CASE: UM 1744
WITNESS: JASON KLOTZ

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Reply Testimony

October 2, 2015

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

A. My name is Jason R. Salmi Klotz. I am employed as a Senior Utility Analyst in the Energy Resources and Planning (ERP) Division of the Utility Program. My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. To respond to various issues raised by parties in their response testimony.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff 301, consisting of one portable document file. I have also prepared Exhibit Staff 302, consisting of one portable document file.

Q. Which issues that were raised by parties in their response testimony will you be addressing in your reply testimony?

A. I will address the following issues:

1. Cost of the project
    a. Risk and Cost
    b. Poor Definition of Total Approvable Costs
    c. Comparing Project Costs to Carbon Market Participation Costs
2. The proposed company incentive of $10 per ton of emission reductions
3. The emission reduction calculation methodology
    a. EPA's eGrid Non-Baseload Emission Rate Methodology
    b. Oregon Department of Energy Emissions Methodology
    c. Utility Emission Rate Methodology

d. The Northwest Power and Conservation Council Emissions Methodology

e. Criteria for Choosing an Emission Rate Methodology

f. Staff Proposal on Emission Reduction Value Methodology

4. Fuel switching

a. SB 844 and Fuel Switching

b. Staff's Findings on Fuel Switching

c. Aspects of SB 844 Fuel Switching Limiting Factors

<u>Issue 1. Cost of the Project</u>

Q. Did the parties' response testimony raise project cost issues that you would like to address?

A. Yes. Staff agrees with the Citizens' Utility Board of Oregon's (CUB) assessment regarding the overall cost of the program being too high. CUB correctly points out that the average rate increase associated with Northwest Natural Gas Company's (NW Natural, NWN, or the Company) application is higher than the rate increase from the Company's last approved general rate case. CUB/100 McGovern-Jenks/19. Northwest Energy Coalition (NWEC) also noted its concern over the cost of NWN's proposed program. NWEC points out that at the cost per ton proposed by NWN, the proposed program could cost ratepayers as much as $10.2M per year or as much as $42.49 per ton of emissions reduced. NWEC Response Testimony at 2. NWEC asserts that "The effective cost per tonne of emissions reductions at facilities under the program could be less, to the extent that such facilities continue to operate and provide net reduced emissions after the 10th year." *Id*. NWEC seems to agree with Staff that NW Natural has a duty to explore how extending the program life might lower the overall cost of the program. Additionally, NWEC shares Staff's concern that NW Natural's proposed program simply exposes NWN ratepayers to too great a cost risk, "To say the least, this could create considerable exposure for ratepayers, who would effectively take on the entire program risk since there is no capital investment required by NW Natural." NWEC Response Testimony at page 6.

Issue 1.a. Risk and Cost

Q. Has any party raised issues related to the burden of the project cost potentially falling on NWN's ratepayers?

A. Yes. NWEC raises concerns about how the structure of the proposal places nearly all cost risks on NWN ratepayers. NWEC Opening Testimony UM 1744 page 6. Staff finds merit in NWEC's comment. The proposed program as structured allows NWN to carry no risk should the program fail in any manner. The program structure provides an incentive to NW Natural for each ton of emission reduction. In the stakeholder process, the issue of risk was raised. NW Natural explained that the Company would only be paid for verified emission reductions.

Q. Did SB 844 (ORS 757.539) and the rules approved by the Commission (OAR 860-085-0500 through 860-085-0750) contemplate penalties in case of nonperformance?

A. While the statute and rules are silent on the issue, Staff does not believe that the legislature would allow a company to be approved for an emissions reduction program where the Company would not be held responsible for poorly administered or managed programs. The fact that incentive money and program success are directly tied to performance, the reduction of greenhouse gas emissions per ton, may not be enough protection for ratepayers in this instance. Staff is of the opinion that the full cost risk should not be borne by the ratepayers of NWN. NWN should not only share in the rewards of the program but also in the risks associated with the program.

Issue 1.b. Poor Definition of Total Approvable Cost

Q. Did the parties in their response testimony or the Company during the September 18 workshop raise questions regarding total approvable costs?

A. Yes. During the September 18 workshop, NW Natural was not clear and seemed to offer two perspectives with regard to how the Commission was to determine the total approvable costs. On one hand, NW Natural suggested that the total cost the Commission would be approving would be related the total number of emission reductions and that this would act as a total cap on the cost of the program. However, another member of the NW Natural team stated that this statement was not entirely accurate. As such, Staff is concerned that the program costs are not clearly defined or contained. Given the poor definition Staff suggests a cap be placed on the overall cost of the program. Staff believes NW Natural should have an opportunity to respond to this proposal if the Company deems that a response is necessary.

Issue 1.c. Comparing Project Costs to Carbon Market Participation Costs

Q. Do you believe it is appropriate to compare (a) carbon market allowance costs to (b) carbon reduction project cost as CUB has done in its response testimony?

A. No. Staff wishes to address CUB's assertion that NW Natural's program costs are high when compared to California's emissions allowance price. CUB/100 McGovern-Jenks/17. CUB glosses over the fact that carbon prices between carbon reduction schemes occupy a significant range from under $1 per ton in the Mexican carbon tax up to $168 per ton in the Swedish carbon tax. (World Bank Group, *State and Trends of Carbon Pricing,* 2014, p 32 Figure 5.) Prices in emission trading schemes tend to be lower, generally around $12 per ton. (World Bank Group, *State and Trends of Carbon Pricing,* 2014, p 32 Figure 5.) Lower prices are demonstrated by emission trading schemes because tax schemes often exempt industry and put the tax burden on private households. In an emission trading scheme increased stringency and broader sector application could lead to increased prices. The Tokyo Cap-and-Trade Program trades closer to $95 per ton, explained in part by an illiquid market where few reductions are traded. The point being that, prices of other markets do not necessarily reflect the economic fundamentals of all possible markets and the maturity of those markets. As such, Staff does not believe it is appropriate to compare the price of SB 844 projects with external pricing schemes. Although, Staff believes that other market prices for emission reductions or carbon pricing can be used as a helpful guide, care should be taken when making comparisons. Oregon has no formal carbon market or formal carbon regulation.

Q. Do you think Oregon should be free to find the correct carbon price given the particularities and policy goals of Oregon's interests and economy?

A. Yes. The Legislature created SB 844 in an attempt to better establish a carbon value. *See* ORS 757.539(9). Presently, NW Natural has presented an overall project cost broken out on a per ton basis. Parties are free to disagree and question the overall cost of the project and rightly should. Staff questions whether the proposed cost of $43 per ton is reasonable and whether the $30 per ton incentive offered to participants and the $10 per ton incentive to NWN are reasonable. But, using a separate market to suggest that the project costs are greatly inflated should be done carefully without promoting misconception of value or relevant program costs.

Issue 2. The proposed company incentive of $10 per ton of emission reductions

Q. Did the parties' response testimony raise issues with regard to the proposed company incentive of $10 per ton of emission reductions that you would like to address?

A. Yes. Like Staff, CUB and NWEC also question how the $10 per ton company incentive is tied to the present project tasks and whether the proposed incentive amount is proper. CUB/100/McGovern-Jenks/18, *see also* NWEC Opening Testimony at page 2.

Staff notes that in NW Natural's response to Staff IR 11, the Company creates the base case assuming that a 45 MW CHP customer will participate in the CHP program. This single customer would represent 37.5 percent of the total 120 MW in the base case and more than half of the total 75 MW in the low utilization case.

Q. Do you agree with the Northwest Industrial Gas Users' (NWIGU's) testimony that the Company incentive should be capped at $5 per ton of emission reduction?

A. Yes, with an explanation. Staff believes that NWIGU witness Finklea's testimony may help define a proper range for the Company incentive. Staff in Response Testimony at Staff/200 St. Brown/22 supported including a "$0 in the range of possible monetary-incentive values." In Response Testimony NWIGU witness Finklea stated, "In my judgment, if NW Natural paid customers no more than $30.00 per ton, and charged an additional $5.00 per ton as its own incentive to launch, administer and implement the program, NW Natural's ratepayers would be making a cost-effective investment in greenhouse gas emission reductions." NWIGU/100 Finklea/3.

Q. Does NWIGU witness Finklea's position have merit?

A. Yes. NWIGU witness Finklea's position regarding the incentive payment to NW Natural can be supported by market data, but there is no support for the proposed $30 per ton customer incentive payments which Staff witness St. Brown is addressing in Staff/400. According to preliminary survey results undertaken by the World Bank in 2013 the global average price for voluntary carbon offsets was $4.9 per ton. (World Bank Group, *Climate Change, State and Trends of Carbon Pricing* 2014, page 43.) Another type of carbon offset known as the REDD+ or Reducing Emissions from Deforestation, Forest Degradation fluctuated in 2013 to between $5 and $6 per ton. (World Bank Group/ *Climate Change, State and Trends of Carbon Pricing 2014*, page 43). If NW Natural were to undertake the proposed CHP project without ratepayer support, it could expect to sell its emission reductions in the voluntary market at between $5-6 per ton for the life of the measure. Staff has revised NW Natural cell B12 in tab "CHP Budget" of NWN OPUC IR 3 Attachement-1 spreadsheet to show the overall program cost implications of moving to a $5 per ton of emissions reduction company incentive. The results show an overall program savings of $12,180,000. Residential bill impacts are correspondingly adjusted downward from $0.99 to $0.87. This spreadsheet scenario assumes $30 per ton participant incentive, a base case emission reduction at 2,000 per MW and 120MW of CHP participating in the program.

Issue 3. Emission Reduction Calculation Methodology

Q. What issues were raised in response testimony with regard to the emissions reduction calculation methodology that you would like to address?

A. PacifiCorp witness Wiencke raises a valid concern regarding the issue of “lock in” for the emission reduction value for the full ten year period of NW Natural’s proposed program. PAC 100, Wiencke/6-7. Staff understands that locking in the emission reduction value at the beginning of the program will help eliminate uncertainty (NWN/101, Summers/46) but Staff agrees with PacifiCorp witness Wiencke that NWN has “not sufficiently explained why the benefit of such certainty” justifies using a static emission reduction value. PAC/100, Wiencke/7. Staff notes however that NW Natural has been conservative by choosing to use the eGrid non-baseload emission reduction value. It is Staff’s understanding from participation in stakeholder meetings that NW Natural was advised by the developer of the Washington State University RELCOST model, that NW Natural could arguably use the higher eGrid baseload emission reduction value. PGE witness Barra notes that “PGE tracks greenhouse gas emissions associated with the power we generate and purchase on behalf of our customers and reports is annually.” PGE/100 Barra/4.

Q. Is PGE Witness Barra’s testimony on this point valid?

A. PGE witness Barra’s statement is true but Staff does not find the statement to be in-and-of-itself persuasive. PGE may have a valid position but the assertion falls short of usable analysis. Although NW Natural has the burden to defend the methodology chosen, PGE, which has raised the possibility of using another methodology has the responsibility to share its methodology and advocate for its use. If PGE is successful in advocating for a utility specific emission reduction value, PacifiCorp and any other utilities with an affected CHP unit under the proposed program would also need to develop a methodology for an emissions reduction value. These methodologies would be analyzed, scrutinized and possibly disputed. In testimony the Northwest Energy Coalition correctly points out that the emissions factor issue is about the actual electric resources deferred when CHP is successfully operated. NWEC Response Testimony at page 4.

Q. Does the parties' discussion in their response testimony on the issue of emission reduction methodology require further consideration?

A. Yes. The issue of calculating avoided emissions is difficult. Given the complexity of the subject matter, the issue was raised and discussed at the September 18 workshop where PGE presented an argument for using its utility specific methodology, the Oregon Department of Energy presented its emissions reduction methodology and Staff raised the Northwest Power and Conservation Council's marginal emissions reduction methodology. Several competing methodologies have been made available and considered during this stakeholder process and during formal proceedings. NWN has presented for consideration the EPA's eGrid methodology. PGE has presented an alternative avoided emissions number but no discrete methodology. PGE does calculate an emissions value as part of its integrated resource plan. The Oregon

Department of Energy (ODOE) presented another methodology named the Unspecified Market Purchase Mix. Staff has discussed the Northwest Power and Conservation Council's marginal carbon dioxide production rate of the Northwest power system.

Issue 3.a. EPA's eGrid Non-Baseload Emission Rate

Q. Did the parties' response testimony directly raise questions with regard to NW Natural's proposal to use EPA's eGrid Non-Baseload emission rate and can you summarize the eGrid methodology?

A. Yes, several parties did raise concern regarding NW Natural's proposed use of EPA's eGrid Non-baseload methodology. CUB agrees with NW Natural's proposal to use EPA eGrid non-baseload methodology. However, both CUB and NWEC raise similar questions such as; what plant, or plants would reduce generation? What type of resources would be ramped down? CUB/100, McGovern-Jenks/13. What are the actual resources not used if CHP conversion is accomplished? NWEC Response Testimony at page 4. The EPA eGrid non-baseload emission rate represents an average emission rate for the generating units that are likely to be displaced by the end-use usage change.

Q. Please explain your understanding of the EPA'a eGrid methodology.

A. The eGrid database includes operational data such as total emissions and emission rates, generation, resource mix, capacity factors and heat input. The eGrid model does not account for T&D losses, imports and exports, transmission constraints or lifecycle emissions. The eGrid non-baseload output emission rates are associated with emissions from plants that are most likely to be backed down when energy efficiency and renewable energy programs are implemented. The emissions data is derived from plant level data and are aggregated up.

The main advantage of this eGrid non-baseload emissions rate approach is that it is somewhat straightforward and simple to calculate. However, possible shortcomings of this approach are that emission savings by program tend to vary over time, using a static annual number may skew the emissions reduction estimates. Additionally, the eGrid model cannot run future scenarios. Using 2010 data for a ten-year period will fail to account for plant retirements, such as Boardman. The eGrid model uses a very broad geographic profile. This model incorporates plants in Arizona, Utah, Wyoming, and Colorado that do not serve load in Oregon. Further, the Northwest and Oregon power system emissions rate is highly influenced by hydro-system supply. This is a factor which is diluted given the geographic scope used in the eGrid model.

Issue 3.b. Oregon Department of Energy Emissions Methodology

Q. Was the Oregon Department of Energy's proposed emission reduction methodology discussed at the September 18 workshop and does this require some review and assessment?

A. Yes. ODOE staff member Julie Peacock was asked by the parties to present at the September 18 workshop a review ODOE's Unspecified Market Purchase

Mix which was also summarized in a letter to Bill Edmonds of NW Natural on November 26, 2014. As the parties did discuss the ODOE's methodology at the workshop Staff will attempt to summarize the methodology, its merits and shortcomings.

Q. Please explain your understanding of ODOE's energy emissions methodology.

A. ODOE has proposed an emissions factor for electricity displaced by NW Natural's proposed CHP project. See Staff Exhibit/301. This methodology known as the Unspecified Market Purchase Mix utilizing reports from utilities on power generation and power purchases, the ODOE collaborates with the Washington Department of Community Trade and Development (CTED) and Washington State University (WSU) to produce a net system power mix report. The net system mix report provides the fuel mix and emissions attributed to Northwest Power Pool (NWPP) market purchases by utilities in Oregon and Washington. ODOE advocates that the Unspecified Market Purchase Mix is the "most likely emissions representation of avoided electricity purchases because it represents spot market purchases." See Staff Exhibit/301. ODOE reasons that it is tshese spot market, non-contractual purchases that would not be made because of investments in CHP. ODOE reports the Unspecified Market Purchase mix emission rate in 2010 was 1,178 lbs CO_2/ MWh, in 2011 it was 880 lbs CO_2/ MWh and in 2012 it was 885 lbs CO_2/ MWh. The advantage of this approach is that it is geographically more specific than eGrid. The approach is also transparent and regularly updated. However, this approach pivots on a resource mix used to serve load when all utility resources are otherwise expended. The value is highly influenced by hydro-generation supply. It is a reflection of market resources thought to be operating in a limited number of hours. The number is updated yearly but the value itself fluctuates to such a degree that relying on it for a program like the one proposed by NWN would be a barrier to participation. Additionally, ODOE is unable to forecast this value for future years.

Issue 3.c. Utility Emissions Methodologies

Q. Was a utility specific emission reduction methodology offered in the parties' response testimony and during the September 18, workshop?

A. Yes. PGE raised concern regarding the use of EPA's eGrid methodology and proposed to use a methodology more specific to the PGE operations: "PGE did attempt to raise its concerns at those workshops; however NW Natural has not been will to reconsider the proposed methodology." PGE/100/Barra/5. NWEC stated that "at the April 14 workshop, it was stated that PGE's gas emission rate is about 800 lbs/MWh compared to 1340 lbs/MWh for the NW Power Pool region, a considerable difference." (NWEC Response Testimony at page 4.)

Q. Was there discussion on the issue of emission reduction methodology offered by any of the parties who commented on this issue in their response testimony?

A. Yes. During the September 18, workshop PGE shared further detail regarding its proposed emission reduction methodology stating that emission reductions should be calculated using a combination of only new resources that might be displaced if the proposed CHP project was approved and successful. PGE witness Barra suggested at the September 18 workshop that a utility specific methodology could leverage the models used in Integrated Resource Planning.

Q. Can you give an overview of the utility IRP model?

A. Yes. Utilities use energy scenario modeling approaches that use dynamic simulation models of the grid. The utility models forecast which generating plant will operate at any given time based on inputs and assumptions in the model, and their algorithms simulate the complex interactions of the grid with consideration of factors such as transmission constraints, import/export dynamics, fuel prices, air pollution control equipment, and a wide range of energy policies and environmental regulations. These models specifically replicate least-cost system dispatch, with the lowest-cost resources dispatched first and the highest-cost last. All of these models can capture a high level of detail on the specific generator displaced. The models can and are used to generate scenarios of the electric grid's operation and emissions. If the power system is altered through load reduction or the introduction of an efficiency program, the model calculates how this would affect dispatch and then calculates the resulting emissions and prices.

Q. In an IRP model, please explain the underlining approach for determining the effects of one resource on the entire resource stack and therefore how emission reduction might be calculate.

A. The basis for this scenario approach is a dispatch model which is run with, and without the efficiency actions, resulting in an estimation of the difference in emissions. The models can also be used to provide hourly, monthly, or annual emission factors. Dispatch modeling can be the most precise means of quantifying avoided emissions (assuming good input assumptions and qualified modelers) because it can model effects of load reductions that are substantial enough to change dispatch (as well as future changes such as new generating units or new transmission corridors) on an hourly basis, taking into account changes throughout the interconnected grid. As such, it is a preferred approach where feasible.

Q. Are there drawbacks to the utility system IRP modeling approach?

A. Yes. Some drawbacks of utility system models are that they typically involve the use of proprietary, commercial programs; require extensive underlying data; and can be labor intensive and difficult for non-experts to evaluate. These models can also be expensive. Utility models do not model the competition among different generating technologies to provide new generation. In general, the model produces a deterministic, least-cost-system dispatch based on a highly detailed representation of generating units—including some representation of transmission constraints, forced outages, and energy transfers among different regions—in the geographic area of interest. This approach is most appropriate to use when a system is expected to be large enough to substantively change electric system operations and the utility resource mix. However, Staff is concerned about the lack of transparency, complexity and proprietary nature of the models constructed and operated by the utilities.

<u>Issue 3.d. The Northwest Power and Conservation Council Emissions Methodology</u>

Q. Did parties' response testimony or the September 18 workshop present a fourth emission reduction methodology that should be reviewed?

A. Yes, during the September 18 workshop Staff presented for consideration the Northwest Power and Conservation Council (NWPCC) emission reduction methodology number noting that the Council's methodology presents a range of between 700 and 1800 lbs/MWh. (Marginal Carbon Dioxide Production Rates of the Northwest Power System, June 13, 2008.)

