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DIVISION OF ENERGY RESOURCES

Minnesota Combined Heat and Power Policies and Potential

Conservation Applied Research & Development (CARD)
FINAL REPORT

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Preface

This study was funded by the Conservation and Applied Research & Development (CARD) program of the Minnesota Department of Commerce to assess alternative approaches to potential changes in Minnesota policies and programs to increase implementation of combined heat and power (CHP). This report incorporates key results from a related CARD-funded study (Assessment of the Technical and Economic Potential for CHP in Minnesota, FVB Energy and ICF International, July 2014) to help inform recommendations for potential goals for CHP growth. The recommendations in this report are those of FVB Energy.

The report is organized as follows.

- **Introduction** summarizes the methodology used in this study, provides an overview of why CHP is important, describes CHP technologies, quantifies the current implementation of CHP in Minnesota and provides an overview of the technical potential for CHP growth.
- **Key Barriers** describes and analyzes the challenges which constrain CHP growth.
- **Current Minnesota Policies and Programs** describes existing Minnesota laws, policies and programs relevant to CHP.
- **Development of Policy Options** provides an analysis of the economic significance of key barriers, briefly notes major findings from research on best practices for CHP policy in other states, briefly notes major findings from research on federal policies relevant to CHP and describes potential Policy Options that were introduced in draft form in a "Straw Man" report that was the basis for informal stakeholder feedback.
- **Policy Analysis** analyzes program design issues in light of stakeholder input, summarizes the estimated impact of Policy Options on implementation of CHP, calculates the impact of Policy Options on Participants and Society for example CHP projects, and draws conclusions regarding the suitability of the policy options for Minnesota.
- **Recommendations** describes FVB's recommendations for Minnesota CHP policies.

Appendices provide additional detailed information as follows.

- **Appendix A** describes best practices in other states relative to CHP policies and programs.
- **Appendix B** describes existing and proposed federal policies and programs relevant to CHP.
- **Appendix C** is a draft report ("Straw Man Options for Minnesota CHP Policies") which was used to elicit informal stakeholder feedback.
- **Appendix D** summarizes the comments received during informal stakeholder consultations conducted by FVB, including electric utilities, gas utilities, thermal utilities, equipment suppliers, customers, advocacy groups and consultants.
- **Appendix E** describes key elements in the analysis methodology, focusing on aspects of the methodology that are not described in the body of the report or which are only briefly mentioned.

References used in the development of this report are listed at the conclusion of the report. These references are noted throughout the report in parentheses in the body of the report or after figure or table captions. Footnotes are used only where additional explanation was deemed appropriate.

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Abbreviations

AEO -- Annual Energy Outlook

Btu -- British thermal unit

NGCC – natural gas combined cycle

CHP – combined heat and power

CIP – Conservation Improvement Program

CO2 -- carbon dioxide

DE – district energy

DHC – district heating and cooling

DOE -- U.S. Department of Energy

DSM -- demand-side management

EERS – Energy Efficiency Portfolio Standard

EIA – U.S. Energy Information Administration

EPA -- U.S. Environmental Protection Agency

GHG -- greenhouse gas

HP – high pressure

IOU -- investor-owned utility

IRP -- integrated resource planning

kW -- kiloWatt

kWh -- kiloWatt-hour

LP – low pressure

MMBtu -- million Btu

MMBtu/hr – million Btu per hour

MPUC – Minnesota Public Utility Commission

MW -- MegaWatt

MWh -- MegaWatt-hour

NG – natural gas

PCT -- participant cost test

ROE -- return on equity

RPS -- renewable portfolio standard

SCT -- societal cost test

T&D -- transmission and distribution

UCT – utility cost test

WACC -- weighted average cost of capital

Executive Summary

This study was funded by the Conservation and Applied Research & Development (CARD) program of the Minnesota Department of Commerce to assess alternative approaches to potential changes in Minnesota policies and programs to increase implementation of combined heat and power (CHP). This report incorporates key results from a related CARD-funded study (FVB Energy and ICF International, Assessment of the Technical and Economic Potential for CHP in Minnesota) to help inform recommendations for potential goals for CHP growth. The recommendations in this report are those of the author.

Methodology

This study began with research on current Minnesota laws, policies and programs relevant to CHP. A review of literature on CHP barriers and policies was then undertaken, including an analysis of best practices for CHP policies in other states. Existing and proposed federal policies relevant to CHP were identified. The economics of a broad range of CHP technologies were analyzed, including sensitivity to key variables that could be affected by new policies and programs, including capital cost, weighted average cost of capital[1], CHP fuel price and avoided price of electricity.

Draft Policy Options for increasing CHP in Minnesota were developed based on the analysis of the economic significance of key barriers as well as review of best practices in other states. A "Straw Man" draft report was prepared. Informal stakeholder consultations were conducted by FVB following distribution of the Straw Man report.

Following the stakeholder consultations, detailed analysis of the Policy Options was undertaken and modifications were made to the Policy Options based on the feedback and analysis. The impact of each Policy Option on CHP implementation was projected.

Recommendations were then developed for consideration by the Department of Commerce and stakeholders in stakeholder workshops to be implemented in fall of 2014.

Why CHP is Important

Of the total 1,706 trillion Btu (TBtu) of energy used in Minnesota in 2012, 350 TBtu was lost in electricity generation, transmission and distribution, resulting in an average power sector efficiency of less than 33 percent. Power generation waste heat in Minnesota is equal to 83 percent of the total requirement for heat energy in buildings and industry.

CHP systems reduce fossil fuel use and greenhouse gas (GHG) emissions by recovering heat that is usually wasted as rejected heat in power plants. This heat can then be used for heating (space heating in buildings, domestic hot water or industrial process heat) or it can be used to produce

[1] Weighted Average Cost of Capital (WACC) is the weighted average cost of repaying the capital invested or borrowed to build a CHP project. There are two main ways to fund a project: 1) equity investment, in which a company invests its own funds and then requires a return on that equity investment through payments made throughout the life of the project from the project revenues; and 2) debt, in which funds are borrowed and principal and interest payments are made each year based on the debt interest rate. WACC is calculated based on the relative portions of debt and equity. For example, if the funds raised are 60 percent debt and 40 percent equity, the debt interest rate is 6 percent and the return on equity is 12 percent, the WACC is calculated as follows: (60% X 6%) + (40% X 12%) = 8.4%.

chiller water for air conditioning or industrial cooling energy by using absorption chillers or steam turbine chillers.

The reductions in fossil fuel use made possible by CHP reduce emissions of air pollutants and GHG, and increase energy security and sustainability by reducing dependence on fossil fuels. Further, reduced consumption of fossil fuels can result in fewer energy dollars leaving the state, potentially strengthening the Minnesota economy.

CHP can help Minnesota achieve goals relative to per capita energy consumption, GHG reduction and renewable energy. Federal environmental regulations, including GHG standards for existing and new power plants, and potentially regional haze regulatory action, are likely to enhance the economics of CHP by increasing the economic value of fossil fuel and GHG reductions.

CHP also has the potential to enhance grid resiliency, reduce power line losses and strengthen peak power demand management. CHP systems are typically located much closer to the end user than more traditional centralized power plants; close proximity to end-users can reduce the losses of power along transmission and distribution lines. Additionally, many CHP systems are capable of ramping up to full output very quickly, and are more nimble electric system assets than many traditional generation resources.

CHP Barriers

CHP faces a range of economic, regulatory and institutional challenges:

- Relatively low electricity prices in Minnesota make CHP economic viability more challenging in comparison with other states.
- Most potential industrial or commercial entities require a very short payback on efficiency investments including CHP.
- Most industrial and commercial entities do not have the experience, skills and time for the difficult task of developing a CHP project.
- Decades of energy supply and price volatility inhibits CHP investment.
- There is no market value established for the GHG, power grid resiliency or other benefits of CHP.
- Historically, CHP projects have been discouraged by unfavorable interconnection requirements and standby rates.

Technical Potential

CHP is best applied at facilities that have significant and concurrent electric and thermal demands. In the industrial sector, CHP thermal output has traditionally been in the form of steam used for process heating and for space heating. For commercial and institutional users, thermal output has traditionally been steam or hot water for space heating and potable hot water heating. More recently, CHP has included the provision of space cooling through the use of absorption chillers or steam turbine chillers.

A wide range of CHP technology types and sizes were evaluated, as summarized in Table 1.

Technology Type	Fuel	Size range
Microturbine	Natural Gas	30 kW to (3 x 250) kW
Internal Combustion Engine	Natural Gas	800 kW to 5 MW
Gas Turbine	Natural Gas	3 to 40 MW
Steam Turbine	Biomass	4 to 40 MW
Phosphoric acid fuel cell	Natural Gas	200 kW
Molten carbonate fuel cell	Natural Gas	(2 x 300) kW
Organic rankine cycle	Waste heat	1 MW

Table 1. Overview of CHP Technologies Analyzed

Estimated technical potential for new natural gas-fired CHP plants in Minnesota is summarized in Table 2. Of this total, 1,406 MW of potential in sizes greater than 5 MW were identified at 72 sites. In addition, 230 MW of biomass CHP potential were identified.

CHP Size Range	Sites	MW
30 - 500 kW	3,263	545
500 - 1000 kW	287	481
1 - 5 MW	240	616
5.1 - 20 MW	54	562
> 20 MW	18	844
Total	3,862	3,049

Table 2. Technical Potential (Natural Gas CHP)

There is a further potential opportunity for CHP that cannot be easily analyzed: conversion of existing power plants to recover currently wasted heat for distribution to buildings and industry through district energy systems.

Based on Minnesota Pollution Control Agency (MPCA) air quality permitting fuel use data, calculations were made of the GHG emissions, quantity of waste heat and the amount of building floor space that could be heated with that waste heat. Based on the MPCA data, the estimated GHG emissions from Minnesota power plants were 34 million metric tonnes of carbon dioxide equivalent in 2011, and it is estimated that over 5 billion square feet of building space could be heated with the estimated waste heat from Minnesota's non- nuclear power plants. There are 21 plants producing enough waste heat to heat more than 10 million square feet of building space each.

Recovery and productive use of waste heat from existing power plants could help reduce total Minnesota fuel consumption and GHG emissions. This potential may help meet proposed federal standards for GHG emissions from existing power plants.

Business as Usual

There are currently 961.5 MegaWatts (MW) of CHP at 52 sites in Minnesota. Of this total, 83 percent resides in large systems with capacities greater than 20 MW.

Of the 3,049 MW of existing CHP/WHP technical potential in Minnesota, 984 MW has economic potential with a payback of less than 10 years. The 984 MW of economic potential is located mostly in the high load factor markets in Xcel and Minnesota Power territories, with smaller amounts present in Alliant and municipal/cooperative territory. Generally, calculated payback is shorter 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 typically characterizing larger customers.

The 984 MW of CHP economic potential with a payback of less than 10 years was then pared down to CHP market penetration. Additional CHP of about 210 MW and 250 MW are projected to be implemented by 2030 and 2040, respectively, without new policies ("Business As Usual" or "Base Case"). In addition, a Base Case market penetration of 50 MW is estimated for Waste Heat to Power. This capacity is almost all in Xcel service territory with some in Minnesota Power and Alliant territory.

Policy Options

Table 3 provides an overview of the Policy Options analyzed in this study. The options are summarized as follows:

- Policy Option groups 1 and 2 are based on natural gas and electric utility Conservation Improvement Program (CIP) incentives targeted at end-users. Specific Policy Options were modeled with either capital incentives, operating incentives, or a combination of both capital and operating incentives.
- Policy Option group 3 was based on CIP operating incentives for customer- or third party-owned CHP as well as significant utility ownership of CHP where the utility would receive an operating incentive, with the utility using its low weighted average cost of capital (WACC) to fund CHP systems.
- In Policy Option 4 it is assumed that a specific carve-out[2] is made for bioenergy CHP[3] in either the existing Renewable Portfolio Standard (RPS) or an expanded RPS.

[2] Under Minnesota's Renewable Portfolio Standard (RPS), Xcel Energy is required to generate or procure 31.5 percent of its electricity from renewable resources by 2020, and all other utilities are required to generate or procure 26.5 percent of their electricity from renewable resources by 2025. CHP fueled with biomass, landfill gas or other bioenergy is an eligible technology, Most of the RPS requirement must be met with specific "carve-outs" for wind and solar. Of the 31.5 percent renewables required of Xcel Energy in 2020, 1.5 percent must be met with solar PV (10 percent of which must be met with systems of 20 kW or less) , at least 25 percent must be generated by wind-energy or solar energy systems, with solar limited to no more than 1 percent of the requirement. In effect, this means that the wind standard is at least 24 percent, 1.5 percent must be met with solar, and solar may contribute up to another 1 percent, and the "remaining" 5 percent may be generated using other eligible technologies.

[3] Bioenergy is an inclusive term that encompasses: 1) biomass combustion CHP (in which wood or other biomass is combusted to produce steam that is used to spin a steam turbine-generator or to vaporize an organic chemical such as isopentane for organic rankine cycle turbine-generation; 2) internal combustion engine or combustion turbine CHP using gaseous or liquid fuel produced from biomass such as manure, agricultural residues, sewage sludge, etc.

- Policy Option group 5 addresses the potential to create a new Alternative Portfolio Standard (APS), which would require electric utilities to obtain a specified percentage of sales from CHP (regardless of fuel) by a given year.

		Conservation Improvement Program					Renewable Portfolio Standard		Alternative Portfolio Standard	
		CIP Incentives for Customer- or Third Party-Owned CHP	CIP Credit to Utilities for Utility-Implemented CHP	CHP requirements in separate new CIP tier (% of sales each year)			Bioenergy CHP requirement (% of sales by 2030)		CHP requirement (% of sales by 2030)	
Policy Option Summary	Option #			Natural Gas	Electric IOUs	Electric Munis & Coops	Electric IOUs	Electric Munis & Coops	Electric IOUs	Electric Munis & Coops
Gas Utility CIP with Incentives for Customer- or Third Party-Implemented CHP	1.1	Capital Incentive ($100 per 1000 Btu/hr)	N/A	0.10%	N/A	N/A	N/A	N/A	N/A	N/A
	1.2	Operating Gas Rate Discount ($0.75/MMBtu, 15 yrs)	N/A	0.10%	N/A	N/A	N/A	N/A	N/A	N/A
	1.3	Capital and Operating Incentives in Options 1.1 and 1.2	N/A	0.15%	N/A	N/A	N/A	N/A	N/A	N/A
Electric Utility CIP with Incentives for Customer- or Third Party-Implemented CHP	2.1	Capital Incentive ($500 per kW)	N/A	N/A	0.20%	0.08%	N/A	N/A	N/A	N/A
	2.2	Operating Electric Rate Discount ($10 per MWh, 15 yrs)	N/A	N/A	0.20%	0.08%	N/A	N/A	N/A	N/A
	2.3	Capital and Operating Incentives in Options 2.1 and 2.2	N/A	N/A	0.30%	0.12%	N/A	N/A	N/A	N/A
Gas Utility with Customer Incentives Plus CIP Credit for Utility Owned CHP	3.1	Same as Option 1.2	$0.75 per MMBtu gas supplied to CHP, 15 yrs	0.23%	N/A	N/A	N/A	N/A	N/A	N/A
Electric Utility with Customer Incentives Plus CIP Credit for Utility Owned CHP	3.2	Same as Option 2.2	$10 per MWh of CHP electricity produced, 15 yrs	N/A	0.45%	0.18%	N/A	N/A	N/A	N/A
RPS carve-out for bioenergy CHP in existing or expanded RPS	4	N/A	N/A	N/A	N/A	N/A	1.50%	0.60%	N/A	N/A
New Alternative Portfolio Standard for CHP	5.1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	8.00%	3.20%
	5.2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	12.00%	4.80%

Notes:

CIP = Conservation Improvement Program
IOU = Investor-Owned Utility
Muni = Municipal Utility
Coop = Cooperative
MMBtu = milion British Thermal Units
MWh =MegaWatt-hour
kW = kiloWatts
RPS = Renewable Portfolio Standard
APS = Alternative Portfolio Standard
IRP = Integrated Resource Planning

Table 3. Overview of Policy Options

Economic Potential with New Policies

Estimated 2030 CHP market penetration under the Base Case (Business as Usual) and with the Policy Options is summarized in Figure 1. The following discussion summarizes the results of market penetration estimates and the cost-effectiveness analysis of the Policy Options using two cost-benefit tests: participant cost test (PCT) and the societal cost test (SCT).

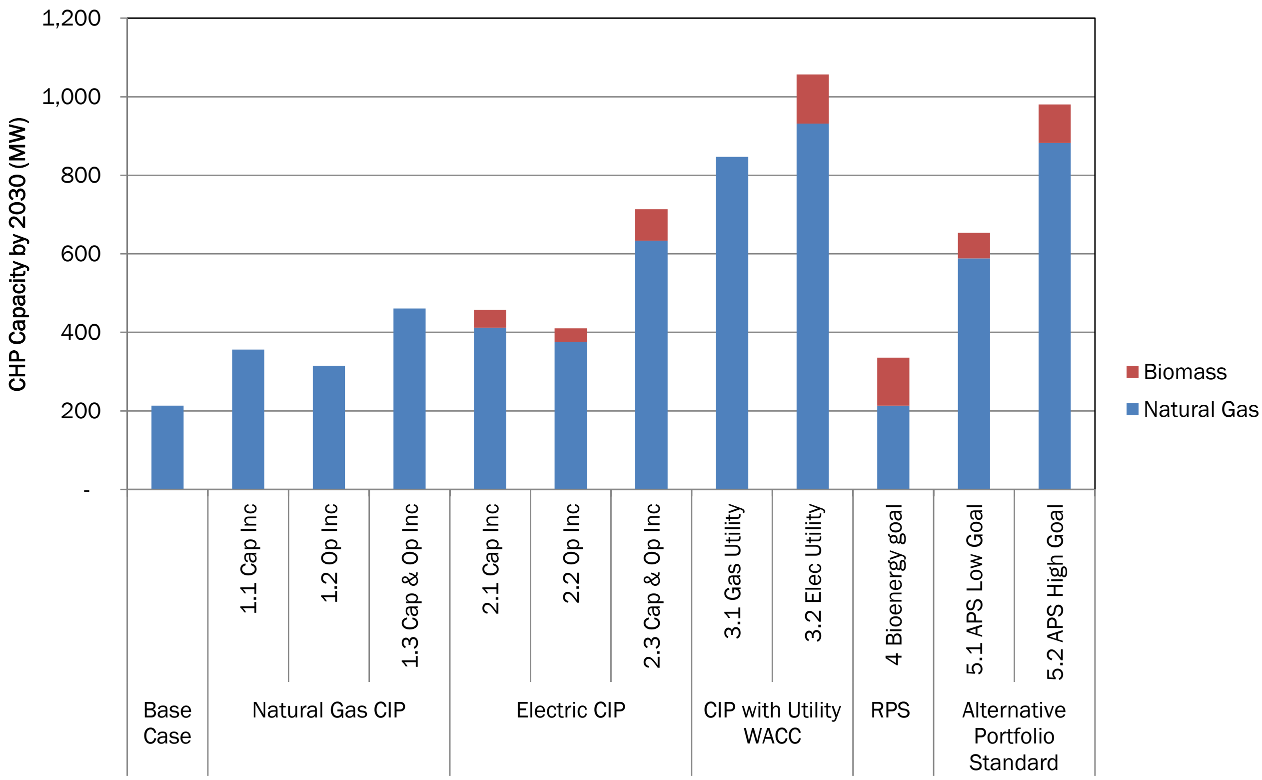

Figure 1. Summary of Estimated 2030 CHP Market Penetration with Policy Options

Policy Option 3.2 (a separate new CIP tier for CHP in electric utility CIP, with an emphasis on utility investment in CHP) and Policy Option 4.2 (APS high goal) are each projected to result in about 1,000 MW of new CHP by 2030. This magnitude of new CHP capacity represents approximately a doubling of current CHP.[4]

The impact of each policy option on projected CHP growth is discussed below.

Conservation Improvement Program (CIP)

In Policy Options 1.1, 1.2, 2.1 and 2.2, CIP incentives for customer investment in CHP, at levels approximately consistent with recent levels of CIP expenditures per unit of electricity or natural gas saved, are estimated to result in approximately 100 to 240 MW of additional CHP beyond the Base Case. However, most CHP installations do not meet both the PCT and SCT.

Policy Options 1.3 and 2.3, which provide more substantial CIP incentives (combining capital and operating incentives) for customer investment in CHP, are estimated to result in approximately 250

[4] Policy Option 3.1 (a separate new CIP tier for CHP in gas utility CIP, with an emphasis on gas utility investment in CHP) is projected to result in about 850 MW of new CHP by 2030. This also represents significant growth but is lower than in Policy Option 3.2 because the historical value of natural gas reductions in CIP (which were used to establish natural gas utility CIP credits in the policy options) are less beneficial than the historical value of electricity reductions in CIP (which were used to establish electric utility CIP credits in the policy options).

to 500 MW of additional CHP beyond the Base Case. However, while these policy options improve PCT results, most CHP installations not meet both the PCT and the SCT.

In Policy Option group 3, deploying the relatively low Weighted Average Cost of Capital (WACC) of utilities to build CHP significantly enhances CHP economics. Utility investment in CHP is estimated to result in approximately 630 to 840 MW of additional CHP beyond the Base Case, with positive results for both cost-benefit tests for a wide range of CHP installations.

Renewable Portfolio Standard

With Policy Option 4, establishing a specific "carve-out" for bioenergy CHP in the RPS is estimated to result in about 125 MW of new biomass CHP by 2030. The RPS was not analyzed for the Cost-Benefit tests.

Alternative Portfolio Standard

In Policy Option group 5, an Alternative Portfolio Standard is estimated to result in approximately 440 to 770 MW of additional CHP beyond the Base Case (for Low and High APS targets). At the high end of this range, CHP would more than double by 2030.

Although the APS was not directly analyzed for the Cost-Benefit tests, it was indirectly analyzed[5] and is projected to result in positive results for both Cost-Benefit tests for wide range of CHP installations.

Conclusions

Conservation Improvement Program

As a mechanism for advancing CHP, the CIP has a significant advantage because it is an established program for reductions in electricity and natural gas consumption that is familiar to utilities, stakeholders and state agencies. Further, CIP provides opportunities for incentives ("carrots") for utility adoption of CHP, in contrast to the APS, which relies solely on a "stick" approach. However, there are a range of issues surrounding use of CIP as a mechanism to advance CHP.

There are disparities in CHP opportunities between utilities, particularly limitations in the service territories of municipal utilities and cooperatives. A system of tradable credits would provide a way to address this issue and promote economic efficiency (i.e., result in the lowest costs to society by promoting implementation of CHP at the most cost-effective sites regardless of location).

One concern regarding the CIP is the high level of opt-out and the fact that the opt-outs tend to be the larger energy users who are generally the best candidates for CHP. To the extent that CHP is implemented within CIP primarily through utility ratebase investments, this issue is largely mitigated. However, at least as envisioned in the policy analysis, a CIP credit ($/MWh) would also flow to the CHP project even with utility ownership in order to provide an economic advantage to CHP in competing for dispatch of utility resources.

Legislation to establish a CHP tier in CIP would have to resolve the current lack of clarity regarding the potential role of CHP in CIP. Further, the legislation would require resolution of issues of

[5] The impacts of the APS were indirectly analyzed by assessing the impacts of CIP operating credits as a proxy for a tradable APS credits.

interaction between electric utility CIP and gas utility CIP. For example, if natural gas utilities could include CHP in their CIP, there would be a shift in revenue from the electric utility to the gas utility. This would engender resistance from electric utilities out of concern for impacts on rates. On the other hand, including CHP in both gas and electric utility CIP may increase the interest of electric utilities in CHP in order to retain revenues.

Decoupling of both gas and electric utility revenues from sales would in concept address concerns related to potential shifts in revenue from one utility to another. (Decoupling is a complex issue that extends far beyond CHP, and was not part of the scope of this study.)

An argument in favor of focusing responsibility for CHP implementation on electric utilities is that it can better facilitate timely and positive resolution of barriers relating to interconnection and standby rates. Further, setting goals for CHP in both electric and gas utility CIP would result in the potential for electric and gas utilities to be competing for the same pool of prospective CHP projects.

Renewable Portfolio Standard

Establishing a specific "carve-out" for bioenergy CHP in the RPS (Policy Option 4) is projected to provide relatively little additional CHP and ignores the largest CHP potential (natural gas CHP). Either the CIP or an APS would be a more effective mechanism for promoting CHP because either approach would not only address renewable CHP but also natural gas CHP, which constitutes the vast majority of the potential.

Alternative Portfolio Standard

Minnesota currently has no Alternative Portfolio Standard (APS), so new legislation would be required to create a new program and related implementation mechanisms. Creation of a new program will likely face greater political and implementation challenges in comparison to expanding an existing program such as CIP.

On the other hand, because the APS would be a new program it may be able to avoid some of the complexities discussed above relative to adapting the CIP to include CHP. An APS can be structured from the beginning as an enforceable standard with clear cost penalties for non-compliance.

Table 4 provides a summary of the major advantages and disadvantage of CIP compared with APS as the major CHP policy mechanism.

	CIP	APS
Advantages	CIP is an established program for reductions in electricity and natural gas consumption that is familiar to utilities, stakeholders and state agencies.	As a new program can avoid some of the complexities related to adapting the CIP to include CHP.
	Provides opportunities for both "carrots" and "sticks" for utility adoption CHP.	
Disadvantages	There are disparities in CHP opportunities between utilities, particularly limitations in the service territories of municipal utilities and cooperatives. (Potential solution: system of tradable credits.)	Legislation would be required to create a new program and related implementation mechanisms. Creation of a new program will likely face greater political challenges in comparison to expanding an existing program.
	Lack of statutory clarity regarding applicability of CHP in CIP. (Solution: clarifying legslation.)	Primariily a "stick" approach.
	Less clear path to enforceablIity than a portfolio standard. (Solution: clear enforcement provisions in legislation.)	
	High level of opt-out and the fact that the opt-outs tend to be the larger energy users who are generally the best candidates for CHP. (Largely mitigated if utility investments in CHP are in rate base.)	

Table 4. Overview of Advantages and Disadvantages of CIP and APS as Major CHP Policy Vehicles

Integrated Resource Planning

Integrated Resource Planning (IRP) can be a useful element in Minnesota CHP policy because it provides a context for: 1) consideration of potential benefits of CHP that currently do not have a market value (GHG emission reductions, grid resiliency, reduced transmission/distribution losses, etc.); and 2) comparison of CHP opportunities in the utility service area to other potential utility resources.

Utility Investment in CHP

A major conclusion of this study is that significant increases in implementation of CHP will require investment by utilities in CHP because:

- Utilities have a sufficiently low weighted average cost of capital to make many CHP projects cost-effective;
- Implementation of CHP will be significantly facilitated if electric utilities are motivated and incented to provide CHP project planning and engineering, including grid interconnection, and to dispatch CHP units once they are built; and
- CHP has the potential to help utilities comply with upcoming regulations on GHG emissions from power plants.

A number of issues relating to utility investment in CHP must be more closely examined. Such investment at customer sites could result in ratepayer risk in the event that the thermal host goes out of business. The risk profiles of potential thermal hosts vary dramatically, with industrial plants competing internationally at the high end of the risk continuum, and institutional customers (e.g., district energy systems, colleges, universities, hospitals) at the low end. Risks related to CHP should be considered in the context of existing risks to ratepayers, such as cost overruns for refurbishment of conventional power plants, and risks associated with environmental regulations. Potential ratepayer risks associated with utility investment in CHP could be addressed through range of mechanisms, including a return on equity risk premium, a state-funded loss reserve, or other mechanisms.

Recommendations

Near-term Steps

During the balance of 2014, we recommend the following steps:

1. Initiate a robust stakeholder discussion of this report including feedback on policy options for increasing implementation of CHP. (Note: planning for this is already well underway by the Department of Commerce.)

2. Initiate an interagency working group to integrate potential CHP policy with Minnesota's plan to comply with the EPA's Clean Power Plan.

3. Develop a draft "Minnesota CHP Policy Act" for consideration by the legislature in 2015.

Either the CIP or an APS can be an effective centerpiece in Minnesota policies to significantly increase CHP, with the focus on facilitating use of the low WACC of utilities to finance CHP projects. On balance, the CIP appears to be a stronger vehicle for increasing CHP if the legislation effectively addresses the disadvantages outlined above. A priority should be placed on successfully adapting the CIP to include CHP, with the APS considered as a back-up approach.

Regardless of whether the CIP or an APS is the primary CHP program, a system of tradable credits will be important to promote economic efficiency (i.e., result in the lowest costs to society by promoting implementation of CHP at the most cost-effective sites regardless of location).

An achievable and readily understood goal for the State of Minnesota is doubling CHP capacity by 2030.

Key provisions for the "Minnesota CHP Policy Act" are recommended below. In addition to the CIP as the centerpiece, additional recommendations are provided relative to integrated resource planning and standby rates.

Minnesota Combined Heat and Power Policy Act

ARTICLE 1. FINDINGS AND GOAL

Subd. 1. FINDINGS. The legislature finds that combined heat and power (CHP) systems should be encouraged because such systems:

a) Reduce fossil fuel use by recovering heat that is usually wasted as rejected heat in power generation;
b) Reduce emissions of air pollutants and greenhouse gases;
c) Increase energy security and sustainability by reducing dependence on fossil fuels; and
d) Enhance grid resiliency, reduce power line losses and strengthen peak power demand management.

Subd. 2. GOAL. The State of Minnesota establishes a goal of doubling CHP capacity from the current 962 MegaWatts (MW) by the year 2030.

ARTICLE 2. CONSERVATION IMPROVEMENT PROGRAM.

Subd. 1. ENERGY CONSERVATION IMPROVEMENT. Minnesota Statutes Section 216B.241 Subd. 1(e) is modified by adding:

> *Energy conservation improvement also includes combined heat and power as defined in Subd. 11.*

Subd. 2. COMBINED HEAT AND POWER REQUIREMENTS. Minnesota Statutes Section 216B.241 Subd. 1c. is modified by adding the following new paragraphs (c) and (d) and renumbering subsequent paragraphs:

> *(c) Each individual investor owned electric utility shall have an annual CHP energy savings requirement equivalent to 0.45 percent of gross annual retail energy sales unless modified by the commissioner under paragraph (e). This CHP requirement shall be shall be tracked in a category that is separate and distinct from other energy savings goals in this section. The CHP requirements must be calculated based on the most recent three-year weather-normalized average. A utility may elect to carry forward energy savings in excess of 0.45 percent for a year to the succeeding three calendar years. A particular energy savings can be used only for one year's requirement.*
>
> *(d) Each individual municipal electric utility, electric cooperative or association shall have an annual CHP energy savings requirement equivalent to 0.18 percent of gross annual retail energy sales unless modified by the commissioner under paragraph (e). These CHP requirements shall be shall be tracked in a category that is separate and distinct from other energy savings goals in this section. The CHP requirements must be calculated based on the most recent three-year weather-normalized average. A utility may elect to carry forward energy savings in excess of 0.18 percent for a year to the succeeding three calendar years. A particular energy savings can be used only for one year's requirement.*

Subd. 3. OWNERSHIP OF COMBINED HEAT AND POWER. Minnesota Statutes 216B.241 Subd. 3 is modified with the *italicized* insertion as follows:

> Subd. 3.Ownership of energy conservation improvement.
>
> An energy conservation improvement made to or installed in a building in accordance with this section, except *combined heat and power systems or other* systems owned by the utility and designed to turn off, limit, or vary the delivery of energy, are the exclusive property of the owner of the building except to the extent that the improvement is subjected to a security interest in favor of the utility in case of a loan to the building owner. The utility has no liability for loss, damage or injury caused directly or indirectly by an energy conservation

improvement except for negligence by the utility in purchase, installation, or modification of the product.

Subd. 4. DEFINITIONS. Minnesota Statutes 216B.241 is modified by adding the following new subdivision:

Subd. 11.Combined heat and power.

(a) Eligibility. CHP Credits from combined heat and power are eligible to be counted towards an electric utility's CHP energy savings requirements, as established in Subd. 1c. (c) and Subd. 1c. (d), subject to department approval.

(b) Definitions.

1. *Combined Heat and Power (CHP). A process which uses the same energy source for the simultaneous or sequential generation of electrical power, mechanical shaft power, or both, in combination with the generation of steam or other forms of useful thermal energy (including heating and cooling applications).*

2. *CHP Credits. CHP Credits are defined as follows for each category of CHP opportunity:*

    a) *CHP Credit for New Non-Renewable CHP Plant. A Qualifying CHP plant using a non-renewable fuel, which produced neither electrical nor Useful Thermal Energy before January 1, 2016, shall generate CHP Credits, measured in MegaWatt-hours, equal to the values shown in Table 5 based on the total energy efficiency (thermal and electric) measured on a Higher Heating Value (HHV) basis.*

    b) *CHP Credit for New Renewable CHP Plant. A Qualifying CHP plant using renewable fuel, which produced neither electrical nor Useful Thermal Energy before January 1, 2016, shall generate CHP Credits, measured in MegaWatt-hours, equal to the values shown in Table 6 based on the total energy efficiency (thermal and electric) measured on a Higher Heating Value (HHV) basis.*

Non-Renewable Fuels		
Tier	Efficiency (HHV)	% of Power Output Credited
	<60%	0%
Tier 1	>60<70%	80%
Tier 2	>70<80%	90%
Tier 3	>80%	100%

Table 5. Recommended Efficiency Standards and Crediting Tiers for Non-Renewable CHP

Renewable Fuels		
Tier	Efficiency (HHV)	% of Power Output Credited
	<50%	0%
Tier R1	>50<60%	80%
Tier R2	>60<70%	90%
Tier R3	>70%	100%

Table 6. Recommended Efficiency Standards and Crediting Tiers for Renewable CHP

c) *CHP Credit for CHP Retrofit of Existing Power Plant. A power plant which produced electrical energy before January 1, 2016 and added the production of incremental Useful Thermal Energy after January 1, 2016, shall generate CHP Credits equal to the result, if positive, of the following calculation: take the sum of (1) the Incremental Electrical Energy generated divided by the overall efficiency of electrical energy delivered to the end-use from the electrical grid (which efficiency is equal for this purpose to 0.40); and (2) the Incremental Useful Thermal Energy divided by the overall efficiency of thermal energy delivered to the end-use from standalone heating units (which efficiency is equal for this purpose to 0.80); and subtract from this sum the total of all Incremental Fuel consumed by the CHP Unit expressed in MWh and calculated using the energy content of the fuel based on its Higher Heating Value. This calculation of the CHP Credit can also be expressed with the following terms and equation:*

IEE = Incremental Electrical Energy
IUTE = Incremental Useful Thermal Energy
IF = Incremental Fuel

CHP Credit = (IEE / 40%) + (IUTE / 80%) - IF

d) *CHP Credit CHP Retrofit of Existing Heating or Process Energy Plant. A heating plant or industrial process plant which produced Useful Thermal Energy before January 1, 2016 and added production of Incremental Electrical Energy after January 1, 2016 using Process Waste Heat shall be generate CHP Credits equal to the result, if positive, of the following calculation: take the sum of (1) the Incremental Electrical Energy generated divided by the overall efficiency of electrical energy delivered to the end-use from the electrical grid (which efficiency is equal for this purpose to 0.40); and (2) the Incremental Useful Thermal Energy divided by the overall efficiency of thermal energy delivered to the end-use from a standalone heating unit (which efficiency is equal for this purpose to 0.80); and subtract from this sum the total of all Incremental Fuel consumed by the CHP Plant expressed in MWh and calculated using the energy content of the fuel based on its Higher Heating Value. This calculation of the CHP Credit can also be expressed with the following terms and equation:*

IEE = Incremental Electrical Energy

IUTE = Incremental Useful Thermal Energy
IF = Incremental Fuel

CHP Credit = (IEE / 40%) + (IUTE / 80%) - IF

3. *CHP Plant. Facilities and equipment used for combined heat and power.*

4. *Incremental Electrical Energy. Electrical energy generated by a Qualifying CHP Plant that is either greater than (expressed as a positive amount) or less than (expressed as a negative amount) the electrical energy generated by the CHP Plant prior to the addition of new electric generation nameplate capacity, Useful Thermal Energy, or Incremental Useful Thermal Energy.*

5. *Incremental Fuel. The amount of additional fuel used by a Qualifying CHP Plant which is attributable to the production of Incremental Useful Thermal Energy or Incremental Electrical Energy.*

6. *Incremental Useful Thermal Energy. Useful Thermal Energy produced by a Qualifying CHP Plant that is distinct in its final distribution, beneficial measure, and metering from Useful Thermal Energy previously produced by the CHP Plant, but only to the extent that the Incremental Useful Thermal Energy does not reduce the Useful Thermal Energy previously produced.*

7. *Non Renewable CHP. A Qualifying CHP Plant for which more than 10 percent of the annual fuel input is composed of natural gas, coal, oil, propane, other fossil fuels, or nuclear energy.*

8. *Process Waste Heat. Heat contained in gases or liquids exhausted from a boiler plant, industrial process or municipal process (such as sewage sludge incineration) that is currently and/or conventionally not recovered for useful purposes.*

9. *Qualifying CHP Plant. Any CHP Retrofit of Existing Power Plant, any CHP Plant CHP Retrofit of Existing Heating or Process Energy Plant, or any new CHP Plant which: 1) which has a minimum annual energy efficiency on a higher heating value basis of 60 percent (if using non-renewable fuels) or 50 percent (if using renewable fuels); and 2) which produces at least 20 percent of its total useful energy in the form of thermal energy which is not used to produce electrical or mechanical power (or combination thereof), and at least 20 percent of its total useful energy in the form of electrical or mechanical power (or combination thereof).*

10. *Renewable CHP Plant. A Qualifying CHP Plant for which at least 90 percent of the annual fuel input is composed of energy sources other than natural gas, coal, oil, propane, other fossil fuels, or nuclear energy.*

11. *Useful Thermal Energy. Energy 1) in the form of direct heat, steam, hot water, or other thermal form that is used in production and beneficial measures for heating, cooling, humidity control, process use, or other valid thermal end use energy requirements and (2) for which fuel or electricity would otherwise be consumed.*

12. *Utility Customer. A Utility Customer is an entity who purchases retail electricity from the utility.*

(c) Incentives.

1. *Incentives for Utility Customer- or Third Party-Owned CHP. Utilities shall provide an operating incentive to customers who finance a CHP plant, or third parties who finance a CHP plant to serve a customer or group of customers.*

2. *Duration of Incentives. Operating incentives shall be provided for a period of fifteen (15) years.*

3. *Level of Incentive. The operating incentive shall be calculated as follows:*

   CIPE = Statewide average total CIP expenditures by electric utilities for non-CHP incentives and programs over the three (3) calendar years prior to the initiation of commercial operation of the CHP plant, inclusive of administrative costs

   CIPS = Statewide average total first year CIP savings (MWh) by electric utilities for non-CHP incentives and programs over the three (3) calendar years prior to the initiation of commercial operation of the CHP plant

   Level of Incentive = CIPE / (CIPS x 15 years)

4. *Utility-Owned CHP. If the electric utility finances a CHP plant, it may include as a CIP expenditure the amount which would otherwise be provided to a CHP Plant financed by a customer or third party.*

(d) Alternative Compliance.

1. *Alternative Compliance Payment. A utility may discharge its obligations, in whole or in part, for any Compliance Year by making an Alternative Compliance Payment (ACP) to the Minnesota Department of Commerce. The ACP Rate, in $ per MWh CHPC, and provisions for modifying the rate, shall be established in rulemaking.*

2. *Use of Funds. The Department of Commerce shall oversee the use of ACP funds so as to further the implementation of CHP, district energy systems and other energy efficiency and renewable energy systems.*

(e) Tradable Credits. A system of tradable CHP credits (CHPCs) will be established so that a customer, third party or natural gas utility can generate CHP Credits for sale to electric utilities.

1. *Lifetime. CHPS Credits will have a trading lifetime of 4 years according to the year of generation (e.g., all credits generated during 2017, regardless of the month, expire at the end of 2021).*

2. *Whole Credits. CHPCs must remain "whole" and may not be disaggregated into separate environmental commodities (e.g., carbon emission credits)*

ARTICLE 3. INTEGRATED RESOURCE PLANNING

Subd. 1. Minnesota Statutes 216B.2422 Subd. 4 is modified with the *italicized* insertion as follows:

Subd. 4.Preference for renewable energy facility.

The commission shall not approve a new or refurbished nonrenewable energy facility *which generates only electricity* in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest. The public interest determination must include whether the resource plan helps the utility achieve the greenhouse gas reduction goals under section 216H.02, the renewable energy standard under section 216B.1691, or the solar energy standard under section 216B.1691, subdivision 2f. Electric utilities are required to demonstrate that, before power-only capacity is proposed in Integrated Resource Plans, CHP opportunities within their service territory have been thoroughly assessed to determine the GHG, grid resiliency and other benefits of CHP.

Subd. 2. Minnesota Statutes 216B.2422 is modified by adding the following new Subdivision and renumbering subsequent subdivisions:

Subd. 5. Preference for combined heat and power.

The commission shall not approve a new or refurbished nonrenewable energy facility which generates only electricity in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that: 1) opportunities for new combined heat and power plants within their service territory have been thoroughly assessed to determine the greenhouse gas, grid resiliency and other benefits; 2) the potential for converting existing power plants to combined heat and power, with distribution of recovered energy through district energy systems, has been thoroughly assessed to determine the greenhouse gas, grid resiliency and other benefits; and 3) a combined heat and power facility is not in the public interest, which public interest determination shall include whether the resource plan helps the utility achieve the combined heat and power requirements in Minnesota Statutes 216B.241

ARTICLE 4. STANDBY RATES

Minnesota Statutes 216B.164 is modified by adding the following new subdivision and renumbering subsequent subdivisions:

Subd. 3. STANDBY RATES. Standby rates charged by public utilities must conform to the following principles:

1. *Standby rates should be transparent, concise and easily understandable. Potential CHP customers should be able to accurately predict future standby charges in order to assess their financial impacts on CHP feasibility.*
2. *Standby energy usage fee should reflect both demand and time-of-use cost drivers. Time-of-use energy rates send clear price signals as to the cost for the utility to generate needed energy. This would further incentivize the use of off-peak standby services.*
3. *The Forced Outage Rate should be used in the calculation of a customer's reservation charge. The inclusion of a customer's forced outage rate directly incentivizes standby customers to limit their use of backup service. This further ties the use of standby to the*

price paid to reserve such service, creating a strong price signal for customers to run most efficiently.

4. *The standby demand usage fees should only apply during on-peak hours and be charged on a daily basis. This rate design would encourage CHP customers to shift their use of standby service to off-peak periods when the marginal cost to provide service is generally much lower. Furthermore, this design would allow customers to save money by reducing the duration of outages.*

5. *Grace periods exempting demand usage fees should be removed where they exist. Exempting an arbitrary number of hours against demand usage charges sends inaccurate prices signals about the cost to provide this service. Standby demand usage should be priced as-used on a daily and preferably an on-peak basis. This method directly ties the standby customer to the costs associated with providing standby service.*

Implementation and Rulemaking

Following passage of legislation, the following steps are recommended:

1. Conduct a study to quantify the "Value of CHP" relative to total primary energy efficiency, GHG emissions, power grid resiliency, peak demand management, risk management and other potential values of CHP. Further, the study should assess potential constraints to increased implementation of CHP, such as natural gas pipeline capacity limitations.

2. Establish clear policies regarding inclusion of CHP costs in electric utility rates, including mechanisms for addressing ratepayer risks associated with utility investment in CHP through a return on equity risk premium, a state-funded loss reserve or other mechanism.

3. Initiate a high-level dialog with the Midwest Independent System Operator to create rules that encourage maximum dispatch of CHP units.

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Introduction

Methodology

This study began with research on current Minnesota laws, policies and programs relevant to CHP. A review of literature on CHP barriers and policies was then undertaken, including an analysis by the American Council for an Energy-Efficient Economy (ACEEE) of best practices for CHP policies in other states. Existing and proposed federal policies relevant to CHP were identified. The economics of a broad range of CHP technologies were analyzed, including sensitivity to key variables that could be affected by new policies and programs, including capital cost, weighted average cost of capital[6], CHP fuel price and avoided price of electricity.

Draft Policy Options for increasing CHP in Minnesota were developed based on the analysis of the economic significance of key barriers as well as review of best practices in other states. A "Straw Man" draft report was prepared which summarized existing Minnesota policies, described CHP barriers and the analysis of the economic significance of key variables, outlined draft Policy Options, and addressed issues associated with the Policy Options. Informal stakeholder consultations were conducted by the author following distribution of the Straw Man report, including discussions with electric utilities, gas utilities, thermal utilities, equipment suppliers, customers, advocacy groups and consultants.

Following the stakeholder consultation, detailed analysis of the Policy Options was undertaken and modifications were made to the Policy Options based on the feedback and analysis. Additional analysis of potential issues relating to the Policy Options was undertaken, including specific questions relating to program design as well as potential cost-benefit impacts on program participants, utility ratepayers and society. The impact of each Policy Option on CHP implementation was projected, primarily using ICF International's model for estimating natural-gas fired CHP market penetration. In addition, analysis of Minnesota Pollution Control Agency fuel consumption data was used to check and augment the ICF model on gas-fired CHP and to estimate the potential market penetration of biomass CHP.

Recommendations were then developed for consideration by the Department of Commerce and stakeholders in stakeholder workshops to be implemented in fall of 2014.

Appendix E provides additional information on the analysis methodology, focusing on aspects of the methodology that are not described in the body of the report or which are only briefly mentioned.

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[6] Weighted Average Cost of Capital (WACC) is the weighted average cost of repaying the capital invested or borrowed to build a CHP project. There are two main ways to fund a project: 1) equity investment, in which a company invests its own funds and then requires a return on that equity investment through payments made throughout the life of the project from the project revenues; and 2) debt, in which funds are borrowed and principal and interest payments are made each year based on the debt interest rate. WACC is calculated based on the relative portions of debt and equity. For example, if the funds raised are 60 percent debt and 40 percent equity, the debt interest rate is 6 percent and the return on equity is 12 percent, the WACC is calculated as follows: (60% X 6%) + (40% X 12%) = 8.4%.

Why CHP is Important

The supply and use of energy in Minnesota is illustrated in Figure 2. This chart shows a striking level of energy waste – only 44 percent of the total energy consumed in Minnesota is converted to useful energy. Of the total 1,706 trillion Btu (TBtu) of energy used in Minnesota:

- 350 TBtu was lost in electricity generation, transmission and distribution, resulting in an average power sector efficiency of less than 33 percent;
- 235 TBtu was lost the Residential, Commercial & Industrial sectors (RCI) in converting RCI primary energy or electricity to useful energy services; and
- 4,380 TBtu was lost in transportation, primarily due to inefficiencies in cars.

Transportation energy is not the focus of this study, so we will focus on non-transportation energy use. As illustrated in Figure 3, of the total non-transportation energy use in Minnesota (1,227 TBtu):

- Only 51 percent is converted to useful energy;
- 29 percent is lost in the power sector (mostly as heat); and
- 20 percent is lost in the Residential, Commercial & Industrial sectors (RCI) in converting RCI primary energy or electricity to useful energy services.

The total 350 TBtu of wasted energy in the power sector is estimated to consist of 10 TBtu of electrical line losses[7] and 340 TBtu of waste heat. This power generation waste heat in Minnesota is equal to 83 percent of the total estimated requirement for heat energy in the RCI sectors (408 TBtu).[8]

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[7] Assumes 5.6 percent average Minnesota transmission/distribution losses (EIA State Electricity Profiles 2010)

[8] Assumes 90 percent of RCI primary energy is for heat production and is converted to useful energy at an average efficiency of 70 percent.

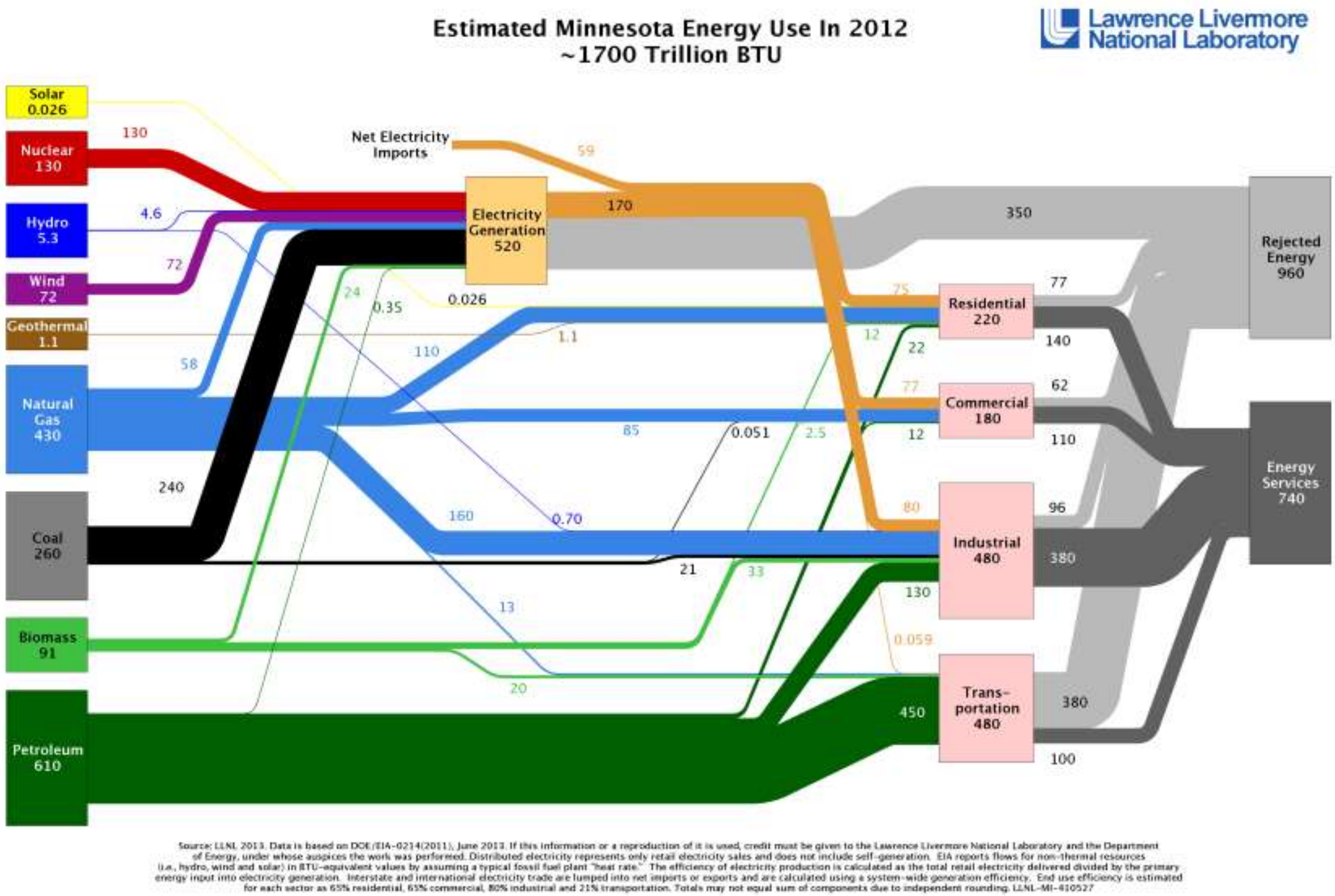

Figure 2. Minnesota Energy Supply and Use

Source: Lawrence Livermore National Laboratory

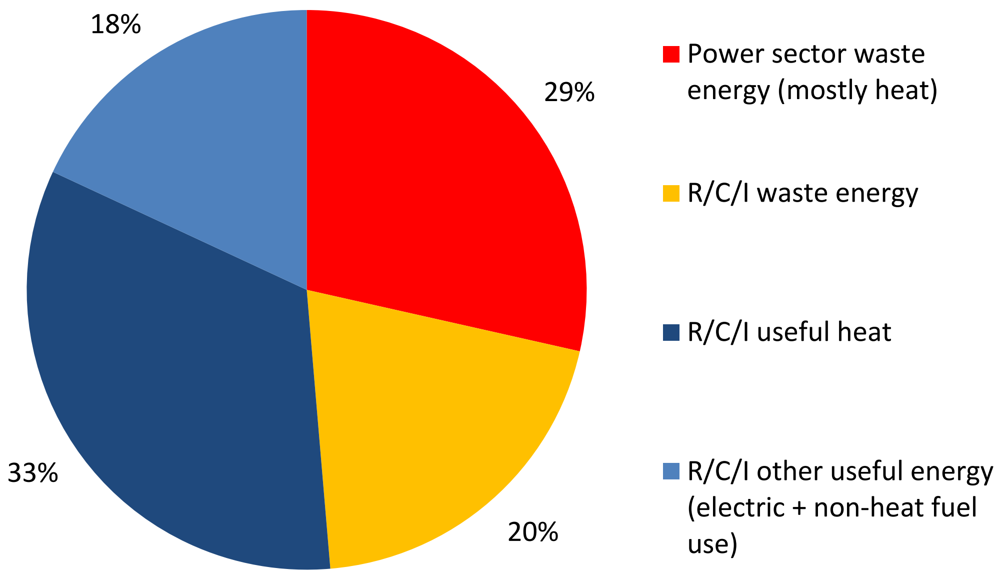

Figure 3. Minnesota Non-Transportation Energy Consumption 2012 (total 1.227 Trillion Btu)

("R/C/I" means Residential/Commercial/Industrial)

Source: FVB analysis of Lawrence Livermore National Laboratory data

CHP systems reduce fossil fuel use and greenhouse gas (GHG) emissions by recovering heat that is usually rejected in power plants. This heat can then be used for heating (space heating in buildings, domestic hot water or industrial process heat) or it can be used to produce chiller water for air conditioning or industrial cooling energy by using absorption chillers or steam turbine chillers. A range of CHP technologies are described in the next section.

As noted above, the electricity sector in Minnesota is less than 33 percent efficient in converting primary energy to useful delivered electricity. In Figure 4, typical efficiencies for representative CHP technologies are compared with typical power-only plants and with the average power plant efficiency in Minnesota.

The reductions in fossil fuel use made possible by CHP reduce emissions of air pollutants and GHG, and increase energy security and sustainability by reducing dependence on fossil fuels. Further, reduced consumption of fossil fuels can result in fewer energy dollars leaving the state, potentially strengthening the Minnesota economy.

CHP can help Minnesota achieve goals relative to per capita energy consumption, GHG reduction and renewable energy. Federal environmental regulations, including GHG standards for existing and new power plants, and potentially regional haze regulatory action, are likely to enhance the economics of CHP by increasing the economic value of fossil fuel and GHG reductions.

