BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

NW Natural

Reply Testimony of Barbara Summers

UM 1744
Carbon Emission Reduction Program
Combined Heat & Power (CHP)

October 2, 2015

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I. INTRODUCTION

Q. Please state your name.

A. My name is Barbara Summers.

Q. Are you the same Barbara Summers who previously submitted direct testimony in this proceeding?

A. Yes. My title, address, and job responsibilities with Northwest Natural Gas Company ("NW Natural" or the "Company") have not changed.

Q. What is the purpose of your testimony?

A. The purpose of my reply testimony is to respond to Staff and intervenor testimony regarding the Company's Application for Approval of NW Natural's Combined Heat & Power Solicitation Program (the "CHP Program"). Throughout the parties' testimony, there are many points of support for the CHP Program for which a response is not required. As such, my testimony will focus on the parties' concerns regarding the CHP Program incentives and costs, customer benefits, carbon savings, measurement and verification, fuel switching, and NW Natural's incentives. However, in my reply testimony I do not respond to every concern raised in the other parties' testimony; some of these concerns may be addressed by NW Natural in legal briefing.

NW Natural witness Andrew Speer addresses parties' concerns related to the Company's calculation of the rate impact and associated incremental margin from incremental gas sales associated with the CHP Program. (See *NWN/400, Speer*).

Q. Does NW Natural propose any changes to its CHP Program in this reply testimony?

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A. Yes. NW Natural does not propose any fundamental changes to the CHP Program; however, the Company makes some clarifications and minor modifications that address concerns raised by Staff and intervenors. Specifically, NW Natural can agree to: 1) seek reauthorization of the CHP Program if the "base case" amount of carbon savings is achieved; 2) issue a comprehensive report following year three of the CHP Program, to be considered at a public meeting; 3) provide all measurement and verification data to the Commission at substantially the same time NW Natural receives the information from the independent evaluator; 4) a 50/50 sharing of the incremental margin associated with the CHP Program with NW Natural's customers. The sharing arrangement would remain in place up to the effective date of the Company's next general rate case, at which time customers receive 100% of the benefit of the increased throughput; and 5) update the eGRID customer carbon savings for reporting purposes over the life of the program.

II. NW NATURAL'S CHP PROGRAM

CUSTOMER INCENTIVES AND PROGRAM COSTS

Q. Please summarize the CHP Program customer incentive payment.

A. NW Natural will pay participating CHP Program customers $30 per metric ton of carbon dioxide equivalent ($MTCO_2(e)$) reduced, based on measured and verified performance. The essential purpose of the incentive payment is to help overcome barriers that prevent customers from investing in CHP.

Q. Please summarize the concerns raised by other parties regarding the proposed CHP program incentives and costs.

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A. Staff raised concerns that the customer incentive payment may be too high and would provide financial windfalls to CHP Program participants; that the overall program costs are too high; and that there is too much variation in potential cost impacts. (*Staff/100, Klotz/1-5*).

The Citizens' Utility Board of Oregon (CUB) raised concerns that the overall program costs may be too high; concerns about how the CHP Program will impact the Clean Power Plan (CPP); and concerns about incentive stacking. (*CUB/100, McGovern-Jenks/3*).

A. Customer Incentive Payment

Q: Does NW Natural believe that the CHP program will deliver carbon savings at a reasonable cost?

A. Yes. The Company's proposed CHP Program is designed under Senate Bill (SB) 844, a law specifically structured to enable gas utilities to develop programs to facilitate greenhouse gas (GHG) reductions related to the use of natural gas where there are also other customer benefits. NW Natural believes that in order to assess the reasonableness of the costs of the proposed CHP Program, it is appropriate to compare the options open to gas utilities under SB 844 rather than compare these SB 844 projects to all other carbon reduction programs available economy-wide. As explained by Ed Finklea of the Northwest Industrial Gas Users (NWIGU), NWIGU shares NW Natural's point of view: "there is not a bright-line way to measure what is a cost-effective greenhouse gas reduction measure. . . So the cost-effective judgment for carbon reduction under SB 844 must be made by comparing the proposed program to other carbon reduction

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measures. . . . My conclusion [that the program reduces emissions on a cost per ton basis that is in a reasonable range] is based on my review of the programs that have been identified throughout implementation of the SB 844 rules, and during the NW Natural stakeholder processes to date." (*NWIGU/100, Finklea/3*).

And, as described in my initial testimony, and later in this reply testimony, NW Natural does not believe that it can deliver an effective CHP carbon reduction program at a lesser cost than has been proposed in this proceeding.

Q. Does the all-in GHG price of $42/tonne compare favorably with other carbon reduction opportunities under SB 844?

A. Based on NW Natural's evaluation of projects that fit this designation and based on the carbon cost curve developed for the state,[1] the Company has found that CHP reductions are likely the largest source of reductions and the least expensive of those reductions obtainable under SB 844. The other projects evaluated by the Company include using a compressor to reinject methane emissions, a project to accelerate the replacement of oil furnaces in residential homes, and work with Waste Water Treatment plants to access renewable natural gas.

Q. CUB believes the cost of carbon under the program is expensive compared to the cost of carbon in the State of California's cap and trade program. Do you believe this is a fair comparison?

A. No, these two costs are not directly comparable. In 2006, the State of California passed AB 32, the California Global Warming Solutions Act of 2006, which

[1] ODOE GHG_Totals_AP" tab of the "ODOE-RCI-Options-final" spreadsheet.

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among other things, established a cap and trade program for GHG emissions. There are many important differences between the price of carbon reductions under California's cap and trade program and price of reductions under SB 844. The market for carbon under California's AB 32 is driven by supply and demand for reductions. In California, the supply of reductions is driven substantially by various complementary measures (such as the Renewable Portfolio Standard, efficiency requirements, the Low Carbon Fuel Standard, etc.). These ancillary requirements drive the supply of carbon reductions and impact the price paid under AB 32.

There are other important differences as well. NW Natural's CHP Program is based on the cost to reduce carbon emissions in actual natural gas related programs in its service territory. This is different from a market price that may not be related to any actual projects. The purpose of SB 844 is not to simply buy carbon allowances in the California market, but to incentivize real reductions in Oregon emissions.

Q. To reduce overall program costs, Staff recommends that NW Natural conduct a reverse auction process, and asserts that this could result in an overall lower incentive. (*Staff/100, Klotz/3; Staff/200, St. Brown/12-17).* Do you support this recommendation?

A. No. NW Natural appreciates Staff's effort to formulate a model that could potentially, in theory, reduce the costs of the CHP Program; however a reverse auction is inappropriate because it will likely have the practical effect of reducing participation. NW Natural considered the reverse auction option to determine if it would lead to additional CHP or carbon reductions at lower costs. (*NWN/101,*

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Summers/10-11). NW Natural concluded that this approach would not result in higher CHP or carbon savings or lower costs because: 1) CHP installations are ill-suited for an auction process; 2) the timing of an auction will likely reduce participants; 3) the low historic level of CHP installation cautions against raising additional barriers like an auction process; and 4) it could result in higher costs.

Developing CHP projects is a long and complicated process, and customers need a high level of certainty in the incentive to assess its risks, costs, and benefits. A fixed incentive allows customers to definitively evaluate project economics in what is already a long and difficult process. In contrast, a reverse auction approach would leave the customer with uncertainty, and will increase the chances that many eligible customers will not invest the time and effort to determine the feasibility of the CHP option.

The timing aspects of a reverse auction process could also be problematic. NW Natural would have to ensure that all proposals were received at the same time to rank and prioritize them, which would likely result in an annual cycle. An annual auction may not match individual customers' budgeting and planning cycles, could result in unnecessary delays, and would likely reduce the number of CHP Program participants.

A reverse auction would add an additional barrier to the adoption of CHP, which already has a poor historic development record. As discussed later in this reply testimony, the current incentive payment may be insufficient, and the CHP Program should be designed to remove rather than add new barriers.

Finally, there may be limited demand during any bidding process period, which could increase costs. For example, if bidders were to expect that there

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would be very little competition during a bidding process, they would have little reason to narrow their proposal to only the necessary payback, and may instead seek to maximize any payments.

B. Payback Period.

Q. Please summarize the concerns Staff raised regarding the payback period for participants in the CHP Program.

A. Staff asserts that the $30 per metric tonne incentive is overly generous and will result in windfall payments to CHP Program participants because, under a simple payback, the participant will be paid back in 4-7 years, but the participant will continue to receive the incentive payment through year 10. Staff recommends ramping down the incentive payment after the payback period has been reached to a "more market competitive payment." (*Staff/100, Klotz/17-18).*

Q. Can you explain what a Simple Payback is?

A. Yes. Simple Payback is "simply" the number of years it takes to recover a capital investment. Washington State University calculates simple payback on the number of years of Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA) it takes to recover Net Capital Investment. EBITDA is simply net income with interest, taxes, depreciation, and amortization added back. Simple Payback does not consider interest expense, if the investment was to be financed, or taxes on the avoided energy purchase or incentive revenue.

In addition, Simple Payback does not speak to the benefit required for a company to consider taking the risk of electing to generate its own electricity instead of continuing to purchase its electricity from the grid. It does not speak to the benefit required for a company to consider investing in CHP instead of

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investing in its core business. Instead, it simply calculates how long it will take to get their money back *assuming everything goes as planned*.

The economics of CHP, even under this program, are largely driven by forecast avoided electricity purchases and avoided natural gas purchases and the cost of natural gas purchases to fuel the CHP. The SB 844 revenue was designed to cover O&M costs, accelerate payback, and provide a return to NW Natural that is adequate to incent CHP to be installed and to continue to be operated.

Q. Simple Payback represents the time for a company to only recover its initial investment. Can you elaborate on why a company is unlikely to invest in CHP just to obtain its money back?

A. Yes. "Simple Payback" is only one look at a CHP investment decision. Simple Payback calculates the time it takes to pay back net invested capital from the total of "avoided electricity purchases", "avoided natural gas purchases" and the "$MTCO_2$(e)" reduction incentive (SB 844)".

Net invested capital refers to the total investment less the upfront credits from the Oregon Department of Energy (ODOE) and Energy Trust of Oregon (Energy Trust), if any. For example:

If you spend $20,000,000 and you get $5,000,000 credit from ODOE and Energy Trust, then you have a net spend of $15,000,000. If your first year EBITDA is $5,000,000, then you would have a 3 year payback. If there was no ODOE and Energy Trust credit, then the simple payback would be 4 years.

The simplicity of the "Simple Payback" calculation makes it an attractive first test, and is a convenient metric to use, but leaves out:

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1. The cost of capital to make that investment, whether that is interest on debt or Return on Equity;

2. Taxes, i.e., avoided energy purchases and any SB 844 revenue would both increase earnings and be taxable;

3. The impact of SB 844 incentive revenue on O&M after the payback period. The WSU RELCOST model calculates “Simple Payback” by dividing net capital by first full year EBITDA;

4. The uncertainty of future cash flows, i.e., the assumptions around electricity prices, offset electrical purchases, natural gas prices, offset natural gas purchases, purchased fuel costs, operating hours, etc.

Ongoing O&M expenses are also a critical factor in the continued operation of CHP. NW Natural’s program was specifically designed to provide ongoing support for O&M expenses to compliment the upfront incentives provided by ODOE and Energy Trust. Stacking these incentives are complimentary both in their design and in their purpose. ODOE and Energy Trust monies are designed to incent energy efficiency investments. The SB 844 incentives are designed to incent reduced carbon emissions.

Q. Is the Simple Payback period required for companies to make similar investments generally longer than three years?

A. No. There is a plethora of data suggesting that the capital investment criterion for energy efficiency investments by commercial and industrial customers is less than 3 years, including:

1. Best Business Practices in Energy Efficiency, prepared by William R. Prindle for Pew Center on Global Climate Change, April 2010, reported that a 3 year payback was about as far as most companies were willing to go with the average of survey respondents being 2.8 years with an 18.5 percent IRR.

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2. Energy Trust, Industrial Market Research Results, March 2012, prepared by Forrest Marketing reported that overwhelmingly research indicated that bottom line concerns are the most important considerations in making decisions about whether to implement energy efficiency projects with Return on Investment (ROI) being the most significant consideration with many wanting to see a payback within 2 years.

3. Energy Trust Commercial Sector Focus Group Research, December 2011, prepared by Davis, Hibbitts, Midghall, Inc., reported that most organizations wanted to see a payback of less than 2 years.

4. Primen's 2003 Distributed Energy Market Survey shows that with a 4 year simple payback, expected customer adoption rate would be about 30% at 5 years it would be about 15% and at 6 to 10 years it would drop to 5%.

C. Forecasting Program Costs

Q. Staff states that it is currently unable to support NW Natural's CHP Program because of the varying, or uncertain cost impacts to customers. (*Staff/100, Klotz/3-4*). What is your response?

A. The CHP Program costs are largely variable based on the number of participants and the actual measured and verified savings. Most of the costs of the CHP Program stem from its success at reducing carbon emissions based on the customer and Company incentive that together account for $40 per MTC02(e) out of the total projected cost of $42.59. NW Natural does not believe it possible to fundamentally restructure the program to lower the overall cost to ratepayers while still expecting program participation.

Q. Does NW Natural have any program modifications to allay Staff's concerns related to the uncertain total rate impacts of the program?

A. Yes. NW Natural is willing to make two changes.

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First, NW Natural will seek re-authorization to continue the program if the base case customer participation is reached. The base case assumes a target of 240,000 MTCO2(e) per year, and assumes 120 MWs of installed CHP capacity. NWN/101, Summers/52-53. The expected cost of the base case is 1.511% of NW Natural's total revenues. NWN/101, Summers/54. Once there is at least 240,000 MTCO2(e) in savings in one year, then NW Natural will return to the Commission and seek approval to continue the program for new participants (existing customers at that time would continue to receive the program benefits, of course). This should address Staff's concern that the Commission may approve a program with a wide variation of cost impacts because the Commission will have an opportunity to review the program once NW Natural reaches its target emission reduction of 240,000 MTCO2(e).

Second, NW Natural proposes to make a full and comprehensive CHP Program report after three years, regardless of the level of participation. NW Natural proposes that this report be considered at a Commission public meeting. The report would be for informational purposes, not to address whether the CHP Program should be reauthorized.

CUSTOMER BENEFITS

Q. Please summarize the customer benefits resulting from the program.

A. The primary benefit NW Natural identified was the incremental gas throughput expected from the installation of CHP in NW Natural's service territory, which will lower overall system costs to the Company's customers. NW Natural believes that it took a conservative approach to identifying benefits, and focused on only concrete benefits that would flow to the Company's customers.

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Q. What concerns have been raised about the customer benefits?

A. Staff is concerned that NW Natural has not identified sufficient benefits to justify the CHP Program's costs. Staff has also identified additional benefits that the Company did not identify in its original application. (*Staff/100, Klotz/8-11*). Even with these additional benefits, Staff does not believe that the benefits justify the CHP Program's costs. (*Staff/100, Klotz/8*).

CUB agrees that there are customer benefits, but raises concerns about whether: 1) the benefits have been adequately demonstrated; 2) the Company has too narrowly defined customer benefits and has not considered the impact on electric customers; and 3) there is no specific mechanism to pass the benefits back to customers. (*CUB/100, McGovern-Jenks/4-10, 17-20*).

Q. Do you agree that NW Natural needs to demonstrate that the CHP Program's benefits outweigh the costs?

A. No. I do not believe any party is advocating that customer benefits must exceed costs; instead, some parties are arguing that additional benefits or lower costs should be established before they can recommend approval of the program. It is unclear what level of benefits or costs would be sufficient to allow these parties to support the CHP Program.

It is my understanding that SB 844 requires that customers obtain some benefits from the CHP Program, but that the benefits of a voluntary carbon reduction program do not need to exceed the costs. In other words, NW Natural's understanding is that it has already been established (through the legislation and the Commission's rulemaking) that a reasonably priced voluntary program that lowers carbon emissions effectively is inherently beneficial, and that

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customers can pay for its costs, as long as they do not increase costs by more than 4% of the Company's revenue requirement. A key purpose of requiring that there be at least some benefits is to determine which customers should pay for the costs of the program. Requiring customer benefits to exceed costs would have the practical impact of preventing NW Natural from offering any SB 844 programs, which would defeat the entire purpose of the law.

Q. Does NW Natural agree with Staff that the CHP Program provides additional, less quantifiable benefits that broadly benefit the State?

A. Yes. NW Natural agrees with Staff that there are additional benefits from CHP installations that are difficult to quantify. For example, individual CHP customers will benefit by obtaining more reliable and fixed power costs, and by gaining the benefits of effective use of the heat produced by the plant. NW Natural customers may benefit indirectly by an improved economy resulting from additional CHP development, and NW Natural customers will also benefit from lower carbon emissions. Many of these benefits are intangible and will result from overall economic improvement due to CHP installations, and cannot be specifically measured.

