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DIVISION OF ENERGY RESOURCES

# Analysis of Standby Rates and Net Metering Policy Effects on Combined Heat and Power (CHP) Opportunities in Minnesota

**Prepared for**: Minnesota Department of Commerce, Division of Energy Resources
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## Acronyms

| | |
|---|---|
| DG | Distributed Generation |
| CEAC | US DOE Midwest Clean Energy Application Center |
| CHP | Combined Heat and Power |
| COMM | Minnesota Department of Commerce, Division of Energy Resources |
| DOE | U.S. Department of Energy |
| EIA | U.S. Energy Information Administration |
| ERC | Energy Resources Center |
| FOR | Forced Outage Rate |
| IOU | Investor Owned Utilities |
| IREC | Interstate Renewable Energy Council |
| kW | Kilowatt |
| kWh | Kilowatt-hour |
| MPUC | Minnesota Public Utility Commission |
| MW | Megawatt |
| NG | Natural Gas |
| NM | Net Metering |
| NEG | Net Excess Generation |
| UIC | University of Illinois at Chicago |
| WHP | Waste Heat to Power |

# Executive Summary

The Energy Resources Center (ERC), located at the University of Illinois at Chicago (UIC) conducted the research for this paper for the State of Minnesota Department of Commerce, Division of Energy Resources under CARD Grant #59974. The goal of this project was to analyze the effects of Minnesota's existing net metering rules and standby rates on combined heat and power (CHP) and waste heat to power (WHP) applications, to identify possible modifications to these rates and to analyze the benefits of identified policy modifications.

Utility Energy Efficiency Programs that offer direct grants and incentives to encourage investment in traditional energy efficiency measures are effective in moving the market in the short term; however, sound energy policies are also crucial to promote long term, sustainable energy efficiency. This paper examines the energy policies of standby rates and net metering and their impact on CHP development in Minnesota. Specifically, this paper:

1. Assesses the existing standby rates and net metering policies and how they affect the market acceptance of CHP projects today and presents recommendations that could help reduce the barriers that these factors impose on CHP development in Minnesota.

2. Models the economic potential of CHP projects in Minnesota investor owned utility (IOU) service territories based on analyzing the impact of current versus hypothetically improved standby rates.

When CHP systems are properly sized and installed, they can reduce energy costs, improve power reliability, improve power quality, increase energy efficiency, and improve environmental quality. Significant potential exists in Minnesota for CHP projects today, but as this report explores, barriers such as standby rates may be preventing some of this potential growth.

## Standby Rate Analysis and Recommendations

Standby rates in Minnesota have been perceived as a significant barrier to CHP development. Standby service comprises the set of retail electric rates for customers with on-site, non-emergency, distributed generation (including CHP). This paper used two different methodologies to evaluate Minnesota standby rates in order to more comprehensively understand the barriers within each rate structure.

The first approach used three criteria to evaluate the efficacy of standby rates: transparency, flexibility and promotion of efficient consumption. These three criteria represent overarching functional categories which have ascribed through utility rate theory as applied to cost of service regulations and realized through successful standby rates from utilities across the U.S. The definitions of each of these criteria are as follows:

- *<u>Transparent rates</u>* provide customers with clear signals on the cost of electric service and help customers operate in a cost-effective manner that lessens their burden to the utility.

- *Flexible rates* are those which allow the customer to avoid charges when not using service.

- Electric rates that promote *economically efficient consumption* should be designed to discourage the wasteful use of utility services while promoting all that is economically justified in terms of private and social costs incurred and benefits received.

The second approach assesses the financial impact created by standby rates through an analytic framework using the avoided rate as the primary metric for evaluating the barriers within standby rates.[1] The concept evaluates the financial impacts of standby rates on DG systems by comparing the aggregate per-kilowatt hour (kWh) cost of full requirements customers (that is, customers with no on-site generation) to that of standby customers. The avoided rate is the aggregate per unit price of electricity not purchased from the utility due to on-site generation. This rate is then compared to the aggregate per unit price of electricity purchased before the installation of a CHP system. The avoided rate percentages used in this paper reflect the extent to which the avoided rate (on a per unit basis) matches the full-requirements rate. An avoided rate of 100% means that the value of a kWh purchased will remain the same when not purchased.

Although the standby recommendations for each utility are somewhat unique and are further explored in the full paper, Table 1 summarizes the most reoccurring standby modifications for IOUs in Minnesota grouped by functional criteria[2]:

| 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. |

[1] The guidelines and methodology regarding the concept of the avoided rate were presented by the U.S. EPA CHP Partnership in their 2009 paper titled, "Standby Rates for Customer-Sited Resources: Issues, Considerations, and the Elements of Model Tariffs."
[2] See section 2 for an overview of standby rate concepts and component definitions.

| Principle | Analysis and Recommendation |
|---|---|
| **Economically Efficient Consumption** | *Grace periods exempting demand usage fees should be removed where they exist and standby rates should be priced to reflect usage.* 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 1: Standby Rate Policy Recommendations**

When evaluating standby rates using the avoided rate metric/analysis, the results shown in Table 2 range between 77% and 97%. In general, when analyzing the avoided rate metric, the closer the values are to 100% the lower the economic barrier standby rates impose on CHP projects. The IOUs of Xcel Energy, Minnesota Power and Otter Tail Power demonstrated rates 87% and greater while Alliant Energy modeled no avoided rates greater than 78%.

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.

| | 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% |
| Otter Tail Power | 97% | 96% | 96% | 97% |

**Table 2: Avoided Rates of Minnesota IOUs**[3]

## Net Metering Analysis and Recommendations

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.

The net metering rates updated through House File 729 (which increased the capacity limit from 40 kW to 1 MW for IOUs) are fundamentally in line with successful approaches used in other states as well as

[3] Further information on the modeling assumptions can be found in Section 2.4. Utility specific modeling inputs can be found in Sections 3.5 (Xcel), 4.5 (Alliant), 5.5 (Minnesota Power) and 6.5 (Otter Tail Power).

those approaches advocated by the Interstate Renewable Energy Council (IREC) and the Regulatory Assistance Project (RAP).[4] A possible impediment identified is that larger net metering customers (100 kW to 1 MW) might face standby charges. The inclusion of standby rates for the larger net metering customer base could essentially cap net metering at 100 kW since standby charges would increase acceptable payback windows for most clean distributed energy projects. Much like utilities are currently required to demonstrate, "the effects of net metering on the reliability of the electric system"[5] in order to implement a net metering aggregate capacity limit so should they be required to demonstrate inaccurate cost recovery through regular rate structures before implementing any standby rate on net metering customers. This report identifies 17 states that exempt standby charges for net metering customers. Table 3 summarizes the recommendations to the current net metering policies in Minnesota:

| Recommendation | More Information |
|---|---|
| Standby rates should not be applied 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. |
| 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. |

**Table 3: Recommendations to Minnesota Net Metering Policies**

## Economic Potential Analysis

ERC worked in conjunction with ICF International in order to develop the overall economic potential analysis of CHP generating capacity within Minnesota IOU service territories (i.e. not including CHP systems installed within electric municipality and cooperative service territories). The ICF model analyzed the impact of standby rates on economic potential incorporating project simple payback rates. Simple paybacks were modeled using current utility electric prices, natural gas rate estimates based on average prices from the U.S. Energy Information Administration (EIA) for the commercial and industrial sector, and average CHP equipment cost and performance characteristics. Payback periods were grouped into three categories, 0-5 years, 5-10 years and above 10 years.

