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July 16, 2015

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attention: Filing Center
201 High Street SE, Suite 100
Post Office Box 1088
Salem, Oregon 97308-1088

**Re: UM 1744 – Emissions Reduction Program (SB 844)
Errata Filing**

Northwest Natural Gas Company, dba NW Natural ("NW Natural" or "Company"), files herewith a correction to its originally submitted Application for Emissions Reduction Program ("Application") on June 24, 2015 as follows:

- <u>Tariff Sheet 510-2</u>:
  The erratum corrects Tariff Sheet 510-2, which incorrectly capped the amount of the CHP Program incentive at $2 million per customer site per year. The actual cap is $4.5 million per customer site per year, which is supported by the testimony and business plan filed with the Application. The change is limited to Original Sheet 510-2.

- <u>CHP Program Business Plan:</u>
  The CHP Business Plan is being replaced in its entirety and reflects the following changes.

  - <u>Appendix D</u>:
    The original application noted the WSU RELCOST MODEL would be provided digitally. A CD is being mailed to the Commission today, July 16, 2015.

  - <u>Appendix E:</u>
    "The Assessment of the Technical and Economic Potential for CHP in Oregon Final Report, July 2014", was inadvertently not included in the original filing and is attached.

- Appendix F
  "Energy 350 Summary of Measurement and Verification Gaps and Remediation" has been replaced in its entirety with "Energy 350 NW Natural CHP Program M&V Requirements Comparison".

- Table of Contents:
  The table of contents is updated to reference the Appendix E CHP Sensitivity Study which was included in the original filing but not shown in the table of contents. In addition, the table of contents is updated to reflect the change to Appendix F discussed above.

Should you have any questions, please feel free to contact me directly at 503.721.2476.

Sincerely,

/s/ Mark R. Thompson

Mark R. Thompson
NW NATURAL

Attachments

SCHEDULE 510
COMBINED HEAT and POWER SOLICITATION PROGRAM
(SB 844 Carbon Emission Reduction Program)
(continued)

PROGRAM DESCRIPTION (continued)

Customer Incentives: Incentives for CHP Program carbon emissions reductions are available on a first come, first serve basis. Customer incentives are based on measured and verified MTCO2 reductions on a quarterly basis for the first 40 quarters (10 years) of operation in accordance with the Measurement and Valuation provision of this **Schedule 510**.

Schedule 510 CHP Program Incentive:
$30 per MTCO$_2$ saved, capped at $4.5 million per customer site per year.

NW Natural Incentives: NW Natural will include $10.00 per MTCO2(e) reduced in the annual deferral balance in accordance with the Program Cost Recovery provision of this **Schedule 510**.

SPECIAL CONDITIONS

1. As part of the application for participation under this **Schedule 510**, all participants must qualify for and meet all terms and conditions of service under the Rate Schedule under which Customer will take natural gas service for the CHP system, including but not limited to the establishment of credit under **Rule 2** of the Tariff of which this Schedule is a part.

2. The Participant will be required to pay the Company, in advance, for any construction costs or other distribution facilities costs required to provide service to a Customer under this CHP Program in accordance with **Schedule X** or **Rule 20**, whichever shall apply.

   Where the approved project requires an increase in natural gas system pressure, the Company will provide such high pressure service under the same terms and conditions as set forth in **Schedule H** "Large Volume Non-Residential High Pressure Gas Service (HPGS) Rider of the Company's approved Tariff, which provide for charges to the customer to recover all costs associated with the installation of required compression equipment.

3. At the time of application for participation in the CHP Program, the Customer must include a Technical Assessment for the Customer's proposed CHP system. The Technical Assessment must include all of the information required by the Company's Technical Assessment criteria, which is available on request, or from the Company's website. At a minimum, the Technical Assessment must provide Engineering specifics on the facility, thermal and electric loads, proposed CHP system, and a proposed commissioning and measurement and verification (M&V) plan.

(continue to Sheet 510-3)

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

NW Natural

Exhibit 101 of Barbara Summers

Carbon Emission Reduction Program
Combined Heat & Power (CHP)
Business Plan

NW NATURAL

Combined Heat & Power Solicitation

Carbon Solutions Project Proposal

Business Plan

NW Natural

Table of Contents

Introduction

This business plan contains details regarding NW Natural's development of a Combined Heat & Power (CHP) Solicitation Program, for which the Company plans to seek approval by the Oregon Public Utility Commission as part of the utility's Carbon Solutions Program. This document serves the purpose of documenting the proposed program design and assumptions for NW Natural's internal purposes, but is also for use in assisting the stakeholders under the processes called for in ORS 757.539 in evaluating the proposal.

Combined Heat and Power Overview and Related Policy

CHP, also known as cogeneration, produces electricity and useful thermal energy in an integrated system. CHP systems can range in size from megawatts in industrial, institutional and large commercial applications, down to a few kilowatts in small commercial and even residential applications. Combining electricity and thermal energy generation into a single process can save up to 35 percent of the energy required to perform these tasks separately. The energy efficiency comes from the displacement of natural gas with what is otherwise "waste heat," but which is instead recovered from on-site electricity generation for use in space and water heat and industrial processes.

CHP efficiency benefits both the natural gas and electricity systems. CHP is a substitute for baseload electric generation and the waste heat is a substitute for natural gas and on-site combustion equipment otherwise needed to produce heat. In addition to the benefits of making productive use of waste heat from electricity generation beyond that which is possible with a Combined Cycle Gas Turbine (CCGT), there are other benefits that accrue to the electric system. These include avoidance of transmission and distribution losses (around 6-10% of generated electricity), and the potential to reduce generation redundancy.

The benefits of CHP are widely recognized, and have been the focus of actions and policy making at both the state and federal level. For example, President Obama's August 30, 2012 order on "Accelerating Investment in Industrial Energy Efficiency" directed, among other things, "certain executive departments and agencies to convene national and regional stakeholders to identify, develop and encourage the adoption of investment models and State best practice policies for industrial energy efficiency and CHP; provide technical assistance to States and manufacturers to encourage investment in industrial energy efficiency and CHP; provide public information on the benefits of investment in industrial energy efficiency and CHP; and use existing Federal authorities, programs, and policies to support investment in industrial energy efficiency and CHP."[1] That order also set a national goal of deploying 40 gigawatts of new, cost effective industrial CHP in the United States by the end of 2020.

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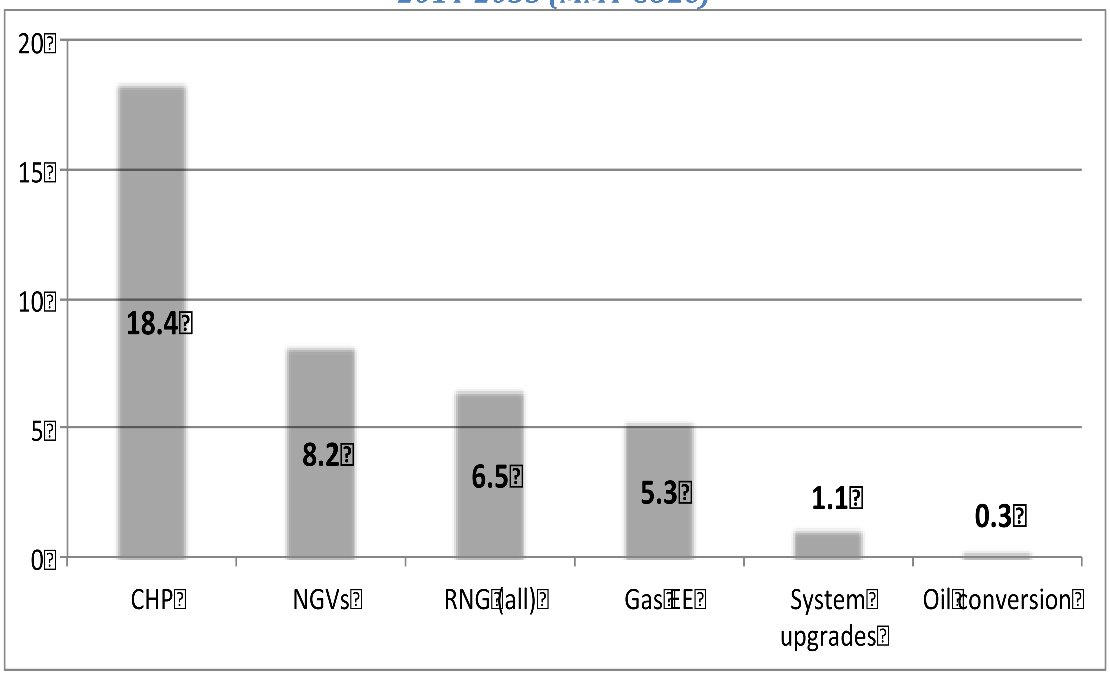
[1] *See* Executive Order on Accelerating Investment in Industrial Energy Efficiency, August 30, 2012, *available at* http://www.whitehouse.gov/the-press-office/2012/08/30/executive-order-accelerating-investment-industrial-energy-efficiency.

In 2013, Governor Kitzhaber requested that the USDOE include Oregon in the list of states partnering in support of Present Obama's Executive Order[2]. In addition, Governor Kitzhaber's 10-year Energy Plan similarly focuses on the benefits of distributed generation and Combined Heat and Power, noting that it "has huge potential to help the state meet its energy goals."[3]

NW Natural believes that CHP should be a major focus of GHG reduction efforts, and notes that CHP provides the greatest natural gas-related abatement potential (2013-2035), based on findings from the Oregon Department of Energy and Center for Climate Solutions, Energy Trust of Oregon (ETO) and The Climate Trust as well as company estimates[4].

Figure 1
Total Natural-Gas Related Abatement Potential
2014-2035 (MMT CO2e)



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[2] Letter dated February 6, 2013, from Governor John A. Kitzhaber, M.D., to Katrina Pielli, US Department of Energy.

[3] *See* p. 27 of Governor Kitzhaber's 10-Year Energy Action Plan, *available at* http://www.oregon.gov/energy/Ten_Year/Ten_Year_Energy_Action_Plan_Final.pdf

[4] Center for Climate Strategies (2012). *10-Year Energy Action Plan Modeling: Greenhouse Gas Marginal Abatement Cost Curve Development and Macroeconomic Foundational Modeling for Oregon*. Oregon Department of Energy, July 30, 2012. Accessed February 17, 2014 at http://www.oregon.gov/energy/GBLWRM/docs/Energy_Plan_GhG_MACC__Foundational_Modeling_Final_Report.pdf.

Weisberg, Peter, and Thad Roth (2011). *Growing Oregon's Biogas Industry: A Review of Oregon's Biogas Potential and Benefits*. The Climate Trust and The Energy Trust of Oregon. Accessed February 17, 2014 at http://www.oregon.gov/energy/RENEW/Biomass/docs/GrowingORBiogasIndustryWhitePaper.pdf.

CHP Solicitation Program Summary

The CHP Solicitation Program is a voluntary carbon emission reduction program proposed under ORS 757.539, which grants the Oregon Public Utility Commission the authority to allow a natural gas utility to recover costs associated with implementing a program or measures that reduce greenhouse gas (GHG) emissions through the provision of natural gas. Commission rules OAR 860-085-0500 through 860-085-0750 put forth further requirements for voluntary carbon reduction programs, including the requirements for submitting an application to the Public Utility Commission of Oregon for approval of a program.

The CHP Solicitation Program proposal was developed through a cooperative effort between NW Natural, the Oregon Department of Energy (ODOE), the Washington State University (WSU), Northwest CHP Technical Assistance Partnership (TAP) with United States Department of Energy (USDOE), and was designed to leverage the services and capabilities of the Energy Trust of Oregon (ETO). The proposal seeks to marshal the combined resources of these parties by offering customers that are potential developers of CHP plants, a package of incentives and services necessary to cause the development of CHP that would otherwise not happen.

NW Natural, through its CHP Program, is targeting to reduce greenhouse gas emissions by 240,000 MTCO2(e) per year in the State of Oregon by the end of 2020. This goal translates to 80 MWs of CHP at an average of 3,000 MTCO2(e) per MW assuming systems operate 95% of the time and utilize 100% of the reclaimable waste heat and about 120 MWs assuming an average of 2,000 MTCO2(e) per MW. Minimum program eligibility requires CHP to be at least 10% more efficient than a combined cycle gas turbine (CCGT). CHP systems, however, can exceed the efficiency of a utility-scale CCGT by about 35%. So, systems that recover less of the waste heat may still be eligible but would result in less carbon savings. Target greenhouse gas emissions and the resulting program budget assumes CHP, on average, achieves 2,000 MTCO2(e) per MW of reduced emissions (66%) to account for this variability, a level that still exceeds minimum program eligibility efficiency.

As described more fully below, NW Natural's proposed CHP Program leverages funding and services from a number of sources. This includes ODOE's Energy Incentives Program (EIP) funds and the ETO's incentive for CHP and the Federal Business Investment Tax Credits (ITCs). NW Natural proposes to offer customers an incentive payment of a fixed dollar-per-ton of verified $MTCO_2$(e) reduced. The amount of the payment from NW Natural is calculated to provide customers a payment opportunity that, when combined with the available funds from ODOE and the ETO and Federal tax credits, gives them a chance to realize a payback from their CHP investment that makes the economics attractive enough to invest.

Although not a common requirement, the program also involves the option for NW Natural to install compression, if necessary, to support CHP under standard terms and conditions similar to NW Natural's Schedule H.[5] This removes an additional barrier that CHP currently faces.

At a high level, the key aspects of NW Natural's proposed program include:

- A solicitation available to all customers to install CHP facilities (recognizing, however, that current residential technologies do not meet eligibility criteria);
- Eligibility criteria that requires CHP to be 10% more efficient than a CCGT;
- Incentives to CHP customers paid quarterly, for the first 40 operating quarters, based on verified MTCO2(e) of carbon reduced;
- CHP capital investment borne by the customer installing the CHP unit;
- At customer's option, NW Natural to provide gas service at higher pressures to support CHP, if required, under standard terms and conditions similar to Schedule H;
- Upgrades or extensions to distribution system handled consistent with established policy (Schedule X and G-5.5);
- Minor program upfront costs with majority of the program costs realized only as program uptake increases, thereby limiting the risk of stranded costs;
- CHP program and incentive costs treated as O&M expenses for rate making purposes since capital costs are paid for by CHP customers;
- Project certification and Measurement and Verification handled by an independent third party contractor (Energy 350).

From the customer's perspective, developing a successful CHP project in Oregon will involve:

- Common eligibility criteria for receiving the available funds from ODOE, ETOTO, and NW Natural;
- Common measurement and verification requirements;
- The potential for stacked incentives, with ETO basing its incentive on energy efficiency, ODOE basing its incentive on capital investment, and NW Natural basing its incentive on measured and verified carbon savings;
- Gas service at pressures that will support installation of CHP under standard terms and conditions similar to Schedule H;
- A means to rely on the ETO to provide a Preliminary Assessment and Technical Assessment of proposed projects eligible for ETO incentives; and through ODOE and NW Natural through the USDOE Technical Assistance Partnership with WSU for projects not eligible for ETO incentives.

[5] Schedule H provides for the installation of compression equipment under an arrangement that requires the customer to pay for the installation over time.

Market Potential of CHP

The ODOE engaged ICF International to assess the technical and economic potential of CHP in the state of Oregon. ICF identified 1,457 MW of existing CHP technical potential and 319 MWs of economic potential (*i.e.* payback of less than 10 years). See Appendix E, ICF International, Assessment of the Technical and Economic Potential for CHP in Oregon, Final Report, July 2014.

Currently, there are only 24 MWs of existing non-biomass CHP in the State of Oregon, represented by only two installations:

Oregon State University	9 MW
University of Oregon	15 MW

NW Natural confirmed the reasonableness of ICF International's assessment by estimating CHP potential based on the thermal loads of customers that are typically the best CHP applications. The best CHP applications are those where electrical and thermal loads coincide. Examples of such applications include industrial processes that need heat and electricity during the same time period (particularly those with 24/7 operation), and commercial applications such as hotels, hospitals, nursing homes, schools, colleges, laundries, health facilities, and multi-unit apartments. Round-the-clock thermal and electrical loads are of key importance in allowing a return on the CHP capital investment within an acceptable amount of time. NW Natural estimated CHP capacity is summarized in Table 2, below.

Table 2

Potential CHP Candidates

CHP System Size	Customers	Estimated MWs	Average Cost per kW (000)
< 1 MW	243	51	$2.0
1 - 5 MW	58	92	$1.8
>5 – 20 MW	7	87	$1.3
>20 MW	4	155	$0.8
Total	312	385	

Solicitation Program Design

NW Natural proposes to solicit CHP projects as described in detail in Appendix A, Combined Heat and Power (CHP) Solicitation. Under the program, NW Natural will pay customers an incentive to install and operate a CHP facility, based on the carbon emissions savings achieved as a result of the installation. All NW Natural customers will be eligible to propose projects at locations within NW Natural's franchised service territory within the State of Oregon; however, incentives will only be paid on measured and verified carbon savings. NW Natural will release its initial solicitation upon approval by the OPUC and will coordinate, if possible, with ODOE's announcements of available EIP funds for CHP in 2015. (ODOE funds are allocated on a biennial basis, with the next biennium beginning July 1, 2015.) NW Natural's program will remain open after the initial solicitation until terminated by the Company.

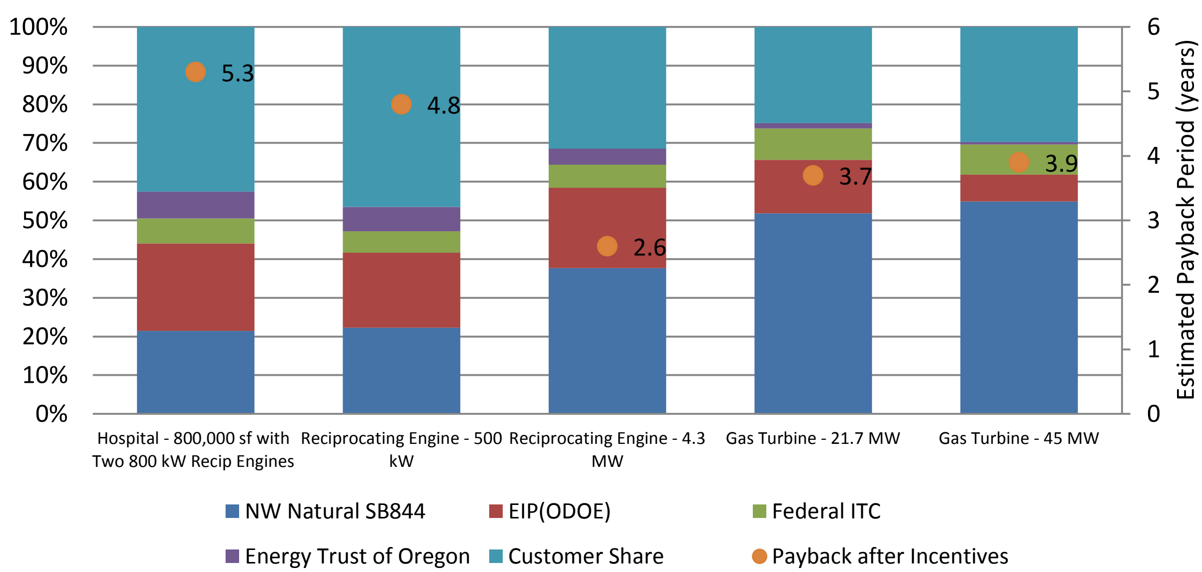
NW Natural's proposed incentive level was modeled assuming full utilization of incentives from ODOE, the ETO and Federal ITCs. NW Natural incentive levels described in Appendix A, Combined Heat and Power (CHP) Solicitation, Section III, Incentives, were set assuming other incentives were available and fully applied ahead of NW Natural incentives.

Figures 2 & 3 below depict the stacking of incentive payments that would be available to customers installing CHP facilities, and the estimated payback of their investment. Further below, Table 3 provides more information regarding each payment stream available to customers.

Figure 2

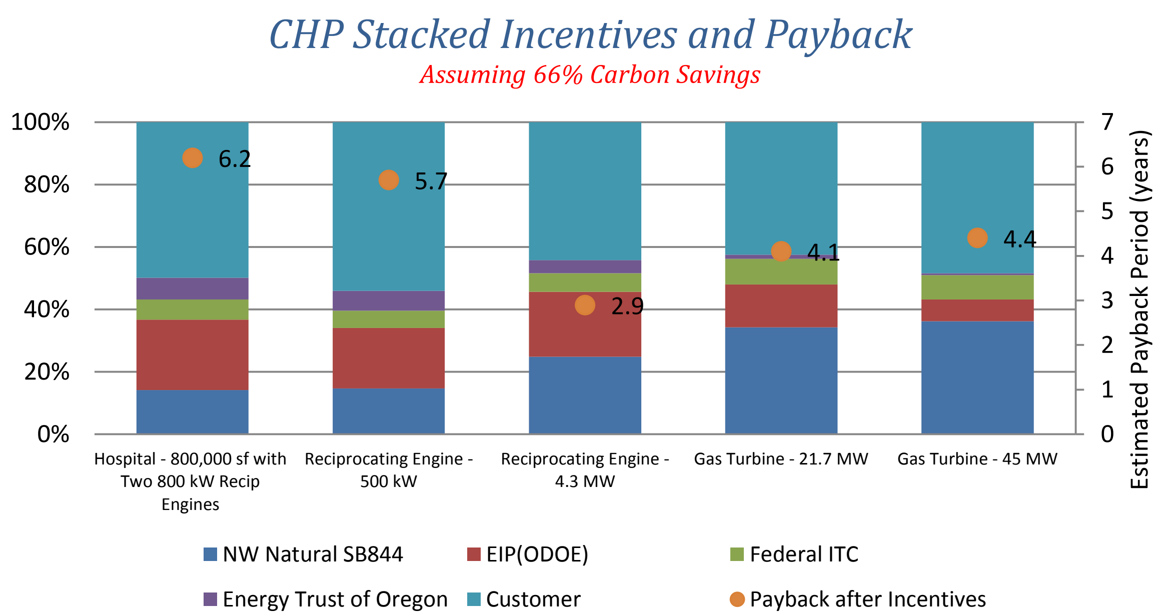
CHP Stacked Incentives and Payback

Assuming 100% Carbon Savings



CHP Stacked Incentives and Payback- Assuming 100% Carbon Savings						
	SB844	***EIP***	***ITC***	***ETO***	***Customer***	***Payback***
Hospital - 800,000 sf with Two 800 kW Recip Engines	21%	23%	6%	7%	43%	5.3
Reciprocating Engine - 500 kW	22%	19%	6%	6%	47%	4.8
Reciprocating Engine - 4.3 MW	38%	21%	6%	4%	31%	2.6
Gas Turbine - 21.7 MW	52%	14%	8%	1%	25%	3.7
Gas Turbine - 45 MW	55%	7%	8%	1%	30%	3.9

Figure 3



CHP Stacked Incentives and Payback- Assuming 66% Carbon Savings

	SB844	*EIP*	*ITC*	*ETO*	*Customer*	*Payback*
Hospital - 800,000 sf with Two 800 kW Recip Engines	14%	23%	6%	7%	50%	6.2
Reciprocating Engine - 500 kW	15%	19%	6%	6%	54%	5.7
Reciprocating Engine - 4.3 MW	25%	21%	6%	4%	44%	2.9
Gas Turbine - 21.7 MW	34%	14%	8%	1%	42%	4.1
Gas Turbine - 45 MW	36%	7%	8%	1%	48%	4.4

In order to qualify for NW Natural's program, projects must meet the requirements described in Appendix A, Combined Heat and Power (CHP) Solicitation.

In addition to the incentives, *at the customer's option*, NW Natural proposes to install compression, if required, under standard terms and conditions similar to Schedule H, as necessary, to enable the installation of CHP at participating customers' sites.

NW Natural considered an alternative program design, under which the company would issue a request for proposals and allow individual customers to then propose CHP projects and the necessary incentives that they would need in order to commit to the projects. This approach was considered to determine if it would yield higher installations of CHP or a carbon reduction at a lower cost. NW Natural has determined that this approach would likely not be as effective as its proposed program design for several reasons.

First, NW Natural understands that developing CHP projects is a long and complicated process, and believes that customers require a high level of certainty in the incentive that would be provided in order to assess the merits, and pros and cons of installing CHP at their facilities. Having a fixed incentive allows customers to quickly and easily envision the economics of a CHP installation. This allows them to make informed decisions about whether they will invest the time and resources required to assess the viability of a project and move forward with what can be a long and difficult process. In contrast, a bidding process approach would leave the customer with uncertainty as to whether their project would be selected and the incentive that could be available. As a result, customers may not include the availability of an incentive in their decision-making process, or may not invest the time and effort to determine the feasibility of a CHP installation.