Again, NW Natural does agree that there are other benefits associated with CHP installation that the Company has not sought to quantify in this docket. We are aware of numerous sources of information that discuss these benefits.[2]

[2] See, for example: Center for Clean Air Policy, Combined Heat and Power for Industrial Revitalization ("While improving efficiency by reducing waste, CHP offers a number of benefits, including cost savings, improved manufacturing competitiveness, job creation and maintenance, improvements to the robustness and security of the electrical grid, and reduction in environmental impacts like greenhouse gas emissions."); International Energy Agency, Combined Heat and Power: Evaluating the Benefits of … ("CHP systems are attractive because they can deliver a variety of energy, environmental and economic benefits. These benefits stem from the fact that these applications produce energy where it is needed, avoid wasted heat, and reduce T&D network and other energy losses. Other benefits cited by policy makers and industry include:

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Q. CUB is concerned that NW Natural has not made a showing of the Project benefits received and the allocation of the benefits for each type of ratepayer. (*CUB/100, McGovern-Jenks/5-6*). What is your response?

A. CUB correctly notes that the Company cannot know with certainty what the exact customer benefits are as they relate to lower average system costs, primarily because this is a solicitation based program, and the benefit that gets passed back to customers is dependent upon the incremental therms generated from CHP usage.

Q. What does the Company propose to do to address the concern around customer benefit uncertainty?

- Cost savings for the energy consumer;
- Lower CO2 emissions;
- Reduced reliance on imported fossil fuels;
- Reduced investment in energy system infrastructure;
- Enhanced electricity network stability through reduction in congestion and 'peak-shaving'; and
- Beneficial use of local and surplus energy resources (particularly through the use of waste, biomass, and geothermal resources in district heating/cooling systems).");

Office of Energy Efficiency and Renewable Energy, http://www.energy.gov/eere/amo/benefits-combined-heat-and-power ("Combined heat and power (CHP) positively impacts the health of local economies and supports national policy goals in a number of ways. Specifically, CHP can:

- Enhance our energy security by reducing our national energy requirements and help businesses weather energy price volatility and supply disruptions
- Advance our climate change and environmental goals by reducing emissions of CO_2 and other pollutants
- Improve business competitiveness by increasing energy efficiency and managing costs
- Increase resiliency of our energy infrastructure by limiting congestion and offsetting transmission losses
- Diversify energy supply by enabling further integration of domestically produced and renewable fuels
- Improve energy efficiency by capturing heat that is normally wasted);

See also Oak Ridge National Laboratory, http://info.ornl.gov/sites/publications/files/Pub13655.pdf; EESI http://www.eesi.org/papers/view/fact-sheet-combined-heat-and-power#1; NRDC, http://www.nrdc.org/energy/files/combined-heat-power-ip.pdf; ACEEE http://aceee.org/files/proceedings/2013/data/papers/2_182.pdf.

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A. NW Natural proposes to seek approval of the "base case," which will cap emissions reductions at 240,000 MTCO2(e) per year. At this level, one might expect approximately $700,000 in system benefits to be passed back to customers on an equal percent margin basis. It should be noted that the $700,000 customer benefit is only an estimate. Because CHP systems have different efficiencies and therm usage, which can only be known when the system is installed and operational, the Company cannot be absolutely certain of the level of customer benefits if the base case is reached..

Q. Please respond to CUB's concern that the customers of NW Natural are also the customers of the electric utility and could be impacted as electric customers, in ways such as potential increased electric customer distribution and load factor changes. (*CUB/100, McGovern-Jenks/5, 9-10)*.

A. NW Natural recognizes that CHP adoption impacts electric utilities in multiple ways that result in overall benefits to electric customers. Some of these benefits include reduced transmission and distribution costs, lower cost electric generation, better system resiliency, avoided lines losses, improved power quality and provision of ancillary services, fast and flexible asset development, improved environmental compliance, fuel flexibility, and increase customer retention. NW Natural is not in a position to calculate these benefits, but we believe that the benefits should more than offset any potential reduction in electric loads.

The electric customer benefits listed above are more fully described in the American Council for an Energy-Efficient Economy (ACEEE) White Paper entitled "How Electric Utilities Can Find Value in CHP" authored by Anna

Chittum, ACEEE, July 2013, pages 2-9.[3] The entire White Paper is attached as Exhibit NWN/301.

Electric customers also benefit from the energy efficiency impacts of CHP. NW Natural assumes that the benefits from energy efficiency that accrue to the electric system were the basis of the existing Energy Trust incentive for CHP that has been in place since 2002. In other words, NW Natural assumes that Energy Trust would not have a CHP incentive program unless it resulted in overall benefits to electric customers.

Energy Trust has explained that its Fossil Fuel CHP Policy recognizes that CHP "projects may have certain economic and environmental advantages, including potential energy efficiencies, which make them of interest to the Energy Trust."[4] Energy Trust states that it has only adopted policies to promote CHP when it increases total system efficiency, is more cost-effective than the alternative resource, and would be used on-site.

Q. CUB is also concerned that customers will not receive the identified benefits until NW Natural's next general rate case. (*CUB/100, McGovern-Jenks/6-7)*. Does NW Natural have a new proposal to address CUB's concerns?

A. Yes. NW Natural proposes to separately track in a deferred account the incremental margin related to the increased throughput from CHP (excluding capital investment, if any) and share the benefit on a 50/50 basis between

[3] Additional benefits are identified in the source documents cited in footnote 2 above.

[4] https://www.energytrust.org/library/policies/4.11.000-P.pdf

customers and the Company until the next general rate case. Following the next general rate case, customers will receive 100% of the benefits associated with the increased throughput from the CHP installations. To accomplish this, NW Natural will require the independent third party verifier to include the tracking of incremental therms in its monitoring and verification reporting.

Q. Why does NW Natural propose a 50/50 sharing mechanism?

For some customer installations, NW Natural will be required to make capital investments, which would ordinarily be recouped in part between rate cases from the margin associated with the incremental gas usage. NW Natural should not be expected to absorb costs that normally would be covered by incremental margin. Further, while NW Natural believes that it may be possible to establish a method to separately track the increased margin associated with CHP, there are concerns about the accuracy of such information. For example, there could be other end use customer changes that could result in higher or lower gas usage that are not related to the CHP installation. Similarly, the baseline usage for tracking customer benefits may not accurately estimate what the future usage would have been without the CHP installation. For the above reasons, the Company believes that a 50/50 margin sharing is a fair and reasonable proposal.

The margin sharing associated with CHP investments would end upon the effective date of the Company's next general rate case as 100% of the benefits related to any specific CHP installations within the base year will flow to customers through the resetting of rates. New CHP installations that occur after the effective date of a general rate case would be subject to the tracking

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mechanism and shared on a 50/50 basis with customers until the subsequent general rate case.

MTCO2(e) SAVINGS OF CHP

Q. Please summarize NW Natural's plan to account for the $MTCO_2$(e) savings of CHP.

A. $MTCO_2$(e) savings are accounted for by comparing the net incremental natural gas usage at the site with the overall avoided emissions reductions. The $MTCO_2$(e) emissions reductions are based on the: 1) avoided emissions from reduced central station utility electric generation; 2) avoided central station electric transmission and distribution line loss; and 3) efficiency of the rated thermal production equipment that the heat recovery will displace.

Q. Please summarize the concerns raised by parties regarding NW Natural's plan to account for the $MTCO_2$(e) savings of CHP.

A. Portland General Electric (PGE) alleges that NW Natural's method of calculating the avoided greenhouse gas emissions is flawed. (*PGE/100, Barra/1, 4-5*).

While PGE does not propose a different methodology, PGE recommends that: 1) PGE's data be used instead of eGRID; and 2) incentive payments should not be "locked in" for ten years.

PacifiCorp also objects to the incentive payments being "locked in" for ten years. (*PAC/100, Weincke/6*).

Northwest Energy Coalition (NWEC) raised the issue of accounting for methane and upstream emissions. (*NWEC/100, Heutte/6*).

CUB's testimony states that they believe "that NW Natural's approach is reasonable." (*CUB/100, McGovern-Jenks/12).*

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Staff only raises a different concern about emissions reduction over the 20-year measure life. (*Staff/100, Klotz/2, 5, 10-11*).

A. <u>The Methodology to Calculate Emissions Reductions</u>

Q. Is there only one way to calculate the carbon benefits from CHP?

A: No, there are a variety of considerations that affect the carbon intensity factor and a number of stakeholders, including the electric utilities, raise this issue. This is a matter that NW Natural has worked hard on with stakeholders, experts in the region, as well as with Environmental Protection Agency (EPA), which is the agency that is developing national regulations for GHG reductions.

Q. Why has NW Natural proposed the use of the non-baseload EPA eGrid number?

A. The primary reason to rely on eGRID to determine the GHG benefits associated with CHP is that EPA recommends this model for this very purpose.[5] EPA is clear that using average emissions is not an appropriate method for understanding the displaced resources on the entire regional system. EPA is also clear that the eGRID subregion, rather than the state or electric utility, is the appropriate boundary for such an analysis. The EPA states:

> Using the state aggregation level may not be appropriate, because emissions factors and heat rates for this level often omit generation that is imported into the state or generation that is exported to other states, and therefore may less accurately reflect the fuel use and emissions impacts of generation displaced by a specific CHP system than the eGRID subregion aggregation level. The EGC level likely omits an even greater amount of imports and exports than the

[5] EPA's CHP partnership recommendations are included in a document entitled "<u>Fuel and Carbon Dioxide Emissions Savings Calculation Methodology for Combined Heat and Power Systems</u>" from February 2015.

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> state level, and, therefore, also may not be appropriate for the same reasons as for the state level.

Along with EPA, there was support for this approach – albeit not from the electric utilities – among our stakeholders.

Q: What's wrong with using the data proposed by PGE?

A: First, PGE has not put forth in testimony any data or methodology for the use of the data that would suggest that there is a superior methodology than that of the EPA's recommended eGRID model. PGE has merely stated that it "tracks greenhouse gas emissions associated with the power [PGE] generate[s] and purchase[s] on behalf of [PGE's] customer and reports it annually [to Oregon Department of Environmental Quality (Oregon DEQ)]." (*PGE/100, Barra/4*). Second, with respect to the annual reports to Oregon DEQ, PGE provides data from their generation resources, which is only useful to determine average system carbon intensity. This information is not designed to help decision makers understand which resources are most likely not to run when a new CHP resource is added. In comparison, the EPA non-baseload eGRID model is designed to address this very issue and drops out all resources that operate at a capacity factor of 80% or more, assuming these will operate nearly all the time and are unlikely to be impacted by a new CHP plant. For example, PGE's Boardman generating station, which operates at a 78% capacity factor based on eGRID data,[6] hardly impacts the non-baseload eGrid number, and, similarly, its closure will cause little to no movement in the eGRID metric.

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[6] See: http://www.epa.gov/cleanenergy/energy-resources/egrid/

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Q. In PGE's testimony, PGE states that the EPA guidance is to use eGRID "*in the absence of consistent and complete utility import and export data*," and that PGE's data should be used because it exists (*PGE/100, Barra/4*; *emphasis in original*). Do you think this is a fair representation of EPA's guidance?

A. No, I do not. In the EPA guidance, EPA thoroughly explains the usefulness of using the eGRID subregion, how state and utility level data is insufficient, and how US average and aggregate levels do not reflect regional variation. The quote used by PGE appears to be shortened and out of context. The full quote states: "In summary, in the absence of nationally consistent and complete utility-specific import and export data, the eGRID subregion level heating rates and emissions factors most accurately characterize the generation that is displaced by CHP systems."[7] When the quote is read in context, it is clear that EPA does not recommend using a single electric utility's data to determine carbon reductions from CHP.

B. "Locking in" emissions reductions numbers

Q. Pacificorp and PGE assert that NW Natural should not lock in the eGrid number for the life of a CHP project because it will, purportedly, overstate emissions reductions. (*PAC/100, Wienke/6-7*); (*PGE/100, Barra/4*). Can you explain why NW Natural proposes to "lock-in" the eGrid number for each project?

[7] Fuel and Carbon Dioxide Emissions Savings Calculation Methodology for Combined Heat and Power Systems, U.S. EPA, Combined Heat and Power Partnership, February 2015, p. 25.

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A. Yes. NW Natural's Application proposed that a CHP customer's emissions reduction numbers will not change once they are approved. However, new participating CHP customers will have their GHG reductions based on the EPA's most recent eGrid carbon emissions value. NW Natural believes that the eGrid number must remain constant throughout the life of the project because it is tied to the level of incentive that the participant can expect. Therefore, a change to the eGrid number would inject uncertainty into a participant's ability to forecast project economics. Because of the significant capital investment involved with CHP, the customer should be able to count on a specific payment for the entire life of the program.

Q: Is NW Natural willing to update the customer's emissions reductions numbers based on the latest eGrid number over time, so as not to overstate emissions reductions?

A: Yes. NW Natural could agree to update estimated emissions reductions to reflect actual emissions reductions over the life of the program, provided the customer incentive payment does not change from what was anticipated at the time the customer entered into a contract to participate in the CHP Program. NW Natural believes this approach will meet the goals of providing customers with certainty regarding incentive payments while accurately estimating carbon savings based on the most current information.

Q: How would this work?

A: It is important to make it clear that the customer incentive would not change. The customer would receive an incentive payment based on the estimated carbon

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reductions made at the time of their proposed CHP installation. This is exactly the same as NW Natural's Application.

Over the life of the program, however, more current and accurate information regarding the actual carbon emissions savings could become available as eGRID is updated. When that new eGRID information becomes available, then the amount of $MTCO_2$(e) savings reported for that customer will be updated.

For example, assume a single 50 MW CHP installation that at the time of their application has a forecast of 150,000 $MTCO_2$(e) savings, based on certain operating assumptions. Also, assume that five years after the CHP installation eGRID is updated and forecasts 140,000 $MTCO_2$(e) savings, assuming the same operations. This specific customer would continue to be paid its incentive payment based on the original 150,000 $MTCO_2$(e) savings; however, the actual savings for reporting purposes will be 140,000 $MTCO_2$(e). This means that the reported price of carbon in dollars-per-tonne would go up, but that the customer's economics would not be affected.

C. Methane and Upstream Emissions

Q. Are upstream methane emissions important in determining the GHG benefits associated with voluntary projects?

A. Yes. NWEC suggests in its testimony that the issue of methane emissions "be an ongoing focus in this docket and for any other voluntary emissions reduction program application NW Natural bring forward." (*NWEC/100, Heutte/6*). The Company fully agrees that upstream emissions need to be closely considered when examining voluntary reduction projects under SB 844. The Company

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looked closely at this issue, but found that upstream analysis of emissions – when comparing CHP with grid electricity – is a highly complex and unsettled process. This analysis requires us to look at the upstream emissions from the natural gas system – both as it supplies natural gas to the CHP unit and to electric generating units on the grid. The analysis also demands a full accounting of upstream GHG emissions from various generating sources (coal, and even new estimates for hydro). There is not a well understood and broadly accepted methodology for determining these upstream emissions from the electric sector.

Q. Does the Company have any idea of how upstream estimates would impact the project analysis?

A: Yes. At the urging of our stakeholders in the stakeholder process, we asked the modelers from Washington State University to help us find their best estimates for upstream emissions. The modeling runs that included upstream impacts resulted in greater carbon benefits from converting to CHP than without the upstream impacts included. (*NWN/101, Summers/30*).

Q. Why has the Company not included all upstream emissions in the CHP analysis?

A. Because the upstream methodology for electric grid power is unsettled, and because the screening analysis suggested using an upstream look would actually increase the GHG benefits, the Company took the more conservative position of not including upstream emissions at this time.

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D. <u>Measure Life</u>

Q. What concerns have been raised about emissions reduction over the 20-year measure life?

A. Staff states that NW Natural is only accounting for emission reductions from CHP units for the 10-year program life when the assumed CHP project measure life is 20 years. (*Staff/100, Klotz/10-11*). Staff states that NW Natural should "leverage the 20-year measure life to lower the overall cost of the proposed CHP program." (*Staff/100, Klotz/10-11*). Additionally, Staff asserts that ratepayers "may be losing out on valuable emission reduction and their associated benefits which occur in years 11 through 20. (*Staff/100, Klotz/10-11*).

Q. How do you respond to these concerns?

A. We do not believe that our ratepayers will be losing out on the benefits of CHP in years 11-20 of a CHP unit's life. NW Natural attempted to take a conservative approach by limiting payments to program participants for 10 years. If the CHP unit continues to operate after year 10, our ratepayers will continue to benefit from carbon emission reductions into the future without incurring the costs of the CHP Program.