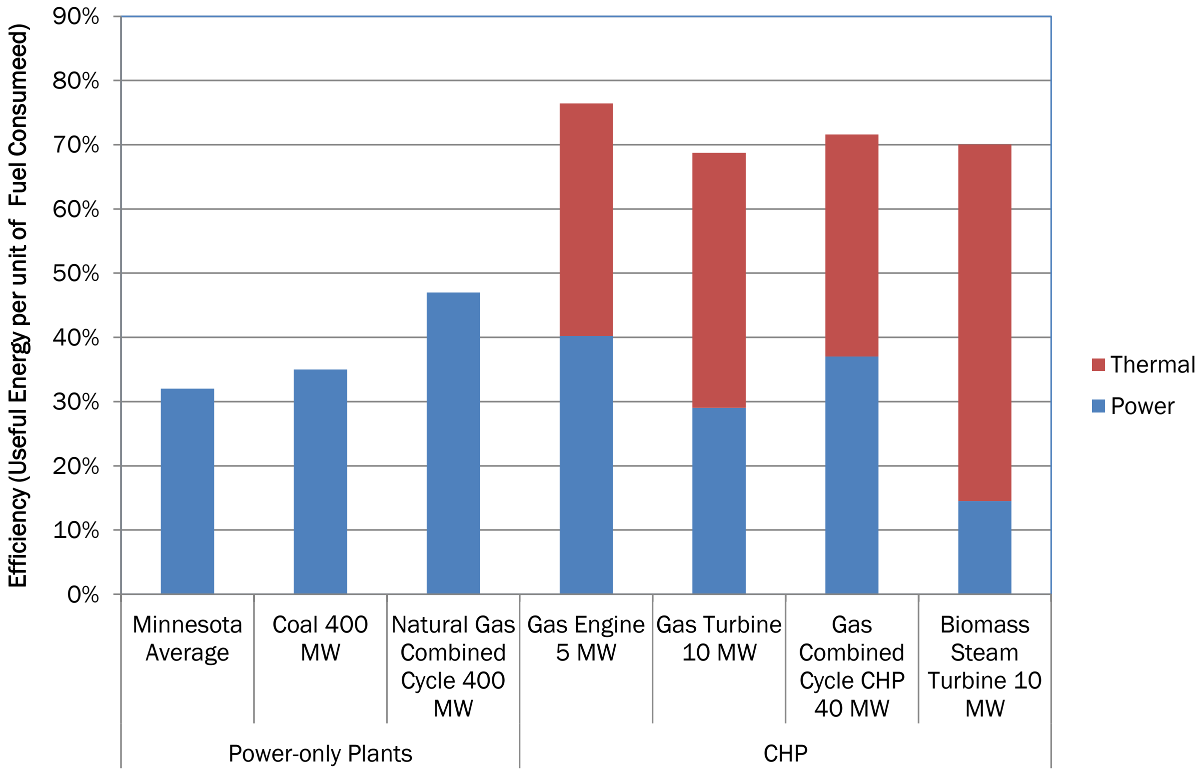

Figure 4. Comparative Efficiency of CHP and Power-Only Plants

Source: FVB Energy

CHP also has the potential to enhance grid resiliency, reduce power line losses and strengthen peak power demand management. CHP systems are typically located much closer to the end user than more traditional centralized power plants; close proximity to end-users can reduce the losses of power along transmission and distribution lines. Additionally, many CHP systems are capable of ramping up to full output very quickly, providing more nimble electric system assets than many traditional generation resources.

Overview of CHP Technologies

In electric-only power plants, most of the energy input to the plant ends up as waste heat. Power plants using a steam turbine (either steam turbine or gas turbine combined cycle plants) condense the steam exiting from the turbine. This creates a vacuum on the exit end of the steam cycle, thus increasing the torque and power output of the steam turbine. However, most of the energy then ends up in the condenser cooling system (using cooling towers which put the heat into the air, or dissipating the heat in a body of water such as a river). In combustion turbines all of the energy in the exhaust gases is wasted, unless it is used to produce steam to drive a steam turbine to generate electricity (this configuration is called a combined cycle plant). Reciprocating engines lose heat through the exhaust gas, engine cooling jacket, lubricating oil and other systems.

When one of these power generation technologies is adapted for CHP, much of the waste heat can be recovered for heating or for conversion to cooling using steam-driven chillers. CHP is defined in

U.S. statutes [26 USC § 48 (c) (3)] as a system "which uses the same energy source for the simultaneous or sequential generation of electrical power, mechanical shaft power, or both, in combination with the generation of steam or other forms of useful thermal energy (including heating and cooling applications), and which produces—

- at least 20 percent of its total useful energy in the form of thermal energy which is not used to produce electrical or mechanical power (or combination thereof), and
- at least 20 percent of its total useful energy in the form of electrical or mechanical power (or combination thereof), and
- the energy efficiency percentage of which exceeds 60 percent."

As discussed below, most CHP systems have typical efficiencies of 65-80 percent.

There are two major classifications of CHP systems:

- Topping-cycle systems produce electricity first, then recover the excess thermal energy for heating or cooling applications (See Figure 5). A topping cycle may use an internal combustion engine, gas turbine, steam turbine, microturbine or fuel cell.
- Bottoming-cycle systems, also known as "waste heat to power," use waste heat from an existing process to produce electricity (See Figure 6). A bottoming cycle may use the heat source to produce electricity using an organic rankine cycle or backpressure steam turbine.

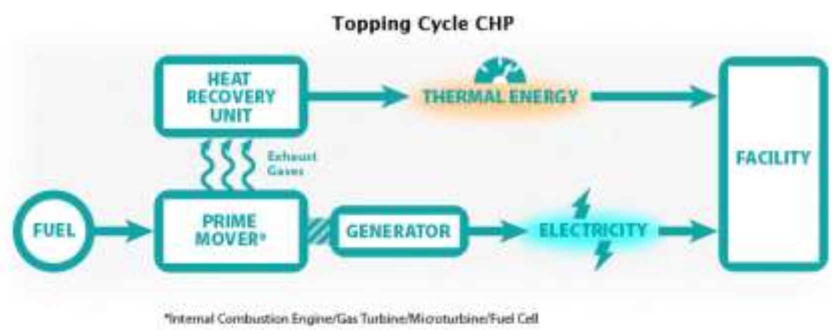

Figure 5. Topping Cycle CHP

Source: Center for Sustainable Energy website

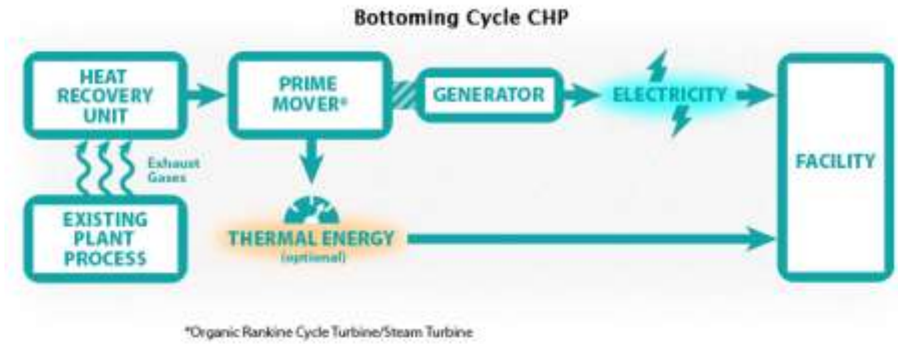

Figure 6. Bottoming Cycle CHP

Source: Center for Sustainable Energy website

Steam Turbine CHP

Steam turbine power plants are the most common type of power plant in the world today. Any type of fuel can be burned in a boiler to make steam, which drives a steam turbine which in turn spins a generator. The capital cost of steam turbine plants are higher than other alternatives, but the ability to burn lower-cost solid fuels (e.g., biomass) can make steam turbine plants cost-effective.

Combustion Turbines

Combustion turbines, often called "gas turbines," are basically jet engines (in fact, many commercial systems are so-called "aero-derivatives," i.e., they are directly evolved from aircraft engines) configured for generating electricity. Fuel, usually natural gas (fuel oil could also be used) is combusted, and the hot gases drive a turbine which in turn spins a generator. The exhaust gas coming out of the turbine is very hot (850-1000◦F) and represents over 40 percent of the input energy. In a gas turbine plant, all of the heat in the exhaust gases is available. The hot exhaust gases from a gas turbine (about 1000◦F) can be directed to a heat recovery boiler to generate steam or hot water for thermal energy end-uses. See Figure 7.

In a gas turbine combined cycle plant, the recoverable heat is in the steam exhausted from the steam turbine that would otherwise be dissipated in the cooling towers.

Gas turbines are available in very small "micro" sizes as small as 30 kiloWatts (kW) (see separate discussion of Microturbines below) but are most economical in sizes of 5 MegaWatts (MW) and larger.

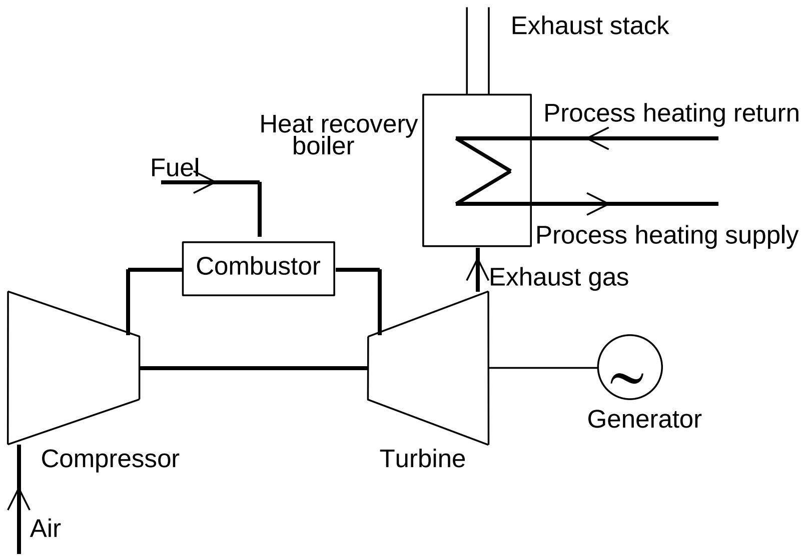

Figure 7. Combustion Turbine CHP

Internal Combustion Engines

Internal combustion engines (ICE), sometimes called "reciprocating engines", can be designed for CHP. In an ICE, a generator is attached to the shaft of an internal combustion engine. Heat is recovered when the hot exhaust gas is cooled in a heat recovery boiler. Heat can also be recovered from the engine cooling water and oil lubrication system. In addition, heat can be recovered from other devices (turbocharger and intercooler). Both gaseous and liquid fuels can be used in reciprocating engines. See Figure 8.

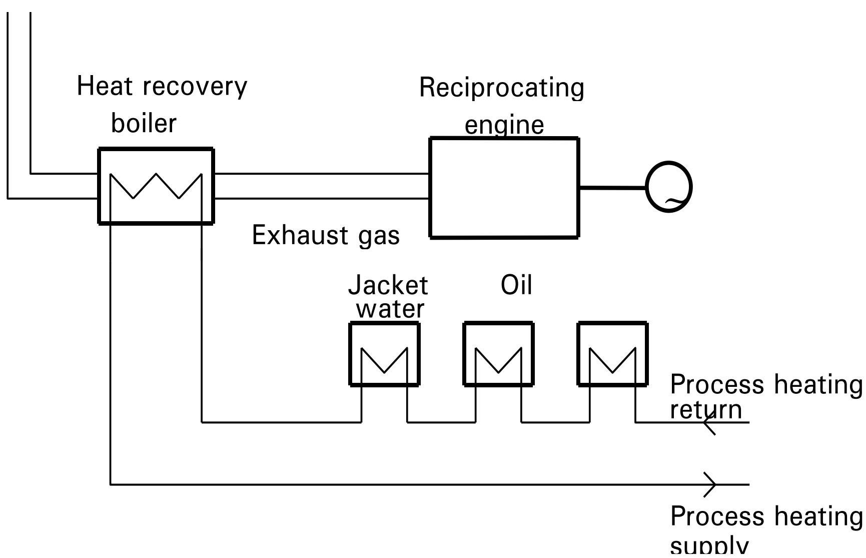

Figure 8. Internal Combustion Engine CHP

There are two types of ICEs based on the relative “richness” of the combustion air:

- Rich burn engines operate with a relatively high fuel to air ratio, are typically used in smaller sizes and commercial CHP systems, and are offered around 100 kW. Rich burn engines are marketed with integrated emissions control systems, usually a three way catalyst and an engine control module. Thermal energy is typically available as hot water.
- Lean burn engines operate with excess air to limit nitrogen oxide (NOx) formation, are typically used in larger sizes. These systems are economical in sizes from 800-5,000 kW. Larger engines are also available. Thermal energy is usually available as hot water, but steam recovery is also an option.

Organic Rankine Cycle

Organic rankine cycle (ORC) is a technology for generating power that is similar to a steam turbine except that the working fluid is a volatile organic fluid, such as isopentane, rather than steam. ORC uses a low-temperature (about 200 F and greater), low-pressure energy source to heat a thermal oil. The heat source could be any of a range of heat sources, e.g., biomass combustion, industrial waste heat, solar collectors, geothermal hot water, etc. The heat is then used to boil a compressed working fluid that has a lower boiling point than water (such as pentane or other volatile organic compound). The pressurized vapor then drives a turbine-generator to produce electricity.

Figure 9 illustrates the ORC process:

- A heat source heats thermal oil in a closed circuit. Although this graphic indicates the heat source as gas turbine exhaust, as noted above it could be any of a range of low temperature heat sources.
- The thermal oil evaporates an organic working fluid in a heat exchanger system (pre-heater and evaporator).
- Organic vapor expands in the turbine, producing mechanical energy, which is used to produce electric energy through a generator.
- The vapor is then cooled and condensed in a closed condenser loop. The condenser water warms to about 175 - 195°F and can be used for different applications requiring heat.
- The condensed organic fluid is pumped back into the regenerator to close the circuit and restart the cycle.

When ORC is driven by waste heat, it is classified as “bottoming cycle” CHP. When driven with heat from biomass combustion, it is considered “topping cycle” CHP.

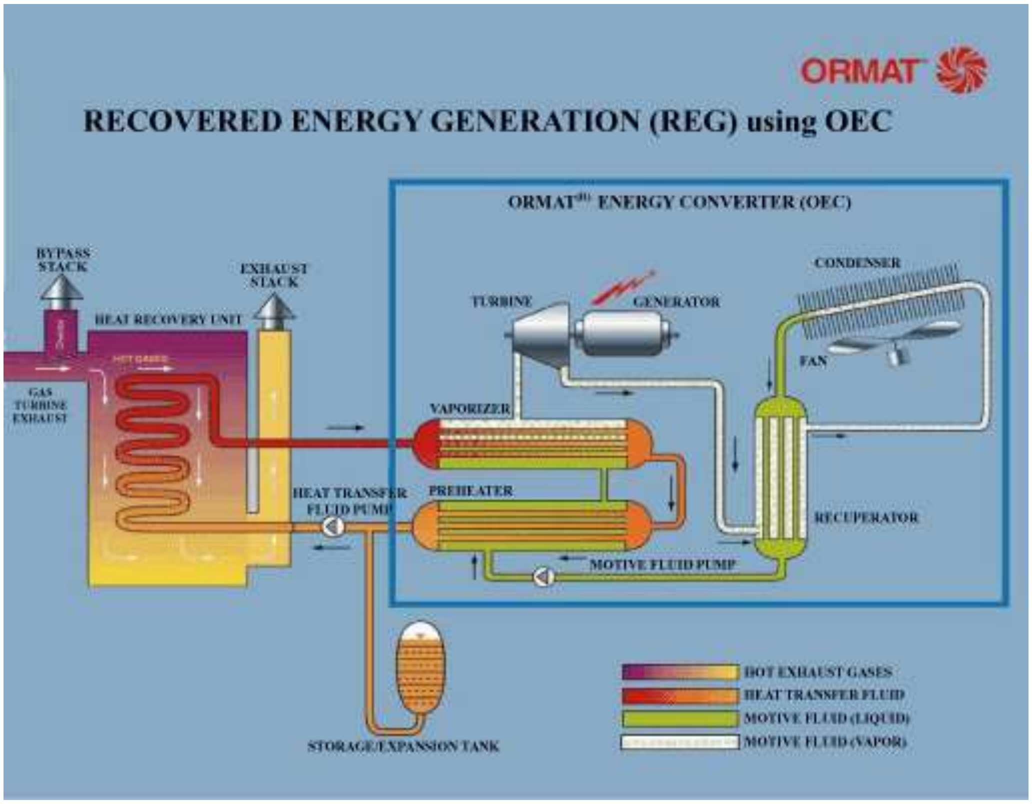

Figure 9. Organic Rankine Cycle Process

Source: Ormat

The electrical efficiency of an ORC depends on temperature levels of evaporator and condenser. An increase in evaporator temperatures and/or decrease in condenser temperatures will give higher efficiencies. When waste heat is used in a bottoming cycle, the fuel efficiency is generally considered to be 100 percent. Although the topping cycle electrical efficiency of ORC is lower than a steam turbine, the low temperature and pressure of the system may allow for lower operating requirements and costs (e.g., labor) in many jurisdictions.

Microturbines

Microturbines are very small gas turbines. They have more in common, though, with truck turbochargers than with large, multi-stage gas turbines. Microturbines are available now in sizes as small as 30 kW. Some extremely small (5 kW) microturbines are now being developed but are not yet commercially available. Microturbines have lower electrical conversion efficiencies than engines or fuel cells, but they offer more waste heat at temperatures up to 500 – 600◦F. Microturbines can be used to produce only power or they can be designed and operated as a CHP unit.

Fuel Cells

Fuel cells produce electricity through electrochemical reactions rather than by combustion. There are many different kinds of fuel cells named after the chemical make-up of their electrolyte (for example, phosphoric acid, molten carbonate, solid oxide, and solid polymer electrolyte). Phosphoric acid and molten carbonate are two types of fuel cells which are commercially available.

CHP System Analysis

A representative sample of commercially available systems was selected to profile performance and cost characteristics in CHP applications. CHP technologies to be evaluated in this study range in capacity from approximately 30 to 40,000 kW and are summarized in Table 7.

Category	Fuel	Market Sectors	Range (electric)	CHP Technologies
NG.1	NG	C, I	30-500 kW	30 kW MT
				100 kW ICE
				200 kW PAFC
NG.2	NG	C, I	500-1,000 kW	800 kW ICE
				250 kW MT x 3
				300 kW MCFC x 2
NG.3	NG	C, I, DE	1-5 MW	3 MW ICE
				3 MW GT
				1.5 MW MCFC
NG.4	NG	C, I, DE	5-20 MW	5 MW ICE
				10 MW GT
NG.5	NG	C, I, DE	> 20 MW	40 MW GT
WH.1	WH	I	< 5 MW	1 MW ORC
B.1	B	C, I, DE	1-5 MW	3 MW ST
B.2	B	C, I, DE	5-20 MW	10 MW ST
B.3	B	C, I, DE	> 20 MW	40 MW ST

Abbreviations	
Market Sectors	**Technologies**
C = Commercial	MT = Microturbine
I = Industrial	ICE = Internal combustion engine
DE = District Energy	PAFC = phosphoric acid fuel cell
Fuels	MCFC = molten carbonate fuel cell
NG = Natural Gas	GT = gas turbine
B = Biomass	ST = steam turbine
WH = Waste Heat	ORC = organic rankine cycle

Table 7. Selected CHP Technologies for Analysis

CHP Efficiencies and Costs

The efficiency and costs of a given CHP facility depends on many case-specific factors, including equipment characteristics, temperature of recovered thermal energy, ambient temperature conditions and part-load operations. Table 8 summarizes generalized efficiency assumptions for a range of CHP technology types and sizes.

Technology	Electric capacity (kW)	Efficiencies (Higher Heating Value)		
		Power	Heat	Total
MT	30	24%	40%	64%
	250 X3	28%	35%	63%
ICE	100	27%	53%	80%
	800	35%	43%	78%
	3,000	39%	39%	77%
	5,000	40%	36%	76%
GT	3,000	24%	42%	66%
	10,000	29%	40%	69%
	40,000	37%	35%	72%
ST bp LP	3,000	11%	57%	68%
	10,000	15%	56%	70%
	40,000	21%	55%	75%
ST bp HP	3,000	6%	62%	68%
	10,000	9%	61%	70%
	40,000	14%	61%	75%
ORC	1,000	17%	0%	17%
PAFC	200	34%	26%	60%
MCFC	300 X 2	43%	27%	69%
	1,500	43%	26%	69%
Technologies				
MT = Microturbine				
ICE = Internal combustion engine				
GT = gas turbine				
ST bp LP = steam turbine backpressure 15 psig				
ST bp HP = steam turbine backpressure 185 psig				
ORC = organic rankine cycle				
PAFC = phosphoric acid fuel cell				
MCFC = molten carbonate fuel cell				

Table 8. CHP Technology Efficiencies

Basic Statistics

Compared to all other U.S. states, Minnesota is slightly above average when it comes to number of CHP sites and total installed capacity. Minnesota has a total of 52 CHP sites and about 962 MW in installed capacity (ICF CHP Database). Total electric generation capacity in Minnesota in 2012 was 15,447 MW (EIA Electricity Data). There have not been any new installations in Minnesota over the past few years—the most recent CHP installations were in 2010.

CHP facilities in Minnesota are used in a variety of applications, as summarized in Table 9. Perhaps unsurprisingly, the largest portion of CHP capacity resides in energy-intensive industrial settings, with district energy systems also representing a significant share. There are also a significant number of smaller CHP facilities installed in a variety of applications across the state, including institutional uses at hospitals, universities, and waste treatment plants. Further information on existing CHP facilities in Minnesota is provided in a companion report (FVB Energy and ICF International 2014).

Application	# Sites	Capacity (MW)
Chemicals	2	252.0
Paper	8	247.0
District Energy	7	182.9
Mining	1	105.0
Food Processing	8	58.9
Utilities	1	48.6
Hospitals	4	30.1
College/Universities	2	16.2
Wastewater Treatment	4	7.2
Solid Waste	2	5.0
Agriculture	7	4.9
Military	2	2.2
Misc. Manufacturing	2	1.3
Amusement/Recreation	1	0.1
Courts/Prisons	1	0.1
Total	52	961.5

Table 9. Existing Minnesota CHP Applications

Source: ICF CHP Database

CHP Potential

The potential market for CHP is much larger than what is currently installed. As described in a companion report (Assessment of the Technical and Economic Potential for CHP in Minnesota), the estimated technical potential[9] for additional CHP exceeds 3,000 MW, as summarized in Table 10. Of the total technical potential, 1,720 MW is in the industrial sector, 561 MW in the institutional sector and 769 MW in the commercial sector. See Table 11.

	Current Technical Potential (MW)					
Utility	**50-500 kW**	**500-1 MW**	**1-5 MW**	**5-20 MW**	**>20 MW**	**Total**
Northern States (Xcel)	409	354	431	389	483	2,067
MN Power	50	33	51	70	267	470
Alliant	12	11	46	52	25	146
Otter Tail	24	34	29	20	0	106
Muni/Co-op	50	49	60	31	69	259
Total	545	481	616	562	844	3,049

Table 10. Minnesota CHP Technical Potential by Electric Utility

Source: ICF International

	50-500 kW	**500-1 MW**	**1-5 MW**	**5-20 MW**	**>20 MW**	**Total**
Industrial	146	97	317	430	730	1,720
Institutional	118	62	155	112	114	561
Commercial	282	323	144	21	-	769
Total	545	481	616	562	844	3,049

Table 11. Minnesota CHP Technical Potential by Sector

Source: ICF International

The technical potential estimates consider only what is technologically possible rather than what is economically feasible. There are many facilities that could, in theory, make use of CHP, but due to a variety of factors the economic potential for CHP is less than the technical potential. As further described below under “Policy Analysis,” the economic potential[10] for additional CHP with no changes in policy is estimated to be about 250 MW by the year 2040. Further information on CHP technical and economic potential in Minnesota is provided in a companion report (FVB Energy and ICF International 2014).

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[9] The technical potential is an estimation of market size constrained only by technological limits — the ability of CHP technologies to fit customer energy needs. CHP technical potential is calculated in terms of CHP electrical capacity that could be installed at existing and new industrial and commercial facilities based on the estimated electric and thermal needs of the site. 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, or variation of energy consumption within customer application/size class.

[10] The economic potential for CHP is quantified using simple 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.

Key Challenges

This section describes the challenges facing CHP including technical, economic, financial and institutional barriers.

Unfavorable Spark Spread

A fundamental economic test for CHP is "spark spread" – the difference between the value to the generator of the electricity and thermal energy produced and the cost of the fuel needed to produce that electricity. In general, higher grid-provided electricity prices and lower natural gas prices make CHP projects more economic.

Spark spreads are usually calculated with the following equation:

SS = APP + (ATFP / E / PHR / 3.413 MMBtu/MWH) – (FP x HR)

Where: SS = Spark spread ($/MWh)

APP = Avoided power price ($/MWh)

ATFP = Avoided thermal production fuel price ($/MMBtu)

E = Thermal boiler efficiency (percent)

PHR = Power to Heat Ratio

FP = CHP fuel price ($/MMBtu)

HR = CHP heat rate (MMBtu/MWh)

The value of the electricity generated may be a weighted average of avoided purchased power and sales of excess power. Minnesota has relatively low electricity costs, with an average *retail (all consumers)* rate lower than the national average, as illustrated in Figure 10.

Minnesota natural gas and electricity prices are lower than the national averages for each end use sector. Table 12 shows the comparative Minnesota and USA average prices for natural gas and electricity for each end use sector and for power generation in 2011.

Spark spread is affected by both the particular CHP technology and sector in which the CHP facility would be located. The heat rate (BTU's of fuel required to produce a kWh of electricity) varies among CHP technologies, with lower heat rates (higher electric generation efficiencies) helping to increase the spark spread and make the economics of the CHP system more attractive. Industrial power prices are generally lower, thus reducing the spread. (On the other hand, economies of scale in larger industrial CHP projects can enhance the economics of CHP compared with smaller commercial sector projects.)

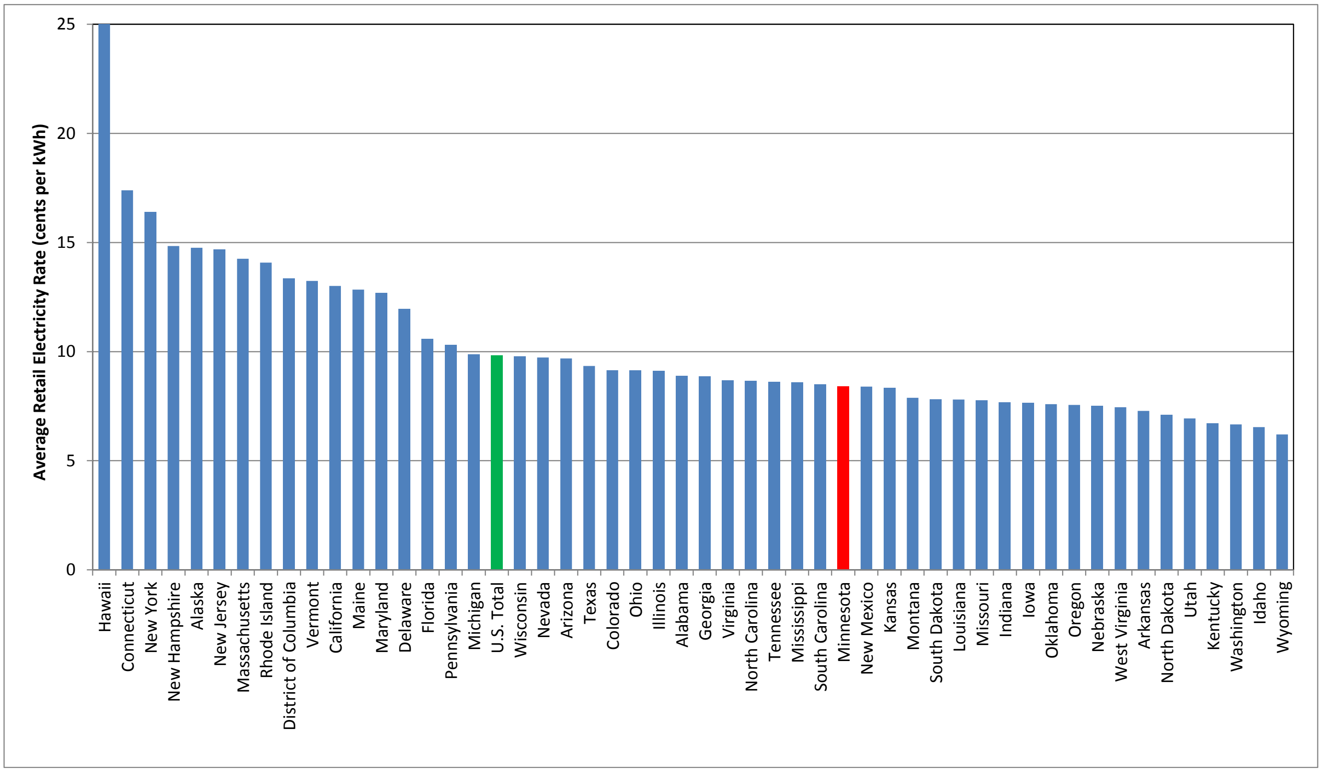


Figure 10. Average Retail Electricity Rates by State

Source: EIA State Electricity Profiles 2010

	Natural Gas ($/MMBtu)			Electricity (cents/kWh)		
	MN	USA	MN % of USA	MN	USA	MN % of USA
Residential	$ 8.76	$ 10.78	81%	10.97	11.72	94%
Commercial	$ 7.39	$ 8.80	84%	8.63	10.24	84%
Industrial	$ 5.49	$ 5.98	92%	6.47	6.83	95%
All End Use	$ 7.10	$ 8.23	86%	8.68	9.94	87%
Power Generation	$ 5.88	$ 4.80	123%			

Table 12. Minnesota Natural Gas and Electricity Prices Compared with U.S. Average Prices (2011)

Source: EIA State Data 2011

The effective spark spread for any given CHP system is one of the basic assessments conducted in a feasibility assessment. If the spark spread is not significant enough, and the total benefits of generating power onsite are thus not larger than the cost of fuel required to generate that power, the project will likely not go further. Tools such as discounts on natural gas or additional revenue streams for excess power production may improve the spark spreads of CHP systems.

Lack of Market for Excess Power

To maximize CHP efficiency it is necessary to size and operate the CHP system to follow the thermal load of the thermal energy user. However, in many facilities this can result in significant production of power in excess of the host site's needs, and the power will only be produced if a suitable buyer for the power is identified. Consequently, the price to be received for sale of the excess power is often a crucial factor in the financial feasibility of a CHP project. Unless owned by the electric utility, CHP systems in Minnesota cannot sell electricity on a retail basis, so the revenue for excess CHP power sales is limited to the price the electric utility is willing to pay.

Absent an opportunity to sell excess power, the size of a CHP system at a large industrial facility with high thermal demand will likely be constrained by the onsite power needs. The facility will not be incentivized to build a CHP system that produces any more power than it needs onsite. This can effectively reduce the system's efficiency, because the system will not be properly matched and sized to the facility's thermal needs.

One policy approach to increasing the value of excess power is net metering. Net metering was originally implemented in order to encourage investment in renewable energy resources such as solar and wind. However, in some states it is also applied to smaller CHP projects. The following discussion of key concepts is adapted from Energy Resources Center 2014.

Net metering allows for the flow of electricity both to and from the customer – typically through a single, bi-directional meter – allowing qualified distributed generation customers to export electricity to the grid during times when their generation exceeds their on-site consumption. In the instances during a billing cycle when a customer's generation exceeds their electric purchases the net excess generation (NEG) in the form of a kiloWatt-hour (kWh) is stored in a bank to be credited against future kWh purchases. In effect, the customer uses excess generation to offset electricity that the customer otherwise would have to purchase at the utility's full retail rate. Some states require utilities to monetarily credit all NEG that's been stored for a specific period of time, other states expire NEG credits after a set amount of time while some allow for indefinite rollover. The monetary rate at which NEG is credited can vary depending on state regulations and utility policy from the average retail rate to the much lower PURPA avoided rate.

While net metering rates allow customers to reduce the energy potion of their bill, there is no mechanism by which billing demand is similarly reduced. A net metered customer must still pay for their maximum level of demand imposed on the grid through the demand charge in their full-requirements rate. Because net metering eligible technologies have historically been either quite small or limited to low load factor (renewable) applications, the use of the demand charge was an appropriate method for recovering incurred capacity costs. However, difficulties in recovering incurred capacity costs arise when net metering laws include technologies with high load factors – like CHP systems – that are able to reliably remove load from the grid for great durations but that also need utility service for planned maintenance or unplanned outages. Standby rates have sometimes been used to recover incurred capacity costs that could otherwise not be recovered through regular demand charges, but this practice varies by state.

Cost of Capital and Internal Investment Priorities

CHP requires a significant capital investment, and the equipment has a long life – generally over 15 years. The investment required for CHP will generally come from some combination of debt and equity. Access to debt capital, and the associated interest rate, will vary significantly from one organization to another. Further, credit availability will vary depending on broader economic conditions. Access to internal equity funding is affected by a company's financial condition and internal competition with other potential investments. CHP is not regarded as part of most end-users' core business focus and, as such, is sometimes subject to a high internal investment "hurdle rate", i.e. the rate of return a project is required to meet in order to get capital funding. Another way to express this is that for many organizations the payback period required to "green light" a CHP project is very short.

Simple payback is a commonly understood measure of financial viability. It is calculated by dividing the initial capital investment by the annual operating savings.

Another way to quantify investment return thresholds, for private sector businesses, is Return on Equity (ROE). This is the return to equity investors on a discounted cash flow basis. ROE cannot be compared directly with simple payback, because typically companies do not fund 100 percent with equity; instead they "lever" the equity return by borrowing some of the funds. The ratio between debt and equity varies depending on the company and the project. A typical capital structure for the electric utility industry is 45 percent debt and 55 percent equity (EIA NEMS Model 2013).

The appropriate comparison with simple payback is Weighted Average Cost of Capital (WACC), which takes into account not only ROE but also the after-tax cost of debt. WACC is the weighted average cost of repaying the capital invested or borrowed to build a CHP project. WACC is calculated based on the relative portions of debt and equity, as follows:

Debt interest rate = IR

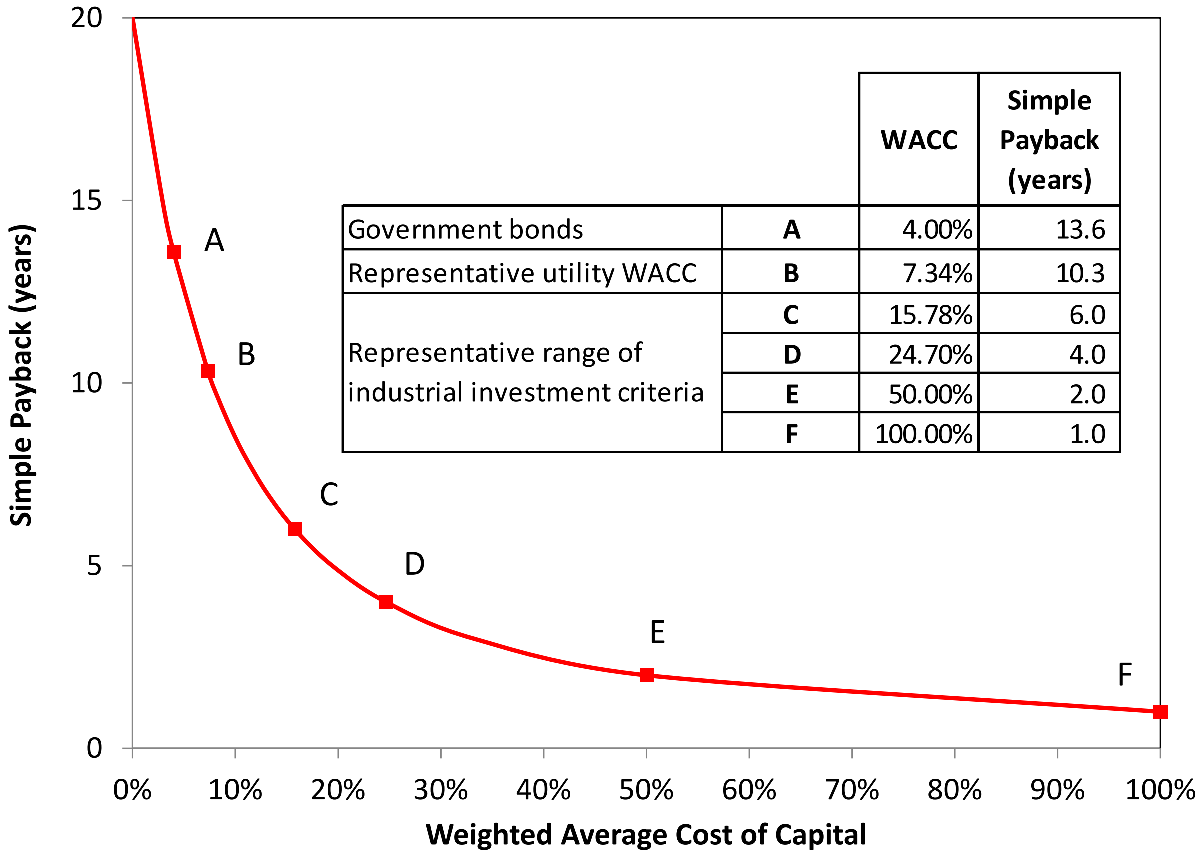
Return on Equity = ROE

Debt as percent of total capital = DR

Corporate tax rate = T

Weighted average cost of capital = [(IR x DR) x (1 – T)] + [ROE x (1 - DR)]

Figure 11 shows the relationship between simple payback and WACC.



		WACC	Simple Payback (years)
Government bonds	A	4.00%	13.6
Representative utility WACC	B	7.34%	10.3
Representative range of industrial investment criteria	C	15.78%	6.0
	D	24.70%	4.0
	E	50.00%	2.0
	F	100.00%	1.0

Figure 11. Relationship Between Weighted Average Cost of Capital (WACC) and Simple Payback (SP)

Source: FVB Energy

Particularly in industrial companies, competing capital investment demands can make energy efficiency a relatively low investment priority. Some companies will not accept a payback on a CHP project that exceeds 6 months (Primen 2003). This is equivalent to a WACC of 200 percent. More typical is a payback range of one to four years, equal to a WACC of 100 percent to 25 percent.

On the other hand, utilities have longer investment timeframes. For example, Xcel's current ROE is 10.26 percent (Ycharts). We will estimate that Xcel's average debt interest rate is 6.0 percent, and that the corporate tax rate is 38 percent. This yields an estimated Xcel WACC of 7.34 percent, equivalent to a simple payback of slightly over 10 years.

Decision-makers at other types of facilities, such as colleges, universities, hospitals, and municipalities, have an even longer investment horizon and a willingness to accept longer paybacks. For example, 20-year municipal bonds currently carry interest rates of 2.95 to 3.85 percent, as illustrated in Figure 12 (FMS Bonds). 9In Figure 11 we made the conservative simplifying assumption that government bonds carry an interest rate of 4.0 percent, corresponding to 30-year, "A" rated bonds, which is equivalent to a simple payback of 13.6 years.)

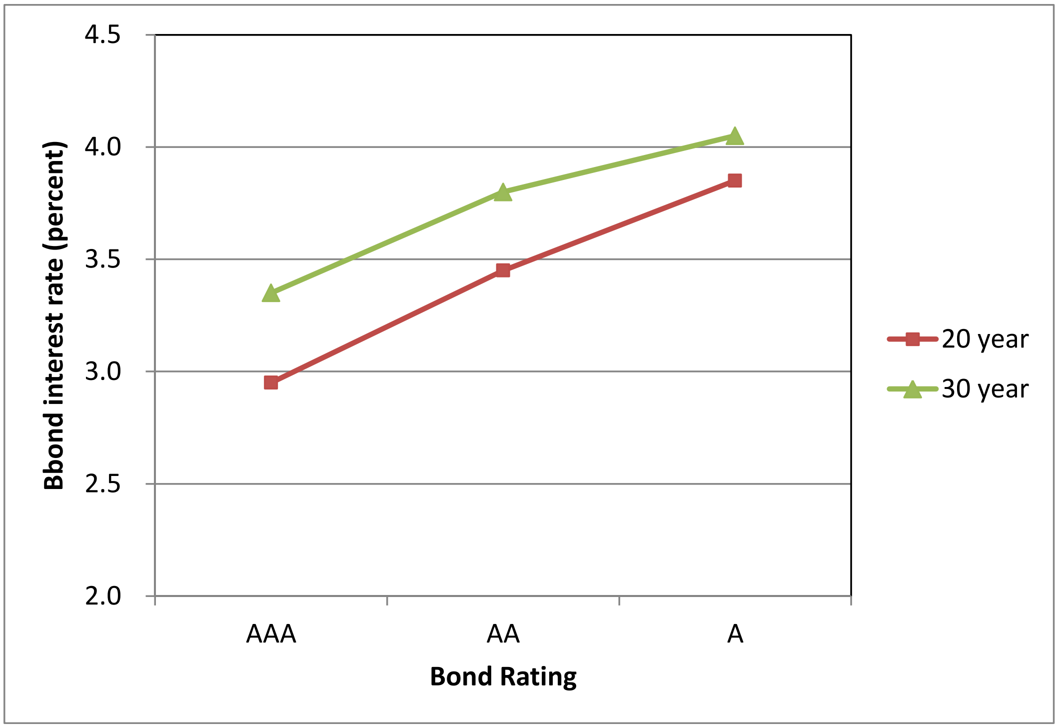


Figure 12. Municipal General Obligation Bond Yields By Bond Rating and Term (July 29, 2014)

Source: FMS Bonds

Figure 13 shows the percentage share of potential users that would be willing to implement CHP based on a given simple payback period, based on a 2003 survey (Primen 2003). This survey data is now a decade old, and post-recession attitudes are likely further reducing payback thresholds. To our knowledge no more recent surveys of this nature have been undertaken. In 2012, ACEEE engaged a broad group of industrial decision-makers in an evaluation of a broad range of issues associated with energy efficiency decision-making, although it did not address payback period thresholds (Russell and Young 2012).

CHP systems have recently reported payback periods from 3.5 to 10 years, depending on the facility, technology, local spark spreads, and other variables. It is very common for CHP systems to have simple payback periods of four to six years. It is important to remember, however, that CHP systems may be in place for decades (Chittum and Farley 2013).

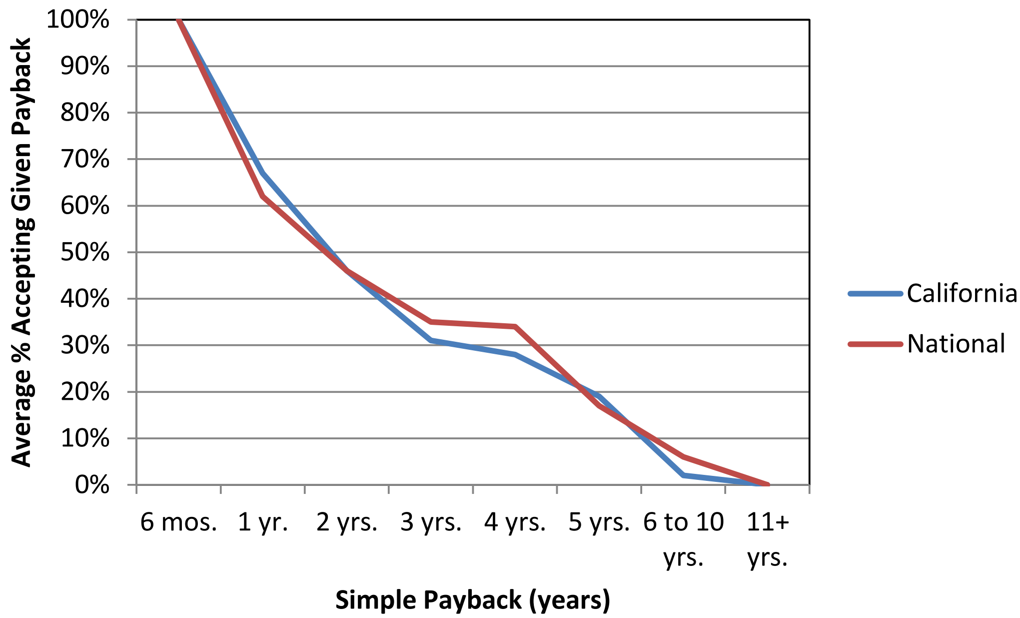


Figure 13. Results of Market Survey on Acceptable CHP Payback Periods

Source: Primen 2003

Economic Uncertainty

Analysis of the economic feasibility of CHP must be based on assumptions regarding future values of a wide range of factors, including:

- Price of fuel used for CHP;
- Prices of fuels otherwise used for heat production, and/or value of heat sold to other users;
- Prices of electricity otherwise purchased to meet power requirements;
- Prices of electricity sold to the grid or to other users;
- Projected growth in requirements for electricity and thermal energy, which in turn is based on assumptions about future economic conditions;
- Changes in utility regulation; and
- Changes in environmental regulations, including criteria air pollutants and greenhouse gases (GHG).

The uncertainties associated with these variables make decision-making challenging and, coupled with the other barriers discussed here, tend to discourage investment in CHP. To the extent that the decision criterion is a very short payback, as discussed above, the economic feasibility analysis is simplified because in essence it is based only on current values for key economic parameters.

Lack of a Utility Value Proposition

Many investor-owned electric utilities tend to view CHP as an economic threat because traditional utility business models link electricity sales to cost recovery and revenues, and a CHP-using facility will typically require much less utility-provided electricity than it did prior to CHP system installation. Most facilities that install CHP remain connected to the grid and do need to rely on the local power utility for supplemental power and/or for standby and back-up service during CHP system outages or planned maintenance. Consequently, utility attitudes, policies, requirements and tariffs related to this backup and supplemental power can make or break a CHP project's economics. The following discussion summarizes the potential value proposition that CHP represents for utilities, drawing on a recent report by ACEEE (Chittum and Farley 2013):

> *"Recognizing the substantial remaining potential for CHP and the substantial challenges facing its increased deployment, President Obama issued an Executive Order in 2012 calling for 40 GW of new CHP by 2020. As a result of the order, the U.S. Department of Energy is supporting regional and state efforts to identify CHP opportunities and address existing barriers. One of the major barriers identified is the fact that while utilities could play an important role in CHP deployment, they are often not economically incentivized to do so.*
>
> *Utilities are well-versed in making long-term investments, and they are well-positioned to encourage strategically sited CHP that can provide major benefits to the grid. Utilities have existing relationships with most of the customers that would be good candidates for CHP, and they can enjoy many of the benefits of CHP much more directly than individual CHP users might be able. Utilities also have the ability to use ratepayer funds to support projects that will provide system-wide benefits, and their CHP programs can help accelerate market adoption of the technology, all while providing economic and environmental benefits to all energy system users.*
>
> *Despite these capabilities, utilities — especially electric utilities — are structured and regulated in a manner that often discourages them from fully monetizing the benefits of CHP. They are also often encouraged to make investments in centralized generation resources rather than distributed generation, realizing greater rates of return on the centralized investments.*
>
> *CHP offers tremendous direct and indirect benefits to utilities. Most of these benefits are not fully valued today. These include:*
>
> - *CHP's low cost and more efficient power relative to more traditional centralized power plant resources and related transmission investments;*
> - *CHP's ability to adapt to different fuels depending on availability;*
> - *The speed with which CHP can be deployed relative to other generation and transmission resources;*
> - *CHP's ability to avoid significant line losses on transmission and distribution lines;*
> - *The reduced emissions compliance costs resulting from CHP's increased efficiency and avoided line losses;*
> - *A reduced strain on distribution and transmission systems and a reduced need for distribution and transmission infrastructure and reserve margins;*
> - *CHP's ability to function as a capacity resource;*
> - *CHP's ability to balance system power fluctuations and provide ancillary services;*
> - *The increased and higher load natural gas sales benefits to natural gas utilities; and*

- *The ability to use CHP to supplement and support greater renewable energy deployment".*

ACEEE has also published two associated reports, one focusing on CHP benefits for electric utilities (Chittum 2013a) and the other focusing on benefits for natural gas utilities (Chittum 2013b).

Frequently, utilities are generally unable to take advantage of these benefits. Changes in policies and regulations would enable utilities to better monetize these benefits, increasing the likelihood that utilities could begin to view CHP systems as true economic opportunities rather than threats.

Challenging Interconnection Standards

The technical requirements, procedures, and agreements for interconnection of CHP and other distributed generation are commonly referred to as interconnection standards. Policies, regulations, and rules governing the interconnection of distributed generation may be established by state law and, for regulated utilities, may be established and enforced by the state public utility commission (PUC). The Federal Energy Regulatory Commission (FERC), however, may have jurisdiction over distributed generation interconnected at the distribution or transmission level if it involves sales for resale of electric energy in interstate commerce by public utilities.

Some states lack interconnection standards entirely, or have very general interconnection standards that do not allow for a clear path for certain technologies and applications. This, as well as size and fuel limitations, can make interconnection of a CHP system very challenging. Fortunately, as discussed below under "Current Minnesota Policies and Programs," Minnesota's interconnection standards do not have many of these issues, though there is room for improvement.

The most effective interconnection standards have different tiers with different requirements for CHP systems of different sizes, reflecting the fact that smaller systems are often less complex technically to interconnect. Connecting a 25 MW system to the grid might involve significant technical and safety challenges, and it would not necessarily be appropriate for a 50 kW system to be subject to the same oversight procedures. Allowing different tiers essentially provides a "fast track" for smaller systems, and longer, more detailed analysis of the more complex interconnection of larger systems.

Unfavorable Standby Rates

Most facilities with CHP require service from the local utility for:

- Supplementary power when load is greater than the CHP output;
- Back-up supply during planned scheduled maintenance of the CHP system; and
- Back-up supply in case of unexpected, unscheduled outages of the CHP system.

The set of tariffs applying to customers with CHP or other distributed generation are sometimes called "standby rates" or "partial requirements tariff." High standby rates can discourage implementation of CHP by reducing the net savings on electricity costs. Standby rates are further discussed below under "Current Minnesota Policies and Programs".

Lack of Recognition of Resiliency Benefits

Hurricanes Sandy (2012), Irene (2011), Gustav (2008), Ike (2008), Katrina (2005) and Wilma (2005) brought power grids down, causing huge economic losses in output, income and employment. The Northeastern blackout in 2003 was not caused by severe weather but by transmission system failures, but also resulted in substantial economic losses as data centers, factories, hospitals, offices and other employers shut down.

The economic losses from energy supply disruption from interruption of business operations are enormous. For instance, economic research firm Moody's Analytics attributed nearly $20 billion in losses from suspended business activity just due to Superstorm Sandy (CNN Money 2012). Rutgers recently published a report that estimates economic losses, not including damages to physical structures, of approximately $11.7 billion in state Gross Domestic Product (Rutgers 2013). The study found that overall GDP losses could have been reduced in New Jersey if there had been additional backup sources of power such as CHP, which would have lessened the economic losses associated with power outages.

The Electric Power Research Institute evaluated industrial and digital economy businesses to determine the economic costs of power outages and power quality disturbances (EPRI 2001), focusing on 3 sectors:

- Digital Economy (DE) sector: comprised mainly of data storage and retrieval, data processing, or research and development operations such as the telecommunications, data storage, biotechnology, electronics manufacturing, and the financial industry.
- Continuous Process Manufacturing (CPM) sector: comprised of manufacturing facilities that continuously feed raw materials through an industrial process such as the paper, chemical, petroleum, rubber and plastics, stone, clay, glass, and primary metals industries.
- Fabrication and Essential Services (F&ES) sector: all other manufacturing industries, plus utilities and transportation facilities, water and wastewater treatment, and gas utilities and pipelines.

Although these three sectors only accounted for 17 percent of all U.S. businesses, they amounted to 40 percent of U.S. GDP. The study found that industrial and digital economy firms are losing about $45.7 billion per year due to power outages, with an additional $6.7 billion in costs resulted from power quality disturbances other than outages. The EPRI study concluded that the cost of power outages for all industry combined is an estimated at $120 to $190 billion per year.

The total cost of business interruptions from the 2003 Northeastern blackout, which lasted 2 days, have been estimated as follows: 1) Anderson Economic Group (Anderson and Geckil 2013) -- $4.5 to $8.2 billion; 2) U.S. Department of Energy (Parks 2003) -- $6 billion; and 3) ICF Consulting (ICF 2003) -- $7 to $10 billion.

CHP and other local energy sources are inherently more resilient to disruption from natural disasters or other events that interrupt electric energy supply from complex and interconnected grids. Additionally, CHP systems can be designed to operate in "island" mode during a grid outage. CHP and district energy systems have demonstrated that they can keep the power on, keep factories and business running, and continue to keep people warm in the winter and cool in the summer even when the power grid is down.

A recent report for Oak Ridge National Laboratory (ORNL 2013) notes, "When Superstorm Sandy made landfall on the eastern coast of the United States –New Jersey, New York and Connecticut were the most heavily hit areas. Extended power outages affected the region for days. However, some commercial and industrial facilities in the area were able to power through Superstorm Sandy due to onsite CHP." CHP can also help key infrastructure such as water treatment facilities continue functioning during a power outage. It is also important to note that hospitals and places of refuge such as universities were also able to keep running due to CHP systems, which helped protect the most vulnerable in the population.

These resiliency benefits are typically lacking from most cost-benefit analyses employed by the individual facilities using CHP and the utilities in whose service territory a CHP system would be deployed. So while the anecdotal evidence has been clear that CHP can provide highly critical resiliency and reliability benefits during times of grid power outages, there is no mechanism in which those benefits are specifically delineated. In contrast, the potential of the CHP system to fail is embedded in every utility's standby and backup power rates.

Lack of Recognition of Other Grid Benefits

CHP systems are typically located much closer to the end user than more traditional centralized power plants. Additionally, many CHP systems are capable of ramping up to full output very quickly, and are more nimble electric system assets than many traditional generation resources.

These two aspects of CHP systems provide numerous benefits to the grid at large. For instance, the close proximity to end-users can dramatically reduce the losses of power along transmission and distribution lines. On average, line losses in the U.S. are about 7 percent (EIA 2012), but research suggests that losses are much higher during times of peak grid demand (Chittum and Farley 2013). One analysis suggested that total losses during peak grid demand could rise to over 20 percent, representing a startling loss for utilities (Lazar 2011). By siting CHP systems in the most constrained areas of the grid, such dramatic losses could be reduced or avoided.

CHP systems are also well positioned to provide ancillary and capacity services to the grid. Ancillary services are those that help stabilize grid voltage, and they must be capable of providing these services in a timely manner – some as quickly as within one minute of the request. Each power market has its own market for ancillary services, and CHP systems are selling their ancillary services to these markets in some parts of the country (Chittum and Farley 2013). At present, however, the use of CHP for such ancillary services is not at all widespread.

CHP can also operate as a critical capacity resource, providing cost-effective system capacity in smaller increments than a single large centralized power plant. The efficiency benefits of increased CHP deployment can also be bid into forward capacity markets that currently treat energy efficiency as a capacity resource, such as PJM. CHP is not regularly assessed for its potential as a capacity resource, but it could indeed provide such services around the country.

Lack of Expertise

Many potential adopters of CHP lack the information and expertise to:

- Identify and assess the costs and benefits of CHP;
- Develop a CHP project, including navigation of the institutional, technical, legal and financial issues associated with these projects; and
- Operate and maintain a CHP system.

These barriers can be overcome through the participation of third party CHP developers and operators, but some organizations are reluctant to take on such a third party relationship, reducing the amount of CHP deployed.

Natural Gas Pipeline Capacity

An issue that was raised by several people in the stakeholder discussions was the potential constraint on CHP growth due to limited natural gas pipeline capacity in some areas. This issue was not envisioned in the work plan for this study and there was no time for analysis of the extent to which this might pose a significant issue for CHP growth.

