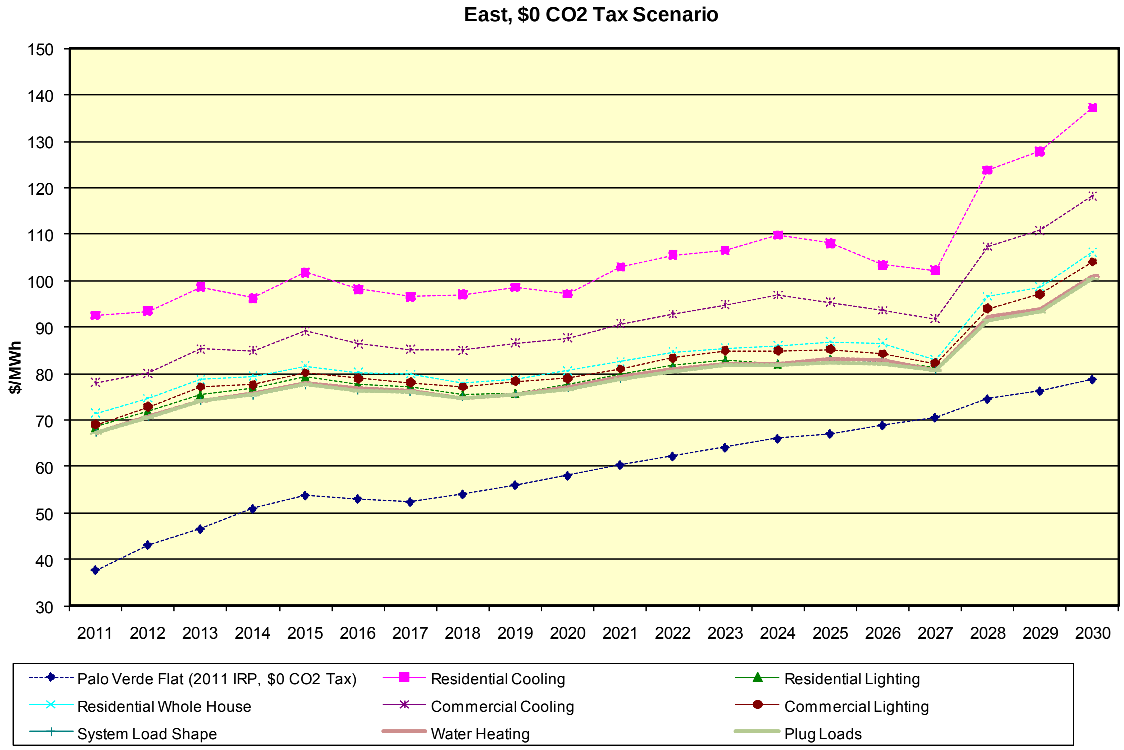
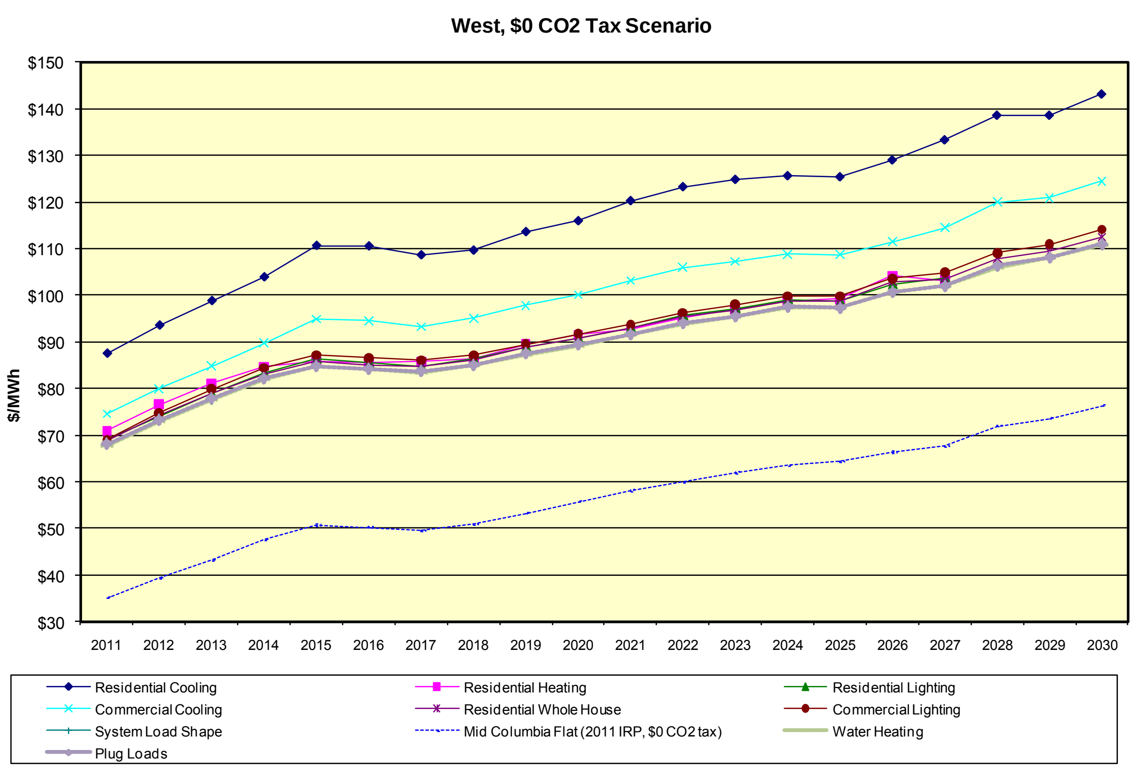


Figure 11 – West Class 2 DSM Nominal Avoided Cost Trends, No CO_2 Tax Scenario



BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Direct Testimony of Bill Eddie

Progress towards 8% community-based renewable energy goal in ORS 469A.210; SB 838 § 24

Assumptions:
List all OR RPS and CA RPS certified facilities located in Oregon
Also includes Threemile Digester project (not yet listed with Oregon or California regulators)
Excludes projects over 20 MW
Excludes hydro efficiency projects at large hydro faciliities
Assumed capacity factors:

	Biogas and Biomass:	90%
	Hydro	50%
	Solar	15%
	Wind	30%
1,604,528	MWh estimated production from projects under 20 MW	
45,759,936	MWh consumed in Oregon per EIA data	
3.51	% from projects under 20MW	

Generator Plant Name	Name Plate Capacity (MW)	Fuel Type	Assumed CF	Estimated Annual Generation (MWh)
Coffin Butte Phase II	3.2	Biogas	90%	25229
Coffin Butte Resource Project	2.46	Biogas	90%	19395
Columbia Ridge Landfill Electric Ge	6.4	Biogas	90%	50458
Dry Creek Landfill Gas to Energy I	3.2	Biogas	90%	25229
Farm Power Tillamook	0.995	Biogas	90%	7845
Finley Bioenergy	4.8	Biogas	90%	37843
Metropolitan Wastewater Managem	0.8	Biogas	90%	6307
Oregon Environmental Industries, L	3.2	Biogas	90%	25229
Riverbend Renewable Energy Facil	4.8	Biogas	90%	37843
Short Mountain	3.2	Biogas	90%	25229
Threemile Canyon Farms Digester	4.8	Biogas	90%	37843
Cascade Pacific - Halsey	8	Biomass	90%	63072
Cogen II	9.375	Biomass	90%	73913
Douglas County Forest Products	5	Biomass	90%	39420
Evergreen BioPower LLC	10	Biomass	90%	78840
Seneca Sustainable Energy - Senec	19.778	Biomass	90%	155930
Bend	1.1	Hydro	50%	4818
Central Oregon Irrigation District Ju	5	Hydro	50%	21900
Central Oregon Siphon Power Proj	5.4	Hydro	50%	23652
Clearwater 1	15	Hydro	50%	65700
Cline Falls	1	Hydro	50%	4380
Copper Dam Plant	3	Hydro	50%	13140
Eagle Point	2.8	Hydro	50%	12264
Eastside	3.2	Hydro	50%	14016
Falls Creek Hydroelectric Project	4.1	Hydro	50%	17958
Farmers Irrigation District	4.8	Hydro	50%	21024
Fish Creek	11	Hydro	50%	48180
Juniper Ridge Hydroelectric Facilit	5	Hydro	50%	21900
Lacomb Irrigation District Hydro Pr	0.962	Hydro	50%	4214
McNary Fishway Hydro Project	10	Hydro	50%	43800
Middle Fork Irrigation District Hydr	3.3	Hydro	50%	14454
North Fork Sprague River Project	0.75	Hydro	50%	3285

Opal Springs Hydro	4.3	Hydro	50%	18834
Peters Drive Dam	1.8	Hydro	50%	7884
Powerdale	6	Hydro	50%	26280
Prospect 1	3.8	Hydro	50%	16644
Prospect 3	7.2	Hydro	50%	31536
Prospect 4	1	Hydro	50%	4380
Slide Creek	18	Hydro	50%	78840
Soda Springs	11	Hydro	50%	48180
Wallowa Falls	1.1	Hydro	50%	4818
Westside	0.6	Hydro	50%	2628
Willamette Falls Hydroelectric Proj	14.4	Hydro	50%	63072
Willamette Falls Hydroelectric Proj	1	Hydro	50%	4380
Baldock Solar Highway LLC	1.75	Solar	15%	2300
Bellevue Solar, LLC - Bellevue Sol	1.56	Solar	15%	2050
Black Cap Solar	2	Solar	15%	2628
Industrial Finishes - PREM 117102	0.215	Solar	15%	283
Industrial Finishes - PREM 117168	0.159	Solar	15%	209
Jennifer District Center #1 - ProLo	0.38	Solar	15%	499
Jennifer District Center #2 - ProLo	0.342	Solar	15%	449
Jennifer District Center #3 - ProLo	0.304	Solar	15%	399
Joseph Community Solar	0.5	Solar	15%	657
Kendall Dealership	0.169	Solar	15%	222
ODOT-I5 & I205	0.104	Solar	15%	137
Outback Solar	4.95	Solar	15%	6504
PAC OSIP CO 1	0.209	Solar	15%	275
PAC OSIP CO2	0.043	Solar	15%	57
PAC OSIP CR 1	0.112	Solar	15%	147
PAC OSIP EO 1	0.211	Solar	15%	277
PAC OSIP EO2	0.025	Solar	15%	33
PAC OSIP PO 1	0.132	Solar	15%	173
PAC OSIP SO 1	0.25	Solar	15%	329
PAC OSIP SO 2	0.265	Solar	15%	348
PAC OSIP SO3	0.243	Solar	15%	319
PAC OSIP SO4	0.248	Solar	15%	326
PAC OSIP SO5	0.034	Solar	15%	45

PAC OSIP WV 1	0.227	Solar	15%	298
PAC OSIP WV2	0.242	Solar	15%	318
PAC OSIP WV3	0.165	Solar	15%	217
PDX ProLogis Park 1 - ProLogis	0.418	Solar	15%	549
PDX ProLogis Park 2 - ProLogis	0.163	Solar	15%	214
Pepsi-Cola Bottling Co	0.208	Solar	15%	273
PGE-SPO-G1	0.245	Solar	15%	322
PGE-SPO-G10 - PGE-SPO-G10	0.25	Solar	15%	329
PGE-SPO-G11 - PGE-SPO-G11	0.25	Solar	15%	329
PGE-SPO-G12 - PGE-SPO-G12	0.25	Solar	15%	329
PGE-SPO-G13 - PGE-SPO-G13	0.246	Solar	15%	323
PGE-SPO-G14 - PGE-SPO-G14	0.248	Solar	15%	326
PGE-SPO-G15 - PGE-SPO-G15	0.249	Solar	15%	327
PGE-SPO-G16 - PGE-SPO-G16	0.249	Solar	15%	327
PGE-SPO-G17-Clackamas - PGE-S	0.498	Solar	15%	654
PGE-SPO-G18 - PGE-SPO-G18	0.249	Solar	15%	327
PGE-SPO-G19 - Kohls Departmen	0.299	Solar	15%	393
PGE-SPO-G2	0.248	Solar	15%	326
PGE-SPO-G20 - PGE-SPO-G20	0.248	Solar	15%	326
PGE-SPO-G21 - PGE-SPO-G21	0.248	Solar	15%	326
PGE-SPO-G22 - PGE-SPO-G22	0.25	Solar	15%	329
PGE-SPO-G3	0.248	Solar	15%	326
PGE-SPO-G4	0.25	Solar	15%	329
PGE-SPO-G5	0.25	Solar	15%	329
PGE-SPO-G6	0.25	Solar	15%	329
PGE-SPO-G7 - PGE-SPO-G7	0.25	Solar	15%	329
PGE-SPO-G8 - PGE-SPO-G8	0.25	Solar	15%	329
PGE-SPO-G9 - PGE-SPO-G9-3C S	0.5	Solar	15%	657
ProLogis East 1	0.288	Solar	15%	378
ProLogis East 2	0.288	Solar	15%	378
ProLogis PDX Park 4	0.518	Solar	15%	681
Solwatt Solar LLC	0.307	Solar	15%	403
Southshore Corp Bldg A - ProLogis	0.38	Solar	15%	499
Southshore Corp Bldg C - ProLogis	0.418	Solar	15%	549
Walgreens - Newberg, OR (#6663)	0.03	Solar	15%	39

Walgreens - Cornelius, OR (#9353)	0.019	Solar	15%	25
Walgreens - Gresham, OR (#3817)	0.025	Solar	15%	33
Walgreens - Keizer, OR (#4230)	0.03	Solar	15%	39
Walgreens - Lake Oswego, OR (#9	0.03	Solar	15%	39
Walgreens - Oregon City, OR #380	0.026	Solar	15%	34
Walgreens - Portland, OR (#3818)	0.025	Solar	15%	33
Walgreens - Portland, OR (#5647)	0.03	Solar	15%	39
Walgreens - Salem (#4229)	0.025	Solar	15%	33
Walgreens - Salem, OR (#9287)	0.03	Solar	15%	39
Walgreens - Sherwood, OR (#7665	0.03	Solar	15%	39
Walgreens - Tigard, OR (#5780)	0.025	Solar	15%	33
Walgreens - Wilsonville, OR (#768	0.03	Solar	15%	39
Yamhill Solar, LLC - Yamhill Solar	1.04	Solar	15%	1367
Big Top - Big Top LLC	1.65	Wind	30%	4336
Butter Creek Power LLC - Butter C	4.95	Wind	30%	13009
Four Corners Windfarm LLC	10	Wind	30%	26280
Four Mile Canyon Windfarm	10	Wind	30%	26280
J Bar 9 Ranch	0.1	Wind	30%	263
Oregon Trail Windfarm	9.9	Wind	30%	26017
Pacific Canyon Windfarm	8.25	Wind	30%	21681
Patu Wind Farm	9	Wind	30%	23652
Sand Ranch Windfarm	9.9	Wind	30%	26017
Threemile Canyon Wind	9.9	Wind	30%	26017
Wagon Trail	3.3	Wind	30%	8672
Ward Butte Windfarm	6.6	Wind	30%	17345
			Total	**1,604,528**

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Direct Testimony of Bill Eddie

Northwest Gas Association, “2012 Gas Outlook: Natural Gas Supply, Demand, Capacity and Prices in the Pacific Northwest”, 2012

NWGA
NORTHWEST GAS ASSOCIATION

NATURAL GAS SUPPLY, DEMAND, CAPACITY AND PRICES IN THE PACIFIC NORTHWEST

PROJECTIONS THROUGH OCTOBER 2021

This report, compiled by the Northwest Gas Association (NWGA) and its members, provides a consensus industry perspective of the Pacific Northwest's current and projected natural gas supply, demand, prices and delivery capabilities through 2021. The Pacific Northwest in this case includes British Columbia (BC) and the U.S. states of Washington, Oregon and Idaho. Additional information, including white papers on specific natural gas topics, can be found at www.nwga.org.

NWGA NORTHWEST GAS ASSOCIATION www.nwga.org

WHAT'S NEW

The abundance of natural gas across North America continues to be a game-changer – transforming the energy landscape as well as the direction of public policy. Continental supply continues to grow as producers bring increasing quantities of natural gas (primarily shale gas) to market.

U.S. Natural Gas Strategy

"We have a supply of natural gas that can last America nearly 100 years, and my administration will take every possible action to safely develop this energy. The development of natural gas will create jobs and power trucks and factories that are cleaner and cheaper, proving that we don't have to choose between our environment and our economy."

-- President Barack Obama, *State of the Union speech*, Jan. 24, 2012.

North America's vast and economic supply of natural gas coupled with lower commodity prices is causing a shift in thinking about the role of natural gas in our economy. The dramatic swing in North America's natural gas supply picture has also affected the global gas market – slashing the need for liquefied natural gas (LNG) imports while providing market incentives to explore exports.

Regionally, expectations are that economic recovery will remain moderate across the U.S. Pacific Northwest, tempering natural gas demand growth for the next few years. (BC was less affected by the recent economic downturn and is poised for quicker recovery.) Meanwhile, Northwest consumers are benefitting as regional gas distribution companies (LDCs) pass the lower cost of natural gas through to their customers.

PUTTING IT ALL TOGETHER

Since natural gas is a fundamental economic input (e.g. used in industrial and commercial processes, as a fuel to generate electricity and for space and water heating in new home construction), the economy remains the key driver influencing natural gas demand in the Pacific Northwest and across North America. The speed at which an economic recovery occurs will dictate how quickly demand grows over the next 10 years, as well as federal, state and provincial efforts to maximize the benefits of this abundant resource (boosting energy independence, creating jobs), and actions taken by energy industry participants and energy consumers to comply with carbon-reducing energy policy mandates. This, in turn, will influence decisions to expand or invest in additional delivery infrastructure such as pipelines and storage facilities.

British Columbia's Natural Gas Strategy

"We will advance natural gas actions and strategies to help fuel BC's economy for the next decade and beyond."

-- Rich Coleman – BC Minister of Energy and Mines

"[T]here are new and expanded uses of natural gas in North America and British Columbia, including transportation, fuel switching from coal to natural gas for power generation, and as a feedstock to make other products."

-- BC's Natural Gas Strategy, Feb. 3, 2012

For example, in Oregon and Washington, we are already seeing large investments in renewable wind power, which may lead to future investment in new fast-start gas-fired generation plants to balance intermittent wind generation. In addition, the announced closure of two regional coal plants (in Boardman, Oregon, and Centralia, Washington) portends additional gas demand for electric generation. Both plant operators have publicly expressed their intentions to replace at least some of that generation capacity with gas-fired generation.

U.S. energy independence grows stronger

The U.S. has increased the proportion of energy demand met from domestic sources (oil and natural gas) over the last six years to an estimated 81 percent through the first 10 months of 2011, according to data compiled by Bloomberg from the U.S. Department of Energy (DOE). The transformation, which could see the country become the world's top energy producer by 2020, has implications for the economy and national security – boosting household incomes, jobs and government revenue; cutting the trade deficit; enhancing manufacturers' competitiveness; and allowing greater flexibility in dealing with unrest in the Middle East.

Source: Bloomberg, Feb. 6, 2012, *Americans gaining energy independence with U.S. as top producer.*

At the same time, the low price of North American natural gas is itself playing an important role in economic recovery by stimulating growth of industries that use natural gas[1,2] and, because global prices are much higher, by bringing overseas manufacturing jobs back to North America.

One thing is certain: thanks to the vast shale gas reserves unlocked by breakthroughs in drilling technologies, the natural gas resource available to serve our energy needs is abundant, secure and accessible across North America. And with plentiful supply comes a mandate to responsibly produce and use natural gas.

Directly heating homes, buildings and water with natural gas is one way to optimize its use. It is also an economic feedstock and process fuel that can help revitalize regional industry. In addition, natural gas is a reliable, low carbon fuel for generating electricity. It's a safe, clean and more affordable fuel than gasoline or diesel for fueling fleet vehicles like garbage trucks and transit buses, long-haul trucks, even ferries.

Regional stakeholders can capture the benefits of this newly plentiful resource and help to ensure supply viability for the long-term by encouraging its use.

[1] Shale-gas production is spurring construction of plants that make chemicals, plastics, fertilizer, steel and other products. A report issued in early 2012 by PricewaterhouseCoopers LLC estimated that such investments could create a million U.S. manufacturing jobs over the next 15 years. From *Shale Gas Boom Spurs Race,* Wall Street Journal (WSJ), Dec. 21, 2011. http://online.wsj.com/article/SB10001424052970204844504577100421253005122.html. See also: *Oil and Gas Boom Lifts U.S. Economy*, WSJ, Feb. 8, 2012.

[2] A recent study by the American Chemistry Council noted the potential for 17,000 new knowledge-intensive, high-paying jobs in the U.S. chemical industry, another 400,000 jobs outside the chemical industry and more than $132 billion in U.S. economic output – all associated with the shale gas revolution. http://www.americanchemistry.com/Policy/Energy/Shale-Gas%20

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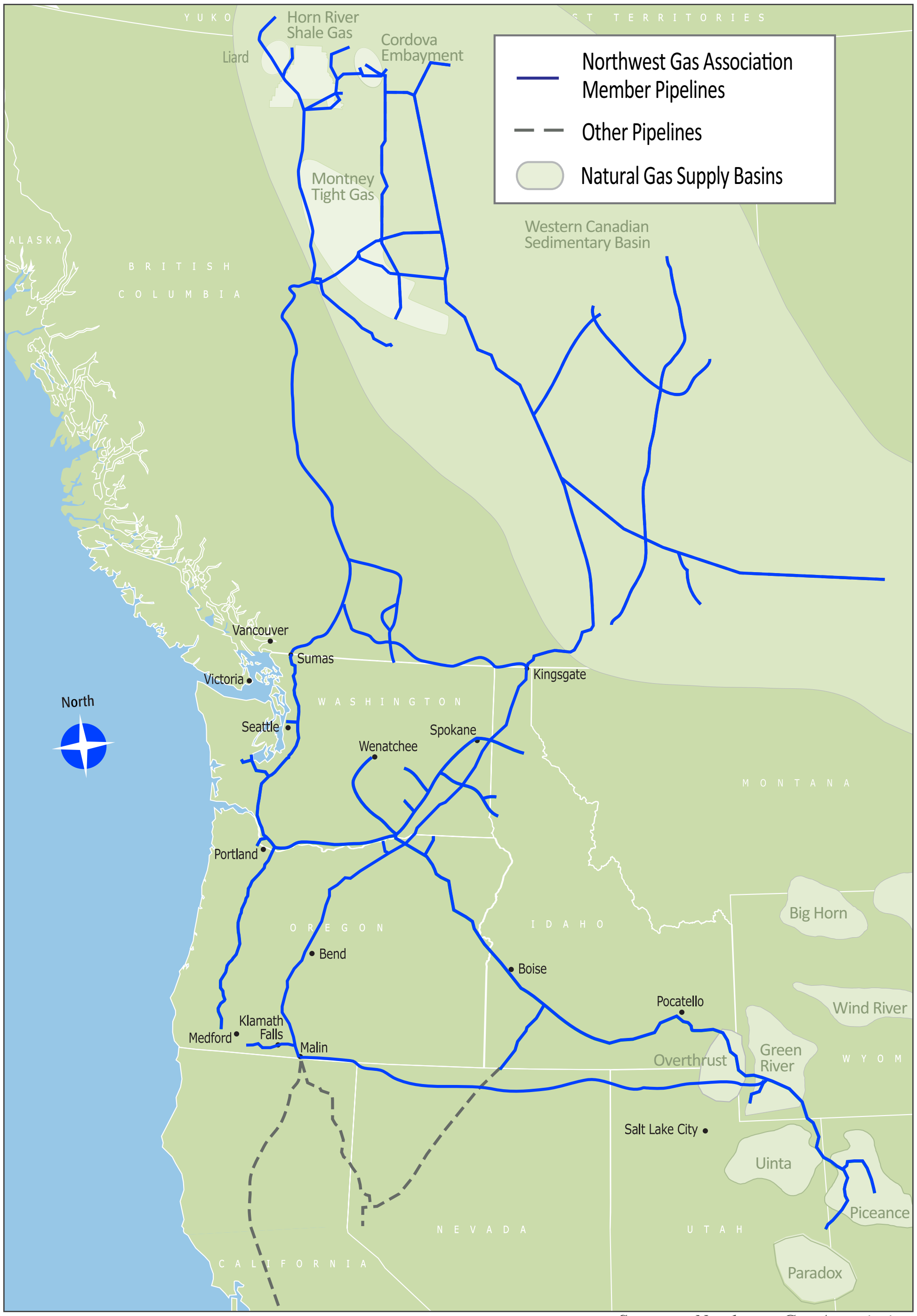
2012 GAS OUTLOOK - SUPPLY SERVING THE REGION

KEY CONCLUSIONS

- The innovative application of decades-old production technologies has unlocked vast reserves of natural gas that were previously inaccessible or uneconomic. This dramatic supply shock has fundamentally changed the nature of the natural gas market. Scarcity and declining production have given way to abundance for decades to come.

- Pacific Northwest natural gas consumers benefit from proximity to the prolific Western Canadian Sedimentary Basin (WCSB) and U.S. Rocky Mountain (Rockies) natural gas-producing regions.

Figure 1. Supply Serving the Pacific Northwest



Source: Northwest Gas Association

A CLOSER LOOK

Shale. What is it and why do we care? Shale rock formations several thousand feet below the surface of the earth are the source of hydrocarbons like oil and natural gas. Low permeability of shale means natural gas does not flow readily, but advances in horizontal drilling and hydraulic fracturing have provided economic access.

As a result, natural gas from shale rock formations has changed the conversation from one of limited and declining supplies just a handful of years ago, to one of abundance and opportunity. According to the Potential Gas Committee (PGC),[3] continental natural gas resources are now estimated at well over 100 years' supply at current consumption rates. Importantly, shale formations are geographically widespread (Figure 2).

Already, shale plays are producing more than 20 percent of U.S. natural gas supply, and are expected to make up nearly 50 percent by 2035.[4] During 2011 alone, U.S. natural gas production grew more than 7 percent, the largest year-over-year volume increase in history.[5]

Figure 2. North American Shale Plays

Prepared by Spectra Energy based on information provided by the U.S. Energy Information Administration (EIA).

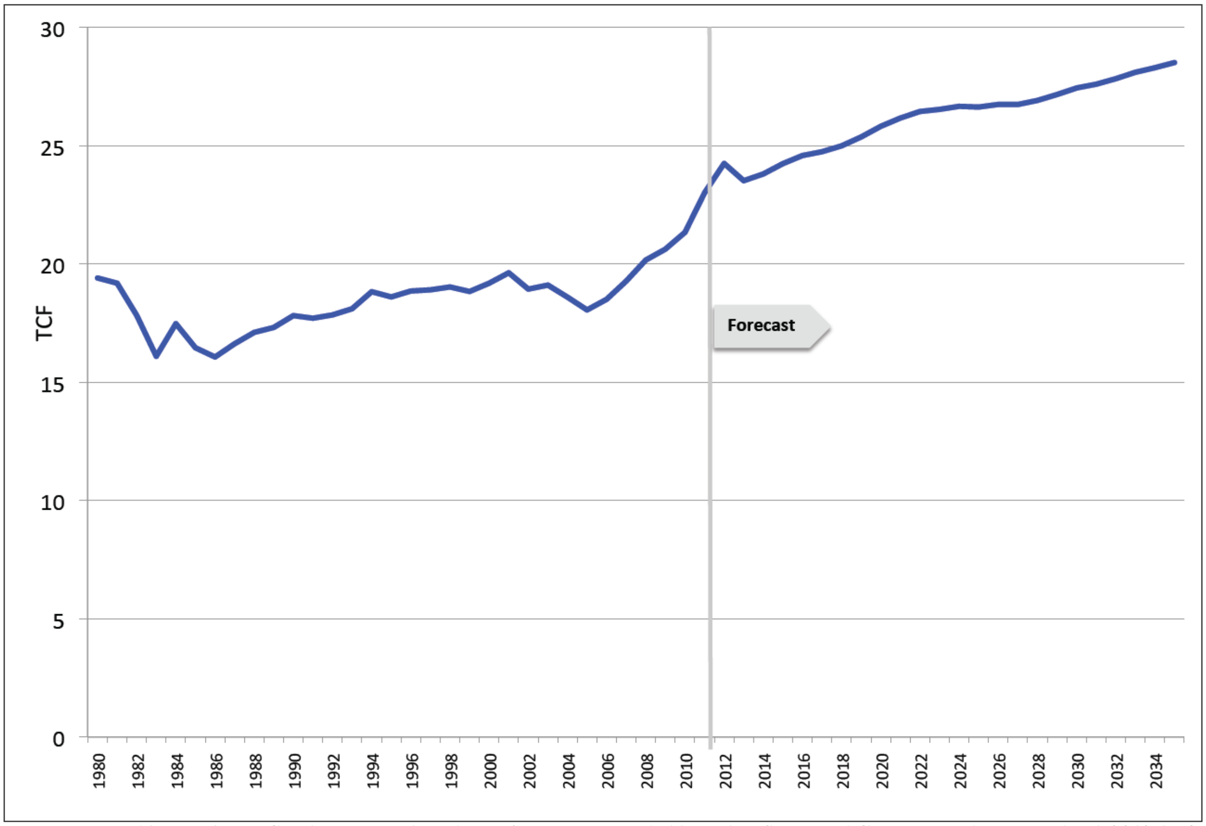
Current gas supplies are plentiful and continue to increase. Figure 3 illustrates that production increases have occurred in spite of a slow economy and lower commodity prices and are being sustained because the economics of shale gas drilling are improving. For instance, individual rigs become more productive over time as producers dial in the best methods of producing each individual field. Perhaps more importantly, sustained high oil prices make it extremely attractive to drill for oil (of which natural gas is often a byproduct) as well as drill for natural gas in liquid rich areas, from which more valuable commodities can be extracted. Finally, land lease agreements often encourage timely well development.

Closer to home, the Northwest is immediately adjacent to and supplied by two large natural gas production areas. The WCSB includes the Canadian provinces of BC and Alberta and provides about 60 percent of the natural gas consumed in the Northwest. The Rockies region provides the rest of the gas consumed here.[6] Combined, the two production areas produced an average of about 27 billion cubic feet per day (Bcf/d) in 2010[7] – more than one third of North America's natural gas supply. To put this into perspective, the

[3] Affiliated with the Colorado School of Mines, the nonprofit PGC provides biennial resource assessments.
[4] U.S. Energy Information Administration (EIA) *2012 Annual Energy Outlook – Early Release*, Jan. 23, 2012.
[5] EIA *Short-Term Energy Outlook*, Dec. 2011.
[6] The primary states in the Rockies producing natural gas include Colorado, New Mexico, Utah and Wyoming.
[7] StatisticsCanada Table 131-0001- Supply and Disposition of Natural Gas, Total Marketable Production Alberta/British Columbia (converted from cubic meters), Dec, 2010; EIA Natural Gas Annual 2010 Table 2 – Natural Gas Production…By State, Dec, 2011.

Northwest uses a little more than 3 Bcf/d on average through the winter months (November through March), although that number can go significantly higher when the weather becomes unusually cold.

Figure 3. U.S. Natural Gas Production



Prepared by Northwest Gas Association based on information provided by EIA U.S. Natural Gas Dry Production and EIA 2012 AEO.

Production from these two areas is expected to approach 30 Bcf/d by 2021, due primarily to anticipated growth in shale and tight sands production in northeast BC (Figure 4) and continued production growth in the Rockies (Figure 5). These forecasts reflect development of the large Montney and Horn River plays in northeast BC and continued development of Niobrara shale in the U.S. Rockies.

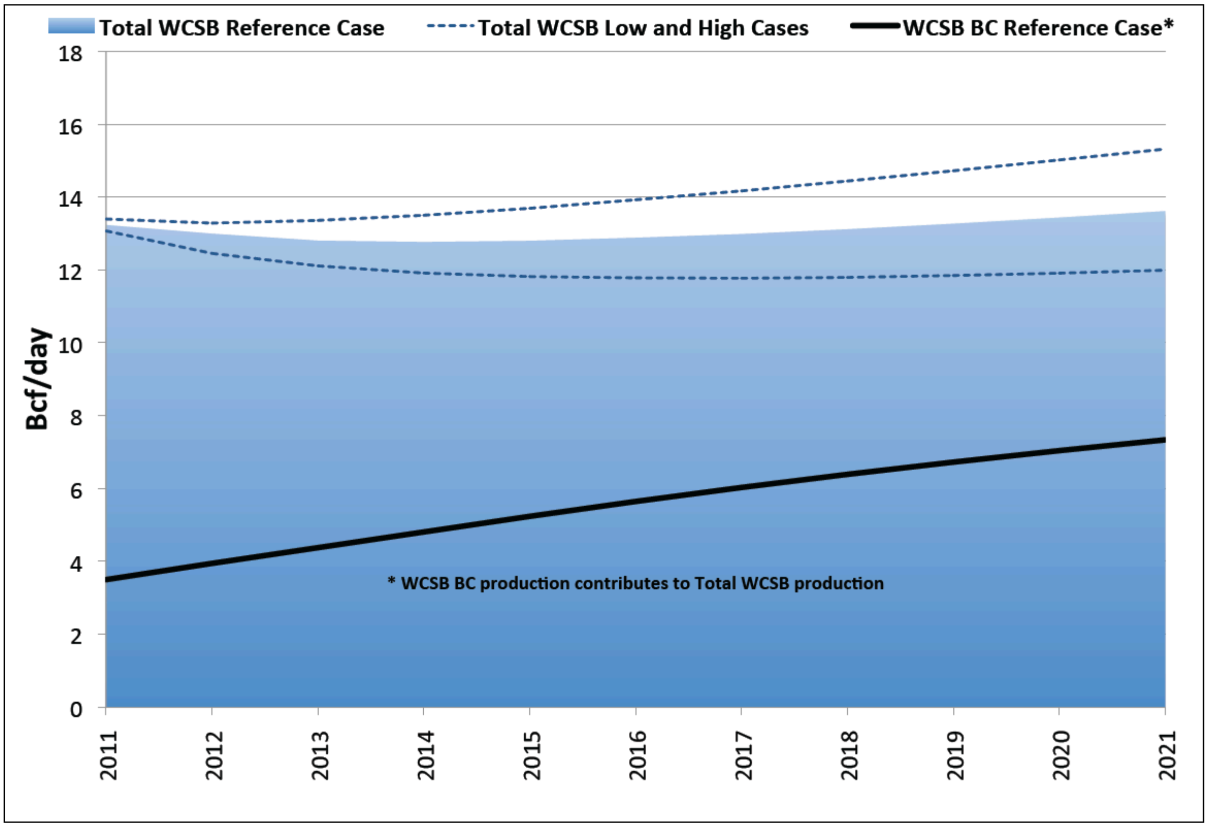
NOTES ON NATURAL GAS SUPPLIES

The natural gas supply picture is a rosy one today and is expected to remain that way for the foreseeable future. However, NWGA members are monitoring a number of evolving issues that could affect supplies, including:

- The impact environmental concerns may have on natural gas production.
- Whether volumes are sustained as producers shift away from dry gas production toward more profitable oil and other liquid hydrocarbon plays.
- The effect domestically if North American natural gas is exported to more lucrative global markets (e.g. Asia).