Further, measure life is not set, and is driven as much by economics as by physical condition. In fact, WSU assumes a 15 year measure life while NW Natural assumes a 20 year measure life. While noteworthy, the difference in assumed measure life does not affect payback and, therefore should not affect program design.

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MEASUREMENT AND VERIFICATION PLAN

Q. Please summarize NW Natural's Measurement and Verification plan (M&V Plan).

A. The Company has proposed an M&V Plan that monitors and verifies emissions reductions and payment of incentives. NW Natural has proposed that Energy 350 will conduct the M&V, including approval of customer specific plans and site inspections. The Application proposed that results would be provided to NW Natural on a quarterly basis, and the ETO and the Commission on an annual basis. The M&V Plan was evaluated by the Climate Action Reserve (CAR), which concluded that the proposed plan is commensurate with the best practices of M&V for energy efficiency programs. CAR noted that specific carbon offset programs frequently use independent third party auditors to perform an audit designed to establish a marketable offset every time credits are paid out of a project. CAR notes that this type of audit would add significant costs to the proposed program.

Q. Please summarize the concerns raised by the parties with the M&V Plan.

A. Staff raised four concerns: 1) how information will be reported to the Commission; 2) questions regarding the baseline methodology for current steam usage; 3) NW Natural's relationship with the independent third party verifier, Energy 350; and 4) the cost for M&V. (*Staff/100, Klotz/2-3, 14-17*).

A. M&V Plan

Q. Staff requested that NW Natural formally propose reporting requirements as part of the Application. (*Staff/100, Klotz/16*). Please provide more

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specific details regarding the information that will be reported to the Commission and when it will be provided.

A. For each project, NW Natural proposes to provide the following documentation to the Commission:

1. The Technical Assessment QA review memo provided by Energy 350, along with a copy of the Technical Assessment. The memo will provide an overview of the CHP system, estimated performance, M&V Plan, and a recommendation as to whether or not NW Natural should approve the proposed project. This memo will be provided to the Commission at the same time it is provided to NW Natural.

2. Post-installation inspection report written by Energy 350. This report will document the system as installed, the M&V equipment, configuration and data collection and reporting plan as well as flag any concerns with the installation, commissioning, or M&V equipment, data collection and reporting procedures. This report will be provided to the Commission at the same time it is provided to NW Natural.

3. M&V QA Review memo written by Energy 350, along with the data and analysis. This memo will outline the M&V reported and highlight any data issues and the handling of them. Furthermore, it will transparently describe the methodology used to quantify performance. Lastly, it will summarize a recommended approved CO_2 reduction and payment amount.

4. In addition to project level reporting, NW Natural will provide an annual program activity report to the Commission that provides an overview of number of participants, CHP size and technology, incentive dollars spent, and program administration dollars spent.

Q. Are you proposing any changes to the Company's reporting in this reply testimony?

A. Yes. NW Natural originally proposed that certain information be provided to the Commission on an annual basis. Staff raised the concern that certain information would not be provided to the Commission quickly enough. (*Staff/100, Klotz/2-3, 14-17*). Based on this concern, NW Natural can agree to provide all

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M&V information to the Commission promptly after the independent third party provides the information to NW Natural. If this reporting system is too frequent or overly burdensome on Staff, NW Natural will work with Staff to develop a system that meets Staff's needs and will update the Commission with an information filing.

B. <u>Existing Steam Usage Baseline</u>

Q. Staff requested that NW Natural create a baseline methodology for systems that are already producing steam. (*Staff/100, Klotz/2, 14-15).* Are there additional requirements for systems already producing steam?

A. Yes. There is a custom program targeting complex commercial and industrial facilities for systems that are already producing steam. As such, custom analysis must be done on a site specific basis, making it difficult to define a specific methodology that will apply to each unique circumstance. Therefore, we require that each participant conduct a Technical Assessment.

One requirement of the Technical Assessment is for the participant to propose a site-specific M&V plan. The Technical Assessments (including M&V plans) will be reviewed by Energy 350 for technical merit. Staff's concern seems to be with respect to a customer intending to use an existing steam boiler at increased capacity to power a steam turbine generator. In that case, we would require boiler stack testing to verify boiler efficiency and dedicated enthalpy meters at the inlet and outlet of the steam turbine to quantify performance specific to the CHP. Additionally, we would require enthalpy metering of any thermal energy rejected, input gas, output electric, and parasitic loads for a complete energy balance. However, this concern is specific to a given

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technology and set of circumstances. Since there are nearly limitless potential scenarios, we believe we must treat this as a custom program and evaluate each project on a custom basis.

Q. Are there other aspects that make the M&V Plan particularly rigorous?

A. Yes. For example, technical assessment and approval is required under the program. (*NWN/100, Summers/35*). Requirements for the application include three years of electricity and gas consumption records for existing facilities. (*NWN/100, Summers/36*). Baseline methodology, in the absence of empirical data, must be derived from customer-provided information, manufacturer's nameplate data, or other information to show that waste heat recovery will be used and useful. Since incentive payments are based on empirical data (*see NWN/101, Summers/38*), applicants and their representatives will strive to use best engineering judgment to be as accurate as possible. Customers may have access to current steam production and may seek to install more measurement devices to improve the accuracy of their operational and financial models. Things such as future loads (thermal and electrical), production increases and decreases due to competition and other market forces must still be derived based on best engineering judgment.

C. Independent Third Party Verifier

Q. What concerns did Staff raise regarding Energy 350?

A. Staff questioned whether Energy 350 was sufficiently independent of NW Natural. (*Staff/100, Klotz/15-16*). Staff did not raise any specific concerns with Energy 350, but appears to want to ensure that Energy 350 is free to identify any and all concerns with the CHP Program.

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Q. Is Energy 350 an independent third party verifier?

A. Yes. One of the objectives of the NW Natural program design was to standardize and simplify CHP applications between Energy Trust, ODOE, and NW Natural programs. Energy 350 was retained as an independent contractor for project certification and measurement and verification as it is the contractor for Energy Trust's CHP program. It is standard industry practice for performance based utility programs to contract for Technical Review, M&V, Quality Assurance, etc. It is also standard practice for Program Administrators to bear the cost of this role. This is typically done through energy engineering firms such as Energy 350 that are experts in energy analysis and M&V. Energy 350 has a strong track record of providing Ex-Ante M&V and QA for program administrators that have held up extremely well to Ex-Post evaluation. Energy 350 has no financial stake in the performance of the CHP systems, and the contract mechanism will be time and materials (T&M).

Q. Is NW Natural willing to make changes to the independent third party verifier?

A. Yes. Staff has not proposed any specific changes; however, NW Natural is willing to consider any specific recommendations that Staff may have.

D. M&V Costs

Q. Are the costs of ongoing M&V reasonable?

A. Yes. Staff raised a concern about the estimated $25,000 per customer per year in M&V costs. (*Staff/100, Klotz/16*). While NW Natural budgeted $25,000 per customer per year, Energy 350 will bill on a T&M basis for discrete tasks to be

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specifically identified in a contract. Their rates and cost effectiveness have proven to NW Natural to be efficient to date. Specific tasks include:

1. Application review of Technical Assessments, including review of:
   a. Overview of CHP system
   b. Baseline analysis, including electric and thermal load profiles
   c. Energy analysis, FCP calculation, and associated CO_2 reduction analysis
   d. Commissioning plan
   e. Measurement & Verification plan

2. Provide NW Natural with a memo outlining the proposed CHP system, estimated performance and our recommendation as to whether or not NW Natural should approve the proposed project. Examples of reasons to not approve a project include anticipated performance worse than the required FCP of 6,120 Btu/kWh, use of unproven or unreliable technology, and wasteful use of heat such as heating storage areas currently not heated.

3. Post installation site inspection. Should this inspection reveal deficiencies, comments and punch lists will be provided to applicants. The post installation inspection will include verification of:
   a. Installed CHP system
   b. Operation and commissioning in a manner that will maximize performance
   c. M&V equipment specifications, monitoring points, installation and data collection protocol consistent with proposed M&V plan.

4. Provide NW Natural with a post installation inspection report detailing our findings and recommended approval, or issues that need to be addressed prior to approval.

5. QA review of reported M&V data and associated analysis on a quarterly basis.

6. Provide NW Natural with a quarterly M&V QA memo outlining the data and analysis and M&V results in terms of energy performance and CO_2 reductions. Lastly, the memo will quantify a recommended quarterly M&V payment.

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FUEL SWITCHING

Q. Were any concerns raised regarding fuel switching?

A. Yes. Both PGE and PacifiCorp assert that NW Natural's CHP Program promotes fuel switching and, therefore, should not be approved by the Commission. (*PGE/100, Barra/1-3*); (*PAC/100, Weincke/2-4*).

Q. Does NW Natural's CHP Program promote fuel switching?

A. No, the CHP Program does not result in fuel switching because PGE and PacifiCorp currently use natural gas powered power plants to provide electricity to their customers in NW Natural's service territory. The generation portfolios of both PGE and PacfiCorp include natural gas fueled generation. According to data reported to the ODOE, 23.6% of PGE's and 14.3% of PacifiCorp's electricity comes from natural gas-fueled generation, with plans to further expand natural gas fueled generation in the future. CHP displaces central station electric generation with distributed generation that is sited to more efficiently use the waste heat produced during electricity generation. CHP is electricity generation that is not owned by the electric utility, but it is nevertheless still electricity generation. CHP does not represent fuel switching, but represents a more efficient generation option using natural gas fuel that would be owned by the customer.

Even though NW Natural does not believe that the CHP Program will result in fuel switching, NW Natural questions why "fuel switching" would be a reason to prevent this SB 844 program from moving forward. If the program was a form of fuel switching, as a matter of public policy, it should not be a reason to put a stop to a program designed to reduce GHG emissions in the State.

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NW NATURAL INCENTIVE

Q. Has NW Natural proposed an incentive payment for the Company under the Program?

A. Yes. NW Natural proposes to receive an incentive of $10.00 per measured and verified reduction in $MTCO_2$(e) emissions under the CHP Program.

Q. What are the concerns raised regarding the incentive payment?

A. Staff, CUB, and NWIGU object to NW Natural's $10.00 $MTCO_2$(e) incentive. Staff does not propose a specific any dollar per $MTCO_2$(e) incentive, but proposes that a lower incentive (including no incentive) be considered. (*Staff/100, St. Brown/*2). NWIGU and CUB support a $5 $MTCO_2$(e). (*CUB/100, McGovern-Jenks/18; NWIGU/100, Finklea/1).* CUB also proposes that any incentive be subject to the earnings test. (*CUB/100, McGovern-Jenks/20-22).*

A. NW Natural Incentive

Q. What are Staff's specific objections to providing NW Natural with any $MTCO_2$(e) incentive?

A. Staff opposes the $10 $MTCO_2$(e) incentive for three main reasons. First, they claim that NW Natural has sufficient incentive to develop and promote CHP because of increased revenues that will be associated with the increased use of gas that will result from CHP; second, Staff argues that the incentive is only tied to future programs, and that NW Natural has not based the incentive on what would be appropriate for the CHP program; and third, Staff argues that the incentive is out of proportion to the total costs. (*Staff/100, Klotz/4; Staff/200, St. Brown/18-22).* I disagree.

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Q. What is your response to Staff's position that the Company already has sufficient incentive to develop and promote CHP because of the increased margin?

A. Staff's position overlooks the fact that any increase in revenues from the use of additional gas will, at the time of the Company's next general rate case, benefit all customers through reducing the allocation of costs that they would otherwise receive without the increased usage. Thus, the margin created by the installation of CHP does not benefit the Company, except to the extent it is realized between rate cases, which could be a very short period. In addition, as discussed in the testimony of Andrew Speer, the increased margin that could be associated even with the base case is quite modest. Certainly it is not enough, in and of itself, to justify the Company's expenditure of time and resources on a program like the proposed CHP Program. And, once that increased usage and margin is factored into rates in a general rate case, the Company receives no future benefit from the margin.

I note that CUB's position in this case is that the Company should make provisions to pass the increased margin through to customers between rate cases, and earlier in this reply testimony I discuss the Company's proposal to share this incremental margin on a 50/50 basis with customers. Clearly, under this proposed sharing method, the incentive Staff cites would not materialize for the Company, and is valid reason for Staff to reconsider its opposition to the Company receiving an incentive on a dollar-per-tonne of reduced carbon basis.

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Q. What is your response to Staff's position that the $10 per MTCO$_2$(e) incentive the Company has proposed is tied to future programs, rather than the CHP Program?

A. Staff has not accurately characterized the Company's proposal. In my initial testimony, I explained that "[t]he Company chose $10 per MTCO2(e) as its requested incentive because it believes that amount represents an appropriate baseline, or default incentive for SB 844 projects, *and* because the Company believes that amount is reasonable in the context of the CHP Program."[8] In other words, the Company believes that $10 is appropriate both for this program, and as a baseline level of incentive for other programs.

Throughout the rulemaking (Docket AR 580), the Company expressed this view consistently—that it would be good policy to establish up front the baseline incentive level that is available for SB 844 programs. The Company believes that this is important so that the available incentive is known to the utility before it undertakes the effort and steps necessary to design SB 844 projects. Put simply, for an incentive to be effective, it needs to be known before one takes the action that is intended to be incented.

NW Natural was unable, through the rulemaking process, to gain the certainty that it desired about the incentives that would be available to it under SB 844. Nevertheless, the Company has developed this CHP Program in reliance on the availability of an incentive for doing so, despite not having certainty about what that incentive is. The Company does not believe that it should be required to do that each time it develops a program, and believes it is

[8] (*NWN/100, Summers/17*) (emphasis added).

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important at this time, in the context of an actual program filing, to set out an incentive level that is appropriate for both the program under consideration, and the baseline for future projects. We believe they should be one in the same--$10 per $MTCO_2$(e).

Q. As described above, Staff also argues that a $10 per $MTCO_2$(e) incentive is "out of proportion" in relation to the costs of the program. What is your response?

A. Staff's view is curious for a couple of reasons. First, it suggests that a $10 per-tonne incentive may be more reasonable if the overall program costs were higher. NW Natural does not believe that standard of judgment would be a good one, because the Company should be seeking to deliver carbon savings at the lowest cost possible.

Second, the Commission's rules state that the incentives provided to utilities for SB 844 programs should make up no more than 25 percent of total program costs. Unless the Commission intended for *no* program to ever potentially encounter the limit provided in the rules, then one would think that it would be the lowest cost programs where the incentive may represent up to around a quarter of the total program costs. As described in my initial testimony, NW Natural believes that the CHP Program may represent some of the lowest-cost and highest potential carbon reduction available to it under SB 844. In NW Natural's view, it is, therefore, appropriate that the incentive for this program may make up around a quarter of total program costs.

To be clear, NW Natural's proposal to use $10 per metric tonne as a baseline incentive for future programs actually means that the Company is not

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requesting that the incentive should vary by project in order to maximize its incentive under the rules. Instead, we are proposing that it is more important to fix the incentive at $10, and provide certainty, than it is to maximize the amount of incentive available under the cap.

Q. Please explain in more detail why the Commission should approve a $10 MTCO$_2$(e) incentive for the CHP Program?

A. NW Natural believes that the CHP program represents high potential and effective carbon reduction program, delivered at some of the lowest costs that may be available under SB 844. NW Natural believes that this is the very type of program that ought to be highly incentivized under SB 844. For this reason, NW Natural believes that it is appropriate to provide an incentive that is near the limit on the incentives proposed under the rules (i.e. that the incentive make up around a quarter of the program costs).

Q. Staff seems to indicate that "level of effort" should determine how much incentive the Company gets for an SB 844 program.[9] What is your response to that?

A. First, I would note that this program has involved a high level of effort. NW Natural has spent considerable time in developing the program and in the stakeholder processes to date. The development of the program has required considerable time from several areas of the Company, including Executive Management, Business Development, Engineering, Marketing, Rates and Regulation, and Environmental Management and Sustainability. NW Natural has

[9] (See *Staff/100, Klotz/12*) ("NW Natural has failed to demonstrate or properly justify, based on the effort entailed in the present program, why the Company should receive a $10 per ton incentive.")

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also engaged numerous consultants, and studied the CHP market and market barriers to a very significant extent. Moreover, implementation of the program will require ongoing effort for many years to come, and adds complexity to NW Natural's business.

However, NW Natural *does not* believe that the level of effort required to put together and implement a program should be the determinant for the level of incentive. If that were the standard, then NW Natural would be incentivized to seek out the most complex and time consuming projects to save carbon. This does not seem appropriate or efficient. NW Natural believes a better approach would be to establish a modest, but fixed incentive—one that is not even likely to maximize the amount available under the rules—that the Company can rely on in order to seek out the lowest-cost, highest potential carbon reduction projects. It is for these reasons that the Company has proposed a $10 per metric tonne incentive.