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[4] Minnesota State Legislature, *House File 729 4th Engrossment*, 88th Legislature (2013-2014). Available at, https://www.revisor.mn.gov/bills/text.php?number=HF729&session_year=2013&session_number=0&version=latest

[5] Minnesota Statute §216B.164, Subd 4b (2013)

Within the four major investor owned utilities, there lies 1,798 MW of CHP technical potential. When modeling the base case and using current standby rates, results indicate 779 MW of new CHP project potential with a payback of 10 years or less. Table 4 provides a breakout of the economic potential in three payback periods.[6]

| | Payback >10 years | Payback 5-10 years | Payback 0-5 years | Total Tech Potential, MW |
|---|---|---|---|---|
| Alliant | 52 | 5 | 0 | 57 |
| MN Power | 95 | 141 | 0 | 236 |
| Xcel Energy | 809 | 633 | 0 | 1,442 |
| Otter Tail | 63 | 0 | 0 | 63 |
| Total | 1,019 | 779 | 0 | 1,798 |

**Table 4: CHP Economic Potential per Utility (Base Case)**

When the avoided rates were increased in the model from their current standing to a hypothetical value of 100%, the overall CHP generating capacity with paybacks of 10 years or less increased by 43% from 779 MW to 1,116 MW, as shown in Table 5. Factoring in that some of the IOUs already have relatively reasonable avoided rate metrics of 87% and greater, it should be noted that even a small increase in improving standby rates can have a significant impact on the payback periods of CHP projects in Minnesota.

| | Payback >10 | Payback 5-10 years | Payback 0-5 years | Total Tech Potential, MW |
|---|---|---|---|---|
| Alliant | 52 | 5 | 0 | 57 |
| MN Power | 95 | 141 | 0 | 236 |
| Xcel Energy | 479 | 964 | 0 | 1,442 |
| Otter Tail | 57 | 6 | 0 | 63 |
| Total | 682 | 1,116 | 0 | 1,798 |

**Table 5: CHP Economic Potential per Utility (100% Avoided Rate)**

Though there have been some recent improvements to standby rates in Minnesota (e.g. Xcel Energy), standby rates still remain as barriers to CHP development as noted in the modeling by ICF International. Hypothetically modifying the standby rates using the avoided rate metric resulted in a 43% increase in CHP projects moving from paybacks greater than 10 years to projects experiencing paybacks less than 10 years. 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.

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[6] Economic potential rests on a continuum involving market acceptance curves that vary between every economic sector and individual business. This definition of economic potential isn't intended to imply that all included capacity is viable but that viable and likely projects form a smaller subset within economic potential.

# 1. Introduction

The Energy Resources Center, located at the University of Illinois at Chicago (ERC) conducted the research for this paper for the State of Minnesota Department of Commerce, Division of Energy Resources under CARD Grant #59974. The goal of this project was to analyze the effects of Minnesota's existing net metering rules and standby rates on combined heat and power (CHP) and waste heat to power (WHP) applications, to identify possible modifications to these rates and to analyze the benefits of identified policy modifications.

Under current Minnesota law, utilities must achieve annual energy savings equal to at least 1.5% of annual retail energy sales. While Utility Energy Efficiency Programs that offer direct grants and incentives to encourage investment in traditional energy efficiency measures are very effective in moving the market in the short term, sound energy policies are crucial for long term, sustainable energy efficiency. This paper addresses two Minnesota energy policies, *standby rates* and *net metering*, and analyzes them to determine whether or not they present barriers to the overall economic potential of distributed generation (DG) technologies, specifically CHP.

A CHP system is a form of DG that generates at least a portion of the electricity requirements of a building, facility, and/or campus while recycling the thermal energy that would typically be exhausted from the electric generation process. This thermal energy can provide space heating/cooling, process heating/cooling, dehumidification and/or increased electrical generation. CHP systems use commercially available state of the art technologies, and if properly sized and installed can:

- Reduce Energy Costs
- Improve Power Reliability
- Improve Power Quality
- Increase Energy Efficiency
- Improve Environmental Quality

CHP is all the more important when one examines the efficiency levels of large utility electric generators. On average, two-thirds of fuel used to generate electricity in the U.S. is wasted by venting unused thermal energy into the atmosphere or dissipating it through cooling systems. While there have been impressive energy efficiency gains in other sectors of the economy since the oil price shocks of the 1970's, the average efficiency of power generation within the U.S. has remained around 34% since

1960.[7] In comparison, CHP systems can operate at efficiency levels as high as 80%, helping to mitigate high energy costs and reduce air pollution.[8]

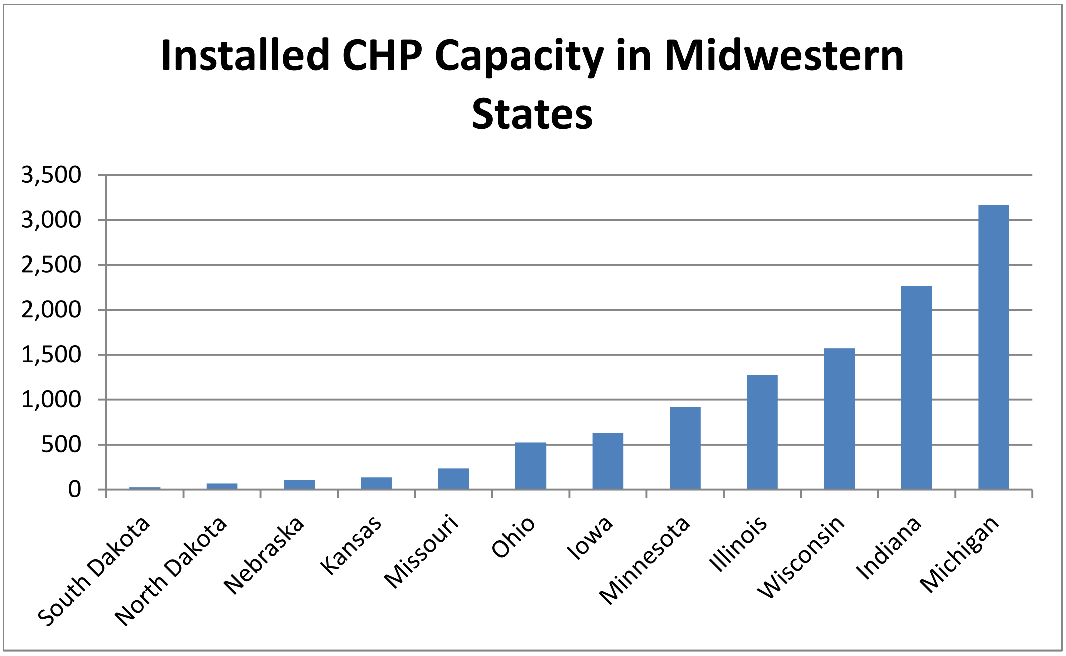


**Figure 1: CHP Capacity in the Midwest, 2013. Source ICF International**

Today, there is an installed CHP generating capacity base of 918 MW in the State of Minnesota, currently ranking 5th among the 12 Midwest states and representing 8.4% of the total CHP installed generating capacity in the 12 Midwest State Region (Figure 1).[9] The 918 MW are installed at 55 site locations and represent 8.0% of the state's utility generating capacity of 11,547 MW.[10] Our research estimates that there remains 1,975 MW of unrealized CHP technical potential in Minnesota. This CHP technical potential is an estimation of market size constrained only by technological limits – the ability of CHP technologies to meet potential end users' electric and thermal requirements – and represents the upper most bound for CHP capacity as technical potential does not consider capital costs, regulatory barriers, energy costs, avoided electric costs, or other factors impacting the economic feasibility of CHP systems. Although there represents a total technical potential of 1,975 MW of unrealized CHP in Minnesota, this paper will focus only on 1,798 MW of this potential – the potential within the four major investor owned utilities of Alliant Energy, Minnesota Power, Otter Tail Power, and Xcel Energy. The remaining potential is lies within the municipal and electric cooperatives.