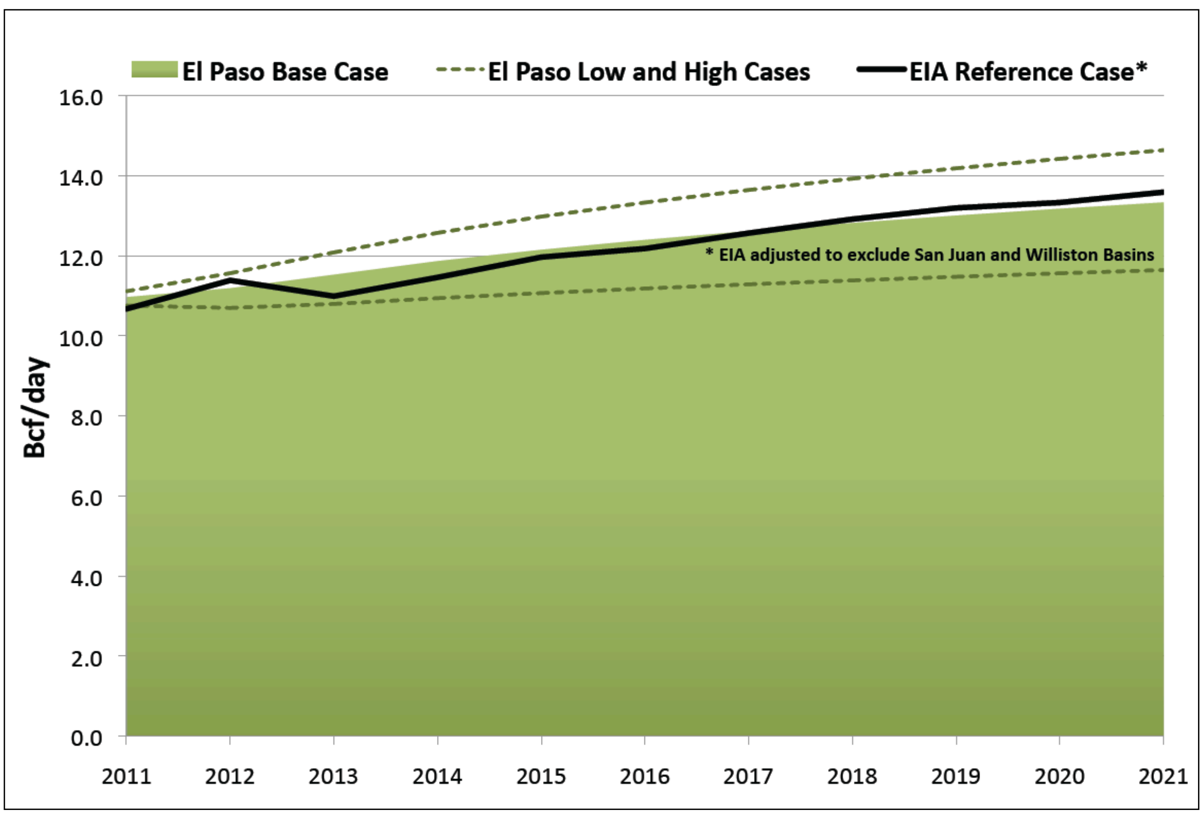
(For a comprehensive look at natural gas supply issues, including the rapidly growing role of shale gas, view the NWGA's White Paper, "Natural Gas Supply Serving the Pacific Northwest," available at www.nwga.org. Click on the Documents & Media tab and then select NWGA White Papers and Studies.)

Figure 4. WCSB Production Forecast[8]



Source: Canada National Energy Board

Figure 5. US Rockies Production Forecast[9]



Source: El Paso Western Pipelines, U.S. Energy Information Administration (EIA).

[8] National Energy Board, Canada's Energy Future – Table A4.2-4 Natural Gas Production, Nov. 2011.
[9] El Paso Pipelines, 2011-2021 Rockies Production Forecast; U.S. Energy Information Administration (EIA) *2012 Annual Energy Outlook – Early Release (adjusted to exclude San Juan and Williston Basins)*, Jan 23, 2012.

2012 GAS OUTLOOK - REGIONAL NATURAL GAS DEMAND

KEY CONCLUSIONS

- Over the next 10 years, natural gas consumption in the Pacific Northwest is expected to grow an average of 0.9 percent per year (see Table 1). Cumulative projected growth through 2021 is 8.1 percent.
- Peak day demand will grow on a year-over-year basis but is lower overall than was projected in the 2008 Outlook. Weather-driven residential and power generation loads continue to grow as a proportion of overall load, implying more variability in demand.
- Natural gas use to generate electricity will grow over the next decade. How much, how quickly and the nature of the demand for natural gas as a generation fuel is the subject of an ongoing dialogue between regional industry stakeholders.

Table 1. Project Regional Demand Growth through 2021[10]

	Low Demand Growth		Expected (base) Demand Growth		High Demand Growth	
	Average Annual	Cumulative	Average Annual	Cumulative	Average Annual	Cumulative
Total	**0.4%**	**3.2%**	**0.9%**	**8.1%**	**1.5%**	**12.3%**
Residential	0.3%	2.4%	1.1%	9.5%	1.9%	15.2%
Commercial	0.1%	1.1%	1.0%	8.9%	1.9%	15.2%
Industrial	0.6%	5.2%	0.6%	5.6%	0.7%	6.1%
Generation	0.4%	3.2%	1.0%	8.8%	1.6%	12.3%

Source: Northwest Gas Association

A CLOSER LOOK

Weak economic conditions continue to linger across the Pacific Northwest, affecting projections for the demand of natural gas across every sector. In fact, demand growth remains well short of NWGA forecasts made prior to the recession.

NWGA members are projecting positive year-over-year growth in demand, although the starting point for the base case demand forecast is about 13 percent lower than the 2008 Outlook (Figure 6). Most of the growth is expected to come from gas-fired electrical generation and modest but steady growth in core market demand (residential, commercial) as the economy recovers (Figure 7). Additional growth could come from fuel-switching by industrial customers and increasing deployment of natural gas vehicles (NGVs).

Residential – New housing construction, long a bastion of dependable growth for the natural gas industry in the Pacific Northwest, remains sluggish at 1.1 percent average annual growth (Table 1). Consumers are also using less natural gas as they install more efficient appliances, weatherize their homes or simply turn down the thermostat.

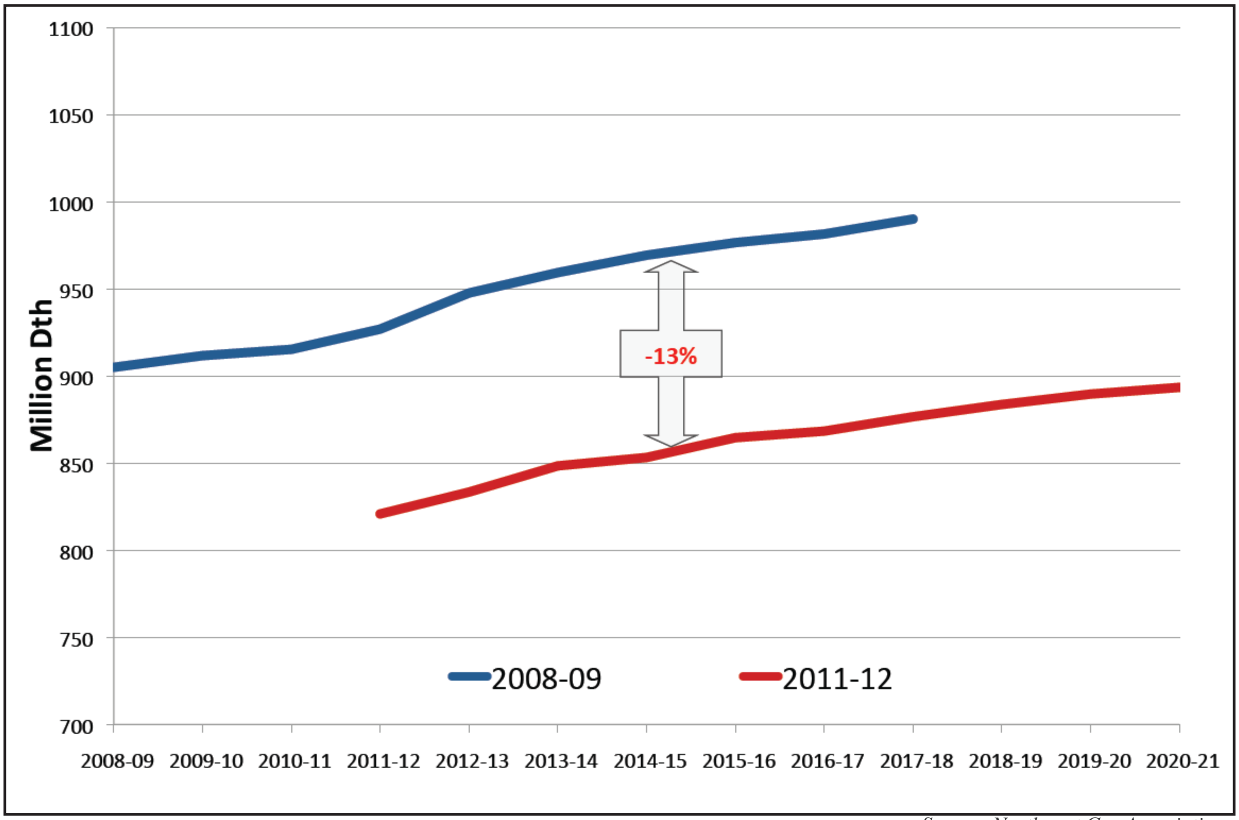
Commercial – As goes the economy, so goes commercial demand for natural gas. Our projection of 1.0 percent average annual growth reflects the expectation that large institutions and other commercial consumers of natural gas will continue to pare back usage until the economy recovers and will remain cautious about adding new facilities.

Industrial –The region lost almost 15 percent of its industrial gas load during the 2008-09 recession (Figure 8). Looking ahead, we are projecting 0.6 percent average annual growth in industrial gas demand. As illustrated in Figure 7, the increase in industrial demand accelerates as the economy recovers through 2013-14, due in large part to existing industry resuming pre-recession production levels and/or switching to natural gas.

Generation – Though subject to weather and the availability of other resources (hydro,[11] coal, wind, nuclear), overall the region is using more natural gas to generate electricity (Figure 8). This trend is expected to continue; we are forecasting an average annual growth rate of 1 percent in gas use for generation.

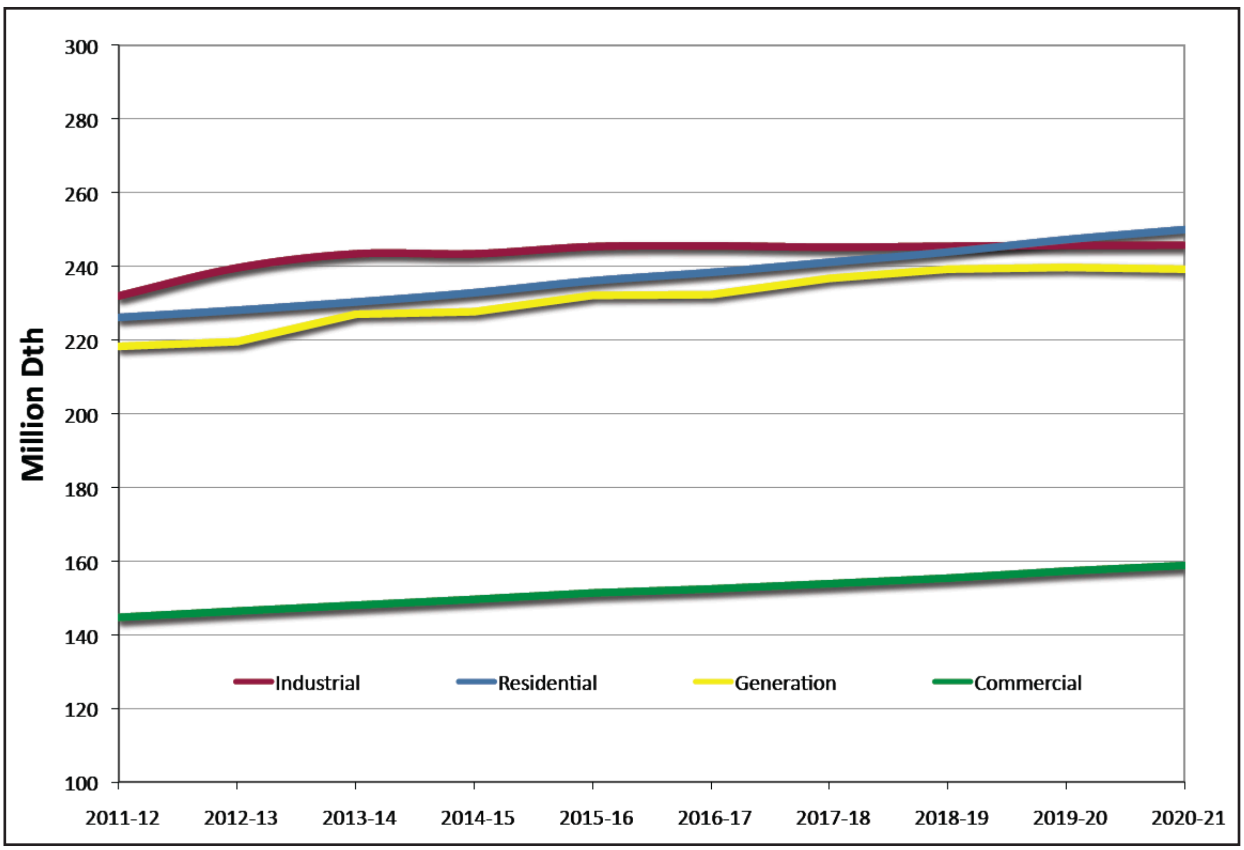
[10] Demand includes natural gas NWGA members project will be consumed in the region by the economic sectors referenced. Expected (base) demand growth reflects a delayed and modest economic recovery. Low demand growth assumes slower recovery, while high demand growth considers a more rapid economic expansion. Projected gas prices also influence the respective forecasts. The possibility of LNG exports from the region is not reflected in any of the demand cases.
[11] 2011 provided an extreme example: near hydro record conditions in the Pacific Northwest significantly reduced gas demand for generation.

Figure 6. Pre-Recession Outlook Forecast Comparison (Base Case)



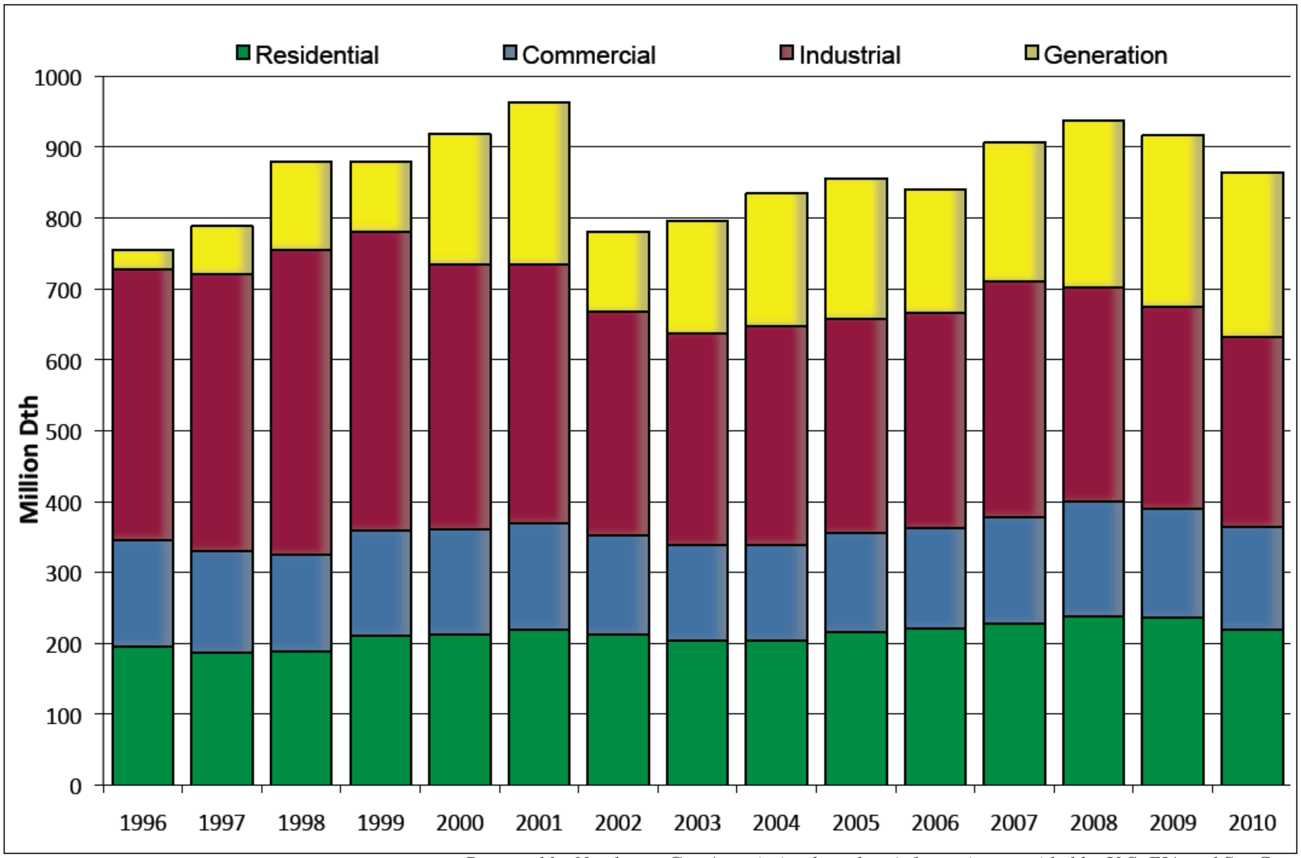
Source: Northwest Gas Association.

Figure 7. Base Case Demand Forecast by Sector



Source: Northwest Gas Association.

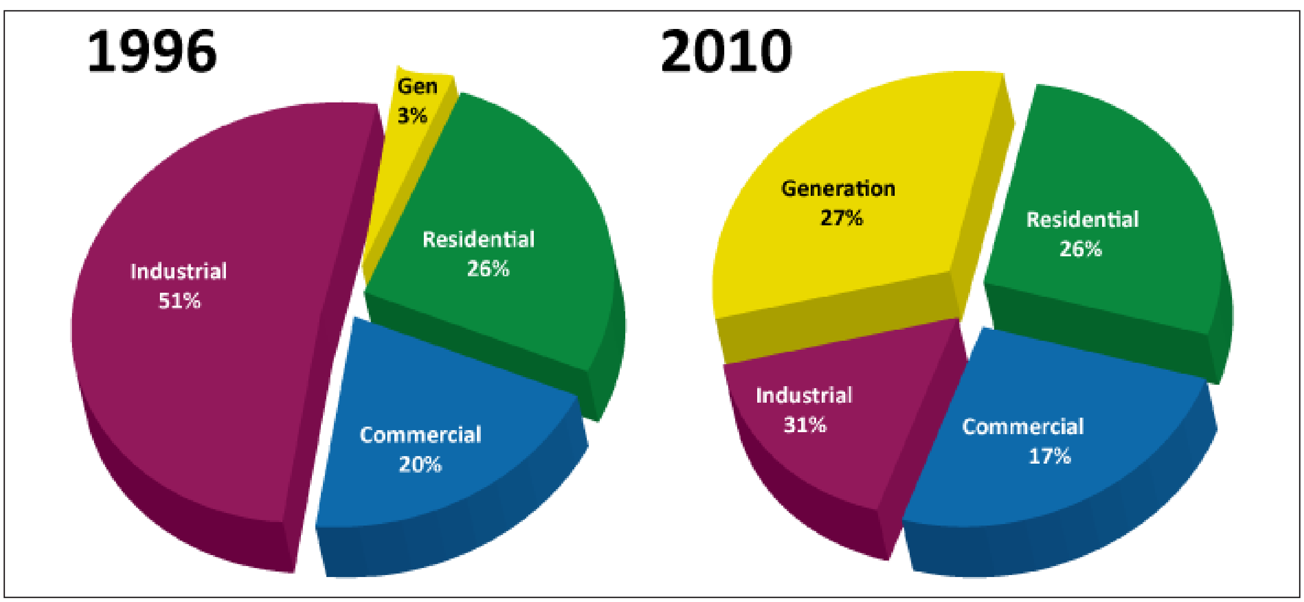
Figure 8. Historic Natural Gas Demand by Sector



Prepared by Northwest Gas Association based on information provided by U.S. EIA and StatCan.

One trend worth noting is the changing nature of the region's load profile. Whereas industrial load once comprised more than half of regional natural gas demand, it is less than one third today (31 percent; Figure 9). This is important because industrial load is generally constant year-around, regardless of weather conditions. Conversely, gas-fired generation – a load that can be quite variable depending on weather and other market conditions – once represented a small portion of natural gas demand in the region. It claimed more than 25 percent annual demand in 2010. Residential and commercial loads are also largely weather driven and hover around the same proportionate shares of annual demand.

Figure 9. Changing Demand Composition

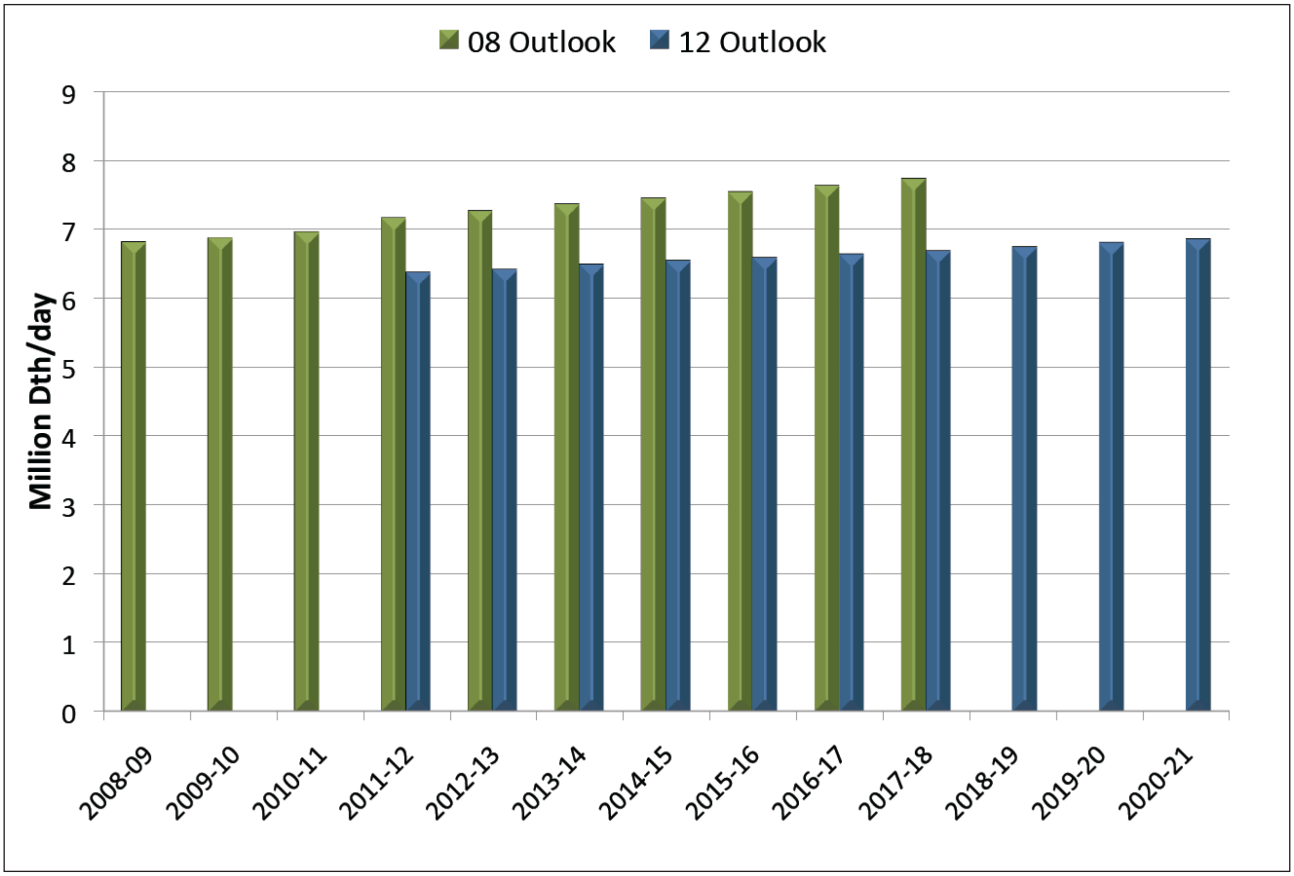


Prepared by Northwest Gas Association based on information provided by U.S. EIA and StatCan.

It is important to note that NWGA member companies plan beyond average or annual demand. To ensure customers are served during extreme weather conditions, planning standards address meeting demand on the coldest day that could occur in their service territory. These "peak" or "design" days are based on an actual 24-hour average temperature recorded at some point in the past.

Projected growth in peak day loads of NWGA member companies has declined a bit compared to forecasts issued prior to the recent recession (Figure 10), due to both the recession and effective energy efficiency measures, but the trend toward more variable, weather-dependent loads bears watching.

Figure 10. Regional Aggregated Peak Day Projection Comparison (Base Case)



Prepared by Northwest Gas Association based on the 2008 Outlook and the 2012 Outlook.

NOTES ON NATURAL GAS DEMAND

Understanding demand – how much, when, where and for what duration natural gas is needed – defines the type and size of infrastructure required to serve it. Regional growth in the use of natural gas has historically been driven by the construction of new housing, commercial and institutional facilities and new industry. The demand projections in this Outlook anticipate a slowly recovering economy.

However, forecast data don't always reflect what's occurring in real-time. The demand for natural gas in the region is changing and NWGA members are watching a number of demand drivers that are yet to be quantified:

- The magnitude and nature of the growing use of natural gas to generate electricity in the region, both to serve growing power demand and balance electrical systems as more intermittent renewable energy resources come online.
- The possibility of new industrial loads due to sustained lower natural gas commodity costs. This may include new industry as well as fuel-switching by existing industry.
- The use of natural gas as a transportation fuel in a variety of applications. (For more information about natural gas vehicles, click here to view the NWGA whitepaper series.)

NORTHWEST GAS ASSOCIATION
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2012 GAS OUTLOOK - REGIONAL PRICES

KEY CONCLUSIONS

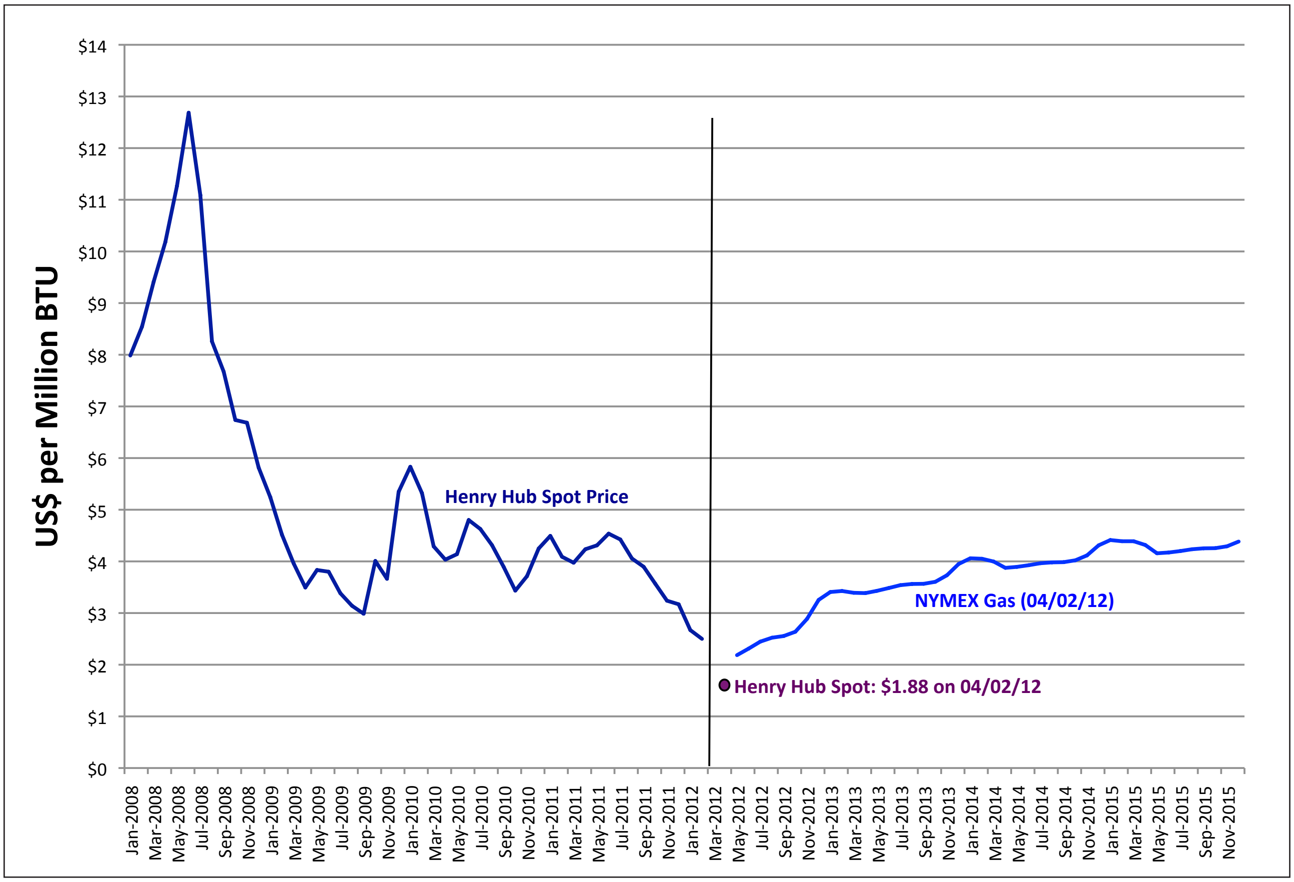
- Natural gas prices in the Pacific Northwest continue to reflect abundant supply availability. Daily spot prices through 2011 averaged a little less than $4 per million British thermal units (MMBtu), according to the EIA, compared to an average of almost $9/MMBtu in 2008.

- Depending on the pace of economic recovery and supply/demand growth, most forecasts project prices to average between $4 and $7/MMBtu through 2021 when adjusted for inflation.

A CLOSER LOOK

Down dramatically from the highs experienced in 2008, natural gas prices are at historic lows (Figure 11), and are expected to hover around current levels until the economy begins a sustained recovery when supply and demand will become more balanced. In response, utilities in the region, which pass through purchased gas costs to customers without markup, have been able to lower commodity rates for the benefit of customers. Even factoring in a growing economy, prices are not expected to rise substantially due to the shale gas dynamics described earlier (Figure 12).

Figure 11. Henry Hub Prices, Historic and Futures[12]

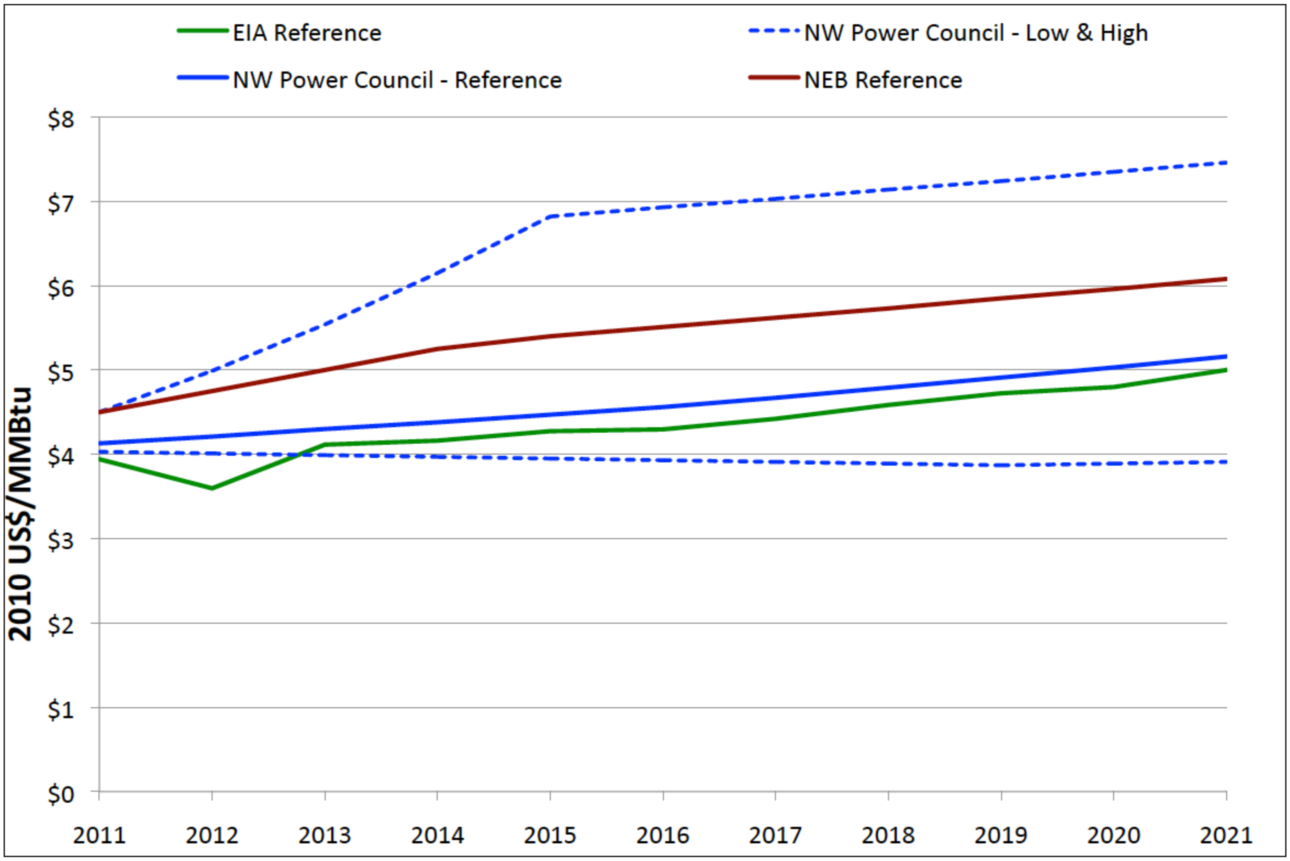


Prepared by Northwest Gas Association based on information provided by EIA Monthly NatGas Report; EIA Short Term Energy Outlook; NYMEX.

In addition to delivering price-lowering volumes to the market, shale gas has another benefit: geographically diverse sources of supply across the continent. Shorter distances between production and consumption reduce transportation costs and mitigate pricing risks from far-flung conventional sources subject to disruptions.

[12] Natural gas is bought and sold at several locations throughout North America. The Henry Hub in Louisiana is the benchmark against which prices at all other trading hubs are compared. Futures contracts bought and sold on the New York Mercantile Exchange (NYMEX) are also transacted at the Henry Hub.