Second, the timing aspects of a competitive bidding process could be problematic. With a competitive bidding process, NW Natural would have to time the receipt of all proposals at the same time so that they could be ranked and prioritized. This timing requirement would tend to push the program to an annual cycle. This could stifle the development of projects by introducing a separate timing process that may not match individual customers' budgeting and planning cycles, and could cause projects to be needlessly delayed to match up with an annual cycle. By contrast, the standard fixed offer that NW Natural proposes would remain available at all times of the year, and is available whenever an individual customer determines to move forward.

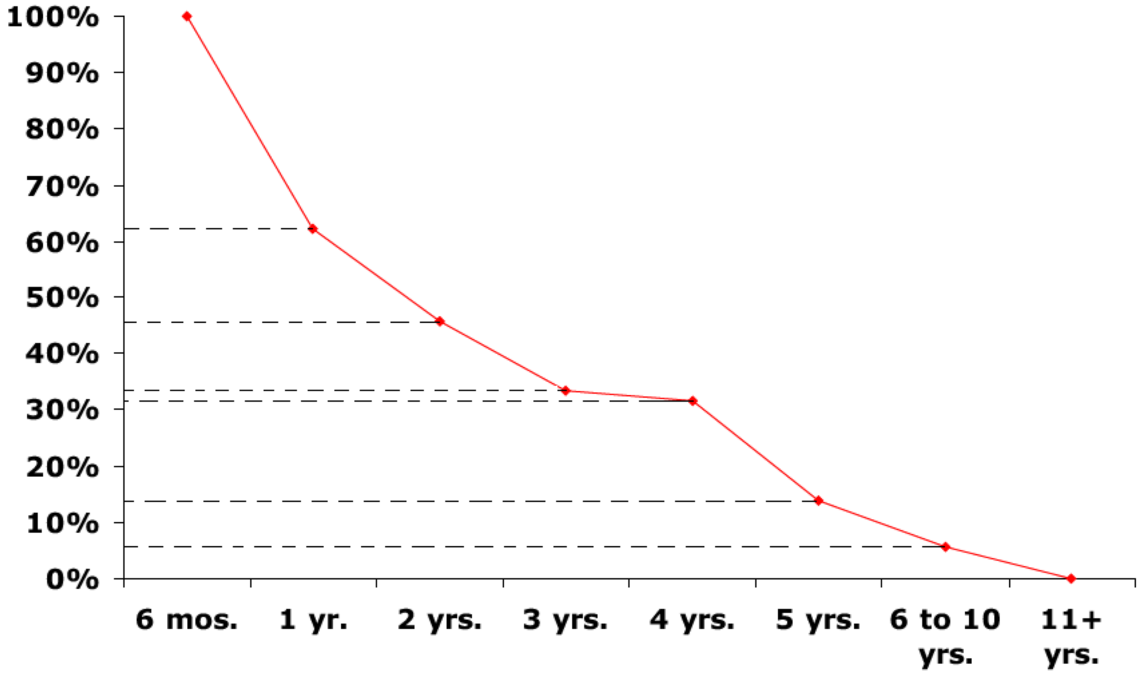
Finally, NW Natural is concerned that a competitive bidding process may not work well for CHP given the lack of robust historic development. It may be that there is limited demand during any bidding process period, which may lead to a situation where costs of delivering the program are unnecessarily high. For example, if bidders were to expect that there 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 available under the program.

CHP Baseline

Figure 4 below represents the expected adoption rate of CHP referenced in the ICF report, given various time periods of payback. As can be seen below, in order to significantly affect the adoption of CHP, customer payback periods must be quite short.

Figure 4

Customer Adoption Payback Curve

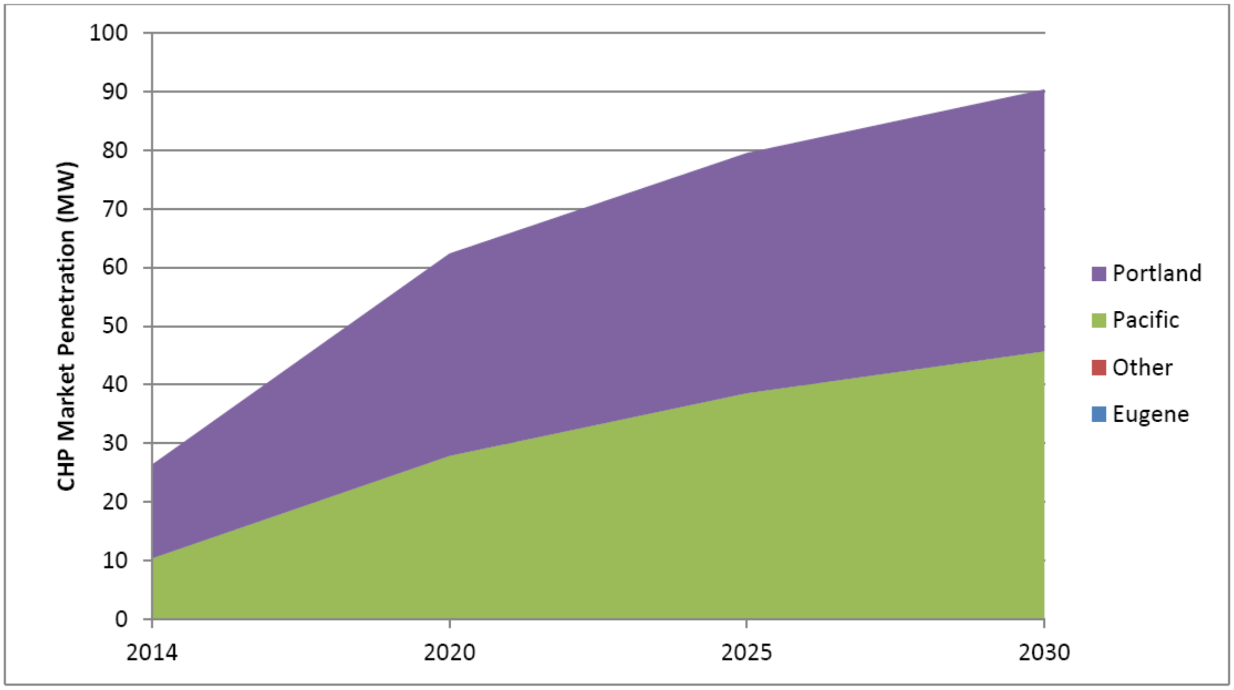


Source: *Primen's 2003 Distributed Energy Market Survey*

ICF arrived at its estimate of CHP market penetration, by multiplying the technical potential, including forecast growth, for each market segment by the share of customers that would accept the calculated economic payback. Based on this approach ICF estimated the market penetration illustrated in figure 5:

Figure 5

ICF Forecast Market Penetration



While the ICF forecast is informative, there is no market evidence to support a CHP baseline above zero. The only operating CHP systems are the two university systems. Forecast CHP to date has not materialized. Neither of the operating systems would have been included in forecast economic potential (less than 10 years). ODOE, ETO and NW Natural are in agreement in setting the baseline for CHP without SB844 incentives at zero.

Customer CHP Incentive Level

Under NW Natural's program, CHP customers will receive \$30 per verified $MTCO_2$(e) reduced based on measured and verified performance. CHP customers are eligible to receive quarterly incentive payments for up to 40 operating quarters based on measured and verified carbon savings. Each CHP customer site will be capped at \$4.5 million of incentive payments per year.

NW Natural's incentive level is based on the results of a financial model (RELCOST) included in Appendix D, developed by USDOE, TAP at WSU, and adapted for NW Natural's program to evaluate project economics considering all incentives for which a qualifying project would be eligible (ETO, ODOE EIP and Federal ITC). The NW Natural incentive was calculated assuming the other incentives were applied in advance of NW Natural's program incentives.

NW Natural relied on the adapted WSU RELCOST model to evaluate payback periods of a range of different prototypes of CHP. NW Natural's proposed incentive of $30 per $MTCO_2$(e) of measured and verified carbon savings was set based on ideal operating conditions, i.e., 8,322 operating hours (95% capacity factor) and 100% utilization of recoverable waste heat.

Since incentives are paid for measured and verified carbon savings, CHP installations that are operated less than 8,322 hours or that utilize less than 100% of the recoverable waste heat would still receive an incentive of $30 per $MTCO_2$(e) for the *actual* measured and verified carbon reduced but would receive an overall lower total amount due to the lower $MTCO_2$(e) savings. The intent was to incent customers to operate CHP systems to achieve maximum carbon savings.

While customers will be paid for actual measured and verified carbon savings of any level, in order to be approved initially, CHP systems must meet the eligibility criteria in the Solicitation. That criterion requires a CHP system to be 10% more efficient than a utility-scale CCGT. A CHP system that operates 8,322 hours per year and utilizes 100% of the recoverable waste heat is estimated to exceed the efficiency of utility-scale CCGT by about 35%.

CHP systems that operate fewer hours or utilize less of the recoverable waste heat may still be eligible if they exceed the efficiency of a utility-scale CCGT by 10%.

While the incentive level of $30 per $MTCO_2$(e) was set assuming CHP systems operated 95% of the time and utilized 100% of the recoverable waste heat, the carbon reduction targets and resulting program budget were set assuming two-thirds of that potential to account for the variability in operations. As described above, CHP systems that operate at optimum efficiency can exceed the efficiency of a utility-scale CCGT by about 35%, however, the program eligibility criteria only requires that it exceed the efficiency by 10%. So, systems that recover less of the waste heat may still be eligible but would result in less carbon savings.

Incentives were set to achieve, on average, about a 3-4 year payback. A 3-4 year payback was targeted to achieve about a 30% - 40% penetration based on the ICF Report and Primen's Customer Adoption Payback Curve. Further, incentives were set using the paybacks assuming ODOE EIP and ETO incentives and Federal ITCs were applied ahead of NW Natural's incentive. Incentives per site are capped at $4.5 Million. Although the cap does have the effect of reducing the incentive for larger installations, the main reason to set the cap was to limit liability in the event actual carbon savings exceed modeled results; not as a factor to reduce the incentive per $MTCO_2$(e).

Table 3 describes the prototype projects that were modeled. Table 4,shows the incentive levels to achieve various paybacks assuming 100% and 66% of forecast carbon savings.

Table 3
WSU Prototype Projects Summary
Baseline Carbon Savings
(Excludes Upstream Emissions)

Project Information								
Description	**Size (MW)**	**Installed Cost**	**Annual O&M**	**100% Carbon Savings**	**66% Carbon Savings**	**EIP Funding at Maximum**	**Current ETO Grant ($.08)**	**Proposed ETO Grant ($.25)**
Hospital - 800,000 sf with Two 800 kW Recip Engines	1.6	$2,932,545	$161,122	3,249	2,144	$1,026,391	$317,834	$500,000
Reciprocating Engine - 500 kW	0.5	$966,154	$78,034	1,297	856	$338,154	$110,183	$344,323
Reciprocating Engine - 4.3 MW	4.3	$7,121,321	$486,671	15,051	9,934	$2,492,462	$500,000	$500,000
Gas Turbine - 21.7 MW	21.7	$29,451,304	$679,009	62,652	41,350	$5,000,000	$500,000	$500,000
Gas Turbine - 45 MW	45.0	$56,160,000	$1,608,082	132,175	87,235	$5,000,000	$500,000	$500,000

Table 4
WSU Incentive Level Analysis

Prototype Facility	Case	NWN CO2e Reduction Incentive ($/tonne/yr)	MTCO2(e) Reduction (Without Upstream)	ETO Rate	ETO Incentive	Before-Tax Simple Payback	After-Tax Discounted Payback
Hospital - 800,000 sf with two 800 kW Reciprocating Engines	N/A	$0	3,249	$0.08	317,834	8.9	Exceeds Project Life
	100%	$30	3,249		317,834	5.3	9.0
	100%	$40	3,249		317,834	4.7	7.1
	100%	$50	3,249		317,834	4.2	5.9
	100%	$60	3,249		317,834	3.8	5.2
	100%	$70	3,249		317,834	3.5	4.7
	100%	$80	3,249		317,834	3.2	4.4
	66%	$30	2,144		317,834	6.2	13.6
	66%	$40	2,144		317,834	5.6	9.9
	66%	$50	2,144		317,834	5.1	8.3
	66%	$60	2,144		317,834	4.7	7.2
	66%	$70	2,144		317,834	4.4	6.3
	66%	$80	2,144		317,834	4.1	5.7
	N/A	$0	3,249	$0.25	500,000	7.6	Exceeds Project Life
	100%	$30	3,249		500,000	4.6	7.3
	100%	$40	3,249		500,000	4.0	5.9
	100%	$50	3,249		500,000	3.6	5.1
	100%	$60	3,249		500,000	3.3	4.6
	100%	$70	3,249		500,000	3.0	4.3
	100%	$80	3,249		500,000	2.7	4.0
	66%	$30	2,144		500,000	5.3	9.7
	66%	$40	2,144		500,000	4.8	8.0
	66%	$50	2,144		500,000	4.4	6.8
	66%	$60	2,144		500,000	4.1	5.9
	66%	$70	2,144		500,000	3.8	5.4
	66%	$80	2,144		500,000	3.5	4.9
Reciprocating Engine - 500 kW	N/A	$0	1,297	$0.08	110,183	8.7	Exceeds Project Life
	100%	$30	1,297		110,183	4.8	7.5
	100%	$40	1,297		110,183	4.2	5.9
	100%	$50	1,297		110,183	3.7	5.0
	100%	$60	1,297		110,183	3.3	4.6
	100%	$70	1,297		110,183	3.0	4.2
	100%	$80	1,297		110,183	2.8	3.9
	66%	$30	856		110,183	5.7	10.5
	66%	$40	856		110,183	5.1	8.3
	66%	$50	856		110,183	4.6	6.9
	66%	$60	856		110,183	4.2	6.0
	66%	$70	856		110,183	3.9	5.3
	66%	$80	856		110,183	3.6	4.9
	N/A	$0	1,297	$0.25	344,323	3.9	8.4
	100%	$30	1,297		344,323	2.1	4.0
	100%	$40	1,297		344,323	1.9	3.8
	100%	$50	1,297		344,323	1.6	3.5
	100%	$60	1,297		344,323	1.5	3.3
	100%	$70	1,297		344,323	1.3	3.1
	100%	$80	1,297		344,323	1.2	3.0
	66%	$30	856		344,323	2.5	4.6
	66%	$40	856		344,323	2.2	4.2
	66%	$50	856		344,323	2.0	3.9

	66%	$60	856		344,323	1.9	3.8
	66%	$70	856		344,323	1.7	3.6
	66%	$80	856		344,323	1.6	3.5
Reciprocating Engine - 4.3 MW	N/A	$0	15,051	$0.08	500,000	3.9	7.1
	100%	$30	15,051		500,000	2.6	3.9
	100%	$40	15,051		500,000	2.3	3.6
	100%	$50	15,051		500,000	2.1	3.2
	100%	$60	15,051		500,000	1.9	3.0
	100%	$70	15,051		500,000	1.8	2.7
	100%	$80	15,051		500,000	1.6	2.6
	66%	$30	9,934		500,000	2.9	4.5
	66%	$40	9,934		500,000	2.7	4.1
	66%	$50	9,934		500,000	2.5	3.8
	66%	$60	9,934		500,000	2.3	3.6
	66%	$70	9,934		500,000	2.2	3.4
	66%	$80	9,934		500,000	2.1	3.2
	N/A	$0	15,051	$0.25	500,000	3.9	7.1
	100%	$30	15,051		500,000	2.6	3.9
	100%	$40	15,051		500,000	2.3	3.6
	100%	$50	15,051		500,000	2.1	3.2
	100%	$60	15,051		500,000	1.9	3.0
	100%	$70	15,051		500,000	1.8	2.7
	100%	$80	15,051		500,000	1.6	2.6
	66%	$30	9,934		500,000	2.9	4.5
	66%	$40	9,934		500,000	2.7	4.1
	66%	$50	9,934		500,000	2.5	3.8
	66%	$60	9,934		500,000	2.3	3.6
	66%	$70	9,934		500,000	2.2	3.4
	66%	$80	9,934		500,000	2.1	3.2
Gas Turbine 21.7 MW	N/A	$0	62,652	$0.08	500,000	5.4	10.9
	100%	$30	62,652		500,000	3.7	5.2
	100%	$40	62,652		500,000	3.3	4.5
	100%	$50	62,652		500,000	3.0	3.9
	100%	$60	62,652		500,000	2.8	3.5
	100%	$70	62,652		500,000	2.6	3.2
	100%	$80	62,652		500,000	2.4	2.9
	66%	$30	41,350		500,000	4.1	6.3
	66%	$40	41,350		500,000	3.8	5.5
	66%	$50	41,350		500,000	3.6	4.9
	66%	$60	41,350		500,000	3.3	4.5
	66%	$70	41,350		500,000	3.2	4.1
	66%	$80	41,350		500,000	3.0	3.8
	N/A	$0	62,652	$0.25	500,000	5.4	10.9
	100%	$30	62,652		500,000	3.7	5.2
	100%	$40	62,652		500,000	3.3	4.5
	100%	$50	62,652		500,000	3.0	3.9
	100%	$60	62,652		500,000	2.8	3.5
	100%	$70	62,652		500,000	2.6	3.2
	100%	$80	62,652		500,000	2.4	2.9
	66%	$30	41,350		500,000	4.1	6.3
	66%	$40	41,350		500,000	3.8	5.5
	66%	$50	41,350		500,000	3.6	4.9
	66%	$60	41,350		500,000	3.3	4.5
	66%	$70	41,350		500,000	3.2	4.1
	66%	$80	41,350		500,000	3.0	3.8
Gas Turbine - 45 MW	N/A	$0	132,175	$0.08	500,000	5.8	12.6
	100%	$30	132,175		500,000	3.9	5.7
	100%	$40	132,175		500,000	3.6	4.9
	100%	$50	132,175		500,000	3.3	4.3
	100%	$60	132,175		500,000	3.0	3.8

	100%	$70	132,175		500,000	2.8	3.4
	100%	$80	132,175		500,000	2.6	3.1
	66%	$30	87,235		500,000	4.4	7.0
	66%	$40	87,235		500,000	4.1	6.1
	66%	$50	87,235		500,000	3.8	5.4
	66%	$60	87,235		500,000	3.6	4.9
	66%	$70	87,235		500,000	3.4	4.5
	66%	$80	87,235		500,000	3.2	4.1
	N/A	$0	132,175		500,000	5.8	12.6
	100%	$30	132,175		500,000	3.9	5.7
	100%	$40	132,175		500,000	3.6	4.9
	100%	$50	132,175		500,000	3.3	4.3
	100%	$60	132,175		500,000	3.0	3.8
	100%	$70	132,175		500,000	2.8	3.4
	100%	$80	132,175	$0.25	500,000	2.6	3.1
	66%	$30	87,235		500,000	4.4	7.0
	66%	$40	87,235		500,000	4.1	6.1
	66%	$50	87,235		500,000	3.8	5.4
	66%	$60	87,235		500,000	3.6	4.9
	66%	$70	87,235		500,000	3.4	4.5
	66%	$80	87,235		500,000	3.2	4.1

Table 5
NW Natural Proposed Customer Incentives

Application	Incentive per $MTCO_2(e)$ of Measured and Verified Carbon Savings	Annual Cap
All Units	$30	$4.5 Million

Note: Multiple units installed at the same customer's site will be viewed as a single unit in determining application of the annual cap.

NW Natural Incentives Under SB 844

NW Natural proposes to receive a $10.00 per MTCO2MTCO2(e) incentive associated with this program based on measured and verified $MTCO_2$(e) savings.

Implementation Plan

NW Natural, ODOE, ETO and the US DOE TAP with WSU worked together to develop a coordinated approach to deliver the services related to administering the program and a consistent eligibility, evaluation and measurement and verification methodology. Under the integrated proposal, applicants will be encouraged to leverage all available funding sources. The services were defined in a way to leverage the strengths of each organization, create common requirements and simplify the process for customers.

Table 6 below shows a summary of each of the three integrated payments that will be available to customers developing CHP under the proposed program.

Table 6

Program Summaries

	Energy Trust of Oregon	**Oregon Department of Energy**	**NW Natural**
Efficiency Requirement	10% more efficient than CCGT Heat Rate	10% more efficient than CCGT Heat Rate	10% more efficient than CCGT Heat Rate
Basis for Incentive	Energy Efficiency	Capital Investment	Carbon Reduction
Incentive	$0.08 per annual kilowatt hour up to 50 percent of eligible project cost up to $500K (proposed to increase to $0.25 per annual kilowatt hour with same limitations).	35% of project cost over 5 years (28.5% NPV). Limited budget. (WSU modeled $5 Million maximum per project.)	$ 30/MTCO2MTCO2(e) CO2 up to $4.5 Million per year
M&V Requirement	Common reporting to the ETO and NW Natural. Short term M&V at time of project completion.	Not Required	Common reporting to the ETO and NW Natural. M&V basis for payment of carbon incentives up to 40 operating quarters.

As described above, the services provided to customers under the program were designed to leverage the strengths and capabilities of each administering entity. Table 7 below shows the various entities and describes the general activities that each would undertake.

Table 7

NWN, ETO, ODOE, USDOE and WSU Coordinated Incentives and Services

Entity	Services Provided / Actions Taken
Customer	• Requests CHP Preliminary Scoping through ETO if customer of PGE or Pacific Power or through NWN or ODOE if outside IOU service territories. • Requests CHP Technical Assessment through ETO if customer of PGE or Pacific Power or through NWN or ODOE if outside IOU service territories. • Completes investment grade analysis or requests CHP Investment Grade Analysis through ETO if customer of PGE or Pacific Power or through NWN or ODOE if outside IOU service territories. • Identifies service requirements under NW Natural line/main extension policies, and required compression. • Applies for ETO, ODOE and NW Natural incentives if project meets eligibility criteria in Appendix A, Combined Heat and Power (CHP) Solicitation. • Acknowledges project certification and acceptance of incentives. • Capitalizes and installs CHP within 24 months of project certification. • Complies with measurement and verification requirements described in Appendix A, Combined Heat and Power (CHP) Solicitation.
NW Natural	• Develops program marketing materials in cooperation with ODOE. • Proactively markets the program to target customers. • Solicits initial CHP proposals. After initial solicitation, NW Natural's offer will remain open. See Marketing Strategy Section, above and Appendix A, Combined Heat and Power (CHP) Solicitation. • Provides expert technical assistance on distribution system requirements. • Measures and verifies carbon savings through independent third party contractor as described below and in Appendix A, CHP Solicitation and provides an annual summary to the ETO and OPUC. • Coordinates efforts with the ODOE and the ETO, including certification of project eligibility. • Pays incentives for measured and verified carbon savings for the first 40 quarters of operation at rates described in Appendix A, Combined Heat and Power (CHP) Solicitation. • At customer's option, provides natural gas service at higher pressures, if required to support CHP, under standard terms and conditions similar to Schedule H. • Upgrades or extends distribution system consistent with established policy (Schedule X and G-5.5 Profitability Analysis for Customer Acquisition). • For customers not eligible for ETO services, provides or coordinates applicable services otherwise provided by the ETO.

Energy Trust of Oregon – (for customers served by Portland General Electric or Pacific Power)	• Provides expert technical assistance through ETO Contractor(s) to include:
	  • CHP Preliminary Scoping.
	  • CHP Technical Assessment.
	These studies are valued at \$3,000 - \$20,000 and are made available from Energy Trust at no cost to customers (self-direct customers pay 50% of cost).
	• Provides technical assistance to develop project specifications, evaluates contractor bids and verifies the project at completion.
	• Provides cash incentives for custom capital projects that are based on annual energy savings, at a rate of \$008 per annual kilowatt hour, up to 50 percent of eligible project cost (proposed to increase to \$0.25 per annual kilowatt hour with same limitations).
	• Coordinates efforts with the Department of Energy and NW Natural.
	• Measures and verifies energy and carbon savings in cooperation with NW Natural.