Environmental Permitting

CHP may increase emissions on-site while reducing emissions regionally; CHP projects benefit from policies that recognize and account for these savings. Air quality regulatory issues are discussed in detail in Appendix B.

CHP installations must comply with a host of local and state zoning, environmental, health and safety requirements at the site. These include rules on water quality, fire prevention, fuel storage, hazardous waste disposal, worker safety and building construction standards. This requires interaction with various local agencies including fire districts, air districts, and water districts and planning commissions, many of which may have no previous experience with a CHP project and are unfamiliar with the technologies and systems (DOE 2013).

Current Minnesota Policies and Programs

State policies, in addition to electricity and natural gas prices, play an important role in how economically feasible it is to install CHP in the state. This section summarizes key Minnesota energy and greenhouse gas (GHG) goals, and then describes specific policies and programs relevant to CHP.

The discussion of CHP-related policies draws heavily on the American Council for an Energy Efficient Economy (ACEEE) *2013 Energy Efficiency Scorecard* (ACEEE Scorecard). Later in this section we describe the policy areas that were considered in the *Scorecard*, including a comparison of how Minnesota compares to other states, as well as incorporate additional information about 2013 legislation and data on program investments and results. Relative to CHP, Minnesota only scored 1 out of a possible 5 points in the *Scorecard*, as summarized in Table 13.

	Potential Points	Minnesota Points
Interconnection	1.0	0.5
RPS/EERS	1.0	0.5
Incentives	1.0	-
Net metering	0.5	-
Emissions treatment	0.5	-
Financing	0.5	-
Additional policies	0.5	-
Total	5.0	1.0

Table 13. ACEEE Scoring of Minnesota CHP Policies

Source: ACEEE Scorecard

Energy and GHG Goals

The State of Minnesota has established specific goals relating to fossil fuel consumption per capita and GHG reduction as described below.

Per Capita Fossil Fuel Consumption

The Next Generation Energy Act, passed in 2007, established a goal of a 15 percent reduction in per capita use of fossil fuel by the year 2015 (Minn. Statutes 216C.05 Subd. 2). Although it is not stated in the law, we assume that the baseline for this percentage reduction was intended to be 2005.

Data from the U.S. Energy Information Administration (EIA State Rankings) indicates that Minnesota ranks 18th in per capita energy consumption compared with other states, as illustrated in Figure 14.

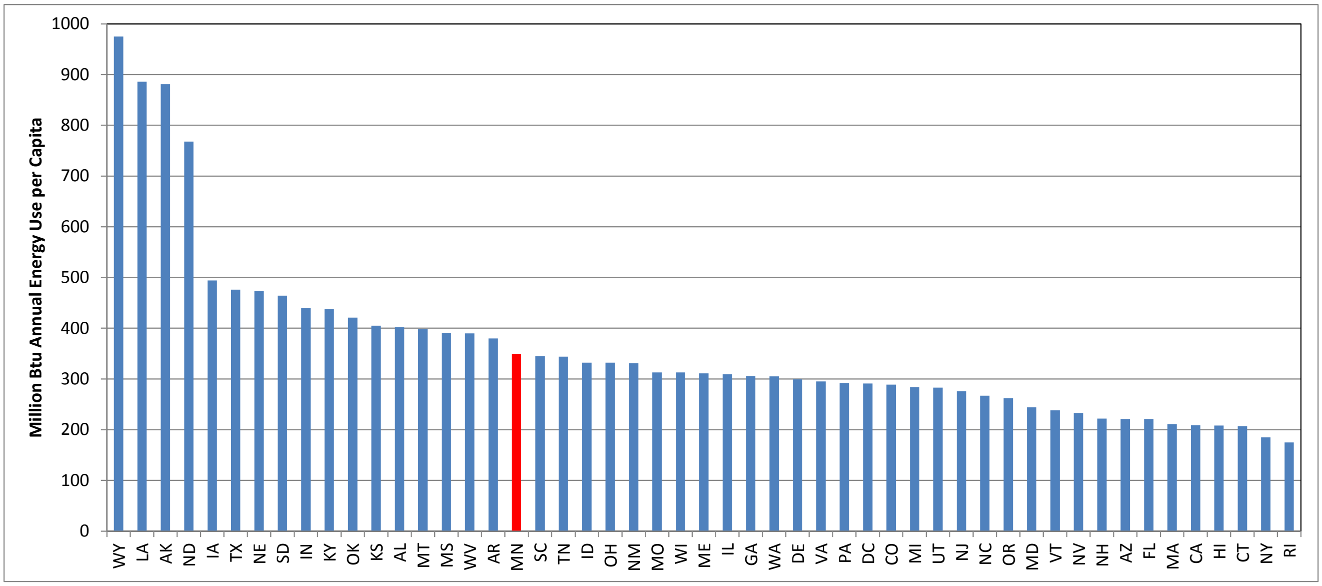


Figure 14. 50-State Comparison of Per Capita Energy Use

Source: EIA State Rankings

GHG Reduction

The *Next Generation Energy Act* (Minn. Stat. 216H.02) established the following GHG reduction goals:

- 15 percent reduction from 2005 levels by 2015;
- 30 percent reduction by 2025; and
- 80 percent reduction by 2050.

Under the *Next Generation Energy Act* goals, given a 2005 baseline of 161.3 million CO_2-equivalent tons, statewide emissions in 2015 would have to decline to about 137.1 million CO_2-equivalent tons (MPCA 2012). After three years of reporting, Minnesota GHG emissions are declining, but at a weak rate that may leave the state short of its reduction goals under the *Next Generation Energy Act* (MPCA 2012).

The law required several state agencies and a wide array of stakeholders to work together to come up with a “climate change action plan” that will identify and evaluate a broad range of greenhouse gas reduction strategies, assess the potential costs and benefits of the various options, including the potential cost to consumers. The Minnesota Climate Change Advisory Group (MCCAG), composed of 56 representatives from a range of public- and private-sector organizations and citizens, was formed in early 2007 and submitted a report to the Legislature in April 2008. The report included a generalized recommendation for “incentives and resources to promote CHP” (MCCAG 2008).

In addition, the *Next Generation Energy Act* prohibits the construction of any power plants that would produce a net increase in carbon emissions after Aug. 1, 2009. The law states that unless "a comprehensive state law or rule … that directly limits and substantially reduces greenhouse gas emissions" is enacted and is in effect by that date:

- no large fossil fuel-fired power plant can be built in Minnesota;

- no utility can import electricity from a large fossil fuel-fired power plant built in another state that was not operating on Jan. 1, 2007; and
- no Minnesota utility can purchase electricity from an outstate utility under a contract that exceeds 50 megawatts for a term of five years.

Portfolio Standards

Portfolio standards are tools states can use to increase the adoption of renewable energy and energy efficiency technologies, including CHP, by requiring electric utilities and other retail utility providers to meet a specified amount of load through eligible clean energy sources. Sometimes such standards are called "clean energy portfolio standards." [11] Renewable portfolio standards (RPS) define a particular percentage of electric resources that must be derived from renewable energy. Energy efficiency resource standards (EERS) define how much of the projected electricity or natural gas requirement should be provided by energy efficiency. The applicability of such standards is often limited to Investor-Owned Utilities (IOUs) regulated by the state, leaving electric coops and municipal utilities more leeway.

Minnesota Renewable Portfolio Standards

The Next Generation Energy Act established a goal of deriving 25 percent of the total energy used in the state from renewable energy resources by the year 2025 (Minn. Statute 216C.05 Subd. 2). This legislation created an RPS for Xcel Energy, created a separate RPS for other electric utilities,[12] and modified the state's existing non-mandated renewable-energy objective. In 2013, further legislation (H.F 729) was enacted to create a 1.5 percent solar standard for public utilities, a distributed generation carve-out, and a solar goal for the state. For the purpose of calculating the solar requirement, the following types of customers are not included: mining extraction and processing facilities; paper mills; wood products and oriented strand board manufacturers (House Research 2013).

CHP that is powered by renewable fuels such as biomass or landfill gas is an eligible technology, but natural gas CHP is not. Because not all types of CHP are covered under this RPS, Minnesota earned only a half point in the RPS/EERS *Scorecard* category for the most recent report. However, as discussed below, legislation passed in 2013 enhanced the potential for Minnesota's EERS to stimulate implementation of CHP.

Eligible Technologies

Electricity generated by solar, wind, hydroelectric facilities less than 100 megawatts (MW), hydrogen and biomass -- which includes landfill gas, anaerobic digestion, and municipal solid waste -- is eligible for the standards and the objective. The definition of eligible biomass was refined slightly in 2008 by S.F. 2996 to include the organic components of wastewater effluent and sludge from public

[11] State policymakers, project developers, advocates, utilities, and others have various definitions of "clean" energy. The SEEAction Guide does not attempt to create one definition, but rather recognizes that the primary audience for the guide is state regulators, and that they define it as they see fit.

[12] Other electric utilities that must comply with Minnesota's RPS are: public utilities providing electric service; generation and transmission cooperative electric associations; municipal power agencies; and power districts operating in the state.

treatment plants, with the exception of waste sludge incineration. After January 1, 2010, hydrogen must be generated by other eligible renewables in order to be eligible.

Xcel Energy Standard

The standard for Xcel Energy requires that eligible renewable electricity account for 31.5 percent of total retail electricity sales (including sales to retail customers of a distribution utility to which Xcel Energy provides wholesale service) in Minnesota by 2020. Of the 31.5 percent renewables required of Xcel Energy in 2020, 1.5 percent must be met with solar PV (10 percent of which must be met with systems of 20 kW or less) , at least 25 percent must be generated by wind-energy or solar energy systems, with solar limited to no more than 1 percent of the requirement. In effect, this means that the wind standard is at least 24 percent, 1.5 percent must be met with solar, and solar may contribute up to another 1 percent, and the "remaining" 5 percent may be generated using other eligible technologies.

Wind energy and biomass energy contracted for or purchased by Xcel Energy pursuant to Minn. Stat. § 216B.2423 et seq. is eligible under the RPS. The RPS schedule for Xcel Energy is as follows:

- 15 percent by 12/31/2010
- 18 percent by 12/31/2012
- 25 percent by 12/31/2016
- 31.5 percent by 12/31/2020 (including 1.5 percent solar)

Standard for Non-Xcel Public Utilities

The standard for other public utilities requires that eligible renewable electricity account for 26.5 percent of retail electricity sales to retail customers in Minnesota by 2025. Of this electricity, 1.5 percent must be solar photovoltaics by 2020, and 10 percent of the solar standard must be met with systems of 20 kW or less.

- 12 percent by 12/31/2012
- 17 percent by 12/31/2016
- 21.5 percent by 12/31/2020 (including 1.5 percent solar)
- 26.5 percent by 12/31/2025 (including 1.5 percent solar)

Standard for Non-Public Utilities

The standard for other Minnesota utilities requires that eligible renewable electricity account for 25 percent of retail electricity sales to retail customers (and to retail customers of a distribution utility to which the one or more of the utilities provides wholesale service) in Minnesota by 2025. The RPS schedule for other Minnesota utilities is as follows:

- 12 percent by 12/31/2012
- 17 percent by 12/31/2016
- 20 percent by 12/31/2020
- 25 percent by 12/31/2025

Renewable Energy Certificates (RECs)

The 2007 legislation required the Minnesota Public Utilities Commission (PUC) to establish a program for tradable RECs by January 1, 2008. The PUC approved the Midwest Renewable Energy Tracking System (M-RETS) for this purpose and required all utilities to register renewable generation assets by March 1, 2008. The program treats all eligible renewables equally and may not ascribe more or less credit to energy based on the state in which the energy was generated or the technology used to generate the energy. Only RECs recorded and tracked through the M-RETS can be used for compliance. Notably, Xcel Energy may not sell RECs to other Minnesota utilities for RPS-compliance purposes until 2021. For the purposes of the solar standard, only RECs associated with solar installed and generating in Minnesota on or after May 24, 2013 but before 2020 are eligible.

In December 2007, the PUC made certain additional determinations for the operation of the REC trading system, listed below:

- RECs will have a trading lifetime of 4 years according to the year of generation (i.e., all credits generated during 2008, regardless of the month, expired at the end of 2012).
- The purchase of RECs through M-RETS may be used in utility green pricing programs, subject to the shelf life described above.
- Consistent with M-RETS operating procedures, RECs must remain "whole" and may not be disaggregated into separate environmental commodities (e.g., carbon emission credits)
- The PUC declined to issue a directive ascribing ownership of RECs where ownership is not addressed in power purchase agreements (PPAs), instead requiring utilities to pursue negotiations and settlements with the owners of generation units.

Compliance and Reporting

Utilities are required to file annual compliance reports with the PUC detailing their retail sales, REC retirements, and REC trading activities. If the PUC finds a utility is non-compliant, the commission may order the utility to construct facilities, purchase eligible renewable electricity, purchase RECs or engage in other activities to achieve compliance. If a utility fails to comply, the PUC may impose a financial penalty on the utility in an amount not to exceed the estimated cost of achieving compliance. The penalty may not exceed the lesser of the cost of constructing facilities or purchasing credits and proceeds must be deposited into a special account reserved for energy and conservation improvements.

In 2013, the Division of Energy Resources published a compliance progress report for compliance through 2011, stating that utilities are on track to comply with 2012 goals.

Conservation Improvement Program (Energy Efficiency Resource Standard)

Statutory Requirements

The *Next Generation Energy Act* (NGEA) established an annual energy savings goal of 1.5 percent of average retail sales for each electric and gas utility beginning in 2010. Utilities may petition the Director of the Division of Energy Resources at the Minnesota Department of Commerce to adjust their savings goals to a minimum of 1 percent based on a conservation potential study, a utility's historic conservation improvement program (CIP) experience, or other factors at the discretion of the Director. Legislation passed in 2009 established an interim savings goal of 0.75 percent over 2010-2012 for qualifying natural gas utilities (Minnesota Department of Commerce website).

The NGEA further established the potential for electric utilities to count the savings that result from qualified improvements to its generation, transmission, or distribution infrastructure, or conservation measures in its own facilities toward the 1.5 percent savings goal, once plans are in place to achieve at least 1 percent savings through conservation improvements. Further legislation passed in 2009 also allowed natural gas utilities to count biomethane purchases toward their savings goal in a similar fashion.

The CIP statutes contain important stipulations regarding how utilities spend CIP funds:

- Electric utilities, except for Xcel Energy, must spend a minimum of 1.5 percent of annual gross operating revenues (GOR) on CIP programs. As an owner of nuclear generation facilities, Xcel Energy must spend at least 2 percent of annual GOR.
- Natural gas utilities must spend a minimum of 0.5 percent of annual GOR on CIP programs.
- Up to 10 percent of the overall minimum spending requirement may be spent on R&D projects.
- Up to 10 percent of the overall minimum spending requirement may be spent on qualifying solar energy projects. Up to 5 percent of the overall minimum spending requirement may be spent on other renewable and distributed generation projects.
- Each electric utility must include in its CIP plan programs intended to encourage the use of energy efficient lighting by its customers and recycling of spent lamps.

Investor owned utilities must file their CIP plans with the energy division at least every three years. Municipal utilities and cooperatives must file annually. Utilities report their actual CIP spending and savings achieved on an annual basis.

Certain large facilities may petition to have their revenues excluded from calculations determining investment and expenditure requirements (Minnesota Statutes 216B.241, Subd. 1a.). The petition must include a discussion of the competitive or economic pressures facing the owner of the facility and the efforts taken by the owner to identify, evaluate and implement energy efficiency improvements.

Program Results

The Department of Commerce must provide reports on the annual energy savings achieved through the CIPs, and related costs. Data from the latest report (Minnesota Department of Commerce 2013) are summarized in Table 14 and Table 15.

The electric utility sector as a whole met the 1.5 percent savings goal in 2010, and investor-owned utilities nearly met the goal, as summarized in Table 16. The natural gas utility sector as a whole met the reduced goal of 0.75 percent approved by the legislature as described above (see Table 17).

	Incremental Savings (GWh/year)	Expenditures ($ million)	Incremental CO2 Savings (tons/year)	$/MWH *
2006	412	$ 82.2	375,537	$ 13.31
2007	468	$ 91.2	426,646	$ 13.00
2008	597	$ 102.0	544,428	$ 11.39
2009	669	$ 144.9	609,905	$ 14.44
2010	826	$ 174.3	753,260	$ 14.07
2011	965	$ 140.6	879,936	$ 9.71

Average last 3 years $ 12.74

* The cost per unit of savings were calculated using a typical weighted average energy efficiency measure lifetime of 15 years.

	Incremental Savings (BCF/year)	Expenditures ($ million)	Incremental CO2 Savings (tons/year)	$/MMBtu *
2006	2.1	$ 16.3	126,750	$0.52
2007	1.9	$ 16.4	115,987	$0.57
2008	1.6	$ 18.1	94,592	$0.77
2009	1.8	$ 22.8	111,522	$0.82
2010	2.6	$ 38.0	158,039	$0.97
2011	2.8	$ 41.5	170,001	$0.99

Average last 3 years $0.93

* The cost per unit of savings were calculated using a typical weighted average energy efficiency measure lifetime of 15 years.

	2010	2011
Investor-Owned Utilities	1.40%	1.5%
Cooperative CIP Aggregators	1.40%	1.9%
Municipal CIP Aggregators	1.60%	1.5%
Other Cooperatives	1.40%	1.6%
Other Municipals	1.00%	1.3%
Total	1.40%	1.6%

Table 16. Electric Utility Savings as percent in 2010 and 2011

Source: Minnesota Department of Commerce 2013

	2010	2011
Investor-Owned Utilities	0.90%	1.0%
Municipal Aggregators	1.90%	1.0%
Other Municipals	0.60%	0.5%
Total	0.90%	1.0%

Table 17. Natural Gas Utility Savings as percent in 2010 and 2011

Source: Minnesota Department of Commerce 2013

Integrated Resource Planning

The PUC approves integrated resource plans that are filed by electric utilities every two years. These plans provide information about each utility's plans for policies, fuel sources, etc., for the next 14 years. Commerce does technical review and analysis of the plans, plus public advocacy and numeric values on emissions. As part of integrated resource planning, each utility is required to file a greenhouse gas mitigation plan. This part of the plan must include total CO_2 emissions, effects of various mitigation strategies on rate programs, and the effects of international or national CO_2 policies on utility systems and ratepayer costs (MPCA 2003).

Cost Allocation for Cogeneration Plants

Subd. 3 of Section 216B.166 established the following cost allocation principles:

"The methods used to allocate or assign costs between electrical and thermal energy produced by cogeneration power plants owned by public utilities shall be consistent with the following principles:

> *(a) The method used shall result in a cost per unit of electricity which is no greater than the cost per unit which would exist if the power plants owned by the public utility had been normally constructed and operated without cogenerating capability.*
>
> *(b) Costs which the public utility incurs for the exclusive benefit of the district heating utility, including but not limited to backup and peaking facilities, shall be assigned to thermal energy produced by cogeneration.*

(c) The methods and procedures may be different for retrofitted than for new cogeneration power plants.

(d) The methods should encourage cogeneration while preventing subsidization by electric consumers so that both heating and electricity consumers are treated fairly and equitably with respect to the costs and benefits of cogeneration."

Interconnection Standards

In response to state legislation enacted in 2001, in September 2004 the Minnesota Public Utilities Commission (PUC) adopted an order establishing generic standards for utility tariffs for interconnection and the operation of distributed-generation facilities up to 10 megawatts (MW) in capacity. The PUC standards contain technical requirements related to engineering studies, mandatory minimum insurance requirements for different sized systems, equipment certification definitions, a dispute resolution process, and standard application fees. The PUC has approved compliance tariffs filed by the state's investor-owned utilities. Municipal utilities and electric cooperatives were required to adopt a tariff that addresses the issues included in the PUC's order.

All utilities must report annually on the number of interconnected systems. The PUC has developed streamlined uniform interconnection applications and a process that addresses safety, economics and reliability issues.

In 2011, the Minnesota Department of Commerce, Division of Energy Resources started a review process of all distributed generation procedures, conducting stakeholder meetings and workshops and accepting comments (DSIRE).

In the 2013 ACEEE *Scorecard*, Minnesota received half a point in the Interconnection section. More than 50 percent of states received no points at all in the Interconnection section, so Minnesota performs better than average in this policy area. Minnesota does *not* have a tiered interconnection standard for CHP. As noted in the following chapter, the Minnesota Public Utilities Commission has established uniform interconnection standards that apply to all CHP systems up to 10 MW including fossil fuel-fired facilities. Although Minnesota performs better than the average state in this policy area, Minnesota interconnection standards could be improved by raising the cap on system size covered by the interconnection standard and implementing a tiered or "fast-track" system for smaller units. An explicitly tiered structure would allow the smallest systems, for instance, to benefit from a "fast-track" interconnection approach, reducing time and paperwork associated with the interconnection application.

Standby Rates

The EPA CHP Partnership developed the concept of the "avoided rate" as a metric for evaluating the barriers of standby rates (EPA 2009). This metric compares the projected average electricity cost, for an assumed set of monthly electricity demand and energy consumption data, under "full requirements" tariffs (assuming no CHP) to projected costs under "partial requirements" tariffs (assuming CHP).

Avoided rate can be calculated as follows:

Definitions

- *Full Requirements Cost (FRC)* = projected annual utility bill under the full requirements tariff
- *Partial Requirements Cost (PRC)* = projected annual utility bill under the partial requirements tariff
- *Full Requirements Use (FRU)* = projected annual kWh purchased under the full requirements tariff
- *Partial Requirements Use (PRU)* = projected annual kWh purchased under the partial requirements tariff

Calculations

- *Full Requirements Average Cost per kWh (FRA)* = FRC / FRU
- *Partial Requirements Average Cost (PRA)* = PRC / PRU
- *Avoided Average Cost (AAC)* = (FRC – PRC) / (FRU – PRU)
- *Avoided Rate* = ACC /FRA

The higher the Avoided Rate, i.e., the ratio of avoided costs to the full retail average price, the higher the user's savings. According to the EPA study, Avoided Rates above 90 percent generally provide adequate savings to support onsite generation.

Stand-by services are provided under a range of tariff structures and rates in Minnesota utilities. The Energy Resources Center (ERC) has completed a study of standby and net metering rates for Minnesota Department of Commerce (Energy Resources Center 2014). This study focused on:

- Assessing the existing standby rates and net metering policies and how they affect the market acceptance of CHP projects today;
- Determining what recommendations, if any, should be considered to reduce the barriers the above factors impose on CHP development in Minnesota; and
- Modeling the economic potential of CHP projects in Minnesota investor owned utility (IOU) service territories based on analyzing the impact of existing and varied standby rates for CHP projects.

Table 18 shares the results of the Energy Resources Study analyzing the avoided rate metric for each Investor-Owned Utility in Minnesota. The results shown range between 77 percent and 97 percent. In general, when analyzing the avoided rate metric, the closer the values are to 100 percent the lower the economic barrier standby rates impose on CHP projects.

	Generating Capacity (kW)		
	500	3,000	10,000
	Voltage		
	Secondary	Primary	Transmission
Xcel Energy	87%	90%	96%
Alliant Energy	77%	77%	78%
Minnesota Power	90%	95%	97%
Otter Tail Power	97%	96%	97%

Table 18. Avoided Rates of Minnesota IOUs

Source Energy Resources Center 2014

As the ERC report notes: "It should be noted that, though simple to calculate and communicate, the avoided rate metric is a blunt tool that may over simplify situations. The economic effect of standby rates is largely related to the specific attributes and operating schedules of a customer's generator. While the avoided rate can give a general overview of economic barriers, the actual effects on standby customers may vary greatly depending on actual circumstances. Because of the limitations in the avoided rate analysis, we also included the three criteria of transparency, flexibility and economic efficiency in the analysis of standby rates."

For the ERC study, ICF International modeled the potential impact on the economic potential for CHP in the service territories of the four IOUs if avoided rates were increased in the model from their current standing to a hypothetical value of 100 percent. The results are summarized in Table 19.

	Simple Payback		
	>10 years	5-10 years	0-5 years
With current standby rates	1,019	779	-
If Avoided Rate = 100%	682	1,116	-

Table 19. Economic Potential of CHP in IOU Service Territories with Current and Assumed 100 Percent Avoided Rates

Source: Energy Resources Center 2014

The ERC report concluded that this "indicates opportunities for improvement within the existing standby rate structures can positively impact the overall economic potential of new CHP generating capacity within Minnesota." However, the author concludes, based on the analysis discussed below under "Policy Analysis," that changing published standby rates is not likely to have a large impact on investments in CHP by utility customers. This conclusion is based on the analysis regarding the economic importance of key variables. Note that the hypothetical change to 100 percent Avoided Rates does not move any potential to simple paybacks under 5 years, which is the likely payback range for most potential implementers of CHP.

Although standby rates are not a major constraint, there are still modifications that can be made to standby rates that would further encourage CHP generators to operate more efficiently to avoid a greater portion of their full requirements rates. The ERC study suggests consideration of the following standby modifications for IOUs in Minnesota as follows:

1. *Standby rates should be transparent, concise and easily understandable.* Potential CHP customers should be able to accurately predict future standby charges in order to assess their financial impacts on CHP feasibility.
2. *Standby energy usage fee should reflect both demand and time-of-use cost drivers.* Time-of-use energy rates send clear price signals as to the cost for the utility to generate needed energy. This would further incentivize the use of off-peak standby services.
3. *The Forced Outage Rate should be used in the calculation of a customer's reservation charge.* The inclusion of a customer's forced outage rate directly incentivizes standby customers to limit their use of backup service. This further ties the use of standby to the price paid to reserve such service, creating a strong price signal for customers to run most efficiently.
4. *The standby demand usage fees should only apply during on-peak hours and be charged on a daily basis.* This rate design would encourage CHP customers to shift their use of standby service to off-peak periods when the marginal cost to provide service is generally much lower. Furthermore, this design would allow customers to save money by reducing the duration of outages.
5. *Grace periods exempting demand usage fees should be removed where they exist.* Exempting an arbitrary number of hours against demand usage charges sends inaccurate prices signals about the cost to provide this service. Standby demand usage should be priced as-used on a daily and preferably an on-peak basis. This method directly ties the standby customer to the costs associated with providing standby service.

Net Metering

Minnesota did not receive any points in the ACEEE scorecard because at the time the scorecard was completed, Minnesota's net metering standards only applied to systems of 40kW or less. However, new Minnesota legislation has substantially strengthened Minnesota's net metering policy.

Minnesota's net metering standard applies to all investor-owned utilities, municipal utilities, and electric cooperatives, and mandates that utilities must compensate customers at the utility's retail rate. Until the passage of H.F. 729, the Minnesota net metering standard only applied to facilities under 40 kW in capacity. H.F. 729 made extensive changes to Minn. Statutes 216B.164, which applies cogeneration (CHP) and small power production. These changes included:

- Definition of "distributed generation" as a facility with less than 10 MW.
- Facilities under 40 kW served by public utilities can opt for net metering based on the average retail utility energy rate.
- In setting rates for facilities over 40 kW but less than 1,000 kW served by public utilities, the Public Utilities Commission (PUC) "shall consider the fixed distribution costs to the utility not otherwise accounted for in the basic monthly charge and shall ensure that the costs charged to the qualifying facility are not discriminatory in relation to the costs charged to other customers of the utility."
- A public utility may not impose a standby charge on a net metered or qualifying facility: of 100 kilowatts or less capacity; or of more than 100 kilowatts capacity, except in accordance

with an order of the commission establishing the allowable costs to be recovered through standby charges.

Additionally, an aggregate system cap can be requested by a utility after net metered generation represents 4 percent of a utility's annual retail sales (DSIRE 2013).

A concern with Minnesota's new net metering law is that it may allow utilities to impose standby charges on net metering customers whose generating capacity is greater than 100 kW (Energy Resources Center 2014). According to the statute, utilities may petition the public utility commission to establish standby charges for larger net metering customers in order to recover allowable costs. Currently, all Minnesota utilities have included systems greater than 100 kW under standby provisions.

For low load factor customers with CHP systems larger than 40 kW but under 100 kW, imposition of standby rates will be onerous for net metering customers that might otherwise pay for their capacity through demand charges built into their electric rate. Standby rates for net metering customers with higher load factor generators may be an appropriate method to recover capacity costs (Energy Resources Center 2014).

Relative to net metering, the Energy Resources Center report had two recommendations:

1. *Standby rates should not be issued when utilities can recover capacity costs through regular rates.* Net Metering rates already include provisions to recuperate the full demand related costs from net metering customers. While net metering rates bill energy consumed or credit energy generated on a net basis they contain no such provision for calculating demand charges; like full-requirement rates, these rates bill customers for their maximum demand placed on the grid. However, not all net metering customers go offline the same amount for time. For those customers with little or infrequent downtime, standby rates might be an appropriate method to recover capacity related costs. In granting utilities the ability to impose standby charges on net metering customers above 100 kW, the Minnesota Public Utility Commission should be careful not to allow utilities to double charge for capacity cost recovery.
2. *The Net Excess Generation Credit should be the average retail electric rate for all net metering customers.* All net metering customers should be treated equally and be provided the same Net Excess Generation Credit.

Incentives and Financing Assistance

The upfront cost of a CHP system is often a significant barrier for businesses, particularly if the payback period is longer than for other investments. Incentives for CHP installations can take a variety of forms, including capacity (kW) or production (kWh) incentives, project-based grants, or tax credits. For states to receive a full point on the *Scorecard* for incentives, the incentives must apply to all forms of CHP and apply to systems in both the commercial and industrial sectors.

Financing assistance for CHP can be in the form of low-interest loan programs, loan guarantees, and bonding authorities. To receive a top score in ACEEE's scorecard, key programs must be available to all forms of CHP and be substantial enough to be able to truly be used by a CHP project.

Currently, Minnesota has no financial incentives or financing assistance in place that give credit to CHP system production or reduce the direct cost of investment. In contrast, over 50 percent of the states earned at least partial credit in the Incentives category of the *Scorecard*, reflecting the fact that most states have an incentive or grant program that can be used by CHP in some circumstances. In states with more aggressive CHP goals, incentive and financing programs are specifically designed around CHP opportunities.

According to the Property Tax Administrator's Manual, Minnesota Statutes 272.02, subd. 29, attached machinery and other personal property which is part of a facility containing a cogeneration system may be exempt if the cogeneration system meets the following criteria:

- The system utilizes natural gas as a primary fuel and the cogenerated steam initially replaces steam generated from existing thermal boilers utilizing coal;
- The facility developer is selected as a result of a procurement process ordered by the Public Utilities Commission; and
- Construction of the facility is commenced after July 1, 1994 and before July 1, 1997.

This tax exemption's criteria render it ineffective in encouraging new CHP in the state today. Additionally, current CHP opportunities can include other fuels such as biomass or biofuel, and they may not always be replacing a coal boiler. Property tax exemptions are useful tools to encourage distributed generation, but they are more supportive of new developments if their criteria are less restrictive.

Development of Policy Options

This section: 1) analyzes the economic significance of key factors in CHP economic feasibility; 2) summarizes the implications of the economic analysis for policy options and briefly notes major findings from research on best practices for CHP policy in other states (with detailed information provided in Appendix A); 3) briefly notes major findings from research on federal policies relevant to CHP (with detailed information provided in Appendix B); and 4) describes potential Policy Options that were introduced in draft form in a "Straw Man" report that was the basis for informal stakeholder feedback (with the "Straw Man" draft report provided in Appendix C and notes from the stakeholder discussions provided in Appendix D).

Comparative Economic Significance of Major Barriers

Introduction

A range of barriers to increased implementation of CHP were described above under "Key Challenges." The purpose of the following analysis is to characterize the relative economic importance of each major element in the CHP financial feasibility equation in order to inform development of draft recommendations for policies and programs.

In simplified terms, CHP is financially viable if CHP savings exceed costs. Key elements in the CHP financial viability equation are summarized in Table 20. Major factors that influence each element are summarized, and potential areas for policy action are noted. Notably, both costs and revenues are affected by the capacity factor (annual output of the CHP facility compared with output at full capacity over 8,760 hours).

	Element in CHP Finacial Equation	Major Influencing Factors	Potential Policy Measures
Costs	Capital amortization costs	Capital cost, WACC	Conservation Improvement Program, Renewable Portfolio Standard, Integrated Resource Planning, Grant and Loan Programs
	CHP fuel costs	Utility tariff, future trends, capacity factor	Gas utility fuel discount due to better load factor
	CHP non-fuel O&M costs	Based on technology	
Savings	Avoided cost of purchased electricity	Utility tariff, future trends, capacity factor	Favorable standby rates, Feed-In Tariff, payment for value-added grid benefits, Integrated Resource Planning
	Avoided cost of boiler fuel	Utility tariff, future trends, capacity factor	
	Export power revenue	Power purchase agreement	Payment for value-added grid benefits, Integrated Resource Planning
	Export thermal revenue	Thermal energy purchase agreement	Funding support for thermal infrastructure

Table 20. Basic Elements in CHP Financial Viability Equation

Source: FVB Energy

In the following analysis we analyze the sensitivity of CHP viability to the following four major variables and discuss the policy implications of that sensitivity:

- Weighted Average Cost of Capital (WACC)
- Fuel costs
- Electricity costs
- Capacity factor

First we will characterize the capital and operating cost characteristics of the CHP technologies and address the calculation of spark spread.

Spark Spread

The concept of "spark spread" was defined and discussed above under "Key Challenges." Basic technical characteristics of the modeled CHP technologies were summarized in Table 8. Base case electricity and fuel price assumptions are provided in Table 21. Economic characteristics of the modeled CHP technologies are summarized in Table 22.

	Small Commercial/ Industrial	Medium Commercial/ Industrial	Large Industrial
Natural gas price ($/MMBtu)	$ 6.64	$ 5.80	$ 4.96
Biomass price ($/MMBtu)	$ 13.44	$ 5.43	$ 2.41
Electricity price ($/kWh)	$ 0.087	$ 0.076	$ 0.065
Avoided electricity rate (%)	90%	90%	90%
Avoided electricity price ($/kWh)	$ 0.078	$ 0.068	$ 0.0584

Table 21. Base Case Fuel and Electricity Price Assumptions

Sources:
Natural Gas – U.S. Energy Information Administration State Price data 2013.[13]
Biomass – Small, wood pellets $215/ton; Medium, clean chips $50/green ton; Large, hog fuel $20/green ton.
Electricity – Based on detailed analysis by ICF of application of Xcel tariffs to a high load factor (Hi LF) and low load factor (Low LF) customers of various sizes.[14]
Avoided electricity rate – Weighted average of avoid rates for IOUs, calculated using data from Energy Resources Center 2014.

	Capital cost	Non-Fuel Operating Costs	CHP fuel price	Avoided fuel price	Avoided electricity cost	Spark spread
Technology	$/kW	$/kWh	($/MMBtu)	($/MMBtu)	($/kWh)	($/kWh)
Natural Gas						
30-500 kW	3,900	$ 0.025	$ 6.64	$ 6.64	$ 0.078	$ 0.038
500 kW - 1 MW	3,800	$ 0.023	$ 6.64	$ 6.64	$ 0.078	$ 0.041
1 - 5 MW	2,963	$ 0.016	$ 5.80	$ 5.80	$ 0.068	$ 0.038
5 - 20 MW	1,850	$ 0.007	$ 4.96	$ 4.96	$ 0.058	$ 0.029
> 20 MW	1,250	$ 0.006	$ 4.96	$ 4.96	$ 0.058	$ 0.032
Biomass						
1 - 5 MW	5,400	$ 0.038	$ 2.41	$ 4.96	$ 0.058	$ 0.120
5 - 20 MW	4,100	$ 0.025	$ 2.41	$ 4.96	$ 0.058	$ 0.097
> 20 MW	2,850	$ 0.017	$ 2.41	$ 4.96	$ 0.058	$ 0.082

Table 22. Economic Characteristics of CHP Technologies

[13] http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SMN_a.htm Data for Commercial sector designated as "Small Commercial/Industrial," EIA data for Industrial sector designated as "Large Industrial" and the average Commercial/Industrial rate designated as "Medium Commercial/Industrial".

[14] "Small Commercial/Industrial" is based on the average of Hi LF customers for 3-40 MW sizes. "Medium Commercial/Industrial" is based on the average of Hi LF and Low LF customers for 3-40 MW sizes. "Large Industrial" is based on the average of Hi LF customers for 3-40 MW sizes.

Calculation of the "spark spread" provides a useful initial screening of the basic operating economics of a particular CHP technology configuration by determining if the savings in avoided electricity and boiler fuel costs will exceed the CHP fuel costs. These savings provide the funds to pay the costs of capital amortization and non-fuel operation and maintenance costs.

Spark spreads are illustrated in Figure 15, assuming the Base Case fuel and electricity prices. Abbreviations used in Figure 15 are explained in Table 23. The spark spread counting electricity savings only is shown in red. The total spark spread, including the addition of boiler fuel savings, is indicated in blue. For example, the 30 kW microturbine has a negative spark spread of about $0.015/kWh counting only electricity savings. The savings from avoided boiler fuel are about $0.060/kWh, providing a positive total spark spread of $0.030/kWh.

Spark spreads are high for steam turbines because we assume that biomass is used to fuel the CHP but the avoided boiler fuel is natural gas. At the relatively small size of CHP plants, steam turbine generation is capital-intensive, so frequently a steam turbine plant will use a low-cost fuel like biomass.

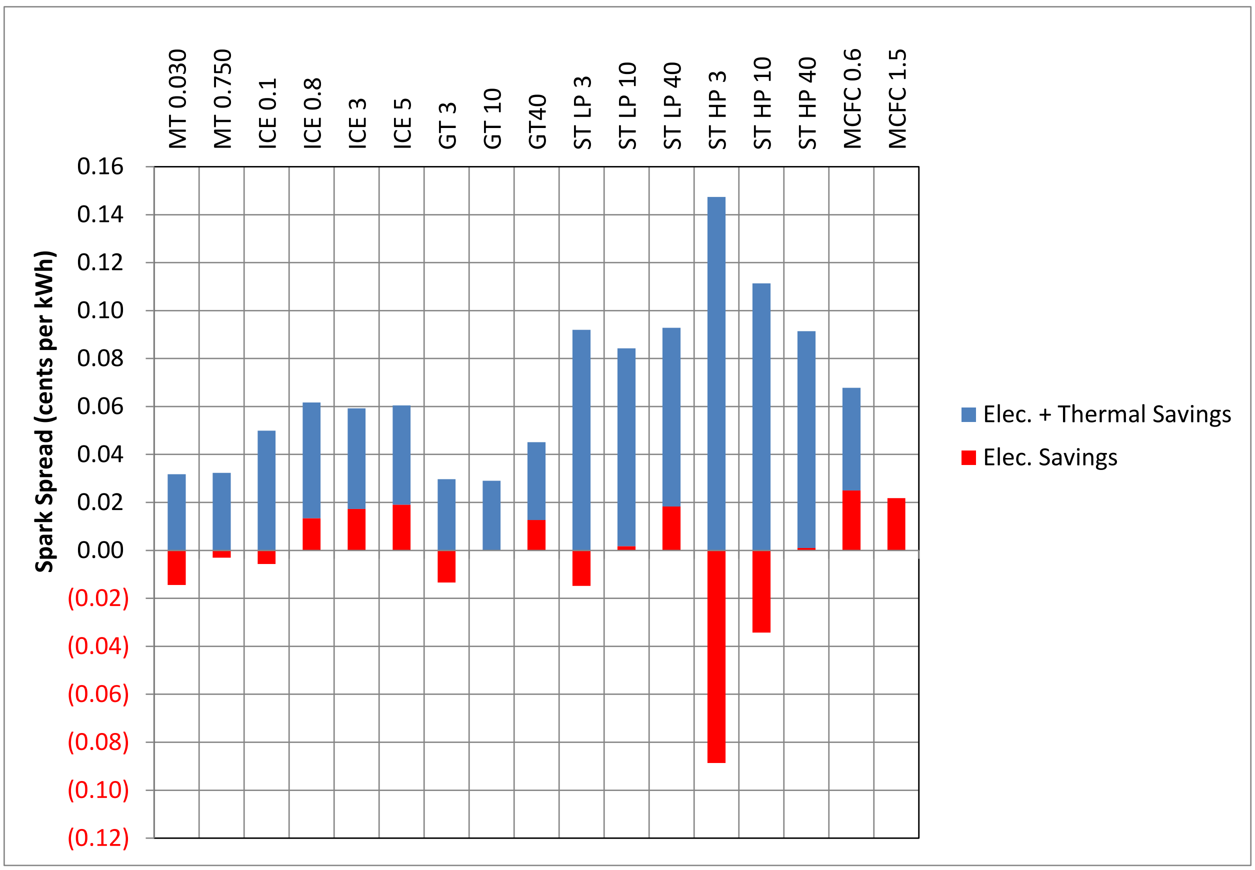


Figure 15. Spark Spreads (Base Case Fuel and Electricity Prices)

Technology *	Electric capacity (kW)	Abbreviation
MT	30	MT 0.030
	250 X3	MT 0.750
ICE	100	ICE 0.1
	800	ICE 0.8
	3,000	ICE 3
	5,000	ICE 5
GT	3,000	GT 3
	10,000	GT 10
	40,000	GT 40
ST bp LP	3,000	ST LP 3
	10,000	ST LP 10
	40,000	ST LP 40
ST bp HP	3,000	ST HP 3
	10,000	ST HP 10
	40,000	ST HP 40
PAFC	200	PAFC 0.2
MCFC	300 X 2	MCFC 0.6
	1,500	MCFC 1.5

*** Technologies:**

MT = Microturbine

ICE = Internal combustion engine

GT = gas turbine

ST bp LP = steam turbine backpressure 15 psig

ST bp HP = steam turbine backpressure 185 psig

ORC = organic rankine cycle

PAFC = phosphroic acid fuel cell

MCFC = molten carbonate fuel cell

Table 23. Key to CHP Technology Abbreviations

Capital Amortization

The annual capital amortization costs are determined by the capital cost and the Weighted Average Cost of Capital (WACC). As defined and discussed earlier, WACC determines the annual cost of repaying the original investment and takes into account both debt interest rate and return on equity. Capital costs are driven by the particular CHP technology used as well as site-specific factors. Although electric utility interconnection costs are a part of the total capital cost, they are relatively small factor. For example, the electrical interconnection cost for a 3 MW gas turbine CHP facility is estimated to be less than 3 percent of the total capital cost.

From a policy perspective, the capital factor of greatest significance is the WACC, which has a dramatic impact on making CHP projects financially viable. Table 24 shows the impact of WACC on total CHP savings, measured as total net annual savings divided by capital cost. WACC has an extremely strong impact on annual savings, with the lowest WACC values resulting in savings for all technology categories except those under 1 MW.

In this analysis the capacity factor is held constant at 0.85 and fuel and electricity prices assumptions are held constant at the values shown in Table 22. In this table and the subsequent sensitivity analysis tables the results cells shown in dark gray indicate technology categories for which savings in the sensitivity analysis were less than zero.

Technology	Annual savings as % of capital with given WACC				
	50.0%	24.7%	15.8%	7.3%	4.0%
Natural Gas					
30-500 kW					
500 kW - 1 MW					
1 - 5 MW					1.2%
5 - 20 MW					1.0%
> 20 MW				5.4%	7.7%
Biomass					
1 - 5 MW				1.2%	3.5%
5 - 20 MW				2.8%	5.1%
> 20 MW			0.7%	6.7%	9.0%
Dark gray cells	indicate size range is not cost-effective in these sensitivity analyses.				

Table 24. Sensitivity Annual Percentage Cost Savings to Weighted Average Cost of Capital (Capacity Factor 0.80 and Base Case Fuel and Electricity Prices, WACC Ranging from 50.0 percent to 4.0 percent

Fuel Prices

Table 25 shows the impact of variations in fuel price on total CHP savings. In this analysis the WACC is held constant at 15.8 percent, capacity factor is held constant at 0.85 and electricity prices are held constant at the values shown in Table 22. The variations in fuel price are expressed as percentages of the Base Case fuel price, with a range of -10 percent to +30 percent. For the biomass technology scenarios both the price of the biomass used to fuel the CHP system and the price of offset natural gas boiler fuel are increased or decreased by the given percentage. It is important to note that this sensitivity analysis only illustrates sensitivity to changes in fuel prices. In the real world, future natural gas prices increases will tend to drive up electricity prices, which would somewhat mitigate the degradation in CHP financial viability.

Note that most of the cells in are dark gray, indicating that savings were less than zero for that specific sensitivity analysis. In other words, with the base case values for the other parameters (particularly WACC at 15.8 percent) CHP is not cost-effective in this simplified analysis except for the very largest biomass CHP scenarios.

Technology	Base fuel cost ($/MMBtu)	Annual savings as % of capital with given change in fuel price				
		-10%	0%	10%	20%	30%
Natural Gas						
30-500 kW	$ 6.64					
500 kW - 1 MW	$ 6.64					
1 - 5 MW	$ 5.80					
5 - 20 MW	$ 4.96					
> 20 MW	$ 4.96					
Biomass						
1 - 5 MW	$ 2.41					
5 - 20 MW	$ 2.41					
> 20 MW	$ 2.41	0.5%	0.7%	0.9%	1.2%	1.4%
Dark gray cells	indicate size range is not cost-effective in these sensitivity analyses.					

Table 25. Sensitivity to Fuel Price (Capacity Factor 0.80, WACC 15.8 percent and Base Case Electricity Prices)

Avoided Electricity Price

Table 26 shows the impact of variations in avoided electricity price on total CHP savings. In this analysis the WACC is held constant at 15.8 percent, capacity factor is held constant at 0.85 and fuel prices are held constant at the values shown in Table 22. The variations in electricity price are expressed as percentages of the Base Case fuel price, with a range of -20 percent to +20 percent. Note that most of the cells in are dark gray, indicating that savings were less than zero for that specific sensitivity analysis. In other words, with the base case values for the other parameters (particularly WACC at 15.8 percent) CHP is not cost-effective in this simplified analysis except for the very largest CHP scenarios.

Technology	Base electricity price ($/kWh)	Annual savings as % of capital with given change in electricity price				
		-20%	-10%	0%	10%	20%
Natural Gas						
30-500 kW	$ 0.078					
500 kW - 1 MW	$ 0.078					
1 - 5 MW	$ 0.068					
5 - 20 MW	$ 0.058					
> 20 MW	$ 0.058				1.7%	4.9%
Biomass						
1 - 5 MW	$ 0.058					
5 - 20 MW	$ 0.058					
> 20 MW	$ 0.058			0.7%	1.5%	2.7%
Dark gray cells	indicate size range is not cost-effective in these sensitivity analyses.					

Table 26. Sensitivity to Electricity Price (Capacity Factor 0.80, WACC 15.8 percent and Base Case Fuel Prices)

Capacity Factor

"Capacity factor" is ratio of the total annual power production compared with the facility running at full capacity for 8,760 hours per year. Table 27 shows the impact of variation in capacity factor on total CHP savings. In this analysis the WACC is held constant at 15.8 percent and fuel prices are held constant at the values shown in Table 22. The earlier sensitivity analyses assumed a capacity factor of 0.85. Capacity factor is a critical variable because if it is too low the fixed costs of CHP are spread over too few units of energy output.

Technology	Annual savings as % of capital with given Capacity Factor			
	0.90	0.80	0.70	0.60
Natural Gas				
30-500 kW				
500 kW - 1 MW				
1 - 5 MW				
5 - 20 MW				
> 20 MW	0.3%			
Biomass				
1 - 5 MW				
5 - 20 MW				
> 20 MW	1.8%	0.7%		
Dark gray cells	indicate size range is not cost-effective in these sensitivity analyses.			

Table 27. Sensitivity to Capacity Factor (WACC 15.8 percent and Base Case Fuel and Electricity Prices)

Implications for Policy Options

This section discusses the implications of the economic analysis presented above relative to policies or programs for potential implementation in Minnesota. In the discussion, references are made to Appendix A, which summarizes best practices in state CHP policies and programs.

Capital Costs

Of all of the key variables, the cost of amortizing the capital costs of CHP stands out as a powerful influence on CHP viability. Those costs can be reduced by:

1. Reducing the initial capital cost to the CHP investor through incentives or rebates.
2. Reducing the Weighted Average Cost of Capital (WACC) through low-interest loans or credit enhancement.
3. Reducing the WACC by facilitating investment entities with a relatively low WACC, such as utilities.

The following discussion briefly comments on these three strategies.

Incentives

As described in detail in Appendix A, incentive programs have been implemented in other states, generally through electric utility rebate programs. This is a policy approach worthy of further investigation for Minnesota.

Some successful electric utility programs combine capital and operating incentives. For example, Maryland's successful Baltimore Gas and Electric (BG&E)'s *Smart Energy Savers Program.* The incentive program is structured as follows:

- $75/kW after the system has been designed and a commitment letter has been signed;
- $175/kW after the system has been installed and commissioned and undergone an inspection; and
- $0.07/kWh for the first 18 months of system performance, after metered data has been reviewed.

This incentive program is applicable to systems that are at least 65 percent efficient and do not export excess power to the grid. The maximum incentive offered by BG&E is $2 million for a single project, and is available to almost all non-residential customer classes.

In New York, NYSERDA's *Combined Heat and Power (CHP) Performance Program* provides the following incentives:

- Systems may earn up to $0.10/kWh generation;
- Systems may earn an additional $600/kW or $750/kW of summer demand reduction, depending on location in the state; and
- Systems may earn additional bonus incentives if they do any of the following:
    - Serve critical infrastructure;
    - Serve an area determined to be a challenged area of the grid of particular interest to the local utility; and
    - Exemplify "superior" efficiency.

These incentives are performance-based and correspond to the summer-peak demand reduction (kW), energy generation (kWh) achieved by the CHP System on an annual basis over a two-year measurement and verification period.

The recently announced Illinois Department of Commerce and Economic Opportunity (DCEO) *public sector* CHP incentive program includes performance based incentives to provide financial assistance during various stages of a project, including after the design phase, commissioning, and after 12 months of measured operational performance:

- Design Incentive: $75/kW capacity (following completion of the design phase).
- Constructive Incentive: $175/kW capacity (following successful commissioning of the system).
- Production Incentive: $0.08/kWh (with efficiency ≥ 70 percent HHV) OR $0.06/kWh (efficiency ≥ 60 percent but < 70 percent HHV) of "useful electric energy" produced (after 12 months of operation based on meeting the measured operating requirements of the system).

The total incentive (Design + Construction + Production) is capped at $2 million or 50 percent of the project cost, whichever is less. The design incentive is capped at $195,000 or 50 percent of design cost, whichever is less. The construction incentive is capped at $650,000 or 50 percent of the construction cost, whichever is less.

The Illinois program was designed to deliver a total incentive value of about $750 per kW when all incentives are combined (Cuttica 2014).

A common constraint in existing state incentive programs is that they are limited to relatively small projects. For example, in both Maryland and Illinois, the maximum incentive is $2 million. In New York the maximum is $2.6 million. Such limitations significantly limit the benefit of incentive programs because the greatest potential MW of CHP are in the larger projects (5 MW and above).

Low-Interest Loans

No examples of state low-interest loans and/or credit enhancement programs were found. Given the generally high WACC of most potential CHP investors, marginal decreases in interest rates are unlikely to trigger significant investment by industrial or commercial businesses. However, institutional entities, such as universities or hospitals, generally have lower WACCs and could potentially benefit from a low interest loan fund or credit enhancement program.

Utility Investment in CHP

Facilitating investment in CHP by entities with low WACC could have a significant positive impact on CHP implementation. Given that electric and gas utilities have relatively low WACCs, this is a highly promising direction for Minnesota policy development. Although there are some current examples of utility ownership of CHP, there is no current goal or set of policies designed to encourage utilities to own and operate CHP plants.

Value of Electricity

The value of CHP-generated electricity is a significant variable. This value is the sum of:

- Avoided purchases of electricity (less the net impact of standby charges);
- Renewable Energy Credits (RECs) or potentially Alternative Portfolio Standard Credits;
- Production incentives incorporated into a Conservation Improvement Program;
- Value of carbon emission reductions;
- Payments for value-added grid services; and
- Revenue from sale of excess generation, if any.

Standby Rates. Based on the Energy Resources Center study (Energy Resources Center 2014), as discussed above under “Key Challenges,” standby rates do not appear to be a relatively significant barrier in most utility service areas. While further progress can be made, action on standby rates alone will not result in significant increases in CHP.

Portfolio Standard Credits. For renewably-fueled CHP, RECs could be an important help in achieving financial viability. However, with significant carve-outs for wind and solar in the Xcel RPS, only 5% of the 2020 goal of 31.5% could be met with biomass.

As discussed in Appendix A, states such as Massachusetts and Pennsylvania have implemented Alternative Energy Portfolio Standards (APS) which set targets for a certain percentage of a supplier’s capacity or generation to come from alternative energy sources such as CHP or municipal solid waste projects. These standards can market-based and credit eligible projects with alternative energy credits or some other form of credit, which can then be purchased by electricity suppliers to meet compliance obligations.

Electricity Production Incentives. An operating incentive tied to production of electricity from CHP is one approach to incentive programs as discussed above under "Incentives." Operating incentives in other states are relatively short-term, e.g. 12-18 months. A longer-term operating incentive is worthy of consideration in Minnesota because it would provide a predictable and stable cash flow.

Carbon Emission Value. As discussed below under "Federal Policy Context," proposed U.S. Environmental Protection Agency regulations for new and existing power plants will create pressure to reduce Minnesota power generation carbon emissions. Although the policy mechanisms have not yet been determined, it is highly likely that some form of direct or indirect economic value of carbon emission reductions will result. It is worthwhile considering how to encourage Minnesota utilities in their Integrated Resource Planning to proactively assess CHP opportunities in their service territory and compare those opportunities to other generation resources with an economic value given to carbon dioxide emission reductions.

Value-Added Services. From a policy perspective, it is worthwhile examining the potential for CHP generation to be given additional value in recognition of value-added services that are not currently priced in the marketplace, such as locational value (reduced transmission/distribution losses) and voltage support. Recognition of these benefits, as well as potential energy supply resiliency benefits of CHP, could help stimulate increased implementation of CHP. However, this is a complex and case-specific issue, and developing an appropriate policy direction would require further study.

Sale of Excess Power. To the extent that policy-makers desire to achieve high gains in efficiency and carbon reduction through CHP, it is important to address the value of excess CHP power generation. This issue is tied to capacity factor. Sizing the CHP system to meet the facility's heating load normally results in the highest efficiency, carbon emission reductions and cost savings. However, in some cases, sizing and operating the system to meet the heating load would result in more electricity being produced than could be used on site. In these cases, the system would need to be operated below capacity to avoid producing excess electricity. As shown in the above analysis, capacity factor has a strong impact on CHP viability. Alternatively, instead of sizing the CHP facility for optimal efficiency and carbon benefits, a CHP facility might be undersized to avoid the institutional and regulatory constraints associated with selling excess power.

If sized and operated at the optimal capacity factor, many CHP systems would have to sell the excess electricity production. However, in such cases, low market values for excess power generation will significantly affect CHP economic viability.