Figure 12. Long-Term Henry Hub Natural Gas Price Forecasts[13, 14]



Prepared by Northwest Gas Association based on information provided by EIA, NW Power Council and NEB.

NOTES ON NATURAL GAS PRICES

Given the continuing abundance of continental supply, consumers are likely to benefit from moderate natural gas prices for the foreseeable future. Still, NWGA members are tracking some market changes that could influence natural gas prices in the future:

- Shifting investment away from dry gas production to oil and other liquid hydrocarbons.
- The impact of increased regulation on production practices and access to viable reserves.
- The pace of economic growth across North America.
- The accelerated adoption of natural gas as a fuel for generating electricity, and as an alternative to petroleum-based fuels in the transportation and industrial sectors.
- The inter-regional price impacts of changing natural gas flows across North America.
- The benefits and costs of exporting North American natural gas to premium overseas markets.

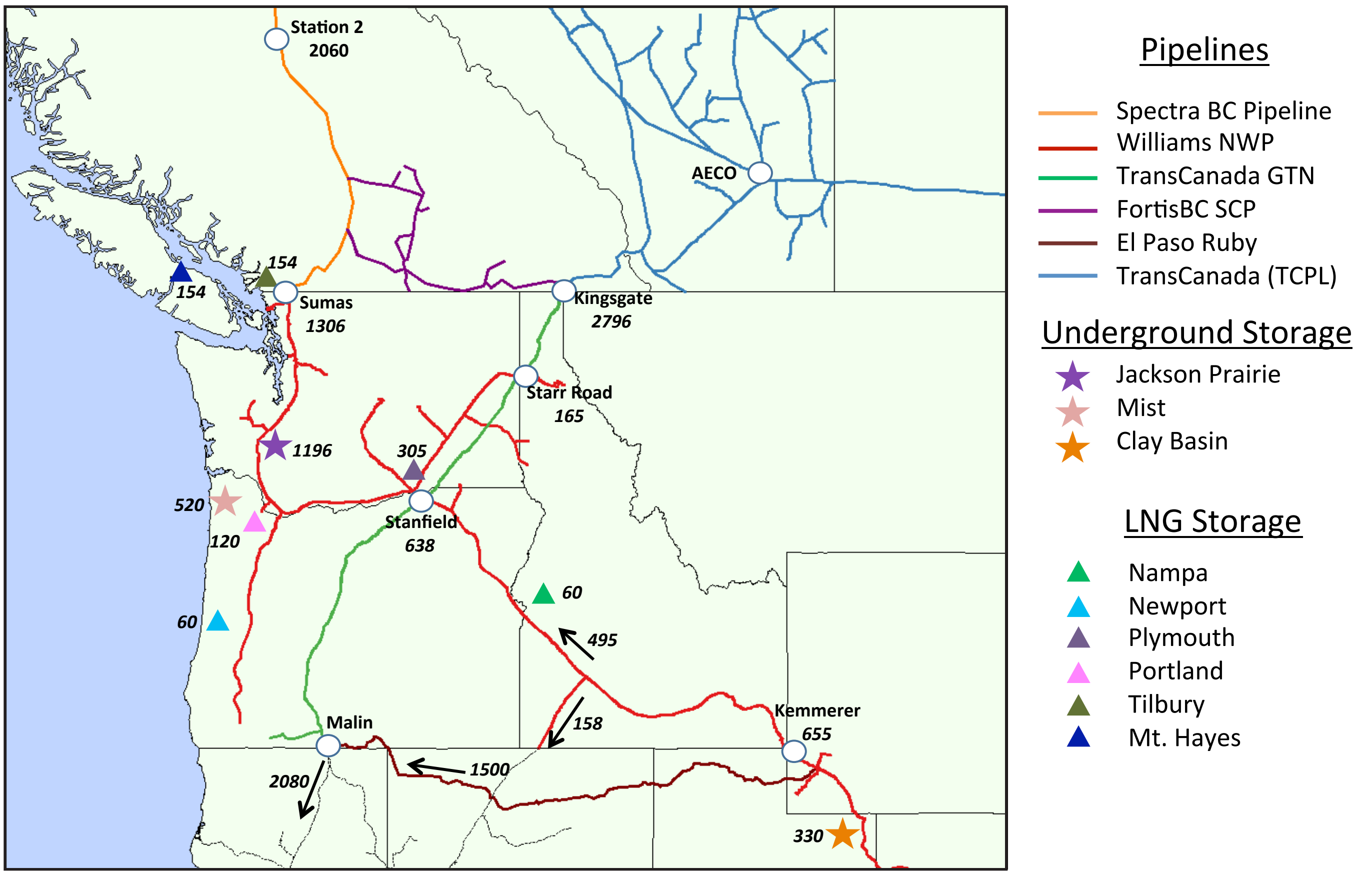
[13] Northwest Power Conservation Council, *Update to the Council's Forecast of Fuel Prices*, Aug. 2011; Canada NEB, *Canada's Energy Future: Energy Supply and Demand Projections to 2035*, Nov. 2011; US EIA, *2012 Annual Energy Outlook (Early Release)*, Jan. 2012.
[14] Each forecast is adjusted for inflation in constant 2010 US$.

2012 GAS OUTLOOK - REGIONAL SYSTEM CAPACITY

KEY CONCLUSIONS

- The existing system of natural gas pipelines and storage facilities in the Northwest has reliably served the load requirements of the region. A number of regional pipeline and storage expansions have been undertaken when needed to maintain reliability.
- Based on current data and assumptions, peak day demand could approach or exceed the region's infrastructure capacity within the forecast horizon.
- The changing nature of the region's natural gas demand will have implications for how existing gas infrastructure is utilized and the timing and type of expansions or additions.

FIGURE 13. KEY INFRASTRUCTURE IN THE PACIFIC NORTHWEST



Source: Northwest Gas Association - Numbers indicate delivery or takeaway capacities in MDth.

A CLOSER LOOK

The Pacific Northwest's 48,000-mile network of transmission and distribution pipelines safely and reliably serves more than 3.2 million natural gas customers. Combined with underground and peak storage facilities (Table 2), the region's natural gas infrastructure is currently capable of delivering more than 6.5 million Dth/day of gas at peak capacity.

Because natural gas utilities are committed to preventing service disruptions regardless of the circumstances, they design their systems to accommodate extreme but still possible weather conditions (peak or design days).

Figure 14 aggregates the design days of NWGA members located in the I-5 Corridor and BC (where most of the region's population resides) and plots them against available capacity. Under the base and high cases, peak day demand could begin to stress the system, approaching or exceeding the region's infrastructure capacity within the forecast horizon.

A few notes are in order concerning Figure 14. While the probability of design days occurring in every system across the region on the same day ("coincidental peak day") is small, the possibility of very cold weather occurring simultaneously along the I-5 Corridor is reasonably high. Furthermore, Figure 14 assumes that existing capacity in the region is operating at 100 percent deliverability.[15] Figure 14 also assumes that gas will not flow on a peak day to customers without firm pipeline transportation contracts (typically industrial users or electricity generators with alternate fuels).

[15] Regional capacity includes all existing facilities, including Fortis BC's Mt. Hayes peak LNG facility, which came online in 2011. Proposed projects are not included in capacity.

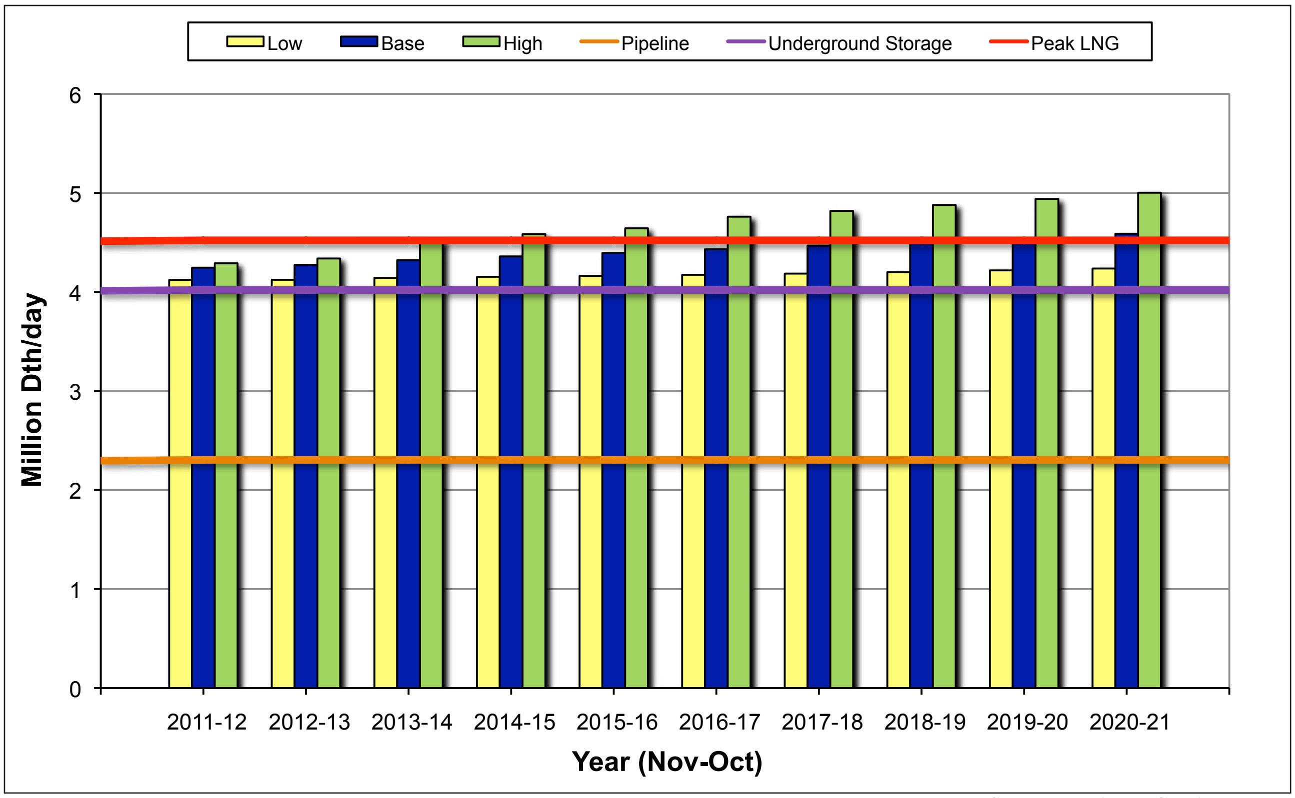
Table 2. Regional Storage Facilities

Facility	Owner	Type	Capacity[1] (MDth)	Max Withdrawal (MDth/day)
Jackson Prairie, WA	Avista, PSE, NW Pipeline	Underground	25,448	1,196 [2]
Mist, OR	NW Natural	Underground	16,100	520 [2]
	Underground Subtotal		41,548	1,716
Plymouth, WA	NW Pipeline	LNG	2,388	305
Newport, OR	NW Natural	LNG	1,000	60
Portland, OR	NW Natural	LNG	600	120
Tilbury, BC	FortisBC Energy	LNG	585	154
Nampa, ID	Intermountain Gas	LNG	588	60
Gig Harbor, WA	PSE	LNG	31	3
Swarr Station, WA	PSE	LPG[3]	130	10
Mt. Hayes, BC	FortisBC Energy	LNG	1,540	154
	LNG/LPG Subtotal		6,862	866
	TOTAL STORAGE		**48,410**	**2,582**

[1] Working gas capacity; gas that can be used to serve the market.
[2] Start of season or full rate; storage withdrawal rates decline as working gas volumes decline below certain levels.
[3] LPG = Liquid Propane Gas and Air mixture

Source: Northwest Gas Association

Figure 14. I-5 Peak Day



Source: Northwest Gas Association

Finally, the states of Oregon and Washington have negotiated two coal plant closures in the region within the planning horizon (Boardman in 2020 and Centralia in two phases, 2020 and 2025). Plant owners have announced their intent to use natural gas-fired generation to replace some or all of the output of those plants. The replacement plants are not included in Figure 14 because utilities have just begun their planning and the type and size of the plants that may be built have not been determined. However, if these plants are built, they will represent significant gas volumes that would require capacity within the forecast period.

Analyses such as the above help send signals to the market of an impending need for additional capacity. Market participants weigh the probability of disruptions and the costs of various infrastructure options to make decisions about what is needed and when.

In response to market signals, several projects have been proposed to accommodate future delivery capacity needs. The first completed – the 683-mile Ruby Pipeline built by El Paso Natural Gas – began operating in July 2011, connecting the Opal trading hub in southwestern Wyoming to the Malin trading hub at the California-Oregon border. Ruby's 1.5 Bcf/d capacity brings gas supply diversity to Northern California and Eastern Oregon and Washington by providing additional access to the prolific Rockies supply basin.

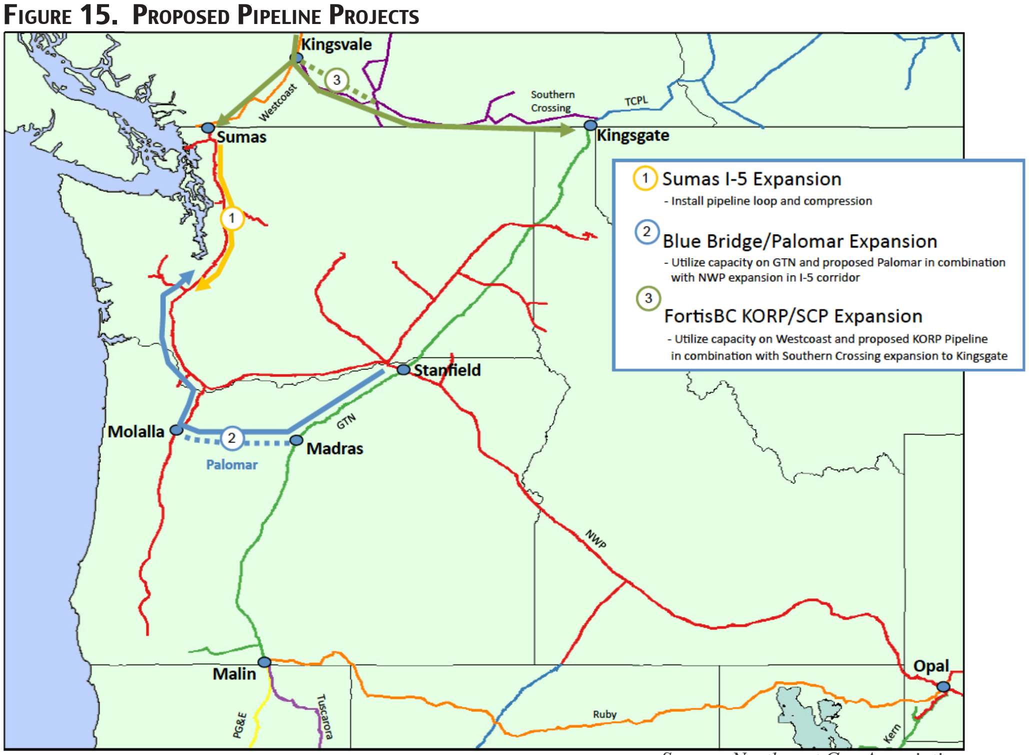
Reductions in projected demand and a slow economic recovery have canceled or deferred several of the other projects. However, it is only a matter of time before new capacity within the region will be required. Figure 15 illustrates the active proposals, which include:

Sumas I-5 Expansion - Williams Northwest Pipeline (NWP) continues to explore options to expand transportation service from Sumas, WA to markets along the I-5 corridor. The expansion would involve looping sections of 36-inch diameter pipeline with the existing pipeline, plus additional compression at existing compressor stations along the I-5 corridor. Actual miles of pipe and incremental compression added will depend on incremental volume and delivery pattern, but can be readily scaled to meet market demand.

Blue Bridge/Palomar Expansion –Williams Northwest Pipeline (NWP) is working with the current Palomar pipeline project sponsors – NW Natural and TransCanada GTN – to develop the Cascade (eastern) section of Palomar in conjunction with an expansion of the existing NWP system. The Cascade section of Palomar would consist of a 106-mile, 30-inch diameter pipeline that would run from GTN's mainline in central Oregon to a NW Natural/NWP hub near Molalla, Oregon – enhancing delivery capacity to the I-5 Corridor. Palomar would be a bi-directional pipeline with an initial capacity of approximately 300 million cubic feet per day (MMcf/d), expandable up to 750 MMcf/d. It would be linked to an expansion on the existing NWP system to deliver gas to other markets along the I-5 corridor.

FortisBC Kingsvale-Oliver Reinforcement Expansion – FortisBC and Spectra Energy are considering a 100-mile, 24-inch expansion project from Kingsvale to Oliver, BC to expand service to Pacific Northwest and California markets. Removing constraints will allow expansion of Spectra's T-South Enhanced Service offering, which provides shippers with the options of delivering to Sumas or the Kingsgate market. Expansion of the bi-directional Southern Crossing system would increase capacity at Sumas during peak demand periods. Initial capacity from the Spectra system to Kingsgate would be 300 MMcf/d, expandable to 450 MMcf/d. Expanded east-to-west flow capability will increase delivery of supply into Sumas to serve the I-5 Corridor by an additional 150 MMcf/d.

FIGURE 15. PROPOSED PIPELINE PROJECTS



Source: Northwest Gas Association

NOTES ON REGIONAL NATURAL GAS SYSTEM CAPACITY

NWGA members continuously monitor a number of dynamics to ensure that regional natural gas consumers have the gas they need when and where they need it, including:

- When, where and how much natural gas the region will require to generate electricity (and support intermittent renewable sources of generation).
- Impacts of the region's changing load profile on the existing natural gas infrastructure.
- Not if but when new or expanded infrastructure will be needed. Projects take time to develop, so foresight is imperative.

2012 Appendices

Northwest Gas Association
2012 Natural Gas Outlook
Peak Day Capacity

SUPPLY	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Pipeline Interconnects	**3,942,149**	**3,932,459**	**3,932,459**	**3,932,459**	**3,932,459**	**3,932,459**	**3,932,459**	**3,932,459**	**3,932,459**	**3,932,459**
WCSB via TCPL/GTN	**1,463,884**	**1,454,194**	**1,454,194**	**1,454,194**	**1,454,194**	**1,454,194**	**1,454,194**	**1,454,194**	**1,454,194**	**1,454,194**
Stanfield (NWP from GTN)	*638,000*	*638,000*	*638,000*	*638,000*	*638,000*	*638,000*	*638,000*	*638,000*	*638,000*	*638,000*
Starr Rd (NWP from GTN)	*165,000*	*165,000*	*165,000*	*165,000*	*165,000*	*165,000*	*165,000*	*165,000*	*165,000*	*165,000*
Palouse (NWP from GTN)	*20,000*	*20,000*	*20,000*	*20,000*	*20,000*	*20,000*	*20,000*	*20,000*	*20,000*	*20,000*
GTN Direct Connects	*444,253*	*444,253*	*444,253*	*444,253*	*444,253*	*444,253*	*444,253*	*444,253*	*444,253*	*444,253*
Kingsgate/Yahk BC Interior from TCPL	*196,631*	*186,941*	*186,941*	*186,941*	*186,941*	*186,941*	*186,941*	*186,941*	*186,941*	*186,941*
Rockies via NWP	**495,000**	**495,000**	**495,000**	**495,000**	**495,000**	**495,000**	**495,000**	**495,000**	**495,000**	**495,000**
NWP north from NWP south	*655,000*	*655,000*	*655,000*	*655,000*	*655,000*	*655,000*	*655,000*	*655,000*	*655,000*	*655,000*
Max Demand on Reno Lateral	*(160,000)*	*(160,000)*	*(160,000)*	*(160,000)*	*(160,000)*	*(160,000)*	*(160,000)*	*(160,000)*	*(160,000)*	*(160,000)*
WCSB via DEGT	**1,983,265**	**1,983,265**	**1,983,265**	**1,983,265**	**1,983,265**	**1,983,265**	**1,983,265**	**1,983,265**	**1,983,265**	**1,983,265**
T-South to Huntingdon	*1,753,060*	*1,753,060*	*1,753,060*	*1,753,060*	*1,753,060*	*1,753,060*	*1,753,060*	*1,753,060*	*1,753,060*	*1,753,060*
T-South to BC Interior	*178,705*	*178,705*	*178,705*	*178,705*	*178,705*	*178,705*	*178,705*	*178,705*	*178,705*	*178,705*
T-South to Kingsvale	*51,500*	*51,500*	*51,500*	*51,500*	*51,500*	*51,500*	*51,500*	*51,500*	*51,500*	*51,500*
Storage	**2,582,808**	**2,582,808**	**2,582,808**	**2,582,808**	**2,582,808**	**2,582,808**	**2,582,808**	**2,582,808**	**2,582,808**	**2,582,808**
Jackson Prairie (NWP from JP)	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000
Mist Storage (NWN)	520,000	520,000	520,000	520,000	520,000	520,000	520,000	520,000	520,000	520,000
Plymouth (NWP from LNG)	305,300	305,300	305,300	305,300	305,300	305,300	305,300	305,300	305,300	305,300
Newport/Portland LNG (NWN)	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000
Nampa LNG (IGC)	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000
Gig Harbor Satellite LNG (PSE)	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Swarr Stn Propane (PSE)	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Tilbury LNG (FortisBC)	155,466	155,466	155,466	155,466	155,466	155,466	155,466	155,466	155,466	155,466
Mt. Hayes LNG (FortisBC)	153,042	153,042	153,042	153,042	153,042	153,042	153,042	153,042	153,042	153,042
Total Available Supply	6,524,957	6,515,267	6,515,267	6,515,267	6,515,267	6,515,267	6,515,267	6,515,267	6,515,267	6,515,267

Northwest Gas Association

2012 Natural Gas Outlook

Annual Demand Summary (Dth) - Base Case

Region/Sector	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
BC Lower Mainland & Van. Island	**144,230,428**	**142,889,136**	**143,254,955**	**143,656,480**	**143,954,063**	**144,262,632**	**144,591,862**	**144,938,228**	**145,302,383**	**145,685,006**
Residential	54,679,629	54,664,103	54,643,114	54,658,399	54,645,932	54,619,963	54,596,321	54,575,082	54,556,331	54,540,153
Commercial (Sales)	38,854,033	39,176,189	39,503,700	39,834,264	40,169,339	40,508,027	40,860,899	41,228,504	41,611,411	42,010,211
Industrial (Transport & Interruptible)	30,694,402	30,760,642	30,889,366	30,971,552	30,972,770	30,972,770	30,972,770	30,972,770	30,972,770	30,972,770
Power Generation	20,002,364	18,288,202	18,218,774	18,192,265	18,166,022	18,161,871	18,161,871	18,161,871	18,161,871	18,161,871
W. Washington	**253,856,136**	**261,258,818**	**270,443,584**	**271,901,158**	**274,609,952**	**273,743,249**	**278,279,643**	**280,575,298**	**277,086,857**	**277,529,658**
Residential	70,337,163	71,868,314	73,351,825	74,786,049	76,474,212	77,592,772	78,976,039	80,367,645	82,089,987	83,286,772
Commercial (Sales)	42,518,235	43,494,798	44,392,511	45,172,592	45,950,960	46,361,902	46,921,653	47,521,674	48,343,097	48,853,277
Industrial (Transport)	74,979,764	78,807,932	79,595,016	79,566,825	79,598,815	79,372,283	79,253,224	79,139,977	79,119,262	78,978,516
Power Generation	66,020,974	67,087,773	73,104,232	72,375,692	72,585,965	70,416,292	73,128,726	73,546,001	67,534,511	66,411,093
W. Oregon	**123,257,234**	**126,750,625**	**129,286,535**	**131,036,934**	**132,087,238**	**132,486,834**	**133,203,184**	**133,963,393**	**135,055,527**	**136,120,475**
Residential	37,817,784	37,956,616	38,371,094	38,890,045	39,637,995	40,181,710	40,891,371	41,603,778	42,484,384	43,370,124
Commercial (Sales)	23,499,533	23,361,116	23,335,383	23,332,670	23,403,568	23,294,759	23,300,799	23,348,173	23,517,690	23,678,574
Industrial (Transport & Interruptible)	41,939,917	45,432,893	47,580,058	48,814,219	49,045,675	49,010,365	49,011,014	49,011,441	49,053,454	49,071,778
Power Generation	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000
BC Interior	**49,799,561**	**49,713,313**	**49,493,423**	**49,504,415**	**49,481,952**	**49,461,001**	**49,450,907**	**49,434,715**	**49,429,938**	**49,431,156**
Residential	16,638,159	16,568,842	16,506,661	16,445,783	16,377,871	16,309,233	16,240,908	16,172,895	16,105,192	16,037,799
Commercial (Sales)	10,140,493	10,181,300	10,223,787	10,267,521	10,312,507	10,360,195	10,418,426	10,470,247	10,533,172	10,601,783
Industrial (Transport & Interruptible)	23,020,909	22,963,171	22,762,975	22,791,111	22,791,573	22,791,573	22,791,573	22,791,573	22,791,573	22,791,573
Power Generation	-	-	-	-	-	-	-	-	-	-
E. Washington & N. Idaho	**92,935,737**	**92,793,975**	**93,711,847**	**95,042,932**	**97,309,146**	**99,046,651**	**100,559,296**	**102,262,646**	**106,241,310**	**107,481,282**
Residential	17,941,006	18,149,436	18,305,518	18,537,073	18,962,668	19,253,261	19,589,693	19,938,110	20,320,619	20,616,056
Commercial (Sales)	13,253,779	13,581,315	13,797,513	14,024,045	14,303,632	14,495,624	14,714,524	14,939,129	15,187,291	15,364,731
Industrial (Transport & Interruptible)	28,725,625	28,789,878	29,022,595	29,241,453	29,351,457	29,507,997	29,685,436	29,863,933	30,049,386	30,226,730
Power Generation	33,015,327	32,273,347	32,586,221	33,240,361	34,691,389	35,789,771	36,569,644	37,521,475	40,684,014	41,273,765
E. Oregon & Medford	**99,550,108**	**99,067,865**	**100,101,328**	**101,163,039**	**104,285,696**	**105,837,846**	**107,065,948**	**108,491,284**	**112,136,666**	**112,470,534**
Residential	7,630,346	7,926,540	8,097,848	8,262,317	8,464,636	8,643,913	8,832,706	9,021,821	9,225,420	9,394,426
Commercial (Sales)	5,584,104	5,820,511	5,911,371	6,003,280	6,109,120	6,198,304	6,293,893	6,389,437	6,494,296	6,574,032
Industrial (Transport & Interruptible)	9,572,001	9,542,343	9,565,813	9,582,032	9,597,893	9,613,936	9,629,373	9,642,163	9,656,997	9,679,389
Power Generation	76,763,658	75,778,472	76,526,295	77,315,409	80,114,046	81,381,693	82,309,976	83,437,864	86,759,953	86,822,687
S. Idaho	**57,264,286**	**60,960,197**	**62,177,472**	**60,983,354**	**62,900,239**	**63,557,593**	**63,482,258**	**64,022,012**	**64,397,763**	**64,778,417**
Residential	21,023,838	20,895,600	20,969,035	21,193,812	21,436,566	21,678,012	21,915,851	22,158,506	22,406,502	22,657,734
Commercial (Sales)	10,830,462	10,764,400	10,802,230	10,918,025	11,043,080	11,167,461	11,289,984	11,414,988	11,542,743	11,672,166
Industrial (Transport & Interruptible)	22,996,223	23,223,721	23,906,208	22,371,517	23,920,593	24,212,120	23,776,423	23,948,518	23,948,518	23,948,518
Power Generation	2,413,763	6,076,476	6,500,000	6,500,000	6,500,000	6,500,000	6,500,000	6,500,000	6,500,000	6,500,000
PNW Annual Demand - Base	**820,893,491**	**833,433,930**	**848,469,144**	**853,288,312**	**864,628,284**	**868,395,807**	**876,633,098**	**883,687,576**	**889,650,445**	**893,496,528**
Residential	226,067,925	228,029,451	230,245,095	232,773,479	235,999,879	238,278,864	241,042,888	243,837,837	247,188,435	249,903,064
Commercial (Sales)	144,680,640	146,379,629	147,966,495	149,552,397	151,292,205	152,386,271	153,800,178	155,312,152	157,229,700	158,754,773
Industrial (Transport & Interruptible)	231,928,841	239,520,580	243,322,032	243,338,708	245,278,778	245,481,045	245,119,815	245,370,376	245,591,960	245,669,274
Power Generation	218,216,086	219,504,270	226,935,522	227,623,728	232,057,422	232,249,627	236,670,217	239,167,211	239,640,350	239,169,416

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2012 Natural Gas Outlook

Annual Demand Summary (Dth) - High Case

Region/Sector	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
BC Lower Mainland & Van. Island	**145,298,798**	**144,978,939**	**146,385,457**	**147,839,255**	**149,129,471**	**150,468,587**	**151,846,468**	**153,259,816**	**154,710,133**	**156,198,903**
Residential	55,244,308	55,794,884	56,346,961	56,934,238	57,477,617	58,030,720	58,591,557	59,160,334	59,737,267	60,322,585
Commercial (Sales)	39,230,536	39,939,123	40,663,268	41,400,886	42,153,719	42,932,228	43,737,104	44,569,531	45,430,750	46,322,062
Industrial (Transport & Interruptible)	30,694,402	30,760,642	30,889,366	30,971,552	30,972,770	30,972,770	30,972,770	30,972,770	30,972,770	30,972,770
Power Generation	20,129,553	18,484,291	18,485,863	18,532,579	18,525,365	18,532,869	18,545,037	18,557,180	18,569,345	18,581,486
W. Washington	**256,241,152**	**264,473,238**	**285,204,057**	**290,234,036**	**293,425,978**	**301,166,854**	**307,984,924**	**312,480,109**	**306,686,293**	**307,033,171**
Residential	70,875,917	72,814,583	74,715,410	76,594,591	78,755,014	80,356,517	82,245,211	84,162,161	86,445,228	88,198,581
Commercial (Sales)	42,987,108	44,272,221	45,473,146	46,565,528	47,664,853	48,393,743	49,285,379	50,229,117	51,416,264	52,283,188
Industrial (Transport)	76,357,152	80,298,660	81,210,999	81,294,105	81,436,163	81,314,410	81,301,851	81,294,654	81,383,403	81,345,512
Power Generation	66,020,974	67,087,773	83,804,502	85,779,813	85,569,949	91,102,185	95,152,484	96,794,177	87,441,399	85,205,889
W. Oregon	**125,787,561**	**129,908,638**	**133,135,776**	**135,416,476**	**136,879,285**	**137,643,577**	**138,652,918**	**139,662,338**	**140,985,463**	**142,019,372**
Residential	38,277,025	38,668,569	39,367,997	40,185,724	41,199,785	41,998,964	42,915,813	43,802,955	44,842,212	45,834,063
Commercial (Sales)	23,899,966	23,921,075	24,070,937	24,239,810	24,446,029	24,448,514	24,540,604	24,662,699	24,902,736	24,926,470
Industrial (Transport & Interruptible)	43,610,569	47,318,994	49,696,842	50,990,942	51,233,471	51,196,099	51,196,501	51,196,683	51,240,515	51,258,840
Power Generation	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000
BC Interior	**50,071,103**	**50,257,492**	**50,315,541**	**50,600,311**	**50,848,562**	**51,108,583**	**51,376,341**	**51,652,294**	**51,936,941**	**52,230,829**
Residential	16,810,225	16,912,350	17,023,230	17,133,201	17,229,277	17,330,788	17,432,925	17,535,691	17,639,090	17,743,127
Commercial (Sales)	10,239,970	10,381,971	10,527,440	10,675,999	10,827,711	10,986,222	11,151,843	11,325,030	11,506,278	11,696,130
Industrial (Transport & Interruptible)	23,020,909	22,963,171	22,764,871	22,791,111	22,791,573	22,791,573	22,791,573	22,791,573	22,791,573	22,791,573
Power Generation	-	-	-	-	-	-	-	-	-	-
E. Washington & N. Idaho	**111,847,036**	**112,691,654**	**114,309,609**	**116,642,237**	**123,861,837**	**122,883,729**	**126,234,505**	**130,028,110**	**130,511,760**	**130,881,722**
Residential	19,193,491	19,570,024	19,916,291	20,352,875	20,762,447	21,123,831	21,528,413	21,974,720	22,456,118	23,036,077
Commercial (Sales)	14,618,026	15,224,226	15,658,282	16,141,995	16,592,734	17,013,051	17,458,516	17,933,199	18,443,804	19,031,883
Industrial (Transport & Interruptible)	29,277,308	29,339,562	29,582,970	29,812,237	29,933,700	30,101,181	30,290,679	30,482,278	30,679,850	30,869,776
Power Generation	48,758,211	48,557,842	49,152,065	50,335,130	56,572,956	54,645,666	56,956,897	59,637,914	58,931,988	57,943,986
E. Oregon & Medford	**113,273,267**	**115,074,303**	**116,742,489**	**117,296,435**	**119,702,692**	**120,590,686**	**121,988,018**	**123,293,422**	**124,796,008**	**124,836,267**
Residential	8,078,885	8,547,390	8,862,141	9,190,111	9,525,937	9,856,306	10,182,376	10,499,678	10,847,190	11,197,977
Commercial (Sales)	5,887,871	6,215,016	6,365,178	6,514,267	6,663,540	6,807,317	6,954,216	7,099,445	7,262,528	7,417,794
Industrial (Transport & Interruptible)	9,811,397	9,779,801	9,808,099	9,828,847	9,849,657	9,870,902	9,891,484	9,909,386	9,930,047	9,958,285
Power Generation	89,495,113	90,532,096	91,707,072	91,763,211	93,663,558	94,056,161	94,959,942	95,784,913	96,756,242	96,262,211
S. Idaho	**58,639,821**	**62,618,097**	**64,202,934**	**63,299,639**	**65,557,709**	**66,566,484**	**66,852,240**	**67,764,709**	**68,524,855**	**68,951,636**
Residential	21,931,691	21,989,814	22,305,839	22,722,561	23,190,496	23,663,880	24,140,040	24,628,686	25,130,382	25,412,058
Commercial (Sales)	11,298,144	11,328,086	11,490,887	11,705,562	11,946,619	12,190,484	12,435,778	12,687,505	12,945,955	13,091,060
Industrial (Transport & Interruptible)	22,996,223	23,223,721	23,906,208	22,371,517	23,920,593	24,212,120	23,776,423	23,948,518	23,948,518	23,948,518
Power Generation	2,413,763	6,076,476	6,500,000	6,500,000	6,500,000	6,500,000	6,500,000	6,500,000	6,500,000	6,500,000
PNW Annual Demand - High	**861,158,737**	**880,002,362**	**910,295,863**	**921,328,389**	**939,405,534**	**950,428,500**	**964,935,414**	**978,140,797**	**978,151,452**	**982,151,900**
Residential	230,411,543	234,297,613	238,537,868	243,113,300	248,140,574	252,361,006	257,036,334	261,764,224	267,097,489	271,744,468
Commercial (Sales)	148,161,621	151,281,720	154,249,137	157,244,046	160,295,205	162,771,557	165,563,440	168,506,526	171,908,314	174,768,587
Industrial (Transport & Interruptible)	235,767,960	243,684,551	247,859,355	248,060,311	250,137,927	250,459,055	250,221,282	250,595,862	250,946,677	251,145,274
Power Generation	246,817,613	250,738,478	269,649,502	272,910,733	280,831,829	284,836,881	292,114,359	297,274,184	288,198,973	284,493,572