B. Earnings Test

Q. CUB proposes that all costs and the incentive be included in the earnings test. (*CUB/100, McGovern-Jenks/20-22).* Do you agree?

A. No. An incentive should not be calculated as revenue in a utility's earnings test. The effectiveness of an incentive is undermined if its collection is subject to the results of an earning test. Inclusion of the incentive in an earnings test would reduce NW Natural's incentive to invest in carbon reduction programs.

Q. Has the Commission provided guidance on the issue of including incentive payments in the earnings test?

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A. Yes. In OPUC Order No. 14-416 at 6, the Commission stated that it would make a case-by-case determination about whether a project's incentive payments should be included in a utility's earnings test.

Q. Does NW Natural think it would be appropriate to apply an earnings test to the CHP Program?

A. No, as we have stated throughout this docket, we believe that subjecting the incentive to an earnings test makes the incentive uncertain, and possibly nonexistent, which undermines the policy behind the promoting voluntary projects under SB 844. Additionally, it is important to note that the Company does not expect any material incremental distribution plant that would provide the Company with an opportunity to invest in rate base. Also, because the incremental margin associated with increased loads from CHP installations is flowed to all customers effective with a general rate case, there is no long term incentive for the Company to pursue the CHP Program. Thus, imposing an earnings test on the $10 incentive per MTCO2(e) reduced introduces the chance of the Company receiving no benefit from the voluntary actions it takes with respect to this program.

Q. Please explain how the Company's current earnings test works.

A. The Company has two different earnings tests that apply to each year's earnings. The first, or traditional test, is based on the Company's results of operations for the year, including any WACOG gains or losses, and also including some revenue and expense adjustments. That test considers whether the Company has earned above a level inclusive of a deadband over its authorized return on equity. The deadband is based on the sharing election for commodity costs that

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is made each year. Also, the authorized return is modified to include 20% of the change in a measure of the risk-free interest rate since the time of the authorized ROE. If earnings are above the benchmark, the Company shares 33% of the excess with customers.

The second test has been recently established for use with environmental deferred expenses. That evaluation of the results of operations is based on the same data that is used in the traditional test, with two significant differences. First, the results are augmented by 50% of any utility asset management agreement benefits received by the Company for the year. Second, the benchmark is the most recent authorized return on equity, unadjusted for a deadband or changes to interest rates. If the Company is earning in excess of the authorized level, then any environmental expenses subject to amortization are absorbed by the company up to the excess earnings.

Q. Given the Company's current earnings tests, what would be the practical impact of including the incentives in an earnings test?

A. Under the traditional earnings test, it is possible that the inclusion of incentive amounts would cause overearning that would trigger sharing, or an effective waiving of a portion of the incentives. More importantly, because the environmental expense related test does not include a deadband, and because it includes the Asset Management Agreement (AMA) benefits, it is much more likely that the CHP Program incentives cause results to exceed the benchmark return on equity (ROE), at which point all incentives are eliminated if environmental expenses remain to be collected.

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OTHER ISSUES

A. Barriers to Participation.

Q. How significant of a barrier to CHP installation will the need for compression and distribution be?

A. CUB notes that compression may make it more difficult for customers to participate in the program. (*CUB/100, McGovern-Jenks/8-9*). We do not anticipate that many of our customers will require compression, except for very large customers. For those customers needing compression, they will have to pay for their own compression. To address this barrier, NW Natural proposed to provide compression under a Schedule H-type tariff. Still, we agree with CUB that increased costs would likely be an additional barrier to participation in the CHP Program.

B. Incentive Stacking

Q. You explained above that NW Natural's CHP Program stacks incentives from Energy Trust and from ODOE. Is this appropriate?

A. Yes. CUB raises the issue that the CHP Program "stacks" incentives from Energy Trust and ODOE to accomplish the objective of building CHP. (*CUB/100, McGovern-Jenks/3, 13-15*). Incentive stacking is appropriate because: 1) it is the normal way to promote demand and supply side investments; 2) it increases the chances for the CHP Program to be successful; and 3) NW Natural is monitoring and accounting for the carbon reductions and not energy efficiency benefits.

First, the Company sought ways to "join forces" with other incentive programs and to reduce the cost of accomplishing carbon reductions under SB 844. Energy efficiency programs can include multiple incentives to promote

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lower and more efficient use of energy. Similarly, programs to encourage certain generation resources often have multiple incentives. For example, a renewable energy project may benefit from state and federal tax credits, direct funding, and other laws that encourage renewable energy, including Renewable Portfolio Standards and the Public Utility Regulatory Policies Act. Therefore, it is normal to stack incentives, which are generally not prorated.

Second, this effort to stack incentives in many cases may be the best, or only, way to achieve reductions under SB 844 at a reasonable cost. My understanding is that a key policy objective under SB 844 is to ensure activities under the law that would not happen without it. In the language of the law, this means that we must show "[t]hat the public utility, without the emission reduction program, would not invest in the project in the ordinary course of business". ORS 757.539(3)(d). NW Natural has been unable to invest in CHP in the past, and without the emission reduction program, there would be no way to provide such a customer-funded CHP incentive.

The historical record has shown that the two current incentives for CHP – from Energy Trust and ODOE – have not been successful in promoting this activity. As stated clearly by those closest to this decision process, the industrial customers themselves: "The history of deployment of natural gas fired CHP in Oregon strongly suggests that current programs do not offer enough of an incentive for many customers to make the needed capital investments in such facilities." (*NWIGU/100, Finklea/4*).

Third, NW Natural's incentives are for a different purpose than the Energy Trust incentives. NW Natural is incenting, monitoring and verifying the carbon

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reductions. In contrast, the Energy Trust provides incentives for energy efficiency. Energy Trust does not formally “count up” the carbon benefits associated with these efficiency investments. Energy Trust does not set a carbon goal for its activities nor does the organization perform any monitoring and verification regarding carbon reductions obtained through energy efficiency. While Energy Trust at times may refer to the broad carbon benefits of their work, they do not perform the work to achieve and verify carbon benefits within a regulatory program.

Q. Staff requested that NW Natural supply information showing how the program costs would change without the ETO and ODOE incentives. (*Staff/100, Klotz/2, 11-12*). Can the program succeed if it cannot leverage the funds available through the ETO and the ODOE?

A. The proposed program is designed with the expectation that participants take advantage of NW Natural’s incentive to reduce $MTCO_2$(e) emission and Energy Trust and ODOE’s programs designed to incent energy efficiency. If the Energy Trust and ODOE incentives were removed, the Company would likely need to consider seeking approval from the Commission to raise the incentive it has proposed in order to keep the effectiveness of the program that we are targeting.

Q. CUB raises concerns that that the CHP Program will double-count benefits with Oregon’s Clean Power Plan. (*CUB/100, McGovern-Jenks/3, 14-15)*. How do you respond?

A. While the details of Oregon’s Clean Power Plan are still emerging, NW Natural believes that the benefits of CHP on the electric utilities’ systems would reduce their future obligations under Oregon’s Clean Power Plan. NW Natural believes

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that this would benefit the electric utilities' compliance under the Clean Power Plan and would benefit the State by targeting carbon reductions now, rather than waiting for the Clean Power Plan to be implemented. While the specific mechanisms are yet to be worked out, it is fair to expect new CHP to create additional "headroom" for electric utilities. This additional headroom is likely to result in savings for electric utilities and their customers.

NW Natural does not believe that this would be appropriately characterized as a "double counting," and instead really represents an additional benefit of the program that may be realized by electric utilities and their customers.

In addition, the process of developing the state's Clean Power Plan will be lengthy, with the compliance obligation beginning in 2022. It is wise policy to continue our efforts to drive reductions as we prepare the plan. As the testimony of Carbon Solutions suggested, the state needs to continue moving forward if it hopes to hit the state reduction targets. Ann Gravatt explains:

> Oregon, therefore, needs to reduce greenhouse gas emissions by 15 million metric tons (MMT) by 2020 to be on track to reach the 2050 target. We further extrapolate that approximately another 15 MMT would need to be reduced by 2030 to continue towards a level of 14 MMT in 2050.

(*Climate Solutions/100, Gravatt/2*). Pausing this potentially impactful project for years will not help Oregon achieve carbon reduction goals.

III. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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NW Natural

Exhibit 301 of Barbara Summers

UM 1744
Carbon Emission Reduction Program
Combined Heat & Power (CHP)

American Council for an Energy-Efficient Economy White Paper "How Electric Utilities Can Find Value in CHP"

October 2, 2015

How Electric Utilities Can Find Value in CHP

Anna Chittum

July 2013

An ACEEE White Paper

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Contents

Executive Summary

Combined heat and power (CHP) is the most efficient way of generating power available today. CHP conveys benefits to its host facilities, but it also conveys significant benefit to the electric utility system in which it is sited. Electric utilities are best positioned to monetize and take advantage of these benefits because the benefits reduce their costs, risks, and losses more so than for any other entity. Utilities are comfortable with long-term investments, they often have access to capital at a cost lower than individual facilities, and they have significant existing relationships with their customers who could be excellent hosts for CHP.

Electric utilities can use CHP to reduce their exposure to the vagaries of consumer electric demand by investing in smaller CHP systems in a piecemeal fashion instead of making big bets on large-scale generators that may not ultimately be justified. The utilities can encourage the deployment of CHP at strategic locations, helping to mitigate peak time grid constraints that put excess strain on valuable equipment and cause major line losses. CHP can help utilities offer higher quality power to their customers and improve system reliability in the face of increasingly severe weather events. It can also help utilities cost-effectively meet environmental regulations and reduce the risk associated with upgrading existing power plants with expensive pollution control equipment.

Due to its many benefits, some utilities and states have begun to more directly target CHP opportunities and consider it in long-term generation plans. Whether owning CHP themselves, partnering with individual facilities, or acquiring it as part of their energy efficiency portfolio, utilities are finding value in CHP. Still, CHP is not currently viewed as economically beneficial by most electric utilities due to policies and regulations that prevent a utility from enjoying the many benefits it provides. Significant changes in how utilities can value and consider CHP as a system asset will be required in many states in order to better encourage deployment of this highly efficient energy resource.

The benefits of CHP are tremendous and cannot be ignored. Individual facilities, such as manufacturing companies, hotels, hospitals, and college campuses, are all excellent hosts for CHP systems. But despite CHP's cost-effectiveness, these facilities find the high capital costs of CHP equipment to be prohibitive. They are typically wary of entering into a business area — energy production — that is outside of their core competency. They also do not typically get to directly enjoy all of the benefits of CHP, so the benefits do not always appear to outweigh the costs or the risk.

Electric utilities should take advantage of the untapped potential for CHP for they are best positioned to enjoy and monetize the benefits CHP provides. Policymakers and regulators will need to become comfortable with utilities making these kinds of investments in order to reach President Obama's goal of 40 GW of new CHP by 2020.

This paper is one of three in a series on CHP and utilities. The other two papers, also available for free download from ACEEE, are:

- *How Natural Gas Utilities Can Find Value in CHP* (July 16, 2013); a white paper outlining specific examples of how natural gas utilities are currently finding value in owning and supporting CHP.
- *Utilities and the CHP Value Proposition* (July 16, 2013) — a peer-reviewed research report outlining all of the primary benefits of CHP to utilities and energy systems at large.

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The author would like to thank the Energy Foundation for their support of this work; Neal Elliott, Sara Hayes, and Ethan Rogers at ACEEE for their feedback and guidance; Renee Nida, Patrick Kiker, and Eric Schwass at ACEEE for their help editing and producing this document; and the many individuals who reviewed this paper, participated in interviews, and provided background documentation for this work.

Introduction

In August 2012, President Obama issued an executive order[1] that established a national goal of 40 GW of new combined heat and power (CHP) installed by 2020. To meet that goal, recent trends in CHP deployment will need to change. In the United States, 82 GW of CHP is currently installed. A tremendous opportunity for new CHP remains, as the current technical potential for new CHP, considering just *existing* facilities, is about 130 GW (SEEAction 2013).

Though a number of economic sectors could benefit from CHP, the large upfront capital costs and perceptions of risk associated with CHP systems discourage private companies from making the significant investments CHP requires. Companies that could benefit substantially from CHP are instead focused on their core businesses: manufacturing companies are focused on improving their products; hospitals are focused on healing their patients; and schools are focused on educating their students.

This reluctance of individual facilities to make investments in CHP systems creates an opportunity for utilities to invest in the remaining CHP potential. Electric utilities are uniquely positioned to take advantage of increased deployment of CHP within their service territories, realizing the efficiency and resiliency benefits that can result from these investments, because utilities:

- Can leverage their existing long-term relationships with would-be hosts of CHP systems, such as large commercial, institutional, and industrial customers;
- Can earn a reliable rate of return on investments in some states, depending on their regulatory structure;
- Are familiar and comfortable with making long-term capital expenditures;
- Can enter into long-term contracts with CHP system hosts that offer reliable payments and mitigate risk;
- Can enjoy CHP's efficiency benefits within state-level energy efficiency goals and targets;
- Have better bond ratings and access to cheaper capital than most other industries; and
- Can be instrumental in removing some of the biggest individual project barriers, such as interconnection challenges and punitive standby tariffs.

With so much cost-effective CHP potential remaining, the entity that works to acquire this energy efficiency resource stands to gain. At present, electric utilities are not significantly incentivized to invest in CHP in the United States. Despite its significant benefits, today CHP represents only about 8% of the entire U.S. electric generating capacity. CHP-based capacity could be much higher. This paper will explore the various benefits to utilities offered by CHP systems and the manner in which current policies and regulations do and do not encourage utility investments in CHP.

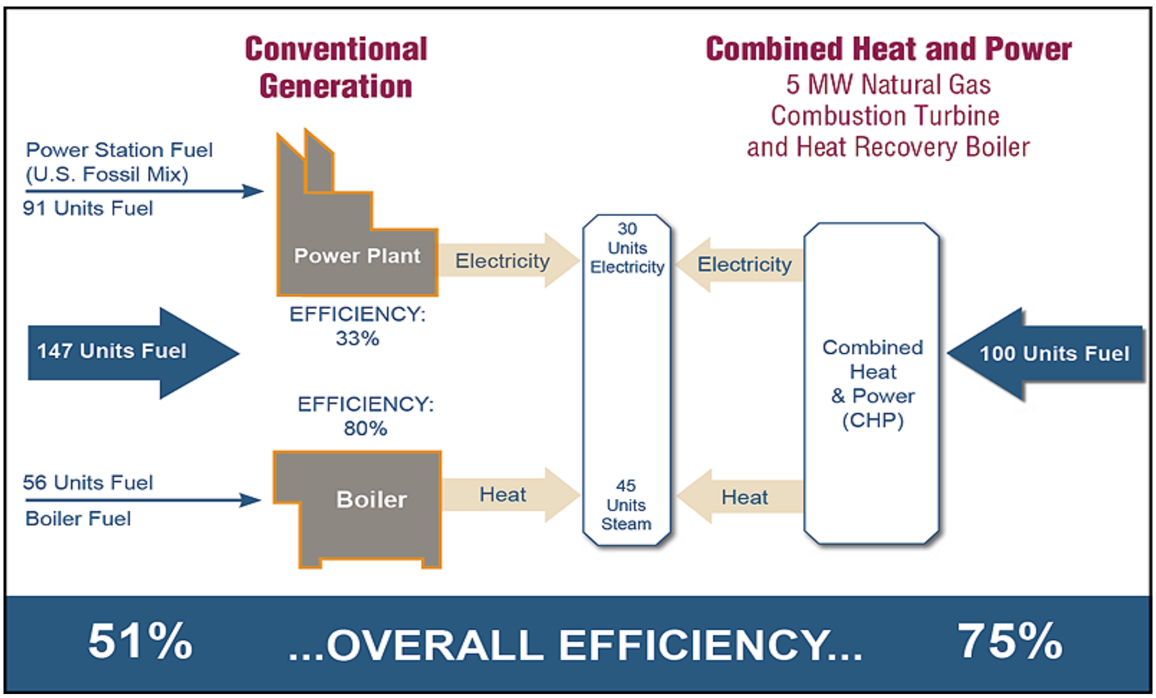
[1] http://www.whitehouse.gov/the-press-office/2012/08/30/executive-order-accelerating-investment-industrial-energy-efficiency

The Benefits of CHP to Electric Utilities

CHP is the simultaneous generation of electric and thermal energy, often using a single fuel. The simultaneous generation of these two types of energy confers tremendous efficiency benefits, as more useful energy is squeezed out of each BTU of input. CHP systems can run on a variety of fuels, including natural gas, biomass, and biogas, and they can include a wide range of technologies, including microturbines, reciprocating engines, and fuel cells.