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[7] Oak Ridge National Laboratory, *Combined Heat and Power: Effective Energy Solutions for a Sustainable Future*, by Anna Shipley et al, (Oak Ridge., 2008), 6.
[8] American Gas Association, *The Opportunity for CHP in the United States*, Prepared by ICF International, (May 2013), 1.
[9] DOE CHP Installation Database.
[10] U.S. Energy Information Administration, Office of Electricity, Renewables and Uranium Statistics, "State Electric Profiles 2012," 2012.

Installing 1,798 MW of unrealized CHP technical potential could lead to cleaner and more energy efficient generation, representing a significant opportunity for new CHP installations to contribute toward the annual utility energy savings goal of 1.5%.

In May 2013, Governor Mark Dayton signed House File 729 (HF 729) that contained provisions pertaining to economic development, housing, commerce, and energy bill. While the energy section of the bill was focused mostly on renewable technology like solar, Article 9 focused exclusively on distributed generation. Though there are still legal details in interpreting sections of the law to be ruled on by the Minnesota Public Utility Commission (MPUC), HF 729 undoubtedly reduces previous barriers to new CHP projects being developed.

The standby rate section is divided into five sections, the first to explain how standby rates function and the latter four to analyze each investor owned utility's (IOU) individual standby rate. Another section discusses net metering rates. Since IOUs in Minnesota have not yet had the requisite time to acquire MPUC approval for new net metering rates, this report only analyzes net metering as specified in HF 729. The final section presents the aggregate modeling results and analyzes the extent to which standby and net metering are barriers to CHP development. The paper analyzes these energy policies and economic potential for the four major IOUs of Xcel Energy (Northern States Power Company), Alliant Energy (Interstate Power and Light), Minnesota Power, and Otter Tail Power Company.

# 2. Standby Rates

Standby rates, otherwise known as partial service rates, constitute a subset of retail electric tariffs that are intended for customers with on-site, non-emergency distributed generation. They are the rates utilities charge an operator of distributed generation to provide backup electricity during both scheduled and unscheduled outages in addition to the cost to reserve such service. In contrast to standby rates, full-requirements rates are those paid by service customers whose sole source of electricity is the utility. To facilitate the understanding of standby rates this chapter is divided into four sections:

1) the first section (2.1) discusses the economics, structure, and regulatory environment surrounding electric rates;

2) the second section (2.2) provides definitions on key concepts in standby rate design;

3) the third section (2.3) presents successful approaches to standby rate construction including three criteria by which to judge the soundness and desirability of cost based standby rates, and;

4) the fourth section (2.4) details the analytic framework by which the economic effects of standby rates were analyzed.

## 2.1 Factors of Cost Based Electric Rate Regulation

Minnesota regulates their utilities using a cost of service methodology. Regulators often use the cost of service standard to calculate "fair and reasonable" rates because its methodology directly ties consumers to the cost of producing those goods and services consumed, in this case, electricity.[11] Furthermore, the Public Utility Regulatory Policies Act of 1978 (PURPA) mandates that electric rates shall be designed, to the maximum extent practicable, to reflect the cost of service.[12] The cost of service standard ties prices and price structures to the costs to render electric service to different classes of customers with the intention that one pays for the costs imposed on the system. Because electric utilities in regulated states, such as Minnesota, are natural monopolies, it is necessary for a state to regulate the electric market in order to protect the consumer. A cost based approach, like the cost of service standard achieves at least three important functions of public utility rate-making intended to stimulate competitive market conditions: *consumer rationing, capital attraction*, and *compensatory income transfer*.[13]

1) **Consumer Rationing** – Under the principle of *consumer rationing*, consumers are free to take service (whatever kinds in whatever amounts), "as long as they are ready to indemnify the

[11] David Moskovitz, *Profits and Progress Through Distributed Resources*, (Gardiner, ME: Regulatory Assistance Project, 2000), 3.
[12] *Public Utility Regulatory Policies*, 16 U.S.C. § 2625, (2012).
[13] James C. Bonbright, Albert L. Danielsen, and, David R. Kamerschen, *Principles of Public Utility Rates* (Arlington: Public Utilities Reports, 1988), 111.

producers…for the costs of rendition," thereby rationing themselves to only what is needed and no more.[14]

2) **Capital Attraction** – To ensure service now and in the future, *capital attraction* guarantees the service provider a funding source for both operating and capital expenses that are necessary to sustain grid infrastructure.

3) **Compensatory Income Transfer** – Lastly, the *compensatory income transfer* function requires those seeking a service to account for the use of the service through a monetary expenditure.

Achieving these three functions helps the cost of service standard recreate competitive market conditions in a situation devoid of competing market forces (i.e. electric utility monopoly in a regulated state or electric distribution utility in a deregulated state). Economists and rate theorists typically use competitive markets as guidelines for the regulation of monopolistic prices. The cost of service methodology is a commonly applied regulatory approach to simulate competitive market conditions.

### 2.1.1 General Rate Attributes

No matter the method in which rates are regulated (i.e. cost of service, value of service, performance standard, etc.), general rate function can be classified into three overarching attributes: revenue, cost, and practicality.[15]

1) **Revenue** related concerns include achieving the total revenue requirement predictably and stably through rates that are themselves stable and predictable.

2) **Cost** related concerns include promoting economically efficient consumption through portioning costs fairly among customers and avoiding discriminatory rates.

3) **Practical** concerns include attributes of payment collection, rate simplicity, and ease of understanding.

These attribute categories are important for shaping the context of the Minnesota standby rate analysis in this paper. Rates that fail to clearly display these attributes may also fail at achieving the larger rate functions mentioned above, which, in turn, could allow for claims of unfair or non-cost based rates. The cost attribute function is important in this discussion as it specifically addresses issues of fair cost allocation. Rates that do not fairly allocate costs might impede the consumer rationing function which in turn hinders a consumer's ability to ration consumption based on accurate and market-simulated pricing. When costs are not fairly recovered or when rates are not cost-based, utilities could manipulate prices in order to increase consumption and thus revenue. The role of a cost of service methodology is to bind customers and customer classes to the specific costs they impose on the utility.

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[14] Ibid.
[15] Bonbright et al, 383.