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Annual Demand Summary (Dth) - Low Case

Region/Sector	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
BC Lower Mainland & Van. Island	**142,768,402**	**139,989,923**	**138,945,876**	**137,942,961**	**136,791,311**	**135,681,221**	**134,600,466**	**133,546,081**	**132,517,218**	**131,563,522**
Residential	53,862,132	53,038,494	52,223,282	51,448,161	50,640,281	49,849,186	49,072,621	48,310,365	47,562,205	46,827,935
Commercial (Sales)	38,258,497	37,984,626	37,715,481	37,448,705	37,185,618	36,934,891	36,696,106	36,469,258	36,254,344	36,051,369
Industrial (Transport & Interruptible)	30,694,402	30,760,642	30,889,366	30,971,552	30,972,770	30,972,770	30,972,770	30,972,770	30,972,770	30,972,770
Power Generation	19,953,371	18,206,162	18,117,747	18,074,542	17,992,641	17,924,373	17,858,969	17,793,688	17,727,898	17,711,447
W. Washington	**249,694,002**	**256,072,362**	**264,473,373**	**265,140,483**	**267,035,492**	**265,371,975**	**269,091,394**	**270,564,520**	**266,217,932**	**265,825,951**
Residential	69,936,097	70,940,486	72,041,656	73,073,787	74,337,353	75,031,012	75,976,586	76,925,362	78,183,627	78,920,848
Commercial (Sales)	42,130,649	42,732,288	43,349,931	43,847,213	44,338,902	44,473,511	44,749,480	45,063,196	45,585,390	45,807,310
Industrial (Transport)	71,606,282	75,311,815	75,977,555	75,843,791	75,773,273	75,451,159	75,236,603	75,029,962	74,914,403	74,686,700
Power Generation	66,020,974	67,087,773	73,104,232	72,375,692	72,585,965	70,416,292	73,128,726	73,546,001	67,534,511	66,411,093
W. Oregon	**120,990,642**	**123,849,743**	**125,750,547**	**127,053,109**	**127,716,712**	**127,807,917**	**128,272,567**	**128,859,843**	**129,835,076**	**130,839,001**
Residential	37,543,015	37,447,098	37,630,044	37,920,727	38,438,789	38,778,179	39,327,954	39,933,532	40,749,675	41,596,384
Commercial (Sales)	23,223,032	22,901,170	22,702,577	22,541,134	22,466,751	22,252,528	22,166,886	22,147,949	22,267,005	22,418,017
Industrial (Transport & Interruptible)	40,224,596	43,501,476	45,417,926	46,591,248	46,811,173	46,777,210	46,777,728	46,778,363	46,818,396	46,824,601
Power Generation	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000
BC Interior	**49,394,657**	**48,909,535**	**48,298,313**	**47,921,740**	**47,512,263**	**47,117,828**	**46,734,246**	**46,361,439**	**45,999,348**	**45,647,929**
Residential	16,389,023	16,075,434	15,775,439	15,479,491	15,176,105	14,882,977	14,595,535	14,313,668	14,037,268	13,766,228
Commercial (Sales)	9,984,726	9,870,930	9,759,899	9,651,137	9,544,586	9,443,278	9,347,137	9,256,197	9,170,507	9,090,127
Industrial (Transport & Interruptible)	23,020,909	22,963,171	22,762,975	22,791,111	22,791,573	22,791,573	22,791,573	22,791,573	22,791,573	22,791,573
Power Generation	-	-	-	-	-	-	-	-	-	-
E. Washington & N. Idaho	**85,800,953**	**85,146,784**	**85,532,992**	**86,526,795**	**87,016,854**	**87,438,303**	**87,495,123**	**88,453,544**	**88,356,967**	**91,383,115**
Residential	17,598,573	17,204,101	16,910,474	16,815,611	16,836,724	16,753,417	16,630,711	16,557,919	16,512,111	18,878,931
Commercial (Sales)	13,162,766	13,253,193	13,252,002	13,348,338	13,502,735	13,559,074	13,654,313	13,771,633	13,934,730	14,595,886
Industrial (Transport & Interruptible)	27,130,179	27,178,174	27,400,604	27,607,650	27,706,456	27,853,568	28,021,601	28,191,129	28,367,168	28,633,336
Power Generation	27,909,436	27,511,315	27,969,911	28,755,196	28,970,939	29,272,243	29,188,497	29,932,863	29,542,959	29,274,962
E. Oregon & Medford	**87,953,820**	**87,987,063**	**89,317,450**	**90,639,128**	**91,589,622**	**92,122,008**	**92,048,293**	**93,189,035**	**92,168,509**	**92,215,052**
Residential	7,529,896	7,610,621	7,704,928	7,805,141	7,924,198	8,013,249	8,114,079	8,198,307	8,296,040	8,385,287
Commercial (Sales)	5,526,376	5,623,147	5,657,666	5,692,979	5,731,628	5,762,806	5,792,738	5,813,108	5,846,283	5,867,618
Industrial (Transport & Interruptible)	8,899,101	8,878,449	8,881,598	8,892,253	8,903,311	8,913,770	8,924,106	8,932,485	8,943,058	8,959,811
Power Generation	65,998,446	65,874,846	67,073,258	68,248,755	69,030,485	69,432,183	69,217,370	70,245,134	69,083,127	69,002,335
S. Idaho	**56,697,700**	**60,040,929**	**61,020,207**	**59,544,612**	**61,164,156**	**61,520,495**	**61,140,952**	**61,372,268**	**61,435,314**	**61,782,868**
Residential	20,649,892	20,288,884	20,205,240	20,244,243	20,290,752	20,333,527	20,370,589	20,409,675	20,451,285	20,680,671
Commercial (Sales)	10,637,823	10,451,849	10,408,760	10,428,852	10,452,812	10,474,847	10,493,940	10,514,075	10,535,511	10,653,679
Industrial (Transport & Interruptible)	22,996,223	23,223,721	23,906,208	22,371,517	23,920,593	24,212,120	23,776,423	23,948,518	23,948,518	23,948,518
Power Generation	2,413,763	6,076,476	6,500,000	6,500,000	6,500,000	6,500,000	6,500,000	6,500,000	6,500,000	6,500,000
PNW Annual Demand - Low	**793,300,177**	**801,996,340**	**813,338,759**	**814,768,827**	**818,826,411**	**817,059,746**	**819,383,041**	**822,346,732**	**816,530,364**	**819,257,437**
Residential	223,508,627	222,605,116	222,491,063	222,787,162	223,644,201	223,641,548	224,088,074	224,648,828	225,792,211	229,056,284
Commercial (Sales)	142,923,869	142,817,204	142,846,317	142,958,359	143,223,030	142,900,936	142,900,600	143,035,417	143,593,770	144,484,006
Industrial (Transport & Interruptible)	224,571,691	231,817,447	235,236,232	235,069,122	236,879,150	236,972,171	236,500,804	236,644,800	236,755,887	236,817,309
Power Generation	202,295,990	204,756,573	212,765,148	213,954,184	215,080,030	213,545,092	215,893,563	218,017,687	210,388,496	208,899,838

Northwest Gas Association
2012 Natural Gas Outlook
I-5 Corridor Peak Day Demand/Supply Balance (Dth/day) - Base Case

DEMAND (Region/Sector)	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
BC Lower Main & Van. Island (I-5 Corridor)	**1,390,697**	**1,394,682**	**1,398,704**	**1,403,089**	**1,407,033**	**1,411,212**	**1,415,607**	**1,420,226**	**1,425,077**	**1,430,170**
Residential	591,542	591,632	591,687	592,061	591,932	591,860	591,824	591,825	591,864	591,944
Commercial (Firm Sales & Transport)	415,393	419,288	423,255	427,266	431,339	435,590	440,021	444,639	449,450	454,464
Industrial (Firm Sales & Transport)	122,164	122,164	122,164	122,164	122,164	122,164	122,164	122,164	122,164	122,164
Power Generation	261,598	261,598	261,598	261,598	261,598	261,598	261,598	261,598	261,598	261,598
W. Washington (I-5 Corridor)	**1,867,894**	**1,889,431**	**1,928,246**	**1,954,088**	**1,978,489**	**2,001,204**	**2,023,206**	**2,045,533**	**2,068,517**	**2,092,775**
Residential	803,403	817,799	835,499	852,773	869,432	885,765	901,883	918,203	934,750	951,932
Commercial (Firm Sales & Transport)	329,329	336,011	344,931	353,900	362,062	368,939	375,328	381,846	388,784	396,342
Industrial (Firm Sales & Transport)	276,814	277,272	289,468	289,066	288,647	288,150	287,646	287,135	286,633	286,152
Power Generation	458,349	458,349	458,349	458,349	458,349	458,349	458,349	458,349	458,349	458,349
W. Oregon (I-5 Corridor)	**986,444**	**989,505**	**994,347**	**1,001,952**	**1,009,183**	**1,018,909**	**1,029,421**	**1,040,886**	**1,052,789**	**1,064,859**
Residential	573,984	576,808	581,517	588,251	595,514	605,235	615,250	625,657	635,969	646,432
Commercial (Firm Sales & Transport)	288,886	287,492	286,741	286,719	286,447	286,491	287,005	288,081	289,668	291,272
Industrial (Firm Sales & Transport)	36,574	38,206	39,090	39,981	40,222	40,183	40,166	40,148	40,151	40,155
Power Generation	87,000	87,000	87,000	87,000	87,000	87,000	87,000	87,000	87,000	87,000
Total Peak (Design) Day Demand	4,245,035	4,273,619	4,321,297	4,359,128	4,394,705	4,431,325	4,468,234	4,506,645	4,546,383	4,587,804
SUPPLY										
Pipeline Interconnects	**2,304,060**	**2,304,061**	**2,304,062**	**2,304,063**	**2,304,064**	**2,304,065**	**2,304,066**	**2,304,067**	**2,304,068**	**2,304,069**
Max north flow on NWP @ Gorge	**551,000**	**551,001**	**551,002**	**551,003**	**551,004**	**551,005**	**551,006**	**551,007**	**551,008**	**551,009**
Huntingdon/Sumas	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**
T-South to Huntingdon	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060
Underground Storage	**1,716,000**	**1,716,000**	**1,716,000**	**1,716,000**	**1,716,000**	**1,716,000**	**1,716,000**	**1,716,000**	**1,716,000**	**1,716,000**
Jackson Prairie (NWP from JP)	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000
Mist Storage (NWN)	520,000	520,000	520,000	520,000	520,000	520,000	520,000	520,000	520,000	520,000
Peak LNG	**501,508**	**501,508**	**501,508**	**501,508**	**501,508**	**501,508**	**501,508**	**501,508**	**501,508**	**501,508**
Newport/Portland LNG (NWN)	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000
Gig Harbor Satellite LNG (PSE)	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Swarr Stn Propane (PSE)	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Tilbury LNG (FortisBC)	155,466	155,466	155,466	155,466	155,466	155,466	155,466	155,466	155,466	155,466
Mt. Hayes LNG (FortisBC)	153,042	153,042	153,042	153,042	153,042	153,042	153,042	153,042	153,042	153,042
Total Supply	**4,521,568**	**4,521,569**	**4,521,570**	**4,521,571**	**4,521,572**	**4,521,573**	**4,521,574**	**4,521,575**	**4,521,576**	**4,521,577**
Supply Surplus/**(Shortfall)**	276,533	247,950	200,272	162,442	126,866	90,247	53,340	14,930	(24,808)	(66,227)

Northwest Gas Association
2012 Natural Gas Outlook
I-5 Corridor Peak Day Demand/Supply Balance (Dth/day) - High Case

DEMAND (Region/Sector)	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
BC Lower Main & Van. Island (I-5 Corridor)	**1,400,830**	**1,415,127**	**1,429,647**	**1,444,727**	**1,459,542**	**1,474,793**	**1,490,471**	**1,506,593**	**1,523,180**	**1,540,249**
Residential	597,520	603,648	609,804	616,351	622,442	628,651	634,959	641,370	647,887	654,513
Commercial (Firm Sales & Transport)	419,548	427,717	436,080	444,614	453,338	462,380	471,750	481,461	491,531	501,975
Industrial (Firm Sales & Transport)	122,164	122,164	122,164	122,164	122,164	122,164	122,164	122,164	122,164	122,164
Power Generation	261,598	261,598	261,598	261,598	261,598	261,598	261,598	261,598	261,598	261,598
W. Washington (I-5 Corridor)	**1,892,022**	**1,918,178**	**2,079,044**	**2,110,564**	**2,140,853**	**2,228,056**	**2,256,312**	**2,285,098**	**2,314,802**	**2,345,061**
Residential	809,534	826,786	847,876	868,884	889,474	909,924	930,277	950,954	972,036	993,235
Commercial (Firm Sales & Transport)	333,630	341,935	352,606	363,382	373,387	382,136	390,434	398,944	407,961	417,394
Industrial (Firm Sales & Transport)	290,509	291,107	303,438	303,174	302,869	302,484	302,089	301,689	301,292	300,920
Power Generation	458,349	458,349	575,124	575,124	575,124	633,512	633,512	633,512	633,512	633,512
W. Oregon (I-5 Corridor)	**996,356**	**1,004,616**	**1,015,544**	**1,029,398**	**1,042,537**	**1,057,254**	**1,071,807**	**1,086,785**	**1,101,632**	**1,116,704**
Residential	576,995	582,898	591,385	602,025	613,228	626,465	639,308	652,161	664,496	677,025
Commercial (Firm Sales & Transport)	291,441	291,930	293,354	295,427	297,109	298,629	300,357	302,500	305,009	307,548
Industrial (Firm Sales & Transport)	40,920	42,789	43,806	44,947	45,200	45,159	45,142	45,123	45,127	45,131
Power Generation	87,000	87,000	87,000	87,000	87,000	87,000	87,000	87,000	87,000	87,000
Total Peak (Design) Day Demand	**4,289,208**	**4,337,921**	**4,524,235**	**4,584,690**	**4,642,932**	**4,760,103**	**4,818,590**	**4,878,476**	**4,939,613**	**5,002,014**
SUPPLY										
Pipeline Interconnects	**2,304,060**	**2,304,061**	**2,304,062**	**2,304,063**	**2,304,064**	**2,304,065**	**2,304,066**	**2,304,067**	**2,304,068**	**2,304,069**
Max north flow on NWP @ Gorge	**551,000**	**551,001**	**551,002**	**551,003**	**551,004**	**551,005**	**551,006**	**551,007**	**551,008**	**551,009**
Huntingdon/Sumas	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**
T-South to Huntingdon	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060
Underground Storage	**1,716,000**	**1,716,000**	**1,716,000**	**1,716,000**	**1,716,000**	**1,716,000**	**1,716,000**	**1,716,000**	**1,716,000**	**1,716,000**
Jackson Prairie (NWP from JP)	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000
Mist Storage (NWN)	520,000	520,000	520,000	520,000	520,000	520,000	520,000	520,000	520,000	520,000
Peak LNG	**501,508**	**501,508**	**501,508**	**501,508**	**501,508**	**501,508**	**501,508**	**501,508**	**501,508**	**501,508**
Newport/Portland LNG (NWN)	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000
Gig Harbor Satellite LNG (PSE)	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Swarr Stn Propane (PSE)	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Tilbury LNG (FortisBC)	155,466	155,466	155,466	155,466	155,466	155,466	155,466	155,466	155,466	155,466
Mt. Hayes LNG (FortisBC)	153,042	153,042	153,042	153,042	153,042	153,042	153,042	153,042	153,042	153,042
Total Supply	**4,521,568**	**4,521,569**	**4,521,570**	**4,521,571**	**4,521,572**	**4,521,573**	**4,521,574**	**4,521,575**	**4,521,576**	**4,521,577**
Supply Surplus/**(Shortfall)**	**232,360**	**183,648**	**(2,665)**	**(63,119)**	**(121,360)**	**(238,530)**	**(297,016)**	**(356,902)**	**(418,037)**	**(480,438)**

Northwest Gas Association

2012 Natural Gas Outlook

I-5 Corridor Peak Day Demand/Supply Balance (Dth/day) - Low Case

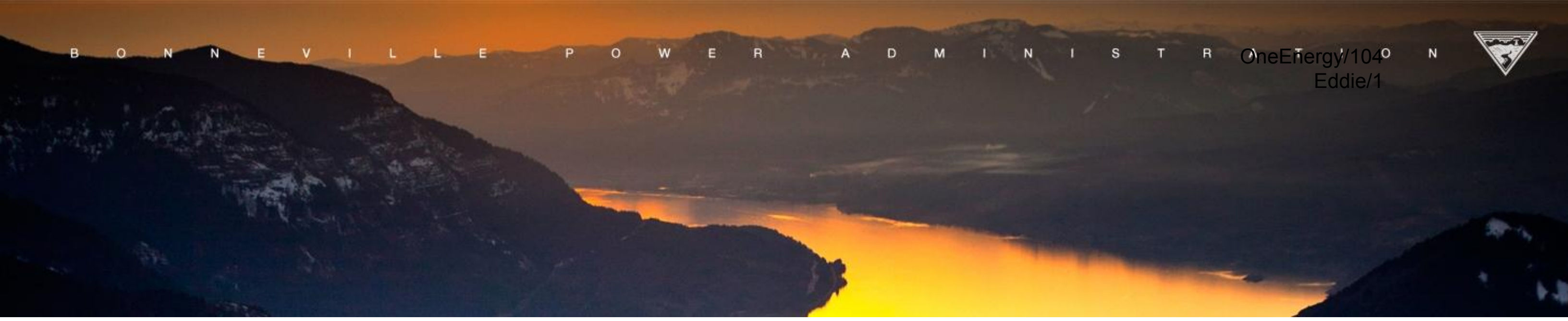
DEMAND (Region/Sector)	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
BC Lower Main & Van. Island (I-5 Corridor)	**1,375,497**	**1,364,399**	**1,353,444**	**1,342,944**	**1,332,134**	**1,321,649**	**1,311,463**	**1,301,572**	**1,291,976**	**1,282,672**
Residential	582,574	573,835	565,190	556,979	548,422	540,049	531,838	523,786	515,890	508,150
Commercial (Firm Sales & Transport)	409,160	406,802	404,491	402,202	399,950	397,838	395,863	394,025	392,324	390,760
Industrial (Firm Sales & Transport)	122,164	122,164	122,164	122,164	122,164	122,164	122,164	122,164	122,164	122,164
Power Generation	261,598	261,598	261,598	261,598	261,598	261,598	261,598	261,598	261,598	261,598
W. Washington (I-5 Corridor)	**1,811,657**	**1,828,294**	**1,861,507**	**1,881,459**	**1,900,011**	**1,916,624**	**1,932,685**	**1,949,036**	**1,966,129**	**1,984,200**
Residential	800,138	811,427	825,433	838,725	851,436	863,517	875,643	887,974	900,648	913,745
Commercial (Firm Sales & Transport)	327,542	332,624	339,753	346,892	353,265	358,355	362,898	367,528	372,549	378,099
Industrial (Firm Sales & Transport)	267,634	267,901	279,978	279,499	278,967	278,410	277,801	277,191	276,590	276,013
Power Generation	416,343	416,343	416,343	416,343	416,343	416,343	416,343	416,343	416,343	416,343
W. Oregon (I-5 Corridor)	**935,060**	**929,929**	**927,627**	**928,668**	**930,396**	**934,914**	**941,218**	**949,653**	**959,589**	**969,658**
Residential	568,919	566,833	567,093	569,725	573,296	579,336	586,415	594,710	603,683	612,784
Commercial (Firm Sales & Transport)	285,015	280,575	277,263	275,029	272,958	271,473	270,714	270,872	271,831	272,796
Industrial (Firm Sales & Transport)	31,126	32,520	33,270	33,913	34,142	34,105	34,089	34,072	34,075	34,078
Power Generation	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
Total Peak (Design) Day Demand	**4,122,214**	**4,122,622**	**4,142,578**	**4,153,070**	**4,162,540**	**4,173,188**	**4,185,366**	**4,200,261**	**4,217,694**	**4,236,530**
SUPPLY										
Pipeline Interconnects	**2,304,060**	**2,304,061**	**2,304,062**	**2,304,063**	**2,304,064**	**2,304,065**	**2,304,066**	**2,304,067**	**2,304,068**	**2,304,069**
Max north flow on NWP @ Gorge	**551,000**	**551,001**	**551,002**	**551,003**	**551,004**	**551,005**	**551,006**	**551,007**	**551,008**	**551,009**
Huntingdon/Sumas	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**	**1,753,060**
T-South to Huntingdon	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060	1,753,060
Underground Storage	**1,716,000**	**1,716,000**	**1,716,000**	**1,716,000**	**1,716,000**	**1,716,000**	**1,716,000**	**1,716,000**	**1,716,000**	**1,716,000**
Jackson Prairie (NWP from JP)	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000	1,196,000
Mist Storage (NWN)	520,000	520,000	520,000	520,000	520,000	520,000	520,000	520,000	520,000	520,000
Peak LNG	**501,508**	**501,508**	**501,508**	**501,508**	**501,508**	**501,508**	**501,508**	**501,508**	**501,508**	**501,508**
Newport/Portland LNG (NWN)	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000
Gig Harbor Satellite LNG (PSE)	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Swarr Stn Propane (PSE)	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Tilbury LNG (FortisBC)	155,466	155,466	155,466	155,466	155,466	155,466	155,466	155,466	155,466	155,466
Mt. Hayes LNG (FortisBC)	153,042	153,042	153,042	153,042	153,042	153,042	153,042	153,042	153,042	153,042
Total Supply	**4,521,568**	**4,521,569**	**4,521,570**	**4,521,571**	**4,521,572**	**4,521,573**	**4,521,574**	**4,521,575**	**4,521,576**	**4,521,577**
Supply Surplus/**(Shortfall)**	399,354	398,947	378,992	368,500	359,032	348,384	336,208	321,313	303,881	285,047

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Direct Testimony of Bill Eddie

Bonneville Power Administration "The Role of Natural Gas in the Northwest's Electric Power Supply", August 2012



The Role of Natural Gas in the Northwest's Electric Power Supply

August 2012

Summary

Northwest energy providers have a growing interest in understanding the role of natural gas in the region's electricity supply. While there is nothing new about gas-fueled electricity generation, it has not been a large part of the supply picture in the hydro-rich Northwest. But there are clear indications that picture is changing. A number of sources, ranging from individual utility resource plans to the Council's Sixth Power Plan, point to an emerging emphasis on natural gas as the fuel of choice to generate electricity to meet future needs.

This paper provides an overview of the shift toward natural-gas fired generation and the issues it raises for the region's electricity and gas industries, as well as regulators and policymakers. The information comes from references listed at the end of the paper, as well as from presentations and speakers at a Northwest electricity and natural gas summit held in early 2012. A recurring question at the summit was whether the Northwest's current natural gas infrastructure can accommodate a large-scale shift to gas-fueled electricity generation. A representative of the Northwest Gas Association (NWGA) said electricity generation is "the wild card" in the mix for natural gas supplies in the Northwest.

The Northwest's gas infrastructure currently serves the needs of the region. But it was not built to serve a large-scale generation market and currently operates at 100 percent of capacity during extreme cold-weather peak periods in the winter. At other times of the year, the pipeline system operates at a relatively low load factor, affording significant flexibility. Without infrastructure additions, however, there is no excess capability to serve large new markets on a year-round firm basis. Utility CEOs, planners, and regulators emphasized the need for the two industries to coordinate their plans, infrastructure, and operations to prepare for a future in which gas is a key component of the Northwest's electricity supply.

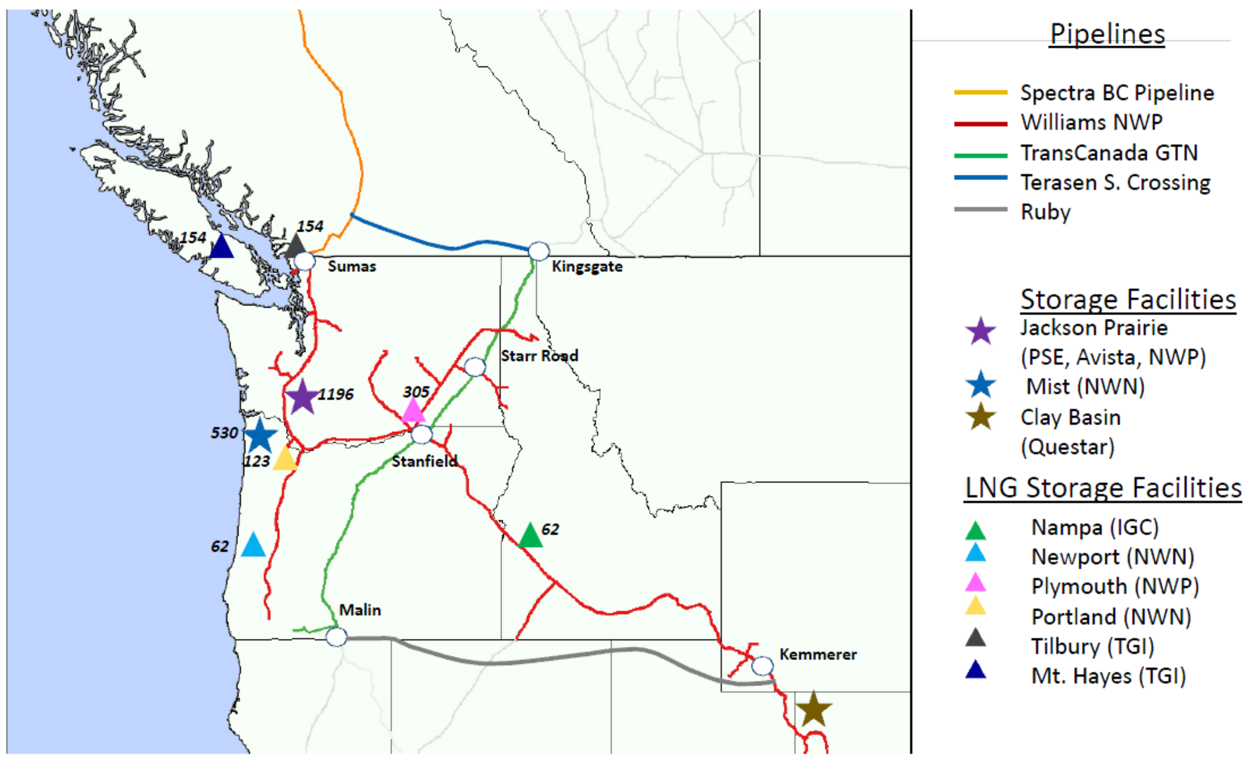
Background on the Electricity/Gas Convergence

The Northwest, including western Canada, is served by five interstate/provincial pipelines and six natural gas distribution companies that operate and maintain about 48,000 miles of transmission and distribution pipelines. There are also a number of natural gas and liquid natural gas storage facilities in the Northwest, which are shown in Figure 1.

According to Allison Bridges of Williams Northwest Pipeline, who spoke at the 2012 summit, the combined system shown in Figure 1 can deliver 6.5 MMDth/d (million dekatherms per day) to the Northwest on a peak day.

Williams Northwest Pipeline, represented by the red line in Figure 1, serves the major population centers in the Northwest along the I-5 corridor, as well as east of the Cascade Mountains into Idaho. Williams Northwest peaks at 3.7 MMDth/d and has 14 MMDth of storage capacity. The pipeline has access to both domestic and Canadian gas supplies.

Figure 1: Pacific Northwest Storage Facilities



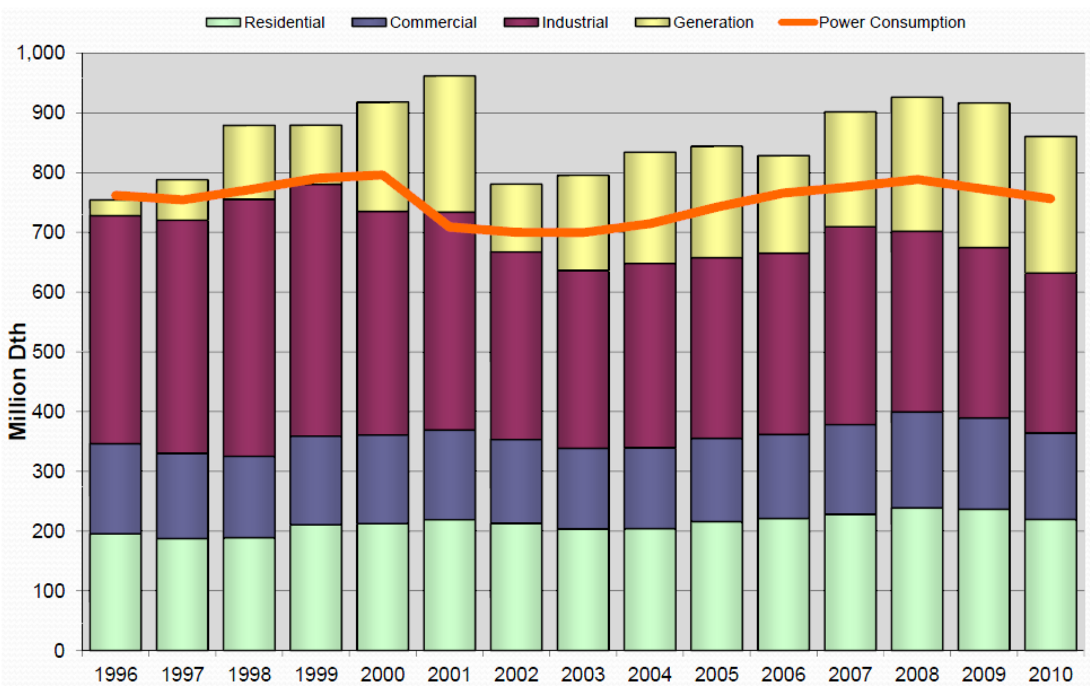
The Northwest now has about 8,400 megawatts (MW) of installed natural-gas fired generating capacity, approximately two-thirds of which is on the Williams Northwest system. Williams Northwest currently serves 24 gas-fired plants in the region that represent a combined capacity of 5,000 MW of electricity generation. About 2,800 MW of that gas-fired generation has been added since 2002.

Today, gas-fired generation in the Northwest is operated to provide electricity to meet base load, peaking, and reserve demands. During the winter months, the use of natural-gas fired generation to meet base load is at its highest. In the late spring and early summer, during the hydro runoff, natural-gas generation falls off markedly, but it picks up again in late summer when it is needed to meet air conditioning load.

All of the region's gas generators dispatch their resources based on electricity prices. Many also operate as peaking plants when needed, varying their output greatly on an hourly basis depending on the generation required to meet peak loads.

Figure 2 provides a view of gas use in the Northwest by customer sector. The use of gas for generation has obviously grown while industrial use has declined. As a result, the combined amount of natural gas used for power generation, industrial, and residential purposes in the Northwest is relatively equal today. While electricity consumption overall has trended downward slightly in recent years, the proportion of electricity generation supplied by natural gas has increased.

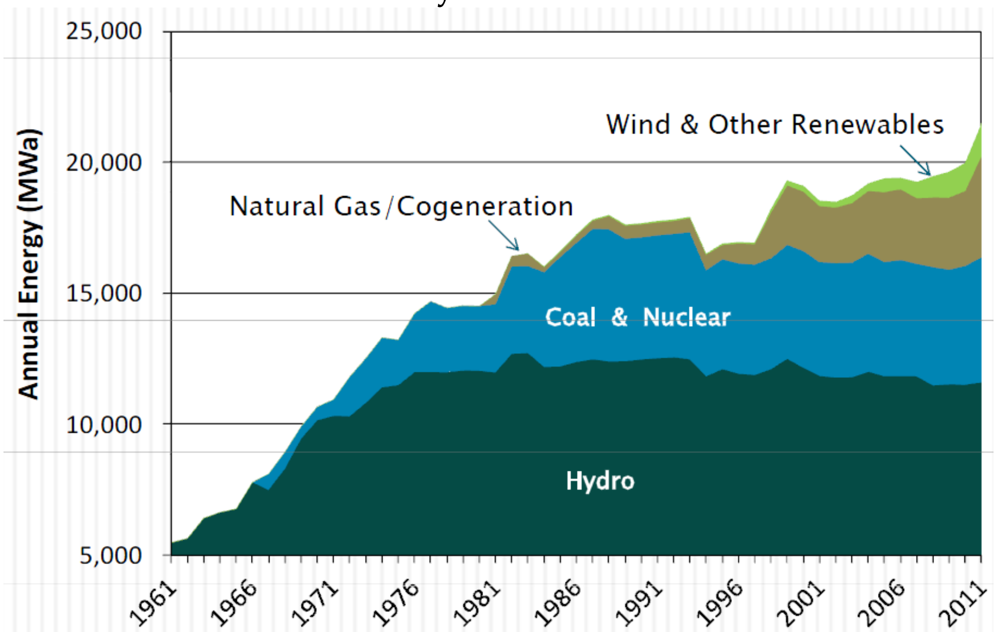
Figure 2: Pacific NW Gas Deliveries by Industry



(soure: US EIA, StatCan)

Hydro provides the largest share of the electric power in the Northwest, with coal and the region's only nuclear plant providing much of the rest. The use of natural gas for electricity generation, however, has grown significantly over the last 15 years, as indicated in Figure 3.

Figure 3: Pacific NW Electric Generation by Fuel

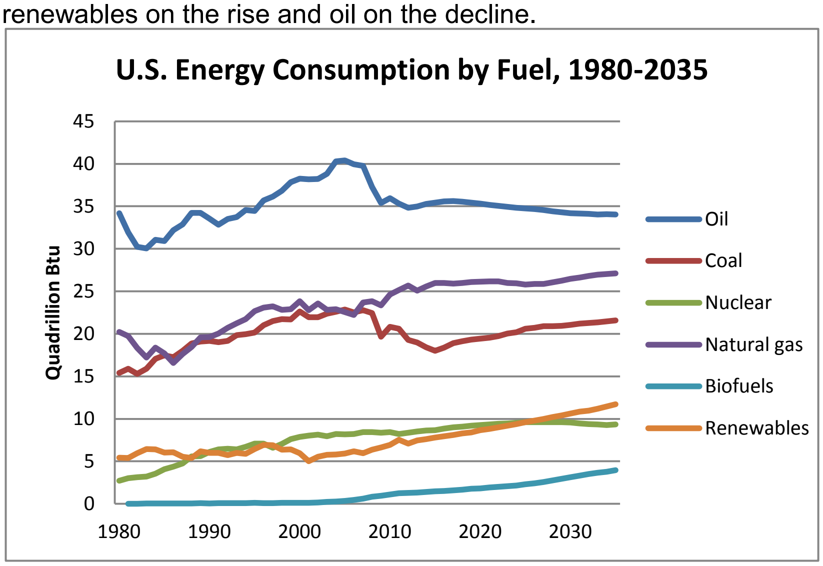


According to According to PNUCC's Northwest Regional Forecast (NRF), electricity loads in the region are expected to grow by about 150 to 200 average MW (aMW) annually over the next decade. The NRF indicates utilities in the Northwest have plans to add significant new resources, including another 2,300 MW of natural gas-fired generation over the next 10 years, most of which is intended for peak-demand situations.