Figure 1 shows a representative CHP system, illuminating the significant efficiency benefits of CHP over conventional power generation. By making use of the waste heat generated during power generation, CHP systems do much more with their energy inputs than conventional power plants.

Figure 1. Representative Schematic of CHP Versus Conventional Generation



Source: EPA 2013

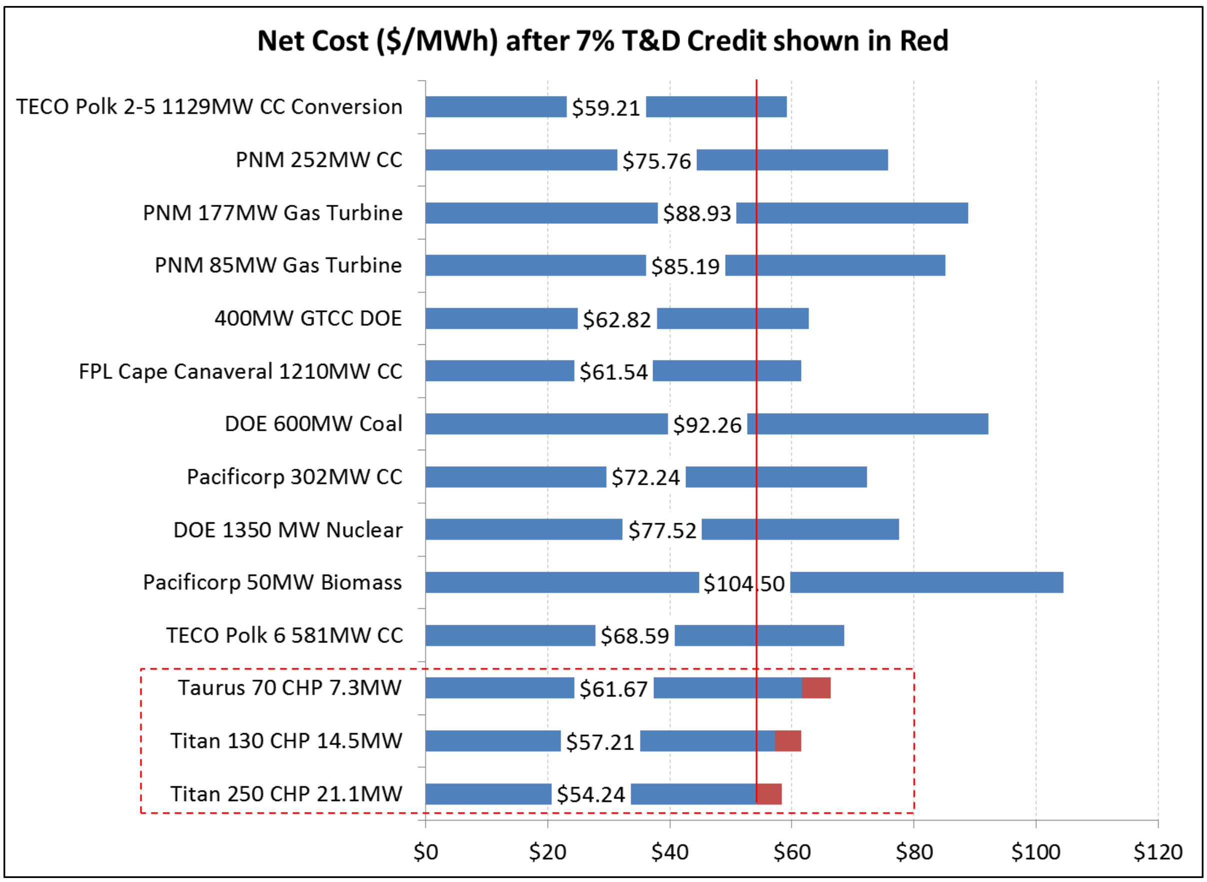
CHP systems can operate at combined efficiencies of over 80%, whereas the electric generating efficiency of an average power plant is about 36%. It offers many benefits to electric utilities and is uniquely suited to address the challenges facing utilities today, including aging infrastructure, increased catastrophic weather events, more stringent environmental regulations, and pressure to keep rates low.

Low Cost, Highly Efficient Generation Resource

CHP systems generate more useful energy from a single unit of fuel than most traditional forms of electricity generation. As one industry expert put it, "properly applied, CHP is the most efficient power generation resource on the planet" (Duvall 2013). By monetizing this benefit of increased efficiency, CHP owners and host facilities can enjoy power and thermal energy at a total cost far less than if they were generated separately. This efficiency benefit is reflected in the levelized cost of energy from a CHP system versus a typical combined cycle plant.

Several recent assessments show that a large gas turbine or engine-based CHP system has a levelized cost of about 6.0 cents/kWh or less, while CHP systems powered by biomass and biogas see levelized costs of well below 4.0 cents/kWh (Chittum and Sullivan 2012; PacifiCorp 2013). In contrast, the levelized cost of natural gas combined cycle plants ranges from 6.9 to 9.7 cents/kWh (Chittum and Sullivan 2012). Figure 2 shows one analysis of the levelized cost of energy from CHP systems versus other, more traditional centralized generation resources. As shown, the considered CHP units display the lowest cost of energy among a variety of other typical generation resources. The costs of the "typical" generation resources were all derived from existing integrated resource plans (Duvall 2013).

Figure 2. Levelized Cost of Energy of Selected Generation Resources



Source: Duvall 2013

CHP systems operate most efficiently when they are sized to a system's thermal load. Due to policies and practices that discourage exporting power from customer-owned CHP systems, CHP systems are often undersized to ensure that the electric output is not greater than the onsite electric demand, which would require power export. This leaves major efficiency savings on the table. If electric utilities owned and dispatched CHP systems, they could be fully sized to meet a facility's thermal energy demand, and any excess power beyond that which was consumed onsite could be exported to the grid, maximizing efficiency and emissions reductions. Utility-owned CHP could be designed to provide the greatest benefit to the utility while meeting the needs of the thermal host.

Cost-Effective Generation, Distribution, and Transmission Resource

Siting CHP close to the point of energy consumption frees up and reduces stress on distribution and transmission lines. Strategically sited CHP can avoid or defer distribution and transmission system investments and reduce maintenance costs for a utility (MDOER 2013). In New York, a CHP system located at New York Presbyterian Hospital was sited near a substation Con Edison anticipated upgrading in 2017. The CHP system effectively offers the utility a 7 MW-equivalent reduction at the substation during system peaks, which allowed Con Edison to avoid an expensive upgrade (Jolly 2013). Through this and other targeted distributed generation projects, Con Edison has deferred "multiple traditional T&D load-relief capital projects" (Jolly et al. 2012). Similarly, Alabama Power found that customer-owned CHP systems helped it avoid the construction of about 1,700 MW of new generation capacity (SEEAction 2013).

Transmission and distribution systems are regularly upgraded and expanded to accommodate changing demand forecasts. They are explicitly designed to carry the "extreme" maximum demand, though such demand may be seen very infrequently (Lazar and Baldwin 2011). In the United States, transmission and distribution infrastructure is largely dated and in need of upgrades to meet 21st century customer needs. One 2008 study found that 70% of all transmission lines and transformers were at least 25 years old. The cost of preparing and expanding existing distribution and transmission systems for increased demand is significant. Preparing the transmission system to handle an additional kW can range from $200 to $1,000; on the distribution system, that preparation can range from $100 to $500 per kW (Hargett 2012). After seeing record investments in distribution and transmission infrastructure in recent years, the Edison Electric Institute still estimates its member utilities will spend $54.6 billion just on transmission infrastructure investments between 2012 and 2015 (EEI 2012).

Unlike an individual industrial facility, the value of strategically sited CHP for certain parts of the distribution grid can be immediately apparent and impactful to a utility, which knows exactly where its most constrained grid assets are. New CHP systems can be considered in forward-looking distribution and transmission plans, and certain investments in the grid could be directly avoided, immediately reducing costs to the utility and ratepayers. The reduced demands on distribution and transmission infrastructure also frees up distribution and transmission capacity to move power from remotely sited renewable energy resources, which are often located quite far from the end point of power consumption. For electric utilities ramping up the amount of renewable energy in their portfolios, CHP can help avoid the transmission costs associated with new renewable energy assets.

Transmission systems can also benefit from strategically sited CHP, and there is precedent for considering CHP as a transmission asset. FERC Order 1000 suggests a framework for utilities that need to make investments in transmission infrastructure to instead invest in energy efficiency and other "non-transmission alternatives" (NTAs) such as CHP. In this order, FERC suggests the cost of such investments could be spread amongst all users of the transmission system via an "interregional cost allocation method" if certain benefits might accrue across multiple transmission system regions (Lyle et al. 2012; FERC 2013). To identify these opportunities, the order further requires neighboring transmission regions to "coordinate to determine if there are more efficient or cost-effective solutions to their mutual transmission needs" (FERC 2011). The regional transmission organizations New York ISO and ISO-NE have considered how energy efficiency and NTAs could meet their regional transmission needs,[2] though the actual use of CHP as an NTA thus far appears to be limited.

In states with energy efficiency goals, CHP can offer a more cost-effective way to reach efficiency targets and earn performance incentives. A single CHP system can offer the efficiency savings of many smaller efficiency projects. In times when some utilities are reporting less low hanging efficiency fruit in the commercial and industrial sector, CHP can offer deep savings at a very low cost, enhancing the overall cost-effectiveness of energy efficiency portfolios.

System Resiliency

Superstorm Sandy was only the most recent catastrophic weather event to showcase the reliability and resiliency of CHP systems. As large swaths of major East Coast cities remained without power for days, facilities served by CHP were able to maintain power, heat, and other services for residents, clients, patients, and staff (Chittum 2012). CHP systems, largely powered by the underground natural gas infrastructure, fared much better than centralized electric distribution systems, which were particularly vulnerable to the impact of downed trees given their above-ground distribution lines.

In New Jersey, the Public Service Electric and Gas Company estimated that the cost just to restore its infrastructure post-Superstorm Sandy would be $250 to $300 million. The estimate did not include the cost to "permanently repair PSE&G's damaged infrastructure or to modify the infrastructure to reduce the risk of damage of future storms" (PSEG 2012). Earlier this year PSEG announced its new Energy Strong campaign, designed to strengthen its grid against Sandy-like events in the future. PSEG requested funds totaling $3.9 billion over a ten-year period for Energy Strong, which has raised the ire of certain customer groups (PSEG 2013a; Kaltwasser 2013).

Avoided Marginal Line Losses

CHP systems are by nature located at or very near the point of consumption, meaning power does not have to travel over transmission and distribution wires for long distances. During the long distance trip made by electrons generated at remotely sited power plants, an average of 7% of the energy is lost in so-called "line losses." While that number is significant, it does not reflect the exponentially higher line losses incurred as a system reaches its peak. One analysis found that during peak demand periods, line losses are about *three times* the average loss amount, resulting in tremendous lost power product and a need to produce even more power at the point of generation to get the same kW at the point of consumption (Lazar 2011; Lazar and Baldwin 2011).

[2] See Lyle et al. 2012 and Chittum and Farley 2013 for additional detail on this transmission planning opportunity.

During peak periods, then, the real value of CHP and energy efficiency investments is not their ability to help avoid a system's average line losses, but instead their contribution to avoiding marginal line losses. The value of a saved kWh grows significantly as a system nears its peak because so much more energy is lost in the transmission and distribution of the kWh consumed during a system peak than one consumed during a typical nighttime trough (Lazar and Baldwin 2011). During the 2006 summer peak period, Ontario Power Authority found that while the marginal cost of providing power from a gas turbine cost about $57/MWh in fuel costs, line losses added an additional cost of $115/MWh to the marginal cost of power (OPA 2007).

Utility systems must have enough generating capacity on hand to meet system peaks and cover the significant line losses during those times. Avoiding the need to develop peak-time (or "peaker") generation and avoiding the attendant line losses throughout the system could have major economic and environmental benefits. One analysis found that "80 GW of strategically-placed [distributed generation]," such as CHP and waste energy recovery could reduce the actual "peak US generation and transmission requirements by 100-120 GW" (Casten 2012). This could yield major additional savings in the form of avoided necessary capacity reserves (Lazar and Baldwin 2011).

Improved Power Quality and Provision of Ancillary Services

Power quality is critically important to utility customers, and CHP systems can offer cost-effective ancillary services to improve power quality where the grid needs it the most. As one assessment found:

> *It's technically feasible to use CHP generators, rather than centralized power plants, to balance supply and demand. And there is reason to believe that CHP generators may be better suited to the task. Some commonly used CHP technologies, such as reciprocating engines, are more amenable to ramping than large turbines. Further, when operating at partial load, generators will sacrifice electrical efficiency but gain thermal efficiency — potentially useful for CHP generators, but not for centralized power plants.* (Siler-Evans 2010)

Though few CHP systems currently participate in ancillary services markets, they can be very well positioned to do so. The CHP system at Princeton University earns about $600,000 per MW per year for its participation in one of PJM's multiple ancillary services markets (Nyquist et al. 2013). Most CHP systems would be able to participate given their existing setup, even if they were not originally designed to provide ancillary services. They do not typically require additional equipment other than the addition of controls. One exception is the ancillary service termed frequency regulation, which is capacity that, if successfully bid into the frequency regulation market, must be dedicated to and available for the provision of frequency regulation instead of on-site capacity needs (Webster 2013).

Ancillary services are arguably becoming even more important as more intelligent machines and controls proliferate, requiring more perfect power. Equipment that is especially sensitive to fluctuations in voltage require the highest power quality, as even a millisecond of sagging voltage can cause tens of thousands of dollars of damage (Schröder 2012). As just one example, J.R. Simplot experienced 12 separate grid outages lasting only a half second or less, which cost the company at least $7.5 million over a two-year period (Sturtevant 2013). Utilities could attract companies that are particularly concerned about reliable power by offering CHP-supplied power to their facilities.

Additionally, the ability of CHP to ramp up quickly and reduce constraints on distribution and transmission infrastructure can help mitigate the concerns of intermittency associated with some renewable resources such as wind and solar power. CHP can offer quick-response voltage support to the grid when necessary and can be a more cost-effective method of doing so than other types of ancillary services (Østergaard 2006).

Fast and Flexible Asset Development

CHP can be built much faster than most alternative resources, offering utilities and policymakers flexibility in meeting fluctuating electricity demand, especially when the future looks very uncertain. Utilities planning their next major centralized plant or transmission line must make decisions to build, and the investments to acquire land and secure contracts well before the asset is built and ready to serve customers. Utilities that develop transmission lines, for instance, are faced with waits for permits as long as ten years (Silverstein 2011).

Longer construction and permitting times of other assets mean higher carrying costs that must be borne by ratepayers. Additionally, since it is difficult to accurately predict customer demand five years into the future, building one large plant or investing in one major distribution line can be a risky endeavor. It may ultimately not be needed to the extent predicted. Instead, smaller customer-sited CHP systems can be brought online as needed, with significantly less lag time and thus less risk, allowing a utility to more tightly fit their supply to the ever-changing load shape. As electric utilities look forward and plan their next major capital investments, CHP can allow them to incrementally meet growing demand without taking on the risk of substantially overbuilding capacity (Duvall 2013).

The International Energy Agency (IEA) finds that typical construction time for large natural gas-powered CHP systems is about two years or less (IEA 2010a). In addition to the speedy construction time, one of CHP's greatest benefits is the fact that new land is not generally necessary, and new transmission infrastructure is not required. In contrast, significant time is spent just *preparing* to construct centralized power plants, during which land is acquired, transmission lines are sited, and other supporting infrastructure is developed. Once that is completed — and such preliminary work can take years — large centralized natural gas turbines have typical construction times of a little over two years (IEA 2010b). Other types of centralized generation, such as nuclear plants, have seen construction times alone of four years at best, and about five years on average (IAEA 2009).

Path to Environmental Compliance

Recognizing that CHP can offer tremendous reductions in harmful emissions, the U.S. Environmental Protection Agency (EPA) and state air regulator authorities have indicated support for the deployment of CHP and other energy efficiency measures as compliance mechanisms within specific air regulations. For instance, State Implementation Plans to meet federal air quality standards can include CHP programs and specific CHP-related emission reductions in their calculations (EPA

2012), reflecting that for over a decade EPA has made clear that the air quality benefits of CHP are substantial enough to be used for air quality compliance (EPA 2000).