Historically, electric utilities have generally not encouraged CHP because they have lacked incentives to promote and/or implement CHP. Customer self-generation reduces electric utility sales and profits. One solution is to "decouple" utility sales from profits, and some gas and electric utilities are exploring decoupling.[15]

[15] Centerpoint, a gas utility, has implemented a pilot program and is now expanding the program. Xcel, an electric utility, has proposed a decoupling pilot in their current rate case. See Minnesota Public Utilities Commission, Docket No. G-008/GR-13-316, June 9, 2014.

CHP Fuel Cost

In the context of incentives that natural gas utilities could provide to encourage CHP, a gas rate discount could improve the economic feasibility of CHP. However, with natural gas CHP, the impact of the natural gas price on CHP economics is somewhat diminished because although increased gas prices increase the costs of CHP they also increase the savings from reduced gas use for heat production.

Federal Policy Context

This section very briefly describes existing federal policies and programs that are relevant to future implementation of CHP in Minnesota, including investment tax credits, production tax credits, Department of Energy and Environmental Protection Agency program. See Appendix B for detailed information about existing federal policies as well as descriptions of relevant proposed federal legislation.

Tax Incentives

Investment tax credits for CHP were established by the Energy Improvement and Extension Act of 2008. The CHP credit is equal to 10 percent of expenditures, with no maximum limit stated, for the first 15 MW of CHP property (United States Code 26 USC 48). The total CHP capacity must be equal to or less than 50 MW. Except for CHP fueled with biomass, the total efficiency must exceed 60 percent. In addition, at least 20 percent of the total useful energy must be in the form of thermal energy, and at least 20 percent must be in the form of electrical or mechanical energy. The CHP credit applies to eligible property placed in service after October 3, 2008. Tax credits are available for owners paying taxes on eligible systems placed in service on or before December 31, 2016.

The federal renewable electricity production tax credit (PTC) is a per-kilowatt-hour tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year (United States Code 26 USC 45). This credit is relevant to CHP systems fuels with renewable energy. Current credit amounts relevant for CHP are:

- Closed-Loop Biomass: $0.023/kWh.
- Open-Loop Biomass: $0.011/kWh.
- Landfill Gas: $0.011/kWh.
- Municipal Solid Waste: $0.011/kWh.

The duration of the credit is generally 10 years after the date the facility is placed in service. Under current law, construction must begin by December 31, 2013. While this expiration makes the PTC moot for the future we include this information in the report because legislative efforts are being made to extend the PTCs.

Interconnection Standards

A range of required or recommended interconnection standards have been developed by federal agencies and other entities. Federal Energy Regulatory Commission (FERC) has established standards for distributed generation connected at the transmission level. The Department of Energy has recommended "best practices" for standards for state adoption. The National Association of Regulatory Utility Commissioners (NARUC) has also recommended model state standards. The Interstate Renewable Energy Council (IREC) has developed model rules for interconnection of small distributed generation. These standards and model rules are described below, drawing on information prepared by the U.S. Environmental Protection Agency (EPA dCHPP database).

Information/Education/Technical Assistance Programs

In August 2012, President Obama issued an Executive Order to facilitate investments in energy efficiency at industrial facilities, with a strong emphasis on CHP as an efficiency strategy. The Order seeks to support these investments through a variety of approaches, including encouraging private sector investment by setting goals and highlighting the benefits of investment, improving coordination at the Federal level, partnering with and supporting States, and identifying investment models beneficial to the multiple stakeholders involved.

DOE's CHP Technical Assistance Partnerships (CHP TAPs), formerly called the Clean Energy Application Centers (CEACs), promote and assist in transforming the market for CHP, waste heat to power, and district energy technologies and concepts throughout the United States.

The Environmental Protection Agency's CHP Partnership is a voluntary program seeking to reduce the environmental impact of power generation by promoting the use of CHP. The Partnership works closely with energy users, the CHP industry, state and local governments, and other clean energy stakeholders to facilitate the development of new projects and to promote their environmental and economic benefits.

Financing

Section 1703 of Title XVII of the Energy Policy Act of 2005 authorizes the U.S. Department of Energy (DOE) to issue more than $10 billion in loan guarantees for energy efficiency, renewable energy and advanced transmission and distribution projects. Projects must "avoid, reduce or sequester air pollutants or anthropogenic emissions of greenhouse gases; and employ new or significantly improved technologies as compared to commercial technologies in service in the United States at the time the guarantee is issued."

CHP technologies are potentially eligible if a project meets the "new/improved" technology criteria. In fact, in 2013 the DOE released a draft loan guarantee solicitation that explicitly mentioned CHP as illustrative types of projects eligible for the program. However, this loan guarantee program will not be useful for combined heat and power (CHP) for two reasons:

- The majority of opportunities for saving energy are in deployment of commercial CHP technologies, which do not appear to be eligible for this program; and
- For CHP projects the proposed fees are onerous, especially in view of the relatively small size of CHP projects.

Air Quality Standards

In December 2012, the U.S. Environmental Protection Agency issued a set of final adjustments to Clean Air Act standards for major source and area source boilers as well as certain solid waste incinerators. These rules are commonly called the "Boiler MACT" (maximum achievable control technology) rule. The rule presents an opportunity for major source sites with coal- and oil-fired boilers to consider switching to natural gas and/or natural gas-fired CHP instead of installing costly emissions controls to achieve compliance. Significant opportunity exists in Minnesota to replace some of the affected boilers with new CHP. Over 55 facilities in Minnesota will be impacted by the new boiler rules, and while CHP may not be an appropriate measure for every affected facility, it represents a potentially attractive opportunity to satisfy the new rules while establishing a long-term onsite energy generation solution.

GHG Regulation of Power Plants

New Source Performance Standards

On September 20, 2013, the Environmental Protection Agency (EPA) issued a proposed new rule pursuant to section 111 of the Clean Air Act (CAA), which would establish new source performance standards (NSPS) for carbon dioxide (CO2) emissions from new fossil fuel-fired electric utility steam generating units (EGUs) and natural gas-fired stationary combustion turbines.

The proposed rule would establish separate standards for certain types of natural gas-fired combustion turbines and for coal-fired electric utility boilers, including integrated gasification combined cycle (IGCC) units.

Notably for CHP, the proposed standard of performance for each subcategory is in the form of a gross energy output-based CO2 emission limit expressed in units of emissions mass per unit of total useful recovered energy, specifically, in pounds per megawatt-hour (lb/MWh). EPA proposes that useful recovered energy include the gross electric output plus 75 percent of the useful thermal output.

In addition, to recognize the environmental benefit of reduced electric transmission and distribution losses of CHP, EPA has proposed that for CHP facilities meeting certain efficiency criteria the measured electric output would be divided by 0.95 to account for a 5 percent avoided energy loss in the transmission of electricity. The efficiency criteria require that at least 20 percent of the total gross useful energy output consists of electric or direct mechanical output and that least 20 percent of the total gross useful energy output consists of useful thermal output on a rolling three calendar year basis,

Clean Power Plan (Existing Power Plants)

On June 18, 2014, the U.S. Environmental Protection Agency proposed rules for reducing greenhouse gas (GHG) emissions in existing power plants through section 111 (d) of the Clean Air Act. In general,[16] the rule defines an "affected source" as a fossil fuel power plant designed to sell more than 219,000 MWh of electricity per year *and* more than one-third of the potential electric output to the grid.

The EPA has provided great flexibility to states in meeting GHG reduction goals by taking a "systems approach" – allowing states to consider a wide range of actions that can be taken "beyond the fence line" of the affected electric generating units (EGUs) to more cost-effectively reduce carbon dioxide emissions. It is important to note that the Clean Power Plan sets out different goals for each state, based on their ability to reduce emissions with these four "building blocks":

- heat rate[17] improvements at coal-fired EGUs;

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[16] There are some inconsistencies in the proposed rule that suggest that gas-fired plants must be both designed to *and actually sell* those threshold amounts on a three-year rolling average.

[17] "Heat rate" means the amount of fuel required to produce one kilowatt-hour of useful energy (usually expressed as Btu per kilowatt-hour of electricity).

- redispatch from steam generators using coal, oil or natural gas to existing natural gas combined-cycle units;
- reductions in EGU emissions due to increased low- or zero-carbon generation; and
- reductions in EGU emissions due to end-use energy efficiency.

State reduction goals, expressed in pounds of carbon dioxide per net megawatt-hour of useful energy, vary dramatically depending on the particular state's opportunities relative to the building blocks. Figure 16 shows the proposed final reduction goals for each state for 2030 and beyond. Minnesota's goal is 873 lbs/MWh. For perspective, the new source performance standards proposed earlier by the EPA for new power plants range from 1,000 to 1,100 lbs/MWh of CO_2, depending on power plant size – a range set based on emissions from natural gas combined-cycle plants generating only power.

The EPA has proposed to include thermal energy as well as electric energy produced in CHP plants in calculating useful energy to meet state goals for 2030. The agency has proposed crediting 75 percent of CHP thermal output. This regulatory recognition of thermal energy recovery via CHP is an important and very sound step, and is consistent with the approach taken in the new source performance standards for new power plants.

Although state goals are based on the four building blocks, state plans need not be restricted to those categories. States are free to employ a wide range of strategies to reduce emissions. In its proposed rule, the EPA specifically asks for comment on the role of CHP in meeting emission reduction goals.

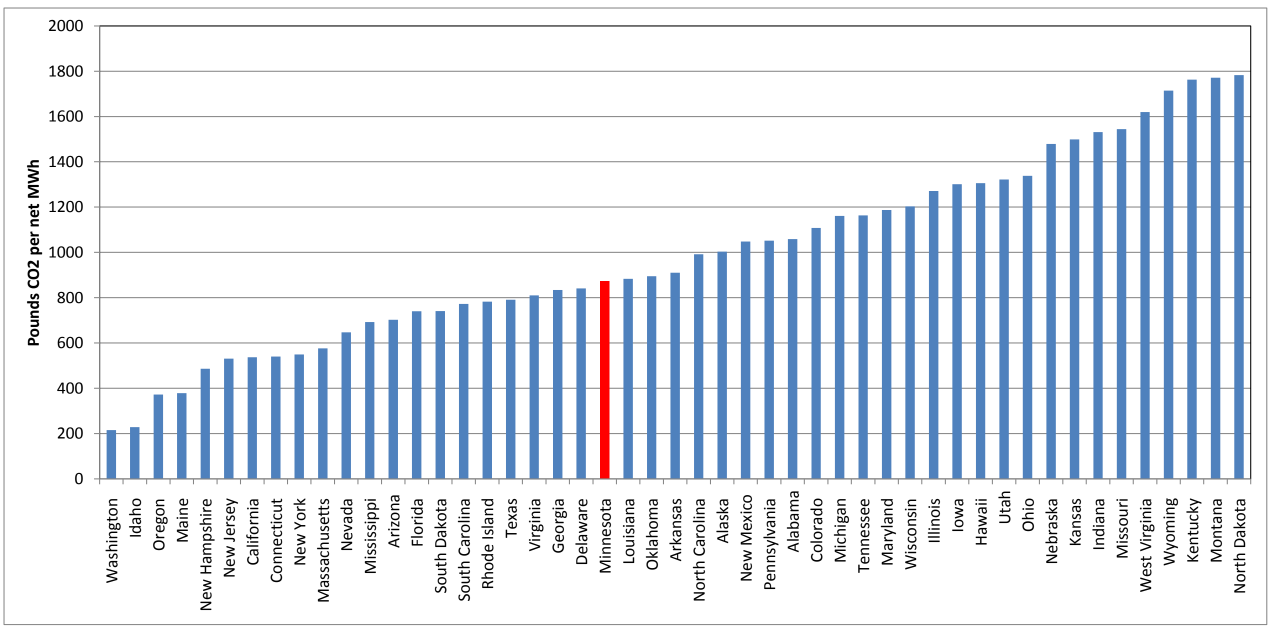

Figure 16. Proposed State Goals for Carbon Dioxide Emissions Reduction by 2030, Clean Power Plan

Source: FVB analysis using data from Federal Register, Vol. 79, No. 117, June 18, 2014.

CHP could be a powerful tool for Minnesota in meeting emission reduction goals and should be considered as Minnesota crafts its compliance plan. Minnesota could achieve emission reductions by recovering waste heat in existing power plants or by implementing highly efficient new CHP production, allowing reductions in high-emissions power generation in affected power plants.

It will not be cost-effective to recover waste heat from every affected power plant, but some plants could be retrofitted for CHP, which would improve the plant heat rate and reduce total CO_2 emissions. Heat can be effectively transported long distances with current hot water district heating piping technology.

Even greater potential exists to reduce power plant emissions by constructing new CHP plants to supply heat and power to industry and buildings. District energy systems can play a crucial role in implementing new CHP plants. These systems pool the thermal users to accommodate larger, more cost-effective CHP units. Economies of scale make it more cost-effective to install CHP in sizes above 5 MW, which is why district energy systems are critical to increased CHP implementation. Widespread district energy use is the reason that countries like Denmark and Finland have high levels of CHP.

Construction of new CHP plants will result in avoidance of emissions from affected EGUs by substituting CHP power for generation from those units, whether the CHP power is delivered to the grid or allows a reduction in purchases from the grid. CHP can deliver significant CO_2 reductions, as shown in Figure 17, which compares CHP and power-only plants relative to CO_2 emissions per unit of useful energy. The CHP emissions were calculated by dividing the CO_2 emissions of the CHP plant by the sum of the electricity output and 75 percent of the thermal output.

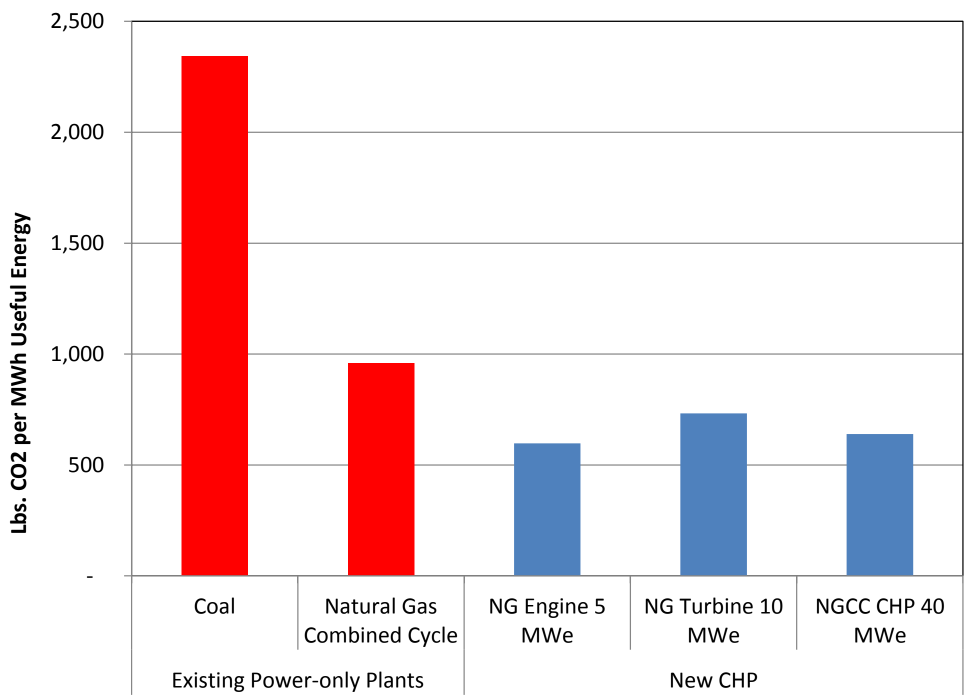

Figure 17. Comparison of Carbon Dioxide Emissions From Power-Only and CHP Plants

Source: FVB Energy analysis

Straw Man Report and Stakeholder Consultation

A "Straw Man" draft report was prepared which: 1) summarized existing Minnesota policies; 2) described CHP barriers and the analysis of the economic significance of key variables; 3) outlined draft Policy Options; and 4) addressed issues associated with the Policy Options.

Informal stakeholder consultations were conducted following distribution of the Straw Man report, including discussions with electric utilities, gas utilities, thermal utilities, equipment suppliers, customers, advocacy groups and consultants.

See Appendix C for the Straw Man report and Appendix D for notes from the stakeholder consultations.

The informal stakeholder discussion provided a wide range of input but a number of common themes. Both electric and gas utilities, and other stakeholders, noted the relatively weak customer interest in CHP, and the barriers posed by limited expertise, resources and time available to customers to develop CHP projects. Disparities in CHP opportunities between utility service territories were noted multiple times.

Utilities were generally unenthusiastic about new goals or mandates.

Many stakeholders recognized the benefits of using low utility WACC to finance CHP systems, as well as the benefits of creating incentives for electric utilities to promote and implement CHP rather than discourage it. Utility/ratepayer risks related to utility ownership of CHP were frequently discussed.

There was almost universal recognition of the potential synergy between state CHP policy and planning for compliance with Clean Power Plan.

Multiple stakeholders noted the opportunity to recover waste heat from existing power plants, and the essential role that district energy system play in distributing the heat (or cooling produced using the recovered heat).

There was strong support for a requirement that electric utilities evaluate CHP in Integrated Resource Planning.

Utilities noted the high level of opt-outs as a potential barrier to using the CIP as a major policy for driving CHP. Utilities and others noted the lack of clarity in current statutes relative to the role of CHP in CIP, including potential confusion regarding whether CHP is a supply side or demand side option.

Multiple stakeholders noted the challenges of funding capital incentives for CHP within CIP given the "lumpiness" of CHP projects, i.e., there may be no projects for a number of years, and then a large project may finally reach fruition.

Policy Options

Following the stakeholder consultation, modifications were made to the Policy Options based on stakeholder feedback and additional analysis. Table 28 provides an overview of the revised Policy Options on which further analysis was undertaken in this study. The section describes the revised Policy Options. The subsequent section addresses detailed analysis of potential issues relating to the Policy Options.

Policy Option groups 1 and 2 are based on natural gas and electric utility Conservation Improvement Program (CIP) incentives targeted at end-users. Specific Policy Options were modeled with either capital incentives, operational incentives, or a combination of both capital and operating incentives.

Policy Option group 3 focused on CIP incentives for utility ownership of CHP, with the utility using its low WACC to fund CHP systems and would be able to gain CIP credit for the CHP operations, This option also provides for operating incentives for CHP implemented by customers or third parties.

In Policy Option 4 it is assumed that a specific carve-out is made for bioenergy CHP[18] in either the existing Renewable Portfolio Standard (RPS) or an expanded RPS.

Policy Option group 5 addresses the potential to create a new Alternative Portfolio Standard (APS) which would require electric utilities to obtain a specified percentage of sales from CHP by a given year.

[18] Bioenergy is an inclusive term that encompasses: 1) biomass combustion CHP (in which wood or other biomass is combusted to produce steam that is used to spin a steam turbine-generator or an organic rankine cycle turbine-generator; 2) internal combustion engine or combustion turbine CHP using gaseous or liquid fuel produced from biomass such as manure, agricultural residues, sewage sludge, etc.

		Conservation Improvement Program					Renewable Portfolio Standard		Alternative Portfolio Standard	
		CIP Incentives for Customer- or Third Party-Owned CHP	CIP Credit to Utilities for Utility-Implemented CHP	CHP requirements in separate new CIP tier (% of sales each year)			Bioenergy CHP requirement (% of sales by 2030)		CHP requirement (% of sales by 2030)	
Policy Option Summary	Option #			Natural Gas	Electric IOUs	Electric Munis & Coops	Electric IOUs	Electric Munis & Coops	Electric IOUs	Electric Munis & Coops
Gas Utility CIP with Incentives for Customer- or Third Party-Implemented CHP	1.1	Capital Incentive ($100 per 1000 Btu/hr)	N/A	0.10%	N/A	N/A	N/A	N/A	N/A	N/A
	1.2	Operating Gas Rate Discount ($0.75/MMBtu, 15 yrs)	N/A	0.10%	N/A	N/A	N/A	N/A	N/A	N/A
	1.3	Capital and Operating Incentives in Options 1.1 and 1.2	N/A	0.15%	N/A	N/A	N/A	N/A	N/A	N/A
Electric Utility CIP with Incentives for Customer- or Third Party-Implemented CHP	2.1	Capital Incentive ($500 per kW)	N/A	N/A	0.20%	0.08%	N/A	N/A	N/A	N/A
	2.2	Operating Electric Rate Discount ($10 per MWh, 15 yrs)	N/A	N/A	0.20%	0.08%	N/A	N/A	N/A	N/A
	2.3	Capital and Operating Incentives in Options 2.1 and 2.2	N/A	N/A	0.30%	0.12%	N/A	N/A	N/A	N/A
Gas Utility with Customer Incentives Plus CIP Credit for Utility Owned CHP	3.1	Same as Option 1.2	$0.75 per MMBtu gas supplied to CHP, 15 yrs	0.23%	N/A	N/A	N/A	N/A	N/A	N/A
Electric Utility with Customer Incentives Plus CIP Credit for Utility Owned CHP	3.2	Same as Option 2.2	$10 per MWh of CHP electricity produced, 15 yrs	N/A	0.45%	0.18%	N/A	N/A	N/A	N/A
RPS carve-out for bioenergy CHP in existing or expanded RPS	4	N/A	N/A	N/A	N/A	N/A	1.50%	0.60%	N/A	N/A
New Alternative Portfolio Standard for CHP	5.1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	8.00%	3.20%
	5.2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	12.00%	4.80%

Notes:

CIP = Conservation Improvement Program	MWh =MegaWatt-hour
IOU = Investor-Owned Utility	kW = kiloWatts
Muni = Municipal Utility	RPS = Renewable Portfolio Standard
Coop = Cooperative	APS = Alternative Portfolio Standard
MMBtu = milion British Thermal Units	IRP = Integrated Resource Planning

Table 28. Overview of Policy Options

Conservation Improvement Program

Current Law

Minnesota's Conservation Improvement Program (CIP), in effect an Energy Efficiency Resource Standard without tradable certificates, is a potential mechanism for encouraging implementation of CHP. H.F.729, passed in 2013, modified the definition of "energy conservation improvement" in Minnesota Statutes 2012, section 216B.241 to include "waste heat recovered and used as thermal energy," which is then defined as "capturing heat energy that would otherwise be exhausted or dissipated to the environment from machinery, buildings, or industrial processes and productively using such recovered thermal energy where it was captured or distributing it as thermal energy to other locations where it is used to reduce demand side consumption of natural gas, electric energy, or both." (H.F. 729)

H.F. 729 also includes Subd. 10 as follows:

> *'(Waste heat recovery; thermal energy distribution). Demand side natural gas or electric energy displaced by use of waste heat recovered and used as thermal energy, including the recovered thermal energy from a cogeneration or combined heat and power facility, is*

eligible to be counted towards a utility's natural gas or electric energy savings goals, subject to department approval.'

The following discussion addresses the question: Does Minnesota Statute 216B.241, as modified by H.F.729, includes CHP as an energy conservation measure that could be incorporated into natural gas or electric utility Conservation Improvement Programs?

1. Prior to H.F. 729, CHP bottoming cycles[19] appear to already be included in Minnesota Statute 216B.241Subd. 1 ("Energy conservation improvement may include waste heat that is recovered and converted into electricity…).

2. CHP topping cycles[20] were added in H.F.729. Article 13, Section 2, Subd. 1, part (e) states "Energy conservation improvement also includes waste heat recovered and used as thermal energy." The definition of "waste heat recovered and used as thermal energy" in Subd. 1, part (n) describes topping cycle CHP, although the phrasing is unconventional. CHP does indeed capture heat energy for useful purposes that would otherwise be exhausted or dissipated to the environment from buildings or industrial processes.

3. One could debate whether there might be an implied condition or caveat, e.g. "….from 'normal' or 'basic' building systems or industrial processes. However, it is clear that if, for example, a building installs an internal combustion engine to generate power and it recovers and uses the waste heat:

    - Such an installation is CHP; and
    - It meets the definition of "waste heat recovered and used as thermal energy".

4. Subd. 10 states that demand side natural gas or electricity savings can be counted toward a utility's natural gas or electricity reduction goal. This could be interpreted to mean that such savings can be counted toward the utility's goal but that CIP funds should not be expended on such projects. However, it is uncertain whether the legislature intended to give "credit" to a utility for something that utility did nothing to implement. Further, the rationale articulated in point 2 above would make CHP an "energy conservation measure" and in Minnesota Statutes 216B.241, utilities can invest in energy conservation measures.

5. The law lacks clarity regarding how electric utilities should count the energy savings. While the construction of Subd. 10 suggests a (logical) parallel – reduced demand side natural gas or electric energy can be counted by the respective utility type (natural gas or electric), the logic breaks down when we come to in the phrase "natural gas or electricity *displaced by the use of waste heat* recovered and used as thermal energy… (Emphasis added.)

6. Certainly, recovery and use of waste heat will displace boiler fuel consumption to produce the heat required by the end user, and in most cases that fuel would be natural gas (although in some instances it could be residual fuel oil, distillate fuel oil, propane or other fuel). Thus, relative to natural gas utilities it is reasonably clear how to count the savings.

7. Waste heat can be used to produce cooling using absorption chillers or steam turbine chillers, but the magnitude of the economically practical potential is limited.

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[19] A bottoming cycle converts waste heat to electricity through, for example, organic rankine cycle technology.

[20] A topping cycle recovers waste heat from electricity generation for use as thermal energy.

8. Technically, an electric utility could displace electricity consumption through recovery and distribution of waste heat. Practically, however, this is not a realistic scenario because CHP heat must be delivered in the form of hot water or steam and would require expensive building conversion investments to convert from electric heat.

9. Based on the reasoning articulated in point 2, CHP is an energy conservation measure. Relative to Subd. 10, CHP will reduce demand side consumption of boiler fuel, usually natural gas, in the process of generating electricity. CHP would reduce demand side electric energy, in the process of generating thermal energy, because the CHP host would displace electricity purchased from the utility with electricity generated through CHP.

10. Methodological questions remain regarding the appropriate calculation of savings in either situation (fuel savings when power generation is considered the base activity, and electricity savings when thermal production is considered the base activity), but these are solvable questions of implementation.

11. Conclusion: There is a reasonable argument that, in sum, Minnesota Statutes 216B.241 as modified by H.F.729 includes CHP as an energy conservation measure, and that either natural gas or electric utilities could count the respective natural gas or electricity consumption reductions in their CIP resulting from: incentives provided by the utility to encourage customer- or third party-financed CHP; or from direct utility investment in CHP at customer sites.

CIP Policy Options for Minnesota

CIP Policy Options and related potential CIP goals are outlined below, following by an analysis of the implications of the potential CIP goals relative to levels of CHP implementation achieved in MegaWatts (MW) of CHP capacity.

Natural Gas Utility CIP

Policy Options 1.1 and 1.2 would establish a new, separate CHP tier in natural gas utility CIP goals equal to 0.10 percent of annual sales.

Policy Option 1.1 would provide a natural gas utility capital incentive following successful commissioning of the system, equal to $100 per thousand Btu of CHP thermal energy output. The impact of this type of incentive on reduction of capital costs for each size category of CHP is shown in Table 29. This table shows that Policy Option 1.1 would provide capital incentives that equate to relatively higher percentages for larger CHP plants than smaller ones. This is due primarily to the fact that larger facilities generally have lower capital costs per unit of thermal output capacity.

	$100 per 1000 Btu/hr thermal output capital incentive
Natural Gas	
30-500 kW	9%
500 kW - 1 MW	10%
1 - 5 MW	14%
5 - 20 MW	25%
> 20 MW	26%

Table 29. Policy Option 1.1 – Capital Incentive Based on Thermal Energy Production Capacity (% of total capital cost)

Policy Option 1.2 would provide a natural gas utility operating incentive equal to $0.75 per MMBtu of CHP thermal energy output verified annually each year for 15 years. This level was selected by multiplying the average natural gas CIP expenditure over the last three years (see Table 15) by 80 percent and rounding to the nearest $0.05.

While the examples of operating incentives in other states are quite short term (up to 2 years), a long-term operating incentive is more consistent with the asset life and can be consistently incorporated into the investment financial analysis and operating budget. A long term incentive will also help ensure that the facility continues to be run. Further, spreading the incentive out will help smooth out utility expenditures for CHP CIP.

Policy Option 1.3 would combine the capital and operating incentives of Options 1.1 and 1.2, and would establish a new, separate tier to natural gas CIP goals equal to 0.15 percent of annual sales.

Electric Utility CIP

Policy Options 2.1 and 2.2 would establish a new, separate CHP tier in electric utility CIP goals equal to 0.20 percent and 0.08 percent of annual sales for IOUs and Cooperatives/Municipal utilities, respectively.

Policy Option 2.1 would provide an electric utility capital incentive following successful commissioning of the system, equal to $500 per kW of CHP thermal energy output. The impact of this type of incentive on reduction of capital costs for each size category of CHP is shown in Table 30. This table shows that Policy Option 2.1 would provide capital incentives that equate to relatively higher percentages for larger CHP plants than smaller ones. This is due primarily to the fact that larger facilities generally have lower capital costs per unit of electric output capacity.

	$500 per kW capital incentive
Natural Gas	
30-500 kW	13%
500 kW - 1 MW	13%
1 - 5 MW	17%
5 - 20 MW	27%
> 20 MW	40%
Biomass	
1 - 5 MW	9%
5 - 20 MW	12%
> 20 MW	18%

Table 30. Policy Option 2.1 – Capital Incentive Based on Electricity Production Capacity (% of total capital cost)

Policy Option 2.2 would provide an electric utility operating incentive equal to $10 per MWh of CHP electricity output verified annually each year for 15 years. This level was selected by multiplying the average electric utility CIP expenditure over the last three years (see Table 14) by 80 percent and rounding to the nearest $1.00.

Policy Option 2.3 would combine the capital and operating incentives of Options 2.1 and 2.2, and would establish a new, separate CHP tier in electric utility CIP goals equal to 0.30 percent and 0.12 percent of annual sales for IOUs and Cooperatives/Municipal utilities, respectively.

CIP with Utility Ownership Focus

As previously discussed, deploying the relatively low WACC of utilities has the potential to significantly increase implementation of CHP. To this end, Policy Options 3.1 and 3.2 address the potential for financing of CHP natural gas utility and electric utilities, respectively, for inclusion in their respective rate bases.

Policy Option 3.1 (natural gas utilities) would include:

- Operating incentives of Option 1.3 for customer- or third party-owned CHP equal to $0.75 per MMBtu of CHP thermal energy produced over 15 years;
- Provision for gas utilities to earn CIP credit for CHP thermal energy produced by utility-financed CHP systems;
- A new, separate CHP tier in natural gas utility CIP goals equal to 0.23 percent of annual sales.

Policy Option 3.2 (electric utilities) would include:

- Operating incentives of Option 2.3 for customer- or third party-owned CHP equal to $10 per MWh of CHP electricity produced over 15 years;

- Provision for electric utilities to earn CIP credit for CHP electricity produced by utility-financed CHP systems;
- A new, separate CHP tier in electric utility CIP goals equal to 0.45 percent and 0.18 percent of annual sales for IOUs and Cooperatives/Municipal utilities, respectively.

Renewable Portfolio Standard

Policy Option 4 would establish, within the existing or an expanded RPS, specific carve-outs for bioenergy CHP as follows:

- IOUs would have to achieve 0.30 percent and 1.35 percent of sales by 2020 and 2030, respectively.
- Cooperatives and municipal utilities would have to achieve 0.12 percent and 0.54 percent of sales by 2020 and 2030, respectively.

Alternative Portfolio Standard

Policy Options 5.1 and 5.2 would establish a new Alternative Energy Portfolio Standard, with Option 5.1 setting lower goals and Option 5.2 setting higher goals.

Option 5.1 would require that:

- IOUs would have to achieve 2.0 percent and 8.0 percent of sales by 2020 and 2030, respectively.
- Cooperatives and municipal utilities would have to achieve 0.8 percent and 3.2 percent of sales by 2020 and 2030, respectively.

Option 5.2 would require that:

- IOUs would have to achieve 3.0 percent and 12.0 percent of sales by 2020 and 2030, respectively.
- Cooperatives and municipal utilities would have to achieve 1.2 percent and 4.8 percent of sales by 2020 and 2030, respectively.

Requirements for cooperatives and municipal utilities were set at lower levels than for IOUs to account for the relatively fewer CHP opportunities in the more rural areas served by coops/munis.

Integrated Resource Planning

One additional option was analyzed that should be considered a complement to, rather than a substitute for, other options. This option would require electric utilities to demonstrate that, before power-only capacity is proposed, CHP opportunities within their service territory have been thoroughly assessed to determine the benefits of CHP relative to total primary energy efficiency, GHG emissions, power grid resiliency, peak demand management and risk management. Analysis was performed with assumed GHG values of \$20, \$40 and \$60 per metric tonne CO2 equivalent.

Policy Analysis

This section: 1) analyzes program design issues in light of stakeholder input; 2) summarizes the estimated impact of Policy Options on implementation of CHP (with further detail provided in the companion report "Assessment of the Technical and Economic Potential for CHP in Minnesota"); 3) calculates the impact of Policy Options on participants and society for example CHP projects; and 4) draws conclusions regarding the suitability of the policy options for Minnesota.

Separate Tier

Minnesota electric and gas utilities have largely met the CIP savings goals established for them, as discussed under "Current Minnesota Policies and Program." In stakeholder discussions, both gas and electric utilities have noted that, having previously addressed the "lowest hanging fruit" relative to efficiency opportunities, the next increments of efficiency will be harder and more expensive to find. In that context, the incorporation of CHP into CIP under the existing goals might be attractive to utilities. On the other hand, based on stakeholder feedback, some stakeholders believe there remain significant opportunities for further end-use efficiency investments. On balance, we believe that if CIP is to be a key vehicle for Minnesota CHP policy, the best way forward would be to establish an additional, separate tier for CHP within CIP programs.

Demand Side or Supply Side

Classification of CHP as a demand-side or supply-side resource is challenging because CHP produces two forms of energy (electricity and heat), thereby affecting customer demand of both electricity and boiler fuel. Topping cycle CHP decreases customer consumption of boiler fuel for thermal production, but this is more than offset by the increase in fuel consumed for CHP. Bottoming cycle CHP decreases customer consumption of electricity, but generally will not decrease customer consumption of natural gas because the temperature of the thermal output from ORC is usually too low to be usable as a substitute for heat produced from a boiler.

The net impact of various CHP technologies on customer natural gas consumption is illustrated in Figure 18, expressed as a percentage of the offset fuel consumption for thermal production. The abbreviations used in this figure for the technologies are explained in Table 23 above.

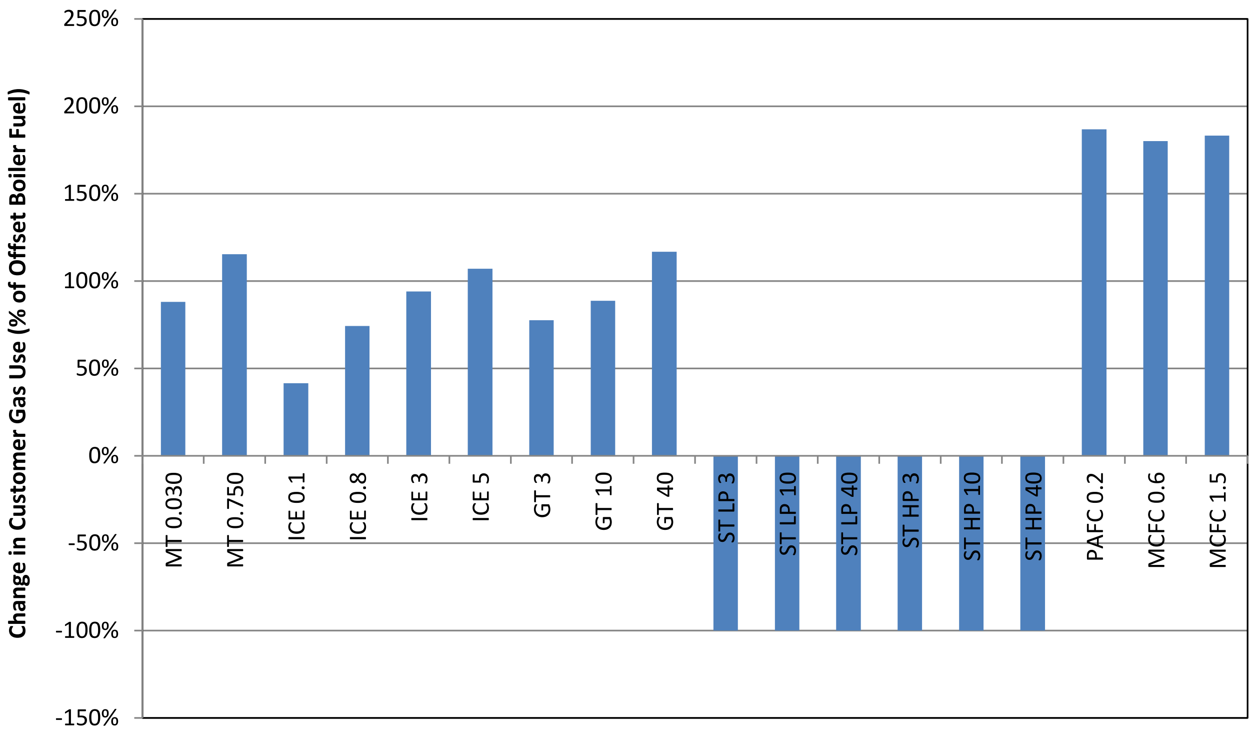

Figure 18. Net Change in Customer Natural Gas Use as Percent of Offset Boiler Fuel Use

The results in Figure 18 show higher increases in on-site natural gas use with CHP technologies with relatively high Power to Heat Ratio (PHR). This is most evident with fuel cells. Given that the steam turbine technologies are assumed to be fueled with biomass but offset thermal production with natural gas, there is a 100 percent reduction in on-site fuel use with CHP.

In addition, CHP reduces fuel consumption for power-only plants operated by the electric utility. Utility power generation fuel efficiency assumptions are discussed under “Avoided Costs of Power Generation” in Appendix E.

Figure 19 shows the combined impact of CHP on customer natural gas use and electric utility natural gas use, expressed as a percentage of offset customer natural gas consumption for thermal production. Once offset grid generation is included, the impact on overall fuel consumption changes dramatically. All CHP technologies result in net decreases in total fuel use.

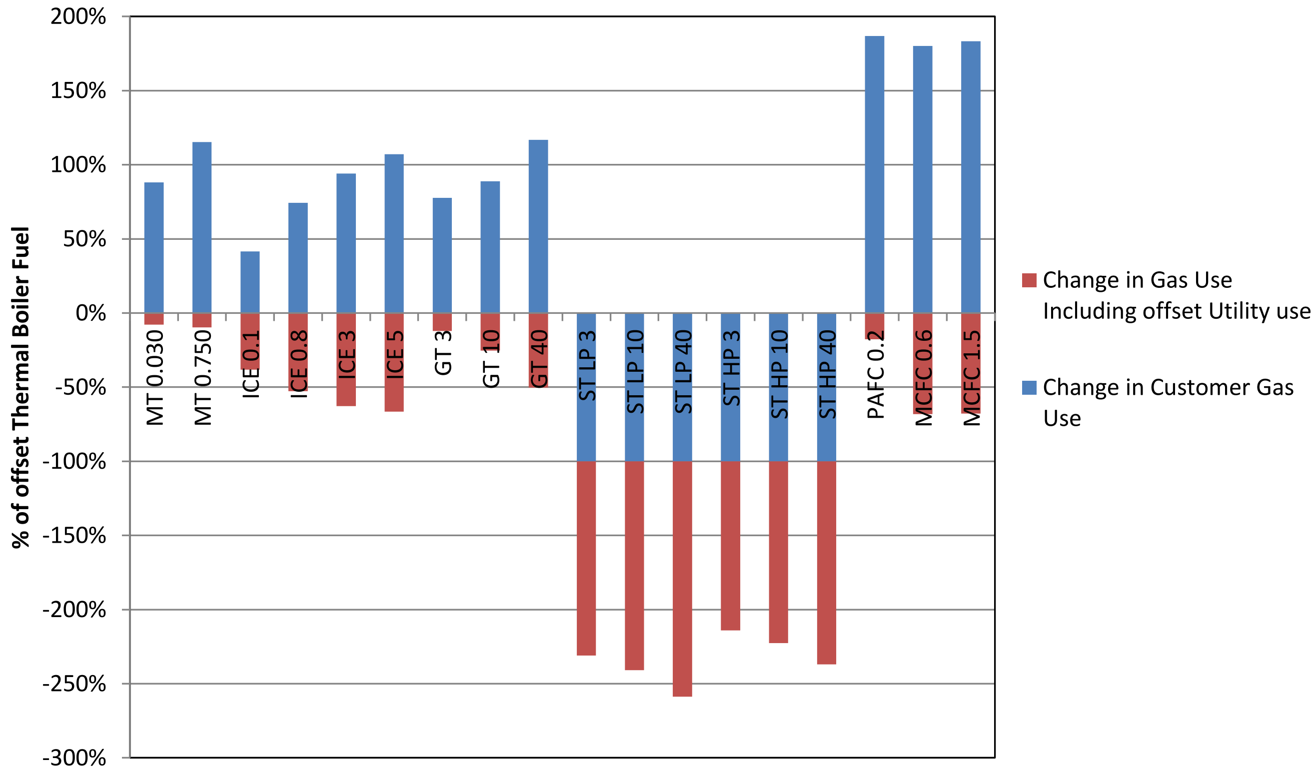

Figure 19. Net Change in Customer and Electric Utility Natural Gas Use as Percent of Offset Boiler Fuel Use

Assessing the energy impact of CHP is also made more difficult because CHP-produced electricity and heat can be used directly or can be converted to meet a range of end-use energy requirements. For example, CHP electricity output can be used to produce chilled water for air conditioning or process cooling. CHP heat output can also be used to produce chilled water for air conditioning or process cooling through absorption chillers or steam turbine drive chillers.

“Demand-side” is often defined as decreases in end-use energy consumption. Natural gas and electricity are not end-use energy needs. They are a means to an end, and are used to meet end-use needs as such as space heating, domestic hot water, air conditioning, process heating, process cooling and a whole range of electrical plug loads including lights, computers, etc. The CIP law does not address end-use energy consumption, but rather energy supplied to customers to meet end-use energy needs.

Uncertainty about whether CHP is demand-side or supply-side stems from a lack of clarity in Minnesota Statutes 216B.241 (hereinafter “the CIP law”) relative to definitions, including a lack of clarity relative to boundaries between utilities, customers and potential third parties. For example:

- Minnesota Statutes 216B.241 Subd. 1(e) defines "Energy conservation improvement" as “a project that results in energy efficiency or energy conservation.”
- Minnesota Statutes 216B.241 Subd. 1 (f) defines "Energy efficiency" as “measures or programs, including energy conservation measures or programs, that target consumer behavior, equipment, processes, or devices designed to produce either an absolute decrease

in *consumption* of electric energy or natural gas or a decrease in *consumption* of electric energy or natural gas on a per unit of production basis without a reduction in the quality or level of service provided to the energy consumer." (*Emphasis* added.)

- The word "consumption" in Subd. 1(f) could refer to end-use needs or to consumption of utility-supplied electricity. However, we conclude that "consumption" refers to consumption of utility-supplied electricity because:
    - Subd. 1(e) states "Energy conservation improvement may include waste heat that is recovered and converted into electricity….." This provision allows a new energy *supply* (conversion of heat to electricity) to be considered an energy conservation improvement. Such a scenario does not reduce *end-use consumption of electricity*, but it does reduce *consumption of grid-supplied electricity*.
    - Subd. 1(e) also states "Energy conservation improvement also includes waste heat recovered and used as thermal energy." This provision allows a new end-use energy *supply* (recovered waste heat) to be considered an energy conservation improvement. That supply of recovered waste heat may occur within the boundaries of utility customer facilities, or it may originate from a third party, such as a district heating provider.

One entity's demand is another's supply. The impact of CHP-produced electricity and heat can be characterized as demand-side or supply-side depending on where the boundaries between "demand" and "supply" are drawn relative to five types of entities:

- Electric utility;
- Electric utility customer;
- Natural gas utility;
- Gas utility customer; and
- Third party CHP plant operator that distributes thermal energy to other utility customers.

Extending the boundaries further, the electric utilities and the gas utilities obtain their natural gas supply from a nationwide gas supply network. This further complicates the distinction between supply and demand.

On balance, we conclude that the Minnesota CIP law fundamentally approaches "demand" and "supply" as referring to energy commodities (natural gas or electricity) crossing the boundary between the utility and the customer, and that CHP can appropriately be viewed as a demand-side resource for both natural gas and electric utilities. This conclusion is based on the following reasoning:

<u>Relative to natural gas utilities --</u>

- CHP is clearly a demand-side resource where CHP heat displaces natural gas. Recovery and use of waste heat through CHP will displace boiler fuel consumption to produce the heat required by the end user, and in most cases that fuel would be natural gas. However, as noted in the analysis presented above—
    - o CHP also generally results in increased customer demand for gas due to the additional fuel required to produce electricity as well as heat;
    - o CHP reduces electric utility fuel consumption, which we assume will likely be natural gas; and
    - o CHP reduces total fuel consumption.

Relative to electric utilities --

- An initial reading of the CIP law suggests that CHP is not a demand-side resource based on the definition of demand-side as reduction in *end-use consumption* of electricity. For example:
  - CHP can displace electricity consumption through recovery of waste heat through use of CHP heat to drive absorption or steam turbine chillers. However, CHP-heat-driven cooling will not be a major element in implementing a CHP project in Minnesota.
  - It is also technically possible to displace electricity through use of heat produced from CHP; however, practically this is not a realistic scenario. Heat produced from CHP is almost never an economically feasible replacement for electric heat because CHP heat must be delivered through hot water or steam.
- However, the CIP law as a whole indicates that the "decrease in consumption of electric energy" that is the objective of the CIP law for electric utilities should be viewed as consumption of electricity *supplied from the utility grid*. CHP reduces demand side electric energy, in the process of generating thermal energy, because the CHP host would displace electricity purchased from the utility with electricity generated through CHP.

Crediting Mechanisms

CHP Power

One of the challenges faced by states considering CHP within portfolio standards is the method by which the CHP savings is calculated and credited. No standard accounting approach has emerged. Appendix E describes and analyzes a range of alternative crediting methods to calculate the number of credited MWh of CHP electricity generation.

As discussed in Appendix E, of the existing methodologies analyzed, the NRDC/OEC methodology is the most promising approach for crediting CHP electricity generation, because it: 1) incentivizes all prime mover technologies and does not pick technology winners; 2) encourages project developers to design higher-efficiency installations, regardless of the prime mover technology; 3) is relatively simple to administer and implement, as it requires only a simple calculation of overall system efficiency based on readily available inputs (and minimizes issues surrounding heat-rates).

However, a simpler and more stringent approach with higher thresholds and fewer tiers would create more incentive for high-efficiency systems and would be even less complex to administer. A recommended approach for gas-fired CHP is shown in Table 31.

Tier	Efficiency (HHV)	Portion of kWh output credited
	<60%	0%
Tier 1	>60<70%	80%
Tier 2	>70<80%	90%
Tier 3	>80%	100%

Table 31. Simplified Approach to Crediting Natural Gas CHP Electricity Production

CHP Thermal

If CHP becomes a part of natural gas utility CIP, the author recommends calculating natural gas savings for CIP credit as equal to total fossil fuel savings. Note that some of the fuel savings from offset grid power production may come from fuels other than natural gas (primarily coal). Note also that in some relatively limited cases the fuel savings from offset thermal boiler operations may come from fuels other than natural gas (primarily fuel oil). However, given the public policy benefits of reducing use of such non-natural-gas fuels, the author recommends that all such fuel savings count toward natural gas reduction goals.

Incentive Levels

Over the last three years, average electric utility CIP expenditures have been $12.74 per lifetime MWh saved (see Table 14). Over the last three years, average natural gas utility CIP expenditures have been $0.93 per lifetime MMBtu of natural gas saved (see Table 15). For the operating incentives in the policy options:

- Average electric utility CIP expenditure levels have been multiplied by 80 percent (to provide an allowance for program overhead) and rounded to the nearest $/MWh.
- Average gas utility CIP expenditure levels have been multiplied by 80 percent (to provide an allowance for program overhead) and rounded to the nearest $0.05 per MMBtu.

For the capital incentives in the policy options:

- The electric utility capital incentive was set to be equivalent to the operating incentive at a 12 percent WACC;
- The gas utility capital incentive was set to be equivalent to the operating incentive for 3-5 MW reciprocating engine CHP at a 12 percent WACC.

Potential Impacts

Effectiveness in Achieving Growth of CHP

In this report we summarize the results presented in detail in the companion report "Assessment of the Technical and Economic Potential for CHP in Minnesota," focusing on projected CHP implementation by the year 2030.

Prior to estimating the impact of Policy Options on CHP market penetration, ICF modeled Base Case market penetration for gas-fired CHP (i.e., additional gas-fired CHP that would be expected to occur in the absence of new policies). The Base Case modeling assumed the Average Acceptance curve[21] that has been found to represent typical investment behavior based on payback criteria. In addition, ICF was asked to run the Base Case a second time, with no new policies but substituting a Strong Acceptance curve that represents payback thresholds of strongly motivated and informed decision-makers. Further, FVB provided an estimated Utility Acceptance curve that was designed to be consistent with utility cost of capital. The results of these three estimates, quantified in MW of gas-

[21] The acceptance curves are fully described in the companion report "Assessment of the Technical and Economic Potential for CHP in Minnesota," FVB Energy and ICF International, 2014.

fired CHP by 2030, are shown in Figure 20. These results clearly demonstrate the critical impact of WACC.

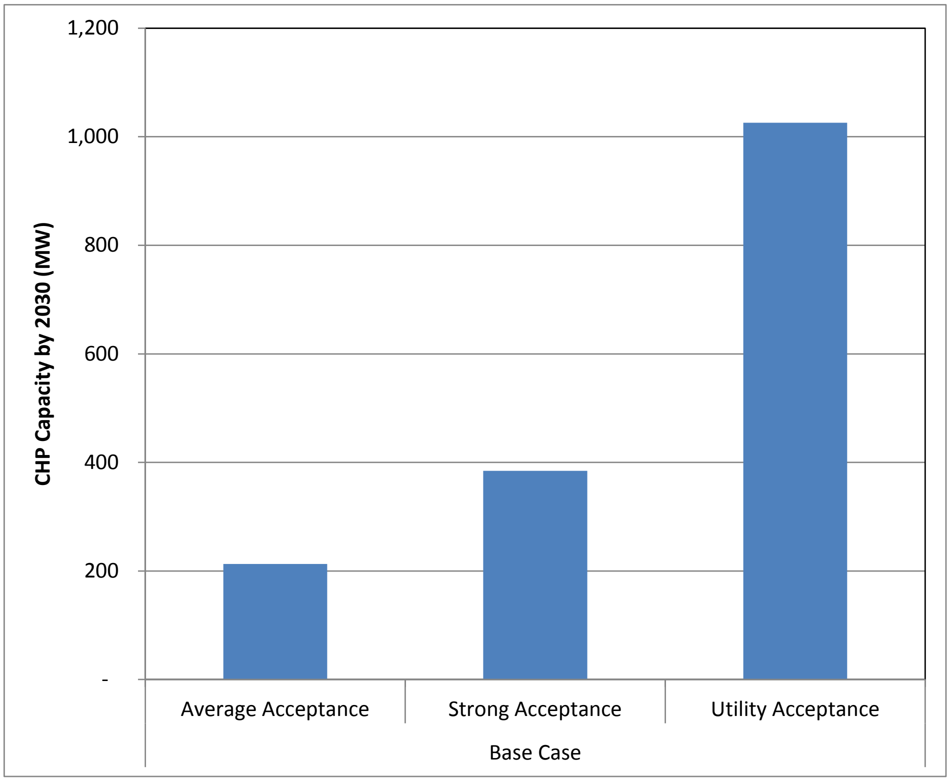

Figure 20. Projected 2030 CHP Market Penetration Without New Policies Under 3 Acceptance Curves

Modeling of the Policy Options was then undertaken, with the Average Acceptance curve assumed in all scenarios except 3.1 and 3.2. Only natural gas CHP was included in gas utility program scenarios. In addition to ICF's estimates of gas-fired CHP, FVB projected bioenergy CHP for scenarios other than gas utility program scenarios. The results are summarized in Figure 21.

The raw results from the ICF model using the Utility Acceptance curve resulted in very high numbers (up to 2,000 MW by 2030). This magnitude of CHP is unlikely to be achievable with the high capacity factors needed for sound CHP economics. Further, Policy Options 3.1 and 3.2 were developed with the idea that incentives would be offered to customers or third parties to build CHP, but that utilities would also be encouraged and incented to use their capital to build CHP. The model was not structured to address this diversity of potential decision-makers. Therefore, as discussed in the companion report (FVB Energy and ICF International 2014), the estimates for Policy Options 3.1 and 3.2 were revised downward, with the resulting revised estimates shown in Figure 21.

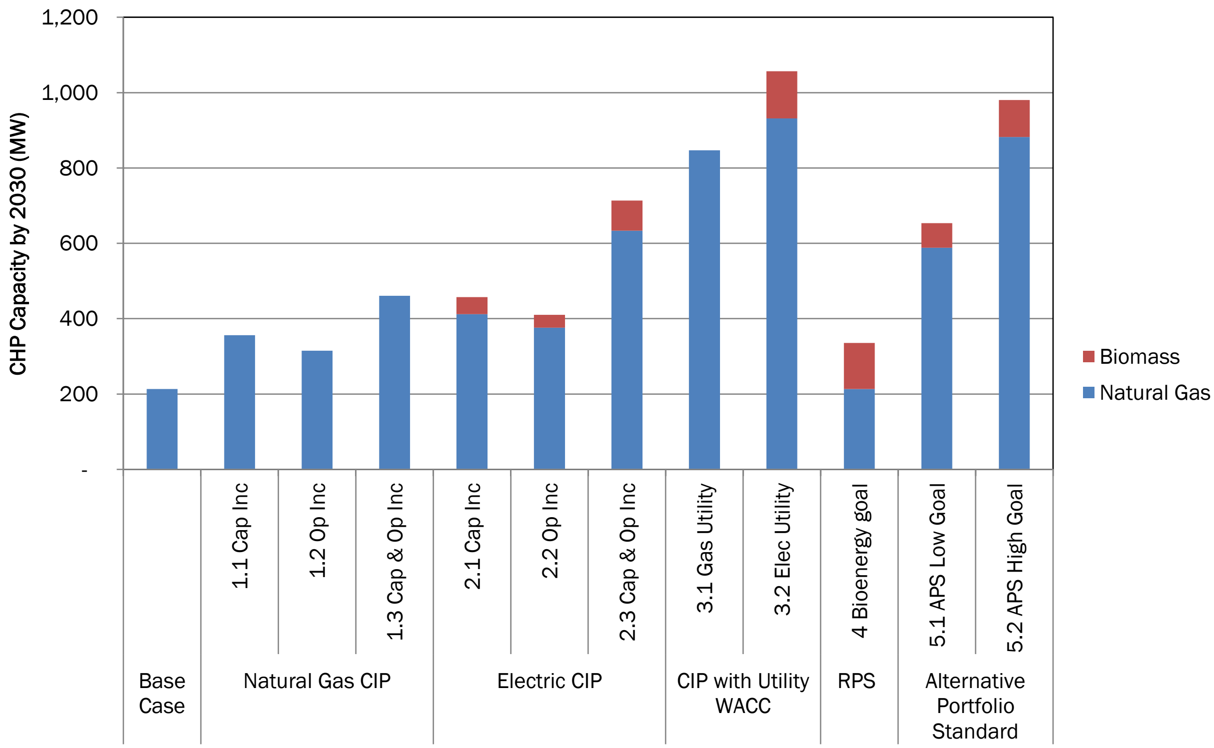

Figure 21. Summary of Estimated 2030 CHP Market Penetration with Policy Options

The potential goals for CHP in CIP, as outlined above, were set to be approximately consistent with the economic potential of CHP as described in more detail in the companion report (FVB Energy and ICF International 2014). The potential goals for the low, medium and high scenarios for gas and electric utilities are summarized in Table 32. Cumulative projected MW of CHP by 2030 range from about 140 to 310 MW for gas utilities and 210 to 470 MW for electric utilities. Additional details from the analysis are shown in Table 33.