The Northwest Power and Conservation Council's Sixth Power Plans puts the growth rate for electricity demand at between 0.8 percent and 1.8 percent

U.S. Gas Consumption on the Rise

The Energy Information Administration (EIA) expects U.S. gas consumption to increase by 10 percent between 2010 and 2035. The following graph shows energy consumption by fuel, with gas and renewables on the rise and oil on the decline.



annually over the next 20 years. That's somewhat higher than the EIA estimate of 0.6 percent for the nation as a whole. Figure 4, which came from the Sixth Power Plan, illustrates the range of forecast growth across a high, medium, and low case, as well as a historical perspective on load growth in the region.

The Council's action plan emphasizes the use of energy efficiency first to meet load growth. It points to wind power as the most readily available and cost-effective renewable resource. But the plan also states that the remaining needs for new energy and capacity should be based on natural gas-fired generation "until more attractive technologies become available." There is no additional coal-fired generation in the Council's plan, and the Council states that in order to reduce carbon emissions in the region, there must be less reliance on the region's existing coal generation.

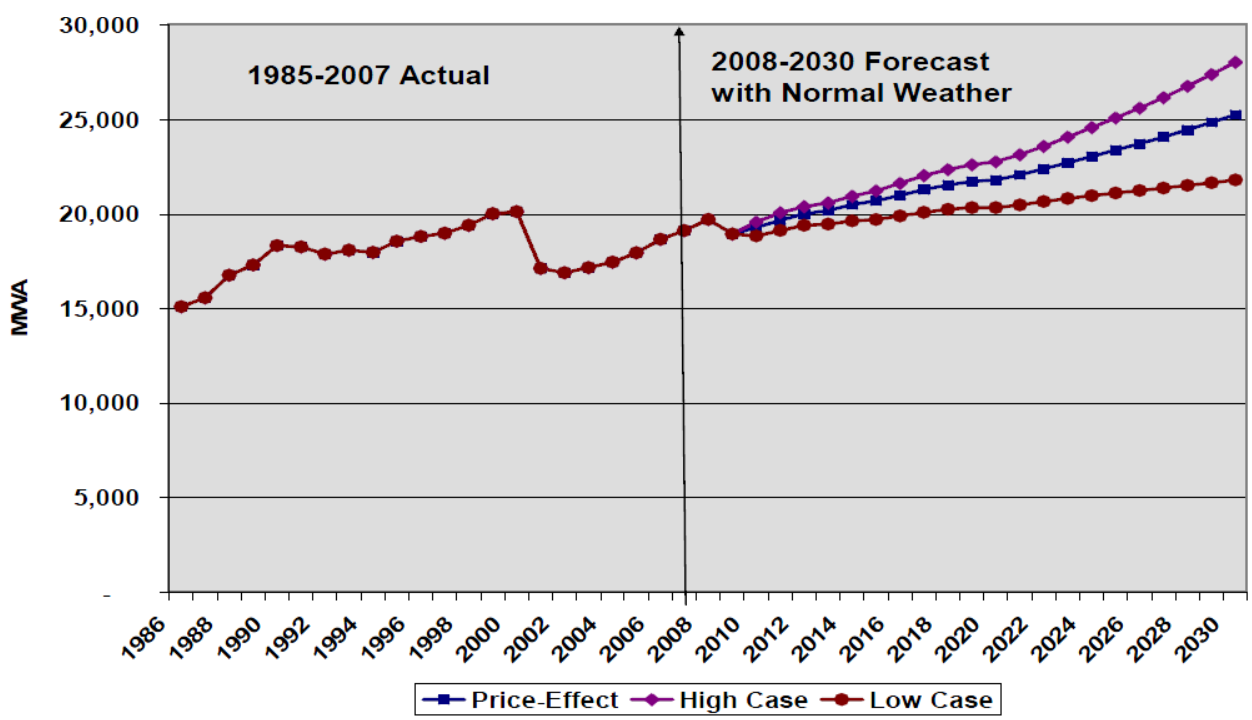
In the U.S. as a whole, EIA reports:
Residential gas demand currently accounts for 20.5 percent of gas consumption. That figure is projected to remain flat between 2012 and 2035.

Commercial gas demand currently accounts for 13.3 percent of gas consumption, projected to increase 11 percent by 2035.

Industrial gas demand currently accounts for 27.4 percent of gas consumption, projected to increase by 6 percent by 2035. According to the EIA, many energy-intensive industries are declining, but non-energy intensive industries are growing.

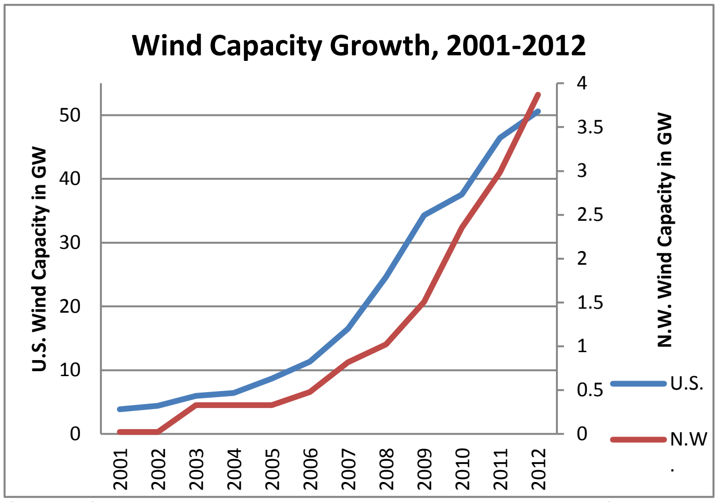
Electric generation gas demand currently accounts for 30.6 percent of gas consumption, projected to increase 21 percent by 2035. The proportion of all gas being consumed by the electric sector will rise from 30.6 percent to 33.7 percent, an annual increase of 0.8 percent.

Figure 4: Sixth Northwest Power Plan Power Demand Forecast (MWa)



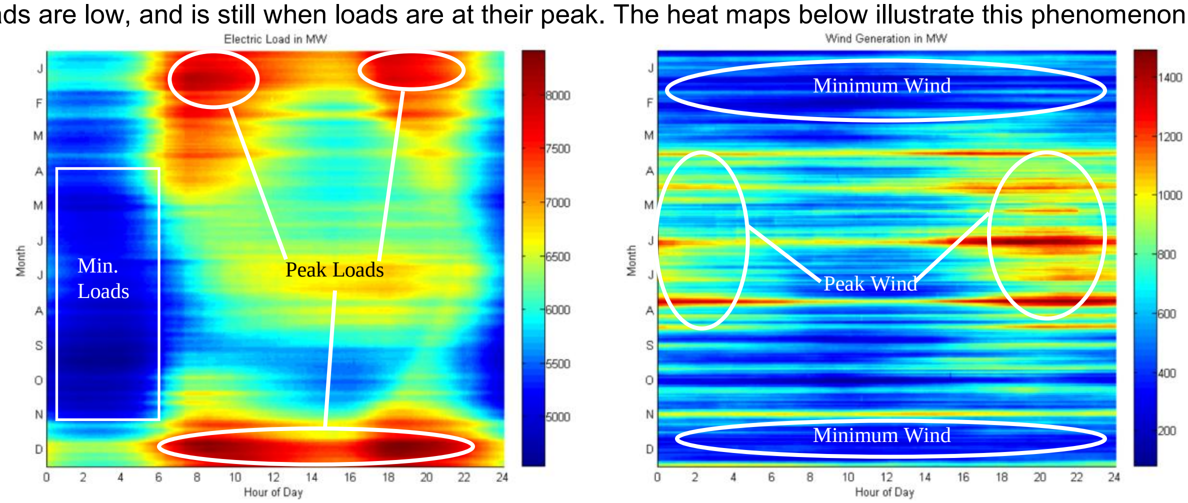
Wind Resources Continue to Grow

The expansion of wind power has exploded in the last 10 years, both nationally and in the Northwest. This figure illustrates the significant and rapid growth in the nation's wind resource, growth that is expected to continue as more states adopt and strengthen renewable portfolio standards.



(U.S. data from EIA Annual Energy Review 2011, NW data from BPAT)

Wind energy poses a challenge to the power system due to its variability and to the seasonal and daily shape of production. The wind does not necessarily blow at times of peak electricity demand or shut down when demand is slack. In the Northwest, the opposite tends to be true. The wind blows at times when loads are low, and is still when loads are at their peak. The heat maps below illustrate this phenomenon.



(Source: BPA Transmission data, 2007-2011 averages)

The map on the left depicts the shape of BPA's electricity load taken at five-minute intervals and averaged. BPA's load is greatest from January through April, drops during the summer, and picks up again in late November and December. The map on the right illustrates the shape of the region's wind generation. Wind generation is low during the winter and highest during the spring and summer. In other words, wind generation in the Northwest tracks poorly with BPA's seasonal load.

The same is true for the daily load shape. BPA's electricity demand is low in the hours from midnight to 5 a.m. and builds as the day begins, peaking at around 8 a.m. Load peaks again in the evening between 6 p.m. and 8 p.m. Wind generation tends to peak before 8 a.m. and picks up in the evening, producing the most electricity overnight when demand is low.

The Outlook for Gas Generation in the Northwest

The evolution to natural gas for generating electricity in the Northwest has occurred for a number of reasons. Like elsewhere in the country, natural gas plants have lower construction costs and shorter lead times compared with other alternatives. Natural gas also offers high generation efficiency, lower carbon content than other fossil fuels, and operational flexibility.

Environmental restrictions and the political landscape have cast doubt that any new large hydro, coal, or oil-fired plants will be built in the near future. The PNUCC forecast indicates there are no plans in the next 10 years for additional coal or large hydro plants in the Northwest. In fact, the region's coal plants are being phased out, and the assumption is that most of that generation will be replaced with natural gas. Similarly, while several new or expanded nuclear plants are being pursued elsewhere, notably in the southeastern United States, there is no expectation of new nuclear generation in the Northwest.

There are also plans to add to the already significant growth in wind power. Wind is considered the most available and cost-effective resource to meet state resource portfolio standards in the Northwest, but it poses challenges in terms of power system operations. The biggest challenge is its variability.

Although some amount of variability can be accurately forecast, there are inevitably differences between the amount of generation wind plants are scheduled to produce and what they actually deliver. System operators must, therefore, have access to resources to firm-up the growing amount of variable generation that is coming onto the system in the Northwest.

Right now, the Northwest balances most of the variability in wind generation with hydro. There is, however, a limit to the amount of hydro capacity that can be dedicated to balance wind. At some point given the planned expansion of the Northwest wind fleet, the region will run short of balancing capability relying primarily on hydro. Recent experiences, which have included requests for wind generators to lower their output, demonstrate that the limit appears to have been reached.

Energy consultant ICF International predicts an additional 2,500 MW of gas-turbine capacity will be needed by 2025 to firm wind generation in the Northwest and that nearly 6 percent of the region's total natural gas demand will be for that purpose. Other areas of the country are also expected to experience this disproportionately large influence on the gas infrastructure for firming wind generation.
In addition to overall variability, firming wind energy poses other issues. The gas demand for a conventional natural gas-fired generating plant follows the shape of the electricity load. But the demand for a wind-firming plant is much more volatile.

While natural gas is the likely incremental balancing resource, it isn't clear the region's existing gas infrastructure is up to the task. Today, this is primarily a concern during peak winter periods, but it could become an issue in other periods, if demand continues to grow as projected. There is also a major question about who will pay for the necessary infrastructure expansions.

As presenters at the 2012 summit indicated, the question is not whether there is enough gas for the job, it is whether the infrastructure can deliver large quantities of gas to specific generators on short notice to make up for the variability of wind. Wind doesn't necessarily create more demand for gas – it may in fact have a tendency to reduce annual base load demand – but it changes the way the gas infrastructure will be called upon to meet the region's needs.

Simply put, generators need to have access to the appropriate gas resources to meet their system demands. This is one of several issues raised by the planned increase in natural gas-fired generation in the region in order to integrate and firm up renewable intermittent resources.

Growing Interdependence of Gas and Electricity in the Northwest

Like any major change in the energy supply, the planned expansion of natural gas-fired electricity generation raises a host of questions, from the adequacy of infrastructure to the lack of symmetry between the everyday operations of two distinct industries. Many of these questions were raised and addressed at the 2012 electricity and natural gas summit. They are not unique to the Northwest, but have lurked below the radar because of the traditionally small amount of natural gas-fired generation in the region.

Infrastructure

Most of the natural gas pipeline network in the United States is a "spaghetti bowl" of interconnected lines. But the Northwest, excluding western Canada, has only two major pipelines. Gas on TransCanada GTN is primarily sourced from Alberta but can also receive gas from the U.S. Rocky Mountains at its terminus at Malin, Oregon, near the California-Oregon border. Williams Northwest Pipeline was designed as a bidirectional pipeline with gas sources at both ends and in the middle of its system, receiving gas from British Columbia, Alberta (via GTN), and the U.S. Rockies.

The gas infrastructure in the region was built to serve entities that subscribed to service, including local distribution companies (LDCs), industrial end-users, and base load power generators. (Peaking facilities in the region have historically relied on oil as a back-up fuel and have not subscribed to firm pipeline service.)

According to the experts, the current infrastructure does not necessarily have incremental firm capacity available in certain areas to serve new generating resources. Nor is the natural gas infrastructure currently adequate to satisfy the significant growth in demand that is projected to be needed to balance regional electricity loads with gas-fired peaking facilities. It is important to note that gas infrastructure is adequate for the resources that are currently in place and reliant on firm gas infrastructure.

Historically, pipeline capacity has been expanded when a customer, such as an LDC, industrial customer, or power generator, requests and commits to a long-term contract for firm capacity. The Federal Energy Regulatory Commission (FERC) regulates capacity expansions and will generally not authorize one unless a customer has already committed to use and pay for it, or if the natural gas pipeline is willing to take on the risk of building or expanding its capacity. Natural gas pipelines in the United States generally are prohibited from passing costs of new capacity on to their other existing customers.

The pipeline network in the I-5 corridor is currently fully subscribed but could be expanded with customer commitment. While available capacity exists on TransCanada GTN, which runs through eastern Washington and Oregon, there are other issues to consider in siting gas-fired generation east of the Cascade Mountains, including east-to-west electricity transmission constraints.

Figure 5 illustrates the supply/demand balance on the natural gas network. The current natural gas load can be met with pipeline capacity, underground storage, and several existing liquefied natural gas (LNG) plants.

Expanding Interstate Pipeline Capacity

The pipeline system in the Northwest has been expanded repeatedly over the years to meet market demand. In order to add new facilities, interstate pipelines like Williams Northwest must first receive a certificate of "public convenience and necessity" from FERC that authorizes construction and operation.

The time required for the FERC review process varies based on the size of the project. Generally, it will take six to 18 months from the time a company submits an application until FERC renders its decision on whether to approve a certificate. FERC authorizes construction to begin when conditions established in its certificate order are satisfied. Typically, major projects take three years to permit and construct.

Figure 5: I-5 Total Firm Peak Day Supply/Demand Balance

Dan Kirschner, NWGA

Storage

Figure 5 illustrates how heavily the regional gas system relies on storage, primarily at two large facilities, Jackson Prairie and Mist, to meet demand and balance variable supply and demand conditions. LNG storage at six existing plants is also important to meeting peak demand in the region. Overall, the storage facilities in the region are well utilized. They are typically filled in the summer and most heavily withdrawn in the winter, but they provide a balancing function throughout the year.

Peak gas demand is projected to outgrow current supply resources between 2014 (high case) and 2019 (base case), according to the NWGA projections in Figure 5. Either additional pipeline capacity and/or storage will be needed within the next decade to meet the projected growth in the base load.

In addition, the gas storage in the region is concentrated in one area, the I-5 corridor, and some isolated locations on the pipeline network do not have ready access. While storage on the network is currently sufficient to respond to an extreme weather event, such as a prolonged cold snap, the heavy reliance on storage makes it vulnerable if there is a problem at a storage facility.

This was the case at Jackson Prairie in December 2009 when equipment malfunctions and subsequent intermittent production over a period of several hours resulted in low pipeline pressures. The situation led to fuel switching at generating facilities that relied on non-firm resources. In addition, several hundred customers lost service in southwestern Washington during the course of the events.

Close Call at a NW Storage Facility

On December 9, 2009, during an extreme cold snap in the Northwest, a series of events, including the closure of a valve at the TransCanada GTN-Williams Northwest Pipeline interconnect at Stanfield in eastern Oregon and equipment failures at the Jackson Prairie storage facility, resulted in a gas shortage in the region

Jackson Prairie Natural Gas Storage Facility

First, in the early morning hours, the Stanfield interconnect between Williams Northwest and TransCanada GTN pipelines closed for three hours due to an insufficient pressure differential between the two pipelines. By itself, this incident would have been insignificant, but it contributed to a situation that escalated throughout the day.

Temperatures at the Jackson Prairie storage facility, operated by Puget Sound Energy, were in the single digits in the morning, and ice formed on individual well water separators. In addition, three flow-measurement meters failed due to high gas volumes. These failures did not impact the gas supply, but they caused problems for operators in responding to subsequent events.

A series of equipment failures ensued, which took time to remedy and disrupted storage withdrawal. In the afternoon, pressure sensors failed due to the cold weather, which caused an emergency shut-down valve to repeatedly close. Storage withdrawal fell to zero on and off for about four hours.

During the incident, a series of communications kept LDCs informed. The LDCs notified interruptible customers to curtail gas usage by switching to alternate fuels or reducing operations, and Puget Sound Energy switched all of its gas-fired generation that has alternate-fuel capability to oil. Pressures on the pipeline got precariously low during the day, but virtually all firm customers were served.

NW Natural, which serves customers in Oregon and southwest Washington, lost service in the early morning to 329 gas customers in Clark County, Washington, and pilots had to be relit. Several hundred more customers, principally interruptible customers, didn't have enough pressure to run industrial equipment. But service to all other LDCs on the pipeline remained intact and gas-fired generators with firm pipeline service remained online.

The pipeline and the LDCs debriefed in the aftermath of the December 9, 2009 events. They determined that communications among the players could have been more robust and carried out earlier, although the extent of the outage was not immediately apparent. But overall, more coordinated regional communications would have helped. All things considered, the system held up well. An outage that affected 25 percent of the peak-day supply for several hours in the I-5 corridor didn't cripple the system or lead to widespread outages.

As a result of the outage, actions were taken at Jackson Prairie to improve weatherization, educate operators on newer equipment and procedures, and replace a control system. And to get at the communications issues, the pipeline and LDCs revitalized the Northwest Mutual Assistance Agreement to help companies, both gas and electric, coordinate their responses to outages and emergencies.

Unseasonably cold weather led to the December 9, 2009 events. Preparedness for weather, which can be extreme in the Northwest, is another issue for the region to consider in planning for increased natural gas-fired generation.

Susceptibility to Weather

Like many regions of the country, the demand for gas and electricity in the Northwest peaks in the winter when temperatures are at their coldest. Since the region relies on gas-fired generation to meet peaks, cold weather patterns can significantly raise the demand for gas. When an extreme cold weather front rolls through, LDC requirements can double from what's needed on an average winter day.

The current gas infrastructure in the Northwest has so far been adequate to meet cold weather events, but equipment failure poses a risk. Without proper winterization, generators, compressors, and storage facilities can fail, particularly in areas east of the Cascade Mountains, where temperatures can drop below -20 degrees F.

In February 2011, electricity customers in Texas and the Southwest experienced rolling blackouts caused largely by failure to prepare gas-fired generating facilities for cold weather. In an outage situation that ultimately affected millions of electricity customers, as well as 50,000 gas customers across three states, the industry learned a cold, hard, and costly lesson.

Cold Snap Catches SW Unprepared

The Southwest was experiencing unusually cold and windy weather in the first week of February 2011. It was the worst time for a widespread generation failure. But over a period of four days at least 210 individual generators in the Electric Reliability Council of Texas (ERCOT) area experienced an outage, derating, or failed to start. Utilities were forced to shed load, and at the peak of the rolling blackouts, 1.3 million customers were out of service.

The gas-electricity interdependency in ERCOT is pronounced. Fifty-seven percent of ERCOT's on-peak generation is gas fired, with 40 percent gas-only and 17 percent dual-fuel capable. Over 29,729 MW of outages and derates occurred during the first day of the event. There was also generation out due to scheduled maintenance, and together, over 33 percent of all ERCOT generation was unavailable. The freezing weather accounted for 67 percent of the generator failures.

Only 12 percent were due to natural gas curtailment or failure to switch fuels for dual-capability plants. The curtailments that occurred were due to high residential demand and interruptible contracts.

After a similar outage event in 1989, regulators recommended winterization methods for the generators, but the weatherization was not mandatory and for the most part it was not implemented. Many of the same units that failed in 1989 also failed in 2011.

The electricity outages caused gas production outages in two basins because electric pumping units and compressors were shut down. Transmission operators generally did not recognize gas facilities as critical loads during the blackouts. In subsequent reviews, the gas/electricity interdependency was considered a contributing factor but not a significant cause of the outages.

A number of recommendations came about as a result of the four-day event. Among them were pre-event reviews and testing of available reserve and fuel-switching generation, and regulations to exempt critical gas facilities from rolling blackouts. In addition, there was a recommendation that gas providers determine if and when gas customers should receive priority over generators.

Dispatching

There are several issues related to electricity and natural gas dispatching that have been raised as the Northwest looks at its energy future.

Timing: While electricity can essentially be delivered in an instant over a power line, gas moves slowly (on the order of 20 mph). Both resources, however, rely on the maximum design of the infrastructure involved. Because of "line pack" and available storage, the natural gas system is resilient to short-term fluctuations between supply and demand that in the electric network might result in blackouts. But limitations with storage and the relative slowness of gas movement mean that extreme prolonged fluctuations could eventually take down portions of a gas network before an influx of new gas supplies can make an impact – such occurrences rarely happen. FERC has ordered and enforces protocols on communication between plant operators and pipelines that must occur if there are any changes that could impact hourly gas flow.

Several speakers at the 2012 summit also took note of the disconnect between the way the electric and gas industries mark time. The gas day begins *nationally* at 9 a.m. Central Time. The electricity day begins at midnight *locally*. Efforts to harmonize the days have been unsuccessful. Such a difference has little impact on prescheduled (or day-ahead scheduled) activity since the magnitude is known and measurable, but it could impact intra-day activity.

Scheduling: Gas "nominations" also occur on a different timetable from electric power scheduling. Gas is scheduled four times a day (two times for day ahead and two times intra-day). The majority of all daily gas transactions take place in the day-ahead market – there are very few transactions intra-day.

Electricity is also largely scheduled on a day-ahead basis. Within the operating day, there is a small amount of trading and schedule-change activity but unlike with gas, it can occur hourly and even sub-hourly. There is a trend in the electric power industry toward increased intra-hour scheduling; in fact, it has been recently ordered by FERC. More intra-day activity for gas-fired generation will likely require additional scheduling flexibilities by pipelines and storage facilities.

Figure 6 depicts the set schedule that is adhered to for gas nominations.

Figure 6: Gas Nomination Schedule

Nomination	Hour CCT	Day
Timely	11:30 AM	Day PRIOR to gas flow
Evening	6:00 PM	Day PRIOR to gas flow
Intraday 1	10:00 AM	Day OF gas flow, effective @ 5 PM
Intraday 2	5:00 PM	Day OF gas flow, effective @ 9 PM

(http://www.pnucc.org/documents/ElderNaturalGasElectricityConvergence.pdf)

In addition to the above schedule, the Williams Northwest Pipeline adds an important fifth cycle following the gas flow day, which is used to align after-hours requests.

Firm Capacity: All customers who purchase firm capacity are treated equally by the pipeline. Most Northwest natural gas-fired peaking generators do not have firm capacity on the pipeline because they have alternate fuel capabilities and the cost of owning pipeline capacity for a low load-factor (or peaking) facility is very high. The combined-cycle (or base load) gas-fired plants in the Northwest generally have firm capacity on the pipeline while peaking facilities generally rely on interruptible or non-firm pipeline capacity.

In addition, some pipelines are required to enforce "bump" rules that allow firm customers to adjust their nominations in a later cycle and bump interruptible customers. Williams Northwest Pipeline is a "no-bump" pipeline, so firm customers cannot bump interruptible customers on an intra-day basis. In short, these operational priorities pose questions for a region that is planning to become more dependent on natural gas-fired generation.

Coordination between Industries

Resource planning: In general, utility Integrated Resource Plans (IRPs) are developed with a narrow viewpoint on a local area where customers reside. Utilities in the region are subject to similar political, economic, and environmental constraints surrounding resource development (conservation, demand response, wind, and natural gas) so most IRPs bear similarities. And while the Northwest has a regional power planning body, the Council's plan does not get into specifics for any particular utility service territory nor does it knit together the electricity and gas industries. There is still a need for a regional planning process that takes a broader view of where both industries intersect.

The current regulatory and planning framework tends to focus on utility-specific solutions and doesn't easily accommodate coordinated efforts between industries or encourage region-wide long-term planning. There is change, however, under way nationally. The North American Electric Reliability Council's (NERC's) Gas/Electric Interdependencies Task Force has made recommendations related to assuring overall resource adequacy and formalizing communications between planning functions in the electricity and natural gas industries.

Daily operations: FERC has enacted regulations proposed by the North American Energy Standards Board (NAESB) that require pipelines to develop communication protocols with power plant operators. Today, gas operators may communicate regularly with personnel at natural gas-fired generators, but they don't often communicate directly with power dispatchers or system operators. As a general rule, system operators in the electric and gas industries conduct daily operations without direct communication. In fact, it was apparent at the 2012 summit that many in the electric power industry were unaware of the near-crisis in 2009 at Jackson Prairie. NAESB is formulating more standards that would require pipeline communication not only with power plants but also with balancing authorities and regional reliability coordinators.

Emergency response: Industry standards of conduct can get in the way of sharing critical information even during an extreme event. FERC regulations instruct regional transmission organizations, independent system operators, independent transmission operators, and power plant operators to sign up to receive operational flow orders and critical notices from gas transmission providers. But not all electricity system balancing authorities are in that loop.

Some regions have enacted their own communication protocols when extreme conditions threaten system reliability. For example, the communication protocols for the Florida Reliability Coordination Council include designating contact persons for each party involved and identifying a reliability coordinator. The Florida agreement requires regular training, testing, and drills for the procedures.

The Northwest Mutual Assistance Agreement (NMAA) was put in place in March 1999 as many industries prepared for potential disruptions arising from the "Y2K bug." The NMAA defined terms for cooperation in an emergency, encouraged communication, and established an Emergency Planning Committee. Participation was limited, however, and the committee did not meet regularly after the year 2000.

Events at Jackson Prairie in December 2009 changed that. The NMAA was revamped and expanded; it now includes 17 gas and electric entities. Members share emergency contact information and participate in planning meetings and emergency exercises. The Emergency Planning Committee meets twice a year and is working on region-wide emergency protocols.

Gas Supply

There have been no major gas shortages in the Northwest and gas-fired power plants are not experiencing reliability issues. Pipeline and storage capacity in the region are currently sufficient to serve both LDCs and power plants. But the lack of redundancy puts the system at risk. Component failures, particularly due to cold weather or at a major storage facility, could cause a gas shortage that affects a large area. In the I-5 corridor, Williams Northwest is capable of serving the market with gas from Sumas or with gas flowing west through the Columbia Gorge, which mitigates some of the risk.

In the event of a shortage, who gets priority?

In general, pipelines do not differentiate within classifications of service. Certainly, interruptible customers are interrupted during peak events, but firm customers are cut on a pro rata basis irrespective of customer class in the rare event that gas is not available to serve all firm customers.

LDCs have traditionally focused on "human needs" customers for a couple of reasons. These customers rely on gas for heat, and losing their gas supply can become a question of life and death. In addition, restoring service to these customers once the gas supply fails is an onerous proposition. Residential gas meters are equipped to turn off the gas when pressure in the system drops too low. Once the supply is interrupted, the flow of gas generally cannot be restarted without a technician visiting the home to relight the pilot light. In the aftermath of the Texas and Southwest outage in 2011, for example, it took weeks for local distribution companies to visit homes and relight the pilots for thousands of customers who were without service.

In a gas supply shortage, residential users are generally prioritized to stay on while power plants and large industrial customers, which are typically interruptible, tend to be the first customers dropped off the system. Customers in those classifications that have subscribed to firm service, however, are usually not curtailed other than on a pro rata basis. In extreme circumstances, such as the 2011 incident in the southwestern United States, loss of significant supply resources may require different curtailment priorities. It is imperative that such actions be coordinated on a regional level to ensure an optimal solution.

The way service is prioritized can obviously create challenges if natural gas-fired generators elect to rely on non-firm gas for plants that are needed for system reliability. When gas supplies are short, some generators can switch to other fuels, such as oil, diesel, or jet fuel. Most newer gas-fired generators in the Northwest are not dual-fueled, but operators have elected to subscribe to firm natural gas service.

It is also important to note that securing firm natural gas transportation service does not guarantee gas supply to any entity. Each entity must also secure firm supply through purchase contracts or storage in the same way power companies must buy energy as well as transmission. One without the other could result in demand not being met.

Economics

In any discussion of energy supply and reliability, economics are a major issue. And certainly that is an issue for electric utilities planning to increase their dependence on natural gas-fired generation, from plant construction costs to fuel supplies.

A 2004 National Regulatory Research Institute (NRRI) entitled "Increased Dependence on Natural Gas for Electric Generation: Meeting the Challenge" addressed the economics of ensuring reliability when the power supply depends on natural gas. The report said regional electric power operators face a potential dilemma in achieving the goals of low wholesale electricity prices and high reliability. Economics factor into decisions by gas-fired generators to purchase non-firm gas transportation service and to forego dual-fuel capability.

FERC also expressed concern in its Order 637 that gas pipeline customers rely too much on short-term service, including interruptible, relative to long-term service. But NRRI points out that requiring gas generators to have firm contracts for gas supply would eliminate some of the threat to reliability, but the costs would be significant and would drive up the price of electricity.

Speakers at the 2012 summit touched on these economic issues. One major money issue is coal-plant closures here and across the country. There is pressure on utilities to close coal-fired plants due to environmental initiatives and a common belief that it will be cheaper for utilities to replace coal with gas-fired generation than comply with EPA rules on emissions. But in reality, the experts say to do that, it will take lots of gas, lots more drilling, lots more coordination, and lots more storage, all of which will pose large economic costs.

Ensuring Reliability

In this new resource picture, where gas provides a bigger share of electricity generation, whose job is it to ensure reliability? In the transition to more gas-fired generation, it's primarily the security of the electric system that is at risk. The power system operator has the responsibility to address day-to-day reliability. But in the big picture, coordination and communication between the industries is required for an orderly transition.

At the 2012 summit, FERC Commissioner Philip Moeller said there are four broad areas in which joint gas and electricity issues need to be resolved: communication; operations and infrastructure; contracting; and planning for contingencies. He sees a role for the commission in shepherding communications between the industries. And while the role for federal regulators and national standards boards are not yet defined, he indicated there will be one. Commissioner Moeller said if the industries don't tackle and resolve the issues on their own, there will be federal intervention.

BPA Administrator Steve Wright agreed a collaborative Northwest solution would be more palatable than one imposed by federal regulation. In a 2012 letter to Commissioner Moeller, Mr. Wright and representatives of the region's gas and electricity industry stressed that reliability of the energy delivery system – from pipelines to power lines – is at the heart of the issue.

They urged FERC to recognize ongoing regional collaboration and told Commissioner Moeller that the Northwest has initiated operational and planning dialogues to address reliability and resiliency of both the gas and electricity systems. The NMAA provides a solid foundation for improving communication and coordination among the players and there are regular meetings now between gas and electric utility planners.

There are unique circumstances in every region of the country, and the Northwest power industry has a long history of working collaboratively to address common issues and reach common goals. The groundwork for collaboration has been laid over decades. The electricity and natural gas convergence issues are another chapter in the way the region's utilities and regulators address and resolve operational, policy, and planning issues.

Critical Issues and Risks for the Northwest

This whitepaper raises a number of issues that must be addressed as the Northwest adds more natural-gas fired generation to its resource portfolio. Leaders in the region's electricity and natural gas industries have teamed up to study the challenges posed in several areas. An ongoing effort is under way to make sure issues are studied in detail and resolved. BPA is playing a major role in this effort.

In particular, BPA and utilities are drawing on the wealth of knowledge about regional power operations and the history of collaboration to tackle the issues. There are already key pieces in place, like the regional associations and the Northwest Mutual Assistance Agreement, that provide a springboard for discussions and participants for the work groups that are necessary to address the issues and resolve them in a way that is appropriate for the Northwest power system.

The pending closure of two coal plants and the rapid expansion of wind generation have near-term implications for the region's gas infrastructure. The region has already undertaken joint gas and electricity planning efforts and is on the road to finding collaborative solutions the Northwest can own and fully support.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Direct Testimony of Bill Eddie

Ruby Pipeline LLC, “Statement of Actual Cost of Facilities Constructed”, FERC Docket No. CP09-54-000 (January 30, 2012)

RUBY PIPELINE LLC

January 30, 2012

Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Attention: Ms. Kimberly D. Bose, Secretary

Re: Ruby Pipeline Project;
Docket No. CP09-54-000;
Statement of Actual Cost of Facilities Constructed

Commissioners:

Ruby Pipeline, L.L.C. ("Ruby") is filing with the Federal Energy Regulatory Commission ("Commission") in Docket No. CP09-54-000, its Statement of Actual Cost of Facilities Constructed ("Statement") for the Ruby Pipeline Project. This Statement is being filed pursuant to Section 157.20(c)(3) of the Commission's Regulations Under the Natural Gas Act.

Description of Filing

Section 157.20(c)(3) requires that the Statement of Actual Cost of Facilities Constructed be filed with the Commission within six months after the authorized facilities have been constructed and placed into service. Ruby placed the Ruby Pipeline Project facilities into service on July 28, 2011. Accordingly, please find attached the Statement for the Ruby Pipeline Project facilities.

Ruby notes that the estimated costs depicted in this Statement are based on the revised Exhibit K filed with Ruby's Second Petition to Amend Certificate Order on April 1, 2011 in Docket No. CP09-54-002.

Filing Information

Ruby is eFiling this Statement with the Commission's Secretary in accordance with the Commission's Order No. 703, *Filing Via the Internet*, guidelines issued on November 15, 2007 in Docket No. RM07-16-000. Ruby is also providing an electronic copy of this filing to the Commission's Office of Energy Projects.

Respectfully submitted,

RUBY PIPELINE, L.L.C.

By Susan C. Stires

Susan C. Stires
Director
Regulatory Affairs Department

cc: David Swearingen, OEP

STATE OF COLORADO)
)
COUNTY OF EL PASO)

SUSAN C. STIRES, being first duly sworn, on oath, says that she is the Director of the Regulatory Affairs Department of Ruby Pipeline, L.L.C., that she has read the foregoing Statement of Actual Cost of Facilities Constructed for the Ruby Pipeline Project and that she is familiar with the contents thereof; that, as such Director, she has executed the same for and on behalf of said Company with full power and authority to do so; and that the matters and facts set forth therein are true to the best of her information, knowledge and belief; and that the construction activities described in said Statement comply with the requirements of Part 157 of the Federal Energy Regulatory Commission's regulations.