Q. Can you give a review of the NWPCC's marginal carbon dioxide production rates methodology?

A. Yes. In a 2008 paper entitled *Marginal Carbon Dioxide Production Rates of the Northwest Power System* Council staff explains its use of the AURORA^{XMP} Electric Market Model to develop its wholesale power price forecasts and in turn the marginal carbon dioxide production rates. See Staff Exhibit 302. This model simulates hourly supply and demand to determine a marginal resource and market-clearing price for every hour of the simulation period for each of the load resource zones in the model.

The Power Council's methodology is also able to project into future possible carbon production rates. A confidence factor of the NWPCC work is that no other entity in the Northwest understands how to model the effects of hydro-generation on available power and the relationship of the Northwest power system to end-use efficiency.

Q. Does the NWPCC's methodology have limitations that you would like to highlight?

A. Yes, the NWPCC model does have some limitations regarding granularity of data for modeled units. While the Power Council does model the operations on units outside the traditional definition of the Northwest Region such as Jim Bridger and Valmy, its model does not incorporate the granularity of unit operations detail that utilities are capable of modeling because utilities possess other confidential operational cost factors that the NWPCC staff may not. Additionally the NWPCC model is not updated yearly or semi-yearly. However with consistency the NWPCC does update their model roughly every five years. For the purposes of the NW Natural's CHP proposal this interval may be sufficient.

Q. Can you please sum up your points regarding the NWPCC methodology?

A. Yes, the NWPCC marginal rate emissions number is a regionally vetted number however it is not utility specific. Further, this model may not grant the kind of accessibility that the EPA's eGrid model does. Although the models used by the Power Council are publically available the NWPCC does use a proprietary licensed model which is not easily understandable or accessible to those stakeholders uninitiated to complex dispatch modeling. For purposes of emission reduction calculations used in voluntary emission offset markets where measurement and verification play a significant rigorous role the eGrid model has traditionally been used. However, the NWPCC model is developed by a local neutral third party whose Regional Technical Forum has a long and nationally recognized role in energy efficiency measurement and verification. The Power Council's estimations of emissions at the margin are developed in a manner approximating utility model rigor. Lastly, the Power Council's emissions rate number is used in the Power Plan to assess the value of end use efficiency and generation and thus is arguably applicable to CHP.

<u>Issue 3.e. Criteria for Choosing an Emissions Rate Methodology</u>

Q. Has Staff identified any criteria that may assist in choosing the proper methodology for determining emission reductions?

A. Yes. Staff has broken out roughly five criteria from the discussion above which should inform parties' discussion on this issue and has helped Staff develop a position regarding which methodology is advisable given the goals of the program presented by NW Natural and other emission reduction counting goals of the Commission. For any model used in this program and others where emission reductions accuracy is a factor in developing costs that will be passed along to ratepayers Staff believes the following weighty factor should be addressed.

1. Geographic inclusion – The breadth and scope of the units and balancing authorities from which any model draws generation unit and emissions information. The model should be no more broad or limiting

in its geographic reach. The model should strive to model resources most likely to serve Oregon and Northwest regional loads.

2. Transparent – The model should be accessible to the public to the greatest extent possible such that third parties and stakeholders have visibility into which generating units are included in the model. Stakeholders should not be left to the mercy of subject matter experts to extract understanding, value and new perspectives.
3. Frequency of model updates – Models used for emission reductions estimates need to use regional data that is contemporary and updated at reasonable intervals.
4. Purpose of methodology – the purpose of any methodology should be to estimate emission reductions. Models that have been readjusted for the purpose of estimating emissions reductions should not be used. To this end the model used should be able to incorporate various types of emission reduction efforts whether they are combined heat and power, energy efficiency or self-generation.
5. Broad market support – Carbon offset projects are similar in nature to the proposed project and other anticipated Senate Bill 844 projects. Voluntary offset markets rely on rigorous measurement and verification practices with include an assessment of electric system emission data. Whatever model used for projects approved through the Senate Bill 844 process should use models that would be at least as stringent as

the models relied on by these voluntary offset markets. Currently these markets rely on eGrid data.

Q. Can you summarize these points and compare the various models against these criteria?

A. Staff developed the following graphic to apply and synthesize the above stated criteria to the model approaches reviewed above.

Emission Reduction Model Criteria					
	Criertia				
	Geographic Inclusion	Frequency of updates	Purpose of Methodology	Transparency	Broad Market Support
eGrid	Too Broad, and far reaching	Data year set is not contemporary			
NWPCC					
ODOE				Staff has not found the data set to be readily available	This methodology has not gained much support
Utility Emission Models				Staff has concerns over the transparency of	Currently unknown

The table above attempts to summarize the discussion sections above on each of the emissions methodologies and attempts to apply the criteria subsequently discussed by Staff. Where Staff felt specific factors needed emphasis, Staff has placed a note in the cell. Each cell is color coded. Green denotes that the methodology meets the stated criteria; yellow denotes concern that the methodology challenges the criteria but may still present merit and lastly, red denotes that the methodology does not meet the stated criteria.

Issue 3.f. Staff Proposal on Emission Reduction Value Methodology

Q. Did the parties in their response testimony raise concerns about finding an accurate methodology for determining emission reduction values?

A. Yes. In her response testimony, PacifiCorp witness Wiencke asks that the "Commission direct NW Natural to develop a methodology for estimating emission reduction that is more current and may change over the life of the project." PAC/100 Wiencke/7. Further, in its response testimony, PGE objects to using, "information that will not accurately reflect actual carbon emission reductions." PGE furthers this statement by suggesting that "a more accurate and realistic number be used." PGE/100 Barra 4. Although both PGE and PAC suggest that a more accurate methodology be used, neither party has presented a substantial proposal.

Q. Does Staff have a response to PAC and PGE's request for a more accurate emission reduction methodology?

A. Yes. Staff has been in discussion with staff members from the Northwest Power and Conservation Council and management of the Regional Technical Forum (RTF). Council staff, RTF staff and Commission Staff have reached an agreement whereby all emission reduction projects would use the Regional Technical Forum process to develop a project specific emissions reduction rate. The Council and RTF staff agreed, beginning after the publication of the Final 7th Power Plan, to use project specific operation data to model the effects of the proposed emissions reduction project on the emissions from regional power resources.

Q. What might this mean for NW Natural and others proposing similar emission reduction projects?

A. This means that NW Natural's combined heat and power proposed project will be sure to be assigned an emissions reduction rate that is accurate and particular to how CHP units operate and how the utilization of these units will ultimately affect the power mix serving the Northwest. Any subsequent project brought forward, whether a NW Natural or any other energy utility, will also receive an accurate emission reduction rate if the project involves electric grid connection or electric efficiency. Staff sees great promise in this approach as it involves a proper public, transparent, third party process. The process can potentially be used for all emission reduction projects that affect electric power resources in the Northwest not just SB 844 projects. The ability to conduct this analysis in an open forum may assist Oregon and other Northwest states if a carbon policy, state or federal, is adopted that requires quantification of emission reductions from various grid connected projects.

Q. Does an analogous process exist that utilities are currently utilizing?

A. Yes. The proposed process is very similar to the RTF process for deemed energy efficiency savings and measurement and verification practices relied on by the utilities and the public utility commissions in the Northwest.

Staff recognizes that NW Natural has not had the opportunity to utilize this process for the proposed project. Therefore, Staff suggests, should the Commission approve NW Natural's application, that NW Natural use this new process to identify the emission reduction rate of the currently proposed project and report the findings to the Commission. All subsequent project proposals would utilize the Council's process prior to application submittal at the PUC. NW Natural should have an opportunity to respond to this proposal if NW Natural finds a response is necessary.

Q. Does this emission reduction methodology proposal have implications for the proposed participant $30 per ton emission reduction incentive?

A. Yes. Staff believes that a reverse auction is the best approach to determine the appropriate level of participant incentive. (*See* St. Brown/200.) Additionally, Staff testimony St. Brown/400 discusses the significant shortcomings of using payment per ton of MTC02(e) emissions reduction. However, Staff underwent an exercise using a 15 percent internal rate of return (IRR) calculation, Staff St. Brown/400, which demonstrates that a reasonable inducement for a participation of a 21.7MW CHP plant would be roughly $2.0M.

Q. Is it possible to translate this method into a per ton of emissions reduction incentive that NW Natural has proposed in its application?

A. Yes, if a payment per ton of MTC02(e) of emissions reduction is desired, it can be computed from the ratio of aggregate yearly payments. Specifically, solving for the unknown in the ratio below will provide Staff's comparable value to the $30 payment per ton of MTC02(e) emissions reduction proposed by the Company:

$$\frac{\$2{,}092{,}580}{\$18{,}795{,}610} = \frac{x}{\$30}$$

The unknown in this equation solves to $3.34 per ton incentive for this type of plant, if the emissions reduction baseline methodology used was EPA's eGrid non-baseload, or 1340.34lbs of CO_2/MWh.

Q. Can you explain how applying Staff's proposal of using the NWPCC methodology may impact the per ton emission reduction participant incentive under IRR method discussed above?

A. Yes. The NWPCC methodology currently gives us a range. For illustrative purposes if we were to choose 850 lbs/MWh as a reasonable emission reduction rate assumption we would expect to pay more per ton of emissions reductions in order to reach a reasonable participation inducement, i.e. $2.0M. Applying this approach, as NW Natural does across all potential CHP units, we would expect to see a per ton emission reduction payment of range of between $0 - $10 per ton of emission reduction as a reasonable participant incentive in-keeping with the application of a 15 percent IRR.

Q. If the IRR method develops a $3 per ton customer incentive why are you suggesting a range from $0-$10?

A. Staff proposes this range recognizing that a final application of the IRR approach combined with modeling emission reductions will necessitate a more flexible approach if per ton emission reduction payments are used as the primary mechanism to induce program participation. Additionally, we believe a range of $0-10 accounts for not only the IRR approach, varying sizes of CHP units, the output and application of the final emissions reduction baseline number developed through the application of the NWPCC methodology but also any market barriers that participants might encounter in their decision to install CHP.

Issue 4. Fuel Switching

Q. Did the parties' response testimony raise any fuel switching issues that you would like to address?

A. Yes. PGE in its response testimony recommends the Commission deny a CHP program because it involves the use of ratepayer funds to promote fuel switching. PGE/100 Barra/6. In its response testimony, PacifiCorp devotes an entire section of testimony to the argument that voluntary emission reduction program incentives should not be used to facilitate fuel switching. PAC/100, Weincke/2-4. Staff believes that parties have raised a valid issue worth exploring in this case.

Q. Do PGE's and PacifiCorp's response testimonies offer other considerations related to fuel switching that Staff believes should be addressed?

A. Yes. PacifiCorp notes that the primary benefit of the proposed CHP program identified by NWN "is increase load for NW Natural….NW Natural does not list any other benefit that accrues to its customers as a result of the CHP Program." PAC/100, Weincke/2. PGE correctly points out that a Department of Justice (DOJ) advisory letter dated May 18, 2005, addressed whether fossil-fueled combined heat and power systems may be funded by public purpose charges.

The memorandum goes on to state that CHP fits the definition of energy conservation.[1] As a supporting source the memo cites OAR 860-027-0310(1)(a) which provides in part that "Conservation also means cost effective fuel switching." PGE does not argue with the DOJ's opinion about whether CHP fits the definition of energy conservation but instead raises the question whether incenting fuel switching is good policy.

Issue 4.a. SB 844 and Fuel Switching

Q. In reviewing the record in this case did you find any insight on the issue of fuel switching?

A. Yes. In passing Senate Bill 844 the legislature did not address the issue of fuel switching. The rules promulgated by the Commission were done so in an open public forum with participation from both electric and natural gas utilities. The rules themselves are written broadly such that they may apply to any energy utility proposing a project under OAR 860-085-0650. Staff currently holds the position that had the utilities or the legislature been concerned with fuel switching it would have been addressed either in statute, legislative history, in the Commission rules or during the public process the Commission engaged in while promulgating the rules.

Issue 4.b. Staff's Findings on Fuel Switching

[1] Department of Justice Interoffice Memorandum, May 18, 2005, "Whether fossil-fueled combined heat and power systems may be funded by public purpose charges."

Q. Given the discussion offered by PacifiCorp and PGE on fuel switching and your review of the record, do you have a proposal?

A. Yes. Staff believes that SB 844 allows for fuel switching where emission reductions are the primary justification for a proposed project. Staff believes, given that reductions in greenhouse gas emission were the primary concern underlying Senate Bill 844, fuel switching is not a road block to implementation. NW Natural should have an opportunity to respond to this finding if NW Natural finds a response is necessary.

Q. Do you agree with some of the issues regarding fuel switching raised by parties response testimony?

A. As parties correctly point out, and Staff agrees, a significant element of the proposed project involves fuel switching, and as such there is an inherent interest and benefit to NW Natural in designing and proposing this project. NW Natural does not challenge this issue and in fact identifies increased system load as a benefit to its ratepayers. CUB notes that the benefit of additional system throughput may be specious or possibly non-existent for most of NW Natural's ratepayers. CUB/100, McGovern-Jenks/8. However, the increased sales and utilization of NW Natural's product is an incentive to NW Natural and perhaps an underlying reason behind proposing a project which involves fuel switching. This inherent incentive is a factor to be contemplated when determining the incentive which SB 844 allows.

Q. Does CUB make any other points to which you which to respond?

A. Yes. To address the fuel switching aspect of the proposed project Staff agrees with CUB that net costs should be subject to an earnings test. CUB/100 McGovern-Jenks/20-21. In its Order adopting rules under SB 844 the Commission retained authority to determine whether the incentive should be included in the earnings test. While Staff has noted that NW Natural's proposed $10 per ton of emission reduction company incentive is poorly justified, this kind of incentive at whatever level, if approved, should not be part of the earnings test as this may amount to a claw back once the earnings test is applied.

Issue 4.c. Aspects of SB 844 Fuel Switching Limiting Factors

Q. Are there aspects to how SB 844 proposal operate that would address the concern of fuel switch and possibly limit the opportunity to conduct fuel switching and thereby address some of parties concerns?

A. Yes. Projects proposed under OAR 860-085-0650 and SB 844 have limiting factors. The applicant must explain why without the emission reduction program the applicant would not invest in the project in the ordinary course of business.[2] The project must be a greenhouse gas emissions reduction project. These two aspects of ORS 759.539 are important as they limit proposed activity to a circumscribed realm. Granted within that realm of possible greenhouse gas emissions reduction projects there exists the possibility that emission reductions are obtained through fuel switching. There are documented instances, such as electric heat pump technology where using

[2] ORS Section 756.040

electricity to cool and heat living spaces and water are more energy efficient then using natural gas. However, for such projects to be considered SB 844 projects, the applicant would need to demonstrate that, but for, the allowance under SB 844 the applicant would not have made the investment in the ordinary course of business.

Q. Does that conclude your testimony?

A. Yes.

OREGON DEPARTMENT OF ENERGY

MEMORANDUM

To: Bill Edmonds, NW Natural

From: Julie Peacock, Oregon Department of Energy

Date: November 26, 2014

Subject: Likely Emissions Factor of Electricity Displaced for an SB 844 Combined Heat and Power Project

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This memo is in response to NW Natural's request that the Department consider what the likely emissions factor of displaced electricity would be as a result of an SB 844 combined heat and power (CHP) project.

The Department suggests that the per megawatt emissions average of the Unspecified Market Purchase Mix is the most likely emissions representation of avoided electricity purchases because it represents spot market electricity purchases. These purchases are non-contractual, or are from very short-term contracts, which are not associated with a specified fuel source. It is the Department's understanding that these non-contractual purchases would be the most likely to not be made by an electric utility during times of fluctuating load. Further, it is the Department's understanding that reduced load on the hydropower system would indirectly reduce spot market electricity purchases by another utility in the NWPP region.

In 2010, this number was 1,178 pounds of carbon dioxide per megawatt hour, in 2011 it was 880 lbs/MWh, and in 2012 it was 885 lbs/MWh.[1]

About the Unspecified Market Purchase Mix Average

The Unspecified Market Purchase Mix (UMP) is defined under OAR 860-038-0005(72) as the mix of all power generation within the state or other region less all specific purchases from generation facilities within the state or region, as determined by the Oregon Department of Energy. As the process currently exists, this number represents the 'net' of unspecified purchases as part of the Northwest Power Pool. This application results in a resource mix and emissions factor for all of the unspecified market purchases by Oregon utilities including the Consumer Owned Utilities.

Process and Analysis

Under OAR 860-038-0300, investor owned utilities are required to provide price, power source, and environmental impact information to their customers annually for each of the products offered by the utility. In order to develop each utility in the state's Electricity Resource Mix the Department works with Washington State University and the Washington Department of Commerce to develop the region's UMP.

[1] For years 2011 (880 lbs/MWh) and 2012 (885 lbs/MWh), hydroelectricity represented an above average portion of the electricity mix. NW Natural could consider using an average of years if it chooses to use one emissions number for more than one project year.

The electric utilities submit reports of their specified purchases and unspecified market purchases to the Department. The data is then transferred to Washington State University who calculates the annual UMP in tandem with Washington's Fuel Mix Disclosure process (RCW – 19.29A). The number is then reported to Washington and Oregon utilities in the fourth quarter of every year. This number is located publically on the Department of Commerce's website[2] is updated in the fourth quarter of every calendar year or can be requested from the Department.

[2] http://www.commerce.wa.gov/Programs/Energy/Office/Utilities/Pages/FuelMix.aspx

Northwest Power and Conservation Council

MARGINAL CARBON DIOXIDE PRODUCTION RATES OF THE NORTHWEST POWER SYSTEM

JUNE 13, 2008

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Marginal Carbon Dioxide Production Rates of the Northwest Power System

SUMMARY

The cost of future carbon dioxide (CO_2) regulation is a significant factor in utility resource planning in the Pacific Northwest. Failure to properly account for this risk when evaluating resources can result in poor resource decisions and higher costs for the region's ratepayers.

One of the benefits of conservation is that it avoids CO_2 emissions.[1] The benefit it provides depends on what generating resources would be replaced and how much CO_2 they produce. This requires understanding what generating resources are on the margin; that is, the generation that could be displaced by the conservation. The marginal resource is the last resource brought on-line to supply power during a given time period (i.e., the highest variable cost resource available and needed during the period). In the Northwest, the average marginal CO_2 production is substantially higher than the average CO_2 production from all electricity generation. This is because hydroelectricity and wind, which have low operating costs and no CO_2 emissions are brought on-line before coal-fired or natural gas-fired generating units. Because only the marginal plants would be displaced by conservation, it would not be proper to use the average of CO_2 emissions from all power generation to estimate the CO_2 saved through conservation.

This paper evaluates what resources are on the margin in every hour and what the CO_2 reduction would be as a result of conservation. The analysis is an extension of the Council's recent interim wholesale power market price forecasts.[2] In the base case for that analysis, natural gas-fired combined-cycle plants are on the margin most of the time so conservation would avoid the CO_2 emission of a gas-fired combined-cycle power plant for most of the hours in a year. When the marginal CO_2 emissions for each hour are averaged over all of the hours in a year, the average of these hourly CO_2 emissions is about 0.8 pounds per kilowatt-hour. This increases the value of conservation by up to $5.60 per megawatt-hour (in constant 2006 dollars) under the base case CO_2 price assumption of $14 per ton in 2025.

The value of conservation can be significantly higher for measures, such as city street-lighting programs, that target load reduction during weekend nighttime hours. This is because coal-fired generation is typically the region's marginal resource during these low load hours. Since coal-fired generation has higher CO_2 emissions than natural gas combined-cycle plants, more CO_2 is displaced by each unit of conservation.