### 2.1.2 Creating Cost Based Standby Rates

Cost-based rate structures must achieve both the rate attributes and rate functions listed previously while also allowing the utility to obtain its revenue requirements. A cost of service study is necessary in order to determine the various costs imposed on the utility by each customer class. The central questions often facing a cost of service study are:

1) What specific costs are included?
2) How are these costs recovered from customers based on their consumption patterns?

Utility customers are typically grouped into rate classes and charged based on how they consume electric service. The most common utility classes correspond to residential, commercial and industrial classifications; however other classifications using similar voltage level and/or load level are also used in creating customer classes. The use of aggregate classes allows the utility to create rates that more accurately allocate costs, yet challenges arise when determining the level at which some customer classes are responsible for utility costs, the example in this paper being standby customers.

Designing the needed generation, transmission and distribution capacity for full-requirements customers is straightforward. Shared infrastructure is sized to meet the coincident peak of customers on each specific distribution and transmission line.[16] Dedicated infrastructure is sized to meet a customer's non-coincident peak demand (or billing demand). Since the full-requirements customers purchase capacity from the utility on a regular schedule the sizing requirements are well understood. However, standby customers have unique load characteristics that differ from full-requirements customers adding additional complications.

The Oregon Public Utility Commission states that cost-based standby tariffs should, "be based on the actual costs of providing backup generation and grid capacity for distributed generators during their occasional outages, spread across the year and following random patterns."[17] Understanding that costs must be fairly accounted for, a fundamental issue in creating cost-based standby rates is determining the appropriate level of reserve capacity that a utility must carry to provide standby service to customers with on-site generation.

For example, reliable standby customers with high availability rates impose their full demand on the grid far less frequently and in shorter durations than a standard full-requirements customer (i.e. some only requiring backup service a handful of days a year). The effect is that a utility supplying standby power will not have to plan as much reserve capacity to serve self-generating customers as it does for full-

[16] Coincident peak demand refers to the demand imposed by the customer at the time of a utility system's maximum demand. Non-coincident peak demand is the customer's largest demand exerted on the grid regardless of time. Utilities build infrastructure to service coincident peak not the summation non-coincident customer peak loads. The only infrastructure that has no coincident peak is that dedicated solely for one customer.

[17] Oregon Public Utility Commission, *Distributed Generation in Oregon: Overview Regulatory Barriers and Recommendations,* Prepared by Lisa Schwartz, Oregon Public Utility Commission (2005), 22.

requirements customers.[18] This is because needed reserve capacity decreases as generator reliability increases such that those generators with lower than average forced outage rates (FOR) require less reserved capacity. Furthermore, since properly scheduled maintenance service falls largely in the off-peak period the amount of reserve capacity held for scheduled maintenance should be far less, if not zero, than that of backup service. As the Oregon PUC noted, an outage during off-peak periods does not impose the same cost on the utility system as an outage during peak demand and should therefore be priced differently.[19]

## 2.2 Definition of Key Concepts

Key concepts are delineated between full-requirements customers and those who require standby service. The following are rate design elements most common to full-requirements customers:[20] Customer Charges, Energy Charges, and Demand Charges.

### 2.2.1 Rate Design Elements of Full Requirements Customers

**The Customer Charge** is the monthly (or daily) fixed charge that is attributed to the costs of metering, drop wire, etc. This functions as a grid access fee to be paid whether or not service is taken.

**The Energy Charges** are those covering the consumption of the electricity commodity applied usually on a per kWh basis. These rates may be differentiated by time-of-use, season, or block depending on how the utility's costs are incurred.

**The Demand Charges**, used more for larger commercial and industrial customers, are based on a customer's peak electric demand and are generally intended to recover the capital costs of capacity necessary to meet peak loads (including both generation and transmission/distribution capacity). Because electric service is provided "on demand" the system must be designed to meet a variety of peak loads: those for the grid as a whole, those of customers served by individual parts of the grid network and those of individual customers. Demand charges are a means of allocating and recovering the fixed costs to provide the necessary capacity with which to serve customers at peak periods.

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[18] Regulatory Assistance Project, and Brubaker & Associates, Inc, *Standby Rates for Combined Heat and Power Systems: Economic Analysis and Recommendations for Five States,* prepared for Oak Ridge National Laboratory, (Montpelier, VT, 2014), 11.
[19] Oregon Public Utility Commission, 22.
[20] Environmental Protection Agency. Office of Atmospheric Programs. Climate Protection Partnerships Division. *Standby Rates for Customer-Sited Resources: Issues, Considerations, and the Elements of Model Tariffs*, by the Regulatory Assistance Project and ICF International, (Washington, D.C., 2009), 3.

### 2.2.2 Rate Design Elements of Standby Customers

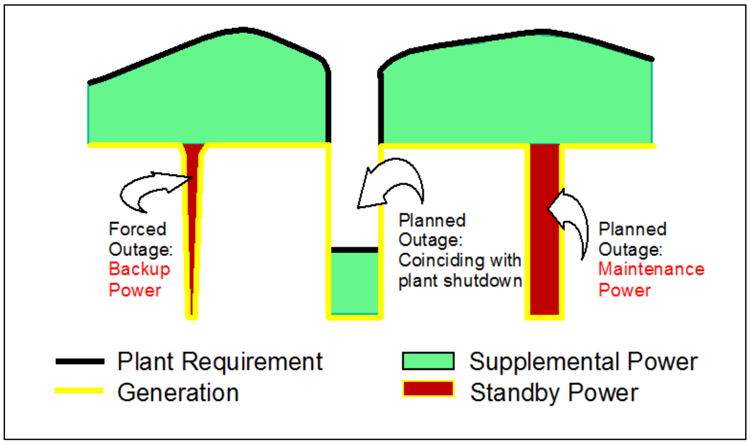


**Figure 2: Illustration of Standby Customers Power Requirements. Source: Regulatory Assistance Project**

Figure 2 depicts how standby functions with regards to planned and unplanned outages, supplemental service and the reservation charge. The yellow line represents the capacity of an on-site generator to which the standby reservation charge applies whereas the red blocks underneath the yellow line represent generator outages when standby service is required. These standby rate elements are further defined:

**The Reservation Charge** is a monthly charge per kW of the customer's needed standby capacity and cannot be avoided when standby is not taken. The reservation charge generally ensures that standby service will be available when needed by the customer during unscheduled and scheduled outages.

**The Demand Ratchet** is a mechanism by which the electric utility bills a customer for the maximum demand measured (or a percentage thereof) over the prior year or season. Ratchets are most commonly used to calculate the demand charges for full-requirements customers; however, they are sometimes applied to bills for the demand caused by an on-site generator outage. In Minnesota this occurs when Xcel or Alliant standby customers exceed 964 hours of unscheduled service. Under such a situation it is possible that a customer would pay both a demand charge and a standby reservation charge for the same capacity.

**Backup Service** is the capacity and energy supplied by the utility during an unscheduled outage of the on-site generator. Generally, the utility must receive a warning from the customer before the use of backup service so that they may ramp up generation if need be. The four Minnesota utilities included in this report use the monthly reservation charge ($/kW) related to the capacity of the on-site generator in order to cover the costs to reserve backup capacity instead of an as-used demand charge issued only during outages.

**Scheduled Maintenance Service** is the capacity and energy supplied by the utility when a customer's on-site generator is down for routine maintenance. Since this service is usually scheduled far in advance and can take place during nonpeak periods and seasons, it creates few additional capacity costs to the utility.