Once EPA finalizes New Source Performance Standards for new power plants, Section 111(d) of the Clean Air Act directs the EPA to establish federal standards of performance for existing power plants. These standards will set rules for carbon dioxide for the first time, impacting a number of existing electric generating units. While these rules will mainly affect coal plants, many coal plants have already emerged as uneconomic, due to other recently established air rules and the changing economics of coal and natural gas (Chittum and Sullivan 2012). Investments in CHP as a compliance mechanism could reduce the cost of compliance for affected utilities and allow utilities increased flexibility in meeting the future electricity needs of their customers.

Increasingly, states are considering the emission reduction benefits in their air quality regulations, and acquiring the necessary air quality permits for CHP operations is a much less costly and risky endeavor than for centralized power plants. For instance, one "fast track" air permit for CHP in Texas reduced the time associated with acquiring state-level air permits from well over 1 year to just 4-6 weeks (ACEEE 2012). Such short permitting time periods save utilities and ratepayers money.

Additionally, CHP systems do not require the extensive water resources for cooling and steam generation required by larger centralized power plants. In places where it's challenging and costly to acquire the rights to new and adequate water resources to support power plant operations, this can have substantial economic benefit.

Fuel Flexibility

CHP is powered predominately by natural gas, but is also well established using other types of fuels. In some cases CHP systems are able to take advantage of local biomass or biogas resources, yielding local economic development impact, as well as improved emissions performance. CHP systems can also adapt to new and changing resource opportunities, such as the CHP system at Dow Chemical Company's Plaquemine, Louisiana facility, which can be powered by both natural gas and hydrogen gas.

Importantly, CHP systems can be configured to take advantage of both natural gas and biomass or biogas resources, depending on local availability. Certain CHP technologies and applications are well equipped to provide a flexible response to changing local fuel opportunities, enabling CHP owners to respond more directly to changing price signals in fuel markets.

Customer Retention

In some cases, customer-sited CHP could be an important customer retention strategy. For large industrial facilities that might be running at full thermal capacity, the addition of a CHP system onsite would allow them to take down certain boilers for maintenance without affecting production. Depending on the structure of the CHP business deal, onsite CHP can yield low or no cost steam resources to an industrial facility, reducing the operating and maintenance expenses of the company while improving reliability. These are the kinds of advantages electric utilities could highlight as a customer attraction and retention strategy, especially in competitive markets where customers are free to choose their energy service providers. Any service that helps a facility reduce its energy-related costs can help utilities maintain a strong customer base.

Summary of Benefits

CHP can provide electric utilities a range of benefits, the magnitude of each benefit differing for each utility due to its market and regulatory conditions. Table 1 summarizes the various benefits of CHP to electric utilities and provides examples of how such benefits are being monetized today.

Table 1. Benefits of CHP to Electric Utilities

Benefit	Benefit Magnitude	Opportunities to Monetize	Example
Low Cost Generation	Major	Rate-based generation resource; energy efficiency resource standard	Alabama, Ohio
Cost-Effectively Meets Transmission and Distribution Needs	Major	Reduced costs	Alabama, New York, Vermont
System Resiliency	Major	Customer satisfaction; resiliency portfolio standard	New Jersey
Avoided Marginal Line Losses	Major	Cost-benefit analyses	
Power Quality	Medium	Ancillary services markets, customer satisfaction	New Jersey
Fast and Flexible Development	Medium	Reduced costs	
Environmental Compliance	Major	Clean Air Act regulations	Ohio
Fuel Flexibility	Medium	Reduced costs	Louisiana
Customer Retention	Minor	Sustain customer base	

Despite these potential benefits, few U.S. electric utilities are deploying or encouraging new CHP systems in their service territories. In large part this is due to the fact that electric utilities are not economically incentivized to do so. Some notable instances exist, however, in which utilities have been direct partners in the successful acquisition of CHP resources.

Successful Utility CHP Programs

Electric utilities can enjoy the benefits of CHP in three major ways: through rate-basing the asset; through utilizing it as an efficiency resource to meet efficiency goals; and as a purely for-profit business arm. The manner in which these three approaches can be used, and the manner in which CHP benefits are monetized, will vary greatly depending on the market, and regulatory and policy framework impacting each utility.

CHP IN RATE BASE

Under the traditional rate-basing model, electric utilities invest in assets, which are added to their rate base. Customer rates are then set based on the rate base and structured to confer some economic benefit to the utility. For utilities that either own CHP themselves or enter in power purchase agreements (PPAs) for CHP-produced power, the costs associated with the CHP resource is typically aggregated with other costs and embedded in the utility's rate base.[3] For a traditionally regulated utility, the growth of the rate base is economically beneficial as they are typically granted a satisfactory rate of return to reach their revenue requirement.

Southern Company currently owns over 700 MW of CHP capacity across six plants, the majority of which are in Alabama Power territory. Southern Company continues to assess customers for CHP potential, "seeking win-win scenarios" in which the customer, the utility, and the utility's ratepaying customers can enjoy the benefits of CHP (Cofield 2012). Alabama Power has been able to integrate the costs of both new PPAs and utility-owned CHP into its rate base (SEEAction 2013).

Similarly, Austin Energy owns a 4.3 MW CHP system located at the Dell Children's Medical Center. The thermal energy provides cooling to the medical center, while the excess electricity, beyond what the medical center consumes, is sold by Austin Energy at retail prices to other customers. Ensuring that Austin Energy would be protected against the risk of stranded assets, the utility entered into a 30-year contract with the medical center for the energy products (TAS 2013; Takahashi 2010; Corum 2007).

Some customer-sited solar programs could offer a model for how to rate-base other distributed resources such as CHP. New Jersey S*olar 4 All* program has targeted 80 MW of new solar projects through 2013, and the $515 million investment for the first phase of the program was approved to be recovered through rates, as well as a return on equity for PSE&G (PSEG 2013b; NJBPU 2013). This program benefitted from clear guidance from regulators on how the investments in the assets would be treated, allowing utilities to develop the program with full certainty that their investments would be recoverable and the returns would be reliably in line with returns on other assets.

CHP AS EFFICIENCY RESOURCE

In states with aggressive energy efficiency goals, CHP can help utilities meet those goals faster and at a lower cost than many other efficiency resources. In Massachusetts, energy efficiency goals and a specific portfolio standard for CHP help signal to utilities that CHP is a prioritized resource. The 2008 *Green Communities Act* required that all cost-effective CHP must be acquired by utilities within their

[3] In some states, such as California, certain types of PPA structures are not added to a utility's rate base and are instead simply directly recovered as costs on customer bills.

energy efficiency programming. In this way the cost of acquiring CHP resources — mostly executed via incentives for customer-owned CHP — is clearly recoverable for regulated utilities in Massachusetts. Massachusetts is a decoupled state, and so the cost of energy efficiency programming is part of the total costs recovered through decoupling mechanisms (Ballam 2013).

An additional incentive for electric utilities to pursue CHP in Massachusetts is a performance incentive embedded in energy efficiency goals (Hayes et al. 2011). In 2011, CHP alone met about 30 percent of the Massachusetts utilities' energy efficiency targets. It was on average the lowest cost efficiency resource, keeping the total cost of the energy efficiency portfolios low and helping utilities meet their target very cost-effectively. In fact, the presence of CHP in utilities' commercial and industrial energy efficiency portfolios was "one of the largest contributing factors" in the overall lifetime cost of saved energy decreasing from $0.022 in 2010 to $0.016 in 2011 (Mass Save 2012). As a result, Massachusetts utilities earned their performance incentive, equal to about 5 percent of their energy efficiency spending, all while providing ratepayers with an incredibly cost-effective energy resource (Ballam 2013).

In Wisconsin, Alliant Energy's *Shared Savings Program* operates as a type of on-bill financing program to encourage customers to take on major energy efficiency investments, such as CHP, that they might not otherwise take on due to capital constraints. The utility now receives a rate of return on its Shared Savings portfolio equivalent to that which it receives from its investments in more traditional assets (ACEEE 2013; Adams 2013).

THIRD-PARTY OWNERSHIP STRUCTURES

For electric utilities that cannot own generation directly, there are some models that still allow them to enjoy some of CHP's benefits. United Illuminating in Connecticut explored a zero-capital program, which helps pair third-party owners with customers interested in having CHP on-site. Five- or ten-year power purchase agreements are encouraged between the customer and the third party in the model. United Illuminating could enjoy the benefits of CHP on its system — reduced congestion, emissions, etc., — without having to own the CHP systems itself. Though the program was just a test, United Illuminating considered the value of seeking approval to operate as the third party themselves, entering into the agreements with customers and maintaining ownership of the CHP systems. To do so, it would have to develop an unregulated subsidiary that could legally own generation resources.

Another electric and natural gas utility (who wishes to remain unnamed) is currently exploring a model that would have the utility design and make the initial capital outlay to own CHP assets themselves. The customer facility at which the CHP system is sited would pay the utility a fixed flat rate each month, for ten or fifteen years, and would then be allowed to access the electricity and thermal energy produced onsite for no additional cost. The customer would enjoy lower monthly payments — paid out of their operating budget instead of their capital budget — and the utility would enjoy fixed monthly payments that offer a rate of return on its investment similar to what it is already earning on other, more traditional generation and distribution assets.

Changing the Utility Business Structure

The potential economic benefits of CHP to utilities are many. However, existing regulatory schemes and policies are not currently designed to help utilities monetize those benefits. Thus, significant CHP opportunities are left on the table and the cost savings and sustainable revenue potential for utilities goes unrealized. Today, less than a quarter percent of all active utility-owned electric generating capacity is CHP (EIA 2013; DOE 2012).

Electric utilities are not currently major players in CHP deployment because their economic incentives are fundamentally misaligned with CHP and distributed generation generally. Utilities do not or are not able to monetize CHP's many benefits, so prefer other investments. Further, where utilities have no decoupling mechanism in place, CHP's impact at the customer level generally yields a large downside — reduced electricity sales — without allowing for an upside — quantification and monetization of CHP's other benefits.

Electric utilities can see some value in CHP when it is explicitly included as part of their applicable energy efficiency goals or programming, and they can earn cost recovery on their related expenditures. However, investments in energy efficiency do not typically offer the same rate of return as other traditional investments in their rate base. Where performance incentives for reach efficiency targets are in place, utilities may see a stronger economic incentive to acquire efficiency resources, but few states have significant performance incentives in place (Hayes et al. 2011).

Where utilities can experience the value of CHP within energy efficiency programming and goals, the cost-benefit analyses that consider CHP as an efficiency opportunity do not fully value many of the significant benefits CHP provides. For instance, while most assessments of benefits to the utility or society reflect an average avoided line loss of about 7%, that value is two or three times higher during system peak periods. This means the avoided lines losses are discounted by several orders of magnitude for some time periods. While the system is not always at its peak, the marginal cost of operating a generating unit or transmitting power on transmission lines is very high during peak periods, and the benefits of avoiding such costs are not immaterial.

These benefits are also absent from considerations of CHP as a generation or distribution resource. A CHP system strategically placed could reduce constraint on a transformer, but a utility may not be evaluating such impact in a manner that shows clear benefit and allows a utility to consider CHP in its distribution plans.

Changes for the Regulated Market

For electric utilities operating in regulated markets, utility investments in CHP should be allowed to be integrated into the rate base. Utilities should be able to clearly understand the value proposition and the return on investment they can earn from ownership of customer-sited CHP. This may mean that regulators need to become familiar with the unique attributes of smaller CHP systems, and the different costs associated with identifying sites and working with individual facilities. CHP systems still offer a cost advantage, but their costs structure is fundamentally different from a large investment in a traditional power plant.

For utilities that are concerned that CHP system assets could be stranded if the host facility reduces its production or shuts down all together, regulators should be familiar with and able to approve the different contractual arrangements that can mitigate this concern. While the concern is legitimate given CHP systems' long lifespan, CHP systems can be run as stand-alone, dispatchable generators if the thermal host is lost, as evidenced in a contractual arrangement provided for in the California QF settlement agreements (see Chittum and Farley 2013).

In fully regulated states, third-party ownership of generation assets is often prohibited. CHP ownership partnerships between utilities and private third parties, such as the host site, may not be allowable under state law. Utilities in these states may not have the flexibility of working with an interested third party or other market player to spread some of the risk and will instead need to be able to integrate CHP investments directly into their rate base.

CHANGES FOR THE DEREGULATED MARKET

In deregulated states, electric distribution utilities are generally prohibited from owning generation assets; investments in CHP are often a non-starter for these utilities. Third-party unregulated subsidiaries of utility companies may, in some cases, be allowed to own generation, but the rules differ from state to state. Distribution utilities in these markets need clear guidance from regulators on how to structure third party unregulated subsidiaries that might own CHP systems.

For electric utilities operating in less regulated markets, greater flexibility in working with third parties exists. Challenges in determine who within a given deal owns the various benefits — emissions reduction credits, efficiency credits, electrical output, and thermal energy output — will need to be worked out on a case-by-case basis to reflect the unique attributes of each deal. Regulators in these states could offer guidance on how the state-developed policies, such as energy efficiency resource standards, could recognize and integrate these different players' contributions to energy efficiency or emissions goals.

Distribution utilities in particular may be attracted to the benefits of CHP to their distribution systems. Treating CHP as a distribution asset is new, but given the known impact of CHP on some distribution systems, it makes sense to encourage it and allow investments in it to be recoverable in distribution utility rate cases. For distribution utilities that are allowed rates of return on their investments, investments in CHP that can be documented as directly mitigating the need for other types of assets should be allowed to earn a return.

SUGGESTED POLICY AND REGULATORY RESPONSES

Many of the regulatory structures in-place do not encourage or economically incentivize utilities to invest in or support CHP systems. Regulatory and policy changes on the state level could help utilities and utility customers enjoy the many benefits of greater deployment of CHP. We suggest state policymakers:

- Offer clarity on how utility investments in customer-sited CHP systems are treated under existing policies;

- Allow the costs of utility-owned and customer-sited CHP assets to be recoverable in rates, as well as eligible for a comparable rate of return to traditional generation, distribution, and transmission investments;
- Establish methods to account for location-specific benefits of CHP (and other types of distributed generation) and provide guidance on how additional benefits should be integrated into cost-benefit analyses for energy efficiency resources and/or traditional energy resources;
- Encourage region-wide analyses of the potential for "non-transmission alternatives," such as CHP, which could be more cost effective than traditional transmission assets;
- Prioritize thermal energy planning within energy planning activities, to ensure CHP opportunities and waste energy recovery opportunities are given the same consideration as other resources when planning for long-term energy needs;
- Establish statewide energy efficiency goals and treat net CHP savings[4] from all types of CHP and waste heat recovery as equivalent to other energy efficiency resources;
- Encourage the dissemination of publicly available information about the areas of distribution and transmission resources that are most constrained, to help utilities better target and market mutually beneficial CHP installations;
- Support performance-based rate structures for utilities, which would allow them to earn revenues based on their performance in certain areas like reliability, environmental performance, etc.;
- Allow CHP to generate compliance credits in any program designed to control carbon dioxide emissions from existing fossil fuel-fired power plants under the federal *Clean Air Act*, and allow CHP supply to offset other state or regional greenhouse gas control programs;
- For markets that are no longer vertically integrated, clarify the specific types of third-party subsidiaries of electric distribution utilities that are legally allowed to own generation resources;
- Explore treating CHP and other distributed generation resources as a distribution asset, for purposes of determining distribution utilities' rate bases; and
- Aggressively pursue the quantification of CHP's reliability benefits and other benefits such as flexibility, ability to participate in ancillary services markets, etc., and more directly integrate these benefits into cost tests that consider the direct benefits to utilities.

Appendix I in Chittum and Farley 2013 offers specific examples of states and utilities that have taken some of the above steps, and specific policy language used in some of these cases.

Conclusion

CHP is the most cost-effective and efficient way to generate electricity today. Significant potential for CHP is found in existing facilities, but much of that potential is left untapped because individual facilities are wary of making such significant capital investments. Utilities are well-positioned to make these investments in CHP and can enjoy the significant benefits that CHP confers to grid systems and

[4] Read more on ACEEE's suggested approach for measuring CHP savings within an energy efficiency standard here: http://aceee.org/blog/2012/11/determining-chp-savings-energy-effici.

electric utility companies better than individual facilities are able. By their ability to sell excess power, utilities can deploy CHP systems that maximize efficiency by fully sizing a system to meet its thermal load, something that individual facilities are sometimes unable to do due to project economics.

Most electric utilities are not incentivized to own and operate CHP systems. In fact, some utility business structures economically incentivize utilities to oppose or discourage expanded CHP. Regulatory and policy changes that allow utilities to see direct economic benefit from CHP systems are necessary to take advantage of the available potential for CHP today.

By taking advantage of CHP opportunities within their service territories, electric utilities can enjoy reduced operating costs, reduced environmental compliance costs, increased customer retention, and increased flexibility and system resiliency. Policymakers should encourage the development of policies that provide utilities with an incentive to embrace CHP.