Susan C. Stires

Susan C. Stires

SUBSCRIBED AND SWORN TO before me, the undersigned authority, on this 30th day of January 2012.

CYNTHIA D NELSON
NOTARY
PUBLIC
STATE OF COLORADO
My Commission Expires 07-17-2014

Cynthia D. Nelson

Cynthia D. Nelson
Notary Public in and for
the State of Colorado
My Commission Expires July 17, 2014

Certificate of Service

I hereby certify that I have this day caused a copy of the foregoing document to be served upon each person designated on the official service list compiled by the Commission's Secretary in this proceeding in accordance with the requirements of Section 385.2010 of the Federal Energy Regulatory Commission's Rules of Practice and Procedure.

Dated at Colorado Springs, Colorado as of this 30th day of January 2012.

Susan C. Stires

P.O. Box 1087
Colorado Springs, CO 80944
(719) 667-7514

RUBY PIPELINE, L.L.C.
FINAL COST OF FACILITIES

Ruby Pipeline Project - Total project costs for the construction of 682.7 miles of 42" O.D. pipeline, four compressor stations, and metering facilities

CATEGORIES		Revised Exhibit K 4/1/11		Total Cost		Difference Over (Under)	
Right of Way	$	44,706,533	$	45,426,136	$	719,603	Note 1
Damages		5,115,951		7,155,191		2,039,240	Note 2
Surveys		42,619,707		50,191,936		7,572,229	Note 3
Materials		1,273,481,219		1,268,384,664		(5,096,555)	Note 4
Labor		1,360,411,275		1,466,098,806		105,687,531	Note 5
Inspection and Engineering		412,001,505		502,555,717		90,554,212	Note 6
Turn-Key Projects		0		21,667,312		21,667,312	Note 7
DIRECT COST	$	3,138,336,189	$	3,361,479,762	$	223,143,573	
Overheads		26,929,436		26,929,436		0	
AFUDC		309,662,876		309,662,876		0	
Legal Fees		12,358,188		13,927,926		1,569,738	Note 8
Contingency		62,713,311		0		(62,713,311)	Note 9
TOTAL COST	$	3,550,000,000	$	3,712,000,000	$	162,000,000	

Totals may not be an exact summation due to rounding in each component.

Note 1. Allocated property taxes were greater due to additional months of construction.

Note 2. Property damages were higher than anticipated.

Note 3. Survey costs were higher than anticipated due to the evaluation of alternate routes for the purpose of mitigating cultural concerns, exclusion windows, wildlife, and other restrictions.

Note 4. Certain materials (such as valves and fittings) were less than originally anticipated. A small discount was also realized on a quantity of pipe.

Note 5. Labor costs were higher due to permitting delays and related construction delays resulting in increased construction during winter weather conditions which led to lower productivity and longer construction duration.

Note 6. Inspection and Engineering costs were higher due to permitting delays and related construction delays resulting in increased construction during winter weather conditions which led to lower productivity and longer construction duration.

Note 7. The cost to upgrade the power line and construct the substation for the Roberson Creek Compressor Station was originally budgeted as separate Material and Labor costs. Ruby chose the more cost-effective alternative of contracting the power line upgrade and substation as "turn-key" projects.

Note 8. Legal costs were higher than anticipated due to litigation.

Note 9. The planned contingency was used to offset total project cost increase.

RUBY PIPELINE, L.L.C.
FINAL COST OF FACILITIES
Ruby Mainline and Lateral - Construct 682.7 Miles of 42" O. D. Pipeline

CATEGORIES	Revised Exhibit K 4/1/11	Total Cost	Difference Over (Under)	
Right of Way	$ 43,617,533	$ 44,485,616	$ 868,083	Note 1
Damages	5,115,951	7,155,191	2,039,240	Note 2
Surveys	42,619,707	50,191,936	7,572,229	Note 3
Materials	1,160,863,620	1,152,171,091	(8,692,529)	Note 4
Labor	1,231,828,772	1,385,824,894	153,996,122	Note 5
Inspection and Engineering	394,419,839	468,065,948	73,646,109	Note 6
DIRECT COST	2,878,465,422	3,107,894,676	229,429,254	
Overheads	25,038,488	25,042,280	3,792	
AFUDC	286,704,936	287,463,900	758,964	
Legal Fees	12,358,188	13,927,926	1,569,738	
Contingency	0	0	0	
TOTAL COST	$ 3,202,567,033	$ 3,434,328,782	$ 231,761,749	

Note 1. Allocated Property Taxes were greater due to additional months of construction.

Note 2. Property damages were higher than anticipated.

Note 3. Survey costs were higher than anticipated due to the evaluation of alternate routes for the purpose of mitigating cultural concerns, exclusion windows, wildlife, and other restrictions.

Note 4. Certain materials (such as valves and fittings) were less than originally anticipated. A small discount was also realized on a quantity of pipe.

Note 5. Labor costs were higher due to permitting delays and related construction delays resulting in increased construction during winter weather conditions which led to lower productivity and longer construction duration.

Note 6. Inspection and Engineering costs were higher due to permitting delays and related construction delays resulting in increased construction during winter weather conditions which led to lower productivity and longer construction duration.

RUBY PIPELINE, L.L.C.
FINAL COST OF FACILITIES
Compression-Construct four mainline compressor stations totaling 157,161 horsepower

CATEGORIES		Revised Exhibit K 4/1/11		Total Cost		Difference Over (Under)	
Right of Way	$	1,080,000	$	937,370	$	(142,630)	
Damages		0		0		0	
Surveys		0		0		0	
Materials		97,827,067		101,155,912		3,328,845	Note 1
Labor		99,979,060		50,358,961		(49,620,099)	Note 2
Inspection and Engineering		13,438,923		29,909,110		16,470,187	Note 3
Turn-Key Projects		0		21,667,312		21,667,312	Note 4
DIRECT COST	$	212,325,049	$	204,028,665	$	(8,296,384)	
						0	
Overheads		1,668,267		1,668,268		1	
AFUDC		20,081,671		19,806,344		(275,327)	
Legal Fees		0		0		0	
Contingency		0		0		0	
TOTAL COST	$	234,074,987	$	225,503,277	$	(8,571,710)	

Note 1. Material costs were higher due to the necessary purchase of spare parts.

Note 2. Prime construction labor was less than estimated. Costs for the Roberson Creek power line and sub-station were originally estimated as separate Material and Labor costs. However, electrical power and sub-station components were contracted as "turn-key" projects and booked as such. See Note 4.

Note 3. Inspection and Engineering costs were higher due to permitting delays and related construction delays resulting in increased construction during winter weather conditions which led to lower productivity and longer construction duration.

Note 4. The cost to upgrade the power line and construct the substation for the Roberson Creek Compressor Station was originally budgeted as separate Material and Labor costs. Ruby chose the more cost-effective alternative of contracting the power line upgrade and substation as "turn-key" projects.

RUBY PIPELINE, L.L.C.
FINAL COST OF FACILITIES
Measurement-Construct Eight Meter Stations

CATEGORIES		Revised Exhibit K 4/1/11		Total Cost		Difference Over (Under)	
Right of Way	$	9,000	$	3,150	$	(5,850)	
Damages		0		0		0	
Surveys		0		0		0	
Materials		14,790,532		15,057,661		267,129	Note 1
Labor		7,743,772		8,814,216		1,070,444	Note 2
Inspection and Engineering		4,142,743		4,580,659		437,916	Note 3
DIRECT COST	$	26,686,047	$	28,455,686	$	1,769,639	
						0	
Overheads		218,888		218,888		0	
AFUDC		2,429,507		2,392,632		(36,875)	
Legal Fees		0		0		0	
Contingency		0		0		0	
TOTAL COST	$	29,334,442	$	31,067,206	$	1,732,764	

Note 1. Material costs were higher than anticipated.

Note 2. Labor costs were higher due to permitting delays and related construction delays resulting in increased construction during winter weather conditions which led to lower productivity and longer construction duration.

Note 3. Inspection and Engineering costs were higher due to permitting delays and related construction delays resulting in increased construction during winter weather conditions which led to lower productivity and longer construction duration.

RUBY PIPELINE, L.L.C.
FINAL COST OF FACILITIES
Other Facilities

CATEGORIES	Revised Exhibit K 4/1/11	Total Cost	Difference Over (Under)	
Right of Way	$ -	$ -	$ -	
Damages	0	0	0	
Surveys	0	0	0	
Materials	0	0	0	
Labor	20,859,671	21,100,735	241,064	Note 1
Inspection and Engineering	0	0	0	
DIRECT COST	$ 20,859,671	$ 21,100,735	$ 241,064	
			0	
Overheads	3,792	0	(3,792)	Note 2
AFUDC	446,763	0	(446,763)	Note 3
Legal Fees	12,358,188	13,927,926	1,569,738	Note 4
Contingency	62,713,311	0	(62,713,311)	Note 5
TOTAL COST	$ 96,381,725	$ 35,028,661	$ (61,353,064)	

Note 1. Reverse contribution in aid of construction costs (R-CIAC) paid to interconnecting pipelines were higher due to increased construction costs.

Note 2. Overhead is not required on R-CIACs.

Note 3. AFUDC is not required on R-CIACs.

Note 4. Legal costs were higher than anticipated due to litigation. The planned Legal Fees was classified in Other Facilities as an administrative (accounting) convenience.

Note 5. Contingency was used to offset higher total costs for the project. The planned Contingency was classified in Other Facilities as an administrative (accounting) convenience.

Document Content(s)

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Direct Testimony of Bill Eddie

Excerpt from North American Electric Reliability Corp., “2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States”, December 2011

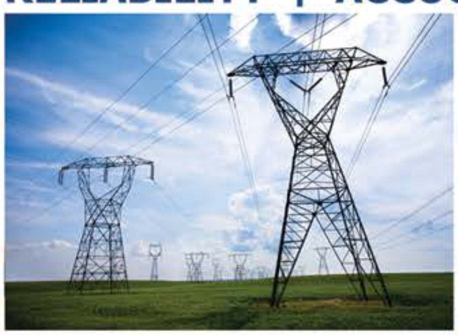
OneEnergy/106
Eddie/1

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States

RELIABILITY | ACCOUNTABILITY






December 2011

Chapter 7—The Gas and Electric Reliability Interface

Since 1988 the electric sector has gone from the smallest consuming sector for the natural gas industry to the largest consuming sector.[101] In addition, going forward the electric sector will be responsible for most of the growth in natural gas demand. The combination of this growth in gas demand within the electric sector and its changing status among the gas consuming sectors has increased significantly the interdependences of the two industries, and caused many within both industries to focus more sharply on the interface between the two industries. A key element of this focus on the interface between the two industries is the need for increased coordination between the two industries, particularly at a regional level.

Pipeline deliverability can impact electrical system reliability in several ways. A physical disruption to a pipeline, or to a compressor station, can interrupt the flow of gas or reduce pressure to multiple electric generating units. At times of peak loading on the gas pipeline system, interruptible customers may be curtailed so that the pipeline may fulfill its contractual obligations to firm customers. As noted, firm customers usually contract up to 100 percent of the capacity in a pipeline, since pipelines do not build capacity to serve interruptible customers.

Historically, pipelines have built capacity to meet a winter peak demand resulting in underutilized capacity in the spring, summer and fall months. Some electrical generators have made business decisions to purchase interruptible gas delivery service. Pipeline delivery service tariffs for firm service typically contain a fixed monthly charge for reserving capacity that is not recovered from the electric marketplace for the low capacity factor operation typically seen by combustion turbine generation in peaking service. Thus, it is economically infeasible for a peaking generator to make capacity reservation payments for firm service that it cannot recover from its sales of electricity. If such a generator served by interruptible transportation has no alternative source of fuel, then that generating capacity could be unavailable to the electric grid at peak times.

Electrical systems also have the ability to adversely impact pipeline reliability. The sudden loss of a large generator can cause numerous smaller, gas-fired combustion turbines to be started in a short period of time, assuming capacity is there or other generators are available. This sudden demand may cause pipeline pressure drops that could reduce the quality of service to other pipeline customers, including other generators. Electric transmission system disturbances may also interrupt service to electric motor-driven gas compressor stations.

Comparison of Pipeline and Electrical System Planning

Many similarities exist between gas pipeline planning and operations and electrical transmission system planning and operations, but significant differences exist as well. These differences occur because the transmission system owner has less control over the size or location of the electrical loads served by the

[101] The electric sector became the largest consuming sector for natural gas in 2007.

transmission system, or in the timing of the use of electricity by the ultimate customer. A pipeline, on the other hand, knows the exact location of the customers who have a firm right to transportation capacity, and has contracts in place that describe exactly how much firm transportation capacity each customer may call upon.

In general, the owners of electrical systems anticipate load growth, and plan, design, and construct a transmission system that meets specific NERC Reliability Standards and that is capable of serving the forecast customer demands. The nature of the electrical grid, with numerous nodes where facilities are interconnected, and multiple parallel paths for electricity to flow, results in a flexible, robust electrical delivery system. Often, capability exists to accommodate growth in demand or to provide service to customer demands from alternative generation sources. NERC Reliability Standards dictate a layer of protection in transmission planning—utility planners must look at adding system backup, or robustness, to cover a scenario called a “single contingency situation” such as the failure of a transformer or other significant event that causes the outage of a transmission line or large generator. These single contingency scenarios are known as “N-1” (N minus one) conditions. The general philosophy is that no single failure of a piece of equipment connected to or comprising the transmission network should cause a large number of customers to lose power. Transmission designers further test the system design by looking at scenarios involving two or more equipment failures (known as “N minus one minus one” scenarios or “N-1-1”). To recognize the specific regional attributes of its transmission grid, some operation and planning areas require additional planning standards. For example, some systems must be designed so that it can handle electric demand under extreme weather conditions (often referred to as a “90/10 load"), the outage of the two most critical generators, and/or limitations on the use of fossil fuel-fired peaking generation units. By using these and other criteria to plan and design the generation and transmission system, transmission utilities seek to ensure that customers rarely lose power because of a problem on the bulk power system. Most customer outages are caused by a local problem on the distribution system such as a tree coming in contact with an overhead wire.

In general, pipelines also react to load growth. FERC will generally not authorize new pipeline capacity unless customers have already committed to it (Firm delivery contracts), and pipelines are prohibited from charging the cost of new capacity to their existing customer base. Thus, additional customers request firm service from a pipeline that then adds new facilities or improves existing facilities, results in new pipeline capacity closely matches the requirements of the new customers. If all of the pipeline’s firm customers use their full capability, little or no excess pipeline capacity will be available. This is a major difference between electric transmission and pipeline infrastructure construction. Electric transmission does not necessarily need to be approved by FERC, but transmission must be built to support speculative growth and socialized cost. Additionally, pipeline contingency planning standards, similar to transmission planning standards, do not exist. However, this does not mean that the pipeline system is not redundant. First, buried steel pipelines are inherently robust than and, therefore more resilient to extreme weather than transmission wires. Second, pipelines use series of side-by-side pipelines (called “loops”) that provide redundancy—even if one gets corroded, needs maintenance, or even loses integrity, the other loops can increase their pressure and make it up. The same is true of compressor stations.

Electrical systems are regulated by a combination of federal, state, and local authorities. FERC approves the rates for transmission service for wholesale electrical transactions. State or federal authorities usually approve electrical system expansion for major facilities—but it is not required for all projects. Retail electric rates are approved by state commissions for regulated utilities, local governments for municipal utilities, or consumer-owner boards for cooperative utilities.

Interstate gas pipelines are regulated by FERC, and approval for new major pipeline facilities is obtained from FERC. A significant amount of electric generation is served by LDCs and intrastate pipelines that are regulated at the state level. Pipeline tariffs for firm service, like electric transmission tariffs, are cost based. Interruptible gas service is provided on an as-available basis at volumetric rates.

From the perspective of the natural gas industry, it is much more difficult to meet the needs of electric customers than it is to meet the needs of its residential, commercial and industrial customers. There are three major reasons for this increased difficulty, namely:

- **High Point Loads:** Relative to other customers, electric units represents very large point loads.
- **High Pressure Loads:** Largely because of improvements in generation technology (*e.g.*, the aeroderivative combustion turbines) the pressure requirements for electric loads are much greater than those for other consumers.
- **Large Variation Loads**: Primarily because gas-fired generation is generally at the margin and is used primarily to meet intermediate and peaking electricity requirements, daily load requirements can be subject to significant variation, as a result of weather events or unplanned outages for other units.
- **Non-ratable takes**: Most pipelines are designed to provide uniform service over a 24-hour period. However, there is a limit on the amount of hourly flexibility that a pipeline can deliver (*i.e.,* burning 24 hours worth of gas with an 8 hour period). Furthermore, pipeline flexibility is greatly reduced should all firm customers take their full entitlement to service.

In the following material presented in this chapter each of these three areas and their impacts on the gas industry are examined in greater detail. This assessment is followed by a discussion of how the two industries have been able to coordinate to date and the need to increase this coordination in the future, particularly in regions which traditionally have not had large electric loads.

CHARACTERIZATION OF ELECTRIC UTILITY GAS LOADS

As noted above, from the perspective of the gas industry the three dominant characteristics of electric utility gas loads are large, high pressure, and highly variable. All three characteristics individually represent significant challenges for the natural gas industry and in particular, the pipeline segment of the gas industry.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Direct Testimony of Bill Eddie

Bridges, Allison, VP and General Manager, Williams Northwest Pipeline, “Plugging into Natural Gas”, proceedings of Plugging into Natural Gas, Portland, Oregon, January 25, 2012

Plugging into Natural Gas

Allison Bridges, VP and General Manager
Williams Northwest Pipeline

Portland, OR
January 25, 2012

Pacific Northwest—Natural Gas Infrastructure

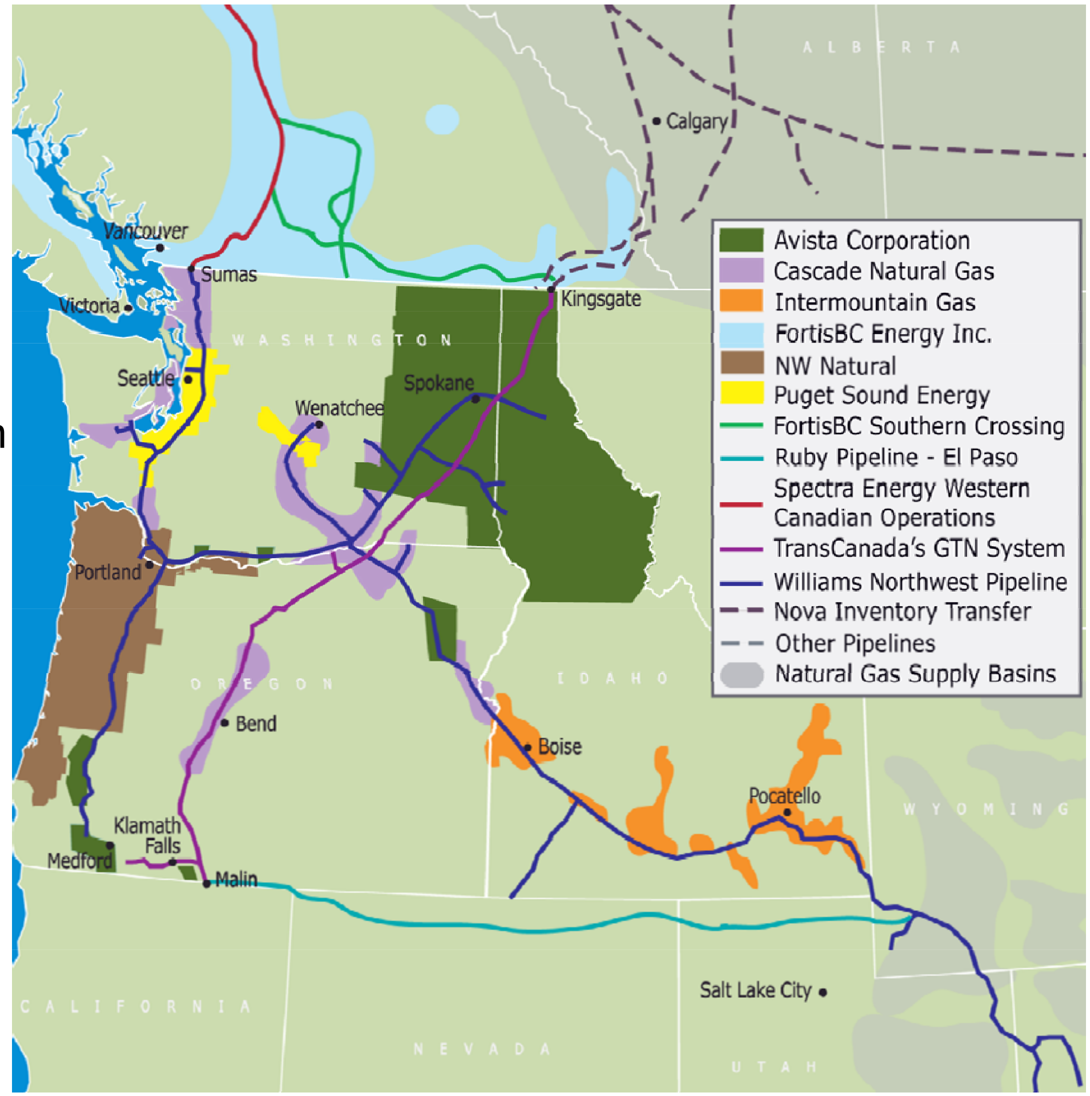
Williams. Ingenuity takes energy.®

> ## Region

- Five interstate pipelines and six distribution companies
- ~48,000 miles of transmission and distribution pipelines
- Combined with underground storage and peaking facilities, the infrastructure can deliver more than 6.5 MMDth/d on a peak day

> ## Northwest Pipeline

- 3.7 MMDth/d peak design capacity
- 14 MMDth of storage capacity (716 MDth/d deliverability)
- Bi-direction system with access to abundant domestic and Canadian gas supplies
- History of expanding the system to meet customers growth needs



Pacific Northwest Storage Facilities

Williams
Ingenuity takes energy.

Pipelines

- Spectra BC Pipeline
- Williams NWP
- TransCanada GTN
- Terasen S. Crossing
- Ruby

Storage Facilities

- Jackson Prairie (PSE, Avista, NWP)
- Mist (NWN)
- Clay Basin (Questar)

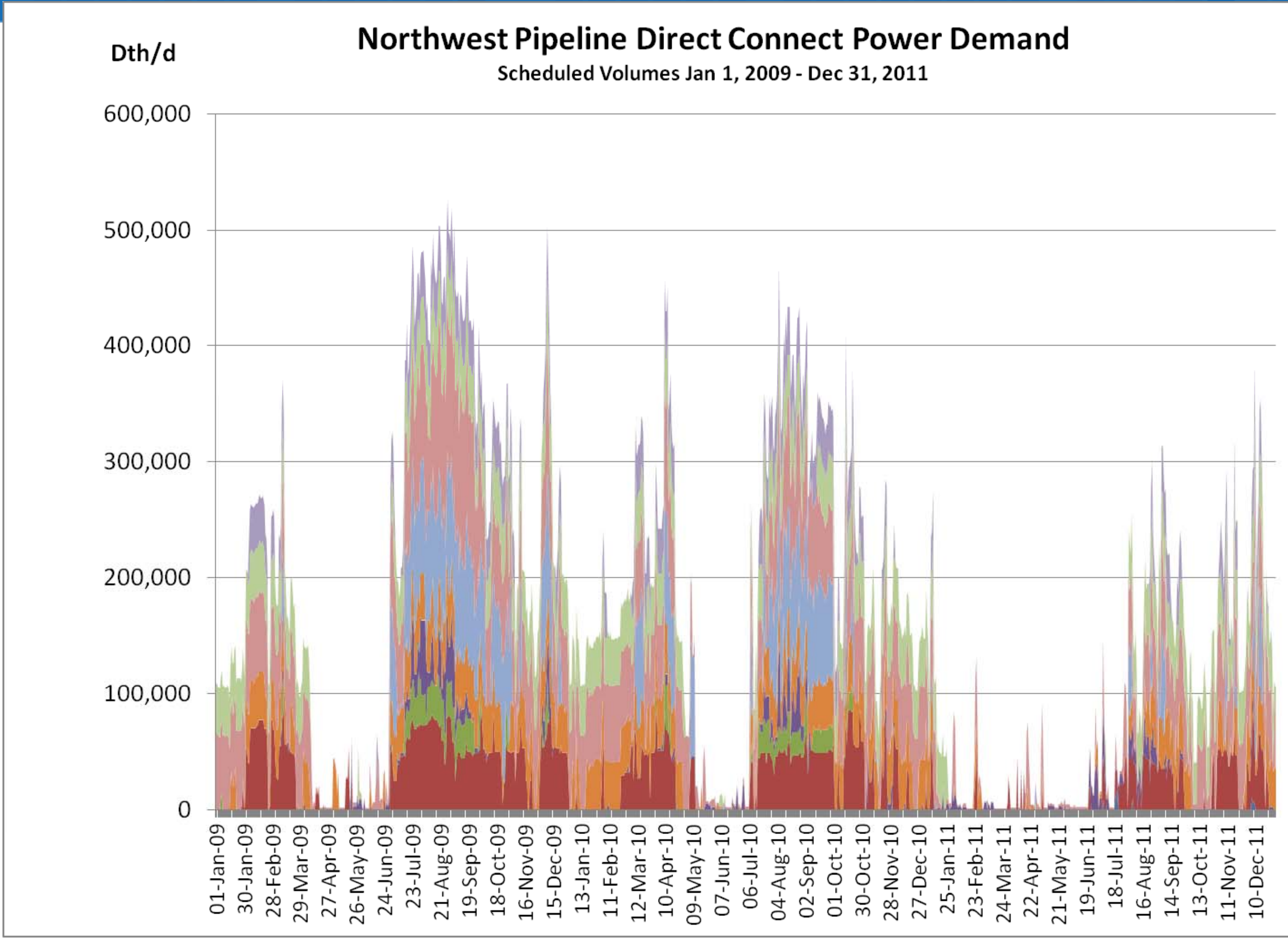
LNG Storage Facilities

- Nampa (IGC)
- Newport (NWN)
- Plymouth (NWP)
- Portland (NWN)
- Tilbury (TGI)
- Mt. Hayes (TGI)

Northwest Pipeline - a Long History Serving Power Plants

> Currently 24 gas-fired generating plants totaling approximately 5,000 MW (representing approximately 1 Bcf/d of potential gas load)
  – Approximately 2,800 MW added since 2002

> Power plants directly connected to Northwest hold approximately 400 MDth/d of firm capacity
  – Power plants behind customer city-gates may also hold capacity directly or may be managed as part of a utility's portfolio
  – Some power plants are served by third parties who hold firm capacity


Northwest Pipeline Direct Connect Power Demand
Scheduled Volumes Jan 1, 2009 - Dec 31, 2011
Dth/d
600,000
500,000
400,000
300,000
200,000
100,000
0
01-Jan-09
30-Jan-09
28-Feb-09
29-Mar-09
27-Apr-09
26-May-09
24-Jun-09
23-Jul-09
21-Aug-09
19-Sep-09
18-Oct-09
16-Nov-09
15-Dec-09
13-Jan-10
11-Feb-10
12-Mar-10
10-Apr-10
09-May-10
07-Jun-10
06-Jul-10
04-Aug-10
02-Sep-10
01-Oct-10
30-Oct-10
28-Nov-10
27-Dec-10
25-Jan-11
23-Feb-11
24-Mar-11
22-Apr-11
21-May-11
19-Jun-11
18-Jul-11
16-Aug-11
14-Sep-11
13-Oct-11
11-Nov-11
10-Dec-11

What Does a Power Generator Need for Reliable "Instantaneous" Natural Gas Service?

> Scheduling flexibility

> Supply and/or storage

> Adequate firm transportation capacity

✓ Scheduling Flexibility

- NAESB, including natural gas and electric participants, have struggled for years with the supposed "disconnect" between the electric and gas days
  - The gas day begins at 9:00 a.m. Central Time <u>nationally</u>
  - Electric day begins at midnight <u>locally</u>
- Since NAESB could not agree on gas day changes, communication protocols were agreed to and endorsed by FERC in Order 698
  - Plant operators and pipelines communicate with each other regarding changes that could impact hourly gas flow rates
- NAESB mandates four cycles in which nominations can be changed
  - Two cycles the day <u>before</u> flow and 2 <u>during</u> the day of flow
- Northwest adds an important fifth cycle <u>following</u> the gas day
  - Used to align after-hours requests, provided all parties confirm the flow

✓ Supply and/or Storage

- Firm supply can be brought on in each nomination cycle
- Storage and balancing are important for customers with highly variable loads (gas moves through the pipeline at approximately 20 MPH)
- Firm storage service can be acquired from the Jackson Prairie partners/capacity holders or from NW Natural at Mist
  - Northwest allows hourly scheduling for Jackson Prairie and Mist
- Northwest offers park and loan services year round
- Northwest has flexible balancing provisions
  - Balancing flexibility is only limited on days of extremely high or low line pack
- Northwest allows non pro rata hourly flows on a best efforts basis
  - Could change as pipeline utilization changes

✓ Firm Transportation Capacity

> Customers need to obtain adequate firm capacity to accommodate their highest instantaneous peak.

- Customers can contract with Northwest for available capacity, if any, or Northwest can design and construct expansion capacity
- Customers can acquire capacity from third party customers through capacity release or buy delivered gas from a third party who holds capacity

> Many factors need to be taken into consideration to determine what capacity is adequate

- Location (on the mainline or lateral; proximity to supply, etc.)
- Required pressures
- Instantaneous peak requirements
- Load profile
- Line pack
- Other contracted services
- Other factors

Firm Transportation Capacity—How Expansion Capacity is Built and Paid For?

Williams. Ingenuity takes energy.®

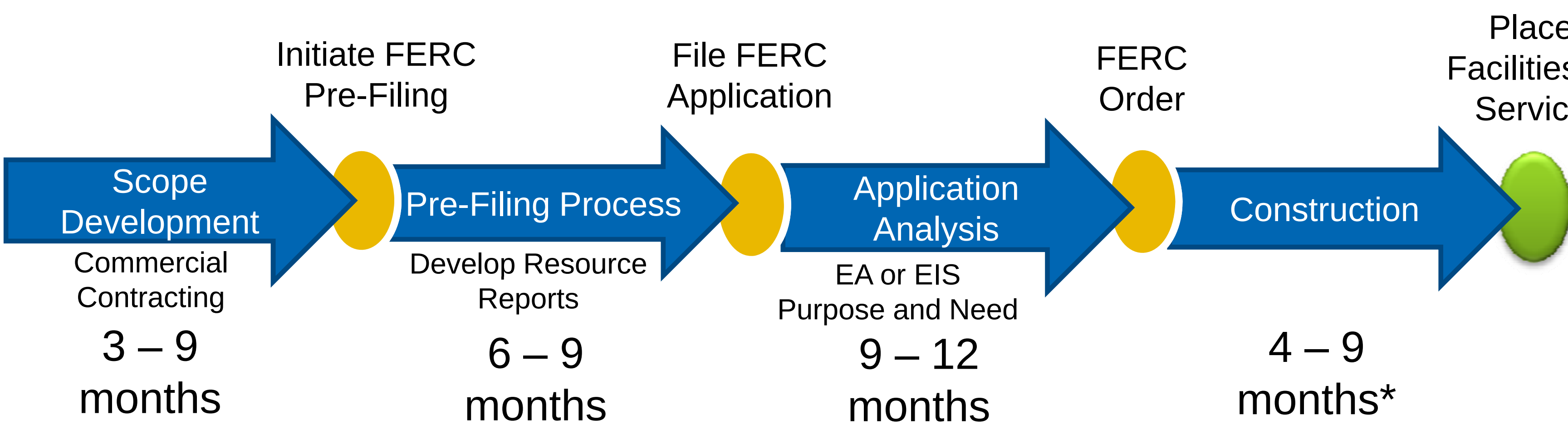
Start by understanding the differences in expansion economics:

- Electric Utilities
  - Regulated by the FERC and state commissions
  - Capital and operating costs collected from ratepayers
  - Expansions, such as new transmission lines or generating facilities, are paid for by rate payers generally
    - Expansions can be "acknowledged" in an integrated resource plan (IRP)
    - Do not require new contracts—costs are spread over entire system

- Interstate Gas Pipelines (U.S.)
  - Regulated by FERC
  - Capital and operating costs collected from contract holders
  - Expansions, such as new pipe and compression, are paid for by the party(s) needing the new capacity
    - Requires long term contracts to recover costs
    - Pipeline put at risk for subscription shortfall
    - Pipeline works with its customers to design and construct expansion capacity based on what the customer is willing to contract
  - Pipelines require an acceptable return

Illustrative Expansion Project Schedule

Will vary depending on scope and potential environmental/public impacts



Major expansion projects typically take 3 years to permit and construct

*Often limited to certain construction period windows (i.e. weather limitation or T&E species windows)

Keep in Mind

> The PNW infrastructure is robust and diverse. Several pipelines and storage facilities serve the region.

> Power plants on Northwest are not experiencing reliability issues.

> If the electric industry wants new services or incremental capacity, there is a clear path to follow.
  – Shippers must be willing to pay for firm service
  – Daily capacity should be calculated as the max flow X 24 hours
  – Regulators must be willing to allow recovery of costs for firm service

> When the electric industry needs expansions, pipelines are ready to respond—tell us what you need.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Direct Testimony of Bill Eddie

Excerpt from Gas Transmission Northwest LLC, “Abbreviated Application for Certificate of Public Convenience and Necessity”, FERC Docket No. CP12-494-000 (July 31, 2012)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C.

	)	
Gas Transmission Northwest LLC	)	**Docket No. CP12-___-000**

ABBREVIATED APPLICATION FOR
CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

Gas Transmission Northwest LLC ("GTN"), pursuant to and in accordance with Section 7(c) of the Natural Gas Act ("NGA"), 15 U.S.C. Section 717 f(c), and Part 157 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, 18 C.F.R. Part 157, hereby files this abbreviated application for a Certificate of Public Convenience and Necessity ("Application") authorizing its Carty Lateral Project ("Carty Lateral" or "Project") as described herein. GTN proposes to construct, own and operate a new lateral pipeline consisting of approximately 24.3 miles of 20-inch diameter pipeline, along with measurement and other associated facilities, located between GTN's Ione Compressor Station and Portland General Electric Company's ("PGE") proposed Carty Generating Station in Morrow County, Oregon.

GTN respectfully requests that the Commission issue an order granting the certificate on or before April 1, 2013. This approval will allow construction of the Project to be completed and in-service by November 1, 2014, PGE's requested in-service date.

I.