	% annual goal		Cumulative CHP (MW) 2020	2030
Natural Gas Utilities				
Low	0.10%		37	140
Medium	0.15%		55	210
High	0.23%		83	314
Electric Utilities	IOUs	Coops/Muni		
Low	0.20%	0.08%	55	208
Medium	0.30%	0.12%	83	312
High	0.45%	0.18%	124	468

Table 32. Cumulative Impact of Potential CIP CHP Goals

											Estimated Total Utility Sales												
		CIP Goals (% of sales)									Natural Gas	Electric			Cumulative CHP Capacity in MW								
		Natural Gas			Electric IOUs			Elec Coops/Munis			Estimated total BCF gas sold *	Estimated total EU power sold (GWH)**	Estimated EU IOU power sold (GWH)**	Estimated EU Other Utilities power sold (GWH)**	Natural Gas Utilities			Electric Utilities			Total		
Year	Policy Status	Low	Medium	High	Low	Medium	High	Low	Medium	High					Low	Medium	High	Low	Medium	High	Low	Medium	High
2015	Pass legislation																						
2016	Program rules																						
2017	First year of goals	0.10%	0.15%	0.23%	0.20%	0.30%	0.45%	0.08%	0.12%	0.18%	306	65,948	39,569	26,379	9	14	20	13	20	30	23	34	51
2018		0.10%	0.15%	0.23%	0.20%	0.30%	0.45%	0.08%	0.12%	0.18%	311	66,938	40,163	26,775	18	27	41	27	41	61	45	68	102
2019		0.10%	0.15%	0.23%	0.20%	0.30%	0.45%	0.08%	0.12%	0.18%	315	67,942	40,765	27,177	28	41	62	41	61	92	69	103	154
2020		0.10%	0.15%	0.23%	0.20%	0.30%	0.45%	0.08%	0.12%	0.18%	320	68,961	41,376	27,584	37	55	83	55	83	124	92	138	207
2021		0.10%	0.15%	0.23%	0.20%	0.30%	0.45%	0.08%	0.12%	0.18%	325	69,995	41,997	27,998	47	70	105	69	104	156	116	174	261
2022		0.10%	0.15%	0.23%	0.20%	0.30%	0.45%	0.08%	0.12%	0.18%	330	71,045	42,627	28,418	56	84	127	84	126	189	140	210	315
2023		0.10%	0.15%	0.23%	0.20%	0.30%	0.45%	0.08%	0.12%	0.18%	335	72,111	43,266	28,844	66	99	149	99	148	222	165	247	371
2024		0.10%	0.15%	0.23%	0.20%	0.30%	0.45%	0.08%	0.12%	0.18%	340	73,192	43,915	29,277	76	114	172	114	170	255	190	285	427
2025		0.10%	0.15%	0.23%	0.20%	0.30%	0.45%	0.08%	0.12%	0.18%	345	74,290	44,574	29,716	86	130	194	129	193	290	215	323	484
2026		0.10%	0.15%	0.23%	0.20%	0.30%	0.45%	0.08%	0.12%	0.18%	350	75,405	45,243	30,162	97	145	218	144	216	324	241	361	542
2027		0.10%	0.15%	0.23%	0.20%	0.30%	0.45%	0.08%	0.12%	0.18%	355	76,536	45,921	30,614	107	161	241	160	240	359	267	400	601
2028		0.10%	0.15%	0.23%	0.20%	0.30%	0.45%	0.08%	0.12%	0.18%	361	77,684	46,610	31,073	118	177	265	176	263	395	293	440	660
2029		0.10%	0.15%	0.23%	0.20%	0.30%	0.45%	0.08%	0.12%	0.18%	366	78,849	47,309	31,540	129	193	290	192	287	431	320	481	721
2030		0.10%	0.15%	0.23%	0.20%	0.30%	0.45%	0.08%	0.12%	0.18%	372	80,032	48,019	32,013	140	210	314	208	312	468	348	522	782
2031		0.10%	0.15%	0.23%	0.20%	0.30%	0.45%	0.08%	0.12%	0.18%	377	81,232	48,739	32,493	151	226	339	225	337	505	375	563	845
2032		0.10%	0.15%	0.23%	0.20%	0.30%	0.45%	0.08%	0.12%	0.18%	383	82,451	49,470	32,980	162	243	365	241	362	543	404	605	908
2033		0.10%	0.15%	0.23%	0.20%	0.30%	0.45%	0.08%	0.12%	0.18%	389	83,687	50,212	33,475	174	260	391	258	388	582	432	648	972
2034		0.10%	0.15%	0.23%	0.20%	0.30%	0.45%	0.08%	0.12%	0.18%	394	84,943	50,966	33,977	185	278	417	276	414	621	461	692	1,038
2035		0.10%	0.15%	0.23%	0.20%	0.30%	0.45%	0.08%	0.12%	0.18%	400	86,217	51,730	34,487	197	296	443	293	440	660	491	736	1,104

* Assumed annual growth in natural gas sales 1.50%
** Assumed annual growth in electricity sales 1.50%

Table 33. Detailed Calculation of Potential CIP CHP Goals

In Policy Options 1.1, 1.2, 2.1 and 2.2, CIP incentives for customer investment in CHP, at levels approximately consistent with recent levels of CIP expenditures per unit of electricity or natural gas saved, are estimated to result in approximately 100 to 240 MW of additional CHP beyond the Base Case. However, most CHP installations do not meet both the PCT and SCT. (See discussion of “Cost-Benefit Tests” below.)

Policy Options 1.3 and 2.3, which provide more substantial CIP incentives (combining capital and operating incentives) for customer investment in CHP, are estimated to result in approximately 250 to 500 MW of additional CHP beyond the Base Case. However, with these policy options improve PCT results, most CHP installations not meet both cost-benefit tests.

In Policy Option group 3, deploying the relatively low Weighted Average Cost of Capital (WACC) of utilities to build CHP significantly enhances CHP economics. These options are estimated to result in approximately 630 to 840 MW of additional CHP beyond the Base Case, with positive results for both cost-benefit tests for a wide range of CHP installations.

With Policy Option 4, establishing a specific “carve-out” for bioenergy CHP in the RPS is estimated to result in about 125 MW of new biomass CHP by 2030. The RPS was not analyzed for the Cost-Benefit tests.

In Policy Option group 5, an Alternative Portfolio Standard is estimated to result in approximately 440 to 770 MW of additional CHP beyond the Base Case (for Low and High APS targets). At the high end of this range, CHP would more than double by 2030.

Although the APS was not directly analyzed for the Cost-Benefit tests, it was indirectly analyzed[22] and is projected to result in positive results for all three major Cost-Benefit tests for wide range of CHP installations.

Table 34 shows the estimated levels of CHP achieved by the years 2020 and 2030 consistent with the Low and High APS scenarios.

		APS Goals		MW CHP	
	Year	IOUs	Coops/Muni	Total	Additional above Base Case
APS Low	2020	2.00%	0.80%	141	66
	2030	8.00%	3.20%	653	440
APS High	2020	3.00%	1.20%	211	137
	2030	12.00%	4.80%	980	767

Table 34. Cumulative Impact of Potential APS Goals

[22] The impacts of the APS were indirectly analyzed by assessing the impacts of CIP operating credits as a proxy for a tradable APS credit.

Cost-Benefit Tests

To assess the impact of the Policy Options, cost-benefit analysis of the Policy Options on selected CHP technologies was undertaken. In our analysis we focus on two tests, which compare costs and benefits for customers (PCT) and society as a whole (SCT). The cost-benefit tests are described in more detail in Appendix E.

The cost-benefit tests were calculated for Policy Option groups 1, 2 and 3. Results of cost-benefit test are summarized in Table 35.

	MT 0.030	MT 0.750	ICE 0.1	ICE 0.8	ICE 3	ICE 5	GT 3	GT 10	GT 40	ST LP 3	ST LP 10	ST LP 40	ST HP 3	ST HP 10	ST HP 40	ORC 1	PAFC 0.2	MCFC 0.6	MCFC 1.5
1.1	no	no	no	no	no	no	no	no	YES							no	no	no	no
1.2	no	no	no	no	no	no	no	no	YES							no	no	no	no
1.3	no	no	no	no	no	no	no	YES	YES							no	no	no	no
2.1	no	no	no	no	no	no	no	no	YES	YES	YES	YES	no	YES	YES	no	no	no	no
2.2	no	no	no	no	no	no	no	no	YES	YES	YES	YES	no	YES	YES	no	no	no	no
2.3	no	no	no	no	YES	YES	no	YES	YES	YES	YES	YES	YES	YES	YES	no	no	no	no
3.1	no	no	YES	YES	YES	YES	no	YES	YES							no	no	no	no
3.2	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES

Table 35. Summary of Cost-Benefit Test Results for Selected CHP Project Types (Both Participants and Society Cost Tests are Positive)

Conclusions

Conservation Improvement Program

As a mechanism for advancing CHP, the CIP has a significant advantage because it is an established program for reductions in electricity and natural gas consumption that is familiar to utilities, stakeholders and state agencies. Further, CIP provides opportunities for incentives ("carrots") for utility adoption of CHP, in contrast to the APS, which relies solely on a "stick" approach. However, there are a range of issues surrounding use of CIP as a mechanism to advance CHP.

There are disparities in CHP opportunities between utilities, particularly limitations in the service territories of municipal utilities and cooperatives. A system of tradable credits would provide a way to address this issue and promote economic efficiency (i.e., result in the lowest costs to society by promoting implementation of CHP at the most cost-effective sites regardless of location).

One concern regarding the CIP is the high level of opt-out and the fact that the opt-outs tend to be the larger energy users who are generally the best candidates for CHP. To the extent that CHP is implemented within CIP primarily through utility ratebase investments, this issue is largely mitigated. However, at least as envisioned in the policy analysis, a CIP credit ($/MWh) would also flow to the CHP project even with utility ownership in order to provide an economic advantage to CHP in dispatching utility resources.

Legislation to establish a CHP tier in CIP would have to resolve the current lack of clarity regarding the potential role of CHP in CIP. Further, the legislation would require resolution of issues of interaction between electric utility CIP and gas utility CIP. For example, if natural gas utilities could include CHP in their CIP, there would be a shift in revenue from the electric utility to the gas utility. This would engender resistance from electric utilities out of concern for impacts on rates. On the other hand, including CHP in both gas and electric utility CIP may result increase the interest of electric utilities in CHP in order to retain revenues.

Decoupling of both gas and electric utility revenues from sales would in concept address concerns related to potential shifts in revenue from one utility to another. (Decoupling is a complex issue that extends far beyond CHP, and was not part of the scope of this study.)

An argument in favor of focusing responsibility for CHP implementation on electric utilities is that it can better facilitate timely and positive resolution of barriers relating to interconnection and standby rates. Further, setting goals for CHP in both electric and gas utility CIP would result in the potential for electric and gas utilities to be competing for the same pool of prospective CHP projects.

Renewable Portfolio Standard

Establishing a specific “carve-out” for bioenergy CHP in the RPS (Policy Option 4) is projected to provide relatively little additional CHP and ignores the largest CHP potential (natural gas CHP). Either the CIP or an APS would be a more effective mechanism for promoting CHP because either approach would not only address renewable CHP but also natural gas CHP, which constitutes the vast majority of the potential.

Alternative Portfolio Standard

Minnesota currently has no Alternative Portfolio Standard (APS), so new legislation would be required to create a new program and related implementation mechanisms. Creation of a new program will likely face greater political and implementation challenges in comparison to expanding an existing program such as CIP.

On the other hand, because the APS would be a new program it may be able to avoid some of the complexities discussed above relative to adapting the CIP to include CHP. An APS can be structured from the beginning as an enforceable standard with clear cost penalties for non-compliance.

Table 4 provides an overview of the major advantages and disadvantage of CIP compared with APS as the major CHP policy mechanism.

	CIP	APS
Advantages	CIP is an established program for reductions in electricity and natural gas consumption that is familiar to utilities, stakeholders and state agencies.	As a new program can avoid some of the complexities related to adapting the CIP to include CHP.
	Provides opportunities for both "carrots" and "sticks" for utility adoption CHP.	
Disadvantages	There are disparities in CHP opportunities between utilities, particularly limitations in the service territories of municipal utilities and cooperatives. (Potential solution: system of tradable credits.)	Legislation would be required to create a new program and related implementation mechanisms. Creation of a new program will likely face greater political challenges in comparison to expanding an existing program.
	Lack of statutory clarity regarding applicability of CHP in CIP. (Solution: clarifying legslation.)	Primariily a "stick" approach.
	Less clear path to enforceablIity than a portfolio standard. (Solution: clear enforcement provisions in legislation.)	
	High level of opt-out and the fact that the opt-outs tend to be the larger energy users who are generally the best candidates for CHP. (Largely mitigated if utility investments in CHP are in rate base.)	

Table 36. Overview of Advantages and Disadvantages of CIP and APS as Major CHP Policy Vehicles

Integrated Resource Planning

Integrated Resource Planning (IRP) can be a useful element in Minnesota CHP policy because it provides a context for: 1) consideration of potential benefits of CHP that currently do not have a market value (GHG emission reductions, grid resiliency, reduced transmission/distribution losses, etc.); and 2) analysis of CHP opportunities in the utility service area in comparison with other resources.

Utility Investment in CHP

A major conclusion of this study is that significant increases in implementation of CHP will require investment by utilities in CHP because:

- Utilities have a sufficiently low weighted average cost of capital to make many CHP projects cost-effective;
- Implementation of CHP will be significantly eased if electric utilities are motivated and incented to provide CHP project planning and engineering, including grid interconnection, and to dispatch CHP units once they are built; and
- CHP has the potential to help utilities comply with upcoming regulations on GHG emissions from power plants.

A number of issues relating to utility investment in CHP must be more closely examined. Such investment at customer sites could result in ratepayer risk in the event that the thermal host goes out of business. The risk profiles of potential thermal hosts vary dramatically, with industrial plants competing internationally at the high end of the risk continuum, and institutional customers (e.g., district energy systems, colleges, universities, hospitals) at the low end. Risks related to CHP should be considered in the context of existing risks to ratepayers, such as cost overruns for refurbishment of conventional power plants, and risks associated with environmental regulations. Potential ratepayer risks associated with utility investment in CHP could be addressed through range of mechanisms, including a return on equity risk premium, a state-funded loss reserve, or other mechanisms.

Recommendations

Near-term Steps

During the balance of 2014, we recommend the following steps:

1. Initiate a robust stakeholder discussion of this report including feedback on policy options for increasing implementation of CHP. (Note: planning for this is already well underway by the Department of Commerce.)

2. Initiate an interagency working group to integrate potential CHP policy with Minnesota's plan to comply with the Clean Power Plan.

3. Develop a draft "Minnesota CHP Policy Act" for consideration by the legislature in 2015.

Either the CIP or an APS can be an effective centerpiece in Minnesota policies to significantly increase CHP, with the focus on facilitating use of the low WACC of utilities to finance CHP projects. On balance, the CIP appears to be a stronger vehicle for increasing CHP if the legislation effectively addresses the disadvantages outlined above. A priority should be placed on successfully adapting the CIP to include CHP, with the APS considered as a back-up approach.

Regardless of whether the CIP or an APS is the primary CHP program, a system of tradable credits will be important to promote economic efficiency (i.e., result in the lowest costs to society by promoting implementation of CHP at the most cost-effective sites regardless of location).

An achievable and readily understood goal for the State of Minnesota is doubling CHP capacity by 2030.

Key provisions for the "Minnesota CHP Policy Act" are recommended below. In addition to the CIP as the centerpiece, additional recommendations are provided relative to integrated resource planning and standby rates.

Minnesota Combined Heat and Power Policy Act

ARTICLE 1. FINDINGS AND GOAL

Subd. 1. FINDINGS. The legislature finds that combined heat and power systems should be encouraged because such systems:

a) Reduce fossil fuel use by recovering heat that is usually wasted as rejected heat in power generation;
b) Reduce emissions of air pollutants and greenhouse gases;
c) Increase energy security and sustainability by reducing dependence on fossil fuels; and
d) Enhance grid resiliency, reduce power line losses and strengthen peak power demand management.

Subd. 2. GOAL. The State of Minnesota establishes a goal of doubling combined heat and power (CHP) capacity from the current 962 MegaWatts (MW) by the year 2030.

ARTICLE 2. CONSERVATION IMPROVEMENT PROGRAM.

Subd. 1. ENERGY CONSERVATION IMPROVEMENT. Minnesota Statutes section 216B.241 Subd. 1(e) is modified by adding:

> *Energy conservation improvement also includes combined heat and power as defined in Subd. 11.*

Subd. 2. COMBINED HEAT AND POWER REQUIREMENTS. Minnesota Statutes section 216B.241 Subd. 1c. is modified by adding the following new paragraphs (c) and (d) and renumbering subsequent paragraphs:

> *(c) Each individual investor owned electric utility shall have an annual CHP energy savings requirement equivalent to 0.45 percent of gross annual retail energy sales unless modified by the commissioner under paragraph (e). This CHP requirement shall be shall be tracked in a category that is separate and distinct from other energy savings goals in this section. The CHP requirements must be calculated based on the most recent three-year weather-normalized average. A utility may elect to carry forward energy savings in excess of 0.45 percent for a year to the succeeding three calendar years. A particular energy savings can be used only for one year's requirement.*
>
> *(d) Each individual municipal electric utility, electric cooperative or association shall have an annual CHP energy savings requirement equivalent to 0.18 percent of gross annual retail energy sales unless modified by the commissioner under paragraph (e). These CHP requirements shall be shall be tracked in a category that is separate and distinct from other energy savings goals in this section. The CHP requirements must be calculated based on the most recent three-year weather-normalized average. A utility may elect to carry forward energy savings in excess of 0.18 percent for a year to the succeeding three calendar years. A particular energy savings can be used only for one year's requirement.*

Subd. 3. OWNERSHIP OF COMBINED HEAT AND POWER. Minnesota Statutes 216B.241 Subd. 3 is modified with the *italicized* insertion as follows:

> Subd. 3. Ownership of energy conservation improvement.
>
> An energy conservation improvement made to or installed in a building in accordance with this section, except *combined heat and power systems or other* systems owned by the utility and designed to turn off, limit, or vary the delivery of energy, are the exclusive property of the owner of the building except to the extent that the improvement is subjected to a security interest in favor of the utility in case of a loan to the building owner. The utility has no liability for loss, damage or injury caused directly or indirectly by an energy conservation improvement except for negligence by the utility in purchase, installation, or modification of the product.

Subd. 4. DEFINITIONS. Minnesota Statutes 216B.241 is modified by adding the following new subdivision:

> *Subd. 11.Combined heat and power.*
>
> *(a) Eligibility. CHP Credits from combined heat and power are eligible to be counted towards an electric utility's CHP energy savings requirements, as established in Subd. 1c. (c) and Subd. 1c. (d), subject to department approval.*

(b) Definitions.

1. *Combined Heat and Power. Combined heat and power ("CHP") is a process which uses the same energy source for the simultaneous or sequential generation of electrical power, mechanical shaft power, or both, in combination with the generation of steam or other forms of useful thermal energy (including heating and cooling applications).*

2. *CHP Credits. CHP Credits shall be defined as follows for each category of CHP opportunity:*

   a) *CHP Credit for New Non-Renewable CHP Plant. A Qualifying CHP plant using a non-renewable fuel, which produced neither electrical nor Useful Thermal Energy before January 1, 2016, shall generate CHP Credits, measured in MegaWatt-hours, equal to the values shown in Table 5 based on the total energy efficiency (thermal and electric) measured on a Higher Heating Value (HHV) basis.*

   b) *CHP Credit for New Renewable CHP Plant. A Qualifying CHP plant using renewable fuel, which produced neither electrical nor Useful Thermal Energy before January 1, 2016, shall generate CHP Credits, measured in MegaWatt-hours, equal to the values shown in Table 6 based on the total energy efficiency (thermal and electric) measured on a Higher Heating Value (HHV) basis.*

Non-Renewable Fuels		
Tier	Efficiency (HHV)	% of Power Output Credited
	<60%	0%
Tier 1	>60<70%	80%
Tier 2	>70<80%	90%
Tier 3	>80%	100%

Table 37. Recommended Efficiency Standards and Crediting Tiers for Non-Renewable CHP

Renewable Fuels		
Tier	Efficiency (HHV)	% of Power Output Credited
	<50%	0%
Tier R1	>50<60%	80%
Tier R2	>60<70%	90%
Tier R3	>70%	100%

Table 38. Recommended Efficiency Standards and Crediting Tiers for Renewable CHP

e) *CHP Credit for CHP Retrofit of Existing Power Plant. A power plant which produced electrical energy before January 1, 2016 and added the production of incremental Useful Thermal Energy after January 1, 2016, shall generate CHP Credits equal to the result, if positive, of the following calculation: take the sum of (1) the Incremental Electrical Energy generated divided by the overall efficiency of electrical energy delivered to the end-use from the electrical grid (which efficiency is equal for this purpose to 0.40); and (2) the Incremental Useful Thermal Energy divided by the overall efficiency of thermal energy delivered to the end-use from standalone heating units (which efficiency is equal for this purpose to 0.80); and subtract from this sum the total of all Incremental Fuel consumed by the CHP Unit expressed in MWh and calculated using the energy content of the fuel based on its Higher Heating Value. This calculation of the CHP Credit can also be expressed with the following terms and equation:*

IEE = Incremental Electrical Energy
IUTE = Incremental Useful Thermal Energy
IF = Incremental Fuel

CHP Credit = (IEE / 40%) + (IUTE / 80%) - IF

f) *CHP Credit CHP Retrofit of Existing Heating or Process Energy Plant. A heating plant or industrial process plant which produced Useful Thermal Energy before January 1, 2016 and added production of Incremental Electrical Energy after January 1, 2016 using Process Waste Heat shall be generate CHP Credits equal to the result, if positive, of the following calculation: take the sum of (1) the Incremental Electrical Energy generated divided by the overall efficiency of electrical energy delivered to the end-use from the electrical grid (which efficiency is equal for this purpose to 0.40); and (2) the Incremental Useful Thermal Energy divided by the overall efficiency of thermal energy delivered to the end-use from a standalone heating unit (which efficiency is equal for this purpose to 0.80); and subtract from this sum the total of all Incremental Fuel consumed by the CHP Plant expressed in MWh and calculated using the energy content of the fuel based on its Higher Heating Value. This calculation of the CHP Credit can also be expressed with the following terms and equation:*

IEE = Incremental Electrical Energy
IUTE = Incremental Useful Thermal Energy
IF = Incremental Fuel

CHP Credit = (IEE / 40%) + (IUTE / 80%) - IF

3. *CHP Plant. Facilities and equipment used for combined heat and power.*

4. *Incremental Electrical Energy. Electrical energy generated by a Qualifying CHP Plant that is either greater than (expressed as a positive amount) or less than (expressed as a negative amount) the electrical energy generated by the CHP Plant prior to the addition of new electric generation nameplate capacity, Useful Thermal Energy, or Incremental Useful Thermal Energy.*

5. *Incremental Fuel. The amount of additional fuel used by a Qualifying CHP Plant which is attributable to the production of Incremental Useful Thermal Energy or Incremental Electrical Energy.*

6. *Incremental Useful Thermal Energy. Useful Thermal Energy produced by a Qualifying CHP Plant that is distinct in its final distribution, beneficial measure, and metering from Useful Thermal Energy previously produced by the CHP Plant, but only to the extent that the Incremental Useful Thermal Energy does not reduce the Useful Thermal Energy previously produced.*

7. *Non Renewable CHP. A Qualifying CHP Plant for which more than 10 percent of the annual fuel input is composed of natural gas, coal, oil, propane, other fossil fuels, or nuclear energy.*

8. *Process Waste Heat. Heat contained in gases or liquids exhausted from a boiler plant, industrial process or municipal process (such as sewage sludge incineration) that is currently and/or conventionally not recovered for useful purposes.*

9. *Qualifying CHP Plant. Any CHP Retrofit of Existing Power Plant, any CHP Plant CHP Retrofit of Existing Heating or Process Energy Plant, or any new CHP Plant which: 1) which has a minimum annual energy efficiency on a higher heating value basis of 60 percent (if using non-renewable fuels) or 50 percent (if using renewable fuels); and 2) which produces at least 20 percent of its total useful energy in the form of thermal energy which is not used to produce electrical or mechanical power (or combination thereof), and at least 20 percent of its total useful energy in the form of electrical or mechanical power (or combination thereof).*

10. *Renewable CHP Plant. A Qualifying CHP Plant for which at least 90 percent of the annual fuel input is composed of energy sources other than natural gas, coal, oil, propane, other fossil fuels, or nuclear energy.*

11. *Useful Thermal Energy. Energy 1) in the form of direct heat, steam, hot water, or other thermal form that is used in production and beneficial measures for heating, cooling, humidity control, process use, or other valid thermal end use energy requirements and (2) for which fuel or electricity would otherwise be consumed.*

12. *Utility Customer. A Utility Customer is an entity who purchases retail electricity from the utility.*

(c) Incentives.

1. *Incentives for Utility Customer- or Third Party-Owned CHP. Utilities shall provide an operating incentive to customers who finance a CHP plant, or third parties who finance a CHP plant to serve a customer or group of customers.*

2. *Duration of Incentives. Operating incentives shall be provided for a period of fifteen (15) years.*

3. *Level of Incentive. The operating incentive shall be calculated as follows:*

CIPE = Statewide average total CIP expenditures by electric utilities for non-CHP incentives and programs over the three (3) calendar years prior to the initiation of commercial operation of the CHP plant, inclusive of administrative costs

CIPS = Statewide average total first year CIP savings (MWh) by electric utilities for non-CHP incentives and programs over the three (3) calendar years prior to the initiation of commercial operation of the CHP plant

Level of Incentive = CIPE / (CIPS x 15 years)

4. *Utility-Owned CHP. If the electric utility finances a CHP plant, it may include as a CIP expenditure the amount which would otherwise be provided to a CHP Plant financed by a customer or third party.*

(d) Alternative Compliance.

1. *Alternative Compliance Payment. A utility may discharge its obligations, in whole or in part, for any Compliance Year by making an Alternative Compliance Payment (ACP) to the Minnesota Department of Commerce. The ACP Rate, in $ per MWh CHPC, and provisions for modifying the rate, shall be established in rulemaking.*

2. *Use of Funds. The Department of Commerce shall oversee the use of ACP funds so as to further the implementation of CHP, district energy systems and other energy efficiency and renewable energy systems.*

(e) Tradable Credits. A system of tradable CHP credits (CHPCs), similar to Renewable Energy Credits (RECs), will be established so that a customer, third party or natural gas utility can generate CHP Credits for sale to electric utilities.

1. *Lifetime. CHPS Credits will have a trading lifetime of 4 years according to the year of generation (e.g., all credits generated during 2017, regardless of the month, expire at the end of 2021).*

2. *Whole Credits. CHPCs must remain "whole" and may not be disaggregated into separate environmental commodities (e.g., carbon emission credits)*

ARTICLE 3. INTEGRATED RESOURCE PLANNING

Subd. 1. Minnesota Statutes 216B.2422 Subd. 4 is modified with the *italicized* insertion as follows:

Subd. 4.Preference for renewable energy facility.

The commission shall not approve a new or refurbished nonrenewable energy facility *which generates only electricity* in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest. The public interest determination must include whether the resource plan helps the utility achieve the greenhouse gas reduction goals under section 216H.02, the renewable energy standard under section 216B.1691, or the solar energy standard under section 216B.1691, subdivision 2f. Electric utilities are required to demonstrate that, before power-only capacity is proposed in Integrated Resource Plans, CHP opportunities within their service territory have been thoroughly assessed to determine the GHG, grid resiliency and other benefits of CHP.

Subd. 2. Minnesota Statutes 216B.2422 is modified by adding the following new Subdivision and renumbering subsequent subdivisions:

Subd. 5. Preference for combined heat and power.

The commission shall not approve a new or refurbished nonrenewable energy facility which generates only electricity in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that: 1) opportunities for new combined heat and power plants within their service territory have been thoroughly assessed to determine the greenhouse gas, grid resiliency and other benefits; 2) the potential for converting existing power plants to combined heat and power, with distribution of recovered energy through district energy systems, has been thoroughly assessed to determine the greenhouse gas, grid resiliency and other benefits; and 3) a combined heat and power facility is not in the public interest, which public interest determination shall include whether the resource plan helps the utility achieve the combined heat and power requirements in Minnesota Statutes 216B.241

ARTICLE 4. STANDBY RATES

Minnesota Statutes 216B.164 is modified by adding the following new subdivision and renumbering subsequent subdivisions:

Subd. 3. STANDBY RATES. Standby rates charged by public utilities must conform to the following principles:

6. *Standby rates should be transparent, concise and easily understandable. Potential CHP customers should be able to accurately predict future standby charges in order to assess their financial impacts on CHP feasibility.*

7. *Standby energy usage fee should reflect both demand and time-of-use cost drivers. Time-of-use energy rates send clear price signals as to the cost for the utility to generate needed energy. This would further incentivize the use of off-peak standby services.*

8. *The Forced Outage Rate should be used in the calculation of a customer's reservation charge. The inclusion of a customer's forced outage rate directly incentivizes standby customers to limit their use of backup service. This further ties the use of standby to the price paid to reserve such service, creating a strong price signal for customers to run most efficiently.*

9. *The standby demand usage fees should only apply during on-peak hours and be charged on a daily basis. This rate design would encourage CHP customers to shift their use of standby service to off-peak periods when the marginal cost to provide service is generally much lower. Furthermore, this design would allow customers to save money by reducing the duration of outages.*

10. *Grace periods exempting demand usage fees should be removed where they exist. Exempting an arbitrary number of hours against demand usage charges sends inaccurate prices signals about the cost to provide this service. Standby demand usage should be priced as-used on a daily and preferably an on-peak basis. This method directly ties the standby customer to the costs associated with providing standby service.*

Implementation and Rulemaking

Following passage of legislation, the following steps are recommended:

1. Conduct a study to quantify the "Value of CHP" relative to total primary energy efficiency, GHG emissions, power grid resiliency, peak demand management and risk management. Further, the study should assess potential constraints to increased implementation of CHP, such as natural gas pipeline capacity limitations.

2. Establish clear policies regarding inclusion of CHP costs in electric utility rates, including mechanisms for addressing ratepayer risks associated with utility investment in CHP through a return on equity risk premium, a state-funded loss reserve or other mechanism.

3. Initiate a high-level dialog with the Midwest Independent System Operator to create rules that encourage maximum dispatch of CHP units.

Appendix A: Best Practices in Other States

This section describes CHP policies and programs in other states, including portfolio standards, interconnection rules, stand-by rates, financial incentives, net metering regulations and other policies.

Portfolio Standards

A number of states have explicitly included some form of CHP as an eligible resource in portfolio standards. CHP can be incorporated into all three of the portfolio standards types described below.

- *Renewable portfolio standard (RPS)* is the most common form of a portfolio standard and is usually focused on traditional renewable energy such as wind, solar, and biomass projects. This type of portfolio standard may incorporate other technologies and fuel types in addition to renewable energy and may have separate tiers or target mandates based on the form of generation. RPS are often market-based— qualifying projects receive tradable credits, typically referred to as renewable energy credits (RECs), which can then be sold for compliance purposes. Connecticut is an example of a state with CHP included in an RPS.
- *Energy efficiency resource standards (EERS)* require utilities to save a certain amount of energy every year. To do this, utilities implement energy efficiency programs to help their customers save energy in their homes and businesses. EERS can be market-based and have a trading system of credits, although this is not as common as in RPS. EERS are typically defined as including end-use energy savings. Some states include other types of efficiency, including distribution system savings and CHP and other efficient distributed generation technologies. Many states have an EERS and a separate RPS, but some combine an RPS and EERS into one comprehensive portfolio standard program. Michigan is an example of a state that passed legislation creating a renewable energy standard (RES). In addition to renewables, the standard requires that both electric and natural gas utilities meet certain energy savings requirements (i.e., EERS targets).
- *Alternative energy portfolio standards (APS)* often set targets for a certain percentage of a supplier's capacity or generation to come from alternative or advanced energy sources such as CHP, coal with carbon capture and storage (CCS), coal co-fired with biomass, or municipal solid waste projects. These standards are often market-based and credit eligible projects with alternative energy credits or some other form of credit, which can then be purchased by electricity suppliers to meet compliance obligations. Examples of states with APS include Massachusetts and Pennsylvania.

According to the EPA (EPA CHP Program website), as of February 2013, some form of portfolio standard has been established in 42 states plus the District of Columbia (see Figure 22). Of these states, 24—Arizona, Connecticut, Colorado, Delaware, Hawaii, Indiana, Louisiana, Maine, Massachusetts, Michigan, Minnesota, Nevada, New York, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Dakota, Utah, Vermont, Washington and West Virginia—specifically call out a form of CHP and/or waste heat to power as an eligible resource in some portion of their CEPS program guidelines (RPS, APS, or EERS). While a number of states have recognized CHP in RPS or EERS programs, many of the RPS programs limit qualified CHP systems to waste heat to power CHP (CHP bottoming cycles), and most EERS programs do not set separate targets for CHP, thereby reducing the effectiveness of these programs in promoting CHP development.

Seventeen states have mandatory portfolio standards that include CHP:

- Four states (Massachusetts, Michigan, Pennsylvania and West Virginia) have a mandatory APS including CHP.
- Nine states (Ohio, New Hampshire, Maine, Connecticut, Illinois, New York, Virginia, Colorado and Hawaii) have a mandatory RPS with CHP qualifying under a separate tier.
- Four states (Washington, Nevada, Arizona and Indiana) have a mandatory RPS with CHP qualifying under the general standard.

In addition, seven states (Alaska, Vermont, Utah, North Dakota, South Dakota, Oklahoma and Louisiana) have a voluntary RPS including CHP.

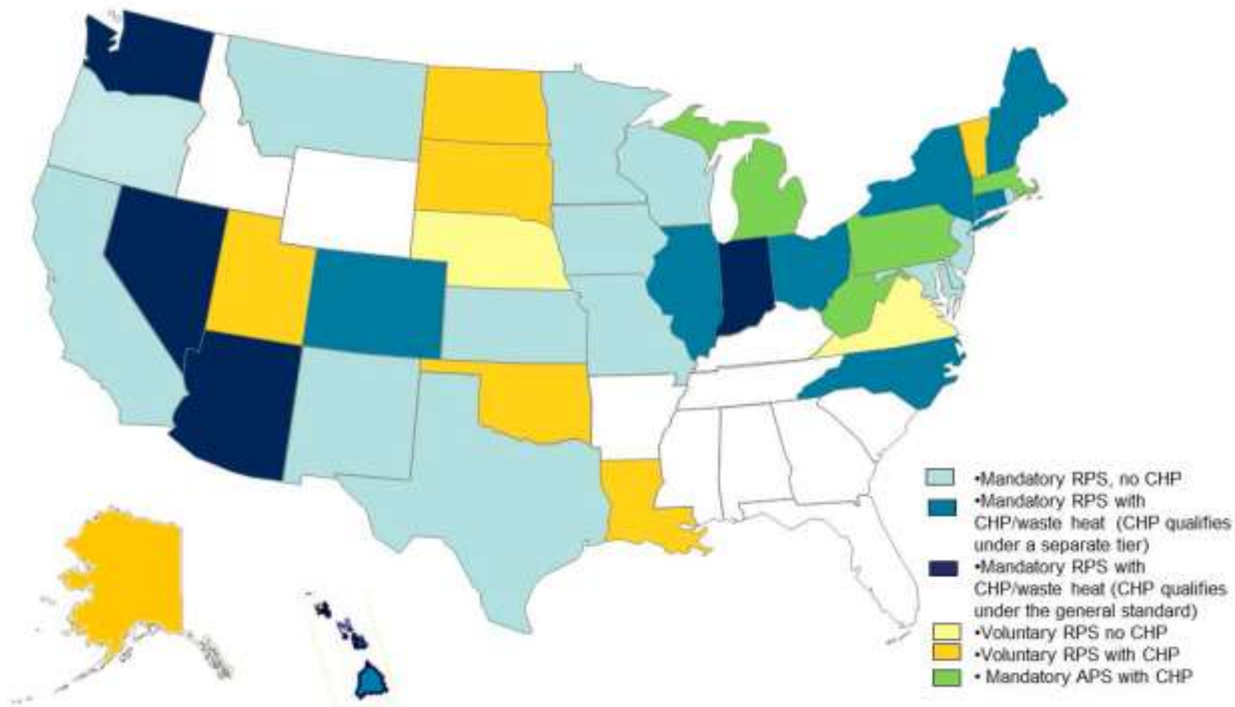

Figure 22. States with Portfolio Standards and how CHP qualifies (under RPS or APS)

Source: U.S. Environmental Protection Agency Combined Heat and Power Program
http://www.epa.gov/chp/policies/standards.html

Following are summaries of two outstanding state CEPs – Massachusetts and Ohio. The standards in these states strongly support use of CHP to meet electric utility efficiency goals, although through different mechanisms: Massachusetts uses an APS; and Ohio uses an RPS with CHP in a separate tier.

Massachusetts

Massachusetts' Alternative Energy Portfolio Standard (APS) is the only in-place portfolio standard in the country that offers CHP-specific goals rather than simply encouraging CHP through an existing energy efficiency or renewable energy portfolio standard. The binding targets for utilities, which ramp up to 5 percent of system load by 2020, can be met with new 200 kW or larger CHP as well as heat recovery or electricity generation added onto existing generation systems. The standard also includes other technologies such as flywheel storage, but CHP dominates, representing 99.1 percent of the technologies acquired for compliance with the standard.

To satisfy the requirements of the APS, utilities purchase tradable credits from qualifying CHP systems. The cost to acquire these credits is recovered in rate cases, and an alternative compliance payment is made by utilities that fail to acquire sufficient resources. The credits carry the environmental benefits of the CHP systems, and while there is no existing strong market in which to monetize all of these benefits, there could be in the future. Additionally, the utilities that can claim CHP savings are able to claim the efficiency savings towards their efficiency targets, and Massachusetts utilities have recently found CHP to help significantly in bringing down the overall cost of their efficiency portfolios (Chittum and Farley, 2013). In fact, CHP was the lowest cost energy efficiency resource reported by Massachusetts utilities in 2011, and the tremendous amount of CHP acquired as efficiency savings helped utilities earn performance incentives (Chittum and Farley 2013).

Ohio

In 2008 Ohio enacted broad electric industry restructuring legislation (S.B. 221) containing advanced energy and renewable energy generation and procurement requirements for the state's electric distribution utilities and electric service companies (hereafter referred to as *utilities*). This definition encompasses all retail electricity providers except municipal utilities and electric cooperatives. Under the standard, utilities must provide 25 percent of their retail electricity supply from alternative energy resources by 2025, with specific annual benchmarks for renewable and solar energy resources. Half of the standard can be met with “any new, retrofitted, refueled, or repowered generating facility located in Ohio,” including fossil fuels, making the renewables portion of the standard 12.5 percent renewables by 2025 (DSIRE).

In 2012 Ohio enacted new legislation, Senate Bill 315, which explicitly establishes CHP as an eligible technology within the state’s existing energy efficiency resource standard (DSIRE). SB 315 promotes cogeneration projects by qualifying them for use by the state’s investor-owned utilities to meet certain requirements under SB 221, Ohio’s landmark energy law enacted in 2008. SB 315 classifies cogeneration technology as both “renewable energy” and “energy efficiency.” That classification qualifies cogeneration for inclusion in Ohio’s renewable portfolio standard (RPS) or as an eligible technology under SB 221’s energy efficiency provisions, which require utilities to achieve certain annual benchmarks for energy savings from energy efficiency projects.

SB 315 allowed project owners to choose which treatment — renewable energy or energy efficiency, but not both — to apply to a particular project. Specifically, the bill:

- States that the energy policy of the State includes encouraging “innovation and market access for cost-effective supply- and demand-side retail electric service including . . . waste energy recovery systems.” R.C. 4928.02(D).
- Creates the term “waste energy recovery system” and defines it as “a facility that generates electricity through the conversion of energy from either of the following:
    - Exhaust heat from engines or manufacturing, industrial, commercial, or institutional sites, except for exhaust heat from a facility whose primary purpose is the generation of electricity.
    - Reduction of pressure in gas pipelines before gas is distributed through the pipeline, provided that the conversion of energy to electricity is achieved without using additional fossil fuels.” R.C. 4928.01(36).

- Includes “waste energy recovery system” in the term “renewable energy resource” unless a waste energy recovery system “is, or has been, included in an energy efficiency program of an electric distribution utility.” R.C. 4928.01(35).
- Clarifies that an electric distribution utility’s energy efficiency programs may include waste energy recovery systems placed in service or retrofitted on or after January 1, 2006. R.C. 4928.66(A)(1)(a) & (A)(2)(d).
- Clarifies that a utility can meet its energy efficiency requirements by counting the effects of waste energy recovery systems, including customer-sited waste energy recovery systems. R.C. 4928.66(A)(2)(c).

Unfortunately, in 2014 Ohio Senate Bill 310 was passed by the legislative and signed by Gov. John Kasich. This legislation essentially put a two-year freeze on Ohio’s renewable and energy-efficiency standards.

Crediting CHP

One of the challenges faced by Ohio and other states considering CHP within existing portfolio standards is the method by which the CHP savings is calculated and credited. As opposed to other efficiency measures, CHP offers overall energy savings but also generally increases on-site fuel usage, which must be considered when calculating overall savings. Several states have developed their own approaches, but no standard accounting approach has emerged.[23] This issue is explored in Chapter 6.

Interconnection rules

Minnesota’s existing interconnection rules have many features of the best interconnection standards in the country, including clear time lines for particular processes, reasonable fees for interconnection and engineering studies, and fees scaled to system size.

Minnesota does not currently offer a fully tiered interconnection standard, however, which would allow smaller systems the option of a “fast-track” process. For qualifying systems that could take advantage of such an option, reduced paperwork, fees, and wait times could yield significant economic benefit.

California

Many states feature tiered interconnection standards with clear benefits to certain generators that satisfy specific requirements. For instance, California’s recently updated Rule 21 interconnection standards vary from utility to utility, but generally offer distributed generators a “fast-track” option. In the case of PG&E, the utility is required to indicate to the applicant whether they are eligible for the fast-track process within 15 business days of the interconnection request.[24] If an application does

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[23] See Kowley 2012 for a discussion of several of the existing methodological approaches to counting CHP savings within a portfolio standard.

[24] See http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf for complete interconnection rules for PG&E. PG&E also offers a clear list of frequently asked questions regarding interconnection, available here: http://www.pge.com/b2b/newgenerator/faq/

not require equipment upgrades, the utility must provide the applicant with an interconnection agreement within another 15 business days.

Connecticut

While Minnesota's existing interconnection standard applies to systems up to 10MW, the leading states offer interconnection standards for systems up to 20MW in size. For instance, Connecticut's interconnection standard offers three distinct tiers of interconnection up to 20MW, each with its own fee:

- Systems less than 10kW, which incur a $100 application fee;
- Systems between 10kW and 2MW, which incur a $500 fee; and
- Systems between 2MW and 20MW, which incur a $1,000 fee and fees for additional studies deemed necessary (013 Connecticut Department of Public Utility Control 2007).

These fees are generally in line with Minnesota's fees for different system sizes.

Maine

Maine's relatively recent interconnection standards are viewed as model standards. They feature four distinct tiers of interconnection, with corresponding fees and studies. [25] Maine's tiers are:

- Systems of 10kW or fewer, which incur a $40 fee;
- Systems between 10kW and 2MW, which incur a $50 + $1/kW fee;
- Systems less than 10MW which will not export, which incur a $100 + $1.50/kW fee; and
- Systems that do not meet any of the above tier definitions, which incur a $100 + $2/kW fee at a maximum, as well as fees associated with necessary studies and utility upgrades (DSIRE).

CHP-friendly stand-by rates

Some of the country's utilities have taken an active approach to devising standby-rates that reflect some of the benefits and features of CHP systems.

Con Edison

Con Edison of New York's offers CHP system owners an Offset Tariff, which applies to campuses with multiple buildings and a CHP system onsite. The CHP system output is applied to the total demand from all the campus' meters, allowing the CHP system output to be credited against the entire campus' peak demand. This can help blunt the impact of demand charges from certain meters by evening out the benefit of CHP output over multiple meters. Individual meter peaks are somewhat minimized, and demand charges are reduced for the customer as a whole (Chittum and Farley 2013).

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[25] See http://www.dsireusa.org/documents/Incentives/ME15R.pdf for the related order from the Maine Public Utilities Commission

Pacific Power

Pacific Power's backup power tariff for partial service customers offers benefits to customers for reducing reliance on grid-provided power during peak grid demand periods.[26] Separate line-items charges per capacity required during the system peak are built into these rates, and customers are only charged for transmission and ancillary services for the power they require during system peak periods. Additionally, the variable distribution charges are much more heavily weighted toward what is demanded during system peak periods than what is demanded during other time periods.

New Jersey

A 2012 bill directing the New Jersey Board of Public Utilities (BPU) to undertake studies into the benefits and issues associated with distributed generation. The BPU concluded that "the rates that distributed generators pay [for] standby service should reflect the costs that they place on the [distribution utility]'s distribution system, to ensure there is equity between Distributed Generators and other utility ratepayers to avoid subsidies." Utilities were required to file exhibits in support of existing rate schedules, or file requests for new standby rates. The BPU asked that these rates consider the impact of CHP systems on the distribution systems during times of peak demand, and calculate such grid benefits accordingly (NJBPU 2012).

Utility Programs, Policies, and Planning

Utilities are an under-utilized partner in the quest for greater deployment of CHP. Without properly aligned economic incentives, however, utilities have little economic interest in seeing increased CHP deployment. Since utilities are so well-suited to support greater CHP deployment – they have many issues that CHP systems can help cost-effectively address; they are used to making long-term investments; and they are better aware of their customers' unique energy needs and opportunities than anybody else – it is critical to understand how they could become more involved in CHP project deployment.

Several examples of both electric and natural gas utilities working to support new CHP projects can be found around the country. In other cases, policies that would help utilities better view CHP as an economic opportunity are in place and could be leveraged to develop strong CHP programming.

Pennsylvania

Philadelphia Gas Works (PGW) is the natural gas utility serving Philadelphia. In order to encourage greater CHP deployment, they offer a unique financing mechanism for CHP systems in their service territory. PGW pays all the initial equipment, installation, and engineering costs of a new CHP system on behalf of the customer, leaving the customer to retain ownership of the system. The customer then pays PGW back for the investment over a five year period, paying a flat monthly fee that typically is less than what the customer was paying previously for grid-provided power and the thermal energy now provided by the CHP system (Chittum and Farley 2013). This program is

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[26] Pacific Power's Schedule 47 and 48 can be viewed in greater detail here:

http://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/Oregon/Approved_Tariffs/Rate_Schedules/Large_General_Service_Partial_Requirements_1_000_KW_and_Over_Delivery_Service.pdf structured to help energy or facility managers gain support internally for a CHP system by reducing the risk and perceived risk associated with making the large up-front investment CHP systems typically require.

Connecticut

Connecticut requires all affected utilities to include CHP in their long-term resource plans (Connecticut Public Act 2007):

> *"The electric distribution companies, in consultation with the Connecticut Energy Advisory Board, established pursuant to section 16a-3 of the general statutes, as amended by this act, shall review the state's energy and capacity resource assessment and develop a comprehensive plan for the procurement of energy resources, including, but not limited to, conventional and renewable generating facilities, energy efficiency, load management, demand response, combined heat and power facilities, distributed generation and other emerging energy technologies to meet the projected requirements of their customers in a manner that minimizes the cost of such resources to customers over time and maximizes consumer benefits consistent with the state's environmental goals and standards.*

These procurement plans consider customers' "energy and capacity requirements" at three, five, and ten years forward. Funded through the state's systems benefits charge, they are updated annually (Connecticut Public Act 2007).

One utility in Connecticut, United Illuminating, explored the option of partnering with third-party entities to encourage new CHP project development. The program was run as a test to gauge interest and has since been cancelled, but it was well-received by potential CHP hosts. The utility understood that it would be able to reap the rewards of increased CHP on its distribution system, while reducing the energy usage of their customers and acquiring cost-effective efficiency resources.

Oregon

Oregon legislation established a voluntary emissions reduction program in which the state's natural gas utilities may participate. Utilities can offer energy efficiency programs that yield emissions reductions, and may recover the costs of those programs from the ratepayers that will benefit from the projects. Projects may thus increase the on-site natural gas use if they reduce overall emissions by avoiding centralized generation, such as with CHP (Oregon Legislative Assembly 2013). One natural gas utility has expressed interest in such a model.

Alabama

In Alabama the investor-owned Alabama Power owns several CHP plants located and industrial facilities around the state. These plants' costs have been integrated into the rate base, allowing the utility to earn a rate of return on their investment akin to that which it receives on other investments.

Missouri

In Missouri two ethanol plants host CHP systems that serve their immediate facilities with thermal energy and their local utilities with electricity. These CHP systems are both owned and maintained by the municipal utilities, with the heat recovery equipment owned by the two ethanol plants. These plants are 10MW and 15MW in size, and were developed with specific one-off agreements between the ethanol plants and the municipal utilities.

California

In California several policies encourage regulated utilities to acquire and support greater CHP deployment. An agreement between CHP developers and the regulated utilities of the state yielded utility-specific acquisition targets for CHP capacity, which can be satisfied by the development of power purchase agreements (PPAs) with CHP facilities. The cost of these PPAs is embedded in customer rates, while the emissions reductions benefits associated with the CHP capacity is creditable to the utility in the state's cap and trade program.

California also established a feed-in-tariff (FIT) program, which pays CHP facilities for excess capacity beyond that which they consume onsite. Ten year contracts for the power are developed, with the price indexed to the short-run avoided cost of power. These costs to the utility are then recovered in customer rates as well.

Massachusetts

As part of the state's 2008 *Green Communities Act*, Massachusetts requires utilities to consider CHP within their three-year efficiency plans. All cost-effective CHP *must* be acquired, and utilities are given the clarity and assurance that the costs associated with acquiring this CHP capacity is recoverable within customer rates, and is creditable within their energy efficiency programs (Massachusetts Session Laws 2008).

CHP financial incentives

There are a number of excellent models for financial incentives and financing assistance specific to CHP. Minnesota currently does not offer any incentives specific to CHP, thus leaving much room for improvement.

Maryland

Maryland's Baltimore Gas and Electric (BG&E)'s *Smart Energy Savers Program* offers a robust incentive program designed to encourage high-performing CHP systems. The incentive program is structured as follows:

- $75/kW after the system has been designed and a commitment letter has been signed;
- $175/kW after the system has been installed and commissioned and undergone an inspection; and
- $0.07/kWh for the first 18 months of system performance, after metered data has been reviewed.

This incentive program is applicable to systems that are at least 65 percent efficient and do not export excess power to the grid. The maximum incentive offered by BG&E is $2 million for a single project, and is available to almost all non-residential customer classes. See http://www.bgesmartenergy.com/chp for further details on this program.

To date the program has been very well received by industrial and commercial customers, and due to interest exceeding available funding, BG&E requested and received an additional $10 million in program funding in 2013. The first round of funding yielded about 20 project applications, and BG&E can claim these savings towards their established energy efficiency goals.

Illinois

In July 2014, the Illinois Department of Commerce and Economic Opportunity (DCEO) announced a new public sector CHP incentive program. The CHP Pilot Program provides cash incentives for CHP projects that increase energy efficiency of local governments, municipal corporations, public school districts, community college districts, public universities, and state/federal facilities located in the service territories of specific IOUs.

The Pilot Program is structured with performance based incentives to provide financial assistance during various stages of a project, including after the design phase, commissioning, and after 12 months of measured operational performance (DCO website):

- Design Incentive: \$75/kW capacity (following completion of the design phase).
- Constructive Incentive: \$175/kW capacity (following successful commissioning of the system).
- Production Incentive: \$0.08/kWh (with efficiency ≥ 70 percent HHV) OR \$0.06/kWh (efficiency ≥ 60 percent but < 70 percent HHV) of "useful electric energy" produced (after 12 months of operation based on meeting the measured operating requirements of the system).

The total incentive (Design + Construction + Production) is capped at \$2 million or 50 percent of the project cost, whichever is less. The design incentive is capped at \$195,000 or 50 percent of design cost, whichever is less. The construction incentive is capped at \$650,000 or 50 percent of the construction cost, whichever is less.

New York

The New York State Energy Research and Development Authority (NYSERDA) offers several CHP-focused programs that dynamically respond to market needs. For instance, two existing incentive programs target separate areas of the CHP market.

The *Combined Heat and Power (CHP) Performance Program*[27] targets larger (over 1.3MW) systems that use well-established technology and are designed to offer summertime peak demand reduction benefits to the grid. Incentives are scaled depending on whether a system is located in upstate New York or downstate New York, where the grid is more congested. Incentives are as follows:

- Systems may earn up to \$0.10/kWh generation;
- Systems may earn an additional \$750/kW of summer demand reduction; and
- Systems may earn additional bonus incentives if they do any of the following:
  - Serve critical infrastructure;
  - Serve an area determined to be a challenged area of the grid of particular interest to the local utility; and
  - Exemplify "superior" efficiency.

[27] For more details on NYSERDA's CHP Performance Program, see: http://www.nyserda.ny.gov/BusinessAreas/Energy-Efficiency-and-Renewable-Programs/Commercial-and-Industrial/CI-Programs/Combined-Heat-and-Power-Program.aspx.

The CHP Performance Program offers a maximum incentive of $2.6 million or 50 percent of the project cost, whichever is less. Systems are subject to a two-year measurement and verification period, and incentives can be reduced for non-performance.

NYSERDA's *CHP Acceleration Program*[28] is specifically designed to accelerate the market for pre-qualified smaller (less than 1.3MW) CHP systems that can be grid-independent and are also installed by pre-approved vendors. These vendors are then required to take full responsibility for the installation and performance of the CHP system, and offer a full warranty or service agreement for at least five years.

Incentives are equipment- and design-based, with the base incentive depending on the specific CHP system selected. Incentives range from $82,500 to $1.5 million per system.[29] Additional bonus incentives are also available for systems that offer additional benefits like those outlined above in the Performance Program.

The maximum incentive under this program is $1.5 million per project. Similar to the above-mentioned Performance Program, the Acceleration Program offers different incentive levels for upstate and downstate installations, reflecting the important benefits to a stressed grid that CHP can provide.

Net metering regulations

Net metering is defined and key issues are discussed above in section 2. Ten states include CHP in net metering policy and exempt net metered customers from standby rates. Most of these states exempt only very small (< 100 kW) CHP systems. However, some states offer net metering to systems larger than 1 MW.