**Supplemental Service** provides for additional energy and capacity a customer might need beyond that generated on-site. In most cases this service is provided under the otherwise applicable full-requirements tariff.

**The Grace Period** is the allotted time a standby customer may use backup service without incurring any additional demand and/or usage charges. Both Xcel Energy and Minnesota Power provide 964 hours of backup service free of additional usage charges. The cost associated with providing the grace period is built into the reservation charge.

**Forced Outage Rate (FOR)** of a generating unit for a given time span is defined as the number of hours the unit is forced out of service for emergency reasons divided by the number of total hours that the generating unit is available for service during that time interval (plus the number of hours during a forced outage). The FOR measures the probability that the unit will not be available for service when required.[21]

**Coincident Factor** is the ratio of a customer's coincident peak demand to its non-coincident peak demand. A customer's coincident peak is the demand imposed during the utility system's maximum demand whereas the non-coincident peak is a customer's maximum demand recorded during any time. A customer having a higher coincidence factor will impose greater demand related costs per kW of non-coincident demand than a customer with a lower coincidence factor.

### 2.3 Successful Approaches in Standby Rate Design

While standby rates are necessary to recover the fully allocated embedded costs that the utility incurs to provide backup and maintenance service, they can also be created in such a way as to financially burden distributed generation customers unfairly thereby erecting barriers to DG development. The goal of well-crafted standby rates should promote economic efficiency, fairness, simplicity, transparency, and system reliability while penalizing those generators that incur large costs to the utility.[22] Rate structures should be created in a manner that avoids arbitrariness, capriciousness and undue discrimination while covering the full costs each customer and customer class imposes on the grid. No rate class should subsidize the costs incurred by other classes nor should customers pay for costs that they themselves do not incur. The following three criteria were created to evaluate the soundness and desirability of cost based standby rates structures:

[21] Regulatory Assistance Project, *Standby Rates for Combined Heat and Power*, 10.
[22] National Regulatory Research Institute, *Electric Utility Standby Rates: Updates for Today and Tomorrow,* Report 12-11, by Tom Stanton (July 2012), Page 10.

**Criterion 1 – Transparency**:

Rates should be easily understood and include rate mechanics and price levels that are stable and predictable. Transparent rates should provide price signals that clearly reflect the many cost drivers associated with electric service allowing customers to understand when, how and where utility costs are incurred. Having clearly delineated price signals and rate mechanics helps promote more accurate consumer rationing and addresses the revenue and practicality rate attributes. Aspects of transparency entail:

- The separation of capacity costs to best reflect the drivers of cost for each component, i.e. dedicated distribution, shared distribution, transmission, and generation capacity;
- A differentiated demand charge reflecting the costs associated with on-peak and off-peak periods for transmission and distribution service;
- Unbundling rates to the maximum extent feasible; and
- Clear, easily understood rate mechanics.

Examples of successful transparent rate design include:

- Pacific Power Partial Service Rate 47 (Oregon) separates the distribution charge into three categories (Basic, Facility, On-Peak) to most accurately capture the drivers of each component.[23] The facilities charge covers the cost of local delivery facilities that must be dedicated to serve a specific customer while the on-peak demand charge covers the costs associated with shared distribution facilities. The basic charge is akin to a customer charge – a fixed monthly charge delineated by voltage class.
- Detroit Edison Rider 3: Parallel Operation and Standby Service (Michigan) uses daily, as-used, on-peak demand charge to recover utility costs; these charges are differentiated depending on the nature of the service (scheduled or unscheduled).[24]
- MidAmerican Energy Rider SPS (Iowa) divides the reservation charge into four categories corresponding to generation, transmission, distribution and substation cost causation. A customer's forced outage rate is used to calculate the generation and transmission components.

**Criterion 2 – Flexibility**:

Rates should distribute the burden of meeting total revenue requirements fairly and without arbitrariness, capriciousness, and inequalities among the beneficiaries of service in order to avoid undue discrimination. Flexible rates should allow customers to avoid charges when not taking service and also provide standby customers with options for taking alternative service. Flexibility in electric rates helps

[23] Pacific Power, Schedule 47: Delivery Service, Sheet No. 47-1, Effective January 1, 2014
[24] The Detroit Edison Electric Company, Standard Contract Rider No. 3: Parallel Operation and Standby Service and Station Power Standby Service, Sheet No. D-70.00, Effective January 5, 2014

promote consumer rationing and addresses the cost and practicality rate attributes. Further aspects of flexibility include:

- Rates that provide the ability to self-supply reserves or remove load during DG outages;
- Rates that incorporate load diversity and outage probability;
- Rates that allow customers to minimize charges by operating in a manner beneficial for the utility; and
- Rates that allow, if available, the ability to purchase power from real-time markets.

Examples of successful flexible rate design include:

- Pacific Power (Oregon) allows customers to self-supply reserve load in order to avoid utility reserve charge.[25]
- Pacific Gas and Electric Schedule S (California) calculates reservation capacity using the outage diversity of a customer's generating unit.[26]
- American Electric Power (Ohio) allows a standby customer to choose their outage level which corresponds to the monthly reservation charge.[27]
- Detroit Edison (Michigan) allows standby customers the choice to purchase all standby capacity from the real time market.

**Criterion 3 – Economically Efficient Consumption:**

Rates should be designed to discourage the wasteful use of utility services while promoting all that is economically justified in terms of the private and social costs incurred and benefits received. Economically efficient rates incentivize customers to take service when service is least expensive. This rate criterion helps promote more accurate consumer rationing and addresses the cost and revenue rate attributes. Rate mechanisms that help achieve economically efficient consumption include:

- Sending clear price signals that charge a premium for unscheduled outage demand that coincides with utility peak, and minimizing charges for scheduled outage demand during periods of excess utility capacity;
- Removing or reducing ratchets in order to allow customers to ration themselves efficiently every month; and

[25] Pacific Power, Schedule 47: Delivery Service, Sheet No. 47-1, Effective March 22, 2011.
[26] Pacific Gas and Electric Company, Electric Schedule S: Standby Service, Sheet No. 28241-E, Effective April 15, 2009.
[27] American Electric Power Ohio, Schedule SBS: Standby Service, Sheet No. 227-2, Effective September 2012.

- Recovering costs in a manner that penalizes customers who use the grid inefficiently while allowing customer to avoid charges when not taking service.

Examples of successful standby rates that promote efficient consumption include:

- NSTAR Rate T-2 (New York), Portland General Electric Rate 75 (Oregon), and MidAmerican's Rider SPS (Iowa) have no demand ratchets.[28]

- Hawaiian Electric Company Rate SS (Hawaii) charges standby customers a fairly high ($0.156/kWh) energy charge during both scheduled and unscheduled DG outages. This provides the customer a strong and direct incentive to ensure that their generator is well maintained.[29]

- Southern California Edison rate TOU-8-RTP-S (California) delineates the price for standby energy in hourly allotments corresponding to ambient air temperature, voltage taken, and day of week. This gives standby customers a detailed knowledge of how utility costs are incurred and how and when to operate to avoid high costs.[30]

In addition to these criteria, further guidance on ratemaking can be found in Federal Regulation, specifically those created by the Public Utility Regulation Policies Act. According to U.S. Code:

> "Rates for sales shall be just and reasonable and in the public interest and shall not discriminate against any qualifying facility [standby customer] in comparison to rates for sales to other customers served by the electric utility. Rates for sales which are based on accurate data and consistent system wide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics."[31]

These three criteria along with PURPA language help structure the analysis of Minnesota standby rates. Analyzing rates using these criteria is also useful because there are multiple approaches to creating successful standby rates. Standby rates and rate structures vary widely between states and utilities based on the costs inherent to specific situations and geographies. Applying these three criteria to standby rates, as opposed to a one size fits all structure, allows for flexibility in creating rates that recognize and recover utility costs.