Oregon Department of Energy	• Reviews projects and awards Tax Credits for qualified CHP/Co-Gen energy projects not to exceed 35 percent of certified cost[6]. ODOE announces total tax credits available for each biennium. The current total available is \$1.5 million, ending June 30, 2015.
WSU (US Department of Energy, Northwest CHP Technical Assistance Partnership)	• Provides CHP Qualification Screening for customers considering an investment in CHP. The analysis is a first cut screening for CHP economic viability at a particular site. It is a high level screen based on minimal site information (e.g., average electric demand, average thermal demand, and average utility rates). The operating cost of a CHP system at a customer's site—including fuel, maintenance, and credit for displaced thermal energy—is estimated assuming performance characteristics of a typical CHP system and prevailing fuel price assumptions for the customer's site location. Qualitative information is also factored in to determine if the site is a potential candidate for CHP. • Provides CHP Feasibility Assessment if the CHP Qualification Screen suggests a more detailed analysis should be pursued to further investigate the technical and economic viability. Under the partnership with the DOE the Technical Assistance Partnership through Washington State University will conduct a "feasibility assessment" which would further explore the customer's facility's energy usage and needs, including overall facility planning and/or goals. The feasibility assessment refines the economics and is based on actual energy usage for the previous 12 to 24 months, information on daily and seasonal electric and thermal load profiles, and insights into site-specific interests such as expansion plans or power reliability concerns or other factors that may impact CHP system selection or sizing. The results of the assessment will provide the customer with a more refined sense of how compelling the estimated economic and

[6] The tax credit is claimed over five years, with 10 percent of the certified cost claimed in each of the first two years and 5 percent claimed in each of the succeeding three years. Alternatively, customers can place the credit with a pass through partner and receive the NPV at 28% of project costs. If the certified cost of the project does not exceed \$20,000, the entire tax credit may be claimed in the first year.

	operational benefits of CHP might be to inform a decision as to whether to take the next step which could include the expenditure of funds for an investment grade analysis.
Tax benefits available under federal law	• IRS Form 3468 sets forth Federal Business Investment Tax Credits (ITCs). The credit is equal to 10% of expenditures, with no maximum limit stated. Eligible CHP property generally includes systems up to 50 MWs that exceed 60% energy efficiency, subject to certain limitations and reductions for large systems. The efficiency requirement does not apply to CHP systems that use biomass for at least 90% of the system's energy source, but the credit may be reduced for less-efficient systems. • Accelerated depreciation (5 year life)

Measurement and Verification Plan

The Company's proposed M&V Plan is set forth in Section VI of the CHP Solicitation. As monitoring and verification is directly linked to payment of incentives, NW Natural contracted with an independent third party, Energy 350, to develop its M&V Plan. (Energy 350 was selected as it is the firm under contract to the ETO to support its CHP program. Energy 350's experience and expertise is summarized in Appendix H of the Business Plan.) Key aspects of NW Natural's proposed M&V Plan include:

1. Measurement and verification will be conducted by an independent third party (Energy 350).
2. Results will be provided to NW Natural on a quarterly basis.
3. Results will be summarized and provided to the ETO and OPUC annually in a format to be agreed upon by the first annual report.
4. Customers propose M&V plan specific to their system that complies with Solicitation.
5. Customer proposed plan must be approved by independent third party (Energy 350) and NW Natural.
6. Independent third party conducts ongoing site inspections consistent with best practices for M&V. The independent third party (Energy 350) will conduct on-site inspection of M&V meter equipment and reporting system processes to ensure performance data is being captured and reporting correctly. All projects will receive a series of periodic inspections after commissioning, M&V, and the post-install inspection has been completed. Conducting periodic M&V inspections based on observations of data is considered best practice. Conducting inspections at defined intervals is not typical or feasible to perform over the lifecycle of each project. Data integrity issues from any site will prompt more frequent visits from the third party M&V contractor to assess the problem. As each project will entail varying degrees of complexity, the number of inspections for each individual project will be determined during the technical analysis phase and budgeted for by the third part M&V contractor. NW Natural has budgeted a flat amount per year per site for M&V, including any onsite inspections.

The Company retained The Climate Action Reserve to review its Measurement and Verification Plan and render an independent opinion as to how closely the specifications aligned with the measurement and verification requirements typically found in standards for carbon offsets. The Climate Action Reserve concluded that the NW Natural specifications align with the carbon offset standards for most measurement and monitoring requirements. See Appendix G for Climate Action Reserve Letter of Opinion and Energy 350 Summary of Identified Gaps.

In addition, NW Natural retained Energy 350 to document the Measurement and Verification requirements of the NW Natural CHP Solicitation program as it compares to the Measurement and Verification requirements of other similar programs. To provide this comparison, Energy 350 researched two well established programs operating today: MassSAVE's CHP Initiative and NYSERDA's CHP Performance Program.

Energy 350 concluded that while NYSERDA and MassSAVE provide more specific programmatic guidelines around what must be included as part of M&V, general guidance provided in the NW Natural document obtains the same level of verification once completed. All programs require a data upload for the duration of the Measurement and Verification period to measure actual performance against claims stated during the technical phase, however NW Natural's performance period is substantially longer (10 years) compared to the other two programs (2 and 3 years).

Several key aspects of the M&V protocols outlined within each program's guidelines were compared to look for significantly different criteria. Overall, no substantial differences were noted with Measurement and Verification requirements among the three programs. A copy of Energy's 350's analysis is contained in Exhibit G.

Budget Overview

The financial forecast includes no capital expenditures. The company accounts for CHP program costs as annual O&M expenditures. Annual costs are represented in "real" dollars and include NW Natural's company incentive. See Appendix C for the specific program year scenarios. The assumptions for program and implementation costs are as follows:

- Customer incentive is $30 per $MTCO_2MTCO_2$(e) up to $4.5 Million per customer site per year.
- Annual program costs include:
    - Measurement and verification (M&V) by independent third party contractor at $25,000 per project per year
    - One time project certification by independent third party contractor at $25,000 per project
    - Marketing at $50,000 at program startup and $10,000 per year during development years
    - Legal at $50,000 at program development and $10,000 per contract

  - WSU modeling and analysis for projects not eligible for ETO services at $20,000 per year during development years.
- Program development consulting at $62,000 (Energy 350 estimated at $50,000 and WSU at $12,000).

As the program is designed to pay only for measured and verified carbon savings and includes a cap on incentives per customer site, overall program costs are based on a number of assumptions as described in Appendix C. Based on those assumptions the program is forecast to incent reduced carbon emissions of 2.5 Million MTCO2(e) over the 15 year program term at a cost of $42.59 per MTCO2(e) including NW Natural's incentive with a low and high range of 1.5 Million to 3.3 Million MTCO2(e) at of cost of $42.51 - $42.85.

Customer Benefits

ORS 757.539(3)(c) and OAR 860-085-0600 (2)(b) require that voluntary projects have customer benefits associated with them. CHP Solicitation Program offers the following benefits, in addition to carbon emissions reduction:

- Increased throughput over the NW Natural system. As CHP is installed, the gas loads at those sites increases substantially. This increase in sales means that there are more therms over which to spread the costs of NW Natural's system. This provides a benefit to all customers, because their rates are set to recover NW Natural's revenue requirement.

- Opportunities for participation in program, which has significant energy cost savings associated with it.

ORS 757.539(8)(a) specifies that costs of emissions reduction programs are allocable to a class of ratepayer only if the Commission finds that "the type of ratepayer receives a benefit from the project." Based on this, and the customer benefits identified above, NW Natural proposes that the costs of the CHP Solicitation Program be allocated to all customer classes, on an equal percent of margin basis.

Based on the Financial Forecast and Budget included as Appendix C and the allocation of costs to all customer classes, the following table represents the rate impact ($/therm) by customer class:

Customer Class	Low Utilization Rate	High Utilization Rate
Residential	0.02125	0.04744[7]
Commercial	0.06376	0.14233
Industrial	0.08746	0.19526

Analytical Considerations

In developing the program proposal, there were key assumptions that needed to be determined. This includes establishing the amount of carbon emissions deemed to be saved through the offset of electrical usage due to CHP.

Below in Table 8 is a description of the key assumptions that went into the program design.

Table 8
Key Analytical Considerations and Conclusions

Consideration	Conclusion(s)
Baseline carbon emissions for alternative grid-supplied electricity.	Stakeholders agreed the EPA eGRID non-baseload rate appeared to be the most highly favored for a number of reasons: • It is specifically called out by EPA as the appropriate value for determining emissions displaced by CHP (in the EPA CHP Partnership guidance documents and in the EPA AVERT model, which seeks to capture marginal GHG emissions displaced by energy efficiency and renewable energy projects) • The values from 2005 to 2010 fall in a fairly narrow range, going both up and down during that period. • It uses a methodology for deriving a marginal resource value, based on the capacity factors of actual plants. • While it is not Oregon-specific, it addresses an area of the grid that the group deemed coherent and appropriate, the multi-state area known as the Northwest Power Pool (NWPP) sub region of eGRID. See Appendix B for analysis and stakeholder process and http://www.epa.gov/cleanenergy/documents/egridzips/eGRID_9th_edition_V1-0_year_2010_Summary_Tables.pdf for original eGRID data.
Baseline carbon emission for the term of the Program.	To achieve investment confidence and financial certainty, baseline carbon emissions for alternative-grid supplied electricity are proposed to be fixed for the term of each project.

[7] The average annual increase in a residential customer's monthly bill assuming a 100% utilization rate is $2.50 based on average residential therm usage.

Carbon emissions per therm of natural gas.	Carbon emissions per therm of natural gas were assumed at 11.7 lbs per therm based on EPA guidelines.
Incentive levels available from the ETO and ODOE.	NW Natural's program assumes ODOE EIP funds will be allocated at levels to support its forecast market penetration and the current ETO incentive level. ETO incentives primarily impact the economics of CHP systems less than 1 MW. At current ETO incentive levels, market penetration of smaller CHP systems is expected to be minimal.
Target overall level of incentives.	WSU solved for NW Natural incentive to achieve a 3-4 year simple payback by evaluating the economics of a range of project prototypes after applying all available incentives. WSU assumed that the NW Natural incentive was applied after other available incentives. These are: the Federal ITC as a grant, an ETO grant and the Oregon Department of Energy's EIP. See Table 4, WSU Incentive Analysis, above and Appendix D. NWN set the program incentive level at $30.00 per MTCO2(e) based on the analysis by WSU. The maximum incentive per customer site per year was set at $4.5 Million.
Assumed market penetration	With a 3-4 year payback, the ICF International, Assessment of the Technical and Economic Potential for CHP in Oregon, July 2014, suggests an expected customer adoption of about 30%-40% based on Primen's 2003 Distributed Energy Market Survey. As stated earlier, NW Natural, through its CHP Program, is targeting to reduce greenhouse gas emissions by 240,000 $MTCO_2$(e) per year in the State of Oregon by the end of 2020. The baseline goal translates to 80 MWs of CHP at 3,000 $MTCO_2$(e) per MW and 120 MWs at 2,000 $MTCO_2$(e) per MW. Eighty MWs represents 25% of ICF *economic* potential and 5% of ICF technical potential. One hundred twenty MWs represent 38% of ICF economic potential and 8% of ICF technical potential.
Assumed operating hours and waste heat recovery for prototype systems.	Incentive levels were set assuming projects operated 8,322 hours (95% of the time) and utilized 100% of the recoverable waste heat. Program targets in terms of reduced MTCO2(e) were set at two thirds of that potential to account for variability in operations. Minimum program eligibility requires CHP to be at least 10% more efficient than a combined cycle gas turbine (CCGT). CHP systems, however, can exceed the efficiency of a utility-scale CCGT by about 35%. So, systems that recover less of the waste heat may still be eligible but would result in less carbon savings. Target greenhouse gas emissions and the resulting program budget assumes CHP, on average, achieves 2,000 $MTCO_2$(e) per MW of reduced emissions (66%) to account for this variability, a level that still exceeds minimum program eligibility efficiency.

Rates Analysis

Under Senate Bill 844, the utility's carbon solutions programs cannot cause an increase in gross revenues in any year of greater than 4%. As the program is designed to pay only for measured and verified carbon savings and includes a cap on incentives per customer site, overall program costs are based on a number of assumptions as described in Appendix C, CHP Financial Plan and Budget and described in the Budget Overview Section, above. Based on those assumptions the program under the base case scenario is forecast to peak at a cost of $10,177,178 Million per year.

Emissions Analysis

WSU calculated the carbon emission reduction for the prototype units shown in Table 9 below.

Baseline emissions factors were estimated using the non-base load eGRID data by sub-region (See Appendix B for summary of analysis and stakeholder process and copies of http://www.epa.gov/cleanenergy/documents/egridzips/eGRID_9th_edition_V1-0_year_2010_Summary_Tables.pdf for original eGRID data and Fuel and Carbon Dioxide Emissions Savings Calculation Methodology for Combined Heat and Power Systems, U.S. Environmental Protection Agency, Combined Heat and Power Partnership February 2015 , (http://epa.gov/chp/documents/fuel_and_co2_savings.pdf) For the region covered by NW Natural, referred to as the Northwest Power Pool, a baseline emissions rate of 1,340 lbs/mWh was utilized in concert with the EPA value for CO_2 content of natural gas of 11.7 lbs/MMBtu.

Table 9

Carbon Emission Reductions

	100%		66%	
Facility Type	**Emission Reductions MTCO2(e)/yr) Without Upstream**	**Emission Reductions MTCO2(e)/yr) With Upstream**	**Emission Reductions MTCO2(e)/yr) Without Upstream**	**Emission Reductions MTCO2(e)/yr) With Upstream**
Gas Turbine - 21.7 MW	62,652	64,023	41,350	42,255
Gas Turbine - 45 MW	132,175	136,234	87,235	89,915
Reciprocating Engine - 500 kW	1,297	1,708	856	1,127
Reciprocating Engine - 4.3 MW	15,051	19,354	9,934	12,774
Hospital - 800,000 sf with Two 800 kW Recip Engines	3,249	4,243	2,144	2,800

Cost Risk Analysis

As most program costs are variable, including customer and company incentives, the main financial risks to customers from the program relate to program startup costs and ongoing fixed costs in the event the program is unsuccessful at causing the development of CHP. Key risks to program success include:

- Customers being unwilling to allocate capital to CHP away from their core business despite incentives; and
- Erosion or removal of ODOE and/or ETO incentives.

If the program were to not succeed at causing the adoption of CHP, then the fixed costs could become stranded. These fixed costs include:

- 1 FTE to manage and administer the program (see mitigation below).
- Collateral material and marketing expenses.

To mitigate the risk of the FTE costs becoming stranded, NW Natural will not hire the FTE to manage and administer the program until after the initial solicitation is released and market response is at or above 37 MWs. NW Natural believes that Major Accounts and Engineering and Operations can support program with current staffing.

The main variable costs associated with the program include:

- Customer incentives.
- NW Natural incentives.
- Capital investment in system compression and related capital costs. (Covered by customer and not an SB844-specific risk.)
- O&M costs associated with system compression. (Covered by customer and not an SB844-specific risk.)
- Capital investment in system expansion or extension (Covered under standard policies; not an SB844-specific risk.)
- Measurement and verification (Energy 350).
- Project certification (Energy 350).
- Project modeling and analysis for program not eligible for ETO services. While the company has budgeted for WSU analysis for this purpose, ODOE/USDOE funding will be relied on instead, if available.

As stated above, these are not incurred except in the event of a successful program.

Stakeholder Engagement Process

Stakeholder meetings were held on the following dates: March 16 and 20th and April 14, 2015. Agendas and Sign-in Sheets are included in Appendix G.

Appendix A: Combined Heat & Power (CHP) Solicitation

I. INTRODUCTION

NW Natural is providing funding to secure CO_2 emissions reductions through the use of Combined Heat and Power (CHP). CHP refers to the simultaneous production of useful energy (most commonly heat and electricity) from a single fuel source, such as natural gas. CHP is a form of distributed generation, which is located at or near the energy-consuming facility. While a typical facility purchases electricity from their local utility and burns fuel in an on-site furnace or boiler to produce useful thermal energy, CHP can be used instead to produce both electricity and thermal energy on-site.

CHP is not a single technology, but rather a method of applying technologies through an integrated system approach. The outcome is a more energy efficient process to meet a facilities thermal and electric energy requirements. This increased efficiency is primarily the result of two main factors:

1. Recovering heat normally lost in central station power generation to provide useful heating or cooling on-site, or to generate additional electricity, and
2. Elimination of transmission and distribution losses from a central power plant (6%-10%)

The increased efficiency of CHP will also result in CO_2 emissions reductions compared to conventional generation sources. This solicitation presents a framework by which NW Natural will fund the CO_2 emissions reductions resulting from the installation and operation of CHP. Eligible CHP systems can receive payments of \$30 per $MTCO_2(e)$ of CO_2 reduction based on measured and verified performance up to \$4.5 Million per customer site per year. See incentives section for details.

In addition to NW Natural funding, the Energy Trust of Oregon (ETO), Oregon Department of Energy (ODOE), and Federal Business Energy Investment Tax Credits (ITC) have CHP incentives available. Applicants are encouraged to leverage all available funding sources.

II. ELIGIBILITY

- Minimum Efficiency – Systems must meet or exceed a Fuel Chargeable to Power (FCP) heat rate of 6,120 Btu/kWh. Calculating FCP allows for a determination of the gas used to generate electricity, incremental to that which would be used for thermal. The FCP heat rate calculation can include a credit for the efficiency of the on-site thermal generation system that the heat recovery is offsetting. The Higher Heating Value (HHV) energy content of natural gas should be used for the FCP calculation.

  - For most prime movers, this will require the use of the majority of total heat available from the CHP system in order to qualify.
- FCP is calculated as follows:

$$FCP = \frac{Gas\ Input\ (Btu) - \dfrac{Heat\ Recovered\ (Btu)}{Offsetting\ Boiler\ Efficiency}}{Net\ Electricity\ Generated\ (kWh)}$$

  Where Net Electricity Generated is net of parasitic loads.

- Fuel Source – The primary fuel source for the prime mover of the CHP must be natural gas.

III. INCENTIVES

- Performance Based CO_2 Reduction Payments – Payment for measured and verified emissions savings in the prior quarter for the first 40 quarters of operation (10 years) after the system is commissioned at $30.00 per MTCO2MTCO2(e) up to $4.5 Million per customer site per year.

- Infrastructure Support – NW Natural will expand the capacity or extend its distribution system to serve the incremental CHP load consistent with established policy (Schedule X and G-5.5 Profitability Analysis for Customer Acquisition). In addition, NW Natural will provide natural gas at higher than system pressure, if required, under terms and conditions similar to Schedule H.

Incentive Calculation

Baseline emissions rates for CHP projects will be based on the annual weighted average emissions of regional utilities. This rate has been determined to be 1,340 lbs/MWh.

The incentive calculation can include an adder for the Transmission & Distribution (T&D) losses avoided by generating electricity on-site. T&D losses are 6% for primary service customers and 10% for secondary. Note that energy exported to the grid will not receive a credit for avoided T&D losses. Once FCP is determined, the incentive can be calculated using the following equation:

$$Incentive = \left(\frac{1{,}340 \frac{lbs}{Mwh} - [.117 \times FCP]}{\frac{2{,}205\ lbs}{tonne}} \right) \times MWh_{CHP} \times (1 + T\&D_{losses}) \times \frac{Incentive\ (\$)}{tonnes}$$

Determining the annual electric generation (MWh_{CHP}) and heat recovered requires an in-depth technical analysis (refer to Technical Assessment Requirements section).

It is the intent of this solicitation to encourage the efficient use of waste heat. As such, NW Natural may not consider added thermal loads as an eligible use of waste heat unless it's part of a facility expansion. For example, if the CHP thermal output is used to heat a facility or process that isn't currently heated, this would not be considered an eligible use of waste heat.

Incentive Cap

Incentives for CHP emissions reductions are available for projects on a first come, first serve basis until NW Natural funds are exhausted under SB844. In addition, incentives are capped at $2 Million per customer site per year.

IV. PARTICIPATION PROCESS

Customers located within NW Natural's franchise service area interested in CHP should take the following steps to secure funding from NW Natural.

1. Submit Application – Applications can be found in Exhibit A of this solicitation. Applications will be reviewed by NW Natural or their contractor for preliminary feasibility. Projects that pass a preliminary feasibility screening will be invited to submit a detailed study.
2. Provide Technical Assessment – A Technical Assessment is an engineering study that will provide Engineering specifics on the facility, thermal and electric loads, proposed CHP system, and a proposed commissioning and measurement and verification (M&V) plan. See section V for details regarding the Technical Assessment. The Technical Assessment will be reviewed by NW Natural or their third party Quality Control contractor for technical and economic feasibility, accuracy of assumptions and analysis, validity of M&V plan, etc. Energy Trust of Oregon will provide preliminary scope and Technical Assessments to their customers at no cost. Energy Trust self-direct customers must cost share 50% of the cost of the Technical Assessment.
3. Install CHP System – Once the Technical Assessment has been approved, funds will be reserved by NW Natural and applicants can install the CHP system.
4. Measure and Verify Performance – Once the CHP system is installed, operational and commissioned, the applicant must measure and verify performance and submit results to NW Natural for payment on a quarterly basis. The M&V must be performed consistent with the plan proposed in the detailed study. An independent third party will conduct a post-install inspection to ensure the specified system is operating according to its design intent, the data collection system and metering equipment is properly installed and calibrated, and the reporting system is receiving and archiving data.
5. Receive Performance Based Payments – M&V submissions must be reviewed and approved by NW Natural's Quality Control contractor. Upon approval of the M&V results, NW Natural will provide performance based payments on a quarterly basis. The sequence of submissions, review, and performance based payments will continue for the first 40 operating quarters.

V. TECHNICAL ASSESSMENT REQUIREMENTS

A technical assessment study must be performed prior to an incentive award. Technical assessments must quantify CHP performance to a high degree of accuracy and defensibility to serve as the basis for determination of an incentive. Below is an outline of major items to address in a CHP technical assessment.

1. Executive Summary
    a. Facility Overview – Description of buildings, processes, annual hours of operation, seasonality, etc. This should identify and summarize key data of major equipment such as central plants, large process loads, HVAC equipment, etc.
    b. Energy Usage – Existing facilities should provide three years of monthly historic electric and gas usage data. New facilities should demonstrate, through engineering analysis, estimates of annual electric and gas usage. Data should be as granular as possible and in no greater intervals than monthly.
    c. Proposed CHP Overview – Provide a high level summary of the system.
    d. Project Life Summary – Narrative describing the service life of the project, including age of existing equipment, if applicable, and engineering and maintenance rationale for estimated service life.
        i. Proposed service life will correspond with industry and regionally recognized sources for equipment life, or a written technical rationale if no source exists.
    e. Economic Summary – Include economics of converting to CHP compared to conventional generation. A conventional generation heat rate of 6,800 BTU/kWh shall be used to represent the grid baseline.
2. CHP Details
    a. Include preliminary equipment selection data including type and efficiency rating of prime mover, (i.e. gas turbine, reciprocating engine, etc.) and equipment specifications.
    b. Describe the annual use for thermal and electric output from the CHP system.
    c. Provide floor plan to specify the location of the CHP.
    d. Identify any required facility upgrades to accommodate the electric and heat output, rejected waste heat, etc.
3. Lifetime Energy Analysis
    a. Describe analytical approach; provide sub-metering data, analytical files, etc.
    b. Load profiles for heat and electric loads must be established in hourly intervals for a representative, full year. Interval metering and/or sub-metering is preferred to support load profile analysis.
    c. Identify periods where CHP capacity may exceed the facilities ability to use or sell electric or heat available from the CHP.

d. Perform hourly energy balance for one-year period including CHP electric and heat output, parasitic loads, use of heat and electric and heat rejection. State all uses for heat recovery and the current heating source for those loads.
e. Account for estimated downtime including planned maintenance and unplanned outages.
f. Document heating efficiency of heating load offset by heat recovery.
g. Calculate Total System Efficiency of CHP system using formula below:

$$Total\ System\ Efficiency = \frac{Net\ Useful\ Energy\ Output}{Total\ Fuel\ Energy\ Input}$$

h. Calculate FCP accounting for offsetting boiler efficiency according to the formula below. The Higher Heating Value (HHV) of gas should be used in this calculation.

$$FCP = \frac{Gas\ Input\ (Btu) - \frac{Heat\ Recovered\ (Btu)}{Offsetting\ Boiler\ Efficiency}}{Net\ Electricity\ Generated\ (kWh)}$$

i. Calculate annual electric generation (MWh_{CHP}) using established annual load profiles and net system output.
j. Calculate incentive based on savings incremental to central power plants based on formula below:

$$Incentive = \left(\frac{1{,}340 \frac{lbs}{Mwh} - .117 \times FCP}{\frac{2{,}205\ lbs}{tonne}} \right) \times MWh_{CHP} \times (1 + T\&D_{losses}) \times \frac{Incentive\ (\$)}{tonnes}$$

4. Cost Details
   a. Provide detailed cost estimates that itemize equipment and installation costs.
   b. Identify and price any required structural or building improvements required.
   c. Include any required electrical upgrades and interconnect expenses.
   d. Include design, permitting, rigging, commissioning and any other expenses.
   e. Identify required annual CHP system maintenance and include estimated costs.
   f. Provide any quantifiable non-energy benefits, such as avoided maintenance costs.
   g. All costs should be supported by additional detail included in the appendix.
5. Commissioning Plan
   a. Include all relevant operating criteria to ensure operation of the system as designed.
   b. Include CHP controls including sequence of operations and integration with existing controls, if applicable.
   c. Include a verification checklist of all equipment and operating parameters that should be verified by NW Natural to ensure complete installation and optimized operation.