Pennsylvania

Pennsylvania's net metering standards apply to systems up to 3 MW, and to systems between 3 MW and 5 MW if they can be counted on to provide electricity to the grid in emergency situations (DSIRE 2013).[30]

Arizona[31]

Arizona's net metering standard limits system size to "125 percent of a customer's total connected load" (DSIRE 2013), allowing for net metered systems to meet the entirety of a customer's load.

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[28] See http://www.nyserda.ny.gov/Funding-Opportunities/Current-Funding-Opportunities/PON-2568-CHP-Acceleration-Program.aspx for details on the CHP Acceleration Program

[29] See http://www.nyserda.ny.gov/-/media/Files/FO/Currentpercent20Fundingpercent20Opportunities/PONpercent202568/2568attc.pdf for the complete catalog of pre-qualified equipment and their related incentive levels.

[30] See http://www.dsireusa.org/documents/Incentives/PA03R.htm and http://www.pacode.com/secure/data/052/chapter75/subchapBtoc.html for the 2004 statutes and the 2006 state code, respectively, that delineate Pennsylvania's net metering rules

[31] See http://www.azsos.gov/public_services/Title_14/14-02.htm#ARTICLE_23 for the applicable administrative code.

Output-based air emission rules

Although CHP systems are much more energy efficient than conventional generation on a system-wide basis, some air quality regulations create a disincentive for CHP. Traditionally, emissions regulations define limits on emissions per unit of fuel input (such as pound of SO_2 per million BTU of coal). Facilities that use CHP maybe penalized for producing more emissions individually because they are generating electricity on-site rather than purchasing from the grid, even though they are more efficient overall.

Output-based emissions standards define emissions limits based on the amount of emissions per unit of useful energy output (such as pounds of SO_2 per MWh). Output-based standards encourage more efficient processes, including CHP. Some states have output-based air permits that are explicitly designed to encourage CHP.[32] Some states have taken this a step further by developing "permit by rule" standards for CHP, which means that CHP systems can take advantage of a fast-track permitting process if they satisfy particular requirements.

Texas

In 2012 the Texas Commission on Environmental Quality (TCEQ) adopted a new Permit-by-Rule for CHP systems up to 15MW. This permit is a streamlined, more expedited permitting process to meet various pollutant standards. The permits are administered on an output basis, meaning that emission limits are set as pounds of pollutant per MWh of system output.[33] The streamlined process ensures that qualifying facilities can obtain their permits much faster than prior to the Permit-by-Rule, greatly reducing the cost associated with acquiring necessary air permits.

Connecticut

Like Texas, Connecticut developed parameters that, if satisfied, allow a CHP system to be permitted to operate without obtaining an individual permit.[34] Connecticut's Permit-by-Rule applies to CHP systems up to 10MW, which must be 55 percent efficient per annual period.

Critical Facilities Rules

Several states have recently developed specific requirements that CHP be strongly considered for resiliency reasons in facilities that are critical to maintain during times of natural and other disasters.

Texas

Texas adopted House Bills 1831[35] and 4409 that, beginning in 2009, required that facilities deemed critical to maintain in emergency situations acquire a CHP feasibility study prior to construction or

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[32] A good recent example can be found in Texas, as summarized here: http://www.texaschpi.org/Assets/downloads/executive-summary_chp-pbr_20120725.pdf

[33] To see the TCEQ's Permit by Rule, visit: http://www.texaschpi.org/Assets/downloads/tceq_chapter-106_chp-pbr-ruling_20120725.pdf.

[34] See http://www.ct.gov/deep/lib/deep/air/regulations/mainregs/sec3d.pdf for the full text of the permit by rule.

significant renovations. This feasibility study should consider both the technical and the economic potential for CHP to meet a facility's energy needs, and is designed to encourage facilities to implement CHP in order to be a critical functional resource when other facilities are without power during emergency situations.

Louisiana

Similar to Texas, Louisiana adopted new legislation in 2012 that asks the state's Department of Natural Resources to develop policies that prompt certain government and other facilities to consider the feasibility of CHP at the point of development or renovation.[36]

New York

The New York Research and Development Authority (NYSERDA) currently offers multiple incentives for CHP. Some of these programs offer additional "bonus" incentives to CHP systems that serve "critical infrastructure, including facilities of refuge." For these purposes, critical infrastructure includes facilities such as hospitals, data centers, energy infrastructure, financial services, food distribution, transportation, and water infrastructure, among many others. Facilities of refuge are those deemed critical to the maintenance of citizen safety and health, by entities such as the American Red Cross or the emergency management office (NYSERDA 2013). At present these additional incentives are offered as a 10 percent bonus on top of the base incentive earned.

Emerging Opportunities

A number of benefits and characteristics of CHP are recognized and leveraged in other countries and some states, but are not at all widespread in the U.S. These benefits could accrue to the citizens of Minnesota with increased CHP deployment, complementing the following opportunities.

Location-Specific Benefits

As discussed previously, strategically sited CHP systems can offer greater benefits to the grid at large by meeting location-specific needs. In addition to incentives scaling to provide greater financial incentive to systems sited at critical facilities, efforts to specifically target CHP to stressed areas of the grid can be viewed as cost-effective alternatives to more expensive infrastructure investments. In Vermont, a Geo-Targeting program encourages energy efficiency projects in areas of the distribution grid deemed most congested. Every time energy efficiency programs are renewed, geo-targeting areas are updated and news ones are added as needed. These areas are selected by committee members, who focus on the areas of the grid that are known to require near-term investment. Efficiency Vermont, which administers the energy efficiency programming, is informed of these areas and is given flexibility to offer richer incentives or greater administrative support to facilities in these areas. The program has already proven to be yielding both energy and demand reductions in the targeted areas (Eaton 2013, Navigant 2011).

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[35] See http://www.capitol.state.tx.us/tlodocs/81R/billtext/pdf/HB01831F.pdf for full text of House Bill 1831, and http://www.capitol.state.tx.us/tlodocs/81R/billtext/pdf/HB04409F.pdf for full text of House Bill 4409.

[36] See http://legiscan.com/LA/text/HR167/id/651999 for the full text of the House Resolution.

California's feed-in-tariff program also scales its tariffs to support greater deployment of CHP in areas where particular substations are close to reaching their maximum capacity. Lists of such substations are made publicly available and the per-kWh payment is increased for systems deployed in these areas (Lipman 2013).

Support for Greater Renewable Energy Deployment

CHP systems' abilities to provide ancillary and capacity services to the grid are being underutilized for their ability to help balance intermittent renewable resources such as wind and solar. CHP located strategically in areas that are subject to the vagaries of wind or solar power can help mitigate the need for additional and more expensive capacity and ancillary resources. Additionally, CHP helps reduce the overall load on the distribution and transmission systems, freeing up space for renewable-fueled electricity to travel to its final destination (Casten 2012). CHP's ability to rapidly increase or decrease output in response to market signals leaves it well-positioned to help support greater renewable energy deployment as well as reducing the costs associated with renewable energy's increased transmission needs (Andersen and Sorknæs 2011).

Reliable Natural Gas Revenue Stream

Natural gas-powered CHP systems represent a reliable and high-quality natural gas customer for local gas distribution utilities. As such, they are highly desirable, as their high load factors help improve the stability of gas demand and their long contracts help gas utilities better forecast and address their future investment needs. Natural gas utilities in several states have developed CHP programs and offer CHP systems rebates on their gas purchases. In some cases, such as Connecticut and New Jersey, the reduction comes in the form of a credit towards all or part of their gas delivery charge. New York and California both also offer preferential rates for gas to natural gas-fueled CHP systems. For instance, California requires that natural gas utilities charge CHP systems the same rates for natural gas as they do electric utilities. These types of discounts reflect the fact that CHP systems can offer long-term certainty to natural gas utilities, and ultimately reduce the amount of emissions in power production (Chittum and Farley 2013).

Involving natural gas utilities is one way to greatly expand the marketing of the CHP opportunity to appropriate facilities. Natural gas utilities have existing relationships with their customers, and are very aware of which larger customers might be well-suited to CHP, or might be planning to replace a boiler or other piece of equipment in the near future. These are the exact opportunities in which CHP can be introduced and explained to potential users, and natural gas utilities with a vested interest in increasing CHP deployment within their service territory could be critical partners in such an effort.

Development of Robust CHP Supply Chain

There are a handful of major CHP equipment manufacturers in the United States. There are more equipment distributors, and many more individual local CHP project developers, which sometimes are the exact same entities that offer buildings customized energy engineering services. There are also many different project financers, as well as other contractors that are involved in the construction and operation and maintenance of the CHP systems. For seamless CHP project installation and operations, these players must be comfortable working with the technology and with each other. It takes many years for a true CHP market to develop, and with it the improving economies of scale of working with partners that have ample experience in these areas.

New York State offers the best example of the benefits of supporting and hastening the development of this CHP supply chain. For years the New York State Energy Research and Development Authority

(NYSERDA) has worked with CHP vendors and engineering firms to understand the challenges they face in their efforts to deploy CHP systems. These exchanges have been two-sided: NYSERDA learns about the market opportunities and market frustrations, which helps them build better programs and suggest improved policies; the vendors learn about the opportunities for NYSERDA support and enjoy opportunities to showcase their services and expertise, which NYSERDA then relies on in future projects. These constant dialogues have yielded a situation in which NYSERDA programs are regularly evolving, responding to changing market conditions and trying to remain as relevant and useful to the market as possible. As a consequence, New York State has seen a tremendous increase in CHP project development in recent years, and public agencies and utilities that previously were uncomfortable working with CHP projects have now grown accustomed to them, reducing project barriers and cost.

Most recently, NYSERDA developed an incentive program, mentioned above, that relies on a list of approved CHP vendors. Potential customers can browse the list of vendors, and know that they have been thoroughly vetted by NYSERDA, which reduces real and perceived project risk. The vendors, for their part, benefit from an additional marketing arm via the NYSERDA website and associated events and publications, and can rely on NYSERDA as well as involved utilities and public agencies for project leads.

Valuation of Ancillary Services

At present Minnesota utilities do not have a clear way to value the ancillary or capacity services provided by CHP. The Midcontinent Independent System Operator (MISO) operates an ancillary services market, and CHP plants within MISO do sell ancillary services to the market, such as the very large Midland Cogeneration Venture in Midland, Michigan. Utility-owned or supported CHP projects could also contract to sell ancillary or capacity services, but the mechanism by which such benefits would accrue directly to a utility and be incorporated into its cost-benefit analyses and energy efficiency goals is unclear. Additionally, the value and importance of ancillary services and capacity services provided by CHP facilities would need to be incorporated into IRPs as well in order to allow a more comprehensive assessment of the value of CHP to CHP owners.

Importantly, CHP systems designed to provide ancillary services and capacity resources may sometimes run in a less efficient manner than those that are designed just to follow the onsite thermal load and ignore the realities of the electric market. It is important that policymakers weigh the benefits and drawbacks of all scenarios when multiple scenarios are potentialities.

Support for Heat Networks

CHP systems produce thermal energy as one of their products, and have, in the U.S., typically been sited next to the end-user. These industrial sites, campuses, hospitals, and other types of buildings have onsite process heat and domestic heating needs. Some CHP systems in the U.S., and many in other countries, generate their heat specifically to sell to district heating systems, which provide space heating and hot water to an aggregation of buildings. These additional thermal demands would represent a significant increase in CHP potential, since CHP systems are most often limited in size by the existing thermal demand.

Appendix B: Federal Policy Context

This section describes existing federal policies and programs that are relevant to future implementation of CHP in Minnesota, including investment tax credits, production tax credits, Department of Energy and Environmental Protection Agency program. In addition, pending relevant federal legislation is summarized.

Existing policies and programs

Tax Incentives

Investment Tax Credit (ITC)

Investment tax credits for CHP were established by the Energy Improvement and Extension Act of 2008.

The CHP credit is equal to 10 percent of expenditures, with no maximum limit stated, for the first 15 MW of CHP property (United States Code 26 USC 48). The total CHP capacity must be equal to or less than 50 MW. Except for CHP fueled with biomass, the total efficiency must exceed 60 percent. In addition, at least 20 percent of the total useful energy must be in the form of thermal energy, and at least 20 percent must be in the form of electrical or mechanical energy. The efficiency requirement does not apply to CHP systems that use biomass for at least 90 percent of the system's energy source, but the credit may be reduced for less efficient systems.

The CHP credit applies to eligible property placed in service after October 3, 2008. Tax credits are available for owners paying taxes on eligible systems placed in service on or before December 31, 2016. In general, the original use of the equipment must begin with the taxpayer, or the system must be constructed by the taxpayer. The equipment must also meet any performance and quality standards in effect at the time the equipment is acquired. The energy property must be operational in the year in which the credit is first taken.

Renewable Electricity Production Tax Credit (PTC)

The federal renewable electricity production tax credit (PTC) is a per-kilowatt-hour tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year (United States Code 26 USC 45). This credit is relevant to CHP systems fuels with renewable energy. Current credit amounts relevant for CHP are:

- Closed-Loop Biomass: $0.023/kWh.
- Open-Loop Biomass: $0.011/kWh.
- Landfill Gas: $0.011/kWh.
- Municipal Solid Waste: $0.011/kWh.

The duration of the credit is generally 10 years after the date the facility is placed in service. Under current law, construction must begin by December 31, 2013. While this expiration makes the PTC moot for the future we include this information in the report because legislative efforts are being made to extend the PTCs.

Modified Accelerated Cost-Recovery System (MACRS) Plus Bonus Depreciation

Under the federal Modified Accelerated Cost-Recovery System (MACRS), businesses may recover investments in certain property through depreciation deductions. The MACRS establishes a set of class lives for various types of property, ranging from 3 to 50 years, over which the property may be depreciated. CHP, fuel cells and microturbines are classified as 5-year properties.

Interconnection Standards

A range of required or recommended interconnection standards have been developed by federal agencies and other entities. Federal Energy Regulatory Commission (FERC) has established standards for distributed generation connected at the transmission level. The Department of Energy has recommended "best practices" for standards for state adoption. The National Association of Regulatory Utility Commissioners (NARUC) has also recommended model state standards. The Interstate Renewable Energy Council (IREC) has developed model rules for interconnection of small distributed generation. These standards and model rules are described below, drawing on information prepared by the U.S. Environmental Protection Agency (EPA dCHPP database).

FERC Small Generator Interconnection Procedures (SGIP) and Agreement (SGIA)

The Federal Energy Regulatory Commission (FERC) has established standard terms and conditions for public utilities to interconnect new sources of distributed generation with generating capacity of 20 MW or less. These requirements are developed based on requirements in FERC Orders 2006, 2006-A and 2006-B. Though the procedures and agreement do not directly reference CHP, they can affect CHP. More specifically, they apply to FERC-jurisdictional interconnections that interconnect at the transmission level. The FERC standards generally do not apply to distribution-level interconnection, which is regulated by state public utilities commissions.

The SGIP contain technical procedures as well as standard contractual provisions. They provide three ways to evaluate an interconnection request:

- Level 1 - 10 kW Inverter Process: applies to certified, inverter-based systems 10 kW or less. There is a $100 processing fee.
- Level 2 - Fast Track Process: applies to certified systems 2 MW or less. There is a $500 processing fee.
- Level 3 - Study Process: applies to systems greater than 2 MW but less than or equal to 20 MW. There is a $1,000 processing fee.

The procedures lay out specific timelines for utility responses, interconnection charges and standard study fees. The review processes for Levels 1 and 2 include technical screens. If the screens are not met, the application would go to the Level 3 review process. The procedures provide guidelines for dispute resolution and require liability insurance "sufficient to insure against all reasonably foreseeable direct liabilities given the size and nature of the generating equipment being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made."

The SGIP require interconnection equipment to be certified according to IEEE Standards 1547 and UL 1741. The SGIP address interconnection to spot networks for inverter-based distribution generation. They do not address other interconnections to spot and area networks. The SGIP also do not cover any external disconnect switch requirements.

The SGIA was developed for all interconnection requests submitted under the SGIP and governs the terms and conditions under which the Interconnection Customer's Small Generating Facility will interconnect with, and operate in parallel with, the Transmission Provider's Transmission System. The SGIA is the agreement used for Levels 2 and 3. There is no standardized form for Level 1. The SGIP apply to all distributed generation technologies including CHP.

Distributed Energy Interconnection Procedures, Best Practices For Consideration

Section 1254 of the Energy Policy Act of 2005 (EPAct) requires each State regulatory authority to determine whether to require interconnection service to any consumer the utility serves who has on-site generation by August 8, 2007. The Distributed Energy Interconnection Procedures were developed as an outcome of this requirement. In the Procedures, DOE's Offices of Energy Efficiency and Renewable Energy (EERE) and of Electricity Delivery and Energy Reliability (OE) encourage State and non-State jurisdictional utilities to consider the following best practices in establishing interconnection procedures:

- EPAct requires that agreements and procedures for interconnection service "shall be just and reasonable, and not unduly discriminatory or preferential." As such, generators and utilities should be treated similarly in terms of State requirements.
- Create simple, transparent (1- or 2-page) interconnection applications for "small generators" (equal to or less than 2 MW), as noted in the FERC Order 2006.
- Standardize and simplify the interconnection agreement for "small generators" and, if possible, combine the agreement with the interconnection application.
- Set minimum response and review times for interconnection applications. Provide expedited procedures for certified interconnection systems that pass technical impact screens.
- Establish small processing fees for "small generators", otherwise the interconnection request must be accompanied by a deposit that goes toward the cost of the feasibility study, per FERC Order 2006.
- Set liability insurance requirements commensurate with levels typically carried by the respective customer class.
- Require compliance with IEEE 1547 and UL 1741 for safe interconnection.
- Avoid overly burdensome administrative requirements, such as obtaining signatures from local code officials, unless such requirements are standard practice in a jurisdiction for similar electrical work.
- Develop administrative procedures for implementing interconnection requirements on a statewide basis through a rulemaking or other appropriate regulatory mechanism for state-jurisdictional utilities to apply uniformly to all regulated electric distribution companies in the State. Where practical, State interconnection administrative procedures should reflect regional best practices and be comprehensive in scope. Administrative procedures should also be transparent to both small generators and electric distribution utilities.

NARUC Model Interconnection Procedures and Agreement for Small DG Resources

The National Association of Regulatory Utility Commissioners (NARUC) represents the state public service commissions that regulate electric utilities by helping to ensure that utility services are provided at rates and conditions that are fair, reasonable and nondiscriminatory for all consumers. In 2003, NARUC released its Model Interconnection Procedures and Agreement for Small Distributed Generation Resources, which can apply to CHP. The procedures are intended to be resources for state commissions and industry stakeholders in their own DG efforts with the hope that they will serve as a catalyst for state DG interconnection proceedings.

The guidelines lay out a process for expedited approval of interconnection for small resources. Under this procedure the applicant would fill out one of two possible applications:

- "Short Form Application for Single Phase Attachment of Parallel Generation Equipment 20 kV or Smaller to the Electric System".
- "Standard Application for the Attachment of Parallel Generation Equipment to the Electric System for single phase equipment larger than 20 kV."

The applications would go through a primary and secondary screening process, after which they would be able to execute an interconnection agreement with the utility. The guidelines provide for general information about the need for interconnection agreements that address study fees, timelines for utility responses, insurance levels, technical requirements, and dispute resolution procedures. However the guidelines do not take a position on what these requirements should be, leaving these issues up to the state utility commissions.

IREC Model Interconnection Rules

The Interstate Renewable Energy Council (IREC) is a non-profit organization that focuses on issues that have an impact on expanded renewable energy use such as rules that support renewable energy and distributed resources in a restructured market and connecting small-scale renewables to the utility grid. IREC developed model interconnection rules that have been used as a template by several state utility commissions and utilities in developing their interconnection standards.

The Interconnection Procedures are applicable for all state-jurisdictional interconnections of Generating Facilities and outline four review paths:

- Level 1 - For inverter-based Generating Facilities that pass specified screens and have a Generating Capacity of 25 kilowatts (kW) or less.
- Level 2 - For Generating Facilities that pass specified screens and have a Generating Capacity of 2 megawatts (MW) or less.
- Level 3 - For Generating Facilities that: (a) pass specified screens; (b) do not export power to the Utility; and (c) have a Generating Capacity of 10 MW or less.
- Level 4 - For all Generating Facilities that do not qualify for Level 1, Level 2 or Level 3 interconnection review processes.

Each path identifies steps towards an interconnection agreement, including the type of form, the process by which an applicant submits an application and the process by which a utility can review an application. Unless waived by the Utility, a Generating Facility must comply with the following standards, as applicable:

- IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems for Generating Facilities up to 10 MW in size.
- IEEE Standard 1547.1 for Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems.
- UL 1741 Standard for Inverters, Converters and Controllers for Use in Independent Power Systems. UL 1741 compliance must be recognized or Certified by a Nationally Recognized Testing Laboratory as designated by the U.S. Occupational Safety and Health Administration. Certification of a particular model or a specific piece of equipment is sufficient. It is also sufficient for an inverter built into a Generating Facility to be recognized as being UL 1741 compliant by a Nationally Recognized Testing Laboratory.

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Information/Education/Technical Assistance Programs

Executive Order -- Accelerating Investment in Industrial Energy Efficiency

In August 2012, President Obama issued an Executive Order to facilitate investments in energy efficiency at industrial facilities, with a strong emphasis on CHP as an efficiency strategy.

The Order seeks to support these investments through a variety of approaches, including encouraging private sector investment by setting goals and highlighting the benefits of investment, improving coordination at the Federal level, partnering with and supporting States, and identifying investment models beneficial to the multiple stakeholders involved.

The Order directed executive departments and agencies to:

1. Coordinate and strongly encourage efforts to achieve a national goal of deploying 40 GigaWatts (GW) of new, cost effective industrial CHP in the United States by the end of 2020.
2. Convene stakeholders, through a series of public workshops, to develop and encourage the use of best practice State policies and investment models that address the multiple barriers to investment in industrial energy efficiency and CHP.
3. Utilize their respective relevant authorities and resources to encourage investment in industrial energy efficiency and CHP, such as by:
    - (i) providing assistance to States on accounting for the potential emission reduction benefits of CHP and other energy efficiency policies when developing State Implementation Plans (SIPs) to achieve national ambient air quality standards;

(ii) providing incentives for the deployment of CHP and other types of clean energy, such as set asides under emissions allowance trading program state implementation plans, grants, and loans;

(iii) employing output based approaches as compliance options in power and industrial sector regulations, as appropriate, to recognize the emissions benefits of highly efficient energy generation technologies like CHP; and

(iv) seeking to expand participation in and create additional tools to support the Better Buildings, Better Plants program at the Department of Energy.

4. Support and encourage efforts to accelerate investment in industrial energy efficiency and CHP by:

(i) providing general guidance, technical analysis and information, and financial analysis on the value of investment in industrial energy efficiency and CHP to States, utilities, and owners and operators of industrial facilities;

(ii) improving the usefulness of Federal data collection and analysis; and

(iii) assisting States in developing and implementing State specific best practice policies that can accelerate investment in industrial energy efficiency and CHP.

CHP Technical Assistance Partnerships

DOE's CHP Technical Assistance Partnerships (CHP TAPs), formerly called the Clean Energy Application Centers (CEACs), promote and assist in transforming the market for CHP, waste heat to power, and district energy technologies and concepts throughout the United States.

Key services of the CHP Technical Assistance Partnerships include:

- Market Opportunity Analyses – Supporting analyses of CHP market opportunities in diverse markets including industrial, federal, institutional, and commercial sectors.
- Education and Outreach – Providing information on the energy and non-energy benefits and applications of CHP to state and local policy makers, regulators, energy end-users, trade associations and others.
- Technical Assistance – Providing technical assistance to end-users and stakeholders to help them consider CHP, waste heat to power, and/or district energy with CHP in their facility and to help them through the project development process from initial CHP screening to installation.

The CHP Technical Assistance Partnerships are offering technical assistance to the more than 550 major source facilities impacted by the Boiler MACT regulation.

EPA CHP Partnership

The CHP Partnership is a voluntary program seeking to reduce the environmental impact of power generation by promoting the use of CHP. The Partnership works closely with energy users, the CHP industry, state and local governments, and other clean energy stakeholders to facilitate the development of new projects and to promote their environmental and economic benefits.

Federal Energy Management Program (FEMP)

In July 2013 the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy (EERE) released a Notice of Intent to make U.S. Federal agencies aware that EERE intends to issue, on behalf of FEMP, a funding opportunity called Assisting Federal Facilities with Energy Conservation Technologies (AFFECT). AFFECT will provide direct funding to U.S. Federal agencies for the development of capital projects and other initiatives to increase the energy efficiency and renewable energy investments at agency facilities. FEMP will provide technical assistance to all Federal agencies prior to and in anticipation of the funding opportunity.

It is anticipated that AFFECT will include CHP as well as renewable energy sources such as solar, wind, biomass, landfill gas, ocean, geothermal and waste to energy.

Financing

U.S. Department of Energy - Loan Guarantee Program

Section 1703 of Title XVII of the Energy Policy Act of 2005 authorizes the U.S. Department of Energy (DOE) to issue more than $10 billion in loan guarantees for energy efficiency, renewable energy and advanced transmission and distribution projects. Projects must "avoid, reduce or sequester air pollutants or anthropogenic emissions of greenhouse gases; and employ new or significantly improved technologies as compared to commercial technologies in service in the United States at the time the guarantee is issued."

CHP technologies are potentially eligible if a project meets the "new/improved" technology criteria. In fact, in 2013 the DOE released a draft loan guarantee solicitation that explicitly mentioned CHP as illustrative types of projects eligible for the program. However, this loan guarantee program will not be useful for combined heat and power (CHP) for two reasons:

- The majority of opportunities for saving energy are in deployment of commercial CHP technologies, which do not appear to be eligible for this program; and
- For CHP projects the proposed fees are onerous, especially in view of the relatively small size of CHP projects.

American Recovery and Reinvestment Act (ARRA)

In 2009, following the passage of the ARRA, the DOE issued $156 million grants for DHC/ CHP/ Waste Energy /Industrial Efficiency to be used in “shovel ready” projects on both institutional and public sectors. After the solicitation was closed on July 14, 2009, in total 359 proposals were submitted to DOE with the total value of $9.2 billion. Out of that the federal share would have had been $3.4 billion compared to the offered $156 million. Therefore, the rate 25:1 from the need to the available grant funds emphasizes the strong interest in the energy market in DHC and CHP.

USDA Rural Utility Service

The Rural Utility Service (RUS) was originally created as the Rural Electrification Administration during the Great Depression. In the 1930s, many rural regions lacked basic utilities that we take for granted today, like electricity, telephone access, and indoor plumbing. One of the goals of the New Deal was to bring these services to rural areas. Today, RUS works to improve rural access to electricity, water and waste services, and telecommunications, including high-speed Internet access. A new program is going through the USDA rulemaking process to implement the Energy Efficiency and Conservation Loan Program, which may be available to fund CHP projects in rural areas. Generally, RUS funding is made available through rural electric service providers (such as Rural Electric Cooperatives) rather than directly to individual farmers or business owners.

The Rural Utility Service Electric Program makes loans to support retail electric service in rural areas or the power supply needs of distribution borrowers. Eligible projects include demand side management, energy conservation, and renewable energy systems, all of which could apply to energy efficiency projects.[37] However, this program does not seem to be frequently used for energy efficiency projects. According to USDA's *Energy Investment Report*[38], the RUS Rural Electric Program funded a loan guarantee for an energy efficiency project in Bismarck, North Dakota for about $50 million in 2003, but no energy efficiency programs since. More recently this program has funded direct loans and loan guarantees for solar, wind, renewable biomass, and anaerobic digester projects, some of which have included CHP. This suggests that this program is an underutilized resource for CHP projects.

Air Quality Standards

Boiler MACT

In December 2012, the U.S. Environmental Protection Agency issued a set of final adjustments to Clean Air Act standards for major source and area source boilers as well as certain solid waste incinerators. These rules are commonly called the "Boiler MACT" (maximum achievable control technology) rule.

Of particular interest to facilities with coal- and oil-fired boilers are the National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. "Major sources" of toxic air emissions are defined as large boilers and process heaters at industrial, commercial and institutional facilities that have the potential to emit 10 tons per year (tpy) or more of any single hazardous air pollutant (HAP) or a combination of such pollutants in excess of 25 tpy. (A companion rule to the major source regulation imposes requirements on area sources, which emit less than 10 tpy of any single air toxin and less than 25 tpy of any combination of them.) The covered pollutants include carbon monoxide as a surrogate for organic HAPs, hydrogen chloride, mercury, filterable particulate matter and total selected metals.

Existing sources must comply with the standards by Jan. 31, 2016; however, if needed, they may request from their permitting authority an additional year to comply.

Under the rule, all boiler sites must follow work practice standards that include boiler tuneups and energy assessments. These work practice standards complete the compliance obligation for natural gas-fired boilers and existing small (i.e., under 10 million Btu/hr heat input) coal- and oil-fired boilers; however, larger coal- and oil-fired boilers must also meet the emissions limits specified in the rule.

The rule presents an opportunity for major source sites with coal- and oil-fired boilers to consider switching to natural gas and/or natural gas-fired CHP instead of installing costly emissions controls to achieve compliance. The U.S. Department of Energy supports the use of natural gas CHP as a compliance strategy by offering technical and other assistance to affected boiler sites through its regional CHP Technical Assistance Partnerships, or CHP TAPs (prior to Oct. 1, 2013, the DOE's Clean Energy Application Centers). For more on key major source and area source requirements, see the DOE Advanced Manufacturing Office's "Summary of EPA Final Rules for Air Toxic Standards for Industrial, Commercial, and Institutional (ICI) Boilers and Process Heaters" (Pielli and Wickwire 2013).

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[37] See 7 CFR 1710; http://www.law.cornell.edu/cfr/text/7/1710.

[38] USDA. "Energy Investment Report." http://www.usda.gov/energy/maps/report.htm. Accessed June 18, 2013. U.S. Department of Agriculture.

Significant opportunity exists in Minnesota to replace some of the affected boilers with new CHP. Over 55 facilities in Minnesota will be impacted by the new boiler rules, and while CHP may not be an appropriate measure for every affected facility, it represents a potentially attractive opportunity to satisfy the new rules while establishing a long-term onsite energy generation solution (Zoet 2013).

Proposed Legislation, Policies and Regulations

Energy Sustainability and Efficiency Grants and Loans (Energy Independence and Security Act)

Although this legislation remains in the statutes, its authorization for appropriations has expired. It is included in this section because some of these provisions may be proposed again in the future. The Energy Security and Independence Act (EISA) of 2007, passed by the Congress and signed by the President, included two provisions relevant to CHP, as described below.

Energy Sustainability and Efficiency Grants and Loans for Institutions

Section 471 authorized appropriations of $750 million annually for 5 years was authorized for implementing or improving sustainable energy infrastructure, including district energy systems, facilities for production of energy from renewable sources, CHP, waste heat recycling or natural sources of thermal energy. Eligible public sector entities include institutions of higher education, local governments, municipal utilities, public school districts or designees of these institutions.

Waste Energy Recovery Incentives

Sections 451-453 of EISA authorize a program to encourage the recovery of industrial waste heat and recycling it into useable heat and electricity. This provision establishes a program to provide waste energy recovery grants at the rate of $10/MWh of electricity or $2.92/MMBtu of useful thermal energy.

Local Energy Supply and Resiliency Act of 2013

The Local Energy Supply and Resiliency Act (LESRA) was introduced by Sen. Al Franken (D-MN) in June 2013. In Sept. 2013 a bipartisan revised version of LESRA was introduced by Sen. Franken and Sen. Lisa Murkowski (R-AK) as an amendment to S. 1392 -- the “Energy Savings and Industrial Competitiveness Act of 2013”, co-sponsored by Senator Jeanne Shaheen (D-NH) and Senator Rob Portman (R-OH). As of Oct. 2013 further consideration of energy legislation in this Congress is questionable.

LESRA is designed to help industry, universities, hospitals and others capture waste heat and use renewable resources for heating, cooling, and power generation. It will also strengthen our ability to keep the lights on, keep buildings comfortable and enable uninterrupted business operations. This is possible through combined heat and power (CHP) and district energy systems, which have proven to be resilient during times of natural disasters.

Reducing interest costs is the key to implementing highly efficient and resilient energy infrastructure. As described below, LESRA would 1) establish a program to provide cost-shared funding for technical assistance for feasibility studies and engineering; and 2) enable qualifying energy infrastructure projects to access lower-interest debt financing through a loan guarantee program.

Technical Assistance Program. The bill establishes a grant program in the Department of Energy to provide technical assistance for identifying, evaluating, planning and designing waste heat recovery systems for the purposes of heating, cooling, and power generation. This program helps for-profit and nonprofit entities identify opportunities, assess feasibility, overcome barriers to project implementation, conduct financial assessments and perform the required engineering. Authorized appropriations: $150 million over the period 2014 to 2018.

Local Energy Infrastructure Loan Guarantee Program. The bill authorizes the Department of Energy to provide loan guarantees to projects that: 1) recover waste heat or use local renewable energy for heating or cooling: 2) generate power locally with CHP or renewable energy; 3) distribute power in microgrids, or 4) distribute heating or cooling energy to buildings. Unlike past DOE loan guarantees for innovative technologies, this program would focus on proven, commercial technologies, with the goal of reducing interest costs for local energy infrastructure. Funds to carry out this program will come from user fees.

Master Limited Partnerships Parity Act

The Master Limited Partnerships Parity Act (MLPPA) was introduced in both the Senate (S. 795, by Sen. Chris Coons, D-DE and others) and the House (H.R. 1696, by Rep. Ted Poe, R-TX and others).

A Master Limited Partnership (MLP) is a business structure that is taxed as a partnership, but whose ownership interests are traded like corporate stock on a market. The liquidity of such a vehicle makes it very attractive to investors. Double taxation (corporate and individual) is avoided because income from an MLP is taxed only at the individual level, thereby significantly reducing the cost of capital.

MLPs have been used for decades but by law have only been available to investors in energy portfolios for oil, natural gas, coal extraction, and pipeline projects. The MLPPA is an elegantly brief bill that simply extends the definition of “qualified” sources to include clean energy resources and infrastructure projects. Specifically included are those energy resources and technologies that qualify under Internal Revenue Code Sections 45 (production tax credits) and 48 (investment tax credits) of the tax code, including biomass, geothermal, solar, municipal solid waste and CHP.

GHG Regulation of Power Plants

New Source Performance Standards

On September 20, 2013, the Environmental Protection Agency (EPA) issued a proposed new rule pursuant to section 111 of the Clean Air Act (CAA), which would establish new source performance standards (NSPS) for carbon dioxide (CO2) emissions from new fossil fuel-fired electric utility steam generating units (EGUs) and natural gas-fired stationary combustion turbines.

The proposed rule would establish separate standards for certain types of natural gas-fired combustion turbines and for coal-fired electric utility boilers, including integrated gasification combined cycle (IGCC) units. By statute, each NSPS is required to reflect the application of the “best system of emission reduction” (BSER) that EPA has determined to be “adequately demonstrated” taking into account costs, environmental impacts, and energy requirements. The proposed rule would set a standard of performance for coal fired electric utility boilers and IGCC units based on the partial application of carbon capture and storage (CCS) technology as the BSER. For natural gas-fired stationary combustion turbines, EPA proposes to establish standards based on the application of natural gas combined cycle (NGCC) technology as the BSER. Citing lack of data, EPA has not proposed standards of performance for modified or reconstructed EGUs.

Notably for CHP, the proposed standard of performance for each subcategory is in the form of a gross energy *output-based* CO_2 emission limit expressed in units of emissions mass per unit of *total useful recovered energy*, specifically, in pounds per megawatt-hour (lb/MWh). EPA proposes that *useful recovered energy* include the gross electric output plus 75 percent of the useful thermal output.

The proposed rule would set an emissions limit for new coal fired EGUs of 1,100 lb CO_2/MWh over a rolling 12-month operating period. This level will require the units to install at least “partial” application of CCS. Alternatively, coal plants could accept a more stringent limit of 1,000-1,050 lb CO_2/MWh averaged over an 84-month operating period. EPA asserts that these limits correspond to a reduction in CO_2 emissions of approximately 40 percent as compared to CO_2 emissions from a new, highly efficient coal-fired power plant without CCS technology.

The proposed rule sets two emissions limit standards for new natural gas-fired stationary combustion units depending on size. Units with a heat rate in excess of 850 MMBtu/hr will be subject to a 1,000 lb CO_2/MWh, while smaller units (less than or equal to 850 MMBtu/hr) must meet a standard of 1,100 lb CO_2/MWh. Both standards are based on the performance of modern NGCC units without CCS.

In addition, to recognize the environmental benefit of reduced electric transmission and distribution losses of CHP, EPA has proposed that for CHP facilities meeting certain efficiency criteria the measured electric output would be divided by 0.95 to account for a 5 percent avoided energy loss in the transmission of electricity. The efficiency criteria require that at least 20 percent of the total gross useful energy output consists of electric or direct mechanical output and that least 20 percent of the total gross useful energy output consists of useful thermal output on a rolling three calendar year basis,

Clean Power Plan (Existing Power Plants)

On June 18, 2014, the U.S. Environmental Protection Agency has proposed rules for reducing greenhouse gas (GHG) emissions in existing power plants through section 111 (d) of the Clean Air Act. In general,[39] the rule defines an “affected source” as a fossil fuel power plant designed to sell more than 219,000 MWh of electricity per year *and* more than one-third of the potential electric output to the grid.

The EPA has provided great flexibility to states in meeting GHG reduction goals by taking a “systems approach” – allowing states to consider a wide range of actions that can be taken “beyond the fence line” of the affected electric generating units (EGUs) to more cost-effectively reduce carbon dioxide emissions. It is important to note that the Clean Power Plan sets out different goals for each state, based on their ability to reduce emissions with these four “building blocks”:

- heat rate[40] improvements at coal-fired EGUs;

[39] There are some inconsistencies in the proposed rule that suggest that gas-fired plants must be both designed to *and actually sell* those threshold amounts on a three-year rolling average.

[40] “Heat rate” means the amount of fuel required to produce one kilowatt-hour of useful energy (usually expressed as Btu per kilowatt-hour of electricity).

- redispatch from steam generators using coal, oil or natural gas to existing natural gas combined-cycle units;
- reductions in EGU emissions due to increased low- or zero-carbon generation; and
- reductions in EGU emissions due to end-use energy efficiency.

State reduction goals, expressed in pounds of carbon dioxide per net megawatt-hour of useful energy, vary dramatically depending on the particular state's opportunities relative to the building blocks. Figure 23 shows the proposed final reduction goals for each state for 2030 and beyond. Minnesota's goal is 873 lbs/MWh. For perspective, the new source performance standards proposed earlier by the EPA for new power plants range from 1,000 to 1,100 lbs/MWh of CO_2, depending on power plant size – a range set based on emissions from natural gas combined-cycle plants generating only power.

The EPA has proposed to include thermal energy as well as electric energy produced in CHP plants in calculating useful energy to meet state goals for 2030. The agency has proposed crediting 75 percent of CHP thermal output. This regulatory recognition of thermal energy recovery via CHP is an important and very sound step, and is consistent with the approach taken in the new source performance standards for new power plants.

Although state goals are based on the four building blocks, state plans need not be restricted to those categories. States are free to employ a wide range of strategies to reduce emissions. In its proposed rule, the EPA specifically asks for comment on the role of CHP in meeting emission reduction goals.

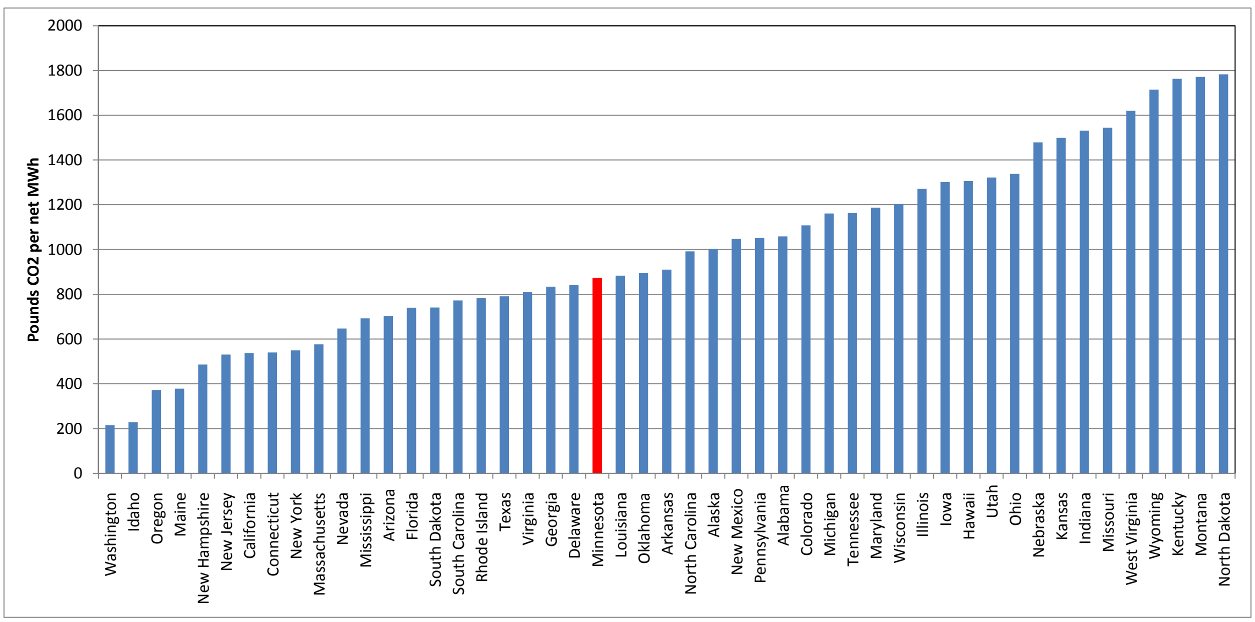

Figure 23. Proposed State Goals for Carbon Dioxide Emissions Reduction by 2030, Clean Power Plan

Source: FVB Energy analysis using data from "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," *Federal Register*, Vol. 79, No. 117; June 18, 2014.

CHP could be a powerful tool for Minnesota in meeting emission reduction goals and should be considered as Minnesota crafts its compliance plan. Minnesota could achieve emission reductions by recovering waste heat in existing power plants or by implementing highly efficient new CHP production, allowing reductions in high-emissions power generation in affected power plants.

It will not be cost-effective to recover waste heat from every affected power plant, but some plants could be retrofitted for CHP, which would improve the plant heat rate and reduce total CO_2 emissions. Heat can be effectively transported long distances with current hot water district heating piping technology.

Even greater potential exists to reduce power plant emissions by constructing new CHP plants to supply heat and power to industry and buildings. District energy systems can play a crucial role in implementing new CHP plants. These systems pool the thermal users to accommodate larger, more cost-effective CHP units. Economies of scale make it more cost-effective to install CHP in sizes above 5 MW, which is why district energy systems are critical to increased CHP implementation. Widespread district energy use is the reason that countries like Denmark and Finland have high levels of CHP.

Construction of new CHP plants will result in avoidance of emissions from affected EGUs by substituting CHP power for generation from those units, whether the CHP power is delivered to the grid or allows a reduction in purchases from the grid. CHP can deliver significant CO_2 reductions, as shown in Figure 17, which compares CHP and power-only plants relative to CO_2 emissions per unit of useful energy. The CHP emissions were calculated by dividing the CO_2 emissions of the CHP plant by the sum of the electricity output and 75 percent of the thermal output.

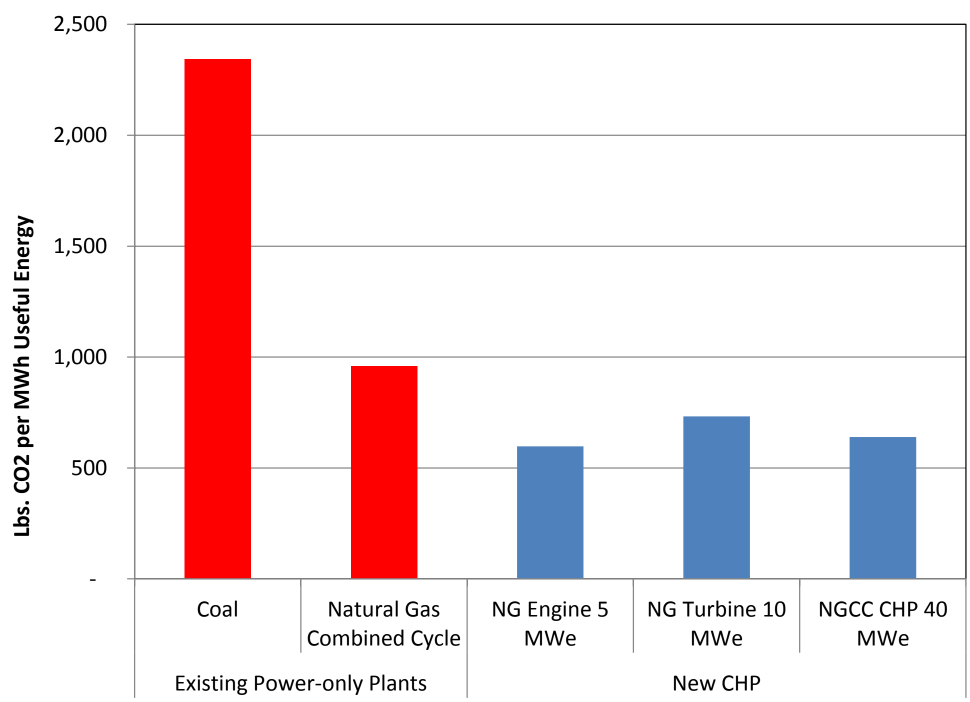

Figure 24. Comparison of Carbon Dioxide Emissions From Power-Only and CHP Plants

Source: FVB Energy analysis

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Appendix C: Straw Man Options for Minnesota CHP Policy

Straw Man Options for Minnesota CHP Policies

Summary Document Derived from Work in Progress on Minnesota CHP Regulatory Issues and Policies Evaluation

June 20, 2014

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1. Executive Summary

This document was prepared to elicit stakeholder comments on draft “Straw Man” options emerging from a study being undertaken for the Minnesota Department of Commerce. That study (“Minnesota CHP Regulatory Issues and Policies Evaluation”) is assessing alternative approaches and developing recommendations for potential changes in Minnesota policies and programs for including CHP. This document incorporates data and material from that study but much of the ultimate final report has been omitted to focus this document on the evaluation of Straw Man policy options. A related study (“Minnesota CHP Potential Study”) is also being undertaken to help inform potential quantitative goals for CHP growth.

Comment is sought on the following key “Straw Man” options, which are described briefly below and summarized in the subsequent table.

1. **Natural Gas CIP – Natural gas utilities would have CHP goals**
   1.1. Low CHP goal with capital incentive for CHP implemented by customers (or third parties on behalf of customers)
   1.2. Low CHP goal with 15-year operating incentive for CHP implemented by customers (or third parties on behalf of customers)
   1.3. Medium CHP goal with both capital and operating incentives

2. **Electric and Natural Gas CIP – Both electric and natural gas utilities would have CHP goals**
   2.1. Low CHP goal with capital incentives for CHP implemented by customers (or third parties on behalf of customers)
   2.2. Low CHP goal with 15-year operating incentives for CHP implemented by customers (or third parties on behalf of customers)
   2.3. Medium CHP goal with both capital and operating incentives

   Customers would have the option of applying for either electric utility or natural gas utility incentives, but could not receive both.

3. **Utility Investments in CHP – In addition to the customer incentives under Option 2, utilities would be encouraged to invest in CHP as ratebase investments and be credited in the CIP program based on CHP output**
   3.1. Medium CHP goal with capital incentives for CHP implemented by customers (or third parties on behalf of customers)
   3.2. Medium CHP goal with 15-year operating incentives for CHP implemented by customers (or third parties on behalf of customers)
   3.3. High CHP goal with both capital and operating incentives

   A system of tradable credits would be created to promote economic efficiency within the CHP tiers of the CIP program.

   Electric and gas utilities would be allowed and encouraged to cooperate to implement CHP projects, with the CIP credit split based on the total financial contribution made by each utility.

4. **Renewable Energy Standard – Expand the Renewable Energy Standard (RES) to include a specific goal within the RES for currently eligible renewable CHP technologies**

4.1. Consistent with current law, include only renewable CHP.
4.2. Incorporate additional provisions for RES credit to encourage use of biomass for thermal energy production without power production in areas of the state without access to natural gas service.

5. **Alternative Portfolio Standard – Establish a new portfolio standard similar to the RES that would provide requirements for non-renewable or renewable CHP**
   5.1. Low APS goals
   5.2. High APS goals

6. **Integrated Resource Planning – Require electric utilities to demonstrate that, before power-only capacity is proposed, CHP opportunities within their service territory have been thoroughly assessed to determine the benefits of CHP relative to total primary energy efficiency, GHG emissions, power grid resiliency, peak demand management and risk management, with the following options for assumed GHG value per metric tonne CO2 equivalent**
   6.1. $25
   6.2. $50

Stakeholder feedback is sought on any aspect of these draft options. In particular, we pose the following questions:

1. *Which options will be most effective in encouraging CHP? Why?*

2. *Which options will be least effective? Why?*

3. *What concerns do you have regarding each option, relative to:*
   3.1. Consistency with current statutes?
   3.2. Administrative practicality?
   3.3. Unintended impacts on other efficiency efforts?
   3.4. Other concerns?

4. *How could the concerns you raise be mitigated?*

5. *Are the incentive levels appropriate?*

6. *Are the calculation methodologies discussed in this paper appropriate? If not, why not? What changes would you suggest?*

7. *Do the low, medium and high draft goals for CHP in the CIP present a reasonable range of goals?*

8. *Do the low and high APS goals present a reasonable range of goals?*

Feedback can be provided to Mark Spurr at mspurr@fvbenergy.com.

Option --->	1			2			3				5		6	
Sub-Option --->	**1.1**	**1.2**	**1.3**	**2.1**	**2.2**	**2.3**	**3.1**	**3.2**	**3.3**	**4**	**5.1**	**5.2**	**6.1**	**6.2**
Conservation Improvement Program														
Separate new CHP goals in CIP (% of sales)	CIP Low	CIP Low	CIP Med	CIP Low	CIP Low	CIP Med	CIP Med	CIP Med	CIP High					
Natural Gas	0.10%	0.10%	0.15%	0.10%	0.10%	0.15%	0.15%	0.15%	0.23%					
Electric IOUs				0.20%	0.20%	0.30%	0.30%	0.30%	0.45%					
Elec Coops/Munis				0.10%	0.10%	0.15%	0.15%	0.15%	0.23%					
Customer incentives from Utility (include as CIP expenditures)														
Natural Gas Utilities														
Capital incentive $/1000 Btu-hr	$ 100		$ 100	$ 100		$ 100	$ 100		$ 100					
Operating gas rate discount ($/MMBtu over 15 years)		$0.93	$0.93		$ 0.93	$ 0.93	$ 0.93		$ 0.93					
Electric Utilities														
Capital incentive ($/kW)				$ 500		$ 500		$ 500	$ 500					
Operating credit ($/MWh over 15 years)					$12.74	$12.74		$12.74	$12.74					
CIP Credits to Utilities for Utility-Owned CHP														
Natural Gas Utilities														
CIP credit ($/MMBtu over 15 years)							$0.93		$ 0.93					
Electric Utilities														
CIP credit ($/MWH over 15 years)								$12.74	$12.74					
Renewable Portfolio Standard														
Additional CHP (Renewable Only) Tier in Expanded RPS (% of sales)														
By 2020														
Electric IOUs										0.25%				
Elec Coops/Munis										0.17%				
By 2030														
Electric IOUs										1.20%				
Elec Coops/Munis										0.83%				
Alternative Portfolio Standard														
CHP goals in new APS (all CHP including gas-fired) (% of sales)											APS Low	APS High		
By 2020														
Electric IOUs											1.25%	4.00%		
Elec Coops/Munis											0.85%	2.75%		
By 2030														
Electric IOUs											4.00%	13.50%		
Elec Coops/Munis											2.75%	9.00%		
Integrated Resource Planning														
EU IRP requirement to look at CHP first, with CO2 value per metric tonne:													$ 25	$ 50

2. Introduction

This document was prepared to elicit stakeholder comments on draft "Straw Man" options emerging from a study being undertaken for the Minnesota Department of Commerce. That study ("Minnesota CHP Regulatory Issues and Policies Evaluation") is assessing alternative approaches and developing recommendations for potential changes in Minnesota policies and programs for including CHP. This document incorporates data and material from that study but much of the ultimate final report has been omitted to focus this document on the evaluation of Straw Man policy options.

A related study ("Minnesota CHP Potential Study") is also being undertaken to help inform potential quantitative goals for CHP growth.

3. Why CHP is Important

Combined heat and power (CHP) systems reduce fossil fuel use and GHG emissions by recovering heat that is usually wasted as reject heat in power plants for useful purposes (heating buildings, domestic hot water, industrial process heat, or conversion to cooling energy for air conditioning or industrial cooling energy).

The electricity sector in Minnesota is only 32% efficiency in converting primary energy to useful delivered electricity. Most of the losses consist of heat rejected in power plant cooling towers and stacks, with additional losses occurring in transmission and distribution of power. As illustrated in Figure 3-1, of the total non-transportation energy use in Minnesota (1,238 trillion Btu or TBtu):

- Only 50% if converted to useful energy;
- 31% is lost in the power sector (mostly as heat); and
- 19% is lost in the Residential, Commercial & Industrial sectors (RCI) in converting RCI primary energy or electricity to useful energy services.

In 2008, the total 384 TBtu of wasted energy in the power sector are estimated to consist of 12 TBtu of electrical line losses and 372 TBtu of waste heat. This power generation waste heat in Minnesota is nearly equal to the total requirement for heat energy in the RCI sectors (390 quads, assuming 90% of RCI primary energy is for heat production, and is converted to useful energy at an average efficiency of 70%).

As discussed in section 4, CHP also has the potential to provide a range of benefits relative to grid resiliency, reduce power line losses and peak power demand management.