In addition to the Interim Base Case, this analysis tests two alternative assumptions about future resource costs. First it looks at a case of higher capital costs for generating resources, similar to recent experience. This case produced no change in the resources that were expected to be developed in the Northwest, but it did eliminate significant coal development in other parts of the West. Fewer coal resources reduce Westwide annual CO_2 production. Interestingly, the annual

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[1] Similarly, the value of other low-CO_2 resources including many types of demand response and most renewable resources should include the value of the CO_2 production displaced by the resource.
[2] The "Interim Wholesale Power Price Forecast" paper is available at: http://www.nwcouncil.org/library/2008/2008-05.pdf

CO_2 emissions in the Northwest increase since Northwest resources run more frequently to meet regional and Western loads. This is because fewer new resources are constructed in this high capital cost case. The increased use of Northwest resources means that coal-fired generation is used less often as the region's marginal resource. So, even though the region's annual CO_2 emissions increase, its marginal CO_2 production rate decreases to about 0.7 pounds of CO_2 per kilowatt-hour.

The second case adds higher CO_2 allowance prices (the possible future costs of CO_2 emissions) of $43 per ton of CO_2 beginning in 2012 to the high capital cost case. This results in much higher average marginal CO_2 emissions, up to 1.8 pounds per kilowatt-hour, and raises the value of conservation to as high as $38.00 per megawatt-hour. The high CO_2 prices increase the operating cost of coal plants more than they increase the operating cost of natural gas combined-cycle plants. This differential is enough to cause natural gas plants to be dispatched before coal-fired plants. With natural gas plants now operating first, coal plants are forced to the margin. This increases the region's average marginal CO_2 production rate and, therefore, the value of conservation to lower CO_2 emissions.

The other side of this change is that with higher CO_2 prices, natural gas-fired plants provide more baseload generation and therefore reduce the use of coal-fired generation as a share of total electricity production. As a result, total CO_2 emissions in this case are greatly reduced. Whereas, total CO_2 emissions in the region continued to grow in the Interim Base Case and the High Capital Cost Case, total CO_2 emissions are reduced to near or below 1990 levels in the High CO_2 Price Case. This is a direct result of the reduction in generation from existing coal-fired plants.

The effectiveness of the higher CO_2 prices in reducing CO_2 emissions appears to be very sensitive to fuel costs. At $43 per ton of CO_2, the variable cost of most existing coal plants is slightly higher than the variable cost of gas combined-cycle plants. However, any increase in the cost of natural gas would favor the dispatch of coal and return combined-cycle plants to the margin. A higher CO_2 price would be needed to restore coal to the margin. The Council intends to further explore this issue during development of the Sixth Power Plan.

Marginal Carbon Dioxide Production Rates of the Northwest Power System

INTRODUCTION

During any given hour of the year, there are numerous generating units supplying power to the Pacific Northwest power system. Some of these units will be hydroelectric units or wind generating units that do not emit CO_2 into the atmosphere. At the same time, some of these units will likely be coal-fired or natural gas-fired generating units that do emit CO_2 into the atmosphere. Each type of generating unit has a distinct rate at which it emits CO2. For example, a contemporary natural gas-fired combined cycle unit emits roughly 0.8 pounds (lbs.) of CO_2 per kilowatt-hour. A typical conventional coal-fired steam unit emits roughly 2.3 lbs. of CO_2 per kilowatt-hour.

One way to measure the CO_2 production rate of the Northwest Power system is to average the rates of all the generating units operating during a given time period. In this paper, we use the term, *average CO_2 production rate*, to refer to an average across *all resources* operating during a given time period.

Another way to measure the CO_2 production rate of a power system is to determine the CO_2 emissions rate of the last resource (or marginal resource) brought on-line to supply power during a given time period. In wholesale power markets, generating resources are typically brought on-line in the order of their operating costs. In other words, resources with low operating costs are used before resources with higher costs. In general, hydroelectric, nuclear and wind generating units will be brought on-line before coal-fired or natural gas-fired generating units. It is the CO_2 emissions of the marginal resource that can be avoided by adding energy-efficiency measures to the system.

This paper estimates the Pacific Northwest power system's marginal resource, and its CO_2 production rate, during each hour for four separate years: 2010, 2015, 2020, and 2025. Because there are typically 8,760 hours during a year, we summarize our results by providing *average marginal CO_2 production rates* for each year. In this paper, we use the term *average marginal CO_2 production rate* to refer to an average across *only the marginal resources* operating during a given time period.

The major findings and conclusions of this new analysis are:

- For the Northwest power system, with its large amount of hydroelectric, nuclear and wind generating resources, the *marginal CO_2 production rate* is considerably higher than the *average CO_2 production rate*. Power system planners and resource analysts should use the marginal CO_2 production rate to quantify and evaluate the ability of energy-efficiency and other resources with low CO_2 emissions to reduce emissions.

- Marginal CO_2 production rates for the Northwest power system, under our Interim Base Case assumptions, are forecast to range between 0.7 lbs. of CO_2 per kilowatt-hour (kWh) and 0.9 lbs. of CO_2 per kWh over the period 2010 through 2025.

- The region's average marginal rate of CO_2 production and its overall level of CO_2 production tend to move together, but in opposite directions. For example, under our combined High Capital Cost and High CO_2 Price Case assumptions, the region's marginal CO_2 production rate is forecast to jump as high as 1.8 lbs. of CO_2 per kWh. Carbon regulation, while decreasing overall CO_2 emissions, also increases the region's marginal CO_2 production rate since coal plants become the marginal resource.

- The type and amount of generating resources added to the Western power system outside our region influence the Pacific Northwest's CO_2 production. For example, although the Interim Base Case and the High Capital Cost Case forecasts have essentially the same resource mix for the Pacific Northwest, the High Capital Cost Case forecasts less overall new plant development, and no new conventional coal-fired plant development, in the Western power system over the planning period. This results in lower annual CO_2 emissions for the Western power system. At the same time, however, annual CO_2 production increases in the Pacific Northwest (and marginal CO_2 production rates decline) as Northwest resources are operated more intensely to meet loads both inside and outside the region.

METHODOLOGY

The methodology we use to estimate the Pacific Northwest power system's marginal resource is an extension of the modeling described in the Council's recent Interim Wholesale Power Price Forecast paper.[3] In this paper, we provide further analysis of two scenarios presented in the interim forecast paper: the Interim Base Case and the High Capital Cost Case. Each of these cases incorporates the same fuel price forecasts, estimates of the future costs of CO_2 allowance prices, and schedule of renewable resource additions to achieve state renewable portfolio standards. The only difference between these cases is the estimated costs of constructing new generating resources.[4] The Interim Base Case assumes construction costs from the "2006 Biennial Monitoring Report of the Fifth Power Plan." Since the release of the monitoring report, construction costs have increased significantly. The High Capital Cost Case was developed to better reflect current estimates of the future cost of building new generating resources and is being used in the preliminary studies for the Sixth Power Plan. We also present new results for a combined High Capital Cost/High CO_2 Price Case. The resource mix underlying each of these forecasts affects the choice of the marginal resource, and therefore, the marginal CO_2 production rate for the Pacific Northwest power system. These effects are discussed in the results section of this paper.

Council staff uses the AURORA$^{xmp®}$ Electric Market Model to develop its wholesale power price forecasts.[5] This model simulates hourly supply and demand to determine a marginal resource and market-clearing price for every hour of the simulation period for each of the load-resource zones in the model. The Council's configuration of AURORA^{xmp} uses 18 load-resource zones to represent the Western power system. The Pacific Northwest power system is

[3] The "Interim Wholesale Power Price Forecast" paper is available at: http://www.nwcouncil.org/library/2008/2008-05.pdf
[4] For a description of our current estimates of new resource capital costs see the "Interim Wholesale Power Price Forecast" paper (pp. 10-13).
[5] Available from EPIS, Inc. (www.epis.com).

represented by 6 of these zones.[6] Therefore, for each hour of a simulation period, AURORA^{xmp} identifies 6 marginal resources for the Pacific Northwest, one for each zone.[7]

In order to identify a single Pacific Northwest marginal resource, and marginal CO_2 production rate, for each hour of the simulation period, Council staff conducted additional analysis on the AURORA^{xmp} hourly output databases. The hourly output databases contain statistics summarizing the simulated operation of each generating unit located in the Pacific Northwest.[8] Staff performed a series of filtering steps to arrive at a single marginal resource for each hour. First, staff removed any units considered to be must-run resources. Must-run resources are those that are operated regardless of wholesale power market prices. For the Northwest, must-run resources include: wind plants, municipal solid waste facilities, industrial co-generation facilities, geothermal steam plants, and landfill gas energy recovery and other biogas facilities. Second, for each hour, any unit that did not generate electricity was removed from consideration. Finally, of the remaining units, the unit with the highest dispatch cost was selected as the region's marginal resource for each hour.[9] This process resulted in a single marginal resource for the Pacific Northwest for each hour of the simulation period.[10]

This methodology for identifying the region's marginal resource is analogous to the resource stacking approach depicted in Figure 1. The figure is a snapshot of our forecast of the region's supply and demand during the peak hour of demand in 2020.[11] The vertical axis of the figure is dispatch cost--the cost that can be avoided by curtailing operation of a resource. For any resource, the dispatch cost comprises the variable operating and maintenance costs (including integration costs for intermittent resources), variable fuel cost, CO_2 allowance cost, any unit cycling premium, and a dispatch premium representing the "profit" over cost demanded by a plant owner to dispatch the resource.

The horizontal axis represents cumulative generating capability for the hour. The supply curve for this hour starts with the region's lowest-cost resource, hydroelectric generation, and adds supply in order of increasing dispatch cost. The forecast demand for electricity in this hour is 38,081 megawatts, shown as the vertical black line. The region's marginal resource for this hour is the generating unit that is situated at the intersection of the region's supply and demand curves.

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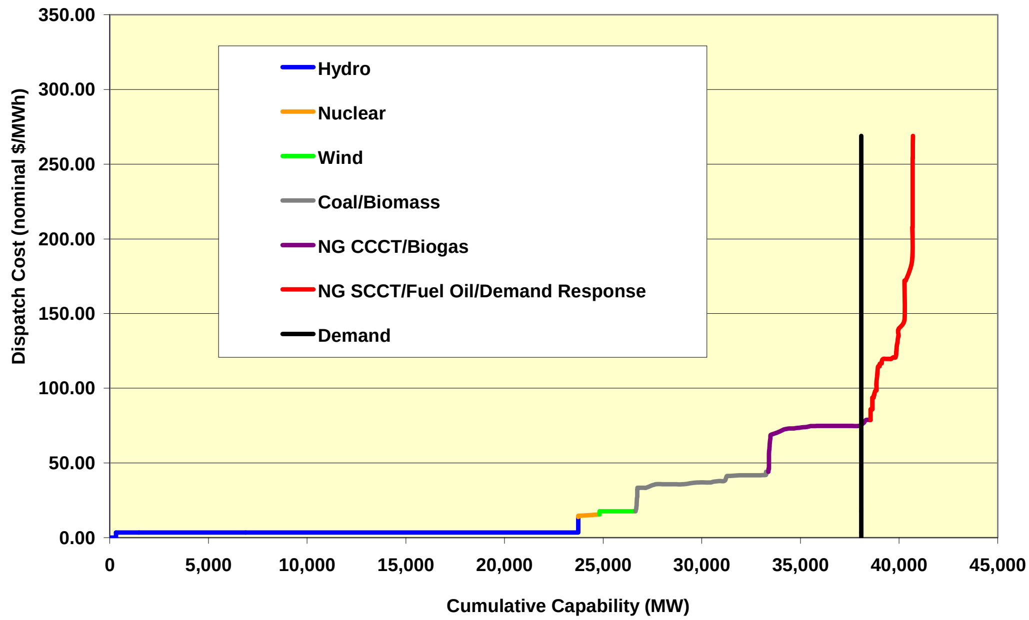
[6] The Pacific Northwest zones are identified as PNW Westside North, PNW Westside South, PNW Eastside North, PNW Eastside South, Idaho South, and Montana East.
[7] This is equivalent to 52,560 marginal resources in the Pacific Northwest on an annual basis (8,760 hours * 6 load-resource zones = 52,560 marginal resources).
[8] The annual databases contain roughly 7.4 million records (844 generating units * 8,760 hours = 7.4 million records)
[9] If two or more units tied for the highest dispatch cost in an hour, the unit operating farthest from its maximum capability (or closest to its minimum capacity) was chosen as the marginal resource.
[10] For an annual simulation period, this results 8,760 marginal resources in the Pacific Northwest.
[11] The snapshot shown is for hour ending 7:00 P.M. on January 15, 2020.

Figure 1: Illustration of the marginal resource selection methodology (High Capital Cost Case)



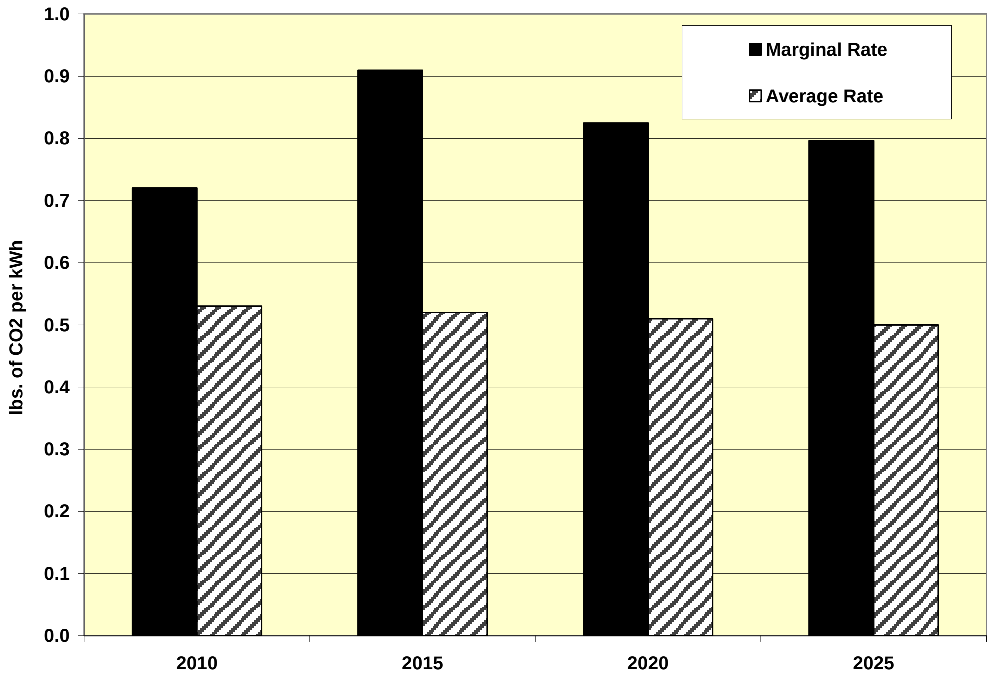
The region's marginal resource will change not only from season to season as the region's water supply, loads, fuel prices, and resource availability varies, but also from hour to hour as demand changes. The filtering methodology described in the previous paragraph is roughly analogous to performing this resources stacking for each hour of the forecast year.

RESULTS

Interim Base Case

For the Northwest power system, with its large amount of hydroelectric, nuclear and wind generating resources, the *marginal CO_2 production rate* is considerably higher than the *average CO_2 production rate*. Figure 2 compares these two rates for the Interim Base Case.

Figure 2: Northwest marginal and average CO_2 production rates (Interim Base Case)



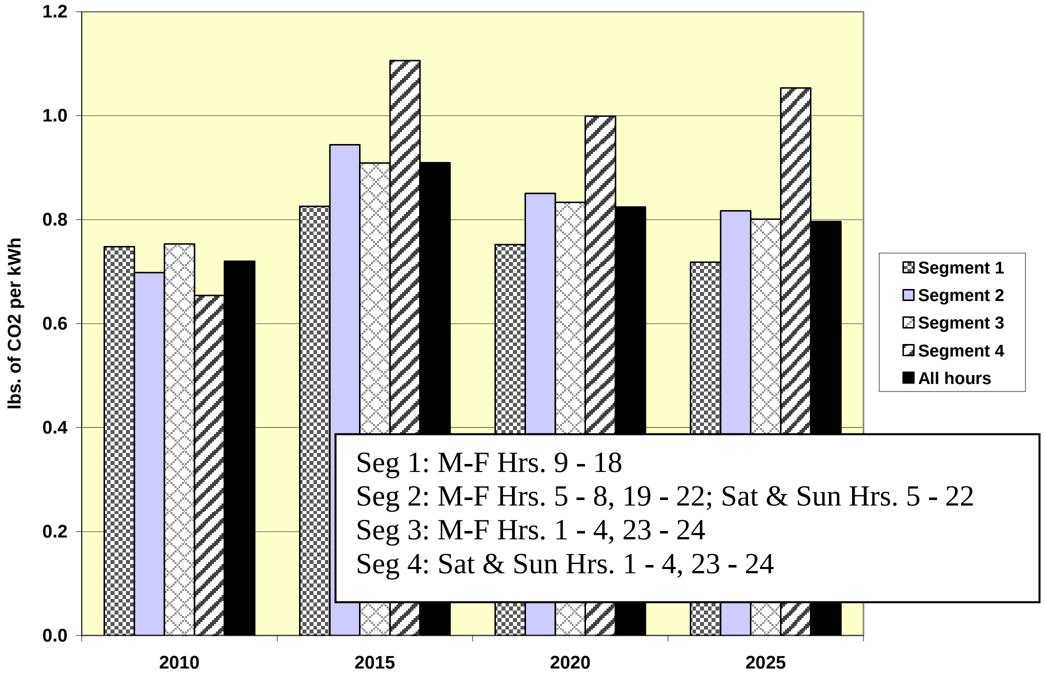
Power system planners and resource analysts should use the marginal CO_2 production rates to evaluate the CO_2 cost associated with future purchases of power from the wholesale power market and the relative benefits of energy-efficiency measures and other resources with lower CO_2 emissions. For example, given the Council's current interim forecast of future CO_2 emissions prices (i.e., $11.12 per ton in 2015, $12.55 per ton in 2020, and $14.15 per ton in 2025), the estimated CO_2 cost included in future purchases from the wholesale power market would be $5.06 per megawatt-hour (MWh) in 2015, $5.17 per MWh in 2020, and $5.63 per MWh in 2025.[12]

Marginal CO_2 emission rates (pounds of CO_2 per kWh) vary by time of day and day of week because the marginal generating resource changes with load. Gas-fired power plants with relatively high variable costs are typically on the margin during heavier load hours, whereas coal-fired plants with lower variable costs can be on the margin during nighttime and weekend light load hours. Therefore, both the physical quantity, and dollar value, of avoided CO_2 emissions vary with time. The Council and the Regional Technical Forum use four load

[12] The calculation of the market CO_2 cost in 2015 is: (0.9 lbs. of CO_2 per kWh) / (2000 lbs. per ton) * (1000 kWh per MWh) * ($11.12 per ton of CO_2).

segments to assess the cost-effectiveness of conservation measures. Figure 3 shows the average marginal CO_2 emission rates for the four segments for the four future years.