6. CHP System Implementation Plan – Include sections on project planning, design, permitting, interconnection, construction, commissioning, maintenance, operations, project management approach and schedule.
7. CHP System Integration – Description of how CHP system will integrate into existing, expanded, or proposed business operation and how it will support a business process or meet a need.
8. Funding/Financial Documentation – Proof of funding or pro forma financial statements that include proposed balance sheet at time of commissioning, estimate balance sheet, cash flow statement, and income statement for three years
9. Construction Plan – Includes project management plan, construction schedule and quality assurance strategy.
10. Measurement & Verification Plan – Applicants should propose an M&V plan consistent with section VI. Measurement and Verification. At a minimum verification should include documentation of monitored points, a list of O&M practices for the CHP system once installed, procedures for identifying concerns found during commissioning and how they are addressed, and a final determination based on findings.

VI. MEASUREMENT AND VERIFICATION

Measurement and Verification (M&V) reporting is required under the provisions of the NW Natural CHP emissions reductions offer. Performance reporting shall be submitted on a quarterly basis (end of March, June, September, December) to NW Natural in the form of a MS Excel spreadsheet in conformance with the reporting template provided in Exhibit B. The method of filing may be by email or uploaded to a drop box determined by the NW Natural Information and Technology Dept. All monitored inputs and outputs regarding CHP shall coincide incrementally hour by hour. The individual Excel tabs shall consist of a format including but not limited to individual input/output points, date stamped in incremental windows of no more than 15 minute increments for the entire quarter. A summary sheet shall be the first Excel tab compiling all the individual tabs within the spreadsheet. An engineering control volume of data points surrounding the CHP system and balance of plant shall give enough empirical data to provide the owner of the CHP system and NW Natural sufficient information to quantify the input energy and useful output of the CHP plant used to derive emissions savings.

Monitoring Points:

- Fuel input: Natural gas metered into the prime mover of the CHP plant or ancillary equipment such as duct burners and recovery boilers used in creating steam for turbines. Where bi-fuel is used for the production of electricity only natural gas supplied fuel will be allowed in the calculation for incentives. For dual-fuel operations, both supplies of fuels shall be reported simultaneously in higher heating value with the proportional ratio of natural gas used in the calculation of emissions savings. NWN supplied billing grade meters will be required or NWN sub metering of billing grade (not rental metering program) will be required.

- Electricity output: With the exception of small and remote parasitic loads where separate metering is not cost justified and an approved engineering solution is presented, the following is true: Electric output must be metered net of parasitic loads. Parasitic loads that are not powered directly by the CHP must be metered separately and netted out of the CHP output. Electric meters shall be accurate to +/- 1%.
- Utility Electric Meter: CHP M&V must include monitoring of the facilities' electric meter(s). If multiple electric meters exist, participants must monitor all that are effected by the CHP.
- Thermal Heat Recovery: Thermal or Waste Heat recovery by definition is used to displace thermal energy that would otherwise be supplied by a device fired by an independent fuel source. Waste heat that does not offset existing natural gas use is not eligible for incentives. Waste heat recovery, used in a process, as steam, hot water or dry heated air, shall be monitored using metering accurate to +/-1%. Liquid, air or steam flow meters must be capable of measuring 120% of the nominal flowrate. The meter must be installed per the flow meter manufacturer's instructions. Where water or air flow is measured, Δ Temperature must also be measured for energy calculations. Where steam is measured, Δ Pressure and Δ Temperature must be measured as well for Enthalpy calculations.
- Heat Rejection: All heat rejected through a condenser or cooling tower must be monitored. Where water or air flow is measured, Δ Temperature must also be measured for energy calculations. Where steam is measured, Δ Pressure and Δ Temperature must be measured as well for Enthalpy calculations.

Meter positioning must be in accordance with manufacturer's specifications and industry best practices. All metering points must be in no greater than 15 minute intervals. All metering points must collect data in the same interval periods.

Data Integrity and Storage: It is the customer's responsibility to maintain the integrity and accuracy of all data reported under this program and all instrumentation required to acquire the required data for the entire 40 quarters contract term. In the event of missing interval data lasting less than 30 consecutive minutes, proxy data shall be used to backfill and noted within the spreadsheet reporting. Catastrophic loss of all data totaling 8 hours or more within any one month will require that the customer make necessary repairs or remedies. Loss of meter information provided by NW Natural shall be reported immediately to NW Natural the next business day. Periods of lost data exceeding 8 hours may result in the suspension of the NW Natural incentive during lost or corrupted data events.

Reporting system data will be cross-checked with electric and gas utility billing grade meters to ensure accuracy. NW Natural will perform calibration and adjustment of provided billing grade meters in accordance with established policy (Refer to Appendix H, NW Natural Meter Testing Procedures) and industry best practices.

Assumptions for the values of carbon dioxide for electricity, natural gas and other energy sources used by the project shall remain in effect for the length of the individual contract of the qualifying project.

VII. NW Natural Contact

Administrative or technical questions regarding this solicitation should be directed to Chris Galati at (503)721-2472 or cfg@nwnatural.com.

Exhibit A – Application

Facility Information	
Facility Name/Organization	Contact Name
Address 1	Day Phone
Address 2	Mobile
City, State, Zip	E-mail

Developer Information	
Developer/Company Name	Contact Name
Address 1	Day Phone
Address 2	Mobile
City, State, Zip	E-mail

Utility Information	
Electric Utility	Electric Account Number(s)
Purchased Electric (kWh)	Electric Rate Class
Average Demand (kW)	Gas Account Number(s)
Purchased Gas (MMBtu)	

Project Information	
CHP System Type (Gas Engine, Gas Turbine, Steam Turbine, etc.)	
Estimated Total Project Cost ($)	
Aggregate Nameplate of CHP System	kW
Annual Electricity Generated from CHP	kWh
Estimated Fuel Chargeable to Power (FCP) Heat Rate	Btu/kWh

Terms & Conditions
Appropriate terms and conditions likely to be added before actual issuance of the CHP Solicitation.

Signature	
Facility Company Name	Authorized Signature Name & Title
Authorized Signature	Date

Exhibit B – Reporting Template

Date	Time	Generator Output	Generator Output Peak	Generator Gas Input	Total Facility Purchased Energy	Total Facility Purchased Demand	Other Facility Gas Use	Unused Heat Recovery	Useful Heat Recovery	Status/Runtime of the Generator	Ambient Temperature	DataQuality Flag 1	DataQuality Flag 2
mm/dd/yyyy	hh:mm:ss	kWh	kW	therms	kWh	kW	therms	MMBtu	MMBtu	hrs	F	na	na

Appendix B: Displacement of greenhouse gas emissions by combined heat and power (CHP) facilities

Fuel and Carbon Dioxide Emissions Savings Calculation Methodology for Combined Heat and Power Systems, U.S. Environmental Protection Agency, Combined Heat and Power Partnership February 2015 ,

http://epa.gov/chp/documents/fuel_and_co2_savings.pdf

Appendix B

http://www.epa.gov/cleanenergy/documents/egridzips/eGRID_9th_edition_V1-0_year_2010_Summary_Tables.pdf

Appendix B

Stakeholder Process and Analysis

Displacement of Greenhouse Gas Emissions by Combined Heat and Power Facilities

Carbon Displacement by Combined Heat and Power (CHP)

NW Natural (contact: Bill Edmonds, Bill.Edmonds@nwnatural.com)
Draft date: March 19, 2015

This memo summarizes stakeholder process and existing research related to the displacement of greenhouse gas emissions by combined heat and power (CHP) facilities. The memo recommends the use of EPA eGRID's nonbaseload calculations and explains the rationale for that recommendation. The memo briefly explains the underlying details of eGRID database and the nonbaseload calculation, and also describes some outstanding issues related to comparing emissions associated with CHP to other contexts involving natural gas. The research, analysis, and stakeholder process described herein were driven by the need for analytical clarity under SB 844, in which it is necessary to specify greenhouse gas emissions associated with various technologies and fuels.

This memo provides NW Natural's recommendation immediately below, and the rest of the memo reviews the process, evidence, existing analysis, and future questions.

NW Natural's recommendation for analysis under SB 844

NW Natural recommends the use of the regionally appropriate value for nonbaseload power from the eGRID database assembled and updated periodically by USEPA. NW Natural's service territory is located entirely within the eGRID sub-region known as the Northwest Power Pool (NWPP).

Furthermore, to strike a balance among the various considerations described below, the company further recommends:

- Use of current value: The company and the PUC shall, in consideration of individual projects, use the most current eGRID value available from EPA. NW Natural is responsible for updating the value in use immediately upon updating by EPA, available at the eGRID web site (http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html).
- Term of use: The value shall be used in calculations of the carbon incentive associated with the project for the entire duration of the project. That is, the value will not change for that project. The value will be valid for ten (10) years.
- Moment of lock-in: The value is locked in once complete project documentation is submitted to the PUC and the official period of agency deliberation and stakeholder engagement has begun. The reason for this provision is to eliminate uncertainty at the latest project stages.

- Calculation details: The value will be the carbon dioxide equivalent (CO_2e) derived from the eGRID emissions rates for carbon dioxide, nitrous oxide, and methane, using 100-year GWP values from the most recent IPCC assessment report, at the moment of submitting project documentation to the PUC. (Currently, the GWP values would therefore come from IPCC Assessment Report 5, published in 2013.)

Consultation with technical and policy stakeholders

In December 2014, NWN convened a group of technical and policy stakeholders from the Oregon Department of Energy, the Energy Trust of Oregon, the Public Utility Commission, and NW Natural itself in order to consider the mixed landscape of guidance documents, protocols, and data sets related to the technical question at hand: What are the carbon emissions displaced by electricity generated at a facility with CHP?

The group considered the evidence at hand, and there appeared to be understanding of and consensus on the following points:

- There are several options, but no single option that immediately rises above all others.
- Nonetheless, it was possible to consider each of the available options through the lens of various criteria (described below).
- Beyond the state agencies involved in the process, there is no agency with clear jurisdiction in this matter.
- NW Natural requires a decision in this area in order to move ahead with CHP projects under SB 844. Therefore, the company is responsible for recommending, and then vetting with others, a path forward.

While the group did not settle conclusively on a single number, all parties were provisionally supportive of using the EPA eGRID nonbaseload value. Everyone also expressed flexibility, with no one strongly advocating for a single particular value.

Challenges and rationale in selecting a measure of carbon displacement by CHP

The selection of a measure is made difficult by the existence of a number of potential options from different sources, the range of values among those options, the absence of national or state policy in this area, and the fact that there is no single authority providing policy in this area.

The basic rationale for using the eGRID subregion nonbaseload value is fairly straightforward: EPA is widely viewed as a credible source; EPA has already recommended the nonbaseload value for precisely this purpose (i.e., quantifying GHG emissions associated with power displaced by CHP); and the use of a "marginal" source rather than an "average source" is appealing to stakeholders.

This last rationale – the desire to capture marginal emissions – is both straightforward and complex. Clearly, we hope to understand, at the margin, what it means to add or subtract a significant resource, such as a large CHP plant. However, the definition of the margin is illusive, and there is no single resource for assessing the marginal impacts of adding resources at a particular time of day or year for all geographies of the electric grid. Fortunately, EPA's eGRID nonbaseload calculation has the only methodology (in the resources that we found or that were suggested by stakeholders) that attempts to look, over the course of an entire calendar year, at which resources come online specifically at lower capacity factors. Furthermore, the methodology is the only one that weights the extent to which a resource figures in the nonbaseload calculation in inverse proportion to its capacity factor. In other words, a resource is not simply in or out of the calculation, but it contributes relatively more to the calculation. (For more discussion of the nonbaseload methodology, see the next subsection of this appendix. For a full description of EPA's eGRID nonbaseload methodology, refer to eGRID supporting documentation.)

Still, every source or value that the group considered had apparent strengths and weaknesses. No one value performs best according to every criterion expressed: conceptual and technical suitability; timeliness of updating and publication; specificity to Oregon or the region; and controlled and updated by Oregon agencies.

In the end, the EPA eGRID nonbaseload rate appeared to be the most highly favored for a number of reasons:

- It is specifically called out by EPA as the appropriate value for determining emissions displace by CHP (in the EPA CHP Partnership guidance documents and in the EPA AVERT model, which seeks to capture marginal GHG emissions displaced by energy efficiency and renewable energy projects)
- The values from 2005 to 2010 fall in a fairly narrow range, both rising and falling during that period.
- It uses a methodology for deriving a marginal resource value, based on the capacity factors of actual plants.
- While it is not Oregon-specific, it addresses an area of the grid that the group deemed coherent and appropriate, the multi-state area known as the Northwest Power Pool (NWPP) subregion of eGRID.

Despite these considerations in favor of the eGRID nonbaseload value, there were concerns as well. The potential concerns raised about the eGRID nonbaseload value were as follows:

- EPA is in control of the updating process and the most recent value available is for 2010 (published in 2014). (This concern is not specific to the selection of the nonbaseload number *per se*, but rather it concerns the use of any source subject to irregular updating.)
- The value for 2004 is very high (and is an outlier) – the reason is not known.
  In the most recent rulemaking on labeling (AR 555), the discussions considered but did not choose to use eGRID.

We intend to research and eventually understand the causes of the high outlier value for 2004. The company will also seek to understand how the value moves with fluctuations in regional hydropower generation, and whether that is relevant to the estimation of a marginal resource.

eGRID database, fuel types, and nonbaseload calculation methodology

EPA's eGRID database is the most comprehensive ground-up (i.e., from the plant level) description of electric power generation in the United States. The narrative in this section references the most recent eGRID technical documentation, *The Emissions & Generation Resource Integrated Database Technical Support Document for the 9th Edition of eGRID with Year 2010 Data*.

EPA established the first version of the eGRID database almost 20 years ago, and since 2007, the database has included information on boiler, generator, plant, state, electric generating company and parent company, and power control area. The data sources include FERC, NERC, US DOE, and various divisions of EPA. As a result, eGRID is regularly referenced in carbon accounting protocols and guidance, as well as life-cycle assessment, other environment impact analysis, and independent research on the electric grid.

To calculate plant-level emissions, eGRID considers both fuel types and plant-specific heat rates. These emissions rates derive from consideration of over forty different fuel types, including coal, oil, natural gas, and biomass, as well as less common fuel resources such as methanol, coke oven gas, and tire-derived fuel (Table 3-6. Plant Primary Fuel, p. 20).

eGRID publishes several emissions rates. The one under scrutiny here is the nonbaseload, a measure of the marginal impacts:

> *Capacity factor is used as a surrogate for determining how much non-baseload generation and emissions occur at each facility... The non-baseload information is published in eGRID just at the aggregate level (state, Power Control Area (PCA), etc.), but not for individual plants. (p. 21)*

While nonbaseload information is aggregated only for the subregion, the full eGRID dataset, available as a public-domain Microsoft Excel file, has data at the plant level for all plants, including those whose capacity factors warrant the plants' inclusion in the nonbaseload calculation. These plants include a wide range of fuels, from natural gas and bituminous coal to wood waste solids and paper pellets. (For the complete list of plants within the nonbaseload calculation, see references below.)

As mentioned in the previous subsection, the nonbaseload calculation includes resources with lower-than-0.8 capacity factors. The explanation in the technical documentation is thorough and concise:

> *The following describes the procedure used to generate these non-baseload emission rates. The emission rates are determined starting with unit or prime mover level data. First, all units and prime movers that do not combust fuel (i.e., hydro, nuclear, wind, solar, and/or geothermal) are removed. Next, a capacity factor relationship is used to determine the percent of the generation and emissions from each unit or prime mover to be considered non-baseload generation. All generation and emissions at units or prime movers with low capacity factors (less than 0.2) would be considered nonbaseload (a non-baseload factor of 1). No generation or emissions at units or prime movers with high capacity factors (0.8 and greater) would be considered non-baseload (non-baseload factor of 0). A linear relationship would determine the percent of generation and emissions that is non-baseload at units or prime movers with capacity factors between 0.2 and 0.8. For these units or prime movers, the non-baseload factor is -5/3*(capacity factor) + 4/3. The capacity factor is determined for both the year and the ozone season. Finally, the total non-baseload generation and the total non-baseload emissions are summed up at each level of aggregation (state, PCA, eGRID subregion, NERC region, and U.S. Total) and are used to calculate the non-baseload output emission rates. (p. 21-22)*

The nonbaseload emissions rate is well above the average for the region for two fundamental reasons. First, all of the resources with the least carbon-intensive "fuels" –wind, hydro, and solar, which together comprise nearly 49% of total generation – are excluded because they are not dispatchable. Second, many fossil resources that have lower capacity factors are used less of the time than baseload resources precisely because they are older, less efficient, and more expensive to operate, and are brought online only when load is high enough or other generation is insufficient, i.e., when higher wholesale prices justify it. Accordingly, they have higher-than-average carbon intensities.

Additional considerations

The group discussed the Unspecified Market Purchase (UMP) mix calculated under statute by ODOE. It was recommended by the group that we might want to pick this number from the latest normal hydro year (which was 2010), and leave that in place until the next typical hydro year. "Normal hydro year" would need to be defined.

In other settings, policy makers have attempted to "pick a marginal resource" – it was mentioned that Washington state had performed a consultant study in this area and found that the marginal resource, a CCCT, was operating near 900 lbs CO2 per MWh. Several stakeholders expressed the appeal of this calculation, so there is some desire to follow up to understand this research. Despite its simplicity and appeal, there is no analysis or official guidance suggesting the use of such a value.

Similarly, there is the option of a similar calculation by the Northwest Power and Conservation Council. While technically strong, the group believes it is not updated frequently enough. The statewide average from the ODOE spreadsheet (net system mix) was considered, but it is a "build up" of the individual utility emissions, so was not viewed as providing useful marginal data.

EPA also recommends the eGRID "fossil rate" for CHP plants with a high capacity factor (operating at more than 6,500 hours per year, about 74%). This emissions rate was viewed as too high and flawed for these displacement purposes, and therefore not relevant to this process.

In all cases, values express a rate associated with combustion, rather than a life-cycle look at emissions throughout the value chain. It is possible that on-going research will provide more accurate life-cycle emissions in the future, at which point the group can discuss the possibilities. Since NW Natural is increasingly using life-cycle values (for example, in analysis of biogas from wastewater treatment plants, and for natural gas in transportation applications), the company would like to work with stakeholders to achieve consistency across applications eventually.

References:

- eGRID database, summary reports, and supporting documentation: All eGRID data, guidance documentation, and original data files with plant-level information can be found on EPA's eGRID web site: http://www.epa.gov/cleanenergy/energy-resources/egrid/.
- *The Emissions & Generation Resource Integrated Database Technical Support Document for the 9th Edition of eGRID with Year 2010 Data*, February 2014, prepared by Abt Associates and Radium Consulting Group: http://www.epa.gov/cleanenergy/documents/egridzips/eGRID_9th_edition_V1-0_year_2010_Technical_Support_Document.pdf
- EPA CHP guidance: The EPA Combined Heat and Power Partnership web page has all of the documentation referenced herein: http://www.epa.gov/chp/.

Appendix C: Combined Heat and Power Financial Plan and Budget

	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 PROGRAM ASSUMPTONS (O&M Costs)					
6	Verification & Monitoring					
7	Independent Certification	$ 25,000	Per project budgeted in year before in-service			
8	M&V	$ 25,000	Per project per year			
9	NWN FTE - 1	$ 115,000	Unloaded Salary Hired in Q3 2015 if solicitation successful			
10	Payroll Loading	71%				
11	Incentives & Emissions					
12	Company Incentive ($/Tonne)	$ 10.00				
13	Customer Incentive ($/Tonne)	$ 30				
14	Marketing, Development & Legal					
15	Marketing	$ 50,000	2015			
16		$ 10,000	Annual			
17	Program Development (Energy 350)	$ 50,000	2015			
18	Program Development Legal	$ 50,000				
19	Ongoing Legal	$ 10,000	Per contract			
20	WSU Development	$ 20,000	2016-2019			
21	WSU Startup	$ 12,000	2015			
22	Other					
23	Inflation Factor	1.5%				
24	Viable Customers					
25	Scenario	Target Carbon Reduction	Target Incremental Carbon Reduction by Year	Carbon Reduction per MW	Installed Capacity	Number of Customers
26	Low	150,000	150,000	3,000	50	2
27	Base	240,000	90,000	3,000	80	6
28	High	330,000	90,000	3,000	110	7

Appendix C: Combined Heat and Power Financial Plan and Budget

	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**					
31	**CHP PROGRAM ANALYSIS & SCENARIOS**					
32		**Scenario Case**	**Real or Nominal $'s**	**NWN Incentive**	**Carbon Reduction per MW**	**Installed CHP Capacity (MW)**
33	**Program Investment Assumption**	**Base**	**Real**	**On**	**3,000**	**80**
34	*Select Cell and Use Dropdown*					

	A	B	C	D	E	F	G	H	I
35	Program Year	2015	2016	2017	2018	2019	2020	2021	2022
36	1st Year Startup Costs	$ 150,000							
37	WSU Development Costs		$ 20,000	$ 20,000	$ 20,000	$ 20,000			
38	WSU Startup Costs	$ 12,000							
39	Marketing		$ 10,000	$ 10,000	$ 10,000	$ 10,000			
40	Independent Certification	$ -	$ 50,000		$ -		$ -		
41	M&V		$ 50,000	$ 50,000	$ 200,000	$ 200,000	$ 200,000	$ 200,000	$ 200,000
42	Ongoing Legal	$ 20,000		$ -		$ -			
43	New FTE for CHP Program		$ 196,777	$ 196,777	$ 196,777	$ 196,777	$ 196,777	$ 196,777	$ 196,777
44	Total Program O&M	$ 182,000	$ 326,777	$ 276,777	$ 426,777	$ 426,777	$ 396,777	$ 396,777	$ 396,777
45	Tonnes of Carbon		$ 150,000	$ 150,000	$ 240,000	$ 240,000	$ 240,000	$ 240,000	$ 240,000
46	Customer Incentive		$ 4,500,000	$ 4,500,000	$ 7,200,000	$ 7,200,000	$ 7,200,000	$ 7,200,000	$ 7,200,000
47	**Total O&M**	**$ 182,000**	**$ 4,899,178**	**$ 4,848,428**	**$ 7,741,178**	**$ 7,741,178**	**$ 7,710,728**	**$ 7,710,728**	**$ 7,710,728**
48									
49	NWN Incentive	$ -	$ 1,522,500	$ 1,522,500	$ 2,436,000	$ 2,436,000	$ 2,436,000	$ 2,436,000	$ 2,436,000
50									
51	Total Program Cost	$ 182,000	$ 6,421,678	$ 6,370,928	$ 10,177,178	$ 10,177,178	$ 10,146,728	$ 10,146,728	$ 10,146,728
52									
53	**Cost of Carbon ($/tonne)**	**$ 42.59**							

	A	J	K	L	M	N	O	P	Q
35	Program Year	2023	2024	2025	2026	2027	2028	2029	Total
36	1st Year Startup Costs								
37	WSU Development Costs								
38	WSU Startup Costs								
39	Marketing								
40	Independent Certification								
41	M&V	$ 200,000	$ 200,000	$ 200,000	$ 150,000	$ 150,000	$ -	$ -	
42	Ongoing Legal								
43	New FTE for CHP Program	$ 196,777	$ 196,777	$ 196,777	$ 196,777	$ 196,777	$ -	$ -	
44	Total Program O&M	$ 396,777	$ 396,777	$ 396,777	$ 346,777	$ 346,777	$ -	$ -	
45	Tonnes of Carbon	$ 240,000	$ 240,000	$ 240,000	$ 90,000	$ 90,000	$ -	$ -	**2,400,000**
46	Customer Incentive	$ 7,200,000	$ 7,200,000	$ 7,200,000	$ 2,700,000	$ 2,700,000	$ -	$ -	
47	**Total O&M**	**$ 7,710,728**	**$ 7,710,728**	**$ 7,710,728**	**$ 3,092,478**	**$ 3,092,478**	**$ -**	**$ -**	**$ 77,861,288**
48									
49	NWN Incentive	$ 2,436,000	$ 2,436,000	$ 2,436,000	$ 913,500	$ 913,500	$ -	$ -	
50									
51	Total Program Cost	$ 10,146,728	$ 10,146,728	$ 10,146,728	$ 4,005,978	$ 4,005,978	$ -	$ -	$ 102,221,288

Appendix C: Combined Heat and Power Financial Plan and Budget

	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 Customer Class**					
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	*Customer Class*					*$/Therm*
12	Residential		$ 409,069,458	6,750,353	1.650%	0.03400
13	Commercial		$ 213,359,648	2,734,376	1.282%	0.10203
14	Industrial		$ 49,079,634	662,003	1.349%	0.13995
15						
16	**TOTALS**		**$ 671,508,740**	**$ 10,146,732**	**1.511%**	