Standby rates in Minnesota were further analyzed using an analytic modelling approach. The three criteria help organize and classify the rate barriers uncovered in the analytic modeling of standby rates. The analytic model analyzed the economic effects both current and modified standby rates have on customers with on-site generation. Possible rate modifications were identified as those that adhere to

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[28] Environmental Protection Agency, 15.
[29] Hawaiian Electric Company, Schedule SS: Standby Service, Sheet No. 69, Effective May 15, 2008.
[30] Southern California Edison, Schedule TOU-8-RTP-S:TIME-OF-USE-GENERAL SERVICE – LARGE REAL TIME PRICING – STANDBY, Sheet No. 52242-E, Effective April 1, 2013.
[31] *Public Utility Regulatory Policies* Act 18 U.S.C. § 292.305 (2012).

the above criteria while also improving the analytic modeling results. The following section explains the analytic model.

## 2.4 Analytic Approach to Modeling Standby Rates

In order to evaluate the economic effects of Minnesota standby rates on DG/CHP systems it was necessary to create two models that examine the economic effects of standby rates. The first model calculated the avoided rates of each utility's standby structure while the second analyzed how possible modifications to this avoided rate might affect the economic potential of CHP projects. The avoided rate is an analytic approach that quantifies the economic impacts standby rates may present to self-generating customers.

### 2.4.1 Avoided Rate Model

Created in Microsoft Excel, the avoided rate model analyzes the extent that standby rates allow DG customers to avoid electric charges. As a metric for evaluation, this model used the guidelines and methodology presented by the EPA CHP partnership in the paper "Standby Rates for Customer-sited Resources: Issues, Considerations, and the Elements of Model Tariffs"; specifically, the EPA's concept and application of the avoided rate.[32] This metric is useful because it simplistically reduces the economic and financial impact created by standby rates to a simple figure that can then be compared between utilities and states.

The concept of avoided rate evaluates the financial impacts of standby rates on DG systems by comparing the per kWh cost of full-requirements customers to that of standby customers. Ideally, a decrease in electricity purchased from the utility would be commensurate with a decrease in monthly electric costs. If a customer reduces their purchased electricity by 50% one would expect their bill to decrease by a similar amount. However, many standby rates are created such that they increase demand charges when a customer decreases energy consumption, thus negating many economic benefits. The avoided rate, then, is a metric that measures the amount of savings per kWh a DG customer receives when not purchasing electricity from the utility. In essence, it compares the value of a purchased kWh to the value of an avoided kWh. This rate requires the comparison between the same facility when on a full-requirements rate and when on a standby rate. After modeling each facility's usage during one year it is possible to aggregate all charges into a simple cost per kWh. This aggregate cost includes the cost of generation, transmission, distribution, demand, taxes and all applicable riders for both full-requirements and standby rates. The avoided rate is created through dividing the money not paid to the utility by the electricity not purchased from the utility. When the avoided rate closely matches the full-requirements rate, the user experiences increased savings.

For example, a hypothetical facility purchases 1,000,000 kWhs per year from the utility at an aggregate cost of 10¢ per kWh for a total cost of $100,000. Say this same facility installs a CHP system that reduces

[32] Environmental Protection Agency. Office of Atmospheric Programs. Climate Protection Partnerships Division. *Standby Rates for Customer-Sited Resources: Issues, Considerations, and the Elements of Model Tariffs*, by the Regulatory Assistance Project and ICF International, (Washington, D.C., 2009).

their need for purchased electricity to 500,000 kWhs per year. In an ideal economic situation, the annual bill would be half the normal bill, or $50,000. Under this ideally constructed scenario the avoided rate from the 500,000 kWhs *not* purchased would be 10¢ ($50,000/500,000 kWh). Thus, this situation would have an avoided rate of 100% the full-requirements rate.

There are limitations in using the avoided rate metric, however. Though simple to calculate and communicate, the avoided rate metric is a blunt tool that can 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.

### 2.4.2 Economic Potential Analysis

The Energy Resources Center worked in conjunction with ICF International in order to develop the economic potential analysis for CHP projects in Minnesota. This model analyzed how changes in the avoided rate from modifications to standby rates might affect the overall project paybacks of CHP projects in the state.

The process for examining how changes to standby rates might affect future installed CHP capacity begins with identifying sites that are technically conducive for CHP applications in terms of their coincidental electric and thermal loads. The technical potential for additional CHP applications in Minnesota is greater than 1,975 MW; 1,226 MW in the industrial sector and 748 in the commercial sector. 1,798 resides within the four major IOUs (See Appendix A for technical potential methodology and Appendix B for a breakout of technical potential by utility, economic sector and SIC code). The CHP technical potential is an estimation of market size constrained only by technological limits – the ability of CHP technologies to fit customer needs – and represents the upper most bound for CHP capacity as technical potential does not consider capital costs, regulatory barriers, energy costs, avoided electric costs, or other factors impacting the economic feasibility of CHP systems. In comparison, Minnesota has 918 MW of already installed CHP capacity and 11,547 MW of a combined utility generating capacity.[33]

The technical potential was then further classified using five different CHP system size ranges (50 to 500 kW, 500 to 1,000 kW, 1 to 5 MW, 5 to 20 MW, and greater than 20 MW) and four different market scenarios: [34]

- CHP with heating only – High load factor applications
- CHP with heating only – Low load factor applications
- CHP with heating and cooling – High load factor applications

[33] U.S. Energy Information Administration, Office of Electricity, Renewables and Uranium Statistics, "State Electric Profiles 2012," 2012.
[34] The model analyzed CHP performance using load factors and not according to on-peak and off-peak rate structures when energy prices may dictate more of the CHP operation than load factors.

- CHP with heating and cooling – Low load factor applications

An economic analysis was developed using assumptions specific to each size and market category such as utility specific electricity rates (including the avoided rates), state average natural gas prices, and average CHP equipment cost and performance characteristics. Because of the changing nature of natural gas prices the model included low and high gas price estimates using EIA data spanning the past five years; $4.50/MMBtu to $6.00/MMBtu for industrial customers and $5.00/MMBtu to $6.50 for commercial customers. Both the technical potential and energy price data was subjected to yearly growth rates using economic growth predictions and forecasted electric rate increases.[35] This analysis resulted in payback windows for each site residing in the technical potential analysis. The Energy Resources Center considered all technical potential with a payback less than 10 years to be economic potential. See Appendix D for greater detail on the assumptions used in the economic analysis.[36]

Economic potential was modeled with current avoided rates and with avoided rates of 100% representing the range that potential standby and net metering modifications could have on CHP potential. It is assumed that the recommendations presented in this paper will increase a customer's avoided rate to at least 100%; however, the actual impact of these recommendations largely depends on the specific operational attributes of each customer generator.