INFORMATION REGARDING THE APPLICANT

The exact legal name of GTN is Gas Transmission Northwest LLC. GTN is a limited liability company organized and existing under the laws of the State of Delaware with its principal place of business located at 717 Texas Street, Suite 2400, Houston, Texas 77002-2761. TransCanada American Investments Ltd. ("TAIL") owns a 75% interest in GTN and TC PipeLines Intermediate Limited Partnership, a Delaware limited partnership and affiliate of TAIL, owns the remaining 25%. GTN is a "natural gas company" as defined by Section 2(6) of the NGA[1] and is engaged in the business of transporting natural gas in interstate commerce, within the jurisdiction of the Commission. GTN operates approximately 1,351 miles of interstate pipeline extending from the International Boundary at Kingsgate, British Columbia to the Oregon-California border. GTN provides firm and interruptible transportation service on an open access basis to qualifying shippers.

The names, titles, addresses and telephone numbers of the persons to whom correspondence and communications in regard to this Application are to be addressed are:

*Robert D. Jackson
Director, Certificates and
Regulatory Administration
Gas Transmission Northwest LLC
717 Texas Street, Suite 2400
Houston, Texas 77002-2761
(832) 320-5487
robert_jackson@transcanada.com

*Eva N. Neufeld
Associate General Counsel
Gas Transmission Northwest LLC
717 Texas Street, Suite 2400
Houston, Texas 77002-2761
(832) 320-5623
eva_neufeld@transcanada.com

[1] 15 U.S.C. § 717a(6).

* Persons designated for official service pursuant to Rule 2010.

II.

BACKGROUND

GTN's proposed Carty Lateral is designed to provide natural gas transportation service to PGE. PGE proposes to meet a portion of future electric demand by constructing and operating the proposed Carty Generating Station, a combined cycle natural gas-fired power plant. PGE and its stakeholders have concluded that an incremental 300 - 500 megawatts of electric generation resources are required to meet its growth forecast. Therefore, PGE has included natural gas-fired generation in its Integrated Resource Plan ("IRP") submitted to the Oregon Public Utility Commission and acknowledged it as a needed resource in its IRP. Natural gas is an environmentally responsible, abundant, North American fuel proposed to be used by PGE to generate electricity to serve its more than 800,000 customers. The proximity of the proposed Carty Generating Station to the existing GTN mainline provides for the most cost-effective and least environmentally impactful solution to satisfying the requirements of this needed resource. Therefore, PGE has specifically requested that GTN construct the Project to supply natural gas to its proposed Carty Generating Station. The Project will provide PGE with an opportunity to meet some of its load resource deficit and to add diversity to its supply portfolio. On March 28, 2011, GTN requested that FERC initiate the NEPA pre-filing process for the Carty Lateral. FERC approved such request on March 31, 2011.

GTN and PGE entered into a Precedent Agreement, dated July 20, 2012, wherein PGE agreed to contract for the entire design capacity on the Carty Lateral for a term of thirty (30) years commencing on the in-service date of the Project at a negotiated rate.

III.

DESCRIPTION OF PROPOSED FACILITIES

GTN proposes to construct, own and operate approximately 24.3 miles of 20-inch diameter natural gas pipeline, along with measurement and other associated facilities, located between GTN's Ione Compressor Station (Compressor Station 9) and PGE's proposed Carty Generating Station in Morrow County, Oregon. As proposed, the Project will have a design capacity of approximately 175,000 dekatherms per day. The majority of the Project's right-of-way will cross privately owned land used for agricultural purposes. The Project will be situated entirely in Morrow County, Oregon. A new tap assembly and pig launcher will be constructed within the Ione Compressor Station boundary or within GTN's adjacent right-of-way, and a new meter station and pig receiver will be constructed at the proposed Carty Generating Station site. No new compressor stations or modifications of existing compressor stations are proposed as part of this Project. There will be no non-jurisdictional facilities constructed by GTN as part of this Project. A summary of related downstream non-jurisdictional facilities being built in concurrence with the Project can be found in Resource Report 1 contained in Exhibit F-1. There will not be any related upstream non-jurisdictional facilities being built concurrently with the Project. The estimated total cost for the Project is approximately $54.3 million, including AFUDC**.** The estimated costs for the construction of the Project are set forth in greater detail in Exhibit K hereto. Maps depicting the location of the Project facilities are included with Exhibit F.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Direct Testimony of Bill Eddie

Excerpt from Questar Pipeline Co., "Abbreviated Application of Questar Pipeline Company to Modify Existing Pipeline Facilities", FERC Docket No. CP12-524-000 (September 1, 2012)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Questar Pipeline Company) Docket No. CP12-__-000

ABBREVIATED APPLICATION OF
QUESTAR PIPELINE COMPANY
TO MODIFY EXISTING PIPELINE FACILITIES

Pursuant to § 7(c) of the Natural Gas Act (NGA)[1] and 18 C.F.R. § 157.7, Questar Pipeline Company (Questar) submits this abbreviated application with the Federal Energy Regulatory Commission (Commission or FERC) seeking authority to modify existing natural gas facilities that are located on Questar's southern pipeline transmission system. In connection with this proposal to modify facilities, Questar reserved capacity on its southern pipeline system for its proposed Main Line (ML) 41 Compression Project (ML 41 Project or Project). Pursuant to the provisions of its approved FERC Gas Tariff (Tariff), Questar submits this application seeking authority to proceed with the Project. The ML 41 Project will increase the pressure on ML 41 for an expansion of a downstream power plant, known as the Lake Side 2 power plant (Lake Side 2), while maintaining service to existing local distribution company customers. The ML 41 Project will be located in Utah and Carbon Counties, Utah.

[1] 15 U.S.C. § 717f(c) (2006).

I

EXECUTIVE SUMMARY

Questar proposes to modify existing natural gas facilities on its southern pipeline transmission system. In particular, Questar will: (1) add a second compressor package at its existing Thistle Creek Compressor Station (Thistle), (2) replace approximately 0.9 miles of existing 18-inch diameter ML 41 pipeline to establish a maximum allowed operating pressure (MAOP) through a Department of Transportation (DOT) Class 3 location and high consequence area (HCA), (3) upgrade metering and ancillary facilities at Questar's existing Payson Gate meter station (Payson) and (4) make piping and meter modifications at Questar's existing Oak Spring Compressor Station (Oak Spring). The proposed Project will increase pressure on ML 41 to allow additional high-pressure deliveries at Payson for the downstream Lake Side 2 power plant.

The majority of the construction for the Project will take place on property owned by Questar, within fenced facilities or existing right-of-way (ROW). However, space for staging, materials and parking will require minor use of temporary extra-work space outside the ROW or existing facility. Questar has worked with the affected landowners and agencies as well as a third-party contractor to prepare the supporting environmental documentation accompanying this certificate application, which includes an Environmental Report (ER), comprising 12 environmental resource reports (*see* Exhibit F-I). The total estimated cost of the ML 41 Project is approximately $19,700,000 (*see* Exhibit K).

Questar's tariff requires that it file a certificate application whenever it reserves capacity for a project. Questar reserved capacity for the Project on November 22, 2011. Pursuant to the provisions of Questar's tariff, capacity may be reserved up to one year prior to Questar filing for certificate authority to construct a project and thereafter until all facilities related to the certificate filing, for which capacity was reserved, are placed in service.[2] Questar believes that, absent the reservation of capacity, the proposed Project could be authorized under prior-notice authority pursuant to 18 C.F.R. Subpart F and Questar's blanket construction certificate.

Questar is requesting a Commission order in this proceeding by April 1, 2013, so that the Project may be constructed and available to provide service by November 1, 2013, prior to the onset of winter weather.

II

PRELIMINARY MATTERS

Questar is a corporation organized and existing under the laws of the state of Utah with authority to transact business in that state and others. The principal office is located at 333 South State Street, P.O. Box 45360, Salt Lake City, Utah 84145-0360.

Questar was found to be a natural-gas company within the meaning of the

[2] *See* section 31 of Part 1 of Questar Pipeline Co.'s FERC Gas Tariff, Second Revised Volume No. 1.

Natural Gas Act (NGA) by order issued in Docket No. CP76-111.[3] Questar provides open-access transportation service in Colorado, Utah and Wyoming and open-access storage service in Utah and Wyoming.

The persons designated to receive service pursuant to 18 C.F.R. § 385.203(b)(3) in connection with this proceeding are:

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III

HISTORICAL BACKGROUND

Questar owns and operates ML 41 as part of its southern pipeline transmission system. The 18-inch diameter pipeline extends northwest approximately 38.7 miles from the terminus of Questar's 20-inch diameter ML 40 at Boardinghouse, to Payson. Questar delivers natural gas to its local distribution company affiliate, Questar Gas Company (Questar Gas) at Payson.

ML 41 was placed into service in 1953 by Utah Natural Gas Company (Utah Natural). In 1961 Mountain Fuel Supply Company (Questar Gas' predecessor) acquired a one-half interest in ML 41 from Utah Natural and in 1975 Mountain Fuel Supply acquired the remainder of Utah Natural's interest in the line. In Docket No. CP80-274, Mountain Fuel Supply was granted FERC authority on May 29, 1984, in

[3] *Mountain Fuel Resources, Inc.*, 55 FPC 2322 (1976).

Opinion No. 221, to effect a comprehensive corporate reorganization along functional lines.[4] The result was to transfer jurisdictional-transmission facilities, including ML 41, among others, to Mountain Fuel Resources, Inc. (Questar's predecessor).

Thistle was placed in service on October 17, 2005, as part of Questar's Southern System Expansion that extended ML 104 by 18.7 miles, added Thistle and the Blind Canyon Compressor Stations, and modified two other existing compressor stations.[5] One compressor currently exists at Thistle and it is fully dedicated to ML 104.

Oak Spring was placed in service on September 30, 1998, and consisted of one compressor on ML 40.[6] On November 19, 2001, two more compressors were placed into service at Oak Spring as part of Questar's ML 104 Project where ML 104 looped a section of Questar's ML 40, and all of ML 41 to Payson, and then from Payson extending west to an interconnect with Kern River Gas Transmission Company at Goshen.[7] After further modifications at Oak Spring, all compressors currently discharge into ML 104.

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[4] *Mountain Fuel Supply Co.*, 27 FERC ¶ 63,316 (1984)
[5] *Questar Pipeline Company*, 111 FERC ¶ 61,035 (2005).
[6] *Questar Pipeline Company*, 82 FERC ¶ 61307 (1998).
[7] *Questar Pipeline Company*, 93 FERC ¶ 61,279 (2000).

IV

PROPOSED PROJECT

Description

The scope of the Project involves four primary components including: (1) installing a Solar Centaur compressor package at Thistle, (2) removing and replacing approximately 4,926 feet of 18-inch diameter ML 41, (3) upgrading Payson and (4) installing piping and equipment modifications at Oak Spring. The purpose of the Project is to provide higher delivery pressures at Payson for Lake Side 2 located at Vineyard, Utah, which is owned and operated by PacifiCorp. No incremental capacity is created from the Project. PacifiCorp will contract for 90,000 Dth/d of natural gas on Questar's existing ML 104. The capacity was acquired through Questar's open season (see the Marketing section below), to supply gas to Lake Side 2 for electric generation. To provide Lake Side 2 with the necessary pressure, Questar Gas requires pressures to be a minimum of 700 psig at Payson. To maintain the required pressure on ML while making contracted for deliveries at Payson, the Project requires facility modifications at the four existing locations more fully described below.

1. Thistle

Thistle is located approximately 1.7 miles northeast of Indianola, Utah, and approximately 20 miles southeast of Payson, Utah in Section 34, Township 11 South, Range 4 East on Questar's ML 104, adjacent to ML 41, in Utah County, Utah. Thistle currently has one Solar Taurus 60-7802S engine driving a C4011 centrifugal compressor that is used to compress gas on ML 104. Questar proposes to add a new compressor package on ML 41 at Thistle, a Solar Centaur C40-4702S SoLoNOx turbine engine driving a C402 two-stage centrifugal compressor that will add approximately 4,700 of nominal horsepower (hp) to compress gas on ML 41. The compressor is needed only to increase pressure on ML 41 to Payson so Questar can meet the downstream pressure requirements of Questar Gas. The new compressor package will be housed in a new separate compressor building. In addition, Questar proposes to install a mainline block valve, piping to tie-in the suction and discharge of the proposed compressor to ML 41, and associated ancillary facilities. No additional capacity is being created by the Project. All work will take place within the fenced Thistle site owned by Questar.

2. Replace Section of ML 41

The replacement section of ML 41 is located approximately 5 miles southeast of Payson, Utah, Sections 3 and 10, Township 10 South, Range 2 East in Utah County, Utah. The Camp Maple Dell Boy Scout camp (BSC) is adjacent to the pipeline along this section and is considered a DOT Class 3 location and HCA. Questar has limited the maximum allowed operating pressure (MAOP) along this section to 663 psig based on the existing physical configuration of the line and DOT Class location requirements. The purpose of pipe replacement is to establish the MAOP on this section of ML 41 at 824 psig by replacing approximately 0.9 miles of 18-inch diameter, .250-inch wall pipe with 18-inch diameter .375-inch wall, grade X-52 pipe. The replacement pipe will be installed in the same trench. The existing pipe will be hauled away. The pipe for the replacement section will be manufactured in accordance with American Petroleum Institute Standard 5L PSL 2, and coated with factory-applied external fusion-bond epoxy. No new permanent ROW will be required for the replacement.

As part of the pipe replacement segment, Questar will replace the existing tap with a new one-inch diameter tap to continue service to the BSC. Questar will also install an isolation valve and other appurtenances to allow safe operation of the existing regulator station at the BSC. The tap, valve and appurtenances will be installed as auxiliary installations pursuant to 18 C.F.R. § 2.55(a).

All pipe wrap and pipe removal will be done in accordance with Questar Standard Practice 8-25-01 to ensure compliance with all applicable state and federal requirements. As part of the disposal activities, Questar will arrange for the transportation of pipe and pipe wrap to an approved Resource Conservation and Recovery Act (RCRA) disposal facility using a licensed hazardous waste transporter (*see* Resource Report 12).

ML 41 is co-located with Questar's 24-inch-diameter ML 104 with an offset of 25 feet. The lines cross twice within the Project area due to terrain constraints so no offset exists at these locations. Each line utilizes a 50 foot wide ROW that overlaps 25 feet for a total permanent ROW width of 75 feet. Three areas of temporary extra work space are needed outside the existing 75 foot permanent ROW. Questar is proposing temporary extra work space at the start, south end, and at the north end of the pipe-replacement segment for staging and to tie-in to ML 41. The third temporary extra work space will be located at the access to the replacement segment and will be used for access, pipeline materials and cross-over for ML 104.

The pipe-replacement work will affect lands managed by the U.S. Forest Service (USFS) and land owned by the Boy Scouts of America (BSA) through the Utah National Parks Council. The parking lot of the BSC will also be utilized for parking and equipment storage. All areas needed for temporary extra work space will be on USFS managed land and land owned by the BSA. Questar has received permission from the landowners or will receive a permit to utilize each temporary extra work space for the Project.

Entrance to the pipeline replacement section will be from an existing road accessed from the South Payson Canyon Road. No new access roads are proposed. Questar will limit the road improvement to the existing travel lane, primarily by grading the road surface and applying some gravel on approximately 1,545 feet of the road leading into the BSC parking lot. The road will be left in its improved condition after construction activities are complete and will be repaired to as good or better condition than prior to construction.

3. Payson

Payson is the existing southern pipeline system gate station where Questar makes deliveries to Questar Gas. It is located on the terminus of Questar's ML 41 pipeline, approximately 4 miles south of the city of Payson, Utah in Section 34, Township 9 South, Range 2 East, in Utah County, Utah. Deliveries to Questar Gas at Payson will increase by 90,000 Dth/d. This capacity on Questar delivered to Payson is not an incremental increase, rather a redistribution of capacity that currently exists on ML 104. The increased deliveries at Payson require an upgrade in metering, valves, piping and ancillary facilities. Specifically, Questar will replace the existing six-inch diameter turbine meter with an eight-inch diameter ultrasonic meter; install a control valve and minor station piping and appurtenances. There will be one staging area located adjacent to the fenced Payson yard that will be used for equipment staging and parking area. The staging property is owned by a private landowner who has agreed to allow Questar to use the site. All other work will take place within the fenced station yard.

4. Oak Spring

To achieve operational flexibility and efficiencies with the proposed modifications on Questar's ML 41, piping and check-meter modifications are required at Oak Spring. Oak Spring is located approximately 7 miles west of Spring Glen, Utah in Section 36, Township 13 South, Range 8 East, on ML 40 and ML 104 in Carbon County, Utah. The Oak Spring modifications will increase the pressure to the suction side of Thistle. This will allow Questar to achieve the needed pressures on ML 41 with a smaller compressor unit, providing cost savings to Questar and fuel-cost savings to Questar's customers. In addition, the modifications will provide Questar with the flexibility to use any extra capacity in the existing Oak Spring unit No. 1. The modifications will provide the necessary pressure in ML 41 to make deliveries to Questar Gas at Payson during periods of low demand without operating the proposed new Thistle compressor. This mode of operation would result in significant fuel-gas savings during these periods and is reflected in the Exhibit G flow diagram for summer operation after the ML 41 Project is in service.

Modifications to Oak Spring will include installing approximately 35 feet of 20-inch diameter pipe from ML 40 to the suction side of Oak Spring unit No. 1 and replacing an existing eight-inch diameter turbine meter with an eight-inch diameter ultrasonic check-meter on an existing 10-inch jumper line connecting ML 104 to ML 40 on the discharge side of unit No. 1. With the piping modifications, Oak Spring will be capable of compressing into both ML 104 and ML 40. All facilities at Oak Spring will be installed as auxiliary installations pursuant to 18 C.F.R. § 2.55(a). All work will take place within the Oak Spring fenced yard located on land leased from the Utah Division of Wildlife Resources (UDWR).

V

MARKET SUPPORT

On November 22, 2011, in anticipation of an upcoming open season, Questar posted a notice to reserve 47,625 Dth/d of capacity on its existing ML 104 that had remained unsold. From December 8, 2011 to December 16, 2011, Questar held an open season to solicit binding support to enhance its southern pipeline system by constructing facilities to deliver volumes at a higher pressure to Questar Gas at Payson. For the Project, Questar reserved 47,625 Dth/d of currently unsold capacity. An additional 42,375 Dth/d of capacity that will become available from future expiring contracts was also offered. In support of the project, one customer, PacifiCorp, signed a precedent agreement for firm transportation service for the entire 90,000 Dth/d of capacity. The contract is for a 30-year term with a rate of $0.1418/Dth.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Direct Testimony of Bill Eddie

Utah PSC Docket No. 12-057-04, unnumbered Order, 2-3 (June 20, 2012)

- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Application of Questar Gas Company to Provide Natural Gas Transportation Service to the Lake Side Power Plant Facility	)	DOCKET NO. 12-057-04 REPORT AND ORDER

ISSUED: June 20, 2012

SYNOPSIS

The Commission approves a special contract for firm gas transportation service between Questar Gas Company and PacifiCorp.

By The Commission:

This matter is before the Commission upon the application of Questar Gas Company ("Questar") for an order approving the Second Agreement for Firm Transportation to PacifiCorp's Lake Side Generating Facilities ("Agreement") entered into between the Company and PacifiCorp on February 15, 2012. The application was filed on March 2, 2012, accompanied by the Agreement and confidential testimony explaining the Agreement's terms and Questar's reasons for accepting them. Broadly, the Agreement describes Questar's obligation to modify, construct, and install additional distribution facilities to provide firm gas transportation service to PacifiCorp's expanded electrical generating facilities at the Lake Side power station. Additionally, the Agreement obligates PacifiCorp to pay monthly payments of a specified amount for a defined period of years for the firm gas transportation service Questar agrees to provide.[1]

[1] Questar considers the terms of the Agreement to be commercially sensitive and presented them with a request they be treated as confidential information in accordance with Utah Admin. Code R746-100-16. No party opposed this request.

In accordance with a schedule established by Commission order,[2] the Division of Public Utilities ("Division") and the Office of Consumer Services ("Office") filed written testimony addressing the application. No other parties filed testimony or presented evidence. The Commission convened a hearing to examine the application on June 6, 2012.

PARTIES' POSITIONS

Questar states it seeks Commission approval of the Agreement so that it may charge PacifiCorp a different amount for firm gas transportation service than provided in its tariffs. Additional considerations Questar mentions are the length of the Agreement, its fuel reimbursement provision, and the corresponding amendment to a pre-existing Commission-approved firm gas transportation agreement Questar refers to as the Lake Side 1 Agreement.[3]

The Agreement at issue in this docket calls for Questar to complete a series of construction projects in order to transport natural gas at volumes and pressures sufficient to meet PacifiCorp's power generation needs when it begins operation of a new generating facility scheduled for completion by June 2014. Questar estimates the cost of these projects is about $13.7 million. Questar testifies the contemplated improvements to Questar's system will benefit existing and future customers. These benefits include: 1) increased capacity on Feeder Line 26 from Payson to Vineyard and, 2) increased system pressures in Salt Lake County, Tooele County, and northern Utah County. According to Questar, the increased system pressures will

[2] See Scheduling Order, Docket No. 12-057-04, March 27, 2012.
[3] See *In the Matter of the Application of Questar Gas Company for Approval of a Firm Transportation Agreement with PacifiCorp*, Order Approving Agreement, May 5, 2005, Docket No. 05-057-02.

provide operational flexibility during maintenance and emergency response operations. Questar contends securing these needed system benefits independent of the Agreement would impose significantly higher costs on its customers. Consequently, Questar believes the terms of the Agreement are just, reasonable, and in the public interest.

Questar also testifies much of this construction is necessary even in the absence of the new service for PacifiCorp, particularly system enhancements in the Saratoga Springs area and replacement of a portion of Feeder Line 26. Together these two system improvements will cost about $8.9 million and, Questar maintains, will benefit existing and future customers as already discussed. Taking into account the cost of these projects that would be necessary regardless of the Agreement, Questar views the improvements contemplated in the Agreement to result in an actual incremental cost of only $4.8 million beginning in 2016. Questar asserts the Agreement will require PacifiCorp to pay more than the revenue requirement associated with this incremental cost.

The Division asserts the Agreement is in the public interest and recommends the Commission approve it as filed. The Division testifies the Agreement will produce financial benefits for all Questar customers and system operational benefits for customers in Utah County and the southern part of Salt Lake County. The Division reaches these conclusions after evaluating Questar’s need to reinforce its system in the Saratoga Springs area to serve customer growth and the need to upgrade Feeder Line 26. The Division concurs the need for these system improvements is independent of the proposed service to PacifiCorp under the Agreement. The Division analyzed the total levelized revenue requirement Questar customers will pay with and without the Agreement in effect. According to the Division, if the Agreement is approved and implemented, Questar's customers will pay substantially less. The Division also believes the system operational benefits will be of great value to customers.

The Division believes the Agreement is also in the public interest from PacifiCorp's perspective. The Division states PacifiCorp selected Questar to provide the gas transportation service described in the Agreement through a competitive bid process and that Questar's bid was equal or superior to all other bids. The only downside risk to Questar the Division identifies is the potential for the actual construction costs necessary under the Agreement to exceed the projections. This risk exists because PacifiCorp's annual payment under the Agreement is a fixed amount. The Division notes, however, Questar has included some contingency costs in the construction cost estimates.

The Office also investigated the Agreement, independently assessing Questar's reasons for entering into it. The Office has no objection to the Commission approving the Agreement but believes Questar improperly seeks relief beyond the proper scope of this proceeding and the approval explicitly requested in the application.[4] From the Questar testimony accompanying the application, the Office concludes Questar seeks approval not only of the Agreement but also of the Company's plans to construct the required new facilities. The Office notes the Agreement does not specify the costs to construct these facilities or explain PacifiCorp's obligation to pay for their construction. The Office also argues Questar's testimony

[4] Similarly, the Office argues the Division's testimony regarding the propriety of PacifiCorp's actions with respect to the Agreement is beyond the scope of this proceeding.

amounts to a request for the Commission to pre-approve a rate increase for GS1 customers outside of a general rate case or other appropriate rate proceeding. This controversy, however, was resolved when the Questar witness during cross examination testified that in this application Questar only seeks approval of the Agreement between itself and PacifiCorp, and no other findings, conclusions, or orders.[5]

DISCUSSION, FINDINGS AND CONCLUSIONS

Questar's testimony adequately supports approval of the Agreement as in the public interest. Having examined the terms of the Agreement and its underlying assumptions, the Division also urges Commission approval. Similarly, the Office, the only other party to offer evidence, concludes approval of the Agreement is appropriate. Based on these unopposed recommendations, the Commission hereby finds the terms of the Agreement to be just, reasonable, and in the public interest. The Agreement is approved, as requested in the application. The Commission makes no findings or conclusions with respect to testimony and other evidence presented in this matter addressing issues beyond the reasonableness of the terms of the Agreement. All other issues, including cost recovery issues, are reserved for an appropriate future proceeding.

ORDER

The Second Agreement for Firm Transportation to PacifiCorp's Lake Side Generating Facilities is approved.

[5] See Transcript of Hearing, June 6, 2012, p. 13.

DATED at Salt Lake City, Utah this 20th day of June, 2012.

/s/ Ted Boyer, Chairman

/s/ Ric Campbell, Commissioner

/s/ Ron Allen, Commissioner

Attest:

/s/ Gary L. Widerburg
Commission Secretary
D#228439

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 20th day of June, 2012, a true and correct copy of the foregoing Report and Order was served upon the following as indicated below:

By Electronic Mail:

Colleen Larkin Bell (colleen.bell@questar.com)
Jenniffer Nelson Clark (jenniffer.clark@questar.com)
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Administrative Assistant

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Direct Testimony of Bill Eddie

Appendix 2 to PacifiCorp's Response to REC Data Request 2.28

PACIFIC POWER
AVOIDED COST CALCULATION

STANDARD RATES FOR AVOIDED COST PURCHASES FROM QUALIFYING FACILITIES OF 10,000 kW OR LESS, THAT QUALIFY FOR SCHEDULE NO. 37

OREGON – March 2012

PACIFIC POWER
AVOIDED COST CALCULATION

STANDARD RATES FOR AVOIDED COST PURCHASES FROM QUALIFYING FACILITIES OF 10,000 kW OR LESS, THAT QUALIFY FOR SCHEDULE NO. 37

OREGON – March 2012

Oregon Schedule 37 contains avoided cost prices to be paid to small qualifying facilities (QF) and applies to QFs with a design capacity of 10 MW or less. Oregon avoided cost filing requirements as listed in OAR 860-029-0040 and 860-029-0080 require the Company to file updated avoided costs at least every two years. The last Oregon avoided costs were filed March 4, 2010.

Sufficiency and Deficiency Periods

In Docket UM-1396 Order 10-488, the Commission directed that the start date of the first "major resource acquisition" in the action plan of the IRP determines the resource "sufficiency" and "deficiency" periods. For purposes of this filing the Company assumes that the action plan from the 2011 IRP has been acknowledged by the Commission.

Table 1 presents an excerpt from the 2011 IRP Table 8.16. **Table 1** shows that the next major resource acquisition occurs in 2016. The 625 MW combined cycle combustion turbine schedule in 2014 is the Lake Side II resource which the Company has contracted for construction and is no longer deferrable.

Avoided Cost Calculation

Based on resources shown in **Table 1**, the avoided cost calculation is separated into two distinct periods: (1) a period of resource sufficiency (2012 through 2015); and (2) a period of resource deficiency (2016 and beyond). During the resource sufficiency period (2012 through 2015), avoided energy costs are Mid-Columbia market purchases. **Table 2** shows the forecast market avoided costs.

During the resource deficiency period (2016 and beyond) in which new resources are required to provide both summer and winter capacity and energy to meet the Company's resource requirements, avoided costs are the fixed and variable costs of a proxy resource that could be avoided or deferred. The current proxy resource is a combined cycle combustion turbine (CCCT)[1].

Since CCCTs are built as base load units that provide both capacity and energy, it is appropriate to split the fixed costs of this unit into capacity and energy components. The

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[1] CCCT (Wet "F" 2x1) - West Side Options (1500') as listed in Tables 6.2 and 6.4 of the 2011 IRP. Fuel costs are from the Company's December 2011 Official Forward Price Curve (1112 OFPC).

fixed cost of a simple cycle combustion turbine (SCCT), which is usually acquired as a capacity resource, defines the portion of the fixed cost of the CCCT that is assigned to capacity[2]. Fixed costs associated with the construction of a CCCT which are in excess of SCCT costs are assigned to energy and are added to the variable production (fuel) cost of the CCCT to determine the total avoided energy costs. **Table 3** shows the capitalized energy costs.

The fuel cost of the CCCT defines the avoided variable energy costs. The gas price forecast used as the basis for the CCCT fuel cost is discussed later in this document. **Table 4** shows the CCCT fuel cost, the addition of capitalized energy costs at an assumed 50.5% capacity factor and the total avoided energy costs.

Because energy generated by a qualifying facility may vary, we have prepared total avoided costs at 75%, 85% and 90% capacity factor to illustrate the impact of differing generation levels. This calculation is shown in **Table 5**.

Avoided energy costs can be differentiated between on-peak and off-peak periods. To make this calculation, the Company assumed that all capacity costs are incurred to meet on-peak load requirements. On an annual basis, approximately 57% of all hours are on-peak and 43% are off-peak. **Table 6** shows the calculation of on-peak and off-peak avoided energy prices.

For informational purposes, **Table 7** shows a comparison between the avoided costs currently in effect in Oregon and the proposed avoided costs in this filing.

Table 8 shows the calculation of the total fixed costs and fuel costs of the CCCT and SCCT that are used in **Table 3** and **Table 4**. In this filing, the Company's proxy resource is a CCCT located on the west side of the Company's system. Current Commission approved avoided costs are based upon a CCCT located on the west side of the Company's system.

Gas Price Forecast

Gas prices used in this filing utilize the Company's December 2011 Official Forward Price Curve (1112 OFPC). **Table 9** shows the natural gas price used in this avoided cost calculation. Gas prices are the average of the Opal, Sumas and Stanfield gas indices. The use of an average of three indices is used to recognize that the CCCT is located on the west side of the Company's system rather than the east side.

The Official Forward Price Curve consists of a blend of the December 31, 2011 market gas curve and long term gas prices.

[2] SCCT Frame (2 Frame "F") - West Side Options (1500'), as listed in Tables 6.2 and 6.4 of the 2011 IRP.

	Market	Long Term
Through January 2018	100%	0%
February 2018 – January 2019	50%	50%
February 2019 and beyond	0%	100%

Example of Gas Pricing Options given Assumed Gas Prices.

Table 10 is provided to assist potential Qualified Facility developers to understand the gas pricing options. The example shows the impact on the avoided cost prices paid by the Company given assumed gas prices from $2.00 to $10.00/MMBtu.

Qualified Facility Pricing Options

With avoided cost prices calculated as discussed above, the Company has prepared the Qualified Facility pricing options consistent with the Commission's Order No. 05-584 and 07-360 in Docket UM-1129. The five options are Fixed Avoided Cost Prices, Gas Market Indexed Avoided Cost Prices, Banded Gas Indexed Avoided Cost Prices, Firm Market Indexed and Non-firm Market Indexed Avoided Cost. The first three pricing options are shown in **Appendix 1**, as **Exhibits 1 through 3**. Firm Market Indexed Avoided Costs are the market index price for day-ahead firm energy at Mid-Columbia, as published in Intercontinental Exchange (ICE) Day Ahead Power Price Report. Non-firm Market Indexed Avoided Costs are 93 percent of the market index price for day-ahead firm energy at Mid-Columbia, as published in Intercontinental Exchange (ICE) Day Ahead Power Price Report, for the On-Peak and Off-Peak periods.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Direct Testimony of Bill Eddie

Appendix 1 to PacifiCorp's Response to REC Data Request 2.28

Table 9
Gas Price Forecast
$/MMBtu

Year	Average Cost of Gas Average of Opal, Sumas and Stanfield Gas Indexes	Burner tip West Side Gas Fuel Cost
	(a)	(b)
2016	$4.66	$4.89
2017	$4.95	$5.21
2018	$5.38	$5.63
2019	$5.79	$6.03
2020	$5.66	$5.90
2021	$5.98	$6.23
2022	$6.53	$6.79
2023	$6.78	$7.07
2024	$6.66	$6.95
2025	$6.87	$7.17
2026	$7.21	$7.51
2027	$7.49	$7.81
2028	$7.69	$8.04
2029	$7.85	$8.23
2030	$7.92	$8.32
2031	$8.06	$8.44
2032	$8.21	$8.60
2033	$8.37	$8.76
2034	$8.53	$8.94
2035	$8.70	$9.10

Source
Official Forward Price Curvedated December 2011

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Direct Testimony of Bill Eddie

Worksheet “O&M- Fuel Trans.” Attachment A to PGE’s Response to CREA Data Request 003

		Fixed O&M $k/yr	Variable O&M $/MWh	Fixed Gas Transp. CCCT $/kW-yr	Fixed Gas Transp. SCCT $/kW-yr
2015	1	6,177	2.840	29.96	39.85
2016	2	6,291	2.893	30.51	40.59
2017	3	6,407	2.946	31.08	41.33
2018	4	6,524	3.000	31.65	42.09
2019	5	6,645	3.055	32.23	42.87
2020	6	6,767	3.111	32.82	43.66
2021	7	6,891	3.169	33.43	44.46
2022	8	7,018	3.227	34.04	45.28
2023	9	7,147	3.286	34.67	46.11
2024	10	7,279	3.347	35.31	46.96
2025	11	7,413	3.408	35.96	47.82
2026	12	7,549	3.471	36.62	48.70
2027	13	7,688	3.535	37.29	49.60
2028	14	7,829	3.600	37.98	50.51
2029	15	7,973	3.666	38.68	51.44
2030	16	8,120	3.734	39.39	52.39
2031	17	8,270	3.802	40.11	53.35
2032	18	8,422	3.872	40.85	54.34
2033	19	8,577	3.944	41.60	55.33
2034	20	8,735	4.016	42.37	56.35
2035	21	8,895	4.090	43.15	57.39
2036	22	9,059	4.165	43.94	58.45
2037	23	9,226	4.242	44.75	59.52
2038	24	9,395	4.320	45.57	60.62
2039	25	9,568	4.400	46.41	61.73
2040	26	9,744	4.481	47.27	62.87
2041	27	9,924	4.563	48.14	64.02
2042	28	10,106	4.647	49.02	65.20
2043	29	10,292	4.732	49.92	66.40
2044	30	10,482	4.820	50.84	67.62
Real Lev. (2010$)		5,639	2.59	27.35	36.38

Capitalization:			
Preferred	0.00%	0.00%	0.00%
Common	50.00%	10.75%	5.38%
All Equity	50.00%		5.38%
Debt	50.00%	5.77%	2.89%
Cost of Capital			8.26%
After-Tax Nominal Cost of Capital			7.11%
After-Tax Real Cost of Capital			5.17%

Fixed O&M (in 2008$, $k)
Years 1-30 $ 5,437

Variable O&M (in 2008$, $/MWh)
Years 1-30 2.5

Fixed Gas Transportation, Current Rates, $/kW-yr, 2011$

	CCCT	SCCT
NW Pipeline	24.95	33.19
PG&E NW	30.76	40.91
Average	27.86	37.05

	Generic 1 x 1 CCCT (G Technology)	SCCT
Total Demand (Dth/day)	70,550	46,200
Duct Firing (MW)	0	0
Duct Firing Heat Rate	n/a	n/a
Demand (non-fired)	70,550	46,200
Gas Transportation Demand Charges ($/Dth/day; 2011$)		
Williams	0.37984	0.37984
PGT, TransCanada, etc.	0.46826	0.46826
Annual Demand Charges		
Williams	$ 9,781,165	$ 6,405,242
PGT, TransCanada, etc.	$ 12,058,046	$ 7,896,268
Annual Demand Charges ($/KW-yr)		
Williams	$ 24.95	$ 33.19
PGT	$ 30.76	$ 40.91

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Direct Testimony of Bill Eddie

“In New England, a Natural Gas Trap”, New York Times (February 15, 2013)

The New York Times

February 15, 2013

In New England, a Natural Gas Trap

By MATTHEW L. WALD

Electricity prices in New England have been four to eight times higher than normal in the last few weeks, as the region's extreme reliance on natural gas for power supplies has collided with a surge in demand for heating.