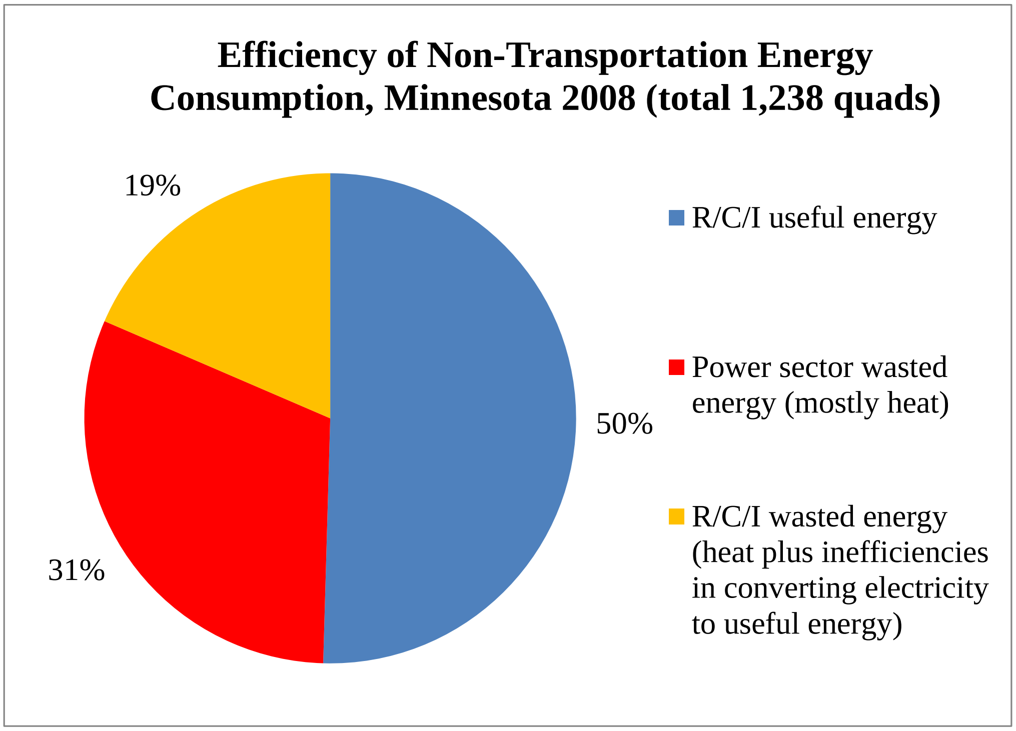

Figure 3-1. Efficiency of Non-Transportation Energy Consumption in Minnesota

4. Key Challenges Constraining Increased Use of CHP

Spark Spread

A fundamental economic test for CHP is “spark spread” – the difference between the value to the generator of the electricity and thermal energy produced and the cost of the fuel needed to produce that electricity. In general, higher grid-provided electricity prices and lower natural gas prices make CHP projects more economic.

The value of the electricity generated may be a weighted average of avoided purchased power and sales of excess power. Minnesota has relatively low electricity costs, with an average *retail (all consumers)* rate lower than the national average, as illustrated in Figure 4-1.

Both natural gas and electricity prices in Minnesota are lower than the national averages for each end use sector. Table 4-1 shows the comparative Minnesota and USA average prices for natural gas and electricity for each end use sector and for power generation in 2011. For the commercial and industrial sectors, natural gas prices are lower than national averages by about the corresponding percentage for electricity prices by sector.

Spark spread is affected by both the particular CHP technology and sector in which the CHP facility would be located. The heat rate (BTU’s of fuel required to produce a kWh of electricity) varies among CHP technologies, with lower heat rates (higher electric generation efficiencies) helping to increase the spark spread and make the economics of the CHP system more attractive. Industrial power prices are generally lower, thus reducing the spread. (On the other hand, economies of scale in larger industrial CHP projects can enhance the economics of CHP compared with smaller commercial sector projects.)

The spark spread for any given CHP system is one of the basic assessments conducted in a feasibility assessment. If the spark spread is not significant enough, and the total benefits of generating power onsite are thus not larger than the cost of fuel required to generate that power, the project will likely not go further. Tools such as discounts on natural gas or additional revenue streams for excess power production may improve the spark spreads of CHP systems.

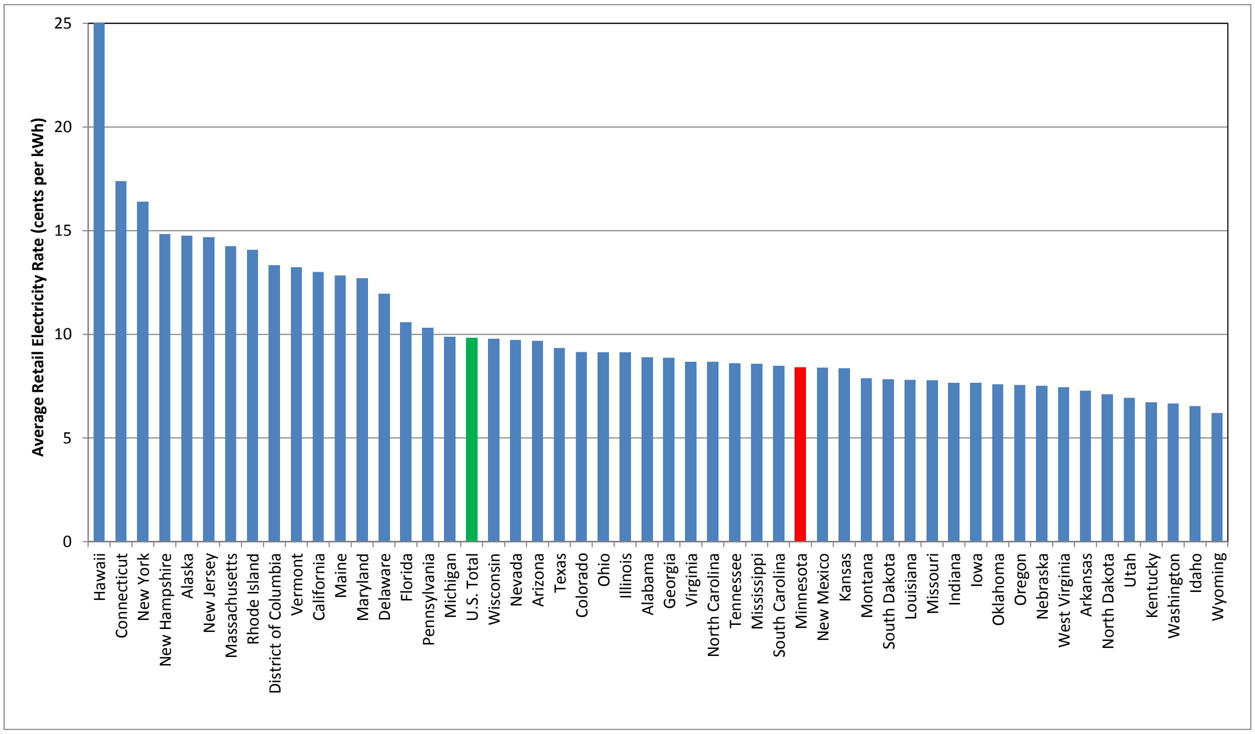

Figure 4-1. Average Retail Electricity Rates by State

	Natural Gas ($/MMBtu)			Electricity (cents/kWh)		
	MN	USA	MN % of USA	MN	USA	MN % of USA
Residential	$ 8.76	$ 10.78	81%	10.97	11.72	94%
Commercial	$ 7.39	$ 8.80	84%	8.63	10.24	84%
Industrial	$ 5.49	$ 5.98	92%	6.47	6.83	95%
All End Use	$ 7.10	$ 8.23	86%	8.68	9.94	87%
Power Generation	$ 5.88	$ 4.80	123%			

Table 4-1. Minnesota Natural Gas and Electricity Prices Compared with U.S. Average Prices (2011)

Source: EIA State Data 2011

Market for Excess Power

To maximize CHP efficiency it is necessary to size and operate the CHP system to follow the thermal load of the thermal energy user. However, in many facilities this can result in significant production of power in excess of the host site's needs, and the power will only be produced if a suitable buyer for the power is identified. Consequently, the price to be received for sale of the excess power is often a crucial factor in the financial feasibility of a CHP project. Unless owned by the electric utility, CHP systems in Minnesota cannot sell electricity on a retail basis, so the revenue for excess CHP power sales is limited to the price the electric utility is willing to pay.

Absent an opportunity to sell excess power, the size of a CHP system at a large industrial facility with high thermal demand will likely be constrained by the onsite power needs. The facility will not be incentivized to build a CHP system that produces any more power than it needs onsite. This can effectively reduce the system's efficiency, because the system will not be properly matched and sized to the facility's thermal needs. This scenario leaves very low cost energy efficiency resources "on the table," since the system could have been sized larger had a market for excess power been identified.

Cost of Capital and Internal Investment Priorities

CHP requires a significant capital investment, and the equipment has a long life – generally over 15 years. The investment required for CHP will generally come from some combination of debt and equity. Access to debt capital, and the associated interest rate, will vary significantly from one organization to another. Further, credit availability will vary depending on broader economic conditions. Access to internal equity funding is affected by a company's financial condition and internal competition with other potential investments. CHP is not regarded as part of most end-users' core business focus and, as such, is sometimes subject to a high internal investment "hurdle rate", i.e. the rate of return a project is required to meet in order to get capital funding. Another way to express this is that for many organizations the payback period required to "green light" a CHP project is very short.

Simple payback is a commonly understood measure of financial viability. It is calculated by dividing the initial capital investment by the annual operating savings.

Another way to quantify investment return thresholds, for private sector businesses, is Return on Equity (ROE). This is the return to equity investors on a discounted cash flow basis. ROE can't be compared directly with simple payback, because typically companies don't fund 100 percent with equity; instead they "leverage" the equity return by borrowing some of the funds. The ratio between debt and equity varies depending on the company and the project. A typical capital structure for the electric utility industry is 45 percent debt and 55 percent equity (EIA NEMS Model 2013).

The appropriate comparison with simple payback is Weighted Average Cost of Capital (WACC), which takes into account not only ROE but also the after-tax cost of debt, and is calculated as follows:

Debt interest rate = IR

Return on Equity = ROE

Debt as % of total capital = DR

Corporate tax rate = T

Weighted average cost of capital = [(IR x DR) x (1 – T)] + [ROE x (1 - DR)]

The Capital Recovery Factor (CRF) is calculated as follows, with Y = term of financing in years:

CRF = [IR x (1 + IR)^Y] / [(1 + IR)^Y - 1]

The annual average cost of both debt and equity can then be calculated by multiplying initial capital investment by the CRF.

Figure 4-2 shows the relationship between simple payback , WACC and CRF, assuming a 20-year amortization period.

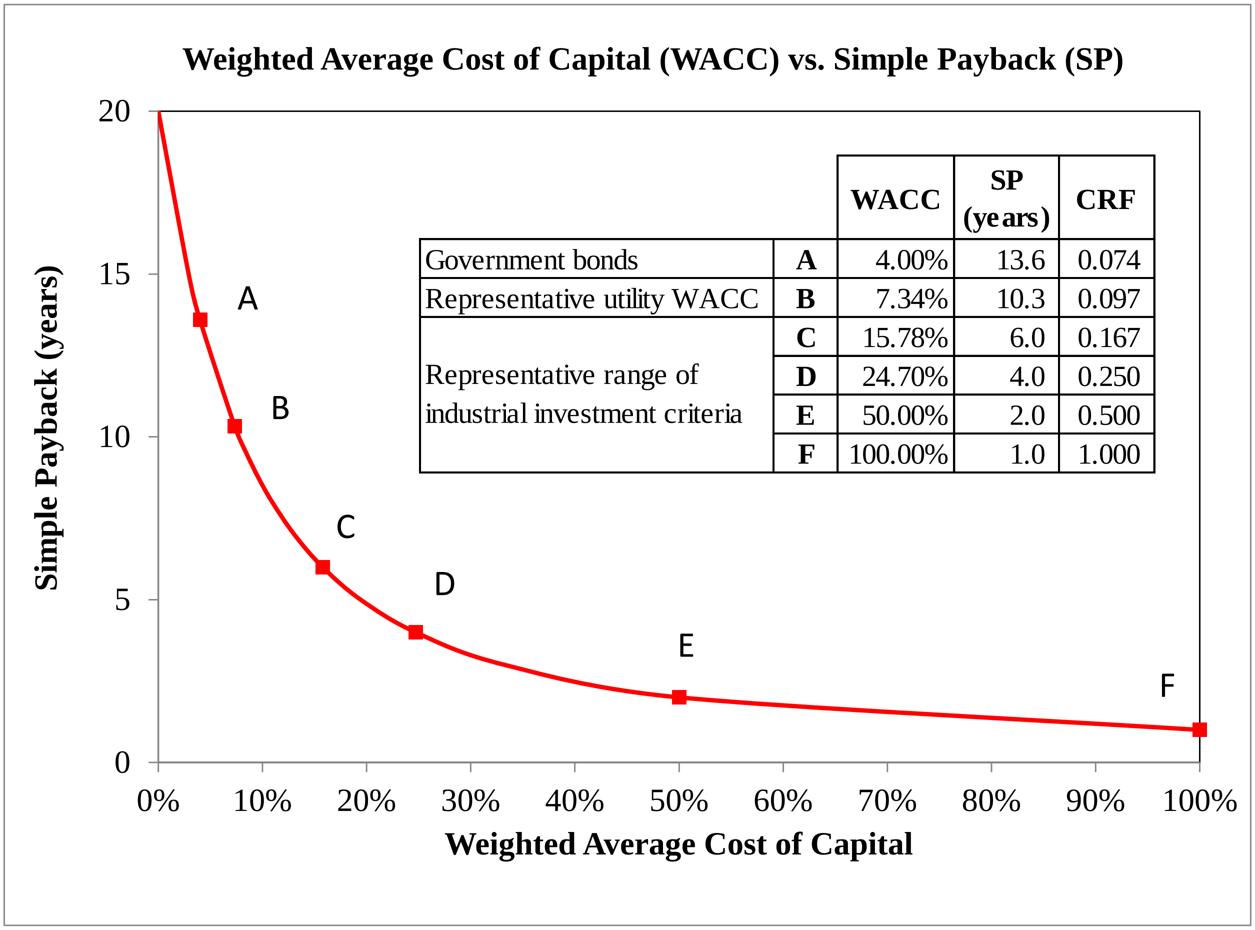

Figure 4-2. Relationship Between Weighted Average Cost of Capital (WACC) and Simple Payback (SP) and Capital Recovery Factor (CRF)

Particularly in industrial companies, competing capital investment demands can make energy efficiency a relatively low investment priority. A 2003 survey of potential CHP implementers of CHP indicated that 47% required simple paybacks less than 2 years, and only 35% would accept a payback as long as 4 years. A 4-year payback is equal to a WACC of 25 percent.

On the other hand, utilities have longer investment timeframes. For example, Xcel's ROE was reported to be 10.26 percent in 2013 (Ycharts). If we estimate that Xcel's average debt interest rate is 6.0 percent, and that the corporate tax rate is 38 percent, the estimated Xcel WACC of 7.34 percent, equivalent to a simple payback of over 10 years.

Decision-makers at other types of facilities, such as colleges, universities, hospitals, and municipalities, have an even longer investment horizon and a willingness to accept longer paybacks. For example, 20-year municipal bonds currently carry interest rates of 3.75 to 4.85 percent. In Figure 4-2 we assume government bonds carry an interest rate of 4.0 percent, corresponding to a 13.6 year simple payback.

Economic Uncertainty

Analysis of the economic feasibility of CHP must be based on assumptions regarding future values of a wide range of factors, including:

- Price of fuel used for CHP;
- Prices of fuels otherwise used for heat production, and/or value of heat sold to other users;
- Prices of electricity otherwise purchased to meet power requirements;
- Prices of electricity sold to the grid or to other users;
- Projected growth in requirements for electricity and thermal energy, which in turn is based on assumptions about future economic conditions;
- General economic uncertainty;
- Changes in utility regulation; and
- Changes in environmental regulations, including criteria air pollutants and greenhouse gases (GHG).

The uncertainties associated with these variables make decision-making challenging and, coupled with the other barriers discussed here, tend to discourage investment in CHP. To the extent that the decision criterion is a very short payback, as discussed above, the economic feasibility analysis is simplified because in essence it is based only on current values for key economic parameters.

Interconnection Standards

The most effective interconnection standards have different tiers with different requirements for CHP systems of different sizes, reflecting the fact that smaller systems are often less complex technically to interconnect. Connecting a 25 MW system to the grid might involve significant technical and safety challenges, and it would not necessarily be appropriate for a 50 kW system to be subject to the same oversight procedures. Allowing different tiers essentially provides a “fast track” for smaller systems, and longer, more detailed analysis of the more complex interconnection of larger systems.

Minnesota does *not* have a tiered interconnection standard for CHP. The Minnesota Public Utilities Commission has established uniform interconnection standards that apply to all CHP systems up to 10 MW including fossil fuel-fired facilities. Although Minnesota performs better than the average state in this policy area, Minnesota interconnection standards could be improved by raising the cap on system size covered by the interconnection standard and implementing a tiered or “fast-track” system for smaller units.

Standby Rates

Most facilities with CHP require service from the local utility for:

- Supplementary power when load is greater than the CHP output;
- Back-up supply during planned scheduled maintenance of the CHP system; and
- Back-up supply in case of unexpected, unscheduled outages of the CHP system.

The set of tariffs applying to customers with CHP or other distributed generation are sometimes called the "partial requirements tariff". The EPA CHP partnership developed the concept of the "avoided rate" as a metric for evaluating the barriers of standby rates (EPA 2009). This metric compares the projected average electricity cost, for an assumed set of monthly electricity demand and energy consumption data, under "full requirements" tariffs (assuming no CHP) to projected costs under "partial requirements" tariffs (assuming CHP). The higher the Avoided Rate, i.e., the ratio of avoided costs to the full retail average price, the higher the user's savings.

Stand-by services are provided under a range of tariff structures and rates in Minnesota utilities. The Energy Resources Center (ERC), located at the University of Illinois at Chicago (UIC), recently completed a study of standby and net metering rates for Minnesota Department of Commerce (Energy Resources Center, 2014). This study focuses on:

- Assessing the existing standby rates and net metering policies and how they affect the market acceptance of CHP projects today;
- Determining what recommendations, if any, should be considered to reduce the barriers the above factors impose on CHP development in Minnesota; and
- Modeling the economic potential of CHP projects in Minnesota investor owned utility (IOU) service territories based on analyzing the impact of existing and varied standby rates for CHP projects.

Table 4-2 shares the draft results of the Energy Resources Study analyzing the avoided rate metric for each Minnesota utility.

	Generating Capacity (kW)			
Standby Avoided Rates	**500**	**3,000**	**10,000**	**10,000**
Xcel Energy	87%	90%	93%	96%
Alliant Energy	77%	77%	78%	78%
Minnesota Power	90%	95%	92%	97%
Ottertail Power	97%	96%	96%	97%

Table 4-2. Avoided Rates of Minnesota IOUs

The results of the study suggest that while standby rates are not as significant of a barrier today as previously perceived, there are still modifications that can be made to standby rates that would further encourage CHP generators to operate more efficiently to avoid a greater portion of their full requirements rates. The UIC study suggests consideration of the standby rate recommendations summarized in Table 4-3.

Principle	Analysis and Recommendation
Transparency	*Standby rates should be transparent, concise and easily understandable.* Potential CHP customers should be able to accurately predict future standby charges in order to assess their financial impacts on CHP feasibility.
	Standby usage fees for both demand and energy should reflect time-of-use cost drivers. Time-of-use energy rates send clear price signals as to the cost for the utility to generate needed energy. This would further incentivize the use of off-peak standby services.
Flexibility	*The Forced Outage Rate should be used in the calculation of a customer's reservation charge.* The inclusion of a customer's forced outage rate directly incentivizes standby customers to limit their use of backup service. This further links the use of standby to the price paid to reserve such service creating a strong price signal for customers to run most efficiently. This would also involve the removal of the grace period.
	The standby demand usage fees should only apply during on-peak hours and be charged on a daily basis. This rate design would encourage DG customers to shift their use of standby service to off-peak periods when the marginal cost to provide service is generally much lower. Furthermore, this design would allow customers to save money by reducing the duration of outages.
Economically Efficient Consumption	*Grace periods exempting demand usage fees should be removed where they exist.* Exempting an arbitrary number of hours against demand usage charges sends inaccurate prices signals about the cost to provide this service. The monthly reservation cost providing the grace periods charges for 964 hours of usage no matter if a customer needs that level of service. Standby demand usage should be priced as-used on a daily and preferably an on-peak basis. This method directly ties the standby customer to the costs associated with proving standby service and allows customers to avoid monthly reservation charges by increasing reliability.

Table 4-3. Standby Rate Policy Recommendations from UIC Study

Recognition of Resiliency Benefits

Nationwide, the economic losses from energy supply disruption from interruption of business operations are enormous. For instance, economic research firm Moody's Analytics attributed nearly $20 billion in losses from suspended business activity just due to Superstorm Sandy. Fortunately, Minnesota does not have hurricanes, but it certainly has tornadoes and other severe weather.

The Electric Power Research Institute evaluated industrial and digital economy businesses to determine the economic costs of power outages and power quality disturbances (EPRI 2001), focusing on 3 sectors:

- Digital Economy (DE) sector: comprised mainly of data storage and retrieval, data processing, or research and development operations such as the telecommunications, data storage, biotechnology, electronics manufacturing, and the financial industry.
- Continuous Process Manufacturing (CPM) sector: comprised of manufacturing facilities that continuously feed raw materials through an industrial process such as the paper, chemical, petroleum, rubber and plastics, stone, clay, glass, and primary metals industries.

- Fabrication and Essential Services (F&ES) sector: all other manufacturing industries, plus utilities and transportation facilities, water and wastewater treatment, and gas utilities and pipelines.

Although these three sectors only accounted for 17% of all U.S. businesses, they amounted to 40% of U.S. GDP. The study found that industrial and digital economy firms are losing about $45.7 billion per year due to power outages, with an additional $6.7 billion in costs resulted from power quality disturbances other than outages. The EPRI study concluded that the cost of power outages for all industry combined is an estimated at $120 to $190 billion per year.

CHP and other local energy sources are inherently more resilient to disruption from natural disasters or other events that interrupt electric energy supply from complex and interconnected grids. Additionally, CHP systems can be designed to operate in "island" mode during a grid outage. CHP and district energy systems have demonstrated that they can keep the power on, keep factories and business running, and continue to keep people warm in the winter and cool in the summer even when the power grid is down.

These resiliency benefits are typically lacking from most cost-benefit analyses employed by the individual facilities using CHP and the utilities in whose service territory a CHP system would be deployed. So while the anecdotal evidence has been clear that CHP can provide highly critical resiliency and reliability benefits during times of grid power outages, there is no mechanism in which those benefits are specifically delineated. In contrast, the potential of the CHP system to fail is embedded in every utility's standby and backup power rates.

Recognition of Other Grid Benefits

CHP systems are typically located much closer to the end user than more traditional centralized power plants. Additionally, many CHP systems are capable of ramping up to full output very quickly, and can be more nimble electric system assets than many traditional generation resources. These two aspects of CHP systems provide numerous benefits to the grid at large. For instance, the close proximity to end-users can dramatically reduce the losses of power along transmission and distribution lines. On average, line losses are about 7% (EIA 2012), but research suggests that losses are much higher during times of peak grid demand (Chittum and Farley 2013).

CHP systems are also well positioned to provide ancillary and capacity services to the grid. Ancillary services are those that help stabilize grid voltage, and they must be capable of providing these services in a timely manner – some as quickly as within one minute of the request. Each power market has its own market for ancillary services, and CHP systems are selling their ancillary services to these markets in some parts of the country (Chittum and Farley 2013). At present, however, the use of CHP for such ancillary services is not at all widespread.

Utility Value Proposition

Many electric utilities tend to view CHP as an economic threat because traditional utility business models, and associated regulatory structures, link electricity sales to cost recovery and revenues. A CHP facility owned by a customer or third party will typically require much less utility-provided electricity than it did prior to CHP system installation. Further, electric utilities are structured and regulated in a manner that often discourages them from fully monetizing the benefits of CHP. Concern about cross-subsidization may lead state regulators to discourage electric utilities from implementing or encouraging CHP systems.

On the other hand, utilities are used to making long-term investments, and as discussed above have a relatively low cost of capital. CHP can offer tremendous direct and indirect benefits to utilities. Most of these benefits are not fully valued today. These include:

- The additional economic value of a second revenue stream for CHP thermal output;
- The speed with which CHP can be deployed relative to other generation and transmission resources;
- CHP's potential to reduce infrastructure investments and line losses associated with transmission and distribution lines;
- The potential for reduced emissions compliance costs;
- CHP's ability to function as a capacity resource; and
- CHP's potential for helping balance system power fluctuations and providing ancillary services.

Unfortunately, utilities are generally unable to take advantage of these benefits. Changes in policies and regulations would enable utilities to better monetize these benefits, increasing the likelihood that utilities could begin to view CHP systems as true economic opportunities rather than threats.

Lack of Expertise

Potential adopters of CHP may lack the information and expertise to:

- Identify and assess the costs and benefits of CHP;
- Develop a CHP project, including navigation of the institutional, technical, legal and financial issues associated with these projects; and
- Operate and maintain a CHP system.

These barriers can be overcome through the participation of third party CHP developers and operators, but some organizations are reluctant to take on such a third party relationship, reducing the amount of CHP deployed.

Air Quality and Other Permitting

CHP may increase emissions on-site while reducing emissions regionally. The U.S. Environmental Protection Agency (EPA) has increasingly recognized the total emissions benefits of CHP in its rulemaking. In recently proposed rules for greenhouse gas emissions from new power plants (EPA Proposed 111 (b) Rule), EPA has proposed that the rules would not apply to:

- facilities with design heat input less than 250 MMBtu/hr;
- facilities that supply less than 219,000 MWh of net electric generation to the utility distribution system; and
- facilities that supply less than one-third of their potential electric output to the utility distribution system.

CHP also has the potential to be part of a compliance strategy in meeting new GHG emission rules for existing power plants in the 111 (d) rules now being finalized by the EPA.

5. Comparative Economic Significance of Major Barriers

A range of barriers to increased implementation of CHP are described above. An extensive analysis was undertaken to assess the relative economic importance of each major element in the CHP financial feasibility equation in order to inform development of draft recommendations for policies and programs. That analysis was applied to a wide range of CHP technologies, which are listed in Table 5-1, and will be presented in the final report. In this Straw Man document we have omitted the analysis for the sake of brevity.

Category	Fuel	Market Sectors	Range (electric)	CHP Technologies
G.1	G	C, I	30-500 kW	30 kW MT
				100 kW ICE
				200 kW PAFC
G.2	G	C, I	500-1,000 kW	800 kW ICE
				250 kW MT x 3
				300 kW MCFC x 2
G.3	G	C, I, DE	1-5 MW	3 MW ICE
				3 MW GT
				1.5 MW MCFC
G.4	G	C, I, DE	5-20 MW	5 MW ICE
				10 MW GT
G.5	G	C, I, DE	> 20 MW	40 MW GT
WH.1	WH	I	< 5 MW	1 MW ORC
B.1	B	C, I, DE	1-5 MW	3 MW ST
B.2	B	C, I, DE	5-20 MW	10 MW ST
B.3	B	C, I, DE	> 20 MW	40 MW ST

Abbreviations

Market Sectors	Technologies
C = Commercial	MT = Microturbine
I = Industrial	ICE = Internal combustion engine
DE = District Energy	PAFC = phosphoric acid fuel cell
Fuels	MCFC = molten carbonate fuel cell
NG = Natural Gas	GT = gas turbine
B = Biomass	ST = steam turbine
WH = Waste Heat	ORC = organic rankine cycle

Table 5-1. CHP Technologies Analyzed in the FVB Study

Key elements in the CHP financial viability equation are summarized in Table 5-2. Major factors that influence each element are summarized, and potential areas for policy action are noted. Each major element is briefly discussed.

A key factor influencing multiple elements is Capacity Factor, which is the annual output of the CHP facility compared with output at full capacity over 8,760 hours, and commonly expressed as a percentage. Capacity factor is a critical variable because a higher capacity factor allows the fixed costs of CHP to be spread over more units of energy output, thereby increasing economic competitiveness.

Sizing the CHP system to meet the facility's heating load normally results in the highest efficiency, carbon emission reductions and cost savings. However, in some cases, sizing the system to meet the heating load would result in more electricity being produced than could be used on site. In these cases, the system would need to be operated below capacity to avoid producing excess electricity. Consequently, instead of sizing the CHP facility for optimal efficiency and carbon benefits, the CHP facility may be undersized to avoid the institutional and regulatory constraints associated with selling excess power.

If a CHP facility was sized and operated at the optimal capacity factor it would have to sell the excess electricity production. However, in such cases, low market values for excess power generation will significantly affect CHP economic viability as discussed below.

	Element in CHP Finacial Equation	**Major Influencing Factors**	**Potential Policy Measures**
Costs	Capital amortization costs	Capital cost, WACC	Renewable Portfolio Standard, Energy Efficiency Resource Standard, Conservation Improvement Program, Integrated Resource Planning, Grant and Loan Programs
	CHP fuel costs	Utility tariff, future trends, capacity factor	Gas utility fuel discount due to better load factor
	CHP non-fuel O&M costs	Based on technology	
Savings	Avoided cost of purchased electricity	Utility tariff, future trends, capacity factor	Favorable standby rates, Feed-In Tariff, payment for value-added grid benefits, Integrated Resource Planning
	Avoided cost of boiler fuel	Utility tariff, future trends	
	Export power revenue	Power purchase agreement, future trends	Payment for value-added grid benefits, Integrated Resource Planning

Table 5-2. Basic Elements in CHP Financial Viability Equation

CHP Capital Amortization Costs

CHP capital costs vary significantly depending on the size and type of CHP technology. From a policy perspective, the capital factor of greatest significance is the WACC, which has a dramatic impact on the financial viability of CHP projects. Of all of the key variables, WACC stands out as a powerful influence on CHP viability. Low WACC can catalyze a broad range of CHP technologies. Given that electric and gas utilities have relatively low WACCs, a high priority should be placed on determining how low-cost utility capital can be directed toward CHP.

CHP Fuel Cost

CHP fuel cost is a significant variable with complex impacts on CHP financial viability. Most CHP installations would use natural gas fuel, so higher natural gas prices would increase the annual cost of CHP but would also increase the value of offset thermal boiler production since natural gas would in most cases be the offset boiler fuel. Higher natural gas prices will also tend to drive up electricity prices since power is increasingly generated with natural gas. The impact of the CHP fuel price is highly dependent on particular CHP application, and generally cannot be influenced by State CHP policies, with the potential exception of allowing or encouraging discounted CHP fuel prices to reflect high gas supply load factor.

CHP Non-Fuel O&M Cost

Non-fuel operation and maintenance (O&M) costs are highly technology-specific. There are no practical policy mechanisms that address this cost variable.

Avoided Cost of Purchased Electricity

The avoided cost of offset electricity purchases is dependent on the particular electricity utility tariff and the operating pattern and capacity factor of the CHP facility. This variable could be influenced by policies on standby rates, feed-in tariffs or other payments per unit of CHP electricity produced, or recognition of CHP in Integrated Resource Planning assessments. Based on the study currently being finalized by the Energy Resources Center, standby rates are not a significant barrier in most utility service areas, but some improvements have been recommended.

Avoided Cost of Boiler Fuel

This variable is influenced by the natural gas tariff and or other contractual arrangement for fuel, and cannot be influenced by State Policy.

Export Power Revenue

To the extent that policy-makers desire to achieve high gains in efficiency and carbon reduction through CHP, it is important to address the value of excess CHP power generation. As noted above, low values for excess power sales often lead to CHP configurations that are sub-optimal from the standpoint of energy and environmental benefit.

Further, from a policy perspective, it is worthwhile examining the potential for CHP generation to be given additional value in recognition of value-added services that are not currently priced in the marketplace, such as locational value (reduced transmission/distribution losses) and voltage support. Recognition of these benefits, as well as potential energy supply resiliency benefits of CHP, could help stimulate increased implementation of CHP.

6. Current Minnesota Policies and Programs

Energy and Environmental Goals

The State of Minnesota has established specific goals relating to:

- fossil fuel consumption per capita;
- renewable energy use;
- GHG reduction; and
- energy savings by electric and natural gas utilities.

The Next Generation Energy Act, passed in 2007, established the following goals:

- 15 percent reduction in per capita use of fossil fuel by the year 2015 (Minn. Statutes 216C.05 Subd. 2);
- 25 percent of the total energy used in the state from renewable energy resources by the year 2025 (Minn. Statute 216C.05 Subd. 2); and
- GHG reduction goals as follows --
  - 15 percent reduction from 2005 levels by 2015,
  - 30 percent reduction by 2025, and
  - 80 percent reduction by 2050.

In addition, the Next Generation Energy Act prohibits the construction of any power plants that would produce a net increase in carbon emissions after Aug. 1, 2009. The law states that unless "a comprehensive state law or rule … that directly limits and substantially reduces greenhouse gas emissions" is enacted and is in effect by that date:

- no large fossil fuel-fired power plant can be built in Minnesota;
- no utility can import electricity from a large fossil fuel-fired power plant built in another state that was not operating on Jan. 1, 2007; and
- no Minnesota utility can purchase electricity from an outstate utility under a contract that exceeds 50 megawatts for a term of five years.

Minnesota Renewable Portfolio Standards

The 2007 legislation also created an RPS for Xcel Energy, created a separate RPS for other electric utilities,[1] and modified the state's existing non-mandated renewable-energy objective. In 2013, further legislation (H.F 729) was enacted to create a 1.5% solar standard for public utilities, a distributed generation carve-out, and a solar goal for the state. CHP that is powered by renewable fuels such as biomass or landfill gas is an eligible technology, but natural gas CHP is not.

Conservation Improvement Program (Energy Efficiency Resource Standard)

Statutory Requirements

The *Next Generation Energy Act* (NGEA) established an annual energy savings goal of 1.5 percent of average retail sales for each electric and gas utility beginning in 2010. Legislation passed in 2009 established an interim savings goal of 0.75 percent over 2010-2012 for qualifying natural gas utilities.

[1] Other electric utilities that must comply with Minnesota's RPS are: public utilities providing electric service; generation and transmission cooperative electric associations; municipal power agencies; and power districts operating in the state.

Utilities must file their CIP plans with the energy division at least every three years. Utilities report their actual CIP spending and savings achieved on an annual basis.

Certain large facilities may petition to have their revenues excluded from calculations determining investment and expenditure requirements (Minnesota Statutes 216B.241, Subd. 1a.). The petition must include a discussion of the competitive or economic pressures facing the owner of the facility and the efforts taken by the owner to identify, evaluate and implement energy efficiency improvements.

Program Results

The Department of Commerce must provide reports on the annual energy savings achieved through the CIPs. Data from that report are summarized in Table 6-1 and Table 6-2.

	Incremental Savings (GWh/year)	Expenditures ($ million)	Incremental CO2 Savings (tons/year)	$/MWH *
2006	412	$ 82.2	375,537	$ 13.31
2007	468	$ 91.2	426,646	$ 13.00
2008	597	$ 102.0	544,428	$ 11.39
2009	669	$ 144.9	609,905	$ 14.44
2010	826	$ 174.3	753,260	$ 14.07
2011	965	$ 140.6	879,936	$ 9.71
Average last 3 years				$ 12.74

* The cost per unit of savings were calculated using a typical weighted average energy efficiency measure lifetime of 15 years.

	Incremental Savings (BCF/year)	Expenditures ($ million)	Incremental CO2 Savings (tons/year)	$/MMBtu *
2006	2.1	$ 16.3	126,750	$0.52
2007	1.9	$ 16.4	115,987	$0.57
2008	1.6	$ 18.1	94,592	$0.77
2009	1.8	$ 22.8	111,522	$0.82
2010	2.6	$ 38.0	158,039	$0.97
2011	2.8	$ 41.5	170,001	$0.99
Average last 3 years				$0.93

* The cost per unit of savings were calculated using a typical weighted average energy efficiency measure lifetime of 15 years.

The electric utility sector as a whole met the 1.5% savings goal in 2010, and investor-owned utilities nearly met the goal, as summarized in Table 6-1. The natural gas utility sector as a whole met the reduced goal of 0.75% approved by the legislature as described above.

Role of CHP in CIP

H.F.729, passed in 2013, modified the definition of "energy conservation improvement" in Minnesota Statutes 2012, section 216B.241 to include "waste heat recovered and used as thermal energy," which is then defined as "capturing heat energy that would otherwise be exhausted or dissipated to the environment from machinery, buildings, or industrial processes and productively using such recovered thermal energy where it was captured or distributing it as thermal energy to other locations where it is used to reduce demand side consumption of natural gas, electric energy, or both."

H.F. 729 also includes Subd. 10 as follows:

> *'(Waste heat recovery; thermal energy distribution). Demand side natural gas or electric energy displaced by use of waste heat recovered and used as thermal energy, including the recovered thermal energy from a cogeneration or combined heat and power facility, is eligible to be counted towards a utility's natural gas or electric energy savings goals, subject to department approval.'*

There is a reasonable case, as presented below, to conclude that Minnesota Statute 216B.241, as modified by H.F.729, includes CHP as an energy conservation measure that could be incorporated into natural gas or electric utility Conservation Improvement Programs.

1. Prior to H.F. 729, CHP bottoming cycles[2] were already included in Minnesota Statute 216B.241Subd. 1 ("Energy conservation improvement may include waste heat that is recovered and converted into electricity…). Although H.F. 729 modified the wording slightly, the content was already there.

2. CHP topping cycles[3] were added in H.F.729. Article 13, Section 2, Subd. 1, part (e) clearly states "Energy conservation improvement also includes waste heat recovered and used as thermal energy." The definition of "waste heat recovered and used as thermal energy" in Subd. 1, part (n) describes topping cycle CHP, although the phrasing is unconventional. CHP does indeed capture heat energy for useful purposes that would otherwise be exhausted or dissipated to the environment from buildings or industrial processes.

3. One could debate whether there might be an implied condition or caveat, e.g. "….from 'normal' or 'basic' building systems or industrial processes. However, it is clear that if, for example, a building installs an internal combustion engine to generate power and it recovers and uses the waste heat:
   - Such an installation is CHP; and
   - It meets the definition of "waste heat recovered and used as thermal energy".

4. Subd. 10 clarifies that demand side natural gas or electricity savings can be counted toward a utility's natural gas or electricity reduction goal. Some people believe that this means such savings can be counted toward the utility's goal but that CIP funds should not be expended on such projects. This position doesn't make policy sense – why would the state give "credit" to a utility for something that utility did nothing to implement? Besides, the rationale articulated in point 2 above would make CHP

[2] A bottoming cycle converts waste heat to electricity through, for example, organic rankine cycle technology.
[3] A topping cycle recovers waste heat from electricity generation for use as thermal energy.

an "energy conservation measure" and in Minnesota Statutes 216B.241, utilities can invest in energy conservation measures.

5. The law lacks clarity regarding how electric utilities should count the energy savings. While the construction of Subd. 10 suggests a (logical) parallel – reduced demand side natural gas or electric energy can be counted by the respective utility type (natural gas or electric), the logic breaks down when we come to in the phrase "natural gas or electricity *displaced by the use of waste heat* recovered and used as thermal energy… (Emphasis added.)
   - Certainly, recovery and use of waste heat will displace boiler fuel consumption to produce the heat required by the end user, and in most cases that fuel would be natural gas (although in some instances it could be residual fuel oil, distillate fuel oil, propane or other fuel). Thus, relative to natural gas utilities it seems pretty clear how to count the savings.
   - Technically, an electric utility could displace electricity consumption through recovery and distribution of waste heat. Practically, however, this is not a realistic scenario. The majority of the CHP potential is in industry, where electricity is not an economical or practical energy source for heating. In institutional or commercial settings, conversion from electric heating to CHP heat requires investment in entirely new hydronic piping systems, making such conversions uneconomical.

6. Based on the reasoning articulated in point 2, CHP is an energy conservation measure. Relative to Subd. 10, CHP will reduce demand side consumption of boiler fuel, usually natural gas, in the process of generating electricity. CHP would reduce demand side electric energy, in the process of generating thermal energy, because the CHP host would displace electricity purchased from the utility with electricity generated through CHP.

7. Methodological questions remain regarding the appropriate calculation of savings in either situation (fuel savings when power generation is considered the base activity, and electricity savings when thermal production is considered the base activity), but these are solvable questions of implementation.

8. Conclusion: There is a reasonable argument that, in sum, Minnesota Statutes 216B.241 as modified by H.F.729 includes CHP as an energy conservation measure, and that either natural gas or electric utilities could invest in CHP and count the respective natural gas or electricity consumption reductions in their CIP.

Cost Allocation for Cogeneration Plants

Subd. 3 of Section 216B.166 establishes the following cost allocation principles:

"The methods used to allocate or assign costs between electrical and thermal energy produced by cogeneration power plants owned by public utilities shall be consistent with the following principles:

> *(a) The method used shall result in a cost per unit of electricity which is no greater than the cost per unit which would exist if the power plants owned by the public utility had been normally constructed and operated without cogenerating capability.*
>
> *(b) Costs which the public utility incurs for the exclusive benefit of the district heating utility, including but not limited to backup and peaking facilities, shall be assigned to thermal energy produced by cogeneration.*
>
> *(c) The methods and procedures may be different for retrofitted than for new cogeneration power plants.*

(d) The methods should encourage cogeneration while preventing subsidization by electric consumers so that both heating and electricity consumers are treated fairly and equitably with

7. Straw Man Options for Minnesota Policies

Description of Options

Comment is sought on the following key "Straw Man" options, which are described briefly below and summarized in the subsequent table.

1. **Natural Gas CIP – Natural gas utilities would have CHP goals**
   - 1.1. Low CHP goal with capital incentive for CHP implemented by customers (or third parties on behalf of customers)
   - 1.2. Low CHP goal with 15-year operating incentive for CHP implemented by customers (or third parties on behalf of customers)
   - 1.3. Medium CHP goal with both capital and operating incentives

2. **Electric and Natural Gas CIP – Both electric and natural gas utilities would have CHP goals**
   - 2.1. Low CHP goal with capital incentives for CHP implemented by customers (or third parties on behalf of customers)
   - 2.2. Low CHP goal with 15-year operating incentives for CHP implemented by customers (or third parties on behalf of customers)
   - 2.3. Medium CHP goal with both capital and operating incentives

   Customers would have the option of applying for either electric utility or natural gas utility incentives, but could not receive both.

3. **Utility Investments in CHP – In addition to the customer incentives under Option 2, utilities would be encouraged to invest in CHP as ratebase investments and be credited in the CIP program based on CHP output**
   - 3.1. Medium CHP goal with capital incentives for CHP implemented by customers (or third parties on behalf of customers)
   - 3.2. Medium CHP goal with 15-year operating incentives for CHP implemented by customers (or third parties on behalf of customers)
   - 3.3. High CHP goal with both capital and operating incentives

   A system of tradable credits would be created to promote economic efficiency within the CHP tiers of the CIP program.

   Electric and gas utilities would be allowed and encouraged to cooperate to implement CHP projects, with the CIP credit split based on the total financial contribution made by each utility.

4. **Renewable Energy Standard – Expand the Renewable Energy Standard (RES) to include a specific goal within the RES for currently eligible renewable CHP technologies**
   - 4.1. Consistent with current law, include only renewable CHP.
   - 4.2. Incorporate additional provisions for RES credit to encourage use of biomass for thermal energy production without power production in areas of the state without access to natural gas service.

5. **Alternative Portfolio Standard – Establish a new portfolio standard similar to the RES that would provide requirements for non-renewable or renewable CHP**

5.1. Low APS goals
5.2. High APS goals

6. Integrated Resource Planning – Require electric utilities to demonstrate that, before power-only capacity is proposed, CHP opportunities within their service territory have been thoroughly assessed to determine the benefits of CHP relative to total primary energy efficiency, GHG emissions, power grid resiliency, peak demand management and risk management, with the following options for assumed GHG value per metric tonne CO2 equivalent

6.1. $25
6.2. $50

Option --->	1			2			3				5		6	
Sub-Option --->	**1.1**	**1.2**	**1.3**	**2.1**	**2.2**	**2.3**	**3.1**	**3.2**	**3.3**	**4**	**5.1**	**5.2**	**6.1**	**6.2**
Conservation Improvement Program														
Separate new CHP goals in CIP (% of sales)	CIP Low	CIP Low	CIP Med	CIP Low	CIP Low	CIP Med	CIP Med	CIP Med	CIP High					
Natural Gas	0.10%	0.10%	0.15%	0.10%	0.10%	0.15%	0.15%	0.15%	0.23%					
Electric IOUs				0.20%	0.20%	0.30%	0.30%	0.30%	0.45%					
Elec Coops/Munis				0.10%	0.10%	0.15%	0.15%	0.15%	0.23%					
Customer incentives from Utility (include as CIP expenditures)														
Natural Gas Utilities														
Capital incentive $/1000 Btu-hr	$ 100		$ 100	$ 100		$ 100	$ 100		$ 100					
Operating gas rate discount ($/MMBtu over 15 years)		$0.93	$0.93		$ 0.93	$ 0.93	$ 0.93		$ 0.93					
Electric Utilities														
Capital incentive ($/kW)				$ 500		$ 500		$ 500	$ 500					
Operating credit ($/MWh over 15 years)					$12.74	$12.74		$12.74	$12.74					
CIP Credits to Utilities for Utility-Owned CHP														
Natural Gas Utilities														
CIP credit ($/MMBtu over 15 years)							$0.93		$ 0.93					
Electric Utilities														
CIP credit ($/MWH over 15 years)								$12.74	$12.74					
Renewable Portfolio Standard														
Additional CHP (Renewable Only) Tier in Expanded RPS (% of sales)														
By 2020														
Electric IOUs										0.25%				
Elec Coops/Munis										0.17%				
By 2030														
Electric IOUs										1.20%				
Elec Coops/Munis										0.83%				
Alternative Portfolio Standard														
CHP goals in new APS (all CHP including gas-fired) (% of sales)											APS Low	APS High		
By 2020														
Electric IOUs											1.25%	4.00%		
Elec Coops/Munis											0.85%	2.75%		
By 2030														
Electric IOUs											4.00%	13.50%		
Elec Coops/Munis											2.75%	9.00%		
Integrated Resource Planning														
EU IRP requirement to look at CHP first, with CO2 value per metric tonne:													$ 25	$ 50

Key Issues -- Conservation Improvement Program

Calculating CIP Credit

Demand Side or Supply Side

Classification of CHP as a demand-side or supply-side resource is challenging because CHP produces two forms of energy (electricity and heat), thereby affecting customer demand of both electricity and boiler fuel. Topping cycle CHP decreases customer consumption of boiler fuel for thermal production, but this is generally more than offset by the increase in fuel consumed for CHP. Bottoming cycle CHP decreases customer consumption of electricity, but generally will not decrease customer consumption of natural gas because the temperature of the thermal output from ORC is usually too low to be usable.

The net impact of various CHP technologies on customer natural gas consumption is illustrated in Figure 7-1, expressed as a percentage of the offset fuel consumption for thermal production (in the analysis we assumed 80% boiler fuel efficiency). In addition, CHP reduces fuel consumption for power-only plants operated by the electric utility (EU). In this analysis we assume that the marginal EU generation that would be offset by CHP is summarized in Table 7-1.

Figure 7-2 shows the combined impact of CHP on customer natural gas use and EU natural gas use, expressed as a percentage of offset customer natural gas consumption for thermal production.

		Coal Steam Cycle	Natural Gas Combined Cycle	Weighted Average *
Efficiency	Plant heat rate (Btu/Kwh)	9,357	6,713	8,710
	Transmission/Distribution losses	7.5%	7.5%	7.5%
	Delivered heat rate (Btu/kWh)	10,116	7,257	9,416
Marginal costs	Fuel cost ($/MMBtu)	$ 2.41	$ 4.62	$ 2.82
	Fuel cost ($/MWH)	$ 24.36	$ 33.52	$ 26.60
	Non-fuel O&M cost ($/MWH)	$ 9.53	$ 5.63	$ 8.58
	Total marginal variable cost ($/MWH)	$ 33.89	$ 39.15	$ 35.18
Emissions	CO2 emissions (Metric ton/MWH)	0.97	0.39	0.83
	* Weighting	76%	24%	100%

Table 7-1. Assumed Characteristics of Offset Grid Electricity

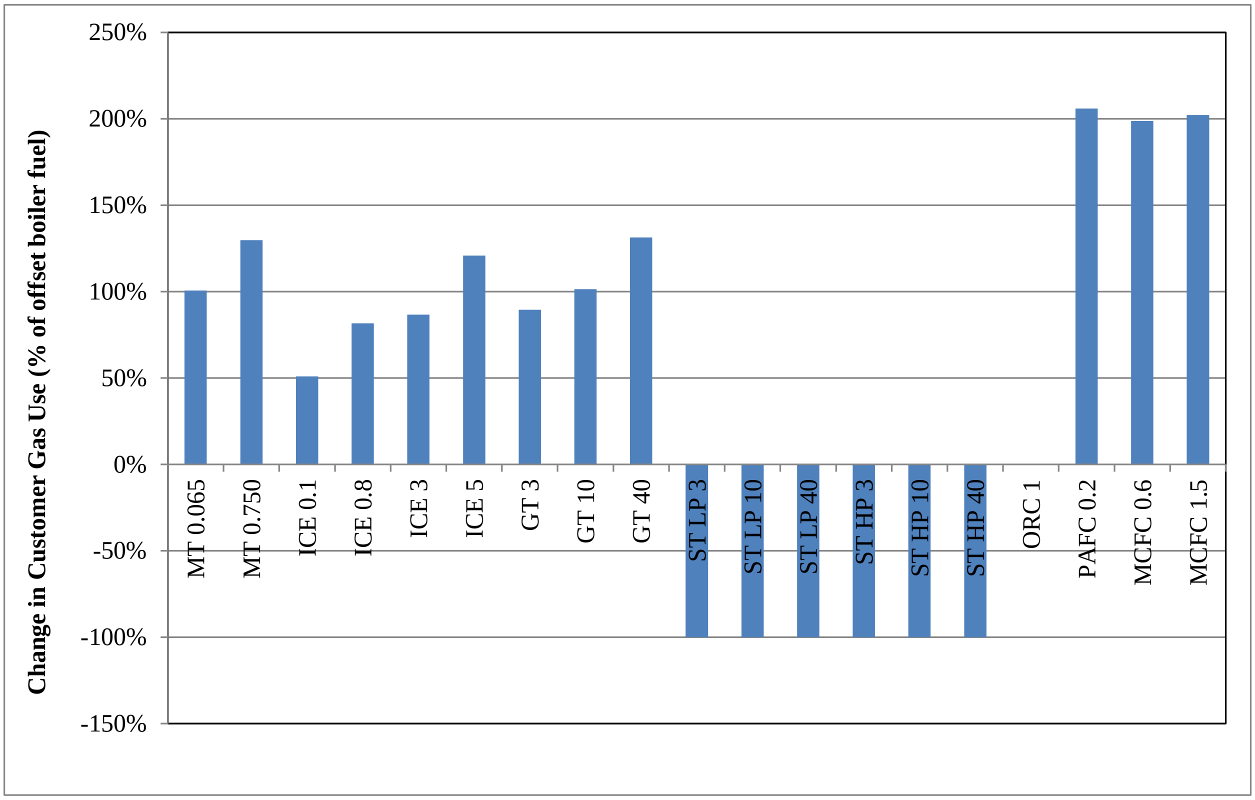

Figure 7-1. Net Change in Customer Natural Gas Use as % of Offset Boiler Fuel Use

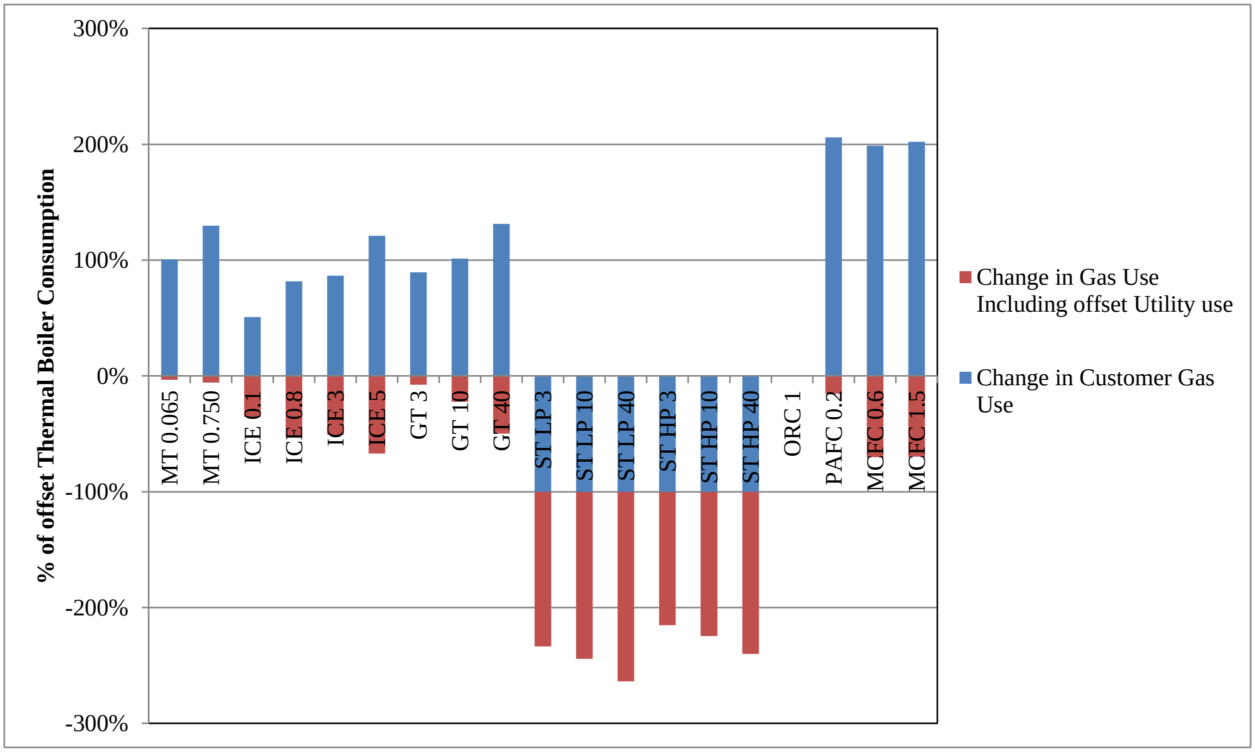

Figure 7-2. Net Change in Customer and Electric Utility Natural Gas Use as % of Offset Boiler Fuel Use

Many people think of "demand-side" as referring to decreases in end-use energy consumption. Natural gas and electricity are not end-use energy needs. They are a means to an end, and are used to meet end-use needs as such as space heating, domestic hot water, air conditioning, process heating, process cooling and a whole range of electrical plug loads including lights, computers, etc. The CIP law does not address end-use energy consumption, but rather energy supplied to customers to meet end-use energy needs.

Uncertainty about whether CHP is demand-side or supply-side stems from a lack of clarity in Minnesota Statutes 216B.241 (hereinafter "the CIP law") relative to definitions, including a lack of clarity relative to boundaries between utilities, customers and potential third parties. For example:

- Minnesota Statutes 216B.241 Subd. 1(e) defines "Energy conservation improvement" as "a project that results in energy efficiency or energy conservation."
- Minnesota Statutes 216B.241 Subd. 1 (f) defines "Energy efficiency" as "measures or programs, including energy conservation measures or programs, that target consumer behavior, equipment, processes, or devices designed to produce either an absolute decrease in *consumption* of electric energy or natural gas or a decrease in *consumption* of electric energy or natural gas on a per unit of production basis without a reduction in the quality or level of service provided to the energy consumer." (*Emphasis* added.)
- The word "consumption" in Subd. 1(f) could refer to end-use needs or to consumption of utility-supplied electricity. However, we conclude that "consumption" refers to consumption of utility-supplied electricity because:
    - Subd. 1(e) states "Energy conservation improvement may include waste heat that is recovered and converted into electricity....." This provision allows a new energy *supply* (conversion of heat to electricity) to be considered an energy conservation improvement. Such a scenario does not reduce *end-use consumption of electricity*, but it does reduce *consumption of grid-supplied electricity*.
    - Subd. 1(e) also states "Energy conservation improvement also includes waste heat recovered and used as thermal energy." This provision allows a new end-use energy *supply* (recovered waste heat) to be considered an energy conservation improvement. That supply of recovered waste heat may occur within the boundaries of utility customer facilities, or it may originate from a third party, such as a district heating provider.