The policy recommendations within this paper focus on a more variable costs recovery for standby service. A customer generator that is often offline during coincident peak periods might see their avoided rate decrease as a result of these policy recommendations; however, a generator operating efficiently is expected to experience increased avoided costs as a result of these recommendations. This analytic approach illuminates how standby rates affect the economic potential of CHP in Minnesota. See Appendix D for a more detailed account of the economic analysis model inputs.

It should be noted that the payback ranges in the economic analysis do not factor in the effects of future grid constraint, coal plant retirements, energy resiliency, increased shale gas production, proposed carbon limits on electric generation, or other possible events affecting the price of electricity or natural gas. Depending on how future events transpire the economic potential of CHP could significantly increase from these modeled figures.

[35] The rate at which electric rates were modeled to increase came from normalizing US DOE EIA data over the past 23 years. Appendix D-4 lays out growth assumptions.

[36] The concept of economic potential is difficult to quantify since each business and economic sector have individualized acceptable payback windows. The ERC choose a ten year range because it encapsulates the widest range of acceptable payback windows.

### 2.4.3 Identifying Potential Tariff Modifications

The Energy Resources Center developed potential rate recommendations for each IOU in three steps:

1. The ERC reviewed the actual standby tariffs using the three criteria presented in section 2.5 and fashioned possible modifications that would put each rate more in line with other successful standby approaches.

2. The ERC then modeled the avoided rates of both the original and modified standby rates in order to understand the economic and financial impacts on self-generating customers.

3. Possible recommendations were identified as those that allowed standby customers to avoid 100% of their full-requirements bill.

A more detailed discussion follows for each of the four investor owned utilities.

# 3. XCEL ENERGY – Northern States Power Company

## 3.1 Description of Standby Tariff – Standby Service Rider

Excel Energy offers a standby service rider (SSR) under revised sheet 101. The SSR is available to any non-residential customer who has their own generating equipment that requires 40kW or more of standby capacity. The SSR is divided into three service offerings:

1. *Unscheduled Maintenance Service*
2. *Scheduled Maintenance Service*
3. *Non-Firm Standby Service*

## 3.2 Description of Standby Charges

The SSR Includes three charges:

1. Distribution Standby Capacity Fee
2. Demand Charges issued when standby is taken
3. Energy charges issued when standby is taken.

In September 2012 Xcel Energy revised their previous standby rates. Xcel's current standby tariff includes separate monthly reservation fees for firm unscheduled and firm scheduled maintenance service and for non-firm standby service. If a customer wishes to procure standby for both scheduled and unscheduled outages they must pay both reservation charges. The reservation charge includes a monthly customer charge and a distribution capacity fee delineated by voltage class. There is a small price difference ($0.10 per kW) between the unscheduled and scheduled reservation fee. Firm customers are allotted 964 hours of unscheduled use exempt from demand usage rates. Use of this grace period will be measured in terms of kWhs used by a customer. The maximum amount of standby energy available to the customer is 964 hours multiplied by the contracted Standby capacity. Non-firm customers only pay a reservation fee for distribution and transmission standby capacity and are allotted no grace period from demand usage charges. All usage demand and energy charges are billed per the full-requirements rate to which this rider is attached.

Notwithstanding the demand usage grace period, in the event a customer requires backup service at times in which the company would have insufficient accredited capacity thereby requiring additional capacity purchases as a result of such backup service, the standby customer shall pay peak demand charges for that month and the five subsequent months thereafter. If the customer gives a three hour notification the customer will only be changed one-sixth of any additional capacity costs but shall not be charged any after-the-fact capacity purchases. If notification is less than three hours the customer will be charged one-sixth of any additional capacity purchases. Additionally, the billing demand for the next five months shall be set as the maximum demand placed on the grid during the time of system peak.

This peak capacity provision is waived if the company has obtained appropriate accreditation from MISO for the customer's generation.

The customer's standby contract capacity is set forth in an electric service agreement. The quantity of standby capacity can be set at different levels for the summer and winter seasons. A customer seems able to set their contract capacity below the nameplate generation rating of their generator.

For customers with a contract capacity ranging from 40 kW to 10,000 kW scheduled maintenance on the generating unit must occur during the months of April, May, October or November. Customers with a contract capacity greater than 10,000 kW must provide an annual projection of scheduled maintenance to the company. The amount of advanced notice that the customer must provide is a function of the expected duration of the maintenance outage.

General Service or General Time of Day Service demand charges shall not apply to use during qualifying scheduled maintenance periods. Further, qualifying scheduled maintenance period time and energy will not count against the grace period.

### 3.3 Assessment of Xcel's Standby Rates

Xcel's current standby rates were recently revised; however, there still remain structural issues which if addressed would improve the economic climate for CHP in Minnesota. First, Xcel's standby tariff does not transparently display the cost components in the reservation rate. The reservation rate does not include any seasonal or on/off-peak differentiated pricing nor does it unbundle and separately price the components (generation, distribution and transmission) that comprise the standby service. The costs to provide capacity to full-requirements customers differs greatly between seasons and peak periods ($12.14 per kW in summer peak compared to $2.10 per kW during winter off-peak)[37]; however, this transparent cost differential is not present in the standby rate. Introducing seasonality and time-of-use distinctions in the reservation rate would ensure consistency with the design of other rate components in Xcel Energy's electric tariff book. Additionally, bundling of standby components masks the drivers of each cost component; transparency entails the unbundling of capacity costs to reflect the drivers of cost for each component.

Xcel Energy's standby rate also fails at providing flexible options for self-generating customers to take service. By paying the reservation rate standby customers are entitled up to 964 hours of unscheduled standby service (corresponding to an 11% FOR) even if they do not need that level of service. Standby customers operating under an 11% FOR are paying for service left unused. A flexible approach would allow the standby customer to choose the level of standby support required.

[37] Xcel Energy, Rate A15: General Time of Day Service; Section 5, Sheet 29, effective January 1, 2013.

Lastly, Xcel's standby rate does not provide necessary price signals to incentivize standby customers to more efficiently operate their generating units. Firm standby customers are paying an 11% FOR which is generally greater than most reliable CHP generator units.[38] This grace period does not encourage customers to reduce the duration of forced outages but can, in fact, incentivize standby customer to go offline when they otherwise might not since they will face few additional charges. Instead of tying the reservation rate to an 11% FOR covering all standby customers no matter their needed level of service, the reservation rate should be tied to a customer's own or chosen forced outage rate. Under such a structure the grace period would be terminated in favor of an on-peak, per day kW charge to recover the costs associated with a forced outage. This should result in a lower monthly reservation charge but a higher variable usage charge. While this rate structure might increase costs for standby customers with a large FOR it will, more importantly, encourage customers to reduce their FOR which will commensurately decrease the fixed monthly reservation charges further encouraging efficient consumption. According to the Regulatory Assistance Project, the use of daily standby demand charges provides incentives to improve the performance of self-generating units.[39]

In addition, a standby customer must reserve backup service and maintenance service separately even though the standby contract capacity that covers one service ought to cover both. The capacity reserved on the distribution system for backup service often is the exact same capacity that would be used during a scheduled outage.