Figure 3: Northwest marginal CO_2 production rates by load segment (Interim Base Case)

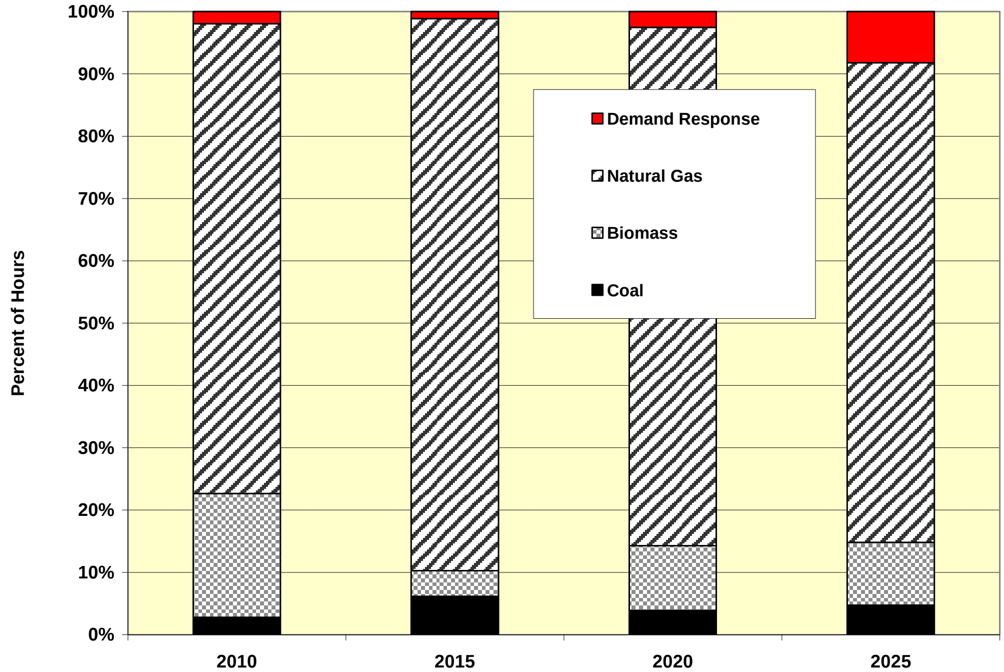


The pronounced increase in the marginal CO_2 production rate during weekend nighttime hours (i.e., during Segment 4 hours) is due to coal-fired units being the marginal resource during these low-load hours. This is consistent with the recent and expected addition of significant amounts of wind generation to the Northwest power system, which pushes coal-fired resources up toward the margin.[13] After 2015, there is a slight downward trend in the Northwest's marginal CO_2 production rates. This downward trend reflects the changing fuel mix of the region's marginal resources over time.

Figure 4 shows the percentage of hours in each year that resources of various fuel types are on the margin. The percentage of hours that coal-fired resources are the marginal resource declines from 6.2 percent in 2015 to 4.7 percent in 2025. As regional loads continue to grow, there is also an increase in the number of high load hours during which demand response is the region's marginal resource. Both of these changes have the effect of lowering the region's marginal CO_2 production rates.

[13] An open issue at this time is whether the coal-fired resources operating at the margin during these light load hours can provide the operational flexibility needed to integrate intermittent resources into the power system.

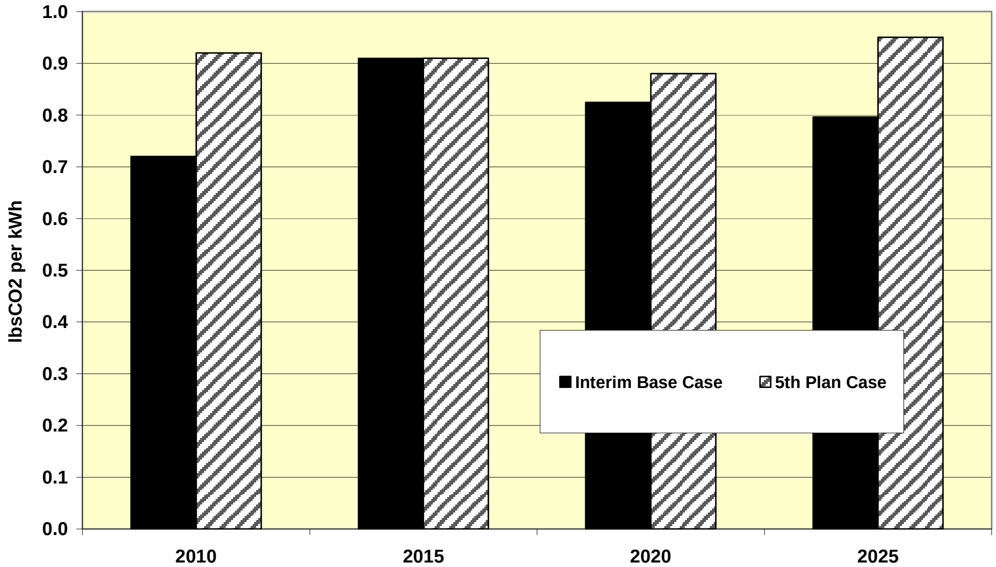
Figure 4: Percentage of hours resources of various fuel types are the marginal resource (Interim Base Case)



The low percentage of hours that coal-fired resources are the region's marginal resource is a significant change from the Council's previous forecast of the marginal rate of CO_2 production in April, 2006.[14] At that time, coal-fired resources were forecast to be the marginal resource in 16 percent of the hours in 2010, declining to 12 percent of the hours in 2025. This difference in marginal resource mix is evident in a comparison of the two forecasts of marginal CO_2 production rates (see Figure 5).

[14] Staff presented, "Power System Marginal CO_2 Production Factors" to the Council's Power Committee on April 11, 2006, in Whitefish, Montana.

Figure 5: Comparison of marginal CO_2 production rates (Interim Base Case vs. 5th Plan Case)



The decrease in coal-fired generation on the margin can be partly attributed to the improved methodology for selecting the region's marginal resource.[15] However, this difference is also partly explained by differences in forecast assumptions and the forecast, or recommended, resource mix for the Pacific Northwest. For example, the Interim Base Case uses higher CO_2 allowance prices than the 5th Plan Case.

It is important to place the declining trend in the Northwest power system's marginal CO_2 production rates, and the underlying changes in its marginal resource mix, within the wider context of the overall power system CO_2 production. In the Interim Base Case, Northwest power system CO_2 emissions are forecast to total 57 million tons in 2010, and to increase to 61 million tons in 2025. For comparison, we previously estimated that the Northwest power system's CO_2 production was 44 million tons in 1990 and that it would have been 57 million tons in 2005 (had normal hydro conditions prevailed).[16] Figure 6 shows our CO_2 emissions forecasts for the Northwest power system under the three future scenarios discussed in this paper.

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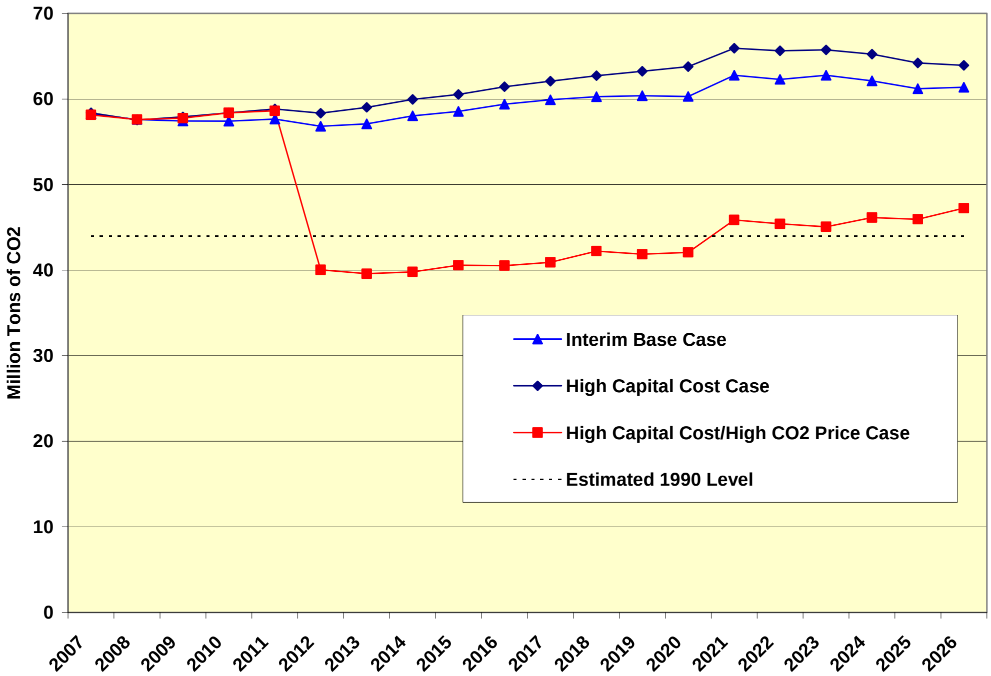
[15] The previous methodology selected a single regional marginal resource during each hour of the year by starting with the units that AURORA^{xmp} identified as the marginal resource in each of the six Northwest load-resource zones. Starting with only one resource in a load-resource zone, and then removing it from further consideration if it is a must-run resource, has the effect of removing all the resources in that zone from consideration as the region's marginal resource. In some hours, this method could erroneously select an intra-marginal resource as the region's marginal resource. The prior method had the potential to overstate the occurrence of coal-fired units and hydroelectric units as the region's marginal resource. The methodology presented in this paper avoids this problem by starting with all of the generating units dedicated to serving loads in the Pacific Northwest.

[16] We also estimated that with implementation of the recommended resource portfolio of the 5th Power Plan, CO_2 emissions would total 67 million tons in 2024. These estimates are from the Council's paper titled, "Carbon Dioxide Footprint of the Northwest Power System." This paper is available at: http://www.nwcouncil.org/library/2007/2007-15.htm

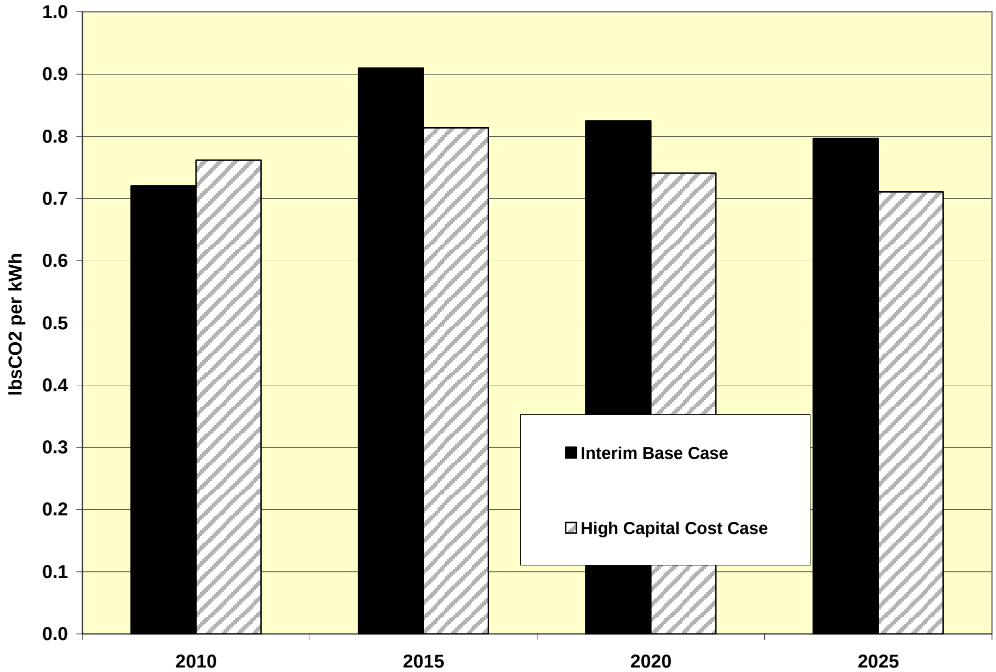
Figure 6: Forecasts of the Northwest power system's CO_2 emissions



High Capital Cost Case

It is also important to describe the sensitivity of our results to changes in key input assumptions. Figure 7 shows the effect of our revised forecast construction costs for new generating resources on marginal CO_2 production rates. The higher construction costs in the High Capital Cost case reduce the level of forecast resource additions in other regions of the West. This leads to more intense use of power resources in the Pacific Northwest, and to lower marginal CO_2 production rates.

Figure 7: Comparison of marginal CO_2 production rates (High Capital Cost Case and Interim Base Case)



The portfolio of Northwest generating resources is essentially the same in both the High Capital Cost Case and Interim Base Case. In both cases, Northwest generating resources consist of existing resources and the forecast addition of renewable resources to meet state renewable portfolio standards. The reduction in marginal CO_2 production in the Northwest is primarily driven by a change in the amount and type of new resources added to meet load in areas outside of the Northwest. The High Capital Cost Case results in more new natural gas-fired resources and fewer new coal-fired resources being added to the Western power system over the planning period.[17] This change in incremental resource mix results in Northwest resources being dispatched more often to serve loads, both inside and outside the region. This increase in the dispatch of regional resources increases the occurrence of natural gas-fired resources on the margin and reduces the Northwest's marginal CO_2 production rates.

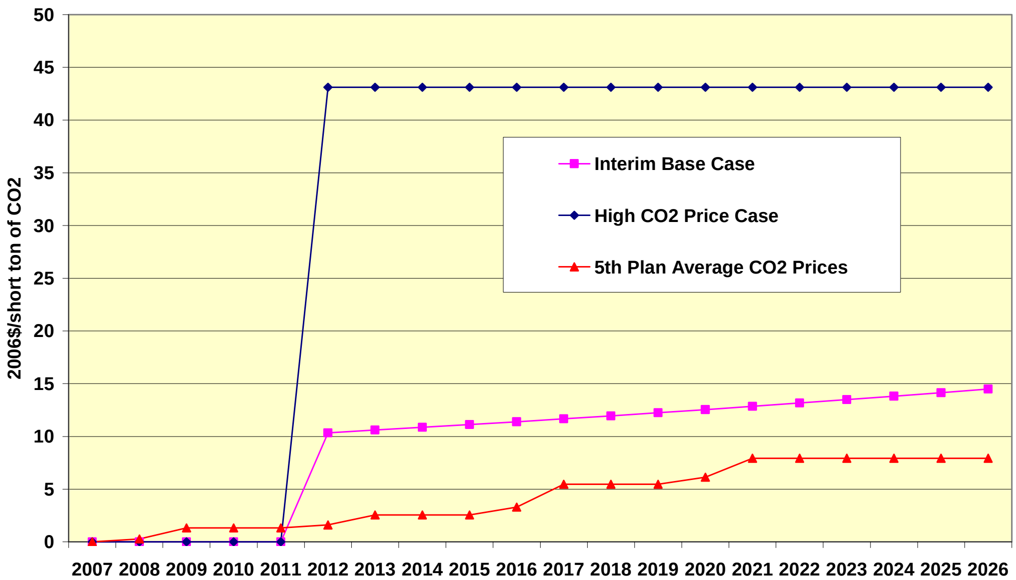
The increased utilization of the Northwest's resources also leads to higher total CO_2 production in the Northwest (see Figure 6). For example, total Northwest CO_2 production is 64 million tons in 2025 in the High Capital Cost Case compared to 61 million tons in 2025 in the Interim Base Case. However, from the perspective of the interconnected-West, the higher resource use in the Northwest contributes to the reduction in total Western CO_2 production to 461 million tons in 2025 in the High Capital Cost Case from 519 million tons in the Interim Base Case.[18]

[17] See "Interim Wholesale Power Price Forecast" paper, p. 26, for a detail description of this change in incremental resource mix.
[18] See "Interim Wholesale Power Price Forecast" paper, p. 24, for a detail description of annual Western Electricity Coordinating Council (WECC) CO_2 production.

Combined High Capital Cost and High CO_2 Price Case

The following figure shows the difference between the CO_2 allowance prices used in the Interim Base Case (and High Capital Cost Case), and the higher CO_2 allowance prices used in the High Capital Cost/High CO_2 Price case.[19] It also shows the average of the 750 possible future trajectories of CO_2 emissions prices used in the Fifth Power Plan.

Figure 8: Base and high CO_2 emission prices

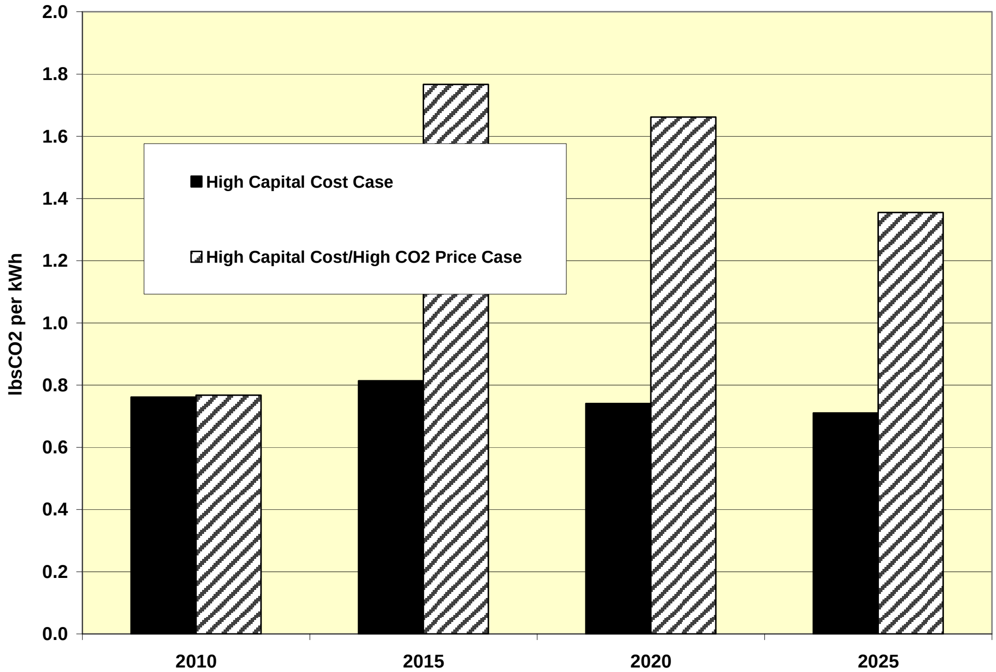


The higher CO_2 emissions prices used in the High Capital Cost/High CO_2 Price Case significantly reduce the forecast annual CO_2 production of the Western power system. Forecast Westwide CO_2 production drops from 461 million tons in the High Capital Cost Case to 384 million tons in the High Capital Cost/High CO_2 Price Case. The higher CO_2 emissions prices also drive a dramatic decline in the forecast of annual CO_2 production from the Northwest power system (see Figure 6).[20]

The higher CO_2 prices also have a significant effect on the forecast of the Northwest's marginal CO_2 production rates. These marginal rates are dramatically higher (see Figure 8). This increase occurs because the higher CO_2 prices drive heavy CO_2 producing resources to the less frequently dispatched end of the region's supply curve and puts them on the margin during more hours of the year.