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Appendix: Suggested Rate-Based Pilot Program Design

ACEEE recognizes that each state and utility have different needs and challenges with distributed generation such as CHP. What follows is a suggested framework for a CHP pilot program designed to cover its costs through customer rates, much like other generation and distribution assets. This model should be viewed as a starting point for a conversation about program shape. In some cases utilities may have the capabilities to administer an entire program themselves; in other cases encouraging market players to conduct some of this activity, such as in the demand response market, might be a more attractive option.

Identify Opportunity and Potential

As part of the President's call for greater CHP deployment, the U.S. Department of Energy is supporting updated state-level analyses of CHP potential. These types of potential studies can help utilities understand some of the opportunities in the states they serve. However, they will likely need to be augmented to fully understand the most promising CHP opportunities in each service territory. Additional ways to identify potential CHP sites include:

- Consider information collected from existing activities with large customers, such as near-term expansion plans, or those looking to augment or update their on-site thermal energy systems in the near term. Review available data on boiler permits and air emissions performance reporting to identify facilities with older boilers that may need replacement in the near term.
- Approach sectors with particular reliability concerns to understand recent reliability challenges and whether on-site distribution might have immediate appeal for its reliability benefits.
- Identify facilities whose parent companies have successfully deployed CHP in other states or service territories, by working with CHP developers and considering CHP case studies.

Educate

After initial sectors or types of facilities are identified for further education, conduct outreach to customers. Such outreach could comprise mailings, social media campaigns, in-person communication through key account managers, participation in trade show events, and outreach to trade association networks. Simple handouts describing the benefits of CHP and the program process should be available through all these outreach efforts.

Most customers will be strongly attracted to promises of increased electric reliability, reduced steam costs, and increased efficiency. In some cases customers may need additional steam capacity, and would be interested in hosting a CHP system that allowed them to have access to increased steam capacity, without the capital costs. For an industrial facility running at full capacity and worried about the impact of taking boilers offline for maintenance, the addition of new steam capacity onsite can provide significant breathing room to undertake maintenance upgrades without affecting production.

Converting customer interest to active participation in the next steps will require personal communication to present to customers the scope of data that will be required to participate in the next steps. Customers may also be attracted to the fact that they can benefit from new equipment, a larger boiler, or other improvements that they did not have to make themselves.

Conduct Initial Assessments

After doing an initial brief assessment of facilities' energy needs, select a dozen facilities for the initial assessment based on expressed interest and individual facility confirmation that basic energy use data can be made available for further inquiry.

Send in-house engineers to conduct initial site visits and conduct a basic facility assessment at no cost to the customer. These visits should also ascertain whether an on-site "CHP champion" might be present.

Conduct "Deep Dive" and Prepare Feasibility Assessment

Narrow down the selected facilities to at least three. Depending on in-house engineering resources, either send utility staff or contracted third-party staff to conduct a deep dive data collection effort and energy assessment to aid in the preparation of a feasibility assessment. Energy use and financial data may be required, and facilities may wish to enter into a non-disclosure agreement if they deem the data to be sensitive or proprietary. This visit may be a day-long event, and facilities would need to offer necessary employee time to help utility engineers access and understand information about the facility's energy use.

After the deep dive, the utility conducts a feasibility assessment to determine whether or not to rule out each of the "deep dive" facilities. Basic equipment quotes are gathered from a variety of vendors to enable a future investment-grade assessment.

Develop Project Priority Pipeline

Based on the results of the feasibility assessment, determine order of priority for the projects that are determined to go forward. Identify if any are in locations that are in particularly constrained areas of the distribution or transmission system. Review long-term generation, distribution, and transmission plans to understand if certain projects should be prioritized over others. Begin investigation into the necessary processes to acquire permits.

Draft Contractual Agreements and Billing Arrangements

Depending on the cost of the project, draft contractual obligations for the host facility to take the power and thermal energy for a five to ten year period. Stipulate the share of risks and the costs associated with early termination of the contract. For instance, a utility could arrange a five-year agreement with a host specifying that the host will pay the utility for thermal power for five years regardless of whether the host remains in business.

If hosts are not being asked to make significant investments and take on the bulk of project risk, a utility can reasonably expect to develop contractual agreements that allow it to enjoy most of the benefits. Unlike situations in which individual host facilities take on all the risk of a new CHP system, a facility enjoying the steam and reliability benefits of a utility-owned system will not require the same degree of direct benefit. Therefore, utilities will likely find themselves in a strong bargaining position to request ownership of assets such as energy efficiency and emissions reductions credits.

If the host facility is paying the utility a fixed cost for the power and/or thermal energy, discuss the fixed cost and clarify what such costs entail, who is paying for maintenance, etc. If the utility intends to integrate the entire cost into its rate base, but allow the host facility access to the thermal energy, discuss the circumstances under which the host facility would be capable of ramping up or down thermal demands.

For CHP systems sited on existing facilities, determine the actual real estate that will be dedicated to the plant, and the arrangements for access to the property during construction and then operation.

Design, Build, Commission and Finalize Contracts

Each utility will have its own preference of how it wishes to construct the actual plant and all of its equipment. Presumably the utility would bid out the bulk of this work and select contractors based on the cost-effectiveness of their bids, their reputation for conducting quality work, and their experience with handling similar projects.

Developer Framework to Evaluate and Measure Long Term Benefits

The benefits of CHP to the local distribution system and the larger transmission system are not adequately valued in most energy efficiency programs or considered in generation and distribution and transmission planning. The need to understand exactly how CHP affects local distribution infrastructure is high. A pilot project offers an exceptional opportunity to quantify, for the given distribution system, the degree to which CHP provides location-specific benefits. Metering of specific distribution assets, for example, would help utilities understand how strategically sited CHP can reduce load immediately on certain pieces of infrastructure.

Data from specific deployments and projects is necessary and would, ideally, be publicly available to other utilities to understand how certain applications affect the grid at large. Assumptions about how future CHP systems might impact the grid need to be based on measured and evaluated experience.

Though a CHP system may be treated as a supply-side asset to the utility, the benefits to the host facility itself should be measured and evaluated as well. There is not a sufficient body of data on how utility-owned or utility-controlled CHP sited at individual facilities impacts the facilities it serves, and improvements to onsite reliability, improved power quality, etc., need to be documented so as to be adequately reflected in future assessments of costs and benefits.

Finally, while CHP case studies abound, case studies identifying actual deployment of utility-owned CHP at individual facilities are needed. These case studies need to be specific to the service territory, and should clearly reflect the economic benefits and costs that accrue to both the utility and the customer.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

NW Natural

Reply Testimony of Andrew Speer

UM 1744
Carbon Emission Reduction Program
Combined Heat & Power (CHP)

Cost Recovery

October 2, 2015

Table of Contents

Rates & Regulatory Affairs
NW NATURAL
220 N.W. Second Avenue
Portland, Oregon 97209-3991
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I. INTRODUCTION

Q. Please state your name.

A. My name is Andrew Speer.

Q. Are you the same Andrew Speer who previously submitted direct testimony in this proceeding?

A. Yes. My title, address, and job responsibilities with Northwest Natural Gas Company ("NW Natural" or the "Company") have not changed.

Q. What is the purpose of your reply testimony?

A. The purpose of my reply testimony is to respond to concerns raised in the testimony of Staff and the intervenors regarding the Company's calculated rate impact for the Combined Heat and Power Solicitation Program ("CHP Program"). I also respond to issues raised in parties' testimony regarding the Company's expected increased margin from the incremental sales of gas under the CHP Program.

II. RATE IMPACT

Q. What concerns have been raised by Staff regarding the rate impact of the CHP Program?

A. Staff stated that they were confused about the Company's expected rate impact of the CHP Program. (*Staff/100, Klotz/4-5*). Staff is also concerned that the average monthly residential rate impact is too uncertain and too high given the identified benefits of the CHP Program. (*Staff/100, Klotz/5*).

Q. Has the Company proposed any changes to the CHP Program that address Staff's concerns?

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A. Yes, in response to Staff's concerns that the program's costs are too uncertain and high, the Company is now requesting authorization of the program up to the base case target of 240,000 MTCO2(e). (*NWN/300, Summers/15*). This proposal is detailed in the Reply Testimony of Barbara Summers. (*NWN/300, Summers/2*).

Q. Will this proposal help clear up concerns Staff raised regarding the rate impact in the Company's initial filing?

A. Yes. In the Application, we provided rate impact analysis for a "low case," "base case" and "high case" – each case varied based on the expected metric tonnes of carbon reduced by the CHP Program. Now that we are specifically asking for approval of the program up to the base case, I believe that we are providing a level of certainty around the rate impact that Staff is seeking.

Q. Were there other sources of Staff's confusion relating to the rate impact of the CHP Program?

A. Yes, it appears that Staff was confused by the differences between my Direct Testimony filed in this docket on June 24, 2015 and the Supplemental Testimony filed on July 16, 2015. In my Direct Testimony filed with the Application, I provided the rate impact of the CHP Program by customer class. This overstated the rate impact to our ratepayers because it presented the rate impact as the sum of the rate impacts for each rate schedule within a customer class. The CHP Program Business Plan filed with the Application included the rate impact by rate schedule. (*NWN/101, Summers/49*). In light of this overstatement, NW Natural refiled testimony to correct for this. In my Supplemental Testimony, I

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updated my testimony by removing the previous presentation of rate impact and, instead, included as an exhibit the rate impact by rate schedule from the CHP Business Plan. This provides the Commission and parties a more accurate reflection of the costs and rate increases associated with the CHP program. (*NWN/201, Speer/1-2*).

Q. In addition to your Supplemental Testimony, has the Company provided additional information that addresses Staff's confusion as it relates to the rate impact associated with the CHP Program?

A. Yes. In response to OPUC IR 3, NW Natural provided two attachments, which included working spreadsheets for the updated rate impact model and margin calculation. With respect to the rate impact model, Attachment 1 to the Company's response to OPUC IR 3 includes the equal percent of margin rate impact analysis, which shows the rate impact by rate schedule and an average bill impact evaluation by rate schedule. I have attached the rate impact and average bill impacts to this testimony as NWN/401 and 402. The Company presented the rate impact analysis and margin calculation at a workshop for the CHP Program held on September 18, 2015.

Q. Please describe the information contained in the rate schedule and average bill impact tables of the Company's rate impact analysis.

A. The table showing rate impact by rate schedule shows all of the Company's rate schedules and shows the incremental volumetric rate increase as well as the amount of allocated cost and revenue generated by rate schedule. (*NWN/401, Speer/1)*. The average bill impact table includes the incremental monthly bill

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increase associated with the base case assumption for the CHP program. (*NWN/402, Speer/1)*. Current volumetric and base rates are used to calculate the monthly bill based on average monthly usage by rate schedule and then the incremental CHP volumetric rate increase is included to calculate the monthly bill increase based on average usage by rate schedule.

Q. Staff points to a footnote in the CHP Business Plan that still shows a $2.50 average monthly bill increase to residential customers. Is this the expected increase for residential customers?

A. No, it is not. While my Supplemental Testimony removed the rate impact by customer class, the footnote in the CHP Business Plan was not revised and reflected the overstated rate impact.

Q. What is the average monthly bill increase for residential customers?

A. The average monthly residential bill impact associated with CHP at the base case for a residential customer is $0.99. (*NWN/402, Speer/1*).

Q. Can the Company replicate Staff's calculation of a rate increase as high as 9 percent? (*Staff/100, Klotz/6*).

A. No. The percentages shown in tables filed by the Company in NWN/201,Speer/2 and the response to OPUC IR 3 do not show any percentages anywhere near 9%.

Q. Did the Company evaluate the potential rate impact associated with the removal of a third-party incentive from the Oregon Department of Energy or the Energy Trust of Oregon?

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A. No, the Company did not evaluate this because the removal of a third-party incentive does not impact the costs of the CHP Program. As such, the removal of a third-party incentive would not change the rate impact. The only costs that comprise the Company's CHP Program costs are the customer incentive ($30), company incentive ($10), and the program implementation and start-up costs.

III. <u>MARGIN CALCULATION</u>

Q. Did the parties raise concerns related to the Company's calculation of the incremental margin associated with the CHP Program?

A. Yes, Staff questioned the Company's calculation of the incremental margin from the CHP Program. (*Staff/200, St. Brown/19*). CUB also raised concerns that the Company has not adequately quantified the benefits to customers (i.e., the increase of throughput in the absence of capital investment) and that we have not provided an adequate showing of those benefits. (*CUB/100, McGovern-Jenks/5-6*).

Q. How do you respond to Staff and CUB's concerns?

A. In my Direct Testimony, I calculated the marginal system benefit from the incremental therms of CHP based on a single 10 MW CHP unit. (*NWN/200, Speer/2*). The margin from the 10 MW CHP unit totaled $136,647, assuming the program participant is a schedule 32 firm transportation customer. Using the Company's example, Staff calculated an annual margin associated with twelve 10 MW resources to achieve the target base case of 240,000 MTCO2(e) based on 120 MWs, which totaled $1,639,764 of annual margin. (*Staff/200, St.*

Brown/20). However, the Company does not expect that it will meet the target base case of 240,000 MTCO2(e) using twelve 10 MW CHP units.

Q. How does the Company expect to meet the target base case?

A. In response to OPUC IR 10, NW Natural provided a more plausible mix of resources that could make up the base case. I have included the Company's response to OPUC IR 10 as NWN403 to my testimony. The mix of resources included, two 45 MW, two 4.3 MW, and one 21.7 MW CHP units. (*NWN/403, Speer/1*).

Q. What is the expected incremental margin based on the Company's expected resource mix at the base case?

A. The Company estimates the incremental margin, or the benefit to customers, to be $680,463 annually, for the year at which the CHP adoption peaks under the base case. (*NWN/404, Speer/1*).

Q. What accounts for the difference between the Company's calculation of incremental margin and Staff's calculation based on twelve 10 MW CHP units?

A. The amount of margin from CHP is a function of incremental therm usage, which is dependent on engineering characteristics, such as plant size and efficiency factors. The five resources that the Company identified assumes a mix of three different sized CHP resources with unique incremental therm usage amounts. (*NWN/403, Speer/1*).

Q. Does this conclude your testimony?

A. Yes.

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BEFORE THE

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Exhibit 401 of Andrew Speer

UM 1744
Carbon Emission Reduction Program
Combined Heat & Power (CHP)

Rate Impact by Rate Schedule

October 2, 2015

	A	B	C	D	E	F
1	**Carbon Solutions - CHP Filing**					
2	**Program Budget and Rate Impact Analysis**					
3	**Appendix C - CHP Financial Plan Budget Rate Impact**					
4						
5	**CHP Proposal Rate Impact Analysis by RS**					
6	*Customer Incentive:*	*$ 30*				
7	*NWN Incentive:*	*$ 10*				
8						
9	*Scenario Case:*	*Base*				
10			**Total Revenue by RS**	**Allocation of CHP Costs to RS**	**% of CHP Costs of Total Revenue**	**Incremental Rate Increase**
11	*Schedule*	*Block*				*$/Therm*
12	2R		$ 424,979,184	$ 6,806,155	1.602%	0.01863
13	3C Firm Sales		$ 162,060,249	$ 2,084,038	1.286%	0.01311
14	3I Firm Sales		$ 3,602,539	$ 42,597	1.182%	0.01118
15	27 Dry Out		$ 746,214	$ 10,866	1.456%	0.01551
16	31C Firm Sales	Block 1	$ 28,263,801	$ 342,696	1.212%	0.00988
17		Block 2	$ -	$ -	n/a	0.00902
18	31C Firm Trans	Block 1	$ 800,604	$ 25,622	3.200%	0.01189
19		Block 2	$ -	$ -	n/a	0.01087
20	31I Firm Sales	Block 1	$ 9,372,355	$ 92,167	0.983%	0.00720
21		Block 2	$ -	$ -	n/a	0.00651
22	31I Firm Trans	Block 1	$ 182,571	$ 5,831	3.194%	0.00732
23		Block 2	$ -	$ -	n/a	0.00662
24	32C Firm Sales	Block 1	$ 22,700,448	$ 193,077	0.851%	0.00573
25		Block 2	$ -	$ -	n/a	0.00487
26		Block 3	$ -	$ -	n/a	0.00344
27		Block 4	$ -	$ -	n/a	0.00201
28		Block 5	$ -	$ -	n/a	0.00115
29		Block 6	$ -	$ -	n/a	0.00057
30	32I Firm Sales	Block 1	$ 7,168,342	$ 43,844	0.612%	0.00424
31		Block 2	$ -	$ -	n/a	0.00360
32		Block 3	$ -	$ -	n/a	0.00254
33		Block 4	$ -	$ -	n/a	0.00148
34		Block 5	$ -	$ -	n/a	0.00085
35		Block 6	$ -	$ -	n/a	0.00043
36	32 Firm Trans	Block 1	$ 5,252,577	$ 167,602	3.191%	0.00401
37		Block 2	$ -	$ -	n/a	0.00341
38		Block 3	$ -	$ -	n/a	0.00241
39		Block 4	$ -	$ -	n/a	0.00141
40		Block 5	$ -	$ -	n/a	0.00080
41		Block 6	$ -	$ -	n/a	0.00040
42	32C Interr Sales	Block 1	$ 12,464,877	$ 65,996	0.529%	0.00412
43		Block 2	$ -	$ -	n/a	0.00350
44		Block 3	$ -	$ -	n/a	0.00247
45		Block 4	$ -	$ -	n/a	0.00144
46		Block 5	$ -	$ -	n/a	0.00082
47		Block 6	$ -	$ -	n/a	0.00041
48	32I Interr Sales	Block 1	$ 20,209,633	$ 88,671	0.439%	0.00395
49		Block 2	$ -	$ -	n/a	0.00336
50		Block 3	$ -	$ -	n/a	0.00237
51		Block 4	$ -	$ -	n/a	0.00138
52		Block 5	$ -	$ -	n/a	0.00079
53		Block 6	$ -	$ -	n/a	0.00040
54	32 Interr Trans	Block 1	$ 6,529,780	$ 208,018	3.186%	0.00359
55		Block 2	$ -	$ -	n/a	0.00305
56		Block 3	$ -	$ -	n/a	0.00216
57		Block 4	$ -	$ -	n/a	0.00126
58		Block 5	$ -	$ -	n/a	0.00072
59		Block 6	$ -	$ -	n/a	0.00036
60	33		$ -	$ -	n/a	0.00023
61						
62	**TOTALS**		**$ 704,333,176**	**$ 10,177,180**	**1.445%**	