Appendix C: Combined Heat and Power Financial Plan and Budget

	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		$ 408,263,428	$ 6,738,315	1.650%	0.01889
13	3C Firm Sales		$ 154,604,491	$ 2,093,461	1.354%	0.01325
14	3I Firm Sales		$ 4,241,361	$ 52,794	1.245%	0.01133
15	27 Dry Out		$ 806,030	$ 12,038	1.493%	0.01511
16	31C Firm Sales	Block 1	$ 17,120,128	$ 270,880	1.582%	0.01309
17		Block 2	$ 14,372,723	$ 143,293	0.997%	0.01195
18	31C Firm Trans	Block 1	$ 189,532	$ 6,200	3.271%	0.01594
19		Block 2	$ 83,775	$ 2,781	3.320%	0.01456
20	31I Firm Sales	Block 1	$ 3,177,304	$ 46,935	1.477%	0.01125
21		Block 2	$ 5,854,187	$ 50,082	0.855%	0.01016
22	31I Firm Trans	Block 1	$ 81,097	$ 2,646	3.263%	0.01602
23		Block 2	$ 114,515	$ 3,775	3.296%	0.01448
24	32C Firm Sales	Block 1	$ 10,363,534	$ 113,985	1.100%	0.00689
25		Block 2	$ 3,297,737	$ 17,586	0.533%	0.00264
26		Block 3	$ 543,346	$ 2,150	0.396%	0.00186
27		Block 4	$ 110,869	$ 270	0.244%	0.00109
28		Block 5	$ -	$ -	0.000%	0.00082
29		Block 6	$ -	$ -	0.000%	0.00041
30	32I Firm Sales	Block 1	$ 2,618,224	$ 26,738	1.021%	0.00617
31		Block 2	$ 2,550,633	$ 13,485	0.529%	0.00524
32		Block 3	$ 844,309	$ 3,311	0.392%	0.00370
33		Block 4	$ 230,618	$ 556	0.241%	0.00216
34		Block 5	$ -	$ -	0.000%	0.00123
35		Block 6	$ -	$ -	0.000%	0.00062
36	32 Firm Trans	Block 1	$ 2,284,736	$ 74,636	3.267%	0.00654
37		Block 2	$ 1,254,603	$ 41,265	3.289%	0.00556
38		Block 3	$ 520,634	$ 17,097	3.284%	0.00393
39		Block 4	$ 528,279	$ 17,287	3.272%	0.00229
40		Block 5	$ 405,898	$ 13,195	3.251%	0.00131
41		Block 6	$ 25,193	$ 807	3.203%	0.00066
42	32C Interr Sales	Block 1	$ 3,640,693	$ 35,727	0.981%	0.00584
43		Block 2	$ 4,062,657	$ 22,009	0.542%	0.00496
44		Block 3	$ 2,048,573	$ 8,239	0.402%	0.00350
45		Block 4	$ 2,463,572	$ 6,099	0.248%	0.00204
46		Block 5	$ 105,391	$ 154	0.146%	0.00117
47		Block 6	$ -	$ -	0.000%	0.00059
48	32I Interr Sales	Block 1	$ 4,387,308	$ 43,303	0.987%	0.00589
49		Block 2	$ 4,748,395	$ 25,696	0.541%	0.00500
50		Block 3	$ 2,434,090	$ 9,779	0.402%	0.00353
51		Block 4	$ 4,678,913	$ 11,566	0.247%	0.00206
52		Block 5	$ 1,748,259	$ 2,553	0.146%	0.00118
53		Block 6	$ 73,447	$ 55	0.075%	0.00059
54	32 Interr Trans	Block 1	$ 1,815,423	$ 59,245	3.263%	0.00661
55		Block 2	$ 1,283,229	$ 42,114	3.282%	0.00562
56		Block 3	$ 660,444	$ 21,643	3.277%	0.00396
57		Block 4	$ 1,005,315	$ 32,825	3.265%	0.00231
58		Block 5	$ 1,097,435	$ 35,600	3.244%	0.00132
59		Block 6	$ 768,414	$ 24,557	3.196%	0.00066
60	33		$ -	$ -	0.000%	-
61						
62	**TOTALS**		**$ 671,508,740**	**$ 10,146,732**	**1.511%**	

Appendix D: WSU RELCOST MODEL

Digitally Provided

Appendix E:ICF International

Assessment of the Technical and Economic Potential for CHP in Oregon
Final Report, July 2014

ICF INTERNATIONAL

Assessment of the Technical and Economic Potential for CHP in Oregon

Final Report

July 2014

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ICF International

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Introduction

Combined Heat and Power (CHP), also known as cogeneration, produces electricity and useful thermal energy in an integrated system. CHP systems can range in size from hundreds of megawatts - such as those being operated at refineries and in enhanced oil recovery fields down to a few kilowatts that are used in small commercial and even residential applications. Combining electricity and thermal energy generation into a single process can save up to 35 percent of the energy required to perform these tasks separately. This report presents the results of a CHP market assessment undertaken for the Oregon Department of Energy to identify the technical and economic potential for CHP market penetration given the current market and regulatory atmosphere for CHP in Oregon. Recommended CHP priority target market criteria with target market recommendations and rationale are also included. Oregon has 41 retail electric utility providers with a wide range of industrial and commercial electric rates and electric rate structures. Per the U.S. Department of Energy's Energy Information Administration's 2011 Electric Sales and Revenue Report, three utilities have over 9,000 industrial and commercial customers (Portland General Electric, Pacific Power, and Eugene Water and Electric) in applications suitable for CHP with electric demand 50 kW or greater. Additional CHP analysis was developed for these three utilities.

Technical Potential for CHP

This section provides an estimate of the technical market potential for combined heat and power (CHP) in the industrial, commercial/institutional, and multi-family residential market sectors. Two different types of CHP markets were included in the evaluation of technical potential. Both of these markets were evaluated for high load factor (80% load factor and above) and low load factor (51% load factor) applications, resulting in four distinct market segments that are analyzed.

- High load factor traditional CHP (heating only)
- Low load factor traditional CHP (heating only)
- High load factor cooling CHP (heating and cooling)
- Low load factor cooling CHP (heating and cooling)

Traditional CHP

Traditional CHP electrical output is produced to meet all or a portion of the base load for a facility and the thermal energy is used to provide steam or hot water. Depending on the type of facility, the appropriate sizing could be either electric or thermal limited. Industrial facilities often need more thermal energy than electrical energy to produce their products, leading them to have "excess" thermal load compared to their on-site electric load. Commercial facilities almost always have excess electric load compared to their thermal load. Two sub-categories were considered:

High load factor applications: This market provides for continuous or nearly continuous operation. It includes all industrial applications and round-the-clock commercial/institutional operations such colleges, hospitals, hotels, and prisons.

Low load factor applications: Some commercial and institutional markets provide an opportunity for coincident electric/thermal loads for a period of 3,500 to 5,000 hours per year. This sector includes applications such as office buildings, schools, and laundries.

Combined Cooling Heating and Power (CCHP)

All or a portion of the thermal output of a CHP system can be converted to air conditioning or refrigeration with the addition of a thermally activated cooling system. This type of system can potentially expand benefits of CHP to facilities that do not have the year-round thermal load to support a traditional CHP system. A typical system would provide the annual hot water load, a portion of the space heating load in the winter months, and a portion of the cooling load during the summer months. Two sub-categories were considered:

Incremental high load factor applications: These markets represent round-the-clock commercial/institutional facilities that could support traditional CHP, but with cooling, incremental capacity could be added while maintaining a high level of utilization of the thermal energy from the CHP system. All of the market segments in this category are also included in the high load factor traditional market segment, so only the incremental capacity for these markets is added to the overall totals.

Low load factor applications. These represent markets that otherwise could not support CHP due to a lack of heating thermal load, but with the addition of cooling, can support CHP with low load hours. These applications include schools, big box retail stores, museums, movie theaters, supermarkets, and restaurants.

The estimation of technical market potential consists of the following elements:

- Identification of applications where CHP provides a reasonable fit to the electric and thermal needs of the user. Target applications were identified based on reviewing the electric and thermal energy consumption data for various building types and industrial facilities.
- Quantification of the number and size distribution of target applications. Several data sources were used to identify the number of applications by sector that meet the thermal and electric load requirements for CHP. Of note is the Oregon Thermal Baseline, developed by the Oregon Department of Energy, which was used to corroborate data from other databases.
- Estimation of CHP potential by megawatt (MW) capacity. Total CHP potential is then derived for each target application based on the number of target facilities in each size category and sizing criteria appropriate for each sector.
- Subtraction of existing CHP from the identified sites to determine the remaining technical market potential.

The technical market potential does not consider screening for economic rate of return or other factors such as ability to retrofit, owner interest in applying CHP, capital availability, natural gas availability, and variation of energy consumption within customer application/size class. The technical potential as outlined is useful in understanding the potential size and size distribution of the target CHP markets in the state. Identifying technical market potential is a preliminary step in the assessment of market penetration. It is noted that biomass feedstocks are often available in Oregon where natural gas is not available, however this analysis only covers natural gas fueled CHP and waste heat to power (WHP) systems.

The basic approach to developing the technical potential is described below:

- *Identify existing CHP in the state.* The analysis of CHP potential starts with the identification of existing CHP. In Oregon, there are 65 operating CHP plants totaling 2,838 MW of capacity[1]. Of this existing CHP capacity, 57% of the number of sites and 86% of the capacity are in the industrial sector. This existing CHP capacity is deducted from any identified technical potential. A summary of the existing CHP capacity by industry is shown in Table 1.

- *Identify applications where CHP provides a reasonable fit to the electric and thermal needs of the user*. Target applications were identified based on reviewing the electric and thermal energy (heating and cooling) consumption data for various building types and industrial facilities. Data sources include the DOE EIA *Commercial Buildings Energy Consumption Survey (CBECS),* the DOE *Manufacturing Energy Consumption Survey (MECS),* and various market summaries developed by DOE, Gas Technology Institute (GRI), and the American Gas Association. Existing CHP installations in the commercial/institutional and industrial sectors were also reviewed to understand the required profile for CHP applications and to identify target applications.

- *Quantify the number and size distribution of target applications*. Once applications that could technically support CHP were identified, the ICF CHP Technical Potential database was utilized to identify potential CHP sites by SIC code or application, and location. The ICF CHP Technical Potential Database is based on a variety of sources for facility level information including: the Oregon Thermal Baseline by the Oregon Department of Energy, the Oregon Boiler database, EPA Greenhouse Gas Reporting Rule database, the Dun and Bradstreet Hoovers database, the Manufacturers News database, Major Industrial Plant Database (MIPD), and industry specific data sources (i.e. Lockwood Post, Iron & Steel Directory, Oil & Gas Journal, etc.). Commercial application-specific information was used from the American Hospital Association, the Database of Accredited Post-Secondary Institutions, the Dept. of Justice (prisons), and the Dept. of Education, etc.

- *Estimate CHP potential in terms of MW capacity.* Total CHP potential was then derived for each target application based on the number of target facilities in each size category. It was assumed that the CHP system would be sized to meet the thermal demand for the facility unless the thermal loads (heating and cooling) would exceed the average electric demand. Table 3 and Table 4 present the specific target market sectors, the number of potential sites and the potential MW contribution from CHP. There are two distinct applications and two levels of annual load, resulting in a total of four market segments. In traditional CHP, the thermal energy is recovered and used for heating,

[1] CHP Installation Database. Maintained by ICF International for Oak Ridge National Laboratory. 2014.

process steam, or hot water. In cooling CHP, the system provides both heating and cooling needs for the facility. High load factor applications operate at 80% load factor and above; low load factor applications operate at an assumed average of 4500 hours per year (51%) load factor. Figure 1 and Figure 2 offer another depiction of CHP technical potential in Oregon, showing total CHP sites and MW potential by major utility.

- *Estimate the growth of new facilities in the target market sectors.* The technical potential included economic projections for growth through 2030 by target market sectors in Oregon. The growth factors used in the analysis for growth between the present and 2030 by individual sector are shown in Table 5. These growth projections were taken from the EIA 2014 Annual Energy Outlook and were used in this analysis as an estimate of the growth in new facilities or expansion of existing facilities. In cases where an economic sector is declining, it was assumed that no new facilities would be added to the technical potential for CHP. Based on these growth rates the total technical market potential is summarized in Table 6 and Table 7.

Table 1 – Existing CHP in Oregon

SIC	Application	# Sites	Capacity (MW)
1	Agriculture	1	0.04
2	Livestock	9	10.7
20	Food Processing	4	1,368.0
24	Lumber and Wood	15	135.8
26	Paper	7	931.0
33	Primary Metals	1	14.0
4939	Utilities	3	316.4
4952	Wastewater Treatment	11	8.2
4953	Solid Waste	3	20.4
5812	Restaurants	1	0.01
6512	Commercial Buildings	1	0.03
8220	Colleges/Universities	4	24.3
9100	Government	1	0.01
9900	Other	4	9.1
Total		65	2,837.8

Table 2 – CHP Technical Potential by Electric Utility Territory (MW Capacity)

Electric Utility	50-500 kW	500-1 MW	1-5 MW	5-20 MW	>20 MW	Total
Portland General Electric	163	105	182	76	87	614
Pacific Power & Light	97	76	99	102	98	471
Eugene Water & Electric Board	21	12	51	0	0	84
Other Electric Companies	57	51	94	16	71	289
Total	338	244	425	195	255	1,457

Table 3 – Oregon Technical Market Potential for CHP in Existing Facilities – Industrial Sector

		50-500 kW		500-1,000 kW		1-5 MW		5-20 MW		>20 MW		Total	
SIC	Application	# Sites	Capacity (MW)	# Sites	Capacity (MW)	# Sites	Capacity (MW)	# Sites	Capacity (MW)	# Sites	Capacity (MW)	# Sites	Capacity (MW)
20	Food	170	29.3	29	20.7	23	45.8	2	15.6	0	0	224	111.3
22	Textiles	4	1	0	0	2	4.7	0	0	0	0	6	5.7
24	Lumber and Wood	233	47.6	54	36.6	44	93.2	10	75.4	0	0	341	252.7
25	Furniture	1	0.1	0	0	0	0	0	0	0	0	1	0.1
26	Paper	29	6	7	5.1	11	29.4	2	18.8	5	221.8	54	281.2
27	Printing	11	1.3	1	0.7	0	0	0	0	0	0	12	2
28	Chemicals	69	12.1	12	7.9	17	34.7	3	25.3	1	33.3	102	113.4
29	Petroleum Refining	0	0	3	2.1	3	6.3	0	0	0	0	6	8.4
30	Rubber/Misc Plastics	55	8.7	2	1.4	1	2.3	0	0	0	0	58	12.4
32	Stone/Clay/Glass	0	0	0	0	1	2.8	0	0	0	0	1	2.8
33	Primary Metals	20	5.1	4	3	7	15.5	1	6.9	0	0	32	30.6
34	Fabricated Metals	9	1.6	0	0	0	0	0	0	0	0	9	1.6
35	Machinery/Computer Equip	5	0.5	0	0	0	0	0	0	0	0	5	0.5
37	Transportation Equip.	24	3.4	0	0	5	6.1	0	0	0	0	29	9.5
38	Instruments	3	0.6	0	0	1	4.1	0	0	0	0	4	4.8
39	Misc. Manufacturing	3	0.2	0	0	0	0	0	0	0	0	3	0.2
	Total	636	117.6	112	77.6	115	245.1	18	142	6	255.1	887	837.5

Table 4– Oregon Technical Market Potential for CHP in Existing Facilities – Commercial Sector

		50-500 kW		500-1,000 kW		1-5 MW		5-20 MW		>20 MW		Total	
SIC	Application	# Sites	Capacity (MW)	# Sites	Capacity (MW)	# Sites	Capacity (MW)	# Sites	Capacity (MW)	# Sites	Capacity (MW)	# Sites	Capacity (MW)
43	Post Offices	3	0.3	0	0	0	0	0	0	0	0	3	0.3
52	Retail	190	20.8	4	2.5	0	0	0	0	0	0	194	23.3
4222	Refrigerated Warehouses	9	0.8	1	0.5	1	1.6	0	0	0	0	11	2.9
4581	Airports	3	0.9	0	0	0	0	1	6.3	0	0	4	7.2
4952	Water Treatment	16	1.9	1	0.6	0	0	0	0	0	0	17	2.6
5411	Food Stores	169	20.2	0	0	2	5.2	0	0	0	0	171	25.4
5812	Restaurants	242	22.6	0	0	0	0	0	0	0	0	242	22.6
6512	Commercial Buildings	726	36.3	223	89.2	56	33.6	0	0	0	0	1,005	159.1
6513	Multifamily Buildings	149	11.2	54	27	8	8.4	0	0	0	0	211	46.6
7011	Hotels	189	24.8	8	5.5	5	7.6	1	5	0	0	203	42.9
7211	Laundries	23	3.3	1	0.8	0	0	0	0	0	0	24	4
7374	Data Centers	31	5.7	2	1.3	1	1.4	0	0	0	0	34	8.4
7542	Car Washes	11	0.8	0	0	0	0	0	0	0	0	11	0.8
7832	Movie Theaters	1	0.1	1	0.9	0	0	0	0	0	0	2	1
7991	Health Clubs	47	5.2	1	0.6	0	0	0	0	0	0	48	5.8
7997	Golf/Country Clubs	44	5.2	0	0	2	2.7	0	0	0	0	46	7.9
8051	Nursing Homes	121	11.7	0	0	0	0	0	0	0	0	121	11.7
8062	Hospitals	37	9.1	12	8.1	16	38	0	0	0	0	65	55.3
8211	Schools	4	0.2	0	0	0	0	0	0	0	0	4	0.2
8221	College/Univ.	33	6.5	9	6.3	17	41.2	4	35.4	0	0	63	89.4
8412	Museums	12	1.5	0	0	0	0	0	0	0	0	12	1.5
9100	Government Buildings	204	29.2	27	19.5	9	15.1	0	0	0	0	240	63.8
9923	Prisons	4	1.5	3	2.1	7	21	1	5.9	0	0	15	30.5
9711	Military	3	0.4	1	1	1	4.7	0	0	0	0	5	6.1
	Total	2,271	220.2	348	165.8	125	180.5	7	52.7	0	0	2,751	619.2

Figure 1– Oregon CHP Technical Potential (MW) by Utility

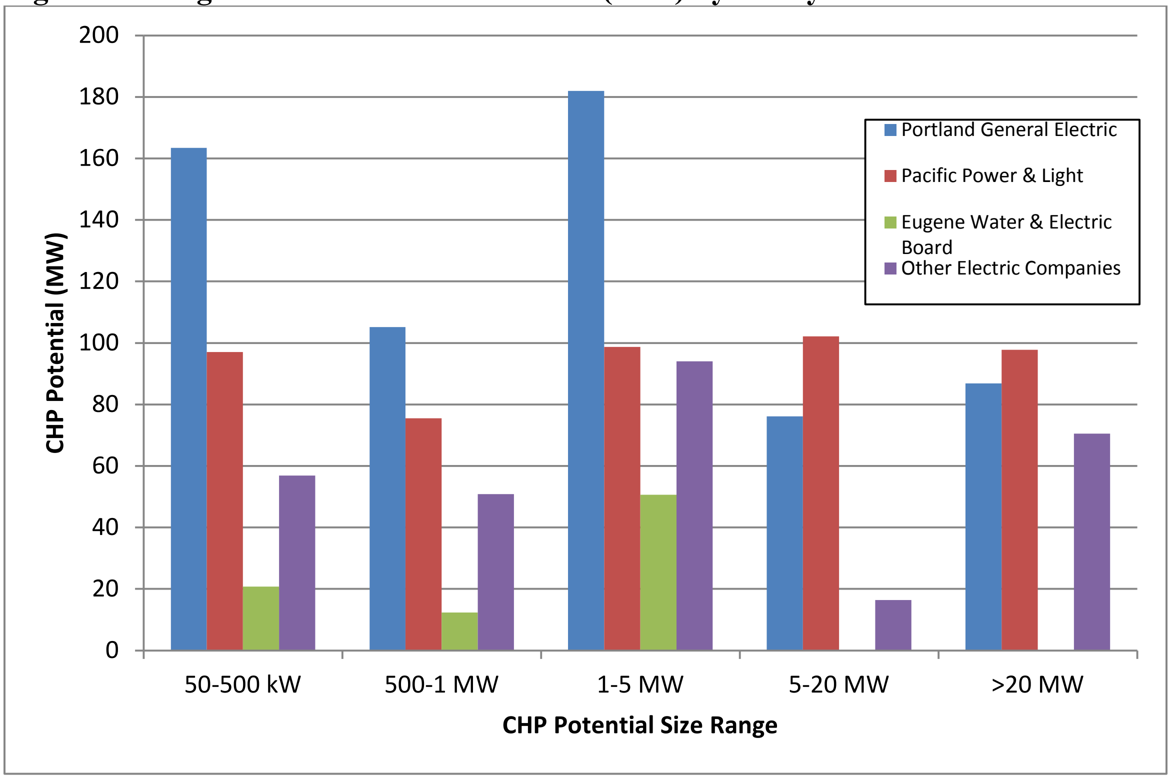


Figure 2– Oregon CHP Technical Potential (Sites) by Utility

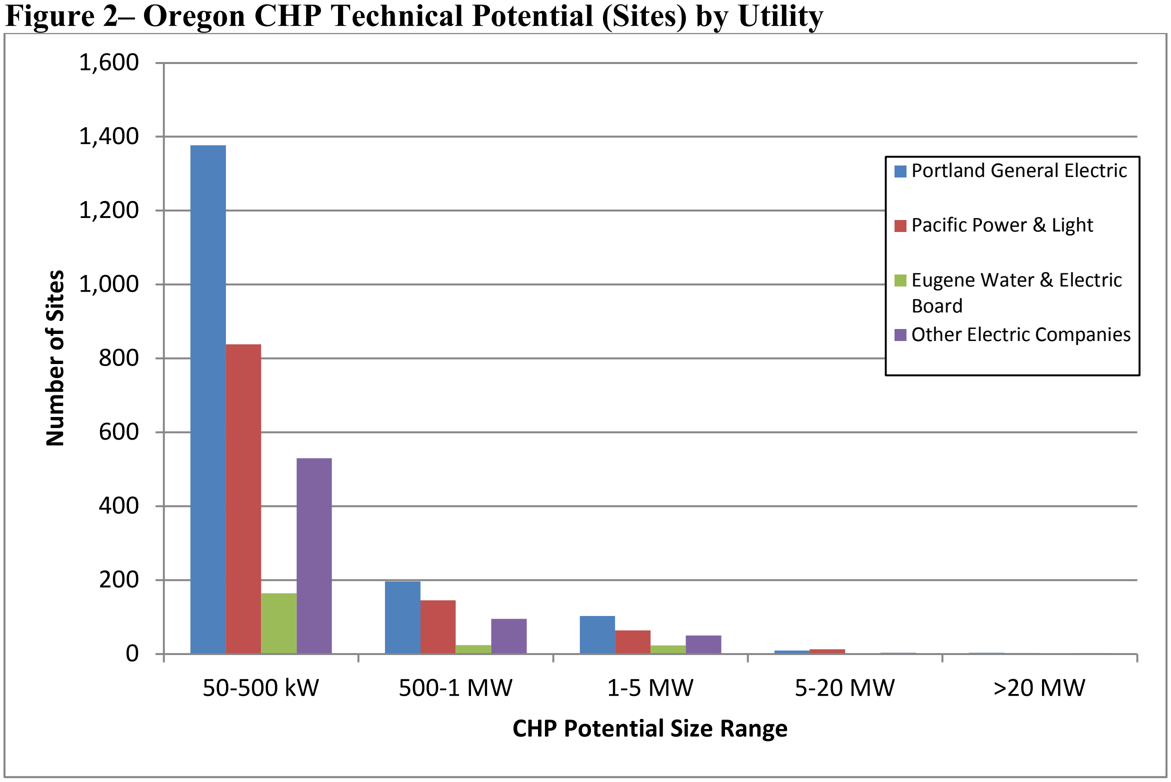


Table 5–Oregon Sector Growth Projections Through 2030

SIC	Application	Yearly 2014-2030 Growth Rate	Cumulative 2014-2030 Growth Rate
20	Food & Beverage	1.8%	32.4%
22	Textiles	0.0%	0.0%
24	Lumber and Wood	0.5%	9.0%
25	Furniture	1.1%	19.4%
26	Paper	1.9%	34.8%
27	Printing/Publishing	0.6%	10.4%
28	Chemicals	2.4%	46.6%
29	Petroleum Refining	0.0%	0.0%
30	Rubber/Misc Plastics	1.5%	26.3%
32	Stone/Clay/Glass	1.3%	23.2%
33	Primary Metals	0.4%	6.8%
34	Fabricated Metals	1.3%	22.9%
35	Machinery/Computer Equip	2.5%	48.0%
37	Transportation Equip.	2.3%	43.1%
38	Instruments	2.6%	50.4%
39	Misc Manufacturing	4.8%	111.9%
49	Gas Processing	1.3%	22.5%
4952	Water Treatment/Sanitary	0.7%	11.2%
9923	Prisons	1.5%	27.2%
9711	Military	1.5%	27.2%
7211	Laundries	1.5%	27.2%
7542	Carwashes	1.5%	27.2%
7991	Health Clubs	1.5%	27.2%
7997	Golf/Country Clubs	1.5%	27.2%
4222	Refrigerated Warehouses	1.5%	27.2%
6513	Multi-Family Buildings	1.5%	26.9%
7011	Hotels	1.2%	21.5%
7374	Data Centers	4.0%	87.3%
8051	Nursing Homes	1.3%	22.1%
8062	Hospitals	1.3%	22.1%
8221	Colleges/Universities	0.4%	7.1%
43	Post Offices	1.5%	27.2%
52	Big Box Retail	1.0%	16.4%
4581	Airports	1.5%	27.2%
5411	Food Sales	1.0%	17.3%
5812	Restaurants	1.1%	18.6%
6512	Commercial Buildings	1.2%	20.3%
7832	Movie Theaters	0.5%	8.0%
8211	Schools	0.4%	7.1%
8412	Museums	0.5%	8.0%
9100	Government Facilities	1.2%	20.3%