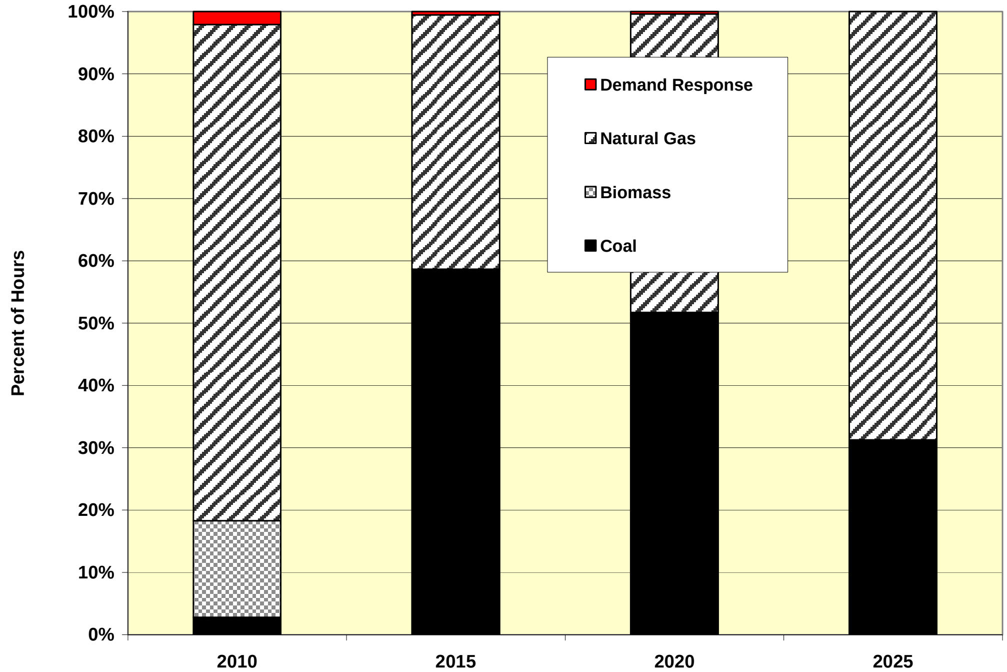
[19] For a description of the rationale underlying our CO_2 emission price assumptions see the "Interim Wholesale Power Price Forecast" paper (pp. 8-10).
[20] The higher CO_2 emissions prices result in 1,200 megawatts (MW) of new wind resources being added to the Northwest power system over the planning period (i.e., 500 MW in 2016, 200 MW in 2024, and 500 MW in 2025). This is installed wind capacity above the amount forecast to be added to meet state renewable portfolio standards.

Figure 8: Comparison of marginal CO_2 production rates (High Capital Cost Case vs. High Capital Cost/High CO_2 Price Case)



Under the High Capital Cost/High CO_2 Price Case assumptions, coal-fired resources are the marginal resource during 59 percent of the hours in 2010, 52 percent of the hours in 2015, and 31 percent of the hours during 2025. Figure 9 shows the increased role of coal as a marginal resource mix for this sensitivity case, compared to the base case shown in Figure 4.

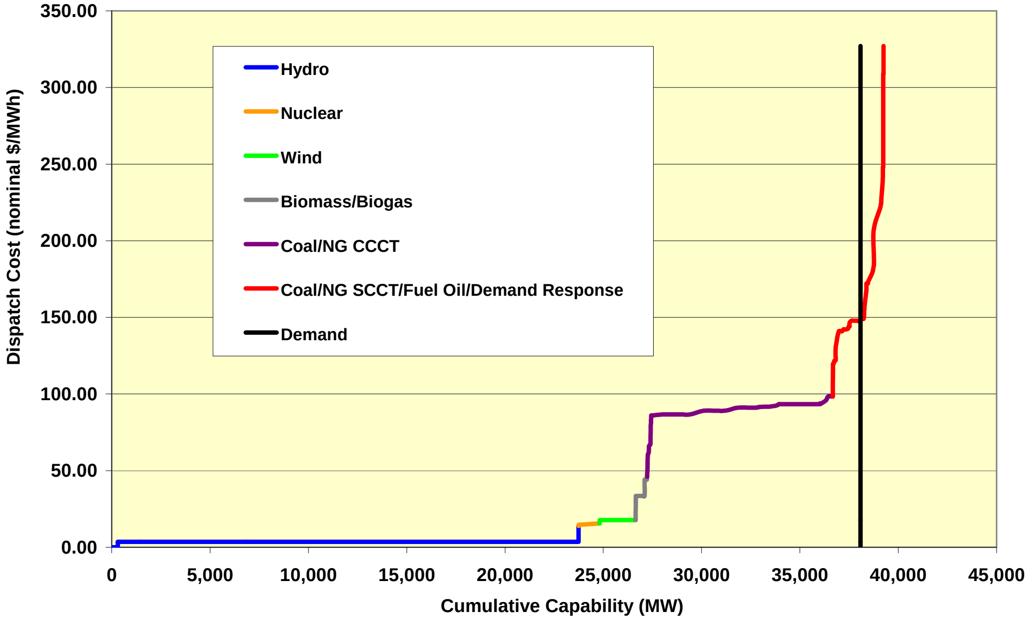
Figure 9: Percentage of hours resources of various fuel types are the marginal resource (High Capital Cost/High CO_2 Price Case)



Again, stated differently, the increase in the percentage of hours that the Northwest's coal-fired resources are on the margin is due to their higher dispatch cost because of emission charges. Their dispatch cost increases to, and in some cases surpasses, the dispatch cost of the Northwest's natural gas-fired combined cycle units. This "leveling" effect of the higher CO_2 emission prices is illustrated in the following snapshot of the region's supply and demand during the peak hour of demand in 2020.[21]

[21] The snapshot shown is for hour ending 7:00 P.M. on January 15, 2020.

Figure 10: Illustration of the change in the regional supply curve (High Capital Cost/High CO_2 Price Case)[22]



With high CO_2 emissions prices, most of the region's coal-fired units move up to share the same relative position on the region's supply curve with natural gas-fired combined cycle units (some of the less efficient coal-fired units move beyond this level to mix with natural gas-fired simple cycle units and other "peaking" resources). This leveling of the costs of coal-fired generation and natural gas-fired generation creates a "high plateau" in the region's supply curve near $90 per MWh. A quick comparison of Figure 10 and Figure 1 also highlights this effect. The resources lying along this plateau would likely clear the market during many hours of the year.

This analysis confirms that high CO_2 emission prices can drive significant reductions in total CO_2 emissions, both Westwide and in the Pacific Northwest. The analysis also shows that high CO_2 emissions prices increase the region's marginal rate of CO_2 production, and therefore, likely increase the value of energy-efficiency measures that reduce CO_2 emissions.

CONCLUSION

This paper forecasts the marginal CO_2 production rates for the Pacific Northwest power system to be between 0.7 lbs. per kilowatt-hour and 0.9 lbs. per kilowatt-hour for the period 2010 through 2025, under interim base case assumptions. The Council and the Regional Technical Forum can use these marginal CO_2 production rates to quantify the value of CO_2 emissions avoided by conservation and to evaluate the cost-effectiveness of energy-efficiency measures and other resources with lower CO_2 emission rates. These marginal CO_2 production rates are

[22] Coal purposefully appears in two places on the legend. With high CO_2 emissions prices most of the Northwest's coal units have dispatch costs similar to natural gas-fired combined cycle combustion turbines (NG CCCT), however, some of the less efficient coal units have even higher dispatch costs, similar to natural gas-fired simple cycle combustion turbines (NG SCCT) and other peaking resources.

very sensitive to changes in the future regulation, and cost, of CO_2 emissions. Because of this sensitivity, the marginal CO_2 production rates may change significantly if the assumptions regarding CO_2 allowance prices change during development of the Sixth Power Plan.

The effectiveness of the higher CO_2 prices in reducing CO_2 emissions also appears to be very sensitive to fuel costs. At $43 per ton of CO_2, the variable cost of most existing coal plants is slightly higher than the variable cost of gas combined-cycle plants. However, any increase in the cost of natural gas would favor the dispatch of coal and return combined-cycle plants to the margin. A higher CO_2 price would be needed to restore coal to the margin. The Council intends to further explore this issue during development of the Sixth Power Plan.

Sensitivity to Higher Natural Gas Price Assumptions

Addendum to Marginal Carbon Dioxide Production Rates of the Northwest Power System

SUMMARY

An important result presented in the Council's paper, "Marginal Carbon Dioxide Production Rates of the Northwest Power System," indicated that with carbon dioxide (CO_2) allowance prices of $43 per ton the Northwest power system's annual CO_2 emissions could be reduced to its1990 level. This result was achieved at the Council's medium fuel price forecast.

Results presented in this addendum indicate that:

- With the Council's high fuel price forecast the $43 per ton CO_2 allowance price assumption fails to produce the same dramatic reduction in annual CO_2 emissions that were shown for the medium fuel price forecast.
- With the Council's high fuel price forecast CO_2 allowance prices would need to increase to nearly $70 per ton in order to achieve annual reductions in CO_2 emissions similar to those achieved under the medium fuel price forecast.

INTRODUCTION

An important modeling result presented in the Council's paper, "Marginal Carbon Dioxide Production Rates of the Northwest Power System," is that the Northwest power system's annual carbon dioxide (CO_2) emissions can be driven below its 1990 level with CO_2 allowance prices of $43 per ton of CO_2 (in constant 2006 dollars). This CO_2 allowance cost would bring about a significant reduction in annual emissions by changing the dispatch order of coal-fired and natural gas-fired generating units. Coal-fired units would become more costly to operate than natural gas-fired units and would dispatch to meet load less often. The reduced operation of coal-fired units would lower the Northwest power system's annual CO_2 emissions.

The result presented in the marginal CO_2 assessment was achieved at the Council's medium fuel price forecast. Higher natural gas prices would be expected to increase the CO_2 allowance prices required to change the dispatch order of coal-fired and natural gas-fired plants. This addendum examines how higher fuel prices might affect this result. How sensitive is the modeled reduction in annual CO_2 emissions to increased natural gas prices? With high fuel prices how high would CO_2 allowance prices need to climb in order to reduce the Northwest power system's annual CO_2 emission to its 1990 level?

METHODOLOGY

The High Capital Cost/High CO_2 Price Case presented in the "Marginal Carbon Dioxide Production Rates of the Northwest Power System" paper serves as the reference case for the analysis presented in this addendum. This case serves as the point of reference because it showed that with CO_2 allowance prices of $43 per ton the region's annual total CO_2 emissions could be reduced to its 1990 level. For ease of reference, we refer to this case as the Medium Fuel/$43 CO_2 Price Case in this addendum.

In this addendum, we also model three high fuel price sensitivity cases. This modeling is an extension of the modeling presented in the Council's recent "Interim Wholesale Power Price Forecast" paper.[23]

The first sensitivity case is a combined high fuel price and $43 per ton CO_2 allowance price case (referred to as the High Fuel/$43 CO_2 Price Case). This case is designed to test the sensitivity of the modeled reduction in the Northwest power system's annual total CO_2 emissions to high fuel prices.

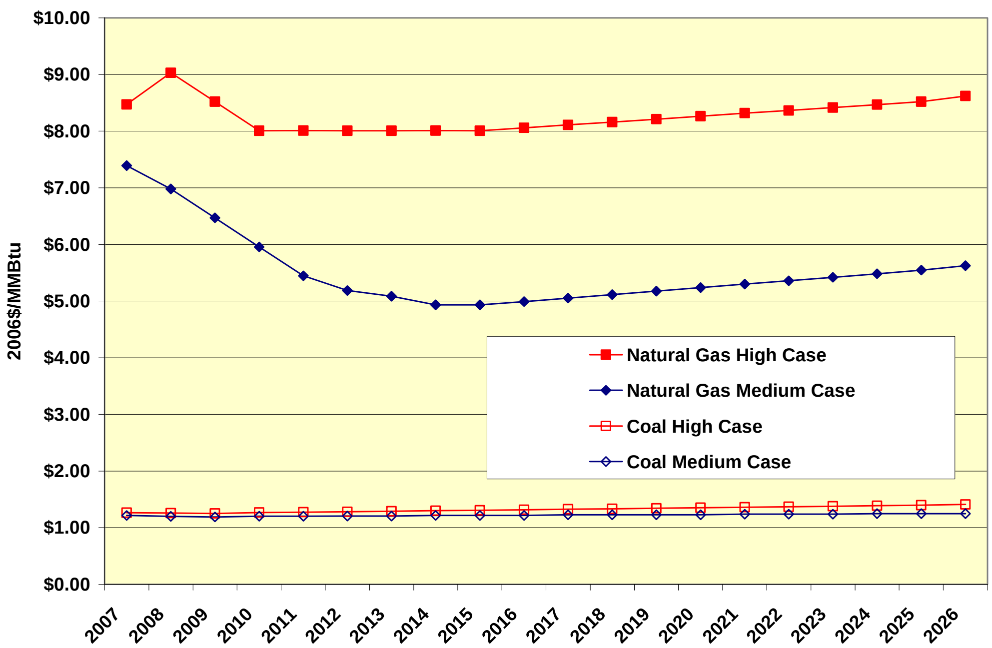
The second sensitivity case is a combined high fuel price and $70 per ton CO_2 allowance price case. This is an intermediate case. The only difference between this case and the first sensitivity case is that the CO_2 allowances prices are increased to $70 per ton (in 2006 dollars). Importantly, the forecast resource mix of the Western power system is held constant in this sensitivity case. The $70 per ton CO_2 allowance price was determined to be the level needed to drive the forecast of the Northwest power system's annual CO_2 emissions below its 1990 level. We refer to this case as the High Fuel/$70 CO_2 Price/Fixed Mix Case.

The third sensitivity case expands on the second sensitivity case by using the AURORA[xmp] model to forecast a new incremental resource expansion for the Western power system under the $70 per ton CO_2 allowance price assumption. In other words, the underlying resource mix is allowed to change in response to the increased forecast of CO_2 emissions costs. We refer to this case as the High Fuel/$70 CO_2 Price/New Mix Case.

The Council's current set of fuel price forecasts were developed in the summer of 2007.[24] The low, medium-low, medium, medium-high, and high fuel price forecasts cover a wide range of possible future price trends. Figure 1 compares the medium and high price forecasts for natural gas and coal delivered to electricity generators located in the western load-resource zones of the Pacific Northwest. For natural gas, the high price forecast is approximately $3 per million British thermal units (MMBtu) higher than the medium price forecast over most of the planning period.

[23] The "Interim Wholesale Power Price Forecast" paper available at: http://www.nwcouncil.org/library/2008/2008-05.htm
[24] The "Revised Fuel Price Forecasts" paper is available at: http://www.nwcouncil.org/library/2007/2007-14.htm

Figure 1: Comparison of medium and high fuel price forecasts



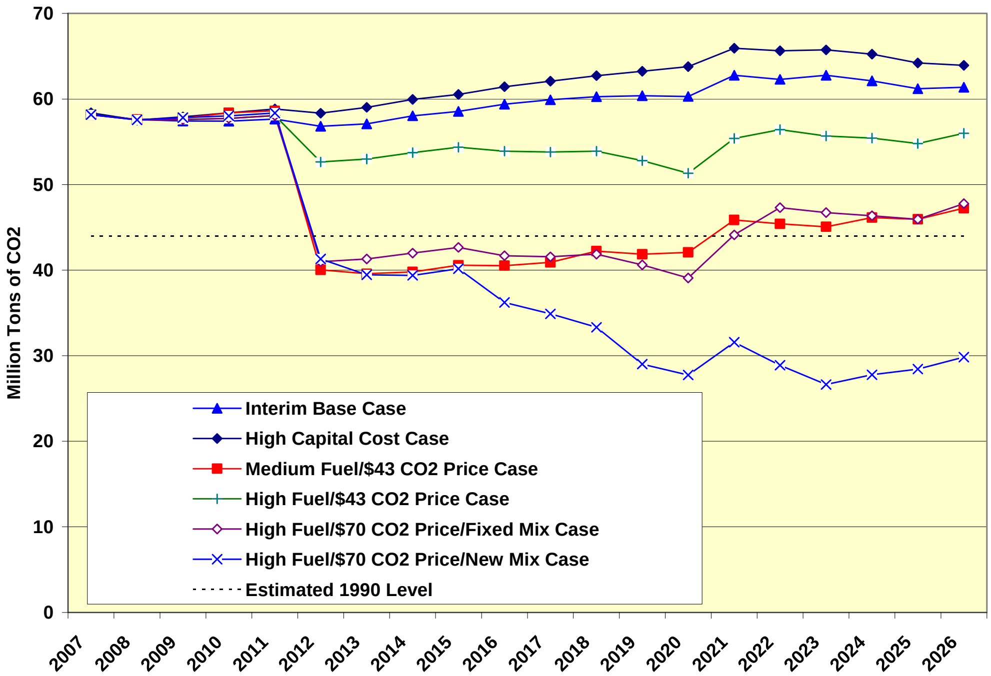
RESULTS

Figure 2 shows the Northwest power system's annual total CO_2 emissions for the reference case and the three high fuel price sensitivity cases. For continuity with the "Marginal Carbon Dioxide Production Rates of the Northwest Power System" paper, it also shows the annual total CO_2 emissions for the Interim Base Case and High Capital Cost Case of that paper.[25]

In the reference case the significant reduction in annual total CO_2 emissions is driven by a switch in the dispatch order of coal-fired and natural gas-fired resources.[26] The results of the High Fuel/$43 CO_2 Price Case show that this reduction in total emissions is sensitive to high natural gas prices. While some reduction in CO_2 emissions is achieved, with natural gas prices in the $8 to $9 per MMBtu range the $43 per ton CO_2 allowance price fails to reduce CO_2 emissions to the 1990 level. This is because the higher cost of natural gas favors the dispatch of coal-fired generating resources. With the higher natural gas prices the $43 per ton CO_2 emission cost is not sufficient to move coal-fired generation to the margin during a significant number of hours each year.

[25] See Figure 6, p. 11, in the "Marginal Carbon Dioxide Production Rates of the Northwest Power System" paper.
[26] See the "Marginal Carbon Dioxide Production Rates of the Northwest Power System" paper (pp. 7 - 16).

Figure 2: Forecasts of the Northwest power system's total CO_2 emissions



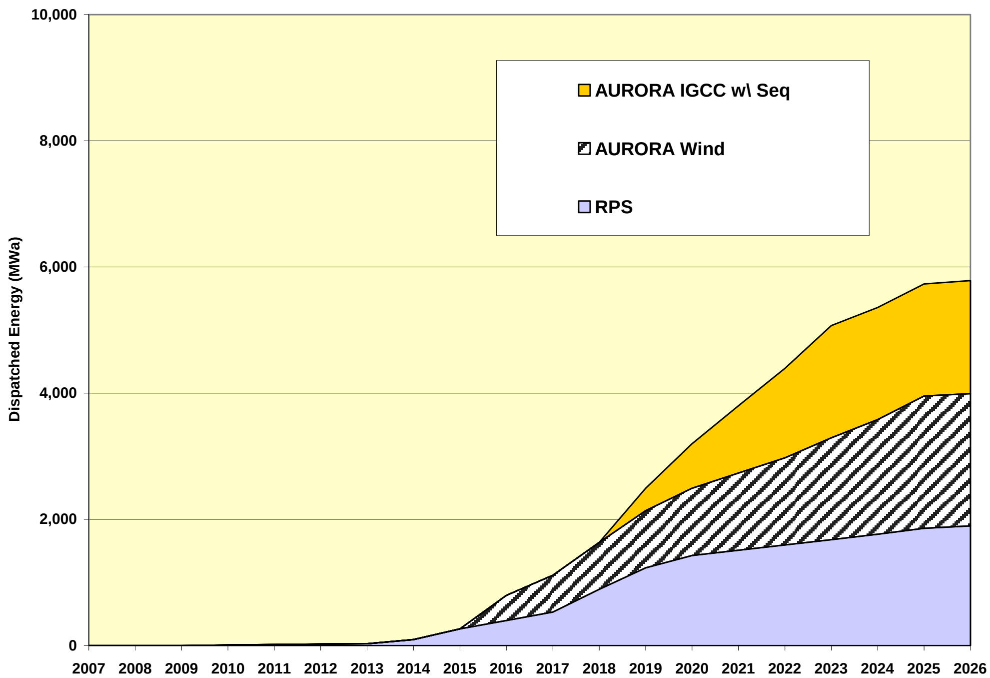
The results for the High Fuel/$70 CO_2 Price /Fixed Mix Case show that under the Council's high fuel price assumptions the price of CO_2 emissions allowances would need to climb to as high as $70 per ton of CO_2 in order for the Northwest power system to reach its 1990 level of CO_2 production with the resource mix of the reference case. The high natural gas prices work against efforts to reduce Northwest CO_2 emissions by forcing the cost of CO_2 allowance prices to climb in order to achieve the same targeted reduction in emissions.