BEFORE THE

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NW Natural

Exhibit 402 of Andrew Speer

UM 1744
Carbon Emission Reduction Program
Combined Heat & Power (CHP)

Average Bill Impact by Rate Schedule

October 2, 2015

Carbon Solutions - CHP Filing
Program Budget and Rate Impact Analysis
Appendix C - CHP Financial Plan Budget Rate Impact
Effects on Average Bill by Rate Schedule
ALL VOLUMES IN THERMS

Schedule	Block	2014 Oregon PGA Normalized Volumes page, Column D	Therms in Block	Normal Therms Monthly Average use	Minimum Monthly Charge	11/1/2014 Billing Rates	11/1/2014 Current Average Bill	Proposed Incremental CHP Rate	Proposed Incremental CHP Average Bill	Proposed Incremental CHP Bill Increase	Proposed Incremental CHP % Bill Change
							F=D+(C * E)		H=D+(C * (E+G))		J = (H - F)/F
		A	B	C	D	E	F	G	H	I	J
2R		365,285,306	N/A	53	8.00	1.01330	$ 61.70	0.01863	$ 62.69	$ 0.99	1.6%
3C Firm Sales		158,936,755	N/A	233	15.00	0.95518	$ 237.56	0.01311	$ 240.61	$ 3.05	1.3%
3I Firm Sales		3,811,735	N/A	1,143	15.00	0.93199	$ 1,080.26	0.01118	$ 1,093.04	$ 12.78	1.2%
27 Dry Out		700,552	N/A	38	6.00	0.91	$ 40.55	0.01551	$ 41.14	$ 0.59	1.5%
31C Firm Sales	Block 1	20,701,736	2,000	3,324	325.00	0.69453		0.00988			
	Block 2	15,317,497	all additional			0.67662		0.00902			
	Total						**$ 2,609.90**		**$ 2,641.61**	**$ 31.71**	1.2%
31C Firm Trans	Block 1	1,022,480	2,000	3,039	575.00	0.17309		0.01189			
	Block 2	1,238,213	all additional			0.15815		0.01087			
	Total						**$ 1,085.50**		**$ 1,120.57**	**$ 35.07**	3.2%
31I Firm Sales	Block 1	4,178,853	2,000	5,744	325.00	0.63779		0.00720			
	Block 2	9,536,789	all additional			0.62191		0.00651			
	Total						**$ 3,929.01**		**$ 3,967.78**	**$ 38.77**	1.0%
31I Firm Trans	Block 1	181,494	2,000	8,981	575.00	0.15988		0.00732			
	Block 2	680,650	all additional			0.14450		0.00662			
	Total						**$ 1,903.51**		**$ 1,964.37**	**$ 60.86**	3.2%
32C Firm Sales	Block 1	26,567,626	10,000	8,483	675.00	0.56907		0.00573			
	Block 2	7,804,067	20,000			0.55465		0.00487			
	Block 3	829,092	20,000			0.53064		0.00344			
	Block 4	20,793	100,000			0.50663		0.00201			
	Block 5	0	600,000			0.49221		0.00115			
	Block 6	0	all additional			0.48261		0.00057			
	Total						**$ 5,502.42**		**$ 5,551.03**	**$ 48.61**	0.9%
32I Firm Sales	Block 1	4,645,409	10,000	21,272	675.00	0.56814		0.00424			
	Block 2	5,152,955	20,000			0.55389		0.00360			
	Block 3	1,826,257	20,000			0.53013		0.00254			
	Block 4	627,963	100,000			0.50636		0.00148			
	Block 5	(0)	600,000			0.49210		0.00085			
	Block 6	0	all additional			0.48263		0.00043			
	Total						**$ 12,599.85**		**$ 12,682.83**	**$ 82.98**	0.7%
32 Firm Trans	Block 1	12,006,597	10,000	55,532	925.00	0.09488		0.00401			
	Block 2	16,315,496	20,000			0.08064		0.00341			
	Block 3	9,641,378	20,000			0.05697		0.00241			
	Block 4	16,134,178	100,000			0.03327		0.00141			
	Block 5	21,282,059	600,000			0.01906		0.00080			
	Block 6	1,920,752	all additional			0.00959		0.00040			
	Total						**$ 4,810.05**		**$ 4,974.35**	**$ 164.30**	3.4%
32C Interr Sales	Block 1	5,686,222	10,000	29,595	675.00	0.57809		0.00412			
	Block 2	7,563,208	20,000			0.56339		0.00350			
	Block 3	3,897,038	20,000			0.53889		0.00247			
	Block 4	4,445,365	100,000			0.51438		0.00144			
	Block 5	71,870	600,000			0.49967		0.00082			
	Block 6	0	all additional			0.48989		0.00041			
	Total						**$ 17,495.53**		**$ 17,605.31**	**$ 109.78**	0.6%
32I Interr Sales	Block 1	7,186,289	10,000	42,618	675.00	0.57815		0.00395			
	Block 2	8,946,142	20,000			0.56345		0.00336			
	Block 3	5,135,755	20,000			0.53895		0.00237			
	Block 4	10,445,179	100,000			0.51445		0.00138			
	Block 5	4,597,392	600,000			0.49977		0.00079			
	Block 6	1	all additional			0.48997		0.00040			
	Total						**$ 24,525.97**		**$ 24,662.58**	**$ 136.61**	0.6%
32 Interr Trans	Block 1	8,779,332	10,000	194,626	925.00	0.09620		0.00359			
	Block 2	15,689,249	20,000			0.08179		0.00305			
	Block 3	11,306,695	20,000			0.05777		0.00216			
	Block 4	28,429,084	100,000			0.03373		0.00126			
	Block 5	56,035,539	600,000			0.01933		0.00072			
	Block 6	78,278,646	all additional			0.00975		0.00036			
	Total						**$ 8,913.82**		**$ 9,212.05**	**$ 298.23**	3.3%
33		0	N/A		38,000.00	0.00554	38,000.00	0.00023	38,000.00	0.00	0.0%
Totals		962,859,686									

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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UM 1744
Carbon Emission Reduction Program
Combined Heat & Power (CHP)

NW Natural Response to OPUC IR 10 – Attachment 1

October 2, 2015

Scenario	Target Carbon Reduction	Target Incremental Carbon Reduction by Year	Carbon Reduction per MW	Installed Capacity	Number of Customers	Average	Mix
Low	150,000	150,000	3,000	50	2	2,986	45 MW + 4.3 = 49.3
Base	240,000	90,000	3,000	80	5	3,030	45 MW + (3) 4.3 + 21.7 = 79.2
High	330,000	90,000	3,000	110	7	3,027	45 MW + (5) 4.3) + (2) 21.7 = 109.9

Scenario	Target Carbon Reduction	Target Incremental Carbon Reduction by Year	Carbon Reduction per MW	Installed Capacity	Number of Customers	Average	Mix
Low	150,000	150,000	2,000	75	2	1,972	45 MW + (2) 4.3 + 21.7 = 75.3
Base	240,000	90,000	2,000	120	5	1,892	(2) 45 MW + (2) 4.3 + 21.7 = 124.6
High	330,000	90,000	2,000	165	7	1,955	(2) 45 MW + (3) 4.3 + (3) 21.7 = 168

CHP PROGRAM ANALYSIS & SCENARIOS

Program Investment Assumption	Scenario Case	Real or Nominal $'s	NWN Incentive	Carbon Reduction per MW	Installed CHP Capacity (MW)
Select Cell and Use Dropdown	Base	Real	On	2,000	120

Program Year	2016 ~~2015~~	2017 ~~2016~~	2018 ~~2017~~	2019 ~~2018~~	2020 ~~2019~~	2021 ~~2020~~	2022 ~~2021~~	2023 ~~2022~~	2024 ~~2023~~	2025 ~~2024~~	2026 ~~2025~~	2027 ~~2026~~	2028 ~~2027~~
1st Year Startup Costs	$ 150,000												
WSU Development Costs		$ 20,000	$ 20,000	$ 20,000	$ 20,000								
WSU Startup Costs	$ 12,000												
Marketing		$ 10,000	$ 10,000	$ 10,000	$ 10,000								
Independent Certificatio	$ -	$ 50,000		$ 75,000		$ -							
M&V		$ 50,000	$ 50,000	$ 125,000	$ 125,000	$ 125,000	$ 125,000	$ 125,000	$ 125,000	$ 125,000	$ 125,000	$ 75,000	$ 75,000
Ongoing Legal	$ 20,000		$ -		$ -								
New FTE for CHP Program		$ 196,777	$ 196,777	$ 196,777	$ 196,777	$ 196,777	$ 196,777	$ 196,777	$ 196,777	$ 196,777	$ 196,777	$ 196,777	$ 196,777
Total Program O&M	$ 182,000	$ 326,777	$ 276,777	$ 426,777	$ 351,777	$ 321,777	$ 321,777	$ 321,777	$ 321,777	$ 321,777	$ 321,777	$ 271,777	$ 271,777
Tonnes of Carbon		$ 150,000	$ 150,000	$ 240,000	$ 240,000	$ 240,000	$ 240,000	$ 240,000	$ 240,000	$ 240,000	$ 240,000	$ 90,000	$ 90,000
Customer Incentive		$ 4,500,000	$ 4,500,000	$ 7,200,000	$ 7,200,000	$ 7,200,000	$ 7,200,000	$ 7,200,000	$ 7,200,000	$ 7,200,000	$ 7,200,000	$ 2,700,000	$ 2,700,000
Total O&M	**$ 182,000**	**$ 4,899,178**	**$ 4,848,428**	**$ 7,741,178**	**$ 7,665,053**	**$ 7,634,603**	**$ 7,634,603**	**$ 7,634,603**	**$ 7,634,603**	**$ 7,634,603**	**$ 7,634,603**	**$ 3,016,353**	**$ 3,016,353**
NWN Incentive	$ -	$ 1,522,500	$ 1,522,500	$ 2,436,000	$ 2,436,000	$ 2,436,000	$ 2,436,000	$ 2,436,000	$ 2,436,000	$ 2,436,000	$ 2,436,000	$ 913,500	$ 913,500
Total Program Cost	$ 182,000	$ 6,421,678	$ 6,370,928	$10,177,178	$10,101,053	$10,070,603	$ 10,070,603	$ 10,070,603	$10,070,603	$10,070,603	$10,070,603	$ 3,929,853	$ 3,929,853

Installed Capacity Receiving Subsidy		75	75	120	120	120	120	120	120	120	120	45	45
Year 1-2	1	45	45	89,915	89,915								
	2	4.3	8.6	12,774	25,548								
	1	21.7	21.7	42,255	42,255								
			75	144,944	157,718								
Year 3-12	2	45	90	89,915	179,830								
	2	4.3	8.6	12,774	25,548								
	1	21.7	21.7	42,255	42,255								
			120	144,944	247,633								
Year 13-14	1	45	45	89,915	89,915								
	0	4.3	0	12,774	-								
	0	21.7	0	42,255	-								
			45	144,944	89,915								

	100%				66%			
Facility Type	**Emission Reductions Excluding Upstream Emissions MTCO2(e)/yr**	**Emission Reductions Excluding Upstream Emissions MTCO2(e) per MW per year**	**Emission Reductions Including Upstream Emissions MTCO2(e)/yr**	**Emission Reductions Including Upstream Emissions MTCO2(e) per MW per year**	**Emission Reductions Excluding Upstream Emissions MTCO2(e)/yr**	**Emission Reductions Excluding Upstream Emissions MTCO2(e) per MW per year**	**Emission Reductions Including Upstream Emissions MTCO2(e)/yr**	**Emission Reductions Including Upstream Emissions MTCO2(e) per MW per year**
Gas Turbine - 21.7 MW	62,652	2,887	64,023	2,950	41,350	1,906	42,255	1,947
Gas Turbine - 45 MW	132,175	2,937	136,234	3,027	87,235	1,939	89,915	1,998
Reciprocating Engine - 500 kW	1,297	2,594	1,708	3,416	856	1,712	1,127	2,254
Reciprocating Engine - 4.3 MW	15,051	3,500	19,354	4,501	9,934	2,310	12,774	2,971
Hospital - 800,000 sf with Two 800 kW Recip Engines	3,249	2,031	4,243	2,652	2,144	1,340	2,800	1,750

BEFORE THE

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UM 1744
Carbon Emission Reduction Program
Combined Heat & Power (CHP)

Incremental Margin

October 2, 2015

32 Firm Trans	Therms per Block	Base Rate	Base Rate Adj	Total Temp Adj	Billing Rate	Margin Rate
Block 1	10,000	0.09385	0.00099	0.00004	0.09488	0.09484
Block 2	20,000	0.07975	0.00085	0.00004	0.08064	0.08060
Block 3	20,000	0.05632	0.00059	0.00006	0.05697	0.05691
Block 4	100,000	0.03286	0.00034	0.00007	0.03327	0.03320
Block 5	600,000	0.01877	0.00020	0.00009	0.01906	0.01897
Block 6		0.00941	0.00010	0.00008	0.00959	0.00951
	Rate	MDDV Volume				
Dist Capacity Charge (based on MDDV)	0.15748	126,930				

	Annual (Therms)	Monthly
Incremental therms from an assumed 5 expected CHP customers	46,329,610	3,860,801

Incremental Monthly Therms by Block	Incremental Margin
-	$ -
-	$ -
-	$ -
-	$ -
-	$ -
3,860,801	$ 36,716
Volumetric Revenue	$ 36,716
Dist. Capacity Revenue	$ 19,989
Total Monthly Margin	$ 56,705
Total Annual Margin	**$ 680,463**
Total Program Margin (10 yrs)	**$ 6,804,627**

Select Case **2,000 lbs/MW**

CHP Resource MW Capacity by Plant Size	Incremental CHP Therm Usage by Plant Size	# of CHP Plants 2,000 lbs/MW	# of CHP Plants 3,000 lbs/MW	Total Capacity by Resource	Total Annual Therm Usage by Resource (MMBtu)
45	1,775,435	2	1	90	3,550,870
4.3	103,161	2	3	8.6	206,322
21.7	875,769	1	1	21.7	875,769
1.6	42,088	-	-	-	-
0.5	18,929	-	-	-	-
	Total	**5**	**5**	**120.3**	**4,632,961**

Note:
See NWN Oregon Rate Schedule 32 Firm Transpiration rate schedule tariff.
https://www.nwnatural.com/uploadedFiles/2532ai(7).pdf

Assumptions:
Margin evaluated as a 32 firm transportation customer only.
It is assumed that customers are already currently taking gas service at blocks 1-5.
The same volumetric margin is used for all incremental therms.
Incremental therm usage is taken from the WA State model which takes into account baseline usage of the existing customer.
Pre-taxed marginal revenue.
No incremental investment.
Installed CHP MW capacity mix is consistent with the resource mix as identified in the Company's response to OPUC IR 10.