Table 6– Industrial CHP Market Segments, Existing Facilities and Expected Growth 2015-2030

			50-500 kW	500-1,000 kW	1-5 MW	5-20 MW	>20 MW	Total
SIC	Application	Total Growth Rate (2015 to 2030)	Capacity (MW)	Capacity (MW)	Capacity (MW)	Capacity (MW)	Capacity (MW)	Capacity (MW)
20	Food	32%	38.8	27.4	60.6	20.6	0	147.4
22	Textiles	0%	1	0	4.7	0	0	5.7
24	Lumber and Wood	9%	51.9	39.9	101.6	82.1	0	275.5
25	Furniture	19%	0.1	0	0	0	0	0.1
26	Paper	35%	8.1	6.9	39.7	25.4	298.9	379
27	Printing	10%	1.4	0.8	0	0	0	2.2
28	Chemicals	47%	17.7	11.6	50.9	37.2	48.9	166.3
29	Petroleum Refining	0%	0	2.1	6.3	0	0	8.4
30	Rubber/Misc. Plastics	26%	11	1.8	2.9	0	0	15.7
32	Stone/Clay/Glass	23%	0	0	3.5	0	0	3.5
33	Primary Metals	7%	5.5	3.2	16.6	7.4	0	32.7
34	Fabricated Metals	23%	2	0	0	0	0	2
35	Machinery/Computer Equip	48%	0.8	0	0	0	0	0.8
37	Transportation Equip.	43%	4.9	0	8.7	0	0	13.6
38	Instruments	50%	1	0	6.2	0	0	7.2
39	Misc. Manufacturing	112%	0.5	0	0	0	0	0.5
	Total		144.5	93.7	301.8	172.7	347.8	1,060.5

Table 7 - Commercial CHP Market Segments, Existing Facilities and Expected Growth 2015-2030

			50-500 kW	500-1,000 kW	1-5 MW	5-20 MW	>20 MW	Total
SIC	Application	Total Growth Rate (2015 to 2030)	Capacity (MW)	Capacity (MW)	Capacity (MW)	Capacity (MW)	Capacity (MW)	Capacity (MW)
43	Post Offices	27%	0.4	0	0	0	0	0.4
52	Retail	16%	24.3	2.9	0	0	0	27.2
4222	Refrigerated Warehouses	27%	1	0.7	2.1	0	0	3.8
4581	Airports	27%	1.1	0	0	8.1	0	9.2
4952	Water Treatment	11%	2.2	0.7	0	0	0	2.9
5411	Food Stores	17%	23.7	0	6.1	0	0	29.8
5812	Restaurants	19%	26.7	0	0	0	0	26.7
6512	Commercial Buildings	20%	43.7	107.3	40.4	0	0	191.4
6513	Multifamily Buildings	27%	14.2	34.3	10.6	0	0	59.1
7011	Hotels	22%	30.1	6.7	9.2	6.1	0	52.1
7211	Laundries	27%	4.2	1	0	0	0	5.2
7374	Data Centers	87%	10.7	2.4	2.6	0	0	15.7
7542	Car Washes	27%	1	0	0	0	0	1
7832	Movie Theaters	8%	0.1	0.9	0	0	0	1
7991	Health Clubs	27%	6.6	0.7	0	0	0	7.3
7997	Golf/Country Clubs	27%	6.7	0	3.4	0	0	10.1
8051	Nursing Homes	22%	14.3	0	0	0	0	14.3
8062	Hospitals	22%	11.1	9.9	46.4	0	0	67.4
8211	Schools	7%	0.3	0	0	0	0	0.3
8221	College/Univ.	7%	6.9	6.8	44.1	37.9	0	95.7
8412	Museums	8%	1.6	0	0	0	0	1.6
9100	Government Buildings	20%	35.1	23.5	18.2	0	0	76.8
9923	Prisons	27%	1.9	2.7	26.7	7.5	0	38.8
9711	Military	27%	0.6	1.2	6	0	0	7.8
	Total		268.3	201.5	215.9	59.6	0	745.3

Waste Heat to Power CHP Technical Potential

In addition to exploring the technical potential of traditional topping cycle CHP in Oregon, this assessment also evaluated the potential for waste heat to power (WHP) in the state. Waste heat to power (WHP) is the process of capturing heat discarded by an existing process to generate power.[2] The following two tables represent current waste heat to power technical potential in Oregon by utility and by application.

Table 8– Waste Heat to Power Potential by Major Utility

Utility Territory	# of Sites	WHP Potential (MW)
Portland General Electric	2	3.2
Pacific Power & Light	10	24.1
Other Electric Company	10	15.2
Total	22	42.4

Table 9– Waste Heat to Power Potential by Application

NAICS Code	Application	# of Sites	WHP Potential (MW)
327310	Cement Manufacturing	1	4.1
486210	Pipeline Transportation of Natural Gas	12	12.1
327213	Glass Container Manufacturing	1	2.9
327420	Gypsum Product Manufacturing	1	3.4
331110	Iron and Steel Mills and Ferroalloy Manufacturing	1	18.3
562212	Solid Waste Landfill	6	1.6
	Total	22	42.4

Economic Potential for CHP

The economic potential for CHP is quantified using payback for CHP systems. Payback is defined as the amount of time (i.e. number of years) before a system can recoup its initial investment. For each site included in the technical potential analysis, an economic payback is calculated based on the appropriate CHP system cost and performance characteristics and energy rates for that system size and application. This section lays out the economic conditions in Oregon that were used to calculate the payback for each technical potential application and size range.

[2] U.S. EPA, Waste Heat to Power Systems fact sheet.

Energy Price Projections

The expected future relationship between purchased natural gas and electricity prices, called the *spark spread* in this context, is one major determinant of the ability of a facility with electric and thermal energy requirements to cost-effectively utilize CHP.

Electric Price Estimation

While state-average spark spreads may mask the differences in specific utility rates on project economics, ICF researched the applicable rates (i.e. full service and partial service/standby rates) for the three largest utilities in Oregon to develop an avoided cost estimate for each utility. The avoided cost is an important concept for evaluating the treatment of onsite generation by partial requirement tariff structures. One of the key economic values of onsite generation is the displacement of purchased electricity and the avoidance of those costs. Ideally, the reduction in electricity price should be commensurate with the reduction in purchased electricity. In other words, if the onsite system reduces electricity consumption by 80 percent, the cost of electricity purchases would also be reduced by 80 percent in an ideal scenario. However, only a portion of the full retail rate is avoided by on-site generation due to fixed customer charges, demand charges, and standby rate structures. The economics of CHP are negatively impacted if partial requirements rates are structured such that only a small portion of the electricity price can be avoided.

The utilities analyzed include Pacific Power, Portland General Electric, and Eugene Water & Electric Board. Facilities in other municipal or coop utility districts were assumed to have rates similar to the Eugene Water & Electric Board. The rates for CHP customers for each utility are shown in Table 10, Table 11, and Table 12.

Table 10 – Pacific Power CHP Customer Electric Rate Summary

System Size Range (kW)	50-500	500-1,000	1,000-5,000	5,000-20,000	> 20,000
High Load Factor (hours)	8760	8760	8760	8760	8760
CHP Availability (%)	95%	95%	95%	95%	95%
Voltage Class	Secondary	Secondary	Primary	Transmission	Transmission
Tariff Class	30	30	47	47	47
Avoided Rate, $/kWh	0.0817	0.0782	0.0639	0.0629	0.0626
Avoided Rate as % of Retail Rate	81.1%	86.5%	91.9%	90.3%	90.7%

Table 11 – Portland General Electric CHP Customer Electric Rate Summary

System Size Range (kW)	50-500	500-1,000	1,000-5,000	5,000-20,000	> 20,000
High Load Factor (hours)	8760	8760	8760	8760	8760
CHP Availability (%)	95%	95%	95%	95%	95%
Voltage Class	Secondary	Secondary	Primary	Sub-T	Sub-T
Tariff Class	85	85	75	75	75
Avoided Rate, $/kWh	0.0784	0.0779	0.0695	0.0676	0.0676
Avoided Rate as % of Retail Rate	93.7%	96.0%	88.9%	93.3%	94.0%

Table 12 – Eugene Water & Electric Board CHP Customer Electric Rate Summary

System Size Range (kW)	50-500	500-1,000	1,000-5,000
High Load Factor (hours)	8760	8760	8760
CHP Availability (%)	95%	95%	95%
Tariff Class	G-2	G-3	G-3
Voltage Class	Secondary	Secondary	Primary
Avoided Rate, $/kWh	0.0678	0.0571	0.0560
Avoided Rate as % of Retail Rate	95.6%	90.1%	95.7%

To estimate the escalation of electric prices over the 2014-2030 timeframe, forecasts form EIA's 2014 Annual Energy Outlook for the WECC[3]/Northwest region were used to escalate Porland General Electric and Eugene Water & Electric Board rates by 0.5 percent per year. Pacific Power's growth rate was estimated using historical prices from EIA. The real compound annual growth rate for Pacific Power rates between 2007 and 2011 is about 6%/yr, and the rate assumed in the model going forward is halved at 3%/yr. The annual price forecasts provided were converted to 5 year averages for use in the market model.

Natural Gas Price Estimation

The natural gas prices used in the analysis are shown below in Table 13. These prices reflect the 2013 annual Oregon state-average rates from EIA[4]. The specific rate for each size range is as follows:

- 50 – 500 kW: OR Commercial average
- 500 – 1 MW: OR Industrial average + 20 percent[5]
- 1 – 5 MW: OR Industrial average
- 5 – 20 MW: OR Industrial average
- >20 MW : OR Citygate average

[3] Western Electric Coordinating Council
[4] Energy Information Administration. Natural Gas Prices. http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SOR_a.htm
[5] 20 percent adder based on past natural gas tariff analysis for these size categories

The escalation rate for natural gas prices over the 2014-2030 timeframe was 1.4 percent per year and was taken from the EIA Annual Energy Outlook 2014 reference case, for the WECC/Northwest region.

Table 13 – Natural Gas Price by CHP System Size Bin ($/MMBtu)

Year	50-500 kW	500-1 MW	1-5 MW	5-20 MW	> 20 MW
2014	$8.67	$6.63	$5.53	$5.53	$4.69
2020	$9.43	$7.22	$6.02	$6.02	$5.11
2025	$10.12	$7.75	$6.45	$6.45	$5.48
2030	$10.86	$8.31	$6.93	$6.93	$5.88

CHP Technology Cost and Performance

CHP systems use fuel to generate electricity and useful heat for the customer. There are many different technologies and products that are capable of generating electricity and useful heat. While these technologies differ in terms of system configuration and operation, the economic value of CHP depends on key factors common to all CHP technologies:

- Installed capital cost of the system, on a unit basis expressed in $/kWh. A subset of capital costs are emissions treatment equipment costs that are required to bring some CHP systems into compliance with California (or other regional non-attainment areas) emissions requirements.
- Fuel required to generate electricity, commonly expressed as the heat rate in Btu/kWh. All heat rates in this report are expressed in terms of the high heating value (HHV) of the fuel. This is the same basis on which natural gas is measured and priced for sale. Vendors typically express engine heat rates in terms of lower heating value (LHV) which does not include the heat of vaporization of the moisture content of the exhaust. Consequently, vendor efficiency and heat rate quotes for natural gas fueled equipment are about 10-11 percent higher than HHV estimates, which reflects the difference in the HHV and LHV heat contents for a given volume of natural gas.
- Useful thermal energy produced per unit of electricity output (again expressed as Btu/kWh).
- Non-fuel operating and maintenance costs, expressed on unit basis in $/kWh. These annual costs include amortization of overhaul costs that can be required after a number of years of operation.
- Economic life of the equipment.

The cost and performance parameters for the representative CHP systems used in this analysis are based on updated versions that ICF is currently working on of CHP technology characterizations prepared for NYSERDA and the EPA CHP Partnership.[6] Data is presented on the representative CHP system characteristics that were used for each size range category in Table 14. The top portion of the table shows the CHP system characteristics for traditional heat utilization (hot water or steam) while the bottom portion of the table shows the additional cost and performance parameters associated with a

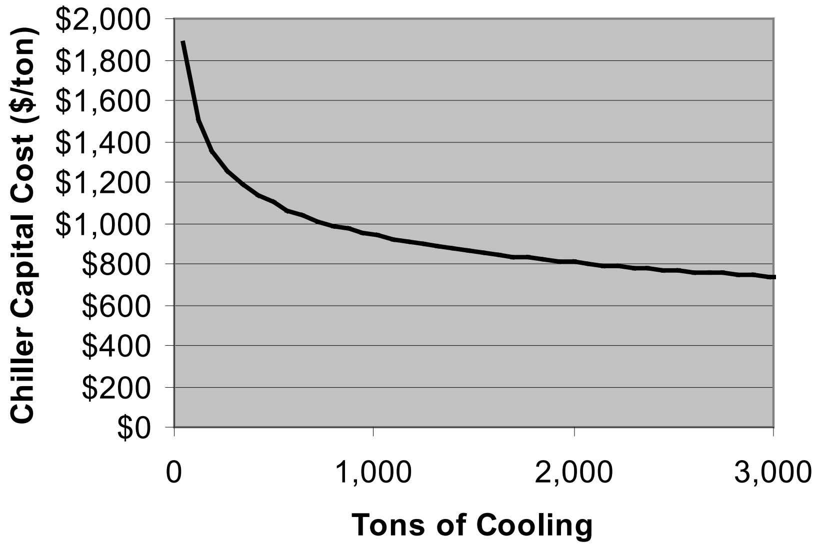
[6] EPA CHP Partnership Program, Technology Characterizations, 2008. http://www.epa.gov/chp/technologies.html.

CHP system used for cooling. In the cooling markets, the additional cost to add chiller capacity to the CHP system is shown in Figure 3. These costs depend on the sizing of the absorption chiller, which in turn depends on the amount of usable waste heat that the CHP system produces.

Table 14 – CHP Cost and Performance Assumptions

Market Size Bin	50-1,000 kW	1-5 MW	5-20 MW	>20 MW
Technology	500 kW RE	3000 kW RE	10 MW GT	40 MW GT
Capacity, kW	500	3,000	12,500	40,000
Capital Cost $/kW	$2,217	$1,604	$1,802	$1,144
After-Treatment Cost, $/kW	$552	$313	$174	$104
Total Capital Cost, $/kW	$2,769	$1,917	$1,976	$1,248
Heat Rate, Btu/kWh	11,293	8,454	12,482	9,488
Thermal Output, Btu/kWh	5,546	3,208	5,262	3,118
Electric Efficiency, %	30.2%	40.4%	27.3%	36.0%
CHP Overall Efficiency	79.3%	78.3%	69.5%	68.8%
O&M Costs, $/kWh	$0.0215	$0.0150	$0.0120	$0.0092
Economic Life, years	15	15	20	20
Avoided Boiler Efficiency	80%	80%	80%	80%
Avoided AC Efficiency, kW/ton	1.00	0.68	0.68	0.68
Cooling Hours	2,000	2,000	2,000	2,000
Absorption Cooling Efficiency, Btu/ton	17,143	17,143	10,000	10,000
Tons of cooling	166	561	6,578	12,473
kW AC/kW Generated	0.32	0.13	0.36	0.21
Capital Cost, $/ton	$1,845	$1,410	$950	$950
Capital Cost Adder, $/kWe	$597	$264	$500	$296

Figure 3 - Absorption Chiller Capital Costs



Waste Heat to Power Cost/Performance

ICF used in-house data, published literature, and held discussions with industry stakeholders to develop cost estimates for steam rankine cycle (SRC) and organic rankine cycle (ORC) systems. SRC and ORC technologies account for nearly all WHP systems currently installed, and are expected to be the dominate technologies that will be installed for the next several years. Other waste heat to power technologies, including emerging technologies, have not yet matured and are therefore not included in this cost analysis. The following assumptions were used to develop the economic analysis of WHP sites:

- Table 15 shows the breakdown of technologies used by NAICS codes. Waste heat stream temperatures have a significant influence on the type of technology a site will choose. In practice, SRC and ORC technologies overlap in each sector. For the purposes of this analysis, however, SRC and ORC technologies are assumed to be divided along typical NAICS codes for that technology.
- Table 16 shows the costs used in the payback calculations of each waste heat to power technology and size range. Costs were differentiated by size to infer economies of scale, meaning that higher capital and O&M costs were assigned to smaller capacity equipment, and vice versa.

Table 15 - Technology Assignment by NAICS Code

NAICS	NAICS Description	WHP Technology
211	Oil and Gas Extraction	ORC
212	Mining except Oil and Gas	ORC
311	Food	SRC
312	Beverage and Tobacco	SRC
321	Wood	SRC
322	Paper	SRC
323	Printing	SRC
324	Petroleum Refining	SRC
325	Chemical	SRC
327	Non-Metallic Minerals	SRC
331	Primary Metals	SRC
333	Machinery	SRC
336	Transportation Equipment	SRC
486	Pipeline Transportation	ORC
562	Waste Management	ORC
611	Colleges	SRC

Table 16 - Waste Heat to Power Cost Assumptions

Technology	Cost Characteristic	Electric Capacity for WHP Technology				
		50-500 kW	500-1,000 kW	1-5 MW	5-20 MW	>20 MW
Steam Rankine Cycle	Installed Capital Cost, $/kW	$3,000	$2,500	$1,800	$1,500	$1,200
	O&M Costs, $/kWh	$0.013	$0.009	$0.008	$0.006	$0.005
Organic Rankine Cycle	Installed Capital Cost, $/kW	$4,500	$4,000	$3,000	$2,500	$2,100
	O&M Costs, $/kWh	$0.020	$0.015	$0.013	$0.012	$0.010

Economic Potential Results

CHP project economics are site-specific. Utility-specific electricity rates and tariff structures, natural gas prices, and site-specific conditions (i.e. space availability and integration into existing thermal and electric systems, permitting, siting and grid interconnection requirements) all contribute to the unique economics of each CHP system. An estimate of economic potential by system size range was developed for this analysis using Oregon-specific electricity and natural gas rates and representative CHP equipment cost and performance characteristics. Simple yearly paybacks were calculated for the five CHP system size categories for all of the applications.

The payback calculation was conducted for each electric utility in the state and the potential in terms of megawatts was categorized into four payback categories representing the degree of economic potential:

- Strong potential – simple payback < 5 years
- Moderate potential – simple payback 5 to 10 years
- Minimal potential – simple payback 10 to 20 years
- No potential – simple payback > 20 years

Table 17 presents the economic potential based on current electricity and natural gas prices, and equipment cost and performance characteristics. As shown, 87 MW of the total technical potential of 1,457 MW has a payback less than 5 years, with all of this potential occurring in Portland General Electric service territory. Just over 230 MW has a payback in the 5 to 10 year range. The majority of the sites with payback under 10 years are large sites in the >20 MW size range.

Table 17 – CHP Economic Potential in Oregon by Electric Utility

	Payback (years)				
Electric Utility	**<5**	**5 - 10**	**10 - 20**	**>20**	**Total**
Portland General Electric	87	134	29	364	614
Pacific Power & Light	0	98	169	204	471
Eugene Water & Electric Board	0	0	0	84	84
Other	0	0	0	289	289
Total	87	232	198	940	1,457

Table 18 shows the WHP economic potential based on WHP cost and performance characteristics and similar electricity and natural gas price assumptions used in the CHP economic potential analysis. While the total WHP technical potential is less than 3% of the CHP technical potential, the majority of the WHP economic potential has an expected payback of less than 5 years. None of the WHP systems have an expected payback of greater than 20 years, which contrasts with the 940 MW of CHP potential that has an expected payback of greater than 20 years.

Table 18 – WHP Economic Potential in Oregon by Electric Utility

Electric Utility	Payback (years) <5	5 - 10	10 - 20	>20	Total
Portland General Electric	2.9	0.0	0.3	0.0	3.2
Pacific Power & Light	18.3	4.1	1.7	0.0	24.1
Eugene Water & Electric Board	0.0	0.0	0.0	0.0	0.0
Other	4.1	6.3	4.8	0.0	15.2
Total	25.3	10.4	6.8	0.0	42.4

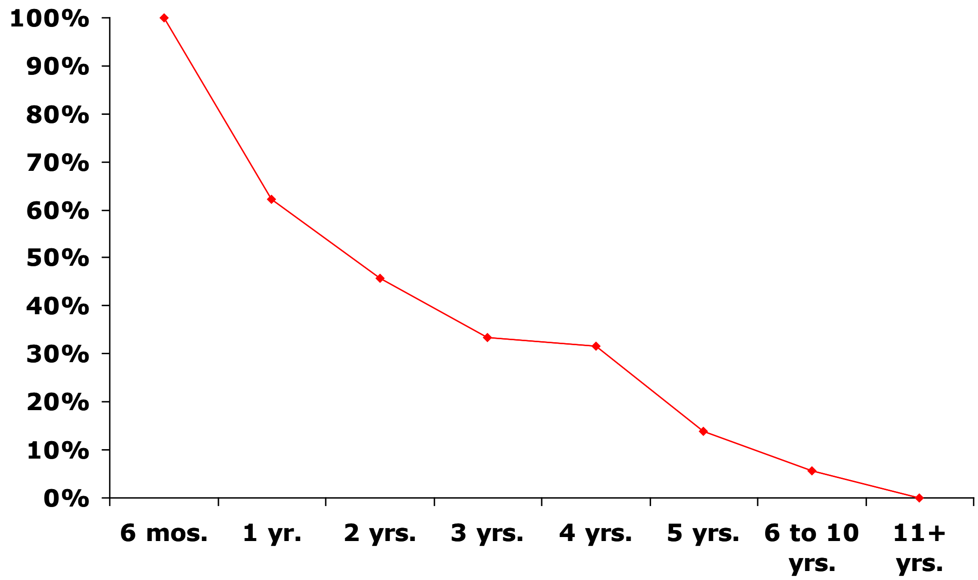
CHP Market Penetration Analysis

Based on the calculated economic potential, a market diffusion model is used to determine the cumulative CHP market penetration over the analysis timeframe. The market penetration represents an estimate of CHP capacity that will actually enter the market between 2014 and 2030. This value discounts the economic potential to reflect non-economic screening factors and the rate that CHP is likely to actually enter the market.

Rather than use a single yearly payback value as the sole determinant of economic potential, the market acceptance rate has also been included. These acceptance rates are based on a survey of commercial and industrial facility operators, identifying the level of payback required to consider installing CHP. Figure 4 shows the percentage of survey respondents that would accept CHP investments at different payback levels[7]. As can be seen from the figure, more than 30% of customers surveyed would reject a project that promised to return their initial investment in just one year. A little more than half would reject a project with a payback of 2 years. This type of payback translates into a project with an ROI of around 50 percent. Potential explanations for rejecting a project with such high returns include 1. The average customer does not believe that the results are valid and is attempting to mitigate this perceived risk by requiring very high projected returns before a project would be accepted, 2. The facility has limited capital and is rationing its ability to raise capital for higher priority projects (i.e. market expansion, product improvement, etc.).

[7] "Assessment of California CHP Market and Policy Options for Increased Penetration", California Energy Commission, July, 2005.

Figure 4 - Customer Payback Acceptance Curve



Source: *Primen's 2003 Distributed Energy Market Survey*

For each market segment, the CHP market penetration represents the technical potential multiplied by the share of customers that would accept the payback calculated in the economic potential section.

The rate of market penetration is based on a *Bass diffusion curve* with allowance for growth in the maximum market. This function determines cumulative market penetration over the analysis timeframe. Smaller size systems are assumed to take a longer time to reach maximum market penetration than larger systems. Cumulative market penetration using a Bass diffusion curve takes a typical S-shaped curve. In the generalized form used in this analysis, growth in the number of ultimate adopters is allowed. The shape of the curve is determined by an initial market penetration estimate and growth rate of the technical market potential.