The results for the High Fuel/$70 CO_2 Price /New Mix Case easily achieve 1990 levels of CO_2 emissions and show a continued decline in annual total CO_2 emissions after 2015. This is because additional wind generation (beyond Renewable Portfolio Standard requirements) and integrated gasification combined cycle (IGCC) generation with carbon capture and sequestration become economic additions to the power system. In addition, two large coal-fired generating units, Boardman and Valmy 1, become uneconomic to operate under these assumptions and are and retired in 2013 and 2020 respectively.[27] Figure 3 shows the energy output of the incremental resources added to the Northwest power system over the planning period. The continuing decline of CO_2 emissions observed in this case suggest that over the long-term, CO_2 allowance prices of less than $70 per ton of CO_2 may be sufficient to maintain emissions below 1990 levels, even with high natural gas prices.

[27] The Boardman unit is also retired in the reference case in 2012.

NORTHWEST VI POWER PLAN

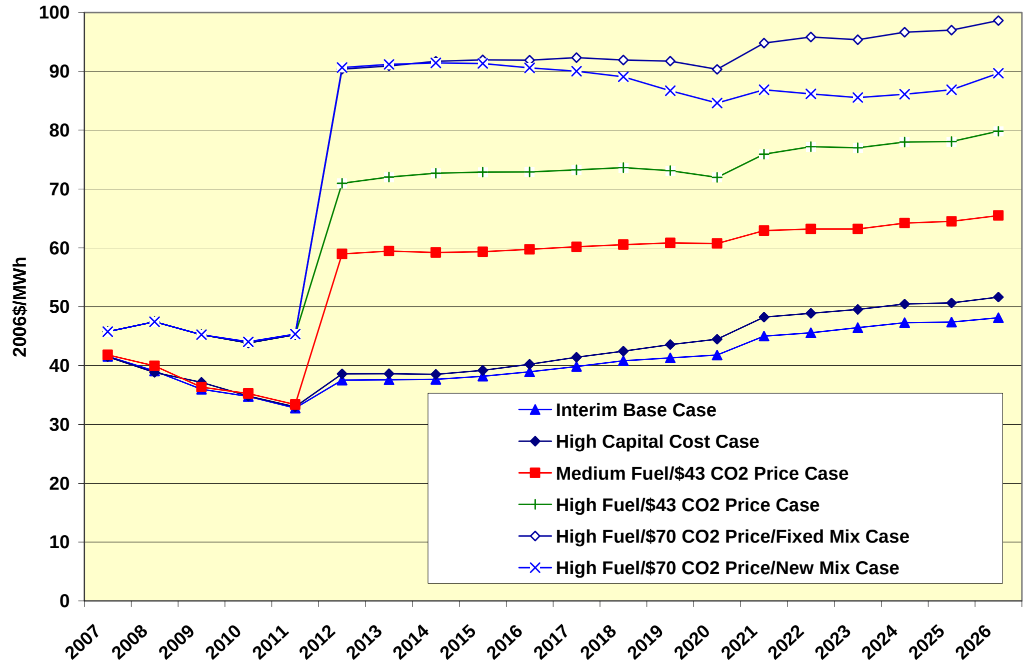
Figure 3: Forecast Pacific Northwest incremental resource mix based on dispatch energy (High Fuel/\$70 CO_2 Price/New Mix Case)



In its Fifth Power Plan the Council assumed that IGCC plants with CO_2 capture and sequestration using unconventional sequestration media (i.e., other than enhanced oil or gas recovery) could be in service in the region in the 2015 - 2020 period. Because of disappointingly slow development of the technologies involved it is uncertain whether five IGCC plants with carbon capture and sequestration could be built in the Northwest between 2019 and 2026. Moreover, because of the absence of relevant plant construction experience, the cost and risk of carbon sequestration is difficult to estimate. The Council will continue to improve its assumptions regarding this technology as it develops the Sixth Power Plan.

Whether CO_2 allowance prices of \$70 per ton of CO_2 would be politically sustainable for a prolonged period of time is also an open question. Many of the cap-and-trade proposals introduced in the 110th Congress call for "safety valve" options designed to release the CO_2 emissions cap if the cost of compliance becomes unacceptably high. Figure 4 shows the forecast wholesale power prices for each of the scenarios studied. The high fuel price sensitivity cases with \$70 per ton CO_2 allowance prices have the highest forecast power prices. For example, the High Fuel/\$70 CO_2 Price/New Mix Case had a levelized wholesale power price of \$73.70 per megawatt-hour (MWh). This is \$20.90 per MWh higher than the levelized price of the reference case. The High Capital Cost Case presented in the Council's "Interim Wholesale Power Price Forecast" paper had a levelized wholesale power price of \$41.30 per MWh. However, a \$70 per ton of CO2 allowance price appears to be more than sufficient to reduce CO2 emissions to 1990 levels, raising the possibility that somewhat lower allowance prices may suffice to achieve this objective, even with high natural gas prices. Moreover, a portion of the allowance revenues would likely be redirected to energy efficiency measures and low carbon generation, partly offsetting the overall cost of power system operation.

Figure 4: Forecasts of Northwest wholesale power prices



CONCLUSION

An important modeling result presented in the Council's paper, "Marginal Carbon Dioxide Production Rates of the Northwest Power System," is that the Northwest power system's annual CO_2 emissions can be driven below its1990 level with CO_2 allowance prices of $43 per ton. This result was achieved at the Council's medium fuel price forecast.

The findings presented in this addendum demonstrate that this modeling result is sensitive to higher natural gas price forecasts. At the Council's high fuel price forecast the $43 per ton CO_2 emission cost is insufficient to achieve the same dramatic reduction in the total annual emissions of the Northwest power system.

The higher natural gas prices tend to work against efforts to achieve significant reductions in total CO_2 emissions. This is because higher natural gas prices favor coal-fired generation by making natural gas-fired units more costly to operate. Our modeling indicates that with the Council's high fuel price forecast, CO_2 allowance prices would need to climb to a level between $43 and $70 per ton of CO_2 in order to reduce the Northwest power system's annual total emissions to its 1990 level.

The Council will continue to explore these issues as it develops its Sixth Power Plan. While a wide range of uncertainties regarding both fuel prices and CO_2 allowance prices will be incorporated in the Sixth Power Plan portfolio risk analysis, CO_2 reduction objectives can only be indirectly considered by subsequent examination of the CO_2 production implied by the resulting preferred resource portfolio.

CASE: UM 1744
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Reply Testimony

October 2, 2015

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

A. My name is Max St. Brown. I am employed as a Utility Economist in the Energy Rates, Finance and Audit Division of the Utility Program. My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/201.

Q. What is the purpose of your testimony?

A. To review the initial application (Application) for approval of a carbon emission reduction project submitted by Northwest Natural Gas Company (NW Natural or the Company).

Q. Did you include an exhibit for this docket?

A. Yes. I included Exhibit Staff/401, consisting of five pages.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Customer Incentive 2
Issue 2. Simple Payback vs. Internal Rate of Return (IRR) 8

ISSUE 1. CUSTOMER INCENTIVE

Q. Did Staff's Response Testimony in this docket make a recommendation in regards to the customer incentive in NW Natural's proposed Combined Heat & Power (CHP) solicitation program?

A. Yes, at lines 1-3 of Staff/200, St. Brown/2, Staff recommended that, "the Company produce a proposal for a reverse auction because a reverse auction can result in lower procurement costs than the Company's current proposal." This is still Staff's recommendation.

Q. Why is Staff readdressing this issue?

A. On September 22, the Company submitted supplemental information responses to Staff IR 11. These responses contain important information that was not available when Staff filed its Response Testimony. Accordingly, Staff is addressing them now.

Q. Please summarize your analysis.

A. The Company's proposed customer incentive of $30 per MTCO2(e) of emissions reduction is excessive to incent participation in the Company's proposed CHP solicitation program.

Q. Please describe the Company's supplemental response to Staff IR 11.

A. The files the Company submitted provide the years to simple payback and years to payback after tax and capital cost for five different CHP installations. For illustrative purposes, the Company creates the base case assuming that 500 kW, 800 kW, 4.3 MW, 21.7 MW, and 45 MW CHP customers participate in the Company's proposed CHP solicitation program. The Company's IR response has been included as Exhibit Staff/401, St. Brown/1.

Q. What percentage of the base case capacity would the 45 MW customer represent?

A. Such a customer would be 37.5 percent of the total 120 MW in the base case.

Q. Does Staff believe that a 45 MW CHP customer would participate in the proposed program if the customer incentive was less than $30 per MTCO2(e) of emissions reduction?

A. Yes, for the following three reasons:

1. Returns for participating customers would be nearly twice that of the Commission approved cost of capital for NW Natural or exceeding twice that cost of capital.
2. In computing the years to payback, the Company might be overstating the incremental costs of a CHP project and thus overstating the costs needing payback. Staff has an outstanding IR inquiring about this issue.
3. Customers have a benefit, due to improved power reliability, associated with building CHP which is not identified in the Company's payback computations.

Q. Do the three reasons also apply to other CHP capacity sizes?

A. Yes, but Staff focuses on the 45 MW plant in order to provide specific examples of how the Company's customer incentive departs from paying customers an incentive just large enough to incent participation (i.e. the least cost method).

Q. Please describe the first reason that Staff believes that a 45 MW CHP customer would participate in the proposed program if the customer incentive was less than $30 per MTCO2(e) of emissions reduction.

A. The Company's September 22 supplemental response to Staff IR 11 indicates that in the 66 percent scenario, simple payback would be achieved in less than five years and payback reflecting tax and capital cost would occur in less than eight years.[1] These payback periods correspond to rates of return greater than 14.87 percent and 9.05 percent, respectively. The payback periods of the same project, but in the 100 percent scenario, correspond to rates of return greater than 18.92 percent and 12.25 percent, respectively. The Company's supplemental response to Staff IR 11 uses 7.778 percent as the cost of capital.[2] Therefore, the CHP solicitation program might provide participating customers returns over twice that of the cost of capital for customers which NW Natural uses in its analyses provided in supplemental response to Staff IR 11. Staff believes that returns nearly twice that of the Commission approved cost of capital for NW Natural or exceeding twice that cost of capital are excessive to induce participation.

Q. Describe the second reason Staff believes that a 45 MW CHP customer would participate in the proposed program if the customer incentive was less than $30 per MTCO2(e) of emissions reduction.

[1] *See*: Cells B28:C28, G17, and J22 of the file *OPUC IR 11 Attachment-6_Supplemental 09-22-15.xlsx* submitted in the Company's supplemental response to Staff IR 11. This is attached as Exhibit Staff/401, St. Brown/2.
[2] *ibid*, Cells A21:L21.

A. As note earlier in computing the years to payback, the Company might be overstating the incremental costs of a CHP project and thus overstating the costs needing payback. Staff has an outstanding IR inquiring about this issue. The Company's supplemental response to Staff IR 11, presents $56.2 million as the cost of capital investment for a 45 MW CHP project.[3] This supplemental IR response does not demonstrate how the cost of capital investment is calculated. Staff has submitted an information request, Staff IR 45, asking for clarification. Staff notes that the capital investment could vary depending on how the CHP plant is put into operation. For instance, if an existing plant is retrofitted to CHP, then this cost might be lower.

As a second example, if a new CHP plant is built, then the costs considered in the payback computations should net out all costs that would have occurred without a CHP plant, such as the capital and installation costs of a boiler to produce steam. While awaiting the Company's response to IR 45 to explain the Company's analysis, Staff believes that this second example might be relevant because Staff has reviewed the March 2015 "Catalog of CHP Technologies" report issued by the U.S. EPA which the Company referenced in footnote 6 of NWN/101, Summers/68 (the Company references the 2008 version of this report).[4] Page 3-14 of the report, provides a total installed plant cost of $55,506,610 for a 46 MW capacity gas turbine CHP system. A component of this cost is heat recovery steam generators, which are a type of

[3] *ibid*, Cell C2.
[4] U.S. Environmental Protection Agency. 2015. "Catalog of CHP Technologies," Combined Heat and Power Partnership, March 2015. Available at: http://www.epa.gov/chp/technologies.html. Page 3-4 is attached as Exhibit Staff/401, St. Brown/3.

boiler. CMCE, Inc. fabricated a CHP unit which, "can be used in … retrofits of existing industrial and commercial boilers."[5] Thus, heat recovery steam generators should not be included in the capital costs of retrofitted CHP installations. Further, two other components of the cost are building, at $100 per square foot, and construction, at $10.2 million, which would partially occur without a CHP plant. Finally, if a customer feels strongly that distributed generation improves power reliability (a benefit identified in Primen's 2003 Distributed Energy Market Survey), then the customer might install a combustion turbine in the regular course of business, in which case the largest component of the total installed plant cost would need to be netted out.[6]

Q. Describe the third reason Staff believes that a 45 MW CHP customer would participate in the proposed program if the customer incentive was less than $30 per MTCO2(e) of emissions reduction.

A. Customers have a benefit, that being improved power reliability, associated with building CHP which is not identified in the Company's payback computations.

As noted in Staff/200, St. Brown/8-9, Primen's 2003 Distributed Energy Market Survey identified improved power reliability as a benefit of distributed generation, where Staff notes CHP is a type of distributed generation. Thus, customers have a benefit associated with building CHP that is not identified in

[5] U.S. Department of Energy, "Combined Heat and Power (CHP) Integrated with Burners for Packaged Boilers," Accessed September 29, 2015 at: http://energy.gov/eere/amo/combined-heat-and-power-chp-integrated-burners-packaged-boilers. This is attached as Exhibit Staff/401, St. Brown/4.

[6] Primen's 2003 Distributed Energy Market Survey is initially referenced on line 18 of NWN/100, Summers/7.

the Company's payback computations presented in the file *OPUC IR 11 Attachment-6_Supplemental 09-22-15.xlsx*. Monetizing and including this benefit would decrease the time to achieve payback (and increase the corresponding rate of return).

Q. What is Staff's recommendation regarding customer incentive?

A. Because it is unclear if $56.2 million is the appropriate value to use as capital investment related to CHP installation for a 45 MW CHP project, Staff believes that data on customer willingness to adopt CHP should be gathered directly, such as through a reverse auction previously advocated by Staff in its Response Testimony.

ISSUE 2. SIMPLE PAYBACK VS. INTERNAL RATE OF RETURN (IRR)

Q. Please describe the Company's approach to simple payback.

A. At NWN/101, Summers/5, NWN witness Summers states, "the amount of the payment from NW Natural is calculated to provide customers a payment opportunity that, when combined with the available funds from ODOE and the ETO and Federal tax credits, gives them a chance to realize a payback from their CHP investment that makes the economics attractive enough to invest."

Q. Are there alternative approaches to making investment decisions?

A. Yes, Internal Rate of Return (IRR) is a commonly used method. Staff asks about IRR in outstanding Staff IR Nos. 46-48.

Q. Please describe IRR.

A. Page 529 of Investment Analysis and Portfolio Management by Reilly and Brown states:

> "The IRR is the discount rate that equates the present value of cash outflows for an investment with the present value of its cash inflows. You compare this discount rate, or IRR (which is also the expected rate of return on the project), to your cost of capital, and accept any investment proposal with an IRR equal to or greater than your cost of capital."[7]

[7] Reilly, Frank K. and Keith C. Brown. 1997. "Investment Analysis and Portfolio Management," The Dryden Press, Harcourt Brace College Publishers, Fifth Edition, p. 529. This is attached as Exhibit Staff/401, St. Brown/5.

Q. For a 45 MW CHP customer does the investment IRR exceed a cost of capital of 7.778 percent?

A. Yes, based on the IRR provided in the Company's electronically provided *Appendix D, WSU RELCOST Model Adapted for NW Natural.xlsx*.

Q. What does this imply?

A. By the investment decision rule outlined in Investment Analysis and Portfolio Management, the per MTC02(e) customer incentive could be lowered while maintaining customer participation in the program. Staff has outstanding information requests inquiring further about this topic.

Q. What is Staff's recommendation regarding simple payback vs. IRR and customer incentive?

A. Because computing simple payback or IRR requires accurate projections of the cash outflow related to an investment, and Staff has demonstrated in this testimony that it is unclear if $56.2 million is the appropriate value to use as capital investment related to a 45 MW CHP installation project, Staff believes a reverse auction should be used to identify customer willingness to adopt CHP.

Q. If the Commission does not approve the use of a reverse auction to determine the optimal level of customer incentives, is Staff supporting the Company's proposed $30 per MTCO2(e)?

A: No.

Q: What is the Company's proposed method?

A: A flat rate $30 customer incentive per MTC02(e) of emissions reduction.

Q. Can you cite to other instances where a competitive approach was used to determine the appropriate level of incentives for a CHP program?

A. Yes, this year San Diego Gas and Electric issued CHP Request for Offers (RFOs) Seeking CHP Power Purchase Agreements to solicit offers from owners and operators of CHP Facilities and Utility Prescheduled Facilities. Exhibit Staff/401, St. Brown/6-12 provides San Diego Gas and Electric's description of the program.[8]

Q. What is the Company's methodology behind a $30 per MTC02(e) customer incentive?

A. NWN/101, Summers/14 states, "Incentives were set to achieve, on average, about a 3-4 year payback."

Q. Does Staff support this methodology?

A. No, Staff believes that the payback method confuses and distracts from the traditional regulatory standard which is to allow the utility an opportunity to earn its authorized return. Rather, and more transparent, Staff thinks the Internal Rate of Return (IRR) methodology is the correct method to evaluate this type of investment. Staff is in agreement with an U.S. Department of Energy document titled "Financing Energy Efficiency in Buildings," which states, "IRR provides a

[8] San Diego Gas and Electric, "2015 Request for Offers Seeking CHP Power Purchase Agreements," Accessed October 10, 2015 at: http://www.sdge.com/2015-request-offers-seeking-chp-power-purchase-agreements

useful measure of the financial value of an improvement, and is a much better way to evaluate competing investments than is simple payback analysis."[9]

Q. Are there additional shortcomings of the payback methodology?

A. Yes, using the payback method fails to fully capture that customers would receive energy savings from CHP after they cease to receive a customer incentive from NW Natural's proposed CHP solicitation program. IRR considers all cash streams and thus fully captures the benefits from energy savings.

Q. What is the format of the WSU RELCOST model, which is appendix D of the Company's initial application?

A. The WSU RELCOST model is a Microsoft Excel file. The file was submitted to Staff on a CD.

Q. Does the WSU RELCOST model provide Project IRRs?

A. Yes and Staff asked for the Project IRRs in outstanding IRs 46-48. However, responses to these IRs are not due until October 12, 2015.

Q. What was Staff's approach to performing analysis?

A. Unless otherwise specified, Staff ran the model using the default input values provided in the WSU RELCOST model. These default input values were preloaded into the model provided to Staff via CD from NW Natural.

Q. In the model that was submitted to Staff, what yearly customer incentive payments does the Company propose to pay to participating customers and what are the customer's corresponding Project IRRs?

[9] U.S. Department of Energy, "Financing Energy Efficiency in Buildings," Accessed September 30, 2015 at: http://www.michigan.gov/documents/CIS_EO_financinghandbook_75701_7.pdf.