Frigid temperatures and the snowstorm that hammered parts of the Northeast last week have revived concerns about the lack of alternatives to natural gas. Many plants that ran on coal or oil have been shuttered, and the few that remain cannot be put into service quickly enough to meet spikes in demand. The price of electricity is determined by the price of gas.

Last year, natural gas provided 52 percent of New England's electricity, and that share is expected to grow. Gas is generally cheaper than other energy sources, and the lower costs have spurred the retirement of aging coal generators and nuclear reactors. The six-state New England region and parts of Long Island are the most vulnerable now to overreliance on gas, a vulnerability heightened by a shortage of natural gas pipeline capacity, but officials worry that similar problems could spread to the Midwest.

"We are sticking a lot of straws into this soft drink," said William P. Short III, an energy consultant whose clients include companies that move and burn gas. "This is a harbinger of things to come in New England, as well as New York."

James G. Daly, vice president for energy supply at Northeast Utilities, a company that, through its subsidiaries, provides electricity to homes and businesses in Connecticut, Massachusetts and New Hampshire, said: "There is concern we don't have enough capacity to supply heating and electricity generation."

Northeast and many other companies are temporarily insulated from the spot market because they sign long-term contracts for electricity supply. But Northeast's energy charges next year could be 10 percent higher than they are now, Mr. Daly said, because the companies that sell power on a long-term basis will charge more to absorb the risk of short-term spikes in prices.

"It is certainly true that a region like New England that relies on a single fuel source like natural gas for the bulk of its power does leave itself open for more disruptions than a region with a more diverse fuel mix," said Jay Apt, executive director of the Electricity Industry Center at Carnegie Mellon University in Pittsburgh. "It's not a knock against natural gas; it's a knock against a single fuel source."

The American Public Power Association has warned since 2010 that demand is outpacing the delivery capacity of gas infrastructure. At coal plants, "you can look out the window and see that 60-day supply of your fuel," said Joe Nipper, the group's senior vice president of government relations. But gas plants tend to deliver fuel just as it is needed.

The gyrations of the spot market are hard to follow because prices are set in units few consumers understand. Electricity is sold on the wholesale market in megawatt-hours, or thousands of kilowatt-hours; a megawatt-hour is enough to run a big suburban house for a month. Natural gas is sold in a unit called an MMBtu, or a million British thermal units. An MMBtu equals 10 therms, the unit home heating customers pay for.

Normally, a megawatt-hour costs $30 to $50, and an MMBtu less than $4. But not lately.

The problem began late last year. During a cold snap around Thanksgiving, electricity prices in New England shot up to the highest in the country: $103.20 per megawatt-hour and $12.37 per MMBtu on Nov. 27.

On Jan. 24, the cost of an MMBtu of natural gas at Algonquin Citygate, a spot near Boston where gas is traded, rose to $31.20, pushing the price of a megawatt-hour over $200. Constellation Energy, which operates plants in the region, attributed the jump to temperatures 15 to 20 degrees below average.

A megawatt-hour cost about $150 early this month, according to weekly reports from ISO New England, the independent operator that maintains the region's electricity market. A year ago, the price was around $30.

New England's problems have been moderated somewhat by imports. "Without Indian Point, New England would have been toast," Mr. Short said. "We're importing 1,400 megawatts out of New York." Indian Point is a twin-unit nuclear plant on the Hudson River that New York State is seeking to close.

But the region is littered with 1950s- and 1960s-era coal and oil plants that have been retired in the last few years. The 214-megawatt, coal-fired AES Thames unit near Uncasville, Conn., shut down in 2011; Somerset Station, a 174-megawatt, coal-fired plant in Somerset, Mass., closed in 2010.

The Salem Harbor plant in Salem, Mass., once had four coal and oil units, with a capacity of 745 megawatts. Two have closed, and the others will probably close next year. A new owner intends to build a 630-megawatt plant that will run on natural gas.

The underlying issue in New England is that gas pipeline capacity is inadequate to keep prices steady in times of high home heating demand, said Vamsi Chadalavada, executive vice president and chief operating officer of ISO New England. ISO is leading a study focused mainly on reliability, but reliability is intertwined with price, he said.

Importing liquefied natural gas would help, Dr. Chadalavada said, but cargoes are going instead to Europe and South America, where prices are higher.

Several companies want to liquefy and export gas from the continental United States because of the shale gas glut, and the events in New England could affect that debate. Opposition has come mostly from domestic industries that use the gas. A spokesman for Senator Ron Wyden, Democrat of Oregon and chairman of the Senate Committee on Energy and Natu said Mr. Wyden saw the price gyrations in New England as a reason to "look bef ahead with unfettered exports of gas."

But the biggest problem may be the inadequacy of existing pipelines. On Feb. 7, ISO New England told the Federal Energy Regulatory Commission that it was concerned about "increasing reliance on natural gas-fueled generators at times when there is an increasingly tight availability of pipeline capacity to deliver natural gas from the south and west to New England."

Additionally, experts say that the natural gas market and the electric market mesh poorly, because while the electric market runs around the clock, the gas market closes down at night.

During the storm last week, with transmission lines being knocked out by snow and high winds, ISO asked some gas-fired generators to start running in the middle of the night, Dr. Chadalavada said, and found they could not. "We were sitting here, 3 in the morning, trying to get gas generators to start up, and we started seeing where they couldn't access that market in the overnight hours," he said.

About 30 percent of the generators in the region burn coal and oil, Dr. Chadalavada said, but they produce less than 1 percent of the energy because they run so seldom. Some can take 24 hours to return to service.

ISO and the Federal Energy Regulatory Commission, which oversees interstate electricity and gas markets and transmission, are trying to make the systems mesh better.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Direct Testimony of Bill Eddie

Excerpt of PacifiCorp's Ten-Year Conservation Potential and 2012-2013 Biennial Conservation Target for its Washington Service Area

Appendix 3
Comparison of Regional Methodologies

Northwest Power Plan and PacifiCorp Integrated Resource Plan Comparison Matrix, Washington Collaborative Working Group Documents on Avoided Cost and Total Resource Cost Methodology Comparisons (Methodology sub-group)

Appendix 3 contains an outline of the methodology used and provided by the Northwest Power and Conservation Council in the development of the regional power plan along with a description of the Company's aligning methodology. It also contains key work product documents (Tables A3-1 and A3-3) generated by the 2011 Washington Collaborative Working group on regional alignment of methodologies. This analysis demonstrates the consistency of the methodologies used in the development of regional plans and the Company's plan.

The information on the left side of the Table A3-1 below is Tom Eckman's (of the Northwest Power and Conservation Council) outline of major elements for the Northwest Power and Conservation Council's Methodology for Determining Achievable Conservation Potential.[32] Tom Eckman stated the methodology outline below applies to both the 5th and the 6th regional power plans. The information on the right side is the comparable information related to PacifiCorp's 2011 Integrated Resource Plan methodology.

Table A3-1
Methodology for Determining Achievable Conservation Potential
Outline of Major Elements

Northwest Power and Conservation Council		PacifiCorp 2011 IRP
1) Resource Definitions	i) Technical Potential	
	ii) Economic Potential	
	iii) Achievable Potential	PacifiCorp uses these same categories.
	(1) Non-lost opportunity resources ("schedulable")	In PacifiCorp's conservation potential assessment, these resources are referred to as "retrofit."
	(2) Lost opportunity resources	PacifiCorp uses same definitions, distinguishing between new construction and "normal replacement" as lost opportunity resources.
2) Technical Resource Potential Assessment	a) Review wide array of energy efficiency technologies and practices across all sectors and major end uses	PacifiCorp examined 341 "unique" measures in its conservation potential assessment, nearly double the number from the 2007 study and inclusive of all measures included in the Council's 6th Plan. Distribution efficiency improvement (DEI) is in the 6th Plan, but

[32] Provided by Tom Eckman to utilities in attendance at a meeting hosted by the Commission in Olympia on September 3, 2009. Refer to http://www.nwcouncil.org/energy/powerplan/6/supplycurves/I937/default.htm.

Northwest Power and Conservation Council		PacifiCorp 2011 IRP
		wasn't assessed in the Company's conservation potential assessment. A separate study was done to assess the conservation potential for DEI (a study is underway for Production Efficiency).
	b) Methodology	
	i) Technically feasibility savings = Number of applicable units * incremental savings/applicable unit	PacifiCorp used same methodology.
	ii) "Applicable" Units accounts for	
	(a) Fuel saturations (e.g. electric vs. gas DHW)	PacifiCorp used the same variables based on the latest survey data available for residential sector. Data for the commercial sector were obtained through field surveys and from the Northwest Commercial Building Stock Assessment (CBSA), the same source used by the Council.
	(b) Building characteristics (single family vs. mobile homes, basement/non-basement, etc.)	
	(c) System saturations, (e.g., heat pump vs. zonal, central AC vs. window AC)	
	(d) Current measure saturations	
	(e) New and existing units	
	(f) Measure life (stock turnover cycle)	Technical specifications for measures were compiled from secondary sources. Measure life estimates are consistent with Council's assumptions.
	(g) Measure substitutions (e.g., duct sealing of homes with forced-air resistance furnaces vs. conversion of homes to heat pumps with sealed ducts)	PacifiCorp examined and accounted for all measure interactions and substitution effects.
	iii) "Incremental" Savings/applicable unit accounts for	
	(a) Expected kW and kWh savings shaped by time-of-day, day of week and month of year	PacifiCorp used hourly (8760) end use load shapes to determine hourly impacts for all measures.
	(b) Savings over baseline efficiency	
	(i) Baseline set by codes/standards or current practices	PacifiCorp set baselines according to codes & standards in effect at the time of the analysis.
	(ii) Not always equivalent to savings over "current use" (e.g., new refrigerator savings are measured as "increment above current federal standards, not the refrigerator being replaced)	All savings were calculated based on existing *codes and standards*, and not existing *stock* characteristics.
	(c) Climate - heating, cooling degree days and solar availability	All analyses were based on typical meteorological year (TMY) data embedded in the eQUEST energy simulation model.
	(d) Measure interactions (e.g. lighting and HVAC, duct sealing and heat pump performance, heat pump conversion and weatherization savings)	Technical measure interactions were taken into account.

Northwest Power and Conservation Council		PacifiCorp 2011 IRP
3) Economic Potential - Ranking Based on Resource Valuation	a) Total Resource Cost (TRC) is the criterion for economic screening - TRC includes all cost and benefits of measure, regardless of who pays for or receives them.	
	i) TRC B/C Ratio ≥ = 1.0	
	ii) Levelized cost of conserved energy (CCE) ≤ levelized avoided cost for the load shape of the savings may substitute for TRC if "CCE" is adjusted to account for "non-kWh" benefits, including deferred T&D, non-energy benefits, environmental benefits and Act's 10% conservation credit	Total Resource Cost is the criterion for economic screening in the 2011 IRP and included cost reduction credits for risk mitigation, transmission and distribution investment deferred benefits, environmental benefits and the 10% regional act credit.
	b) Methodology	
	i) Energy and capacity value (i.e., benefit) of savings based on avoided cost of future wholesale market purchases (forward price curves)	PacifiCorp used full energy and capacity avoided costs in its calculation of measure benefits, based on PacifiCorp's system avoided cost decrements.
	ii) Energy and capacity value accounts for shape of savings (i.e., uses time and seasonally differentiated avoided costs and measure savings)	
	iii) Uncertainties in future market prices are accounted for by performing valuation under wide range of future market price scenario during Integrated Resource Planning process (See 4.1)	Uncertainty is handled through both analysis of three (baseline, high, low) market price/natural gas price scenarios, as well as Monte Carlo production cost simulation using market and natural gas prices as stochastic variables.
	c) Costs Inputs (Resource Cost Elements)	
	i) Full incremental measure costs (material and labor)	PacifiCorp fully accounted for these costs, including 15% program administration expenses.
	ii) Applicable on-going O&M expenses (plus or minus)	
	iii) Applicable periodic O&M expenses (plus or minus)	
	iv) Utility administrative costs (program planning, marketing, delivery, on-going administration, evaluation)	
	d) Benefit Inputs (Resource Value Elements)	
	i) Direct energy savings	All included in the analysis.
	ii) Direct capacity savings	
	iii) Avoided T&D losses	
	iv) Deferral value of transmission and distribution system expansion (if applicable)	PacifiCorp applied a T&D investment deferral credit of $54/kW-yr. The 6th Plan uses a distribution-only credit of $25/kW-yr.
	v) Non-energy benefits (e.g. water savings)	Quantifiable non-energy benefits were captured in the development of the conservation resource supply-curves developed for use in the 2011 IRP.

Northwest Power and Conservation Council		PacifiCorp 2011 IRP
	vi) Environmental externalities	PacifiCorp and the Council use a carbon tax, and both include the tax for derivation of wholesale electricity prices. The Council treats the CO2 price as a stochastic variable for risk analysis (given a uniform distribution with values between $0 and $100), whereas PacifiCorp does not. The Council's forecast of expected CO2 allowance prices begins in 2012 at a price of $8/ton, increasing to $27/ton in 2020, and to $47 per ton in 2030. PacifiCorp does not assume an expected CO2 price stream, but evaluated portfolios with value ranges (2015-2030, in 2015 dollars) of $0, $12 to $93, $19 to 39, and $25 to $68, including real escalation. Preferred portfolio development assumed $19/ton with 3% annual real escalation plus inflation.
	e) Discounted Present Value Inputs	
	i) Rate = After-tax average cost of capital weighted for project participants (real or nominal)	PacifiCorp used the after-tax weighted average cost of capital (WACC) for economic valuation of all measures.
	ii) Term = Project life, generally equivalent to life of resources added during planning period	PacifiCorp uses the same methodology.
	iii) Money is discounted, not energy savings	Only monetary values (avoided cost benefits) were discounted.
4) Achievable Potential	a) Annual acquisition targets established through Integrated Resource Acquisition Planning (IRP) process (i.e., portfolio modeling)	PacifiCorp uses the same methodology.
	b) Conservation competes against all other resource options in portfolio analysis	With the exception of discounts for risk mitigation and the 10% regional act credit PacifiCorp's 2011 IRP model treats energy efficiency resources and supply-side options equally.
	i) Conservation resource supply curves separated into	
	(1) Discretionary (non-lost opportunity)	PacifiCorp used identical definitions and reported the results in these formats in the conservation potential assessment.
	(2) Lost-opportunity	
	(3) Annual achievable potential constrained by historic "ramp rates" for discretionary and lost-opportunity resources	In its Conservation Potential Assessment, PacifiCorp used consumer surveys to determine achievable potentials based on market response. For the Integrated Resource Plan, the Company used the Council's assumption of maximum 85% achievable potential assumption for retro fit or non-lost opportunity and 65% for lost opportunities; an effective achievable of 82%.
	(a) Maximum ramp up/ramp down rate for discretionary is 3x prior year for discretionary, with upper limit of 85% over 20 year planning period	
	(b) Ramp rate for lost-opportunity is 15% in first year, growing to 85% in twelfth year	Ramp rates were developed for each measure and state reflecting the relative state of

Northwest Power and Conservation Council		PacifiCorp 2011 IRP
	(c) Achievable potentials may vary by type of measure, customer sector, and program design (e.g., measures subject to federal standards can have 100% "achievable" potential)	technology and state program. New technologies and states with newer programs, e.g. Wyoming assumed to take more time to ramp up than states and technologies with more extensive track records e.g. Washington and Utah.
	c) Revise Technical, Economic and Achievable Potential based on changes in market conditions (e.g., revised codes or standards), program accomplishments, evaluations and experience	PacifiCorp incorporates the impacts of enacted legislation in the development of its Technical, Economic and Achievable potentials, even if the legislation will not go into effect for several years, The most notable, recent efficiency regulation captured is the Energy Independence and Security Act of 2007.
	i) All programs should incorporate Measurement and Verification (M&V) plans that at a minimum track administrative and measure costs and savings.	PacifiCorp routinely evaluates its programs to measure actual savings based on industry best practices, including the IPMVP. The Company's recently documented EM&V framework is included as Appendix 8 to this report.

Table A3-2
Methodology for Determining Avoided Costs
Washington Collaborative Comparison

	Council	PacifiCorp	Consistency with Council Method
Primary Inputs			
Long-term forward price forecast(s) for energy and capacity	Yes, based on Aurora forecast of 8760 market prices aggregated into 4 time segments per month (48 annual segments) for cost benefits analysis, wide ranges and volatility added for portfolio analysis to capture risk.	Yes. In lieu of Aurora PacifiCorp uses a combination of our System Optimizer and Midas models which also rely on 8760 market price forecasts for energy to meet projected loads which includes both market purchases and generated power.	All utilities rely on hourly market price forecasts, consistent with the Council. Values vary according to the resource needs and options available for each utility.
Deferred/avoided T&D system costs	Yes for distribution system. Based on kW avoided at coincident peak and $ value of deferred kW expansion.	Yes. PacifiCorp applies a T&D deferral credit for energy efficiency in the IRP, currently set at $54/kW-year. The credit reduces measure resource costs in the supply curves prior to IRP modeling.	All utilities, like the Council, include a T&D deferral credit. Values may vary across utilities based on their system characteristics.

T&D line loss adjustment	Yes, 3.9% WECC transmission losses and 5% distribution losses, average about 9% total. Transmission losses vary by load levels so losses differ by load profile of measures.	Yes - System wide sector specific (residential, commercial and industrial) line losses are added to the site level DSM measure savings. Incorporated when DSM costs are levelized in development of supply curves prior to IRP modeling.	All utilities include a line loss adjustment, as does the Council. Utilities are utilizing average system losses; Council assumes marginal losses.
Generation reserve margin adjustment	Not directly. Included in Aurora for cost benefit assessment. Based on resources needed to meet load reliably and avoid high price excursions in portfolio analysis.	Yes. We include a capacity contribution for energy efficiency in our determination of capacity requirements.	All utilities and the Council incorporate reserve margins as part of the avoided capacity costs.
Uncertainty/risk adjustment	Yes. Portfolio analysis evaluates risk level explicitly as a characteristic of a resource strategy, value of efficiency in reducing risk is calculated as a premium for efficiency over market price.	PacifiCorp's IRP modeling of energy efficiency includes a risk reduction credit. The analytical approach was outlined in Appendix 4 to the Company's 2010-2011 biennial conservation target report filed with the Commission in UE-100170 targets the value of energy efficiency for reducing high-cost outcomes in the context of stochastic Monte Carlo production cost modeling. While the analytics are not used specifically to determine DSM avoided costs, it does affect the selection of DSM resources in a manner consistent with the Council methodology. This approach was utilized again in the 2011 IRP for energy efficiency resources selected in all states.	All utilities and the Council incorporate risk, although the values may vary.

10% Power Act credit	Yes. Applied to energy & deferred capacity components of value only.	Yes. The analytical approach was outlined in Appendix 4 of UE-100170 filed to support establishing the first biennial targets. The formula for calculating the $/MWh credit is: (Bundle price - ((First year MWh savings x market value x 10%) + (First year MWh savings x T&D deferral x 10%))/First year MWh savings. The levelized forward electricity price for the Mid-Columbia market is used as the proxy market value. While the analytics are not used specifically to determine avoided cost values, it does affect the selection of DSM resources in a manner consistent with the Council methodology. This approach was utilized again in the 2011 IRP for Washington resources only.	All utilities apply the 10% credit, but not as a direct adjustment to avoided cost in all cases. Avista applies it as benefit in its TRC calculation, rather than to the avoided cost. PacifiCorp applies the 10% adder as an additional benefit during the TRC calculation. PSE is consistent with the Council.
Shape of load (time and seasonality differentiation)	Yes. Four weekly time segments for each month and measure, aggregated from 8760 in Aurora and short-term demand forecast.	Yes. Avoided cost values (expressed in $/MWH for given year) are established by decrementing the load using 8,760 hour load shapes.	All utilities and the Council apply load shapes to their savings and costs. Methodology is generally consistent, but assumptions may vary.
Present Value Calculation Inputs			
Discount rate (real or nominal, pre-tax or post-tax, etc.)	Yes. Real after tax cost of capital. Rates vary for different types of utilities and consumers and debt versus equity.	Yes. IRP uses a weighted average cost of capital (currently 7.17%).	All utilities use their weighted average cost of capital, while the Council uses a hybrid of utility cost of capital and customer long-term discount rate.
Time frame (program/measure life, other term)	Twenty-year program analysis. Measure lives <20 years are re-purchased, longer are prorated and truncated.	Twenty year planning horizon. Measure lives <20 years are repurchased, longer are prorated and truncated.	All utilities handle time frame and measure lives similarly to the Council in their IRP's. For non-IRP program analysis, utilities generally use one measure lifecycle as the time frame.
Calculation algorithms	**Avoided Cost for a Measure =**	.	.

(generalized)			
Energy (if calculated separately)	.	The approach to establishing the DSM avoided cost values is described in the IRP and outlined briefly here. Values are established for resource types that align with measure types such as residential lighting, residential cooling, etc. where an 8,760 hourly load shape is available. Forecasted loads within the IRP preferred portfolio are reduced or decremented by an aggregate amount across each hour of the representative load shape. The change in the IRP preferred portfolio's present value of revenue requirements for each resource type is displayed in \$/MWh and represent the avoided cost for that resource type.	See below
Capacity (if calculated separately)	.	Included in decrement analysis	See below
Energy & Capacity combined (if calculated together)	Avoided Cost for a Measure = Mean point forecast of market price of energy by measure (based on shape of savings) PLUS Uncertainty/Risk Adjustment from portfolio analysis	Decrement analysis is combined value for both energy and capacity.	All parties combine energy & capacity together. PSE: In program analyses outside the IRP, PSE calculates separate avoided cost streams for energy and capacity and brings them together in its TRC calculation. All other parties incorporate capacity into their forecasts of energy prices.

Table A3-3
Methodology for Calculating Total Resource Cost
Washington Collaborative Comparison

	Council	PacifiCorp	Consistency with Council Method
Benefits			
Avoided Energy & Capacity Benefits			
Direct avoided energy savings	Yes, based on Aurora forecast of 8760 market prices aggregated into 4 time segments per month (48 annual segments) for cost benefits analysis, wide ranges and volatility added for portfolio analysis to capture risk.	Yes. See avoided cost matrix.	See Avoided Cost matrix.
Direct avoided capacity savings	Yes, based on Aurora forecast of 8760 market prices aggregated into 4 time segments per month (48 annual segments) for cost benefits analysis, wide ranges and volatility added for portfolio analysis to capture risk.	Yes. See avoided cost matrix.	See Avoided Cost matrix.
Avoided T&D line losses	Yes, 3.9% WECC transmission losses and 5% distribution losses, average about 9% total. Transmission losses vary by load levels so losses differ by load profile of measures.	Yes. See avoided cost matrix.	See Avoided Cost matrix.
Deferred T&D system savings	Yes, for distribution only, at time of peak usage	Yes. See avoided cost matrix.	See Avoided Cost matrix.
Quantified Non-Energy Benefits			
Non-energy benefits (water, etc.)	Yes, for quantifiable benefits or costs such as water, detergent, and internal end-use heating and cooling interactions.	Yes. Although they were not included in the development of our 2008 IRP and calculation of our 2010-11 WA I-937 biennial targets quantifiable non-energy benefits (available in third-party databases) were incorporated in our 2010 potential study update that was used to inform the 2011 IRP DSM selections. Non-energy benefits and O&M savings are incorporated as an adjustment to measure costs.	All utilities are now including NEBs, consistent with the Council. Assumed values may vary.

Environmental externalities	Yes, emissions are tracked and will be reduced through less dispatch of generation. Include cost of required control technologies. Include a range of potential CO2 costs from $0 to $100, growing over time averaging $47 by 2030.	Yes. Included through use of carbon tax assumptions in the IRP modeling process. In addition, environmental externalities beyond carbon with an established compliance cost (i.e. SOX) are included in production costs resulting in the value being captured in the calculation of avoided costs.	All parties handle this similarly. Assumptions about values vary.
10% Power Act credit	Yes. Applied to energy & deferred capacity components of value only.	Yes. See avoided cost matrix.	All utilities apply the 10% credit, but not as a direct adjustment to avoided cost in all cases. Avista applies it as a benefit in its TRC calculation, rather than to the avoided cost. PacifiCorp applies the 10% adder as an additional benefit during the TRC calculation. PSE is consistent with the Council.
Un-quantified Non-Energy Benefits (if/how included)	Not directly, may be partly reflected in 10% Act credit, but otherwise a portfolio judgment by Council. Typically not influential in decision, mostly based on quantifiable costs and benefits.	No. Not included at either the planning/analysis stage, at program cost effectiveness or individual customer level given the difficulty in identifying/quantifying.	Generally not explicitly included by any party, so utilities and Council are consistent. PSE has used this as a "nudge" to its low income program in past years, but it has not been necessary recently.
Tax Credits?	No. TRC is not reduced for tax credits. Renewable resource costs are reduced for credits, creating a potential consistency issue. Efficiency credits are more difficult to calculate.	No. Consider a transfer payment (and inherently hard to accurately quantify).	Council, PacifiCorp, and PSE do not include tax credits. Avista does the calculation with and without tax credits.
Costs			
Measure Costs (net)			

Full incremental measure cost (material & labor)	Yes, full incremental cost over current practice or codes and standards.	Yes. For lost opportunity resources, the incremental cost is the difference between the base and efficient case and may not include full labor costs. For retrofit resources, incremental costs are the full material and labor costs.	All parties treat measure costs consistently. Assumptions about values may vary, depending on local market costs.
Ongoing and periodic O&M costs (plus or minus)	Yes, and to extend a measure life is less than 20 year planning horizon replacement costs are included.	Yes. See avoided cost matrix.	All utilities include O&M costs where data is available and (in PSE's case) where TRC results would be materially affected. Assumed values may vary.
Non-incentive Program Costs (planning, marketing, delivery, admin, evaluation, etc.)	Yes, generally assume administrative costs are 20% of capital cost of measures.	Yes. Calculated as percent to the measure cost	All utilities include non-incentive costs, consistent with the Council. In IRP analyses, utilities apply a percentage "adder" to measure costs, like the Council. For non-IRP program analyses specific program budgets or actual expenditures are used.
Present Value Calculation Inputs (if different than for avoided cost)	same	.	.
Discount rate (real or nominal, pre-tax or post-tax, etc.)	Yes. Real after tax cost of capital. Rates vary for different types of utilities and consumers and debt versus equity.	Yes. IRP uses a weighted average cost of capital (currently 7.17%).	See Avoided Cost matrix.
Time frame (program/measure life, other term)	Over 20 years of the plan	Over 20 years of the plan.	See Avoided Cost matrix.
Results Presented			
B/C Ratio	Yes, present value benefit cost ratio for measure screening	Yes	All utilities, as well as the Council, calculate B/C ratios. PSE does not calculate a B/C ratio in its IRP portfolio analysis, because it is comparing total portfolio costs.
Levelized values	Yes, for portfolio analysis.	Yes. Levelized costs expressed in $/kWh saved.	Calculated by all parties.

Total NPV values	Yes, for parts of analysis and results presentation. Levelized and NPV are functionally equivalent.	Yes. Calculate NPV of costs and benefits.	Calculated by all parties. PSE calculates NPV values, but NPV is not generally reported for non-IRP program analyses.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Direct Testimony of Bill Eddie

Summary of Issues Corresponding to December 21, 2012 Issues List

Summary of Issues Corresponding to December 21, 2012 Issues List

1. *Avoided Cost Price Calculation*

A. What is the most appropriate methodology for calculating avoided cost prices?

i. Should the Commission retain the current method based on the cost of the next avoidable resource identified in the company's current IRP, allow an "IRP" method- based on computerized grid modeling, or allow some other method?

OneEnergy: The avoided capacity cost methodology adopted in UM 1129 should be adjusted to include (1) cost to procure firm fuel capacity rights on gas pipeline; and (2) cost to build (if necessary) and reserve firm delivery rights on transmission system to utility's Oregon control area.

OneEnergy: The standard power purchase agreement (Pac Schedule 37, IPC Schedule 201, IPC Schedule 85) should offer Distributed Generation QFs: (1) an adder for reduced losses, (2) fixed prices for 25-year term; and (3) levelized pricing. Distributed Generation means QFs under 3MW directly interconnected at distribution voltage.

ii. Should the methodology be the same for all three electric utilities operating in Oregon?

OneEnergy: Yes, generally.

OneEnergy: PacifiCorp has not shown that changing from a blended index to the Mid-C index for market prices is an insignificant change.

B. Should QFs have the option to elect avoided cost prices that are levelized or partially levelized?

OneEnergy: QFs under 3 MW directly connected to the distribution system of the purchasing utility should have the option to receive levelized payments.

C. Should QFs seeking renewal of a standard contract during a utility's sufficiency period be given an option to receive an avoided cost price for energy delivered during the sufficiency period that is different than the market price?

OneEnergy: No position at this time.

D. Should the Commission eliminate unused pricing options?

OneEnergy: No position at this time.

2. Renewable Avoided Cost Price Calculation

A. Should there be different avoided cost prices for different renewable generation sources? (for example different avoided cost prices for intermittent vs. base load renewables; different avoided cost prices for different technologies, such as solar, wind, geothermal, hydro, and biomass.)

OneEnergy: There should be on- and off-peak pricing for all Avoided Costs. Applying wind-specific integration costs to non-wind intermittent resources is unreasonable and should not be permitted.

B. How should environmental attributes be defined for purposes of PURPA transactions?

OneEnergy: Clarification whether the Energy Trust of Oregon can support projects that do not control their environmental attributes is important prior to the Commission making a final determination.

C. Should the Commission amend OAR 860-022-0075, which specifies that the non-energy attributes of energy generated by the QF remain with the QF unless different treatment is specified by contract?

OneEnergy: No Position at this time.

3. <u>Schedule for Avoided Cost Price Updates</u>

A. Should the Commission revise the current schedule of updates at least every two years and within 30 days of each IRP acknowledgement?

OneEnergy: Annual updates would result in more accurate avoided costs than the current, 2-year update frequency.

B. Should the Commission specify criteria to determine whether and when mid-cycle updates are appropriate?

OneEnergy: No position at this time.

C. Should the Commission specify what factors can be updated in mid-cycle? (such as factors including but not limited to gas price or status of production tax credit.)

OneEnergy: See 3(A), above.

D. To what extent (if any) can data from IRPs that are in late stages of review and whose acknowledgement is pending be factored into the calculation of avoided cost prices?

OneEnergy: See 3(A), above.

E. Are there circumstances under which the Renewable Portfolio Implementation Plan should be used in lieu of the acknowledged IRP for purposes of determining renewable resource sufficiency?

OneEnergy: No position at this time.

4. <u>Price Adjustments for Specific OF Characteristics</u>

A. Should the costs associated with integration of intermittent resources (both

avoided and incurred) be included in the calculation of avoided cost prices or otherwise be accounted for in the standard contract? If so, what is the appropriate methodology?

OneEnergy: Integration charges should apply to wind only until utilities quantify non-wind integration costs.

B. Should the costs or benefits associated with third party transmission be included in the calculation of avoided cost prices or otherwise accounted for in the standard contract?

OneEnergy: No position at this time.

C. How should the seven factors of 18 CFR 292.304(e)(2) be taken into account?

OneEnergy: Item(vii), smaller capacity increments and shorter lead times, should be modeled using the PacifiCorp's approach used to model resource deferral benefits from Class 2 DSM in its 2011 IRP.

OneEnergy: QFs should have the option to select an adder to their avoided cost in exchange for agreeing to be curtailable up to 100 hours/year.

OneEnergy: DG under 3MW should receive a 3.9% avoided line loss and should have the option to elect a 25-year term with levelized prices.

5. <u>Eligibility Issues</u>

A. Should the Commission change the 10 MW cap for the standard contract?

OneEnergy: No, however, a subclass of QFs (those under 3MW directly interconnected to distribution system) should have additional options in the standard contract.

B. What should be the criteria to determine whether a QF is a "single QF" for purposes of eligibility for the standard contract?

OneEnergy: Agree with PacifiCorp's proposal to reduce availability of the passive investor exception.

OneEnergy: Solar QF capacity should be the maximum AC capacity from the project

C. Should the resource technology affect the size of the cap for the standard contract cap or the criteria for determining whether a QF is a "single QF"?

OneEnergy: No. This is an overly broad remedy for abuse of standard rates by disaggregators. The partial stipulation, with PacifiCorp's proposed modification to the passive investor exception, can prevent disaggregation without discriminating against solar and wind projects.

D. Can a QF receive Oregon's Renewable avoided cost price if the QF owner will sell the RECs in another state?

OneEnergy: Yes, during the sufficiency period.

6. Contracting Issues

A. Should the standard contracting process, steps and timelines be revised? (Possible revisions include but are not limited to: when an existing QF can enter into a new PP A and the inclusion of conditions precedent to the PPA including conditions requiring a specific interconnection agreement status.)

B. When is there a legally enforceable obligation?

OneEnergy: No position at this time.

C. What is the maximum time allowed between contract execution and power delivery?

D. Should QFs smaller than 10 MW have access to the same dispute resolution process as those greater than 10 MW?

E. How should contracts address mechanical availability?

F. Should off-system QFs be entitled to deliver under any form of firm point to point transmission that the third party transmission provider offers? If not, what type of method of delivery is required or permissible? How does method of delivery affect pricing?

G. What terms should address security and liquidated damages?

H. May utilities curtail QF generation based on reliability and operational considerations, as described at 18 CPR §292.304(f)(l)? If so, when?

I. What is the appropriate contract term? What is the appropriate duration for the fixed price portion of the contract?

OneEnergy: The appropriate maximum term for fixed-price contracts for QFs under 3 MW directly connected to the purchasing utility's system is up to 25 years.

J. What is the appropriate process for updating standard form contracts, and should the utilities recently filed standard contracts be amended by edits from the stakeholders or the Commission?

7. Interconnection Process

A. Should PPAs include conditions that reference the timing of the interconnection agreement and interconnection milestones? If so, what types of conditions should be included?

B. Should QFs have the ability to elect a larger role for third party contractors in the interconnection process? If so, how could that be accomplished?

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(correlates to list in December 21, 2012 Order)

CERTIFICATE OF SERVICE

I hereby certify that, on March 18, 2013, I served a true and correct copy of the foregoing *Direct Testimony and Exhibits of Bill Eddie on behalf of OneEnergy, Inc.* on the following named persons/entities by electronic mail.

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