CHP Market Penetration Results

Only Portland General Electric and Pacific power show economic CHP market penetration between 2014 and 2030. About 90.4 MW of CHP is forecasted to be installed, with 44.7 MW occurring in Portland General Electric territory and 45.7 MW occurring in Pacific Power territory. Sites in Eugene Water & Electric Board and other utility territories in Oregon do not show any economic CHP market penetration.

Figure 5 shows the projected CHP penetration rate over the analysis timeframe. Table 19 shows the detailed cumulative results for the state projections of CHP market penetration.

Figure 5 – CHP Cumulative Market Penetration by Electric Utility Territory, 2014-2030

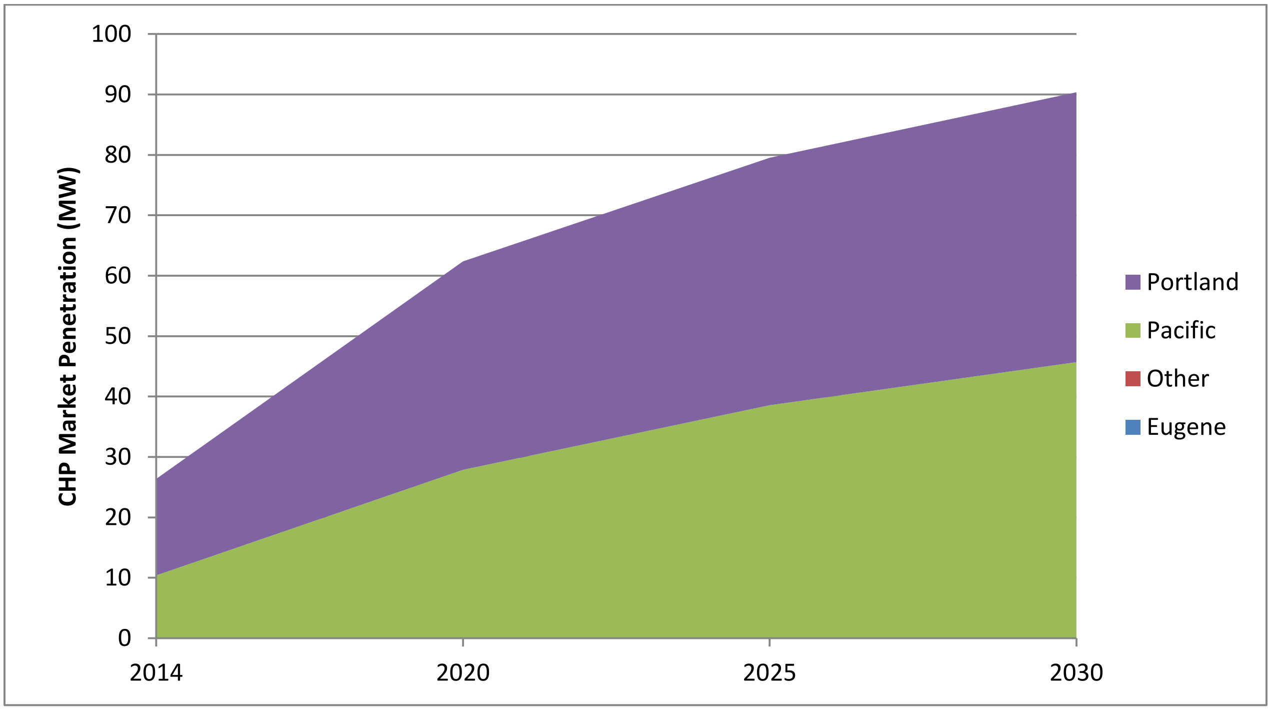


Table 19 – Oregon CHP Market Penetration Results

Cumulative Market Penetration (MW)	**2014**	**2020**	**2025**	**2030**
Industrial	26.2	61.7	78.5	89.2
Commercial/Institutional	0.2	0.7	1.0	1.2
Total	26.4	62.4	79.5	90.4

Annual Electric Energy Generation (Million kWh)	**2014**	**2020**	**2025**	**2030**
Industrial	209	489	619	703
Commercial/Institutional	1	5	7	8
Total	210	494	627	711

Annual CHP Fuel Balance (Billion Btu/year)	**2014**	**2020**	**2025**	**2030**
CHP Fuel	1,951	4,531	5,714	6,465
Avoided Boiler Fuel	843	1,922	2,418	2,736
Incremental Onsite Fuel	1,108	2,609	3,296	3,729

Cumulative Market Penetration by Size (MW)	**2014**	**2020**	**2025**	**2030**
50-500 kW	0.0	0.0	0.0	0.2
500 kW-1,000kW	0.0	0.0	0.0	0.2
1-5 MW	1.7	7.4	11.0	12.4
5-20 MW	0.8	1.9	4.4	6.0
>20 MW	23.9	53.1	64.1	71.6
Total Market	26.4	62.4	79.5	90.4

WHP Market Penetration Results

The total amount of expected WHP market penetration is 9.5 MW, with the majority of this located in Pacific Power & Light's service territory. There is no technical potential for WHP applications in Eugene Water & Electric Board service territory. The WHP market penetration methodology is calculated consistently with the CHP methodology.

Table 19 – Oregon WHP Market Penetration

Utility Territory	**Market Penetration (MW)**
Portland General Electric	0.7
Pacific Power & Light	6.9
Other Electric Company	1.9
Total	9.5

Prioritization of CHP Opportunities

The below prioritized list of CHP opportunities in Oregon are based on the following criteria:

1) The technical potential for CHP (both traditional and waste heat to power) by SIC code;
2) The economic potential for CHP (both traditional and waste heat to power) by SIC code;
3) Economic development of Oregon industry (both job creation and preservation);
4) Recognition of facilities (industrial, commercial, institutional) with critical power loads
5) Reduced need for transmission and distribution upgrades ("non-wires solution";
6) Renewable CHP potential to offset "coal by wires", support forest health and where only fuel oil or propane is available for thermal energy needs (natural gas is not available); and
7) Environmental improvements

It is recognized that these recommendations are based on "best analytical judgment". Other choices could be made. The recommended priority areas and rationale are as follows:

1) Pulp & paper – A large target market opportunity with renewable energy CHP potential with job creation and preservation – 281.2 MW technical CHP potential;
2) Lumber and wood (forest products – A large target market opportunity with renewable energy CHP potential with job creation and preservation – 252.7 MW technical potential;
3) Chemicals – A large target market opportunity with job creation and preservation – 113.4 MW technical potential;
4) Food processing - A large target market opportunity with job creation and preservation – 111.3 MW;
5) Support of very large individual CHP systems – Greater than 100 MW – Transmission and distribution system support; and
6) Critical facilities (hospitals, nursing homes, waste water treatment facilities, prisons and data centers and places of refuge) – Serious consequences for loss of power, adding resiliency – At least 108.5 MW technical potential.

Note: Environmental improvements apply to all CHP systems.

Conclusion

Of the 1,457 MW existing CHP technical potential for CHP in Oregon, 319 MW has economic potential with a payback of less than 10 years. The 319 MW of economic potential is located only in Pacific Power & Light and Portland General Electric territory. Economic potential is determined by calculating payback, which takes into account: 1. Electric rate analysis by utility, system size, and market sector, for both standard customers and CHP customers, 2. EIA natural gas prices (2013 Oregon commercial, industrial, and citygate) by CHP system size, 3. Current and expected CHP cost and performance characteristics by technology type for various CHP sizes. Generally, calculated payback is lower for larger customers, stemming from lower CHP system costs as a result of economies of scale, better CHP system performance characteristics, and lower natural gas prices.

The 319 MW of CHP economic potential with a payback of less than 10 years is then pared down to CHP market penetration. There is 90.4 MW of cumulative CHP market penetration by 2030 in Oregon, also exclusively in the Pacific Power & Light and Portland General Electric service territories. Market penetration includes growth of technical potential to 2030, the customer payback acceptance curve, as well as the bass diffusion curve.

In addition, there is 42.4 MW of current WHP technical potential. With the exception of a few landfill WHP site, all other WHP sites are at least 1 MW in size, which implies more favorable economics than systems smaller than 1 MW. The majority of the WHP potential (i.e. 25.3 MW of 42.4 MW) has a payback of < 5 years, and the total expected market penetration is 9.5 MW. This yields a total CHP and WHP expected market penetration of 132.8 MW.

While these calculated economic potential and market penetration figures provide insight into the amount of CHP and WHP that could penetrate the market in Oregon, there are other factors and uncertainties that affect the economics expected market penetration. Some of these factors include:

- Local state or utility-specific incentives have not been included (however, the Federal Investment Tax Credit is included).
- Gas rates, especially for larger (i.e. > 20 MW) customers, can be negotiated on a case-by-case basis with the utility, generally resulting in more favorable rates for the customer.
- Some customers may accept a CHP or WHP system with a payback of more than 10 years.

Overall, multiple factors point toward increasing levels of distributed generation market penetration in the United States. Some of these factors include the abundance of low-cost natural gas, technology advancements, emissions compliance, as well as favorable policies and incentives. CHP will continue to play an important role meeting demands for distributed generation, particularly in applications with favorable electric and thermal loads. With more than 2,800 MW of existing CHP in Oregon, it is not unexpected that there will be significant levels of CHP and WHP market penetration in the near future.

Appendix E: ICF International Oregon CHP Sensitivity Case February, 2015

February 20, 2015

Mr. Chris Galati, P.E.
NW Natural
220 NW Second Avenue
Portland, Oregon 97209

Subject: CHP Sensitivity Case for Oregon

Dear Chris:

I am pleased to attach a memo describing a sensitivity case for the adoption of combined heat and power (CHP) in Oregon. This sensitivity case examined variations in the following input parameters relative to a base case assessment that was prepared in 2014:

Electricity rates. The base case used an electricity forecast with rates generally higher than those rates forecast by the Energy Information Administration (EIA). For the sensitivity case, electricity rates were assumed to follow EIA's forecast.

Market growth. The base case assumed that target markets for CHP in Oregon would grow at rates comparable to national averages as reported by EIA. For the sensitivity case, market growth was modified to 0% for the paper industry based on recent trends in Oregon for this sector.

The base case, published in 2014, predicts that CHP market penetration will grow by approximately 90 MW of installed natural gas-fired CHP capacity by 2030. In contrast, the sensitivity case shows that CHP market penetration for natural gas-fired CHP will grow by approximately 23 MW by 2030.

If you have any questions or comments, please do not hesitate to give me a call.

Regards,

Rick Tidball

Cc: Anne Hampson
Attachment: Memo describing results of sensitivity analysis

710 Second Avenue ■ Seattle, WA 98104 ■ 206.801.2846 ■ icfi.com

Economic Potential for CHP in Oregon

A Sensitivity Case Analysis

ICF evaluated the potential for combined heat and power (CHP) in Oregon in 2014.[1] This report (referred to as "base case" study in this memo) was prepared for the Oregon Department of Energy, and showed approximately 90 MW of additional natural gas-fired CHP market penetration in Oregon by 2030. At the request of NW Natural, ICF conducted a sensitivity analysis relative to the 2014 report, and this memo describes the results of this sensitivity analysis.

Base Case Results

For reference, a few findings from the base case study are included in this memo. **Table 1** presents the technical potential for CHP divided into payback ranges. As indicated, 87 MW of the total technical potential of 1,458 MW has a payback less than 5 years, with all of this potential occurring in Portland General Electric's service territory. Slightly over 230 MW has a payback in the 5 to 10 year range.

Table 1. ***BASE CASE* – CHP Technical Potential by Payback Range in Oregon by Electric Utility**

Electric Utility	Potential (MW) by Payback Period				Total (MW)
	<5 yrs	5 - 10 yrs	10 - 20 yrs	>20 yrs	
Portland General Electric	87	134	29	364	**614**
Pacific Power & Light	0	98	169	204	**471**
Eugene Water & Electric Board	0	0	0	84	**84**
Other	0	0	0	289	**289**
Total	**87**	**232**	**198**	**941**	**1,458**

Table 2 shows the cumulative market penetration divided between industrial and commercial/institutional market segments. By 2030, the base case shows an expected market penetration of 90.4 MW, with nearly all (89.2 MW) of this penetration in the industrial sector.

[1] *Assessment of the Technical and Economic Potential for CHP in Oregon*, ICF International, July 2014. http://www.oregon.gov/energy/CONS/Industry/docs/Oregon_CHP_assessment_report.pdf

Table 2. *BASE CASE* – **Cumulative Market Penetration by Market Segment**

Market Segment	Year			
	2014	2020	2025	2030
Industrial	26.2	61.7	78.5	89.2
Commercial / Institutional	0.2	0.7	1.0	1.2
Total	**26.4**	**62.4**	**79.5**	**90.4**

Table 3 provides a breakout of the cumulative market penetration by CHP size range. As indicated, nearly 80% (71.6 MW) of the market penetration in 2030 occurs for large systems, with capacities greater than 20 MW.

Table 3. *BASE CASE* – **Cumulative Market Penetration by CHP Capacity**

Electric Capacity	Year			
	2014	2020	2025	2030
50 - 500 kW	0.0	0.0	0.0	0.2
500 kW - 1 MW	0.0	0.0	0.0	0.2
1 - 5 MW	1.7	7.4	11.0	12.4
5-20 MW	0.8	1.9	4.4	6.0
> 20 MW	23.9	53.1	64.1	71.6
Total	**26.4**	**62.4**	**79.5**	**90.4**

Input Assumptions for Sensitivity Analysis

For the sensitivity analysis, the input assumptions were varied for electricity rate escalation and technical potential market growth rates over the analysis timeframe (2015-2030). The variations are summarized in **Table 4**.

Table 4. **Input Assumptions That Varied Between Two Modeling Scenarios**

Input Parameter	Description	
	Base Case	Sensitivity Case
Electricity Rates	3% annual growth	0.5% annual growth
Market Growth	1.9% annual growth for paper production	0% annual growth for paper production

The base case electricity escalation rate was based on historical data for electric rate increases in Oregon over the past several years. In the sensitivity case, electricity escalation was based on EIA's 2014 Annual Energy Outlook for the Western Electricity Coordinating Council (WECC) Northwest region.

The base case market growth rate was based on the EIA 2014 Annual Energy Outlook, which reports national average growth rates by sector. Based on recent trends in the paper industry in Oregon, the growth rate for the paper industry in the sensitivity analysis was set to 0%.

Sensitivity Analysis Results

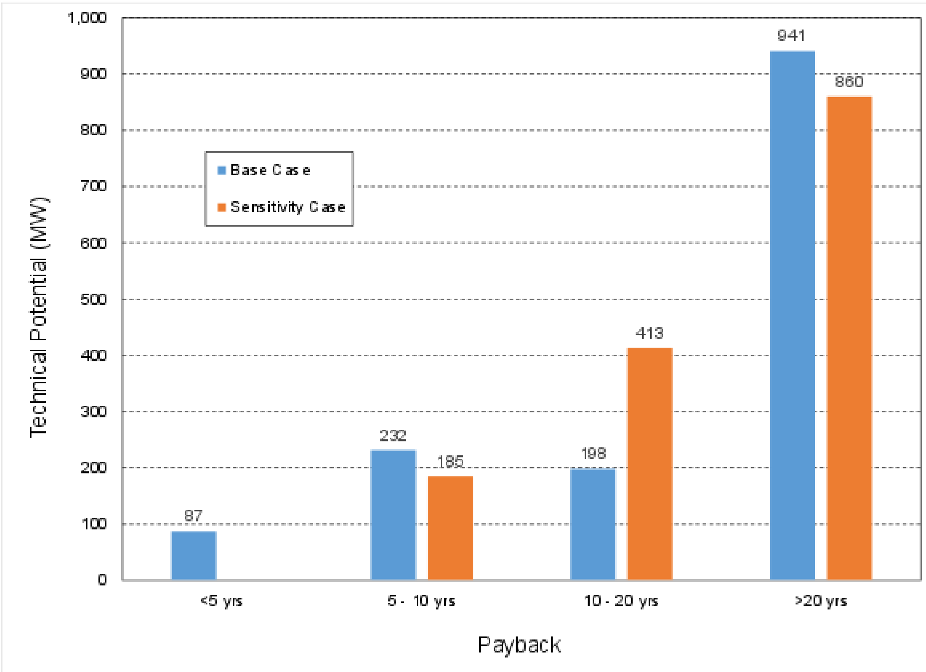
Table 5 shows the technical potential broken out by payback range for the sensitivity case. As indicated, there is no technical potential with a payback under 5 years. The majority of the technical potential occurs for CHP installations that have a payback greater than 20 years.

Table 5. *SENSITIVTY CASE* **– CHP Technical Potential in Oregon by Electric Utility**

Electric Utility	Potential (MW) by Payback Period				Total (MW)
	<5 yrs	5 - 10 yrs	10 - 20 yrs	>20 yrs	
Portland General Electric	0	87	134	393	**614**
Pacific Power & Light	0	98	169	204	**471**
Eugene Water & Electric Board	0	0	40	44	**84**
Other	0	0	70	219	**289**
Total	**0**	**185**	**413**	**860**	**1,458**

Figure 1 shows a comparison of the technical potential between the base case and the sensitivity case. In both scenarios, the total technical potential remains the same (1,458 MW). In the sensitivity case, however, the technical potential is shifted towards higher payback periods. As an example, the base case has 87 MW of technical potential with a payback less than 5 years, but the sensitivity case shows no technical potential with a payback under 5 years.

Figure 1. Comparison of Technical Potential between Two Cases



The expected market penetration of natural gas-fired CHP in the sensitivity case is expected to increase by 23.1 MW by 2030 (see **Figure 2**). Only Portland General Electric and Pacific Power show economic CHP market potential between 2014 and 2030. In 2030, Portland General Electric is estimated to have 15.7 MW of additional CHP market penetration, and Pacific Power is expected to have 7.4 MW of additional CHP market growth.

Figure 2. *SENSITIVTY CASE* – **CHP Cumulative Market Penetration**

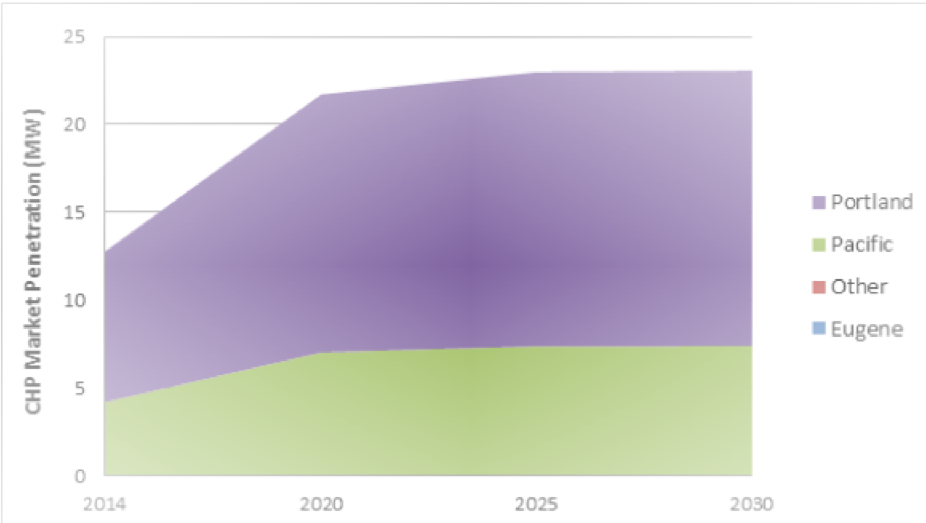


Table 6 shows the cumulative market penetration divided between industrial and commercial/institutional market segments for the sensitivity case. By 2030, the sensitivity case shows an expected market penetration of 23.1 MW, with nearly all (23.0 MW) of this penetration in the industrial sector.

Table 6. *SENSITIVTY CASE* – **Cumulative Market Penetration by Market Segment**

Market Segment	**Year**			
	2014	2020	2025	2030
Industrial	12.7	21.6	22.9	23.0
Commercial / Institutional	0.1	0.1	0.1	0.1
Total	**12.8**	**21.7**	**23.0**	**23.1**

Figure 3 shows a comparison of the cumulative market penetration between the base case and the sensitivity case. By 2030, the CHP market penetration for the sensitivity case is about 75% lower (23.1 MW) than the base case projection (90.4 MW).

Figure 3. Comparison of Market Penetration between Two Cases

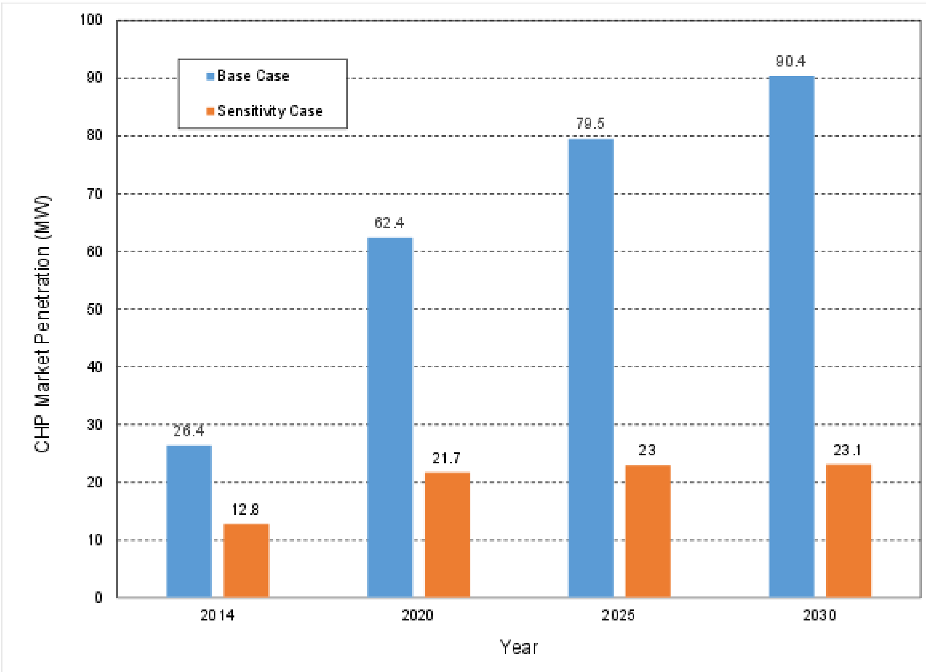


Table 7 provides a breakout of the cumulative market penetration by CHP size range. Nearly 95% (21.8 MW) of the market penetration in 2030 occurs for large (> 20 MW) CHP installations.

Table 7. *SENSITIVTY CASE* – **Cumulative Market Penetration by CHP Capacity**

Electric Capacity	**Year**			
	2014	2020	2025	2030
50 - 500 kW	0.0	0.0	0.0	0.0
500 kW - 1 MW	0.0	0.0	0.0	0.0
1 - 5 MW	0.8	0.8	0.8	0.8
5-20 MW	0.5	0.5	0.5	0.5
> 20 MW	11.5	20.5	21.7	21.8
Total	**12.8**	**21.8**	**23.0**	**23.1**

Appendix F
The Climate Action Reserve Letter of Opinion

CLIMATE
ACTION
RESERVE

LETTER OF OPINION
NW Natural's CHP M&V SPECIFICATION

April 13, 2015

The Climate Action Reserve ("Reserve") has been invited by NW Natural to undertake a brief analysis of its Combined Heat and Power (CHP) measurement and verification (M&V) specification ("NWN specification"), and to offer an opinion, in the form of this letter, as to how closely the M&V specification aligns with the M&V requirements typically found in standards for carbon offsets. To form this opinion, we compared the M&V specification to requirements found in methodologies for CHP and other types of projects under the Reserve's voluntary carbon offset program, California's compliance carbon offset program, and the United Nations Clean Development Mechanism (CDM). Our conclusion is that the NWN specification aligns well with carbon offset standards for most measurement and monitoring requirements. It is not clear from the documentation provided by NW Natural whether verification procedures and requirements would be equivalent to what most carbon offset programs require.

Monitoring Requirements

In the context of carbon offset standards, "monitoring" requirements include specifications for the data that must be collected to determine project performance; the methods and equipment to be used to collect these data (including requirements for accuracy); the required frequency of measurements and/or data collection; data quality assurance and quality control (QA/QC) provisions; and procedures that must be followed if and when required data are missing or cannot be obtained. The NWN specification aligns well with existing CDM methodologies for CHP projects regarding the general types of data that must be collected to quantify greenhouse gas reductions, including data on fuel inputs, electricity generation, and heat generation. Furthermore, most of the prescribed monitoring methods, frequencies, and procedures in the NWN specification are commensurate with those found in the carbon offset standards reviewed here. The one area where carbon offset standards typically provide additional safeguards is in requiring the cross-checking of monitored data with alternative data sources, such as receipts or invoices. We further describe the similarities and differences below, and have summarized them in tabular format at the end of this document.