One entity's demand is another's supply. The impact of CHP-produced electricity and heat can be characterized as demand-side or supply-side depending on where the boundaries between "demand" and "supply" are drawn relative to five types of entities:

- Electric utility;
- Electric utility customer;
- Natural gas utility;
- Gas utility customer; and
- Third party CHP plant operator that distributes thermal energy to other utility customers.

Extending the boundaries further, the electric utilities and the gas utilities obtain their natural gas supply from a nationwide gas supply network. This further complicates the distinction between supply and demand.

On balance, we conclude that the Minnesota CIP law fundamentally approaches "demand" and "supply" as referring to energy commodities (natural gas or electricity) crossing the boundary between the utility and the customer, and that CHP can appropriately be viewed as a demand-side resource for both natural gas and electric utilities. This conclusion is based on the following reasoning:

Relative to natural gas utilities --

- CHP is clearly a demand-side resource where CHP heat displaces natural gas. Recovery and use of waste heat through CHP will displace boiler fuel consumption to produce the heat required by the end user, and in most cases that fuel would be natural gas. However, as noted in the analysis presented above—
  - CHP also generally results in increased customer demand for gas due to the additional fuel required to produce electricity as well as heat;
  - CHP reduces electric utility fuel consumption, which we assume will likely be natural gas; and
  - CHP reduces total fuel consumption.

Relative to electric utilities --

- An initial reading of the CIP law suggests that CHP is not a demand-side resource based on the definition of demand-side as reduction in *end-use consumption* of electricity. For example:
  - CHP can displace electricity consumption through recovery of waste heat through use of CHP heat to drive absorption or steam turbine chillers. However, CHP-heat-driven cooling will not be a major element in implementing a CHP project in Minnesota.
  - It is also technically possible to displace electricity through use of heat produced from CHP; however, practically this is not a realistic scenario. Heat produced from CHP is almost never an economically feasible replacement for electric heat because CHP heat must be delivered through hot water or steam.
- However, the CIP law as a whole indicates that the "decrease in consumption of electric energy" that is the objective of the CIP law for electric utilities should be viewed as consumption of electricity *supplied from the utility grid*. CHP reduces demand side electric energy, in the process of generating thermal energy, because the CHP host would displace electricity purchased from the utility with electricity generated through CHP.

Given the complex web of energy demands and supplies, and given the clear energy and environmental benefits of CHP for the entire energy demand and supply, sound policy goals should be driven by a holistic view of the net energy and environmental benefits of CHP, with credits calculated as described below.

Crediting CHP in Electric Utility CIP

No standard accounting approach has emerged for calculating credit CHP in portfolio standards. A range of alternative crediting mechanisms have been analyzed as described below. In the following discussion of alternative crediting methodologies we will use the parameters defined in Table 7-2. Table 7-3 shows the formulas for the alternative crediting methods to calculate the number of credited MWh of CHP electricity generation.

		Symbol	Units	Formula
CHP	Heat rate (conventional)	HRchp	MMBtu/MWhe	Fchp / E chp
	Marginal heat rate (SWEEP)	HRSWchp	MMBtu/MWhe	(Fchp - Fb) / E chp
	Total efficiency	EFFchp	%	Project-specific
	Fuel consumption	Fchp	MMBtu	Project-specific
	Annual electricity production	Echp	MWhe	Project-specific
	Annual heat production	Tchp	MMBtu	Project-specific
Offset thermal	Boiler efficiency for offset thermal production	EFFb	%	80%
	Reduction in fuel consumption for thermal production	Fb	MMBtu	Tchp / EFFchp
Offset electric	Heat rate including T/D losses	HReut	MMBtu/MWhe	HReug / (1 - TDeu)
	Reduction in fuel consumption due to CHP	Feu	MMBtu	Echp * HReut
	Total reduction in fuel consumption	Ftot	MMBtu	Feu - Fb - Fchp

Table 7-2. Parameters for CHP Crediting Calculations

Methodology	Formula
NRDC/OEC	See Table 6-11.
SWEEP	Lesser of Echp and Ftot / HRSWchp.
Massachusetts APS	Lesser of Echp and (Echp / 33%) + (Tchp / 3.412 / 80%) - (Fchp /3.412)
ACEEE	Ftot /HReut

Table 7-3. Formulas for CHP Crediting Methods

The method recommended by the Natural Resources Defense Council (NRDC) and Ohio Environmental Council (OEC) emphasizes incentivizing maximum efficiency and simplifying implementation (NRDC/OEC 2012). They recommend a tiered approach as shown in Table 7-4, with efficiency measured on Lower Heating Value (LHV) basis. Although the NRDC/OEC White Paper indicates that Ohio law requires a 60% minimum efficiency on an LHV basis, we see no evidence that either LHV or Higher Heating Value (HHV) is addressed in the law. See "Minimum Efficiency Standards" below for definitions and discussion of LHV and HHV. The efficiency data used in this report are HHV basis. Converting the NRDC/OEC tiers to HHV yields the values shown in Table 7-5.

Tier	Efficiency (LHV)	Portion of kWh output considered
	<60%	0%
Tier 1	60-65%	60%
Tier 2	65-70%	70%
Tier 3	70-74%	80%
Tier 4	74-77.5%	90%
Tier 5	>77.5%	100%

Table 7-4. NRDC/OEC Tiers

Tier	Efficiency (LHV)	Efficiency (HHV)	Portion of kWh output considered
	<60%	<54%	0%
Tier 1	60-65%	54-59%	60%
Tier 2	65-70%	59-63%	70%
Tier 3	70-74%	63-67%	80%
Tier 4	74-77.5%	67-70%	90%
Tier 5	>77.5%	>70%	100%

Table 7-5. Conversion of NRDC/OEC Tiers to Higher Heating Value

The NRDC/OEC approach is endorsed by the Environmental Law and Policy Center and the Heat is Power Association. The NRDC/OEC White Paper states:

"This approach has multiple advantages, as it:

- *Incentivizes all prime mover technologies and does not pick technology winners*
- *Encourages project developers to design higher-efficiency installations, regardless of the prime mover technology*
- *Is based on the performance of real CHP systems, of various sizes, configurations and technologies*
- *Is simple to administer and implement, as it requires only a simple calculation of overall system efficiency based on readily available inputs (and minimizes issues surrounding heat-rates) neither underestimates or overestimates savings."*

The SWEEP approach divides the total fuel savings due to CHP by a heat rate that we will term a "marginal heat rate." This heat rate is calculated by subtracting the offset boiler fuel from the total CHP fuel use and dividing the result by the CHP electricity output. The creditable MWh of electricity are the lesser of the calculation or the actual CHP electricity output.

The Massachusetts APS law is the most generous method for crediting CHP. It states that the creditable CHP power output is:

> *".. equal to the result, if positive, of the following calculation: take the sum of (1) the electrical energy generated divided by the overall efficiency of electrical energy delivered to the end-use from the electrical grid (which efficiency is equal for this purpose to 0.33); and (2) the Useful Thermal Energy divided by the overall efficiency of thermal energy delivered to the end-use from a standalone heating unit (which efficiency is equal for this purpose to 0.80); and subtract from this sum the total of all fuel and any other energy consumed by the CHP Unit in that quarter expressed in MWh and calculated using the energy content of the fuel based on its higher heating value."*

ACEEE's recommended method (Elliott, Chittum, Trombley and Watson) divides the total fuel savings (fuel for separate heat and power – CHP fuel) by the grid heat rate. This approach results in the lowest credit to CHP.

The results of all four calculation methods for each CHP technology configuration is illustrated in Figure 7-3. We have omitted the biomass-fired CHP configurations because they will qualify for the RPS. We have omitted the waste heat to power technology (using ORC) because this scenario is not addressed except in the NRDC/OEC method.

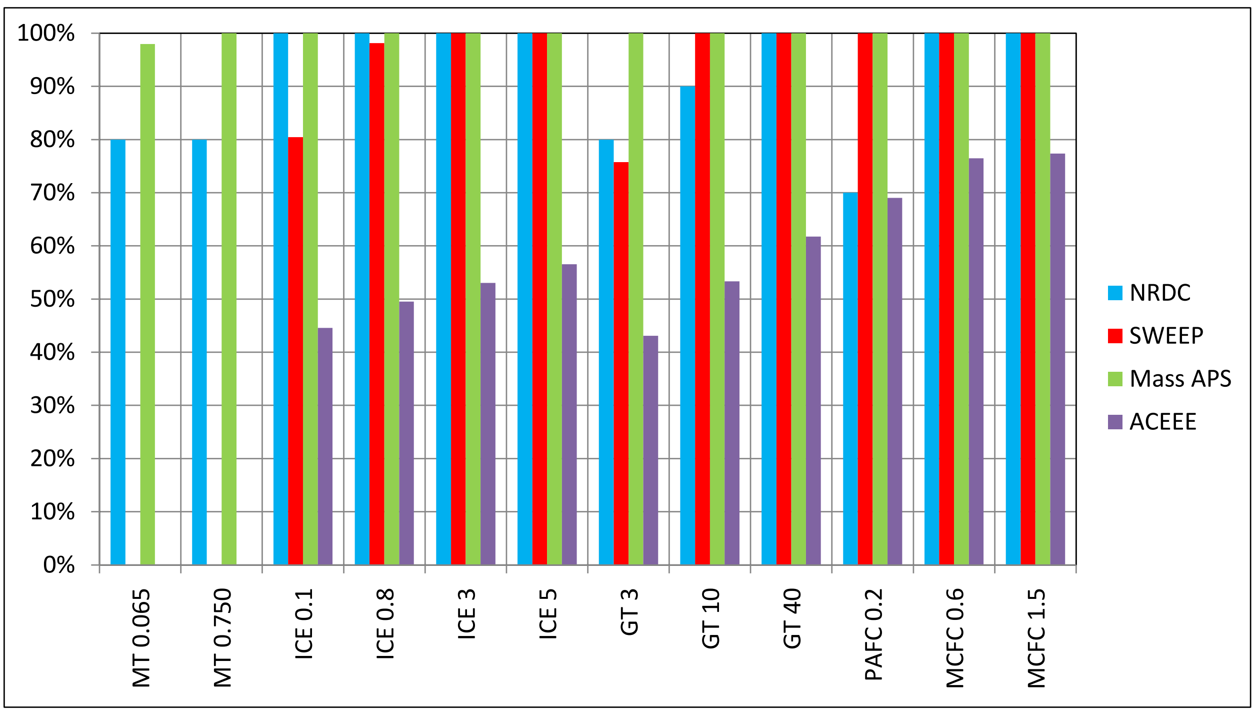

Figure 7-3. Credited CHP Power Generation as a Percentage of Total CHP Power Generation for 12 Technologies Under 4 Calculation Methods

We recommend the NRDC/OEC methodology for crediting CHP electricity generation for the reasons discussed above.

Crediting CHP in Natural Gas Utility CIP

For natural gas utilities, we recommend calculating natural gas savings for CIP credit as equal to total fossil fuel savings (Ftot in Table 7-2). Note that some of the fuel savings from offset grid power production may come from fuels other than natural gas (primarily coal). Note also that in some relatively limited cases the fuel savings from offset thermal boiler operations may come from fuels other than natural gas (primarily fuel oil). However, given the public policy benefits of reducing use of such non-natural-gas fuels, we recommend that all such fuel savings count toward natural gas reduction goals.

Further, we recommend that the Minnesota Legislature consider modifying the CIP law to allow substitution of renewably-fueled thermal energy production for fossil-fuel-fired thermal production to qualify for natural gas CIP credit, regardless of whether or not electricity is also produced. The overarching policy goal is to reduce fossil fuel consumption and related GHG emissions. The CIP mechanism can be adapted in service of these broader goals.

Separate Tiers

It is important that inclusion of CHP in CIP does not crowd out cost-effective end-use efficiency measures. A separate tier for CHP should be established. In conjunction with the second project in this work scope (Minnesota CHP Potential Study), we will recommend potential goals for increasing CIP goals to realize the potential of CHP in Minnesota.

Minimum Efficiency Standards

It is important that minimum efficiency standards be established for CHP to be credited in a portfolio standard. We recommend adopting the standard in the United States Code [26 USC § 48(c)(3)(A)]:

> *"Combined heat and power system property. The term "combined heat and power system property" means property comprising a system—*
>
> > *(i) which uses the same energy source for the simultaneous or sequential generation of electrical power, mechanical shaft power, or both, in combination with the generation of steam or other forms of useful thermal energy (including heating and cooling applications),*
> >
> > *(ii) which produces—*
> >
> > > *(I) at least 20 percent of its total useful energy in the form of thermal energy which is not used to produce electrical or mechanical power (or combination thereof), and*
> > > *(II) at least 20 percent of its total useful energy in the form of electrical or mechanical power (or combination thereof),*
> >
> > *(iii) the energy efficiency percentage of which exceeds 60 percent."*

Utility Ownership of CHP

As discussed above, cost of capital is a critical barrier to increased implementation of CHP. One way to mitigate this constraint is utility ownership of CHP systems. Potential provisions for such arrangements for electric and natural gas utilities are outlined below.

<u>Electric Utilities</u>

1. Electric utility (EU) would finance and own the CHP system and include this asset in its rate base.
2. EU could recover project development costs up to a limit and include those costs as CIP costs.
3. EU could recover management fees up to a limit and include those costs as CIP costs.

4. EU would own the asset for 15 years, at which time the customer has the option to buy the asset at depreciated book value.
5. EU could contract with the customer for operation and routine maintenance under the management of the EU.
6. EU would pay the costs of major maintenance and equipment replacement, which will add to the rate base investment and the depreciable basis of the plant.
7. The CHP system would be dispatched by the EU.
8. CHP power generation would be sold to the customer at the avoided rate of normal electric utility service.
9. CHP thermal production would be sold to the customer a given percentage of the avoided cost of heat production using customer boilers.
10. Excess generation would be dispatched to the grid by the EU.

Gas Utilities

1. Gas utility (GU) would finance and own the CHP system and include this asset in its rate base.
2. GU could recover project development costs up to a limit and include those costs as CIP costs.
3. GU could recover management fees up to a limit and include those costs as CIP costs.
4. GU would own the asset for 15 years, at which time the customer has the option to buy the asset at depreciated book value.
5. GU could contract with the customer for operation and routine maintenance under the management of the GU.
6. GU would pay the costs of major maintenance and equipment replacement, which will add to the rate base investment and the depreciable basis of the plant.
7. CHP system would be operated based on thermal load.
8. CHP power generation would be sold to the customer at the avoided rate of normal electric utility service.
9. Customer would contract with the EU for standby service.
10. CHP thermal production will be sold to the customer at a given percentage of the avoided cost of heat production using customer boilers.
11. Excess generation would be dispatched to the grid in cooperation with the EU at a price equal to the marginal variable cost of CHP electricity generation. To the extent that the marginal electricity generation cost from CHP exceeds the marginal cost of the EU's fossil fuel plants, the excess cost will be considered an EU CIP cost, up to a limit set by the average cost of CIP electricity savings for a benchmark period.

Joint EU/GU Projects

If both the EU and GU participate in financing a CHP facility, the total value of CIP credit for each can be determined as follows:

- PVFtot = Present Value of total financial contribution of both utilities over 20 years at a discount rate equal to the average of the two WACCs
- PVFeu = Present Value of the EU financial contribution over 20 years at a discount rate equal to the average of the two WACCs
- PVFgu = Present Value of the GU financial contribution over 20 years at a discount rate equal to the average of the two WACCs
- EUcip = Average EU CIP expenditure per MWH for a benchmark period
- GUcip = Average GU CIP expenditure per MMBtu for a benchmark period
- MWH CHP electricity creditable to the EU = (PVFeu/PVFtot) / EUcip
- MMBtu CHP natural gas creditable to the GU = (PVFgu/PVFtot) / GUcip

Financial Incentives for Non-Utility CHP Investments

Currently Minnesota has no financial incentives or financing assistance in place that give credit to CHP system production or reduce the direct cost of investment. We believe that such incentives for non-utility-owned should be considered within the context of the CIP. The availability of such incentives may discourage opt-out from CIP.

Incentives for CHP installations can take a variety of forms, including:

1. Project-based grants;
2. Low-interest loans or loan guarantees;
3. Short-term (up to 2 years) performance incentives tied to demonstrated—
    a. CHP power production;
    b. Peak CHP capacity installed; or
    c. Peak demand reduction.
4. Ongoing incentive payments tied to demonstrated CHP power production.

<u>Programs in Other States</u>

Most successful programs combine Incentive 3.a with Incentives 3.b or 3.c. because they address both capacity and energy values. For example, Maryland's successful Baltimore Gas and Electric (BG&E)'s *Smart Energy Savers Program.* The incentive program is structured as follows:

- $75/kW after the system has been designed and a commitment letter has been signed;
- $175/kW after the system has been installed and commissioned and undergone an inspection; and
- $0.07/kWh for the first 18 months of system performance, after metered data has been reviewed.

This incentive program is applicable to systems that are at least 65% efficient and do not export excess power to the grid. The maximum incentive offered by BG&E is $2 million for a single project, and is available to almost all non-residential customer classes.

In New York, NYSERDA's *Combined Heat and Power (CHP) Performance Program* provides the following incentives:

- Systems may earn up to $0.10/kWh generation;
- Systems may earn an additional $600/kW or $750/kW of summer demand reduction, depending on location in the state; and
- Systems may earn additional bonus incentives if they do any of the following:
    - Serve critical infrastructure;
    - Serve an area determined to be a challenged area of the grid of particular interest to the local utility; and
    - Exemplify "superior" efficiency.

These incentives are performance-based and correspond to the summer-peak demand reduction (kW), energy generation (kWh) achieved by the CHP System on an annual basis over a two-year measurement and verification period. CHP systems must:

- Have a minimum 60% total efficiency;
- Have a NOx emission rate ≤ 1.6 lbs/MWhr; and
- Have the ability to operate during a grid outage.

The CHP Performance Program offers a maximum incentive of $2.6 million or 50% of the project cost, whichever is less.

CHP Credit Trading

Economic efficiency is achieved when the lowest-cost measures are undertaken to obtain the desired result. A system of tradable CHP credits within the CIP program is recommended to promote economic efficiency. These credits could be sold between different electric and natural utilities.

8. Potential Impacts

Utility Portfolios and Ratepayers

Five key cost-effectiveness tests have, with minor updates, been used for more than 20 years as the principle approaches for energy efficiency program evaluation. These five cost-effectiveness tests are the participant cost test (PCT), the utility/program administrator cost test (PACT), the ratepayer impact measure test (RIM), the total resource cost test (TRC) and the societal cost test (SCT) (National Action Plan for Energy Efficiency 2008).

The basic structure of each test involves a calculation of the total benefits and the total costs in dollar terms from a certain vantage point to determine whether or not the overall benefits exceed the costs. A test is positive if the benefit-to-cost ratio is greater than 1.0, and negative if it is less than 1.0.

In the final report, the impacts of policy options for example CHP projects will be evaluated using the cost tests outlined in Table 8-1.

Fuel Switching

Concerns have been raised that implementation of CHP through the CIP may lead to a utility customer of a specific fuel type (electric) subsidizing the cost of CHP project incentives or utility load building that may be provided to another utility customer for a different fuel type (natural gas). Note that CIP already leads to some level of cross-subsidization between customers within a utility customer base. The issue here is potential subsidization between customers of different utilities.

This issue must be further explored with the stakeholders, in the context of the guiding public policy goals of reducing fossil fuel use and related environmental impacts. Potential cross-subsidization issues between the electric and gas utilities can be mitigated by giving both types of utilities the opportunity for involvement in CHP development and creation of related CIP credits.

Cost-Benefit Tests for Customer-Owned CHP

Participant Cost Test (PCT)

Costs	CHP fuel costs
	CHP non-fuel operating costs
	CHP capital costs
Benefits	Avoided thermal boiler fuel costs
	Avoided electricity costs
	Incentive payments
	Tax credits

Ratepayer Impact Measure (RIM)

Costs	Program overhead costs
	Incentive payments
	Reduced revenues
	Increased resource costs
Benefits	Increased revenue
	Avoided power grid fuel costs
	Avoided power grid non-fuel O&M costs
	Avoided power grid capacity-related costs

Societal Cost Test (SCT)

Costs	Program overhead costs
	CHP fuel costs
	CHP non-fuel operating costs
	CHP capital costs
Benefits	Avoided thermal boiler fuel costs
	Avoided power grid fuel costs
	Avoided power grid non-fuel O&M costs
	Avoided power grid capacity-related costs
	Avoided externality costs

Cost-Benefit Tests for Utility-Owned CHP

Participant Cost Test (PCT)

Costs	Purchase of heat output of CHP
	Purchase of electric output of CHP
Benefits	Avoided thermal boiler fuel costs
	Avoided electricity costs

Ratepayer Impact Measure (RIM)

Costs	Project development costs
	Management costs
	Incentive
	CHP fuel costs
	CHP non-fuel operating costs
	CHP capital costs
Benefits	Revenue from thermal energy sales
	Revenue from electricity sales
	Avoided power grid fuel costs
	Avoided power grid non-fuel O&M costs
	Avoided power grid capacity-related costs
	Tax credit
	CIP credit

Societal Cost Test (SCT)

Costs	Project development costs
	Management costs
	Incentive
	CHP fuel costs
	CHP non-fuel operating costs
	CHP capital costs
Benefits	Avoided thermal boiler fuel costs
	Avoided power grid fuel costs
	Avoided power grid non-fuel O&M costs
	Avoided power grid capacity-related costs
	Avoided externality costs

Table 8-1. Cost Tests for Analysis of Policy Options

9. Stakeholder Feedback Sought

Stakeholder feedback is sought on any aspect of these draft options. In particular, we pose the following questions:

1. Which options will be most effective in encouraging CHP? Why?

2. Which options will be least effective? Why?

3. What concerns do you have regarding each option, relative to:
   - 3.1. Consistency with current statutes?
   - 3.2. Administrative practicality?
   - 3.3. Unintended impacts on other efficiency efforts?
   - 3.4. Other concerns?

4. How could the concerns you raise be mitigated?

5. Are the incentive levels appropriate?

6. Are the calculation methodologies discussed in this paper appropriate? If not, why not? What changes would you suggest?

7. Do the low, medium and high draft goals for CHP in the CIP present a reasonable range of goals?

8. Do the low and high APS goals present a reasonable range of goals?

Feedback can be provided to Mark Spurr at mspurr@fvbenergy.com.

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Appendix D: Results of Stakeholder Consultation

"Straw Man Options for Minnesota CHP Policies" (Appendix C) was prepared and distributed to a wide range of stakeholders. The document provided background information and analysis developed during this study, and presented "straw man" policy options for the purpose of gathering stakeholder input during informal meetings and conference calls.

The document was provided to Xcel Energy, Minnesota Power, Great River Energy, Otter Tail Power, Minnesota Power Cooperative, Southern Minnesota Municipal Power Agency (SMMPA), Minnesota Municipal Utilities Association (MMUA), CenterPoint Energy, Great Plains Gas, MERC (MERC), Ever-Green Energy, University of Minnesota, Franklin Energy, Cummins, Energy Systems Consulting, Energy Resources Center, Fresh Energy, Center for Energy and Environment, Great Plains Institute, Blue Green Alliance and the Metropolitan Council. Meeting or calls took place with all except Minnesota Power, SMMPA, Minnesota Power Cooperative and Blue Green Alliance. Written comments were received from the Metropolitan Council.

This section lists comments received by entity category.

Electric Utilities

- Electric utilities see weak customer interest in CHP as a key issue.
- CHP can be seen as customer-intrusive.
- The fact that a lot of the largest customers are CIP opt-outs is problematic.
- Most of their work on CHP has been concentrated on bottoming cycles.
- It was suggested that the policy discussion is premature until the potential for CHP is quantified.
- Queries were made regarding how the straw man operating incentive level was set (answer: average statewide electric utility CIP expenditures over the last three years divided by 15 year lifetime kWh savings, per Department of Commerce data).
- It was noted that such expenditures include administrative overhead.
- Concern was expressed that inclusion of CHP in CIP is problematic because it is a supply technology rather than end-use efficiency.
- Relative to utility implementation of CHP, there are risks related to the longevity of the CHP host facility/thermal user.
- Potential solutions include regulatory recovery for losses associated with a CHP customer going out of business, or a higher rate of return in recognition of the risks.
- Xcel noted that they have a partial decoupling in their current rate case.
- One utility has a CHP plant in S. Dakota that is coal-fired, and they may stop dispatching that due to the EPA Clean Power Plan.
- There is competition within the company for funding, so efficiency expenditures compete with other needs.
- They try to cover a range of sectors (residential, commercial, industrial) in their CIP program.
- 70 percent of their expenditures are incentives, and the rest are administration, promotion, etc.
- CHP opportunities in the service territory have not been comprehensively analyzed.
- They did evaluate potential CHP at a wood processing plant, but found it to be too expensive.

- The best potential CHP sites in rural areas are ethanol plants, but most of those have opted out of CIP.
- Concern is long-term stability of gas prices.
- CHP opportunities in the service territory have not been comprehensively analyzed.
- Some customers have really cheap gas, because they are supplied directly from interstate pipelines.
- With new solar incentives, some GRE customers are thinking solar is an easier way to do sustainable energy.
- Relative to the Clean Power Plan, it may be possible to convert some simple cycle peaking plants to combined cycle.
- CHP may be more attractive if a customer has high electric reliability needs.
- There are 12 ethanol plants on the system now, about 5 MW per site. There might be another 6 industrial sites that could be CHP candidates. Perhaps a total of 80-100 MW additional, including mid-sized commercial sites?
- Would argue that non-fuel O&M costs won't really be avoided if they reduce their power output from other capacity – it won't change the way they dispatch.
- MISO is an economic dispatch model – what gets pulled off is the least economic plant.
- Capital incentive is more effective than operating incentive because typically customer capital is tight.
- Funding capital incentives within CIP is difficult.
- Fundamental differences between IOUs and coops relative to CIP.
- See challenges in fitting CHP into CIP, but like the idea of having some funding for CHP.
- Hard to shift funding from other resources.
- Better to address CHP within the RES, rather than a separate APS.
- Hard to meet air permitting with biomass CHP.
- Do not have enough gas pipeline capacity for much more CHP. Some of their gas peaking plants have been curtailed (even before last year).
- Potential problems with public entities financing projects for private entities. Requires taxable debt. Usually can do it with hospitals (non-profits). Their bond counsel doesn't like to see munis financing customer projects.
- If you finance CHP, you constrain a small utility from being able to take on other debt. With more debt the next financing becomes more expensive.
- Hard to get subordinated debt.

Gas utilities

- Do not like the idea of more targets or goals. An "aspirational goal" is OK, but not something as firm as a regular CIP target.
- CHP is attractive because it boosts sales, but in a decoupled environment the additional sales may not be valuable.
- CHP projects may take years to implement, so the flow of MW is lumpy. Set multi-year goals for CHP?
- If a gas utility implements a CHP project it raises additional complications relative to standby rates.
- Electric utilities seem to have a lot of discretion in how they apply standby rates.
- Utilities can afford to have CHP expertise available, but this is more challenging for customers.
- Barrier in capitalizing heat distribution infrastructure within CIP?

- Do we need to have ratebased CHP in CIP? OK to have this as an option, not a mandate.
- Need certainty regarding how CHP fits into CIP.
- Should only be able to claim CIP credit for CHP if you have already met your end-use efficiency goal.
- CenterPoint will apply for CIP credit for the U of MN project.
- If we approach the energy calculation on a net Btu basis for CHP, will other want to apply this to other CIP measures?
- In latest rate case, got a "full decoupling of rates from sales"
- MERC is fully decoupled.
- 50 percent of CIP expenditures are overhead.
- 93 cents per MMBtu is more than their delivery cost in most cases. A lot of customers are paying 70 cents for delivery.
- Delivery costs: $1.70 firm residential; $0.47 large industrial interruptible; $1.00 firm commercial.
- For customer projects, the maximum rebate they can give is $7.00/mcf. Mostly $3-5.
- Regarding renewable thermal – do not restrict it to areas without natural gas.
- Fuel switching – no formal policy or rule. Difference between burning your own waste and buying it from someone else, relative to losing a gas customer. (I do not understand this.)
- Want to make sure that the gas and electric incentives are about the same.
- Noted potential gas pipeline constraints.
- Most large companies are on interruptible gas. Last year there were lots of interruptions, but there hadn't been for the prior 4-5 years.
- What criteria would have to be met to put CHP in the rate base?
- Noted regulatory lag – takes time for costs to be addressed in a rate case. Perhaps cover the costs in the CIP rider until the next rate case?
- They do not have the expertise to develop CHP projects. Would need third party help.
- Just hired a manager of distributed generation (for GPG and associated companies).
- Intrigued with Option 3 (utility development of CHP).
- Key issue is shifting risks to ratepayers (stranded asset issue).
- WACC is tied to risk profile.
- Look at financing options more broadly – not just utility financing. Establish a loan loss reserve to reduce interest costs?
- Systems benefits charge to provide credit enhancement for energy efficiency investments.
- Get input from PUC staff.
- Regulators value diversity, prudent investment.
- In the "MUSH" market (Municipal, Universities, Schools and Hospitals), performance contracting can be effective.
- Bigger financing challenges on the private side.

Thermal Utilities

- Should also address CHP retrofit of existing power plants, e.g. Riverside and High Bridge.
- Provide incentives to install thermal distribution infrastructure to link power plants with thermal users.
- Perhaps add a small rider to electric rates to help fund thermal infrastructure investments.
- Need to highlight potential for integration of CHP with existing or new district energy systems.
- Need to consider potential for shutdown of Sherco 1 and 2.
- Too much emphasis on utility ownership of CHP.

- If the CHP is dispatched by the electric utility, what assurance does the host have that their thermal loads will be met?
- There should be more emphasis on the constraints placed on potential CHP projects by delays and uncertainties surrounding electric utility treatment of interconnection and standby rates. Perhaps there should be an authority (DoC or PUC) to whom a CHP project developer can appeal to prevent utilities from unduly holding up projects.
- If a utility develops CHP on a customer site, perhaps there should be a provision for the host to use the power in times of utility outages.
- Cooling is also a potential service from CHP.
- Data centers present a strong CHP opportunity.
- Not in favor of gas utility investment in CHP.
- Need to ensure that other utilities do not cannibalize a thermal utility by installing CHP at a site served by a district heating system.
- Regarding CHP efficiency standards, we may need to provide some flexibility depending on the seasonality of the thermal host.
- Another policy alternative would be a state production tax credit to pay the CHP host for electricity produced, with a variable credit based on CHP efficiency.
- Minnesota should determine the value of CHP similar to the value of solar studies, and that value should be incorporated into rates paid for CHP electricity.

Equipment Suppliers

- Option 3 is the best, then Option 5, then Option 2, then Option 1.
- Gas utilities already have incentive to do CHP.
- Biggest challenges are with small to medium CHP.
- Biomass CHP already qualifies in RES. Not getting traction. Feedstock constrained.
- Like the APS idea.
- Option 6 is not sufficient. Needs to be combined with another option.
- Typically need 2-3 year payback in projects being built in other states.
- Stressed the importance of establishing a business case for any incentives.
- Do PUC regulations allow business-to-business transfer of power?

Customers

- CHP will help the meet carbon reduction goal.
- Major modification permit required from MPCA.
- Key business need is reliable steam supply.
- CHP would be helped if there was a wheeling law like in New Jersey. If U was able to wheel to other U loads this project would be less expensive.
- Likes the option of including CHP in gas utility CIP.

Advocacy Groups

- Would like to see some of the currently wasted heat in power plants used, e.g. High Bridge, Riverside.
- The fact that (unless Sherco is shut down) there is little or no need for new power capacity is a constraint on developing new CHP.

- With slowing load growth, utilities will be looking for new sources of revenue.
- See incorporation of CHP in CIP as potentially workable.
- CHP should meet a minimum efficiency standard.
- The fact that the biggest customers tend to opt out of CIP is a problem.
- Getting utilities on board is key.
- Like the idea of requiring evaluation of CHP in IRP as a condition of getting Certificate of Need.
- There are statutory barriers to third party ownership of CHP. Third parties can own up to 24 projects but after that you are considered a public utility.
- Including utility owned assets in CIP would be breaking new ground.
- Will clarifying legislation be needed to fully address CHP in CIP?
- Advantage of using CIP is that it has a well-established measurement and verification (M&V) process.
- The fact that 5 percent of CIP can be spent on solar (which generates, not saves, electricity) provides a precedent for the argument that CHP can be included in CIP because it reduces the use of electricity purchased from the utility.
- Bioenergy CHP raises issues of "what is the best use of bio resources?"
- Biomass feasibility is very site-specific.
- Should investigate whether CHP can help facilitate higher levels of renewables by relieving transmission/distribution constraints.
- Most of RES has to be met with wind (and some solar), so there isn't much room for biomass.
- Support a carve-out for biomass CHP.
- Some renewables advocacy groups do not like biomass, primarily out of concern regarding particulates emissions.
- Support credit for renewable thermal-only. Fuel switching issues?
- Like the APS – on balance, that is the best option.
- Should do value of CHP study, just like value of solar.
- Not worried about including CHP in CIP.
- Like having both electric and gas utilities involved in CHP, not just gas.
- Support the emphasis on utility implementation of CHP.
- Would like to see incentives for CHP retrofit of existing power plants.
- Strongly support of requirement to evaluate CHP in IRP.
- Recommend strong role for CHP as Minnesota develops its Clean Power Plan.

Consultants

- Recommend discussion of new Illinois CHP program in report.
- Include waste heat to power under RES?
- Important that an APS "have teeth".
- Recommend a limited number of tiers for calculating CHP credit (NRDC approach has too many -- too complex)
- Can a third party get CIP credit?
- Agree that utility involvement in developing CHP would help a lot.
- Developing and operating CHP is a distraction for most companies. Requires extra (and specialized) expertise and labor.
- Technical support in project development is very important.
- Uncertainty regarding gas prices is a constraint.

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Appendix E: Methodology

This Appendix describes key elements in the analysis methodology, focusing on aspects of the methodology that are not described in the body of the report or which are only briefly mentioned.

Overview

This study began with research on current Minnesota laws, policies and programs relevant to CHP. A review of literature on CHP barriers and policies was then undertaken, including an analysis by the American Council for an Energy-Efficient Economy (ACEEE) of best practices for CHP policies in other states. Existing and proposed federal policies relevant to CHP were identified. The economics of a broad range of CHP technologies was analyzed, including sensitivity to key variables that could be affected by new policies and programs, including capital cost, weighted average cost of capital[41], CHP fuel price and avoided price of electricity.

Draft Policy Options for increasing CHP in Minnesota were developed based on the analysis of the economic significance of key barriers as well as review of best practices in other states. A "Straw Man" draft report was prepared which: summarized existing Minnesota policies; described CHP barriers and the analysis of the economic significance of key variables; outlined draft Policy Options; and addressed issues associated with the Policy Options. Informal stakeholder consultations were conducted following distribution of the Straw Man report, including discussions with electric utilities, gas utilities, thermal utilities, equipment suppliers, customers, advocacy groups and consultants.

Following the stakeholder consultation, detailed analysis of the Policy Options was undertaken and modifications were made to the Policy Options based on the feedback and analysis. Additional analysis of potential issues relating to the Policy Options was undertaken, including specific questions relating to program design as well as potential cost-benefit impacts on program participants and society. The impact of each Policy Option on CHP implementation was projected, primarily using ICF International's model for estimating natural-gas fired CHP market penetration. In addition, analysis of Minnesota Pollution Control Agency fuel consumption data was used to check and augment the ICF model on gas-fired CHP and to estimate the potential market penetration of biomass CHP.

Recommendations were then developed for consideration by the Department of Commerce and stakeholders in stakeholder workshops to be implemented in fall of 2014.

[41] Weighted Average Cost of Capital (WACC) is the weighted average cost of repaying the capital invested or borrowed to build a CHP project. There are two main ways to fund a project: 1) equity investment, in which a company invests its own funds and then requires a return on that equity investment through payments made throughout the life of the project from the project revenues; and 2) debt, in which funds are borrowed and principal and interest payments are made each year based on the debt interest rate. WACC is calculated based on the relative portions of debt and equity. For example, if the funds raised are 60 percent debt and 40 percent equity, the debt interest rate is 6 percent and the return on equity is 12 percent, the WACC is calculated as follows: (60% X 6%) + (40% X 12%) = 8.4%.

CHP Crediting Mechanisms

As discussed under “Key Challenges,” one of the challenges faced by states considering CHP within portfolio standards is the method by which the CHP savings is calculated and credited. No standard accounting approach has emerged. In the following discussion of alternative crediting methodologies we will use the parameters defined in Table 39. Table 40 shows the formulas for the alternative crediting methods to calculate the number of credited MWh of CHP electricity generation.

		Symbol	Units	Formula
CHP	Heat rate (conventional)	HRchp	MMBtu/MWhe	Fchp / E chp
	Marginal heat rate (SWEEP)	HRSWchp	MMBtu/MWhe	(Fchp - Fb) / Echp
	Total efficiency	EFFchp	%	Project-specific
	Fuel consumption	Fchp	MMBtu	Project-specific
	Annual electricity production	Echp	MWhe	Project-specific
	Annual usable heat production	Tchp	MMBtu	Project-specific
Offset thermal	Boiler efficiency for offset thermal production	EFFb	%	80%
	Reduction in fuel consumption for thermal production	Fb	MMBtu	Tchp / EFFchp
Offset electric	Power generation heat rate	Hreug	MMBtu/MWhe	Grid-specific
	Power transmission/distribution losses	TDeu	%	Grid-specific
	Heat rate including T/D losses	HReut	MMBtu/MWhe	HReug / (1 - TDeu)
	Reduction in fuel consumption due to CHP	Feu	MMBtu	Echp * HReut
	Total reduction in fuel consumption	Ftot	MMBtu	Fchp - Fb - Feu

Table 39. Parameters for CHP Crediting Calculations

Source: FVB Energy Inc.

Methodology	Units	Formula
NRDC/OEC	MWH	See Table 37.
SWEEP	MWH	Lesser of Echp and Ftot / HRSWchp.
Massachusetts APS	MWH	Lesser of Echp and (Echp / 33%) + (Tchp / 3.412 / 80%) - (Fchp /3.412)
ACEEE	MWH	Ftot /HReut

Table 40. Formulas for CHP Crediting Methods

The method recommended by the Natural Resources Defense Council (NRDC) and Ohio Environmental Council (OEC) emphasizes incentivizing maximum efficiency and simplifying implementation (NRDC/OEC 2012). They recommend a tiered approach as shown in Table 41, with efficiency measured on Lower Heating Value (LHV) basis. The NRDC/OEC White Paper indicates that Ohio law requires a 60 percent minimum efficiency on an LHV basis. See "Minimum Efficiency Standards" below for definitions and discussion of LHV and HHV.

The efficiency data used in this report are HHV basis. Converting the NRDC/OEC tiers to HHV yields the values shown in Table 42.

Tier	Efficiency (LHV)	Portion of kWh output credited
	<60%	0%
Tier 1	60-65%	60%
Tier 2	65-70%	70%
Tier 3	70-74%	80%
Tier 4	74-77.5%	90%
Tier 5	>77.5%	100%

Table 41. NRDC/OEC Tiers

Tier	Efficiency (LHV)	Efficiency (HHV)	Portion of kWh output credited
	<60%	<54%	0%
Tier 1	60-65%	54-59%	60%
Tier 2	65-70%	59-63%	70%
Tier 3	70-74%	63-67%	80%
Tier 4	74-77.5%	67-70%	90%
Tier 5	>77.5%	>70%	100%

Table 42. Conversion of NRDC/OEC Tiers to Higher Heating Value

The SWEEP (Southwest Energy Efficiency Project) approach divides the total fuel savings due to CHP by a heat rate that we will term a "marginal heat rate" (Kowley 2012).This heat rate is calculated by subtracting the offset boiler fuel from the total CHP fuel use and dividing the result by the CHP electricity output. The creditable MWh of electricity are the lesser of the calculation or the actual CHP electricity output.

The Massachusetts APS law is the most generous method for crediting CHP. It states that the creditable CHP power output is:

> *".. equal to the result, if positive, of the following calculation: take the sum of (1) the electrical energy generated divided by the overall efficiency of electrical energy delivered to the end-use from the electrical grid (which efficiency is equal for this purpose to 0.33); and (2) the Useful Thermal Energy divided by the overall efficiency of thermal energy delivered to the end-use from a standalone heating unit (which efficiency is equal for this purpose to 0.80); and subtract from this sum the total of all fuel and any other energy consumed by the CHP Unit in that quarter expressed in MWh and calculated using the energy content of the fuel based on its higher heating value."*

ACEEE's recommended method (Elliott, Chittum, Trombley and Watson) divides the total fuel savings (fuel for separate heat and power – CHP fuel) by the grid heat rate. This approach results in the lowest credit to CHP.

The results of all four calculation methods for each CHP technology configuration is illustrated in Figure 25. We have omitted the biomass-fired CHP configurations because they will qualify for the RPS. We have omitted the waste heat to power technology (using ORC) because this scenario is not addressed except in the NRDC/OEC method.

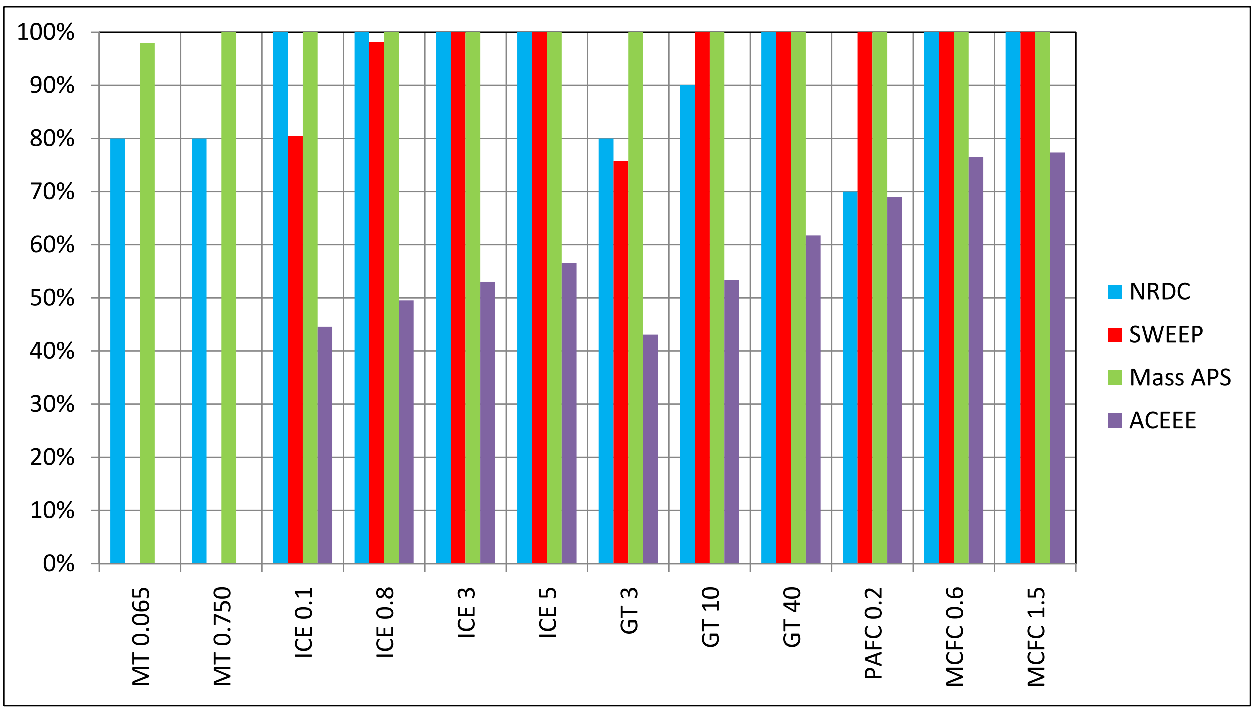

Figure 25. Credited CHP Power Generation as a Percentage of Total CHP Power Generation for 12 Technologies Under 4 Calculation Methods

Of the methodologies analyzed, the NRDC/OEC methodology is the most promising approach for crediting CHP electricity generation, because it: 1) incentivizes all prime mover technologies and does not pick technology winners; 2) encourages project developers to design higher-efficiency installations, regardless of the prime mover technology; 3) is relatively simple to administer and implement, as it requires only a simple calculation of overall system efficiency based on readily available inputs (and minimizes issues surrounding heat-rates).

However, a simpler and more stringent approach with higher thresholds and fewer tiers, such as outlined in Table 43, would create more incentive for high-efficiency systems and would be even less complex to administer.

Tier	Efficiency (HHV)	Portion of kWh output credited
	<60%	0%
Tier 1	>60<70%	80%
Tier 2	>70<80%	90%
Tier 3	>80%	100%

Table 43. Simplified Approach to Crediting CHP Electricity Production

Crediting Mechanisms for CHP Thermal

For natural gas utilities, FVB recommend calculating natural gas savings for CIP credit as equal to total fossil fuel savings (Ftot in Table 39). Note that some of the fuel savings from offset grid power production may come from fuels other than natural gas (primarily coal). Note also that in some relatively limited cases the fuel savings from offset thermal boiler operations may come from fuels other than natural gas (primarily fuel oil). However, given the public policy benefits of reducing use of such non-natural-gas fuels, we recommend that all such fuel savings count toward natural gas reduction goals.

Cost-Benefit Tests

To assess the impact of the Policy Options, cost-benefit analysis of the Policy Options on selected CHP technologies was undertaken.

Five key cost-benefit tests are commonly used to evaluate energy efficiency program evaluation: the participant cost test (PCT), the utility/program administrator cost test (PACT), the ratepayer impact measure test (RIM), the total resource cost test (TRC) and the societal cost test (SCT) (National Action Plan for Energy Efficiency 2008).

The basic structure of each test involves a calculation of the total benefits and the total costs in dollar terms from a certain vantage point to determine whether or not the overall benefits exceed the costs. A test is positive if the benefit-to-cost ratio is greater than 1.0, and negative if it is less than 1.0.

In our analysis we focus on two of those tests, which compare costs and benefits for customers (PCT) and society as a whole (SCT). Table 44 lists the key elements in the tests for CHP projects owned by a utility customer. Table 45 lists the key elements in the tests for CHP projects owned by a utility.

Participant Cost Test (PCT)

Costs	CHP fuel costs
	CHP non-fuel operating costs
	CHP capital costs
Benefits	Avoided thermal boiler fuel costs
	Avoided electricity costs
	Incentive payments
	Tax credits

Societal Cost Test (SCT)

Costs	Program overhead costs
	CHP fuel costs
	CHP non-fuel operating costs
	CHP capital costs
Benefits	Avoided thermal boiler fuel costs
	Avoided power grid fuel costs
	Avoided power grid non-fuel O&M costs
	Avoided power grid capacity-related costs
	Avoided externality costs

Table 44. Elements for Cost-Benefit Tests with Customer-Owned CHP

Participant Cost Test (PCT)

Costs	Purchase of heat output of CHP
	Purchase of electric output of CHP
Benefits	Avoided thermal boiler fuel costs
	Avoided electricity costs

Societal Cost Test (SCT)

Costs	Project development costs
	Management costs
	Incentive
	CHP fuel costs
	CHP non-fuel operating costs
	CHP capital costs
Benefits	Avoided thermal boiler fuel costs
	Avoided power grid fuel costs
	Avoided power grid non-fuel O&M costs
	Avoided power grid capacity-related costs
	Avoided externality costs

Table 45. Elements for Cost-Benefit Tests with Utility-Owned CHP

Each cost-effectiveness test compares the Net Present Value (NPV) of the annual costs and benefits over the life of an efficiency measure or program. In NPV analysis, a long-term stream of annual costs and benefits are discounted based on a discount rate. The discount rate indicates the time value of money, which can be different for the various stakeholders (participant and society). The discount rate is necessary because a dollar today is worth more than a dollar one year from now, depending on an entity's Weighted Average Cost of Capital. Further, each category of costs and benefits may be projected to escalate at different rates over the analysis period. Values for key parameters used in the cost-benefit tests are provided in Table 46 .

Discount Rates (nominal)

PCT	15.78%
SCT	3.45%

Escalation Rates (nominal)

Natural Gas	3.75%
Electricity	2.20%
Non-fuel operating costs	1.76%
GHG emission reduction value	7.50%

Table 46. Parameter Values for Cost-Benefit Tests

Sources:
Discount rates: PCT = 6 year simple payback, RIM = utility WACC; SCT = Average 20 year AA rated municipal general obligation bond interest rate as of July 29, 2014
Escalation rates: Natural gas and electricity -- EIA AEO 2013 West Central region projections for nominal prices of natural gas and electricity (average of commercial and industrial); Non-fuel operating costs -- difference between nominal and constant dollar projections for EIA AEO 2013 West Central region price projections; GHG -- twice the natural gas rate

The Cost-Benefit analyses did not account for CIP performance incentives[42] that utilities might earn by exceeding CIP goals. We have made the simplifying assumption that effective policy action on CHP in CIP will require new legislation and that the issue of bonus incentives can be addressed at that time.

Avoided Costs of Power Generation

In response to information requests from the Minnesota Department of Commerce regarding avoided costs of electricity generation, Xcel and Minnesota Power submitted the data summarized in Table 47.

[42] See Minnesota Statutes 216B.241 Subdv. 2c.

	Xcel	MP&L
Generation capacity cost ($/kW)	$ 87.04	*
Transmission/distribution captial cost ($/kW)	$ 33.00	$ 8.50
Marginal energy cost ($/MWh)	$ 30.38	$ 23.78

* Not provided -- considered a "trade secret"

Table 47. Avoided Costs Provided by Xcel and Minnesota Power

Sources: Xcel Response to Information Request 2012 and
Minnesota Power Response to Information Request 2013

Xcel's estimated marginal energy cost ($30.38/MWh) is consistent with avoided fuel costs for a natural gas combined cycle (NGCC) plant. Non-fuel variable O&M costs are not addressed. Essentially, Xcel calculates the fixed costs avoided by efficiency programs based on inexpensive gas CT peaking plants, but calculates the avoided energy costs based on more efficient NGCC plants.

Minnesota Power's marginal energy cost estimate ($23.78/MWh) appears consistent with avoided fuel costs for a coal-fired steam turbine plant. Again, non-fuel O&M costs are not addressed.

Xcel's estimate of avoided generation capital cost is based on a simple cycle gas-fired Combustion Turbine (CT), as summarized in Table 48. The 195 MW proxy plant is one half of a 2 CT campus as modelled in Xcel's 2011 Integrated Resource Plan. The "Economic Carrying Charge" is based on the Strategist model and appears is consistent with a 15 year amortization at Xcel's WACC. The "capital adjusted for reserve margin" appears to be based on a 16.3% margin. The fixed O&M cost does not seem to be included in the total.

Generic CT Inputs	
Original Capital Cost ($1000)	$ 124,028
Summer capacity (MW)	195
Capital cost per MW	$ 636
Calculations for 2013	
Capital cost Economic Carrying Charge ($1000)	$ 13,682
Final fixed cost of CT ($/kW/yr)	
Capital	$ 70.16
Fixed O&M	$ 2.70
Capital adjusted for reserve margin	$ 81.60
Fixed gas charge	$ 5.44
Total	$ 87.04

Table 48. Xcel Generation Capital Cost for Proxy Combustion Turbine Plant
Source: Xcel Response to Information Request 2012

Thus, while Xcel calculates avoided capital costs based on a CT, the avoided energy costs are based on a NGCC. Xcel's updated Resource Plan (Xcel Resource Plan Update 2011) indicates that in the

2018-2025 period, 1,829 MW of additional generation capacity will be required, of which 53 percent will be CT, 40 percent will be NGCC and the remainder purchased capacity from Manitoba Hydro.

What are the avoided electricity costs resulting from CHP generation? This is a complex question due to the range of utilities and the related issues:

- Current mix of power plant fuels and efficiencies;
- Potential changes in the power plant mix due to –
    - Additional capacity needed to meet future demand,
    - Impact of air quality regulations, particularly regional haze impacts on Sherco, and
    - Impact of EPA regulations on GHG emissions; and
- Future changes in fuel costs.

For the purpose of this statewide study, the avoided cost assumptions summarized in Table 49 will be used to estimate the potential benefits from new CHP capacity which can be operated at a high capacity factor. These calculations are based on the following assumptions:

- EPA GHG regulations and air quality regulatory impacts will result in reduced capacity and production by coal-fired plants in Minnesota;
- Additional capacity will be required which will be a mix of NGCC and CT;
- CHP will be competing more with NGCC than with CT relative to dispatch;
- Not all CHP will be dispatchable at full capacity at under peak grid demand conditions, and thus the capacity credit for CHP will be less than the full avoided capacity cost of NGCC.

	New Gas Combined Cycle (NGCC)	New Combustion Turbine (CT)	Weighted Average
Capital costs			
Summer capacity (MW)	400	210	
Generation			
Capital cost per kW (1)	$ 917	$ 973	
Capital cost ($M)	$ 367	$ 204	
Transmission & Distribution			
Capital cost per kW (2)	$ 33.00	$ 33.00	
Capital cost ($M)	$ 13	$ 7	
Total capital cost ($M)	$ 380	$ 211	
Capacity factor	0.85	0.85	
Fixed costs			
Fixed cost ($/kW/yr)			
Capital (3)	$ 92.05	$ 97.48	
Fixed O&M (1)	$ 13.17	$ 7.34	
Fixed gas charge (4)	$ 3.69	$ 5.44	
Total	$ 108.91	$ 110.26	
Average fixed costs ($/MWh)	$ 14.63	$ 14.81	
Fixed Cost Weighting			
Weighting factor	0%	100%	
Discount factor for average CHP (5)		20%	
Discounted weighted average fixed cost ($/kW/yr)			**$ 88.20**
Variable costs			
Heat rate (Btu/kWh) (1)	7,050	10,850	
Fuel cost ($/MMBtu) (6)	$ 4.62	$ 4.62	
Fuel cost ($/MWh)	$ 32.56	$ 50.11	
Variable O&M costs ($/MWh) (1)	$ 3.60	$ 15.45	
Total variable generation cost ($/MWh)	$ 36.16	$ 65.56	
Transmission/Distribution losses (7)	5.6%	5.6%	
Total variable cost of delivered energy ($/MWh)	$ 38.30	$ 69.44	
Variable Cost Weighting			
Weighting factor	100%	0%	
Weighted average variable cost ($/kWh/yr)			**$ 38.30**

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(1) EIA Updated Power Plant Cost Estimates 2013.
(2) Xcel Response to Information Request 2012.
(3) 20 year amortization at Weighted Average Cost of Capital of 7.34%.
(4) CT value from Xcel Response to Information Request 2012.
NGCC value prorated from CT value based on heat rate.
(5) Discount factor to account for some CHP plants not be fully available at peak grid demand.
(6) Annual Energy Outlook 2014, Early Release. U.S. Energy Information Administration, Dec. 2013. Average 2014 electricity utility natural gas costs.
(7) EIA State Electricity Profiles 2010.

Table 49. Assumed Characteristics of Offset Grid Electricity

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