A. The Company's proposed payments and the customer's Project IRRs are presented in the table below:

Project (prototype unit)	Aggregate Yearly Customer Incentive Payment	Project IRR
Hospital - 800,000 sf with Two 800 kW Recip Engines, eGRID non-baseload baseline	$97,462	16.0%
Reciprocating Engine - 500 kW, eGRID non-baseload baseline	$38,911	36.7%
Reciprocating Engine - 4.3 MW, eGRID non-baseload baseline	$451,528	34.6%
Gas Turbine - 21.7 MW, eGRID non-baseload baseline	$1,879,561	27.2%
Gas Turbine - 45 MW, eGRID non-baseload baseline	$3,965,249	24.9%

Q. Are the Project IRR values in the table above dependent on carbon emission reduction calculation methodologies?

A. No, the IRR values are computed using a stream of cash flows. For instance, for the 21.7 MW gas turbine project, if NW Natural were to provide yearly customer incentives of $1,879,561, then the IRR will be unaffected. The IRR would only be affected if NW Natural provides yearly customer incentives different than $1,879,561. This example illustrates why yearly aggregate payments is a more useful measure than payments per ton of MTC02(e) of emissions reduction.

Q. How do payments per ton of MTC02(e) of emissions reduction vary based on carbon emission reduction calculation methodologies?

A. The payment per ton of MTC02(e) of emissions reduction is computed as:

$$\text{payment per ton of MTC02(e) of emissions reduction} = \frac{\text{yearly customer incentive payments}}{\text{yearly carbon emissions reductions}}$$

Yearly carbon emissions reductions (the denominator of this equation) can fluctuate significantly based on the carbon emission reduction calculation methodology used.

Q. Does staff support the "payment-for-performance" aspect of the Company's proposed payment per ton of MTC02(e) of emissions reduction approach?

A. Yes, however, Staff is concerned about using this approach before a carbon emissions reduction calculation methodology is accepted by all parties.

Q. Why is Staff concerned about using a payment per ton of MTC02(e) of emissions reduction approach before all parties agree to a carbon emission reduction calculation methodology?

A. The equation demonstrates that if the payment per ton of MTC02(e) of emissions reduction is held constant, while the yearly carbon emissions reduction varies, then the yearly aggregate customer incentive payments will change. This is a great concern to Staff. Decision must settle on both a payment per ton of MTC02(e) of emissions reduction and a carbon emission reduction calculation methodology simultaneously, or else ratepayers would be on the hook for unknown yearly customer incentive payments.

Alternatively, the discussion could be moved from a discussion of payment per ton of MTC02(e) to a discussion of yearly aggregate customer incentive payments for plants operating at full capacity and this issue will be eliminated.

Nonetheless, if a payment per ton of MTC02(e) of emissions reduction is desired, it can be computed from the ratio of aggregate yearly payments. Specifically, solving for the unknown in the ratio below will provide Staff's comparable value to the $30 payment per ton of MTC02(e) emissions reduction proposed by the Company:

$$\frac{\text{Staff's aggregate payment}_i}{\text{Company's aggregate payment}_i} = \frac{\text{x}}{\$30}$$

The unknown in this equation solves to the per ton incentive for each given type of plant. The subscript i indicates there are multiple types of plants.

Q. How do the Aggregate Customer Incentive Payments under the Company's proposal compare to existing CHP incentives and CHP plant capital expenditures?

A. This information is presented in Exhibit Staff/401, St. Brown/13. The "Total customer incentive over project Life from NW Natural" and the "CHP plant capital expenditures" are not comparable in real terms because of the timing of cash flows. The "Total customer incentive over project Life from NW Natural" is to be paid out over a ten year lifespan.

Q. Has the topic of IRRs required for companies to participate in energy efficiency programs been studied before?

A. Yes, a 2009 paper authored by William Prindle of ICF International and Andre de Fontaine of the Pew Center on Global Climate Change analyzes this topic. Staff notes that NW Natural's initial application cites the July 2014 report

"Assessment of the Technical and Economic Potential for CHP in Oregon" which was also authored by ICF International.[10]

Q. What were their findings?

A. Their abstract states, "This paper summarizes the results of a 2009 survey of corporate energy efficiency strategies, conducted by the Pew Center on Global Climate Change. Forty-eight companies, ranging in size from $8 billion to $99 billion in revenues, completed the survey. … [Respondents] IRR criteria were mostly in the 10-15% range, though one reported a 35% IRR threshold." Exhibit Staff/401, St. Brown/14 provides this abstract.

[10] Prindle, William and Andre de Fontaine. 2009. "A Survey of Corporate Energy Efficiency Strategies," ACEEE Summer Study on Energy Efficiency in Industry, Available at: http://www.c2es.org/docUploads/Final%20ACEEE%20survey%20paper.pdf.

Q. What aggregate yearly customer incentive payments in NW Natural's proposed CHP solicitation program would result in IRRs of 10 percent, 12.5 percent and 15 percent for each of the five Project IRRs?

A. The customer incentive levels are presented in Table 1 below:

Table 1			
	Aggregate yearly customer incentive payment that would provide project an:		
Project (prototype unit)	IRR of 10%	IRR of 12.5%	IRR of 15%
Hospital - 800,000 sf with Two 800 kW Recip Engines, eGRID non-baseload baseline	$34,079	$60,589	$86,812
Reciprocating Engine - 500 kW, eGRID non-baseload baseline	*	*	*
Reciprocating Engine - 4.3 MW, eGRID non-baseload baseline	*	*	*
Gas Turbine - 21.7 MW, eGRID non-baseload baseline	*	*	$209,258
Gas Turbine - 45 MW, eGRID non-baseload baseline	*	$198,262+	$1,013,782+
*without a customer incentive, the project exceeds the IRR hurdle rate +Staff disputes the Company's methodology behind these values, see Table 2 below			

Q. Does Staff have any other findings due to analyzing the WSU RELCOST model adapted for NW Natural?

A. Yes, the model is sensitive to inputs.

Q. Can you give an example?

A. Yes. In this testimony Staff found that in computing the years to payback for a 45 MW plant, the Company might be overstating the incremental costs of a CHP project and thus overstating the costs needing payback. Outstanding Staff IR 45 asks about this issue. If, for example, the CHP plant cost were lowered ten percent, then Table 2 below would apply:

Table 2:			
	Aggregate yearly customer incentive payment that would provide project an:		
Project (prototype unit)	IRR of 10%	IRR of 12.5%	IRR of 15%
Gas Turbine - 45 MW, eGRID non-baseload baseline, if CHP plant cost were lowered 10%	*	*	$167,862
*without a customer incentive, the project exceeds the IRR hurdle rate			

Q. Why is averaging the entries in Table 1 unadvisable?

A. Because, for instance, similar MW capacity could be achieved by multiple 4.3 MW reciprocating engine projects rather than a single 45 MW gas turbine project, but at a lower cost to ratepayers, according to the WSU RELCOST model provided to Staff.

Q. Is this result surprising?

A. Yes, NWN/101, Summers/78 states, "Generally, calculated payback is lower for larger customers, stemming from lower CHP system costs as a result of economies of scale, better CHP system performance characteristics, and lower natural gas prices."

Q. Are there any additional inputs in the WSU RELCOST model which affect the Project IRRs?

A. Yes, Staff analyzed two additional inputs.

1. In the CD sent to Staff, the "Electricity Sales" inputs are zeroed out. If electricity is sold above its cost of production, as might occur in a power purchase agreement (PPA), then the IRR of any given project is increased. Staff is puzzled by this omission given that the Oregon State University has a PPA with Pacific Power for its gas-fired generation facility for the generation of electric power. Staff reserves the right to raise this issue in further discussions because it impacts the IRR computations.

2. In the CD sent to Staff, the plant salvage value is set to 20 percent; however, Staff cannot determine that the recovery of the salvage value is captured in the Excel formulas. Counterintuitively, if the salvage value input is adjusted to zero percent, then the IRR of any given project is increased. Staff reserves the right to raise this issue in further discussions because it impacts the IRR computations.

Q. What are Staff's findings?

A. In analyzing the WSU RELCOST model, Staff has found that for CHP installations 4.3 MW and 21.7 MW in capacity, customers might be incentivized to install in response to customer incentive payments anywhere in the range of $0 to $209,258 annually.

Staff disputes the Company's methodology for computing the annual incentive payments for CHP installations 45 MW in capacity. Staff is waiting to hear a response to Staff IR 45, which asks about this issue.

If a payment per ton of MTC02(e) of emissions reduction is desired, it can be computed from the ratio of aggregate yearly payments as Staff described above. Specifically, the ratio below represents a 21.7 MW gas turbine project. Solving for the unknown in the ratio below will provide Staff's comparable value to the $30 payment per ton of MTC02(e) emissions reduction proposed by the Company:

$$\frac{\$2{,}092{,}580}{\$18{,}795{,}610} = \frac{x}{\$30}$$

The unknown in this equation solves to $3.34 per ton incentive for this type of plant. Because it is preloaded into the WSU RELCOST model, this $3.34 is developed using the eGRID non-baseload baseline as the carbon emission reduction computation methodology. The Response Testimony of Staff witness Klotz addresses the shortcomings of this methodology. As described above, a different carbon emission reduction computation methodology would necessitate a change in the per ton emission reduction incentive.

Q. Is Staff advocating for a range including a $3.34 customer incentive payment per ton of MTC02(e) emissions reduction?

A. Yes, Staff believes a range of customer incentive payments per ton of MTC02(e) emissions reduction including $3.34 is reasonable. In Table 1 of this testimony (page 16), Staff's IRR methodology has demonstrated that projects smaller than 4.3 MW in capacity might require larger incentive payments. If a policy goal is to incentivize small projects along with large projects, then a $0 to $10 range of customer incentive payments per ton of MTC02(e) emissions reduction could be considered.

Q. What is Staff's recommendation?

A. For CHP installations 4.3 MW and 21.7 MW in capacity, customer incentive payments anywhere in the range of $0 to $209,258 annually is a wide range, Staff advocates finding the appropriate value within the range through a reverse auction, as stated at lines 1-3 of Staff/200, St. Brown/2.

Q. Does this conclude your testimony?

A. Yes.

Exhibit 1

NW Natural

Rates & Regulatory Affairs

UM 1744
Emission Reduction Program

Data Request - Supplemental Response

Request No. UM 1744-OPUC-IR 11: Due 08-12-2015
On page 10 beginning line 17 of Direct Testimony of Barbara Summers, Ms. Summers states, "Individual CHP customers will bear the costs of system expansion or extension as well as any compression, similar to how this would be done under NW Natural's Schedule H "Large Volume Non-Residential High Pressure Gas Service (HPGS) Rider."

a. How will this additional cost change the payback period for participants?

b. How many participants or what percentage of participants will need expansion, extension and/or compression of service?

c. What is the average cost of expansion, extension and compression?

d. Has NW Natural factored in the need of potential participants to extend or expand service or request compression service into NW Natural's adoption rate assumptions?

Supplement Response Provided 09-22-15:

During the September 18th workshop with parties, NW Natural provided additional information related to the participant payback timeline of a 45 MW CHP unit. Through this supplemental response, NW Natural provides the worksheets related to the participant paybacks of a 500kW (see OPUC IR 11 Attachment-2_Supplemental), 800kW (see OPUC IR 11 Attachment-3_Supplemental), 4.3 MW (see OPUC IR 11 Attachment-4_Supplemental), 21.7 MW (see OPUC IR 11 Attachment-5_Supplemental), and 45 MW (see OPUC IR 11 Attachment-6_Supplemental) prototype units. The worksheets are set to the 66% case but can be shifted between 66% and 100% cases in Cell C28. The payback year in the yellow highlighted rows improves by 1 year in most cases under the 100% case on a cumulative after tax and capital cost basis.

*highlighting added by Staff

Exhibit 2

	45 MW Gas Turbine	1	2	3	4	5	6	7	8	9	10
A	Capital Investment Excluding Compression	56.2									
B	ETO Incentive	0.5									
C	ODOE Incentive	5.0									
D	ITC (10%)	5.6									
E	Net Capital Investment (Without Compression)	45.1	Net Capital Investment on which payback cells are highlighted below								
F	Compression	2.0									
G	Meter Set and Line Extension	0.5									
H	Net Capital With Compression	47.1									
I	Avoided Electricity Purchases	17.6	18.0	18.5	19.0	19.4	19.9	20.4	20.9	21.4	22.0
J	Avoided Natural Gas Purchases	8.8	9.0	9.2	9.4	9.6	9.9	10.1	10.3	10.6	10.8
K	844 Incentive*	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
L	O&M Expenses (without Compression)	1.6	1.6	1.7	1.7	1.8	1.8	1.8	1.9	2.0	2.0
M	Compression Under Schedule H	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
N	Fuel Expenses	16.6	17.0	17.4	17.8	18.2	18.6	19.0	19.5	19.9	20.4
O	Annual EBITDA (Without Compression) H+I+J-K-M	10.8	11.0	11.2	11.5	11.6	11.9	12.2	12.4	12.6	13.0
P	Cumulative EBITDA (Without Compression) SIMPLE PAYBACK	10.8	21.8	33.0	44.6	56.2	68.1	80.4	92.8	105.5	118.5
Q	Taxes (Without Compression) MACRS		1.1	2.0	2.2	2.3	3.2	4.1	4.2	4.3	4.4
R	Cumulative After Tax (Without Compression)	10.8	20.7	29.9	39.3	48.6	57.4	65.6	73.8	82.1	90.7
S	Depreciation	0.28	2.22	2.00	1.80	1.62	1.46	1.33	1.33	1.33	1.33
T	Capital Cost @ AT Cost of Capital (.0778)	3.5	3.3	3.2	3.0	2.9	2.8	2.7	2.6	2.5	2.4
U	Cumulative After Tax (Without Compression) After Capital Cost (Assuming Utility AT Rate (.0778)	7.3	13.9	20.0	26.3	32.8	38.8	44.2	49.9	55.8	62.0
V	Annual EBITDA (With Schedule H Compression) H+I+J-K-L-M	10.5	10.7	10.9	11.2	11.3	11.6	11.9	12.1	12.3	12.7
W	Cumulative EBITDA (With Schedule H \Compression)	10.5	21.1	32.0	43.2	54.5	66.1	78.0	90.1	102.4	115.1
X	Annual EBITDA without 844	8.2	8.4	8.6	8.9	9.0	9.3	9.6	9.8	10.0	10.4
Y	Cumulative EBITDA without 844	8.2	16.6	25.2	34.2	43.2	52.5	62.2	72.0	82.1	92.5

*Base Case incentive at about 2,000 MTCO2(e) is forecast to be $2.6, high case at about 3,000 MTCO2(e) is forecast at $3.96. All other assumptions are the same between cases.

* Case 1 = 66% / No or Other Entry = 100% 1

- Year of Simple Payback on Net Capital Investment with ETO, ODOE and 844 Incentives - Based on EBITDA
- Year of Simple Payback on Net Capital Investment with ETO, ODOE and 844 Incentives - Based on EBITDA minus Taxes
- Year of Simple Payback on Net Capital Investment with ETO, ODOE and 844 Incentives - Based on EBITDA minus Taxes and Capital
- Year of Simple Payback on Net Capital Investment with 844, ETO and ODOE Incentives Assuming Schedule H Compression
- Year of Simple Payback on Net Capital Investment with only 844 Incentives, Assuming Schedule H Compression
- Year of Simple Payback on Net Capital Investment without 844 Incentives Assuming Schedule H Compression

Exhibit 3

Table 3-5. Estimated Capital Cost for Representative Gas Turbine CHP Systems[53]

Cost Component	System				
	1	2	3	4	5
Nominal Turbine Capacity (kW)	3,510	7,520	10,680	21,730	45,607
Net Power Output (kW)	3,304	7,038	9,950	20,336	44,488
Equipment					
Combustion Turbines	$2,869,400	$4,646,000	$7,084,400	$12,242,500	$23,164,910
Electrical Equipment	$1,051,600	$1,208,200	$1,304,100	$1,490,300	$1,785,000
Fuel System	$750,400	$943,000	$1,177,300	$1,708,200	$3,675,000
Heat Recovery Steam Generators	$729,500	$860,500	$1,081,000	$1,807,100	$3,150,000
SCR, CO, and CEMS	$688,700	$943,200	$983,500	$1,516,400	$2,625,000
Building	$438,500	$395,900	$584,600	$633,400	$735,000
Total Equipment	$6,528,100	$8,996,800	$12,214,900	$19,397,900	$35,134,910
Installation					
Construction	$2,204,000	$2,931,400	$3,913,700	$6,002,200	$10,248,400
Total Installed Capital	$8,732,100	$11,928,200	$16,128,600	$25,400,100	$45,383,310
Other Costs					
Project/Construction Management	$678,100	$802,700	$1,011,600	$1,350,900	$2,306,600
Shipping	$137,600	$186,900	$251,300	$394,900	$674,300
Development Fees	$652,800	$899,700	$1,221,500	$1,939,800	$3,312,100
Project Contingency	$400,700	$496,000	$618,500	$894,200	$1,526,800
Project Financing	$238,500	$322,100	$432,700	$899,400	$2,303,500
Total Installed Cost					
Total Plant Cost	$10,839,800	$14,635,600	$19,664,200	$30,879,300	$55,506,610
Installed Cost, $/kW	$3,281	$2,080	$1,976	$1,518	$1,248

Source: Compiled by ICF from vendor-supplied data.

3.4.6 Maintenance

Non-fuel operation and maintenance (O&M) costs are presented in **Table 3-6**. These costs are based on gas turbine manufacturer estimates for service contracts, which consist of routine inspections and scheduled overhauls of the turbine generator set. Routine maintenance practices include on-line running maintenance, predictive maintenance, plotting trends, performance testing, fuel consumption, heat rate, vibration analysis, and preventive maintenance procedures. The O&M costs presented in **Table 3-6** include operating labor (distinguished between unmanned and 24 hour manned facilities) and total maintenance costs, including routine inspections and procedures and major overhauls.

[53] Combustion turbine costs are based on published specifications and package prices. Installation estimates are based on vendor cost estimation models and developer-supplied information.

Exhibit 4

COMBINED HEAT AND POWER (CHP) INTEGRATED WITH BURNERS FOR PACKAGED BOILERS

PROVIDING CLEAN, LOW-COST, ONSITE DISTRIBUTED GENERATION AT VERY HIGH FUEL EFFICIENCY

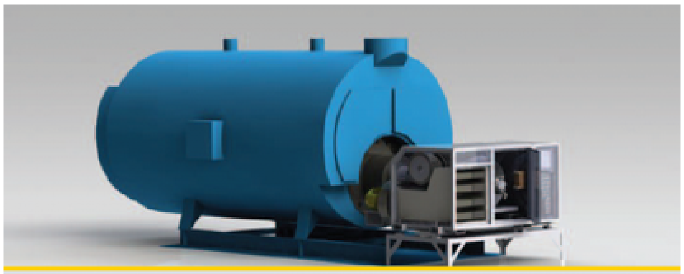
This project integrated a gas-fired, simple-cycle 100 kilowatt (kW) microturbine (SCMT) with a new ultra-low nitrogen oxide (NOx) gas-fired burner (ULNB) to develop a combined heat and power (CHP) assembly called the Boiler Burner Energy System Technology (BBEST).

INTRODUCTION

CHP systems can achieve significant gains in fuel efficiency for power generation and reductions in greenhouse gas emissions. While large CHP systems have been installed and used for many years, small CHP systems (especially less than 250 kW in generating capacity) have seen limited market acceptance. However, the number of potential host sites for large, multi-MW CHP installations is limited by the need for significant thermal loads to fully exploit the benefits of CHP. Small CHP installations, in contrast, have a much greater potential market.

This project developed the BBEST, a CHP assembly of a gas-fired, 100 kW SCMT and a new ULNB, to increase acceptance of small CHP systems. This technology will improve reliability while reducing costs and the need for maintenance.