Fuel inputs

The NWN specification requirements for fuel input monitoring are largely commensurate with requirements in Reserve and California standards,[8] and in relevant CDM methodologies. The NWN specification does not explicitly require ongoing measurement and monitoring of the calorific content of fuels, which is a requirement in all carbon offset standards reviewed here. However, calorific content of pipeline gas is monitored continuously by default on NW Natural's system, obviating the need for project developers to monitor this parameter themselves. System-wide meter testing and calibration requirements are specified in a NW Natural Meter Testing Procedures document (effective date October 31, 2014), and these procedures meet or exceed typical testing and calibration requirements for carbon offsets by aligning with ANSI/manufacturer standards. It should be noted, however, that the requirements are applied on a random sampling basis, across all such meters used by NW Natural. As such, some project meters may not receive the site-specific testing/calibration that would typically be required in the context of a carbon offset project. Nevertheless, given the nature of the system, it appears the Meter Testing Procedures would provide a similar level of assurance as would typically be achieved with carbon offsets.

Otherwise, the only notable differences between the NWN specification and the carbon offset standards, is that the NWN specification does not employ specific QA/QC measures, such as the cross-checking of data against other sources, as found in the carbon offset standards, nor does it include specific positioning guidance for meters.

Electricity generated

The requirements for monitoring electricity output in the NWN specification are commensurate with some electricity monitoring requirements in Reserve and California protocols,[9] and in relevant CDM methodologies, but nevertheless are not fully aligned. The specific parameters to be monitored are commensurate with those in the carbon offset standards, as are the required measurement techniques and devices used; required measurement frequencies; prescribed reporting format; metering calibration requirements, and data substitution methods. However, the NWN specification does not appear to explicitly provide comparable terms for QA/QC cross-checking of data (e.g., against sales records or other data).

Heat generated

The NWN specification requirements for measuring thermal heat recovery associated with CHP units are commensurate with, or exceed, all of the requirements in relevant CDM methodologies.[10]

Verification Requirements

Carbon offset programs require periodic third-party verification of monitoring data. Typical steps in third-party carbon offset verifications include: i) determining whether monitoring data have

[8] The Reserve and State of California do not have offset protocols specifically for CHP projects. However, they do have standards for measuring and monitoring quantities of methane destroyed by projects involving landfills, livestock operations, and mining operations. The standards for monitoring methane quantities are analogous to those that would be required to monitor fuel inputs in a CHP project.

[9] Several Reserve and State of California protocols have requirements for monitoring electricity production and/or consumption associated with project activities.

[10] The Reserve and State of California do not have any protocols involving heat recovery, so there are no relevant monitoring requirements to compare to. The CDM, however, has methodologies for a number of different CHP and cogeneration project activities involving heat recovery.

been collected and reported in accordance with program requirements; ii) conducting onsite inspections as appropriate (including reviewing performance records, interviewing key staff, collecting primary data, observing established practices, and testing the accuracy of monitoring equipment firsthand); iii) verifying the accuracy of monitoring data, and ensuring that related documentation is complete and transparent; iv) recalculating emission reductions; v) identifying concerns and discussing them with the project developers, and finally vi) making a determination based on audit findings. These are seen as essential to ensure the transparency of the system and integrity of claimed emission reductions.

In contrast to these detailed and standardized verification requirements, the NWN specification stipulates that verifications will be carried out either by NW Natural themselves, or by third parties contracted by NW Natural. Little guidance is given regarding prescribed procedures for these verifications, or who is to carry out the work, as would typically be found in carbon offset standards.

Appendix F:
Energy 350 NW Natural CHP Program M&V Requirements Comparison

107 SE Washington St, Suite 140
Portland, OR 97214
Phone: (971) 544-7211
Fax: (503) 465-3793
www.energy350.com

MEMO

TO: Barbara Summers, NW Natural
FROM: Nick O'Neil, Energy 350
SUBJECT: NW Natural CHP Program M&V Requirements Comparison
DATE: July 15, 2015

1. Overview

Energy 350 was tasked with documenting the Measurement and Verification (M&V) requirements of the NW Natural CHP Solicitation program as it compares to the M&V requirements of other similar programs. To provide this comparison, Energy 350 researched two well established programs operating today: MassSAVE's CHP Initiative and NYSERDA's CHP Performance Program.

2. M&V Requirements

A review of MA and NY CHP material indicated that similar M&V methods are being required by those programs as are specified in the NW Natural Solicitation. On a technical level, a detailed energy balance for the proposed CHP system is required for all programs, along with documentation on design specifications, plant layouts, controls drawings, and annual load profile development. This information is assessed during the technical study phase prior to any installation of the CHP system. Included during this phase, and an eligibility requirement among all 3 programs, is the development and submission of an M&V and Commissioning plan from the applicant based on the specific project being proposed. The M&V must be performed consistent with the plan submitted in the technical study.

3. Summary of Key Differences

While NYSERDA and MassSAVE provide more specific programmatic guidelines around what must be included as part of M&V, general guidance provided in the NW Natural document obtains the same level of verification once completed. All programs require a data upload for the duration of the M&V period to measure actual performance against claims stated during the technical phase, however NW Natural's performance period is substantially longer (10 years) compared to the other two programs (2 and 3 years).

Several key aspects of the M&V protocols outlined within each program's guidelines were compared to look for significantly different criteria, and a summary of the key elements compared is given below. Overall, no substantial differences were noted with M&V requirements among the three programs.

107 SE Washington St, Suite 145
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Phone: (971) 544-7211
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www.energy350.com

M&V Element	NW Natural Program	MassSAVE	NYSERDA
Monitoring period	10 years	3 years	2 years
Primary purpose	Give enough empirical data to provide the owner of the CHP system and NW Natural sufficient information to quantify the input energy and useful output of the CHP plant used to derive emissions savings	Quantify inputs/outputs including useful thermal heat recovered and electricity produced	Quantify useful thermal heat recovery, energy generated, fuel consumed, and summer peak demand performance
M&V Reporting Timeframe	Quarterly uploads to NW Natural via developed template and Excel spreadsheet including individual input/output points, date stamped in 15-minute increments	Bi-monthly (with weekly capability) export to third party via email or FTP in 15-minute increments	Upload of 15-minute interval data to NYSERDA's CHP Data Integration Website; prepare reports and determine performance incentive; first report 30-days after first performance period, second report 30 days after second performance period
O&M contract	None required	Required to be in place for duration of M&V period	Required to be in place for duration of M&V period
Commissioning	Required as part of technical analysis	Commissioning required, however not specified to be 3rd party	3rd party commissioning agent required under contract to applicant
Post-install inspection	None specified, however intended as part of technical analysis phase. (Industry standard practice)	PA confirms data collection system properly installed, proper metering, calibration and reporting and archiving of data	Report summarizing project and its ability to meet program performance requirements required 3 months after installation and commissioning complete
Performance payments	Quarterly after review of data to ensure reported performance aligns with submitted data from reporting system	Not performance based. Incentives on tiered system. 80% typically paid up front, remainder paid after CHP	Based on total verified electric energy generated, peak demand reduction, and adjusting for differences between estimated

		commissioning complete.	and verified.
Responsibilities of consultants	Technical oversight and QC for M&V, confirm instrumentation is installed ensure data collection is occurring, verify sensor readings, locations and documentation, validate monitored data	Program Administrator (could be a consultant) oversees QC for M&V, confirm instrumentation is installed, ensure data collection is occurring, verify sensor readings, locations and documentation, validate monitored data	Technical oversight and QC for M&V, confirm instrumentation is installed, ensure data collection is occurring to NYSERDA's website, verify sensor readings, locations and documentation, validate monitored data
M&V inspection	Periodic inspection allowed	Periodic inspection allowed	Periodic inspection allowed
Non-performance	Suspension of payment for data loss in excess of 8 hours	None specified	No grace period for performance failure. 3-month grace period to take corrective action on NOx & CO emissions
Meter accuracy requirements	Accurate to +/- 1%	None specified	Accurate to +/- 1%

Appendix F :

Appendix F: Measurement and Verification - Energy 350 Comparison of NWN Program to MassSAVE and NYSERDA CHP Programs

Table 1. Comparison of Monitoring Requirements - Fuel Inputs

Standard / Specification	Parameter(s) monitored	Required measurement technique(s) or device(s)	Accuracy / Calibration requirements	Required frequency of measurement	Prescribed reporting format?	Prescribed QA/QC procedures	Missing data procedures
CAR	• Flow rate • Gas conc.	• **Flow rate:** gas meters • **Calorific content:** continuous analyzer, or quarterly lab testing	All meters must be: • Cleaned/inspected on quarterly basis; • Field checked within 2 months of end of each reporting period; • Calibrated by appropriately trained service provider; All meters must reveal accuracy within +/-5%;	• **Flow rate:** Measured continuously – recorded every 15 minutes or totalized and recorded daily; • **Calorific content:** continuous analyzer, or quarterly lab testing	No	See accuracy / calibration requirements; Suggested positioning of meters;	Applied to missing data – or data not meeting QA/QC requirements: • < 6 hours = use average of 4 hours before/after gap; • 6-24 hours = use 90% lower / upper confidence limit of 24 hours before/after; • 1-7 days = use 95% lower/upper confidence limit of 72 hours before / after; • >7 days = no data substitution allowed
CDM	• Flow rate • Calorific content	• **Flow rate:** gas meters • **Calorific content:** range of options	All meters should be calibrated regularly per industry practices. Accuracy can be implied based on missing data method.	• **Flow rate:** Monitored continuously. • **Calorific content:** monitored per national / international standard;	Yes	Must cross-check against invoices / receipts for purchased fuels, stock changes etc.	Based on materiality of effected emission reductions relative to overall amount claimed - ie projects applying for more than 500ktCO2-e are permitted only to have up to 0.5% of data missing;
NW Natural	• Flow rate only • (Calorific content monitored on pipeline system)	**Flow rate:** billing grade meters supplied by NW Natural	All meters must be accurate to 1%. Any meter faults must be reported the next day. Meters randomly sampled, tested and calibrated to ANSI / manufacturers standards, in accordance with separate Meter Testing Procedures.	**Flow rate:** 15 minute intervals **Calorific content:** continuous on system	Yes	No	Applies only to missing data, though implies also data not meeting QA/QC: • <30 mins = proxy data used; • catastrophic loss of 8 hours or more = must be remedied; • >8 hours may result in suspension of incentive for missing data period.
Assessment	Meets	Meets	Meets / May Not Meet	Meets	Meets	May Not Meet	Meets
Comments / Explanation	Comparable requirements for flow rate. Calorific content provided by NW.	Comparable requirements for flow rate. Calorific content provided by NW.	Comparable requirement for meter accuracy. Comparable requirement for meter testing and calibration (contained in separate Meter Testing Procedures) – not necessarily applied to each project meter.	Comparable requirement for monitoring frequency.	Comparable requirement for reporting format.	Does not require QA/QC measures.	Comparable missing data requirements.

Table 2. Comparison of Monitoring Requirements - Electricity Generation

Standard / Specification	Parameter(s) monitored	Required measurement technique(s) or device(s)	Accuracy / Calibration requirements	Required frequency of measurement	Prescribed reporting format?	Prescribed QA/QC procedures	Missing data procedures
CAR	• kwh • flow		All meters must be: • Cleaned/inspected on quarterly basis; • Field checked within 2 months of end of each reporting period; • Calibrated by appropriately trained service provider; All meters must reveal accuracy within +/-5%;	Kwh to be monitored and recorded at least hourly. Flow to be measured continuously – recorded every 15 minutes or totalized and recorded daily;	No	See accuracy / calibration requirements; Suggested positioning of meters; Flow must be shown to be contemporaneous with engine output.	Applied to missing data – or data not meeting QA/QC requirements: • < 6 hours = use average of 4 hours before/after gap; • 6-24 hours = use 90% lower / upper confidence limit of 24 hours before/after; • 1-7 days = use 95% lower/upper confidence limit of 72 hours before / after; >7 days = no data substitution allowed
CDM	kwh	N/A	All meters should be calibrated regularly per industry practices. Accuracy can be implied based on missing data method.	Monitored continuously	Yes	Must cross-check data using records for sold electricity	Based on materiality threshold for project.
NW Natural	kwh	Metered net of parasitic loads - with exception of small/remote parasitic loads, where not economical to meter and approved engineering solution provided	All meters must be accurate to 1%. Any meter faults must be reported the next day. No specified calibration requirement. Meters randomly sampled, tested and calibrated to ANSI / manufacturers standards, in accordance with separate Meter Testing Procedures.	15 minute intervals	Yes	No	Applies only to missing data, though implies also data not meeting QA/QC: • <30 mins = proxy data used; • catastrophic loss of 8 hours or more = must be remedied; >8 hours may result in suspension of incentive for missing data period.
Assessment	Meets	Meets	Meets / May Not Meet	Meets	Meets	May Not Meet	Meets
Comments / Explanation		Comparable requirements for electricity generation.	Comparable requirement for meter accuracy. Comparable requirement for meter testing and calibration (contained in separate Meter Testing Procedures) – not necessarily applied to each project meter.	Comparable requirement for monitoring frequency.	Comparable requirement for reporting format.	No cross-checking with flow or sales records.	Comparable missing data requirements.

Table 3. Comparison of Monitoring Requirements - Thermal Output

Standard / Specification	Parameter(s) monitored	Required measurement technique(s) or device(s)	Accuracy / Calibration requirements	Required frequency of measurement	Prescribed reporting format?	Prescribed QA/QC procedures	Missing data procedures
CAR	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CDM	• temperature • flow • pressure	Enthalpies determined based on mass flows – steam tables / equations can be used	All meters should be calibrated regularly per industry practices. Accuracy can be implied based on missing data method.	Monitored continuously, aggregated as appropriate	Yes	N/A	Based on materiality threshold for project.
NW Natural	• temperature • flow • pressure	• where water/air flow measured, temp must also be measured for energy calcs; • where steam is measured, pressure and temp must be measured also; • meters must be able to measure 120% of nominal flow rate;	All meters must be accurate to 1%. Any meter faults must be reported the next day. Meters randomly sampled, tested and calibrated to ANSI / manufacturers standards, in accordance with separate Meter Testing Procedures.	15 minute intervals	Yes	No	Applies only to missing data, though implies also data not meeting QA/QC: • <30 mins = proxy data used; • catastrophic loss of 8 hours or more = must be remedied; >8 hours may result in suspension of incentive for missing data period.
Assessment	Meets	Meets	Meets / May Not Meet	Meets	Meets	Meets	Meets
Comments / Explanation	Comparable requirements for heat measurements.	Comparable requirements for heat measurements.	Comparable requirement for meter accuracy. Comparable requirement for meter testing and calibration (contained in separate Meter Testing Procedures) – not necessarily applied to each project. meter.	Comparable requirement for monitoring frequency.	Comparable requirement for reporting format.	No relevant QA/QC requirements in either CDM or NWN specification.	Comparable missing data requirements.

Appendix G: Stakeholder Meetings

Agendas and Sign-In Sheets

Meeting Agenda:1

Carbon Solutions : Combined Heat and Power Solicitation Program Overview

March 16, 2015

2:00 pm- 4:00 pm NW Natural Offices

Discussion Topics:

- Overview of Program (Summers)
- Solicitation Design (Energy 350)
- Measurement and Verification Design (Energy 350)
- Incentive Design and Levels (Summers, Energy 350, ODOE/WSU)
- Recap of Stakeholder Key Issues and Concerns

Appendix G: Stakeholder Meetings Agendas and Sign-In Sheets

NW Natural Carbon Solutions Program
Combined Heat and Power Market Solicitation
Stakeholder Meeting
March 16, 2015

SIGN-IN SHEET

	Name	Organization	Email Address	Telephone Number	Received Notebook (X)
1	MARTY STIPE	ODOE	marty.stipe@state.or.us	503 378 4926	X
2	[illegible]	WSU	[illegible]	[illegible]	X
3	CAROLYN ROOS	WSU EP	[illegible]	(360) 956-2157	X
4	[illegible]	CUB	bob@oregoncub.org	503-227-1984	X
5	Jason Klotz	PUC	jason.klotz@state.or.us	503-378-6667	X
6	Ed Finklea	NWIGU	efinklea@nwigu.org	503-303-4061	X
7	Chris Smith	E350	chris@energy350.com	503-886-9745	X
8	Nick O Neil	E350	noneil@energy350.com	503-333-8161	X
9	Ann Grahaill	Climate Solutions	[illegible]	503 701 9028	X
10	SOMMER TEMOLT	OIB	[illegible]	503 227-1984	X
11	Jessica Shipley	ODOE	jessica.shipley@state.or.us	503 378 3790	X
12	STEVE Nelson	NWN			X
13	Chris GALATI	NWN			X
14	BILL EDMONDS.	NWN			X
15	Ted BARRA	PGE	Ted.Barra@pgn.com	503 464 8052	X
16	Alex Miller	NWN	[illegible]@nwnatural.com	503 721 2467	X
17	Mary Moerlins	NWN	mem@nwnatural.com	x5771	
18	Barbara Summers	"			
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Meeting Agenda- 2

March 20, 2015

2:00 pm- 4:00 pm NW Natural Offices

Agenda

Topic	Lead
Potential ways to Abuse the Program and Solutions (Revised Appendix A) Disguised use of waste heat Removal of T&D losses if sell back to grid	Energy 350 Summers
"eGrid Only" versus "eGrid Plus Up and Down Stream Emissions" (Revised Appendix B)	Energy 350/Skov
Potential Alternative Incentive Structures	Summers
Updated Financial Plan and Budget (Revised Appendix C) Limited marketing costs to years 1-4	Summers
Measurement and Verification Meeting Scheduling	Energy 350
NW Natural incentives	Thompson
Summary of Open Issues and Discussion of Filing Readiness; Next Steps	Summers

Appendix G: Stakeholder Meetings
Agendas and Sign-In Sheets

NW Natural Carbon Solutions Program
Combined Heat & Power Market Solicitation
Stakeholder Meeting
Friday, March 20, 2015

SIGN-IN SHEET

	Name	Organization	Email Address	Telephone #	Received Updated Appendix B
1	MARTY STIPE	ODOE	marty.stipe@	503 378-4992	
2	SUMMER TEMPLET	CUB	summer@oregoncub.org	503-227-1984	
3	Bob Jenks	CUB	bob@oregoncub.org	503-227-1984	
4	Jason Klotz	PUC	jason.klotz@state.or.us	378-6857	
5	Nick [illegible]	Energy 350	[illegible]@energy350.com	503 [illegible]-3161	
6	Chris Smith	Energy 350	chris@energy350.com	503-886-9945	
7	Alex Miller	NWN	[illegible]@nwnatural.com	503 789 5756	
8	Zach Krautz	NWN	zak@nwnatural.com	503-2[illegible]	
9	Tommy Brooks	NWIGU	tbrooks@cablehuston.com	224-3092	
10	CHRIS GALATI	NWN	[illegible]@nwnatural.com	503-721-2472	
11	JOE BARRA	NWN	JOE.BARRA@NWN.com	503 464-8652	
12	Mark Thompson	NWN	[illegible]@nwnatural.com	503 721 2476	
13	Mary Moerlins	NWN	mom@nwnatural.com	x5771	
14	Barbara Summers	NWN	barbara.summers@nwnatural.com	x3557	
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Attending Via Phone

	Name	Organization	Email Address	Telephone #	Received Updated Appendix B
1	Kim Crossman	ETO			
2	Josh Skov				
3	Ed Finklea	NWIGU			
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Meeting Agenda- 3

April 14, 2015

3:00 pm-5:00pm NW Natural Offices

Discussion Topics:

1. Climate Action Reserve, Letter of Opinion, NWN's CHP M&V Specification (Energy 350)
2. Emission Follow Up – Consideration of Upstream Electricity Emissions Compared to Off-Site Natural Gas Emissions (Including Distribution System Emissions) (Summers/WSU)
3. Final Proposed Customer Incentive/Design (Summers)
4. Final Proposed NWN Incentive/Design (Thompson/Speer)
5. Customer Rate Impact (Speer)
6. Next Steps (Summers)

Appendix G: Stakeholder Meetings
Agendas and Sign-In Sheets

Carbon Solutions CHP Solicitation
Stakeholder Meeting 3, April 14, 2015 3pm-5pm NW Natural Offices

Sign In:

	Name	Organization	email	Materials Received
1	FRED HEUTTE	NW ENERGY COALITION	fred@nwenergy.org	
2	Tommy Brooks	NWIGU	tbrooks@cablehuston.com	
3	Barbara Summers	NWN		
4	CHRIS GALATI	NWN	cfg@nwnatural.com	
5	Andrew Speer	NWN	a1s@nwnatural.com	
6	Mary Moerlins	NWN	mom@nwnatural.com	
7	Nikki Thompson	NWN	nkt@nwnatural.com	
8	JOE BARRA	PGE	JOE.BARRA@PGN.COM	
9	Zach Kravitz	NWN	zdk@nwnatural.com	
10	Nick O'Neil	Energy 350	noneil@energy350.com	
11	Chris Smith	E350	chris@energy350.com	
12	Jason Klotz	PUC	jason.klotz@state.or.us	
13	Bill Edmonds	NWN	wre@nwnatural.com	
14	Bob Jenks	CUB	bob@oregoncub.org	
15	Kim Crossman	ETO		
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Attending by phone

	Name	Organization	email	Materials Received
1	Kim Crossman	ETO		provided digitally
2	Jaimie McGovern	CUB		provided digitally
3	Julia Peacock	ODOE		provided digitally
4	Joshua Skov			provided digitally

Meeting Agenda

Carbon Solutions : Monitoring and Verification Plan Review

June 9, 2015

3:00 pm-4:30 pm NW Natural Offices

Meeting Goal:

1. Answer any remaining stakeholder questions pertaining to structure of M&V plan (Facilitated by Energy 350 and NW Natural)
2. Review of CAR and Energy 350 analysis and summary of Monitoring and Verification Program

Appendix G: Stakeholder Meetings
Agendas and Sign-In Sheets

Carbon Solutions CHP
Special Meeting- CHP M&V Review, June 3:00 pm NW Natural Offices

Sign In:

	Name	Organization	email
1	Bob Jenks	CUB	bob@oregoncub.org
2	Nick oneil	ENERGY 350	noneil@energy350.com
3	MARTY STIPE	ODOE	marty.stipe@state.or.us
4	Barbara Summers	NWN	b3c@nwnatural.com
5	Jason Salmi Klotz	PUC	jason.klotz@state.or.us
6	Jessica Shipley	ODOE	jessica.shipley@state.or.us
7	Zach Kravitz	NWN	zck@nwnatural.com
8	Joe BARRA	PGE	JOE.BARRA@PGN.COM
9	Mary Moerlins	NWN	marymoerlins@nwnatural.com
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Attending by phone

1	Josh Skov		
2	Ed Finklea	NWIGU	
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Appendix H

Energy 350 Overview

STATEMENT OF QUALIFICATIONS – COMBINED HEAT AND POWER (CHP)

CASE STUDY – CHP PROGRAM ASSISTANCE FOR ENERGY TRUST OF OREGON

We recently completed a project with Energy Trust of Oregon to assist them with documenting technical program requirements and developing program materials. These included documentation of performance requirements, analytical requirements (CHP study framework), development of a CHP technical primer, and a program sorting matrix to determine which program is best suited to handle any given project.

Now as program participation ramps up, we're supporting Energy Trust by conducting project reviews, technical analysis studies and Measurement & Verification (M&V). For more information on Energy Trust of Oregon's programs, visit www.energytrust.org.

About Energy 350

Energy 350 is an energy efficiency consulting company based in Portland, OR. Energy 350 specializes in energy programs, energy policy, energy engineering and Measurement & Verification (M&V). We focus on complex systems analysis in the Commercial and Industrial sectors. We are experts in industrial processes in heavy industry such as pulp & paper, wood products, water & wastewater, metals, plastics, high-tech, food processing. Our staff includes Professional Engineers (PE), Certified Energy Managers (CEM), Certified Demand Side Managers (CDSM), Certified Commissioning Agents (CxA) and LEED Accredited Professionals (LEED AP).

Combined Heat and Power (CHP) Expertise

Our staff have analyzed, overseen the installation of, and secured incentives for over a dozen CHP systems. Additionally, we have developed, implemented and assisted with CHP programs nationally. We are able to dive deep on system operation, thermal load analysis, energy mapping and balancing, etc. We have a deep toolbox of submetering equipment to gain detailed insight on thermal and electric load profiles, down to the minute. This allows us to understand the coincidence of thermal and electric loads and accurately analyze the operation of CHP systems before they're installed.

Measurement and Verification (M&V) Expertise

We have the equipment and expertise to accurately measure and verify real world performance of CHP systems. By measuring fuel in, electricity out, heat recovered, heat rejected and parasitic electric use, we can conduct a full energy balance on the system. This allows us to analyze performance in any number of ways such as total system efficiency, fuel chargeable to power, and bottom line $ impacts. Additionally, M&V often reveals opportunity to optimize systems for increased performance.