The project's BBEST system will achieve an overall CHP fuel efficiency of > 80% and a power conversion efficiency of 3,800 British thermal units (Btu)/kilowatt hour. The CHP product will be used in new installations and as a retrofit for existing industrial and commercial boilers in place of conventional burners.



Boiler Burner Electrical System Technology (BBEST) for packaged boilers

Photo courtesy of CMCE, Inc.

PROJECT DESCRIPTION

This project engineered, designed, and fabricated the BBEST CHP assembly that integrates a low-cost, clean-burning, gas-fired 100 kW SCMT with a new ULNB. The compact BBEST CHP product can be used in new installations or in retrofits of existing industrial and commercial boilers.

The first part of the project includes hardware development, assembly, and preliminary testing. Each key CHP system component (ULNB, SCMT, assembly BBEST CHP package, and

BENEFITS FOR OUR INDUSTRY AND OUR NATION

If a low-cost domestic microturbine can be procured, the incremental cost for power generation can be as low as $700/kW, compared to as much as $2,000/kW for conventional CHP. Maximum system efficiency is expected to be > 80%, compared to 70% for conventional systems.

Increased efficiency will benefit industry through energy savings and associated cost reductions, as well as decreased greenhouse gas emissions. The system will also reduce NO_x emissions to meet stringent air quality regulations.

The developed BBEST system offers a new, cost-effective CHP alternative for industrial plants and other facilities with smaller thermal loads. This greatly increases the number of potential CHP sites. It is estimated that each 100 kW BBEST system installation will result in over $100,000 in annual energy savings (based on boiler load factor of 66% and a spark spread defined by $0.16/kWh for price of electricity and $5/MMBtu for natural gas). These savings allow for a simple payback of 2.5 years without incentives. The hotel where the demonstration system was installed is realizing annual energy savings of $117,000 in electricity costs based on 4,250 Btu/kWh microturbine heat rate, a natural gas cost of $6/MMBtu, and an electricity rate of $0.16/kWh.

APPLICATIONS IN OUR NATION'S INDUSTRY

This project will target a large retrofit CHP market consisting of about 130,000 industrial and commercial boilers operating in the United States, each with heat input design capacities of <100 million Btu/hour. The BBEST CHP assembly will be applicable to all major packaged boiler designs (A-Type Watertube, D-Type Watertube, O-Type Watertube, and Firetube). Sectors that will most likely benefit are small industrial plants, schools, and health care facilities.

BARRIERS

- Developing a new ULNB that considers the optimum integration of the SCMT equipment and exhaust gas properties
- Improving the SCMT premix combustor to

*highlighting added by Staff

Exhibit 5

return), and we computed the estimated value (price) of the bond. In this case, it is assumed that we know the price of the bond and we compute the discount rate (yield) that will give us the current market price (P_m).

$$P_m = \sum_{t=1}^{2n} \frac{C_i/2}{(1 + i/2)^t} + \frac{P_p}{(1 + i/2)^{2n}}$$

where the variables are the same as previously, except

i = the discount rate that will discount the expected cash flows to equal the current market price of the bond

This i value gives the expected ("promised") yield of the bond under various assumptions to be noted, assuming you pay the price P_m. We will discuss several types of bond yields that arise from the assumptions of the valuation model in the next section.

Approaching the investment decision stating the bond's value as a yield figure rather than a dollar amount, you consider the relationship of the computed bond yield to your required rate of return on this bond. If the computed bond yield is equal to or greater than your required rate of return, you should buy the bond; if the computed yield is less than your required rate of return, you should not buy the bond.

These approaches to pricing bonds and making investment decisions are similar to the two alternative approaches by which firms make investment decisions. We referred to one approach, the net present value (NPV) method, in Chapter 13. With the NPV approach, you compute the present value of the net cash flows from the proposed investment at your cost of capital and subtract the present value cost of the investment to get the net present value (NPV) of the project. If this NPV is positive, you consider accepting the investment; if it is negative, you reject it. This is basically the way we compared the value of an investment to its market price.

The second approach is to compute the **internal rate of return (IRR)** on a proposed investment project. The IRR is the discount rate that equates the present value of cash outflows for an investment with the present value of its cash inflows. You compare this discount rate, or IRR (which is also the expected rate of return on the project), to your cost of capital, and accept any investment proposal with an IRR equal to or greater than your cost of capital. We do the same thing when we price bonds on the basis of yield. If the expected yield on the bond (yield to maturity, yield to call, or horizon yield) is equal to or exceeds your required rate of return on the bond, you should invest in it; if the expected yield is less than your required rate of return on the bond, you should not invest in it.

COMPUTING BOND YIELDS

Bond investors traditionally have used five yield measures for the following purposes:

Yield Measure	Purpose
Nominal yield	Measures the coupon rate.
Current yield	Measures the current income rate.
Promised yield to maturity	Measures the expected rate of return for bond held to maturity.
Promised yield to call	Measures the expected rate of return for bond held to first call date.
Realized (horizon) yield	Measures the expected rate of return for a bond likely to be sold prior to maturity. It considers specific reinvestment assumptions and an estimated sales price. It also can measure the actual rate of return on a bond during some past period of time.

Exhibit 6

SDGE
A Sempra Energy utility

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2015 Request for Offers Seeking CHP Power Purchase Agreements

Latest Update

- 8/25/2015 – Added additional Q&A responses (under RFO Communication) and a revised Offer Form (Required Forms and Documents)
- 8/20/2015 – Added Q&A responses (under RFO Communication) and a revised Offer Form (Required Forms and Documents)
- 8/11/2015 - Added Bidders Conference Presentation
- 8/4/2015 - Added Bidders Conference Details

In accordance with the Qualifying Facility ("QF") and Combined Heat and Power ("CHP") Program Settlement Agreement and related documents (including the CHP Program Settlement Agreement Term Sheet) approved by the California Public Utilities Commission ("CPUC") on December 16, 2010 in Decision (D.)10-12-035 (collectively, the "Settlement Agreement"), San Diego Gas and Electric ("SDG&E") is issuing its 2015 Combined Heat and Power ("CHP") Request for Offers ("RFO") to solicit offers ("Offers") from owners and operators of CHP Facilities and Utility Prescheduled Facilities ("UPF"). The Settlement Agreement became effective November 23, 2011.

("SDG&E") is issuing this 2015 CHP RFO to achieve its megawatt ("MW") and Greenhouse Gas ("GHG") Emissions Reductions Targets, established in the CHP Program Settlement Agreement and further refined in D.15-06-028 – Decision on Combined Heat and Power Procurement Matters ("2015 CHP Decision"). This RFO solicits offers from owners and operators of CHP Facilities and UPFs.

Pursuant to the CHP Program Settlement, SDG&E seeks to acquire a total of 160 MW of CHP name plate Capacity under Power Purchase Agreements ("PPA" or "Agreements") during the Initial Program Period (2011-2015) and 51 MW in the Second Program Period (2016-2020), both of which periods are defined in the CHP Program Settlement. Through this solicitation, the third and final of three RFOs to be held during the Initial Program Period, SDG&E seeks offers to meet a CHP MW Target of up to 50 MW in order to make progress toward its Initial Program Period goal of 160 MW. SDG&E may consider offers larger than 50 MW depending on an offer's overall attractiveness and contributions to meeting the CHP Settlement MW and GHG reduction goals.

This solicitation sets forth the terms and conditions of SDG&E's third CHP RFO. By responding to this RFO, the bidder agrees to be bound by all the terms, conditions, and other provisions of this RFO and any changes or supplements to it that may be issued by SDG&E, prior to the bidder's response.

Table 1 - Program MW Targets Established by the Settlement Agreement

Year	MW Target in RFO
2012	60 MW
2013	50 MW
2015	50 MW
2016-2020	51 MW
Total	**211 MW**

In this RFO, SDG&E will entertain offers for the following resources as defined in the CHP Program Settlement: Existing CHP, New CHP, Repowered CHP, Expanded CHP, and Existing CHP Facilities Converting to UPF. SDG&E will give preference for offers that are low cost, and have either low associated GHG emissions or provide GHG emissions reductions through changes in operations or technology. Any facility that offers operating flexibility will be considered favorably.

Exhibit 6

Table 2 - CHP Product Types

Generating Facility	CHP Baseload Facility ("CHP")	Utility Prescheduled Facility ("UPF")
Facility Vintage	New, Existing, Repowered, Expanded	
Maximum Term	7 Years for Existing and Repowered, 12 Years for New and Expanded meeting Credit requirements (Section 3).	Up to 12 Years
PPA Type	CHP Pro Forma PPA	CHP UPF PPA
Nameplate	Larger than 5 MW	
Delivery Point	Within the CAISO Controlled Transmission Grid	

Winning Respondents shall enter into a PPA for the energy and capacity from eligible resources that can meet the criteria described in the RFO document (provided below). Respondents may modify the applicable PPA submitted as part of their offer package to the extent such modifications add value to the offer. SDG&E discourages any material modification of the Pro Forma PPA.

Solicitation Documents

Respondents are required to submit at least two offer forms (maximum of 10) to this solicitation by submitting the forms listed below. Forms are available on the RFO Website. The failure to provide the listed information may result in the proposal being deemed non-conforming and may disqualify the proposal from further consideration.

- The RFO (pdf)

Exhibit 6

Required Forms and Documents

- Offer Form (xlsx) – Bidders are required to complete the Offer Form as well as the other applicable appendices. Please submit one per project
  Note: Respondents must submit at least two pricing option (one in which the bidder assumes GHG compliance costs) and no more than 10 pricing options per project.
- Project Description Form (doc) – Submit one per project.
- CEC-2843 Application Form – Submit a copy of respondent's application to the CEC requesting qualification for the Combined Heat and Power System. If this application form is not required for your facility, please provide forecasted amounts in the offer form on tab 6.b 'CEC-2843 Information'.
- Electric Interconnection Information – Copy of completed System Impact Study, a Phase I interconnection study, or results from the WDAT Fast Track process if available.
- Credit Application (doc) - Submit one per project.
- Redline forms of the Applicable PPA
  - CHP Pro Forma PPA (doc)
  - CHP UPF PPA (docx)

All offers must be uploaded to the RFO Website no later than 1 PM, Pacific Prevailing Time, on the CLOSING DATE (see RFO Schedule below). The Project Description Form and Model PPA must be in Word or Word-compatible format (not in PDF). The Offer Forms must be in Excel or Excel-compatible format (not in PDF). The copy of completed Interconnection Study and Site Control Documentation must be in PDF format.

RFO Communication

All questions or other communications regarding this RFO must be submitted via email to CHPRFO@semprautilities.com by the DEADLINE TO SUBMIT QUESTIONS as specified in Section 6.0 RFO Schedule. All questions and answers will be posted on this website anonymously. SDG&E will not accept questions or comments in any other form, except during the pre-bid conference. Respondents are encouraged to check this RFO Website periodically for updates, notices, and postings.

- RFO Q&A
  - Deadline to submit questions is August 14th
  - Answers will be posted no later than August 20th

- RFO Q&A #2

Exhibit 6

Participation from Diverse Business Enterprises

SDG&E encourages Diverse Business Enterprises ("DBEs"), "Women-Owned Businesses" or "Minority-Owned Businesses" or "Disabled Veteran Business Enterprises" as defined in G.O. 156[1], to participate in this RFO.

Furthermore, SDG&E encourages developers to utilize DBEs during various stages of project development and construction. As a part of G.O. 156, SDG&E will require developers to identify and verify their DBE contractor/subcontractor spending if any.

Additional information on SDG&E's DBE program and utilizing DBEs can be found at:

http://www.sempra.com/about/supplier-diversity/

and http://www.cpuc.ca.gov/puc/supplierdiversity/

DBEs can request additional information by contacting SDG&E at vendorrelations@semprautilities.com.

Pre-Bid Conference

- Pre-Bid Conference Presentation (Aug 11, 2015)

SDG&E's 2015 CHP Pre-Bid Webinar Conference on August 11, 2015:

Date: August 11, 2015
Time: 9:00am (Pacific Time) to Noon
Location: Webinar
Audience link: https://engage.vevent.com/rt/sempra/index.jsp?seid=115
Participant dial in (toll-free): (866) 835-8845

SDG&E will host one pre-bid conference on August 11th, 2015. Participation in the pre-bid conference is NOT mandatory in order to submit an offer. Please monitor the RFO Website periodically.

Any party interested in attending this pre-bid conference should email the following information to: chprfo@semprautilities.com

The email should include the following information:

- Company name
- Attendees' names, titles and contact information

RFO Announcements

Exhibit 6

Please check this website periodically as SDG&E will post all solicitation announcements, including scheduling changes or RFO amendments if any.

Register to Submit Offers

The PowerAdvocate® Platform is the means by which Respondents will submit their offers related to this RFO to SDG&E for consideration. Respondents can also find solicitation related documents on PowerAdvocate® that are also on the RFO Website.

Respondents will need to register for a user name and password to access PowerAdvocate® in order to upload their offer(s).

The RFO and all subsequent revisions and documents are available for download from the RFO Website http://www.sdge.com/2015-request-offers-seeking-chp-power-purchase-agreements and the 2015 CHP RFO event on PowerAdvocate®. Potential Respondents are responsible for monitoring the RFO Website and PowerAdvocate® for subsequent updates, notices and postings.

All offers must be uploaded to PowerAdvocate® no later than 1:00 p.m., Pacific Prevailing Time, on the CLOSING DATE (see RFO Schedule). If Respondents encounter technical difficulties with the uploading process, they should provide evidence of such difficulties (e.g. a screen shot of the error message) and email the bid to the RFO inbox by 1:00 p.m., Pacific Prevailing Time, on the Closing Date.

If the Respondent encounters technical difficulties with both the uploading process and the RFO inbox, they should provide evidence of such difficulties (e.g. a screen shot of the error message or a sent email notice with a time stamp before 1:00 p.m. on the Closing Date) and submit a USB Thumb Drive or CD of the bid package to SDG&E and the Independent Evaluator at the addresses below by close of business on the day following the Closing Date.

San Diego Gas & Electric Company

Electric and Gas Procurement Department
Attn: 2015 CHP RFO
8315 Century Park Court, CP-21D
San Diego, CA 92123-1548

Independent Evaluator

Alan Taylor
Sedway Consulting
821 15th Street
Boulder, Colorado 80302
(303) 581-4172 [phone]
(303) 581-4127 [fax]
Alan.Taylor@sedwayconsulting.com

Exhibit 6

2015 CHP RFO Schedule

The following schedule and deadlines apply to this RFO. SDG&E reserves the right to revise this schedule at anytime and at SDG&E's sole discretion. Respondents are responsible for accessing the RFO website for updated schedules and possible amendments to the RFO or the solicitation process.

No.	Item	Date
1.	RFO Issued	July 24, 2015
2.	Pre-Bidder's Conference	August 11, 2015
3.	DEADLINE TO SUBMIT QUESTIONS Question submittal cut-off date. Answers to all questions will be posted on the website no later than August 20, 2015	August 14, 2015
4.	CLOSING DATE: Offers must be uploaded to and received by SDG&E's PowerAdvocate ® web platform no later than 1:00 PM (Pacific Prevailing Time).	August 31, 2015
5.	DEADLINE TO OVERNIGHT one USB thumb drive containing all offer documents and files to IE	August 31, 2015 (for receipt by IE no later than September 1, 2015)
6.	SDG&E and IE begin bid evaluation process	September 1, 2015
7.	SHORTLIST NOTIFICATION SDG&E notifies Shortlisted Bidders	October 23, 2015

Exhibit 6

8.	SHORTLISTED BIDDERS ACCEPTANCE/WITHDRAWAL Letter due from Shortlisted Bidders indicating: 1. Withdrawal from SDG&E's solicitation; OR 2. Acceptance of shortlisted standing; withdrawal of participating in any other solicitation and evidence of withdrawal notice to all other solicitors	+10 Days after Shortlist Notification
9.	SDG&E issues appreciation notices to unsuccessful Respondents	+3 week after Shortlisted Bidders accept/withdraw
10.	SDG&E commences with PPA negotiations	up to 24 weeks*
11.	SDG&E submits PPAs to CPUC for approval	+4 weeks after PPAs are negotiated and executed

* Negotiation time will vary depending on facility vintage and proposed contract modifications.

Exhibit 7

Existing CHP incentives, Aggregate customer incentive payments under the Company's proposal, and CHP plant capital expenditures

			Hospital - 800,000 sf with Two 800 kW Recip Engines, eGRID non-baseload baseline	Reciprocating Engine - 500 kW, eGRID non-baseload baseline	Reciprocating Engine - 4.3 MW, eGRID non-baseload baseline	Gas Turbine - 21.7 MW, eGRID non-baseload baseline	Gas Turbine - 45 MW, eGRID non-baseload baseline
Incentives	1	Federal ITC	$ 293,254	$ 96,250	$ 712,132	$ 2,035,804	$ 1,872,000
	2	ETO Grant	$ 500,000	$ 344,323	$ 500,000	$ 500,000	$ 500,000
	3	ODOE EIP	$ 1,026,391	$ 336,875	$ 2,492,462	$ 5,000,000	$ 5,000,000
	4	Total customer incentive over project Life from NW Natural (yearly rate*10 years)	$ 974,620	$ 389,110	$ 4,515,280	$ 18,795,610	$ 39,652,490
		CHP plant capital expenditures	$ 2,932,545	$ 962,500	$ 7,121,321	$ 29,451,304	$ 56,160,000*

*Staff disputes this value as described in Exhibit Staff/400, St. Brown/5-6.

Exhibit 8

A Survey of Corporate Energy Efficiency Strategies

William Prindle, ICF International
Andre de Fontaine, Pew Center on Global Climate Change

ABSTRACT

This paper summarizes the results of a 2009 survey of corporate energy efficiency strategies, conducted by the Pew Center on Global Climate Change. Forty-eight companies, ranging in size from $8 billion to $99 billion in revenues, completed the survey. Key results included an average energy savings target of 20%, or 2.2% on an annualized basis. The three leading motivations for companies' energy efficiency strategies were reducing carbon footprint, responding to rising energy prices, and demonstrating commitment to corporate social responsibility. 60% of respondents had full-time energy managers, 87% built energy performance into the compensation review systems for facility/plant management, and 38% reported energy performance criteria at the senior management level. Almost all respondents used specific financial criteria for energy efficiency investments, simple payback and internal rate of return (IRR) being the most common. Simple payback criteria were mostly three years or less, though two were as high as 5 years. IRR criteria were mostly in the 10-15% range, though one reported a 35% IRR threshold. Respondents also reported a variety of qualitative factors affecting their internal operations, supply chains, and product and services, and summarized the lessons learned and ongoing needs for their energy efficiency strategies.

Background

The survey's principal objective was to gather quantitative data, and identify management practices as well as trends in corporate energy efficiency strategies. It is a key element of a broader Pew Center study on best practices in corporate energy efficiency strategies, whose goal is to highlight the most effective methods used by companies today to reduce their energy consumption and lower their related greenhouse gas emissions. It encompasses management approaches to improving energy efficiency, including issues such as organizational structures, financial mechanisms, and employee compensation systems that corporations put in place to drive superior energy performance. The survey results will be combined with a set of case studies in a larger report to be published in late 2009 or early 2010. The report, and related communications activities, is being funded by a three-year, $1.4 million grant from Toyota.

With concerns growing over climate change and future energy price increases, most, if not all, companies stand to benefit from a renewed focus on energy efficiency. By cataloging and describing best practices in corporate energy efficiency, the Pew Center report is intended to serve as a resource to other companies seeking to develop new, or improve upon existing, energy efficiency programs. The report builds upon existing Pew Center research that provides practical guidance to companies seeking to manage the risks and maximize the opportunities associated with the global transition to a low-carbon economy. Past Pew Center reports and white papers