### 3.4 Potential Recommendations to Xcel Energy's Standby Rate

Following are suggested modifications to Xcel's standby tariffs for consideration to lessen the barriers to future DG and CHP projects:

Transparency

1. *Combine backup service and maintenance service under one reservation fee.* The amount of capacity reserved for both services is the same. Since these services will not be used simultaneously there is no need to price them separately.

2. *Unbundle the components within the reservation rate*. The drivers of cost for each component can change depending on the behavior of the customer-generator.

3. *Firm standby demand usage fees during times of system constraint should be designed as they would for full-requirements customers of similar size.* Rates for sales which are based on accurate data and consistent system wide costing principles shall not be considered discriminatory as long as they apply to other customers with similar load or cost-related characteristics.

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[38] Oak Ridge National Laboratory, "Distributed Generation Operational Reliability and Availability Database," written by Energy and Environmental Analysis, Inc. (January 2004).

[39] Regulatory Assistance Project, *Standby Rates for Combined Heat and Power Systems: Economic analysis and Recommendations for Five States,* 30.

Flexibility

4. *Remove the grace period for firm backup power and instead tie the reservation charge to the customer's FOR.* The generation, transmission and shared distribution portions of the reservation charge should be calculated using the customer's own FOR.  This would incentivize the customer to reduce the duration of outages.

5. *Create a buy-through option that allows self-generating customers to purchase all standby service from the market at market prices.*  Currently, Xcel charges market prices to customers whose forced outages coincide with utility constraint but on the condition that the customer's standby demand may be ratcheted for five months.  Instead, a buy through option would provide flexibility for customer's seeking a market solution to standby service.  The reservation rate could be structured to only cover the dedicated distribution infrastructure.  All standby capacity would be charged using the applicable real time MISO locational marginal pricing node plus an adder reflecting Xcel's administrative costs.

Efficient Consumption

6. *A daily on-peak, as-used demand charge should replace the grace period and additional demand charges found in the full-requirements tariff.* This variable pricing would be implemented in conjunction with the calculation of the reservation rate using a customer's FOR. The daily, on-peak charge would be structured such that the customer would pay the same amount as the supplemental rate if they took backup service for the entire month.  The decrease in the monthly, fixed charges in combination with the addition of a variable usage charge would encourage the efficient consumption of grid resources.  Since the costs of generation and shared distribution components are incurred during peak periods, standby demand charges for those services should apply only during on peak periods.[40]

### 3.5 Avoided Rate Analysis

Although Xcel's revised standby rate avoids a greater portion of the full-requirements rate than the previous rate, improvements to standby can still be implemented to help further reduce barriers towards the development of financially viable CHP projects.  The standby rates financially burden customers with a smaller generating capacity, especially those with a low load factor, to a greater extent than they do for larger capacity customers.

Though this standby rate can be further improved, Xcel should be recognized for making significant changes to their past standby rates.  By removing the transmission and generation reservation charges which unfairly charged standby customers to reserve capacity during off-peak periods, Xcel's avoided rates jumped from approximately 79% to the avoided rates ranging between 87 and 97%, presented in Table 6.

[40] RAP Standby Report, 31.

| | 500 kW | 3000 kW | 10,000 kW | 10,000 kW |
|---|---|---|---|---|
| Voltage | Secondary | Primary | Transmission Transformed | Transmission |
| Rate | General Service | GS - Time of Day | GS - Time of Day | GS - Time of Day |
| Purchased Energy | 4,380,000 kWh | 26,280,000 kWh | 87,600,000 kWh | 87,600,000 kWh |
| | | | | |
| Customer Charge | $295.32 | $331.32 | $331.32 | $331.32 |
| Demand Charge | $57,640.00 | $345,840.00 | $1,152,800.00 | $1,152,800.00 |
| Energy Charge | $123,997.80 | $719,302.37 | $2,397,674.57 | $2,397,674.57 |
| Fuel Clause | $122,972.11 | $707,843.95 | $2,359,479.83 | $2,359,479.83 |
| Transmission Recovery | $1,428.00 | $8,568.00 | $28,560.00 | $28,560.00 |
| Misc. Riders | $10,170.36 | $61,022.16 | $203,407.20 | $203,407.20 |
| Credits (Energy + Voltage) | -$21,780.00 | -$184,932.00 | -$843,360.00 | -$923,244.00 |
| | | | | |
| Total | $294,723.59 | $1,657,975.80 | $5,298,892.92 | $5,219,008.92 |
| per kWh | $0.07 | $0.06 | $0.06 | $0.06 |
| | | | | |
| | | **Standby Rates** | | |
| Purchased Energy | 219,000 kWh | 1,314,000 kWh | 4,380,000 kWh | 4,380,000 kWh |
| Availability | 95% | 95% | 95% | 95% |
| | | | | |
| Customer Charge | $885.96 | $921.96 | $921.96 | $921.96 |
| RSVP Charge | $35,400.00 | $151,200.00 | $348,000.00 | $204,000.00 |
| Demand Charge | $0.00 | $0.00 | $0.00 | $0.00 |
| Energy Charge | $6,199.89 | $35,965.12 | $119,883.73 | $119,883.73 |
| Fuel Clause | $6,148.61 | $35,392.20 | $117,973.99 | $117,973.99 |
| Transmission Recovery | $1,428.00 | $8,568.00 | $28,560.00 | $28,560.00 |
| Misc. Riders | $508.52 | $3,051.11 | $10,170.36 | $10,170.36 |
| Credits (Energy + Voltage) | $0.00 | -$1,182.60 | -$11,388.00 | -$11,782.20 |
| | | | | |
| Total | $50,570.97 | $233,915.78 | $614,122.04 | $469,727.84 |
| per kWh | $0.23 | $0.18 | $0.14 | $0.11 |
| | | | | |
| Avoided Cost | $244,152.62 | $1,424,060.02 | $4,684,770.88 | $4,749,281.08 |
| Avoided kWh | 4,161,000 kWh | 24,966,000 kWh | 83,220,000 kWh | 83,220,000 kWh |
| Avoided Rate | $0.0587 | $0.0570 | $0.0563 | $0.0571 |
| | | | | |
| % Avoided Rate of Full Requirements Rate | **87.20%** | **90.41%** | **93.06%** | **95.79%** |

**Table 6: Xcel Energy Avoided Rate Analysis**

## 3.6 Economic Potential Analysis

### Technical Analysis

As the largest investor owned utility in Minnesota, Xcel Energy also has the greatest amount of CHP technical potential with 1,442 MW (Table 7). The largest industrial sources for CHP potential are in the food (214.9 MW), chemical (192.7 MW), and petroleum refining (214.4 MW) sectors while the largest commercial/institutional source for CHP potential lie in the college and university sectors (154.7 MW). The majority of technical potential in these sectors is from installations with a capacity greater than 5 MW.

| | Payback >10 Years | Payback <10 Years | Payback 0- 5 Years | Total Potential (kW) |
|---|---|---|---|---|
| Base Rate - $4.50/MMBtu | 809 | 633 | 0 | 1,442 |
| Base Rate - $6.00/MMBtu | 1,442 | 0 | 0 | 1,442 |
| 100% Avoided Rate - $4.50/MMBtu | 479 | 963 | 0 | 1,442 |
| 100% Avoided Rate - $6.00/MMBtu | 809 | 633 | 0 | 1,442 |

**Table 7: Xcel Energy Technical Potential Payback**

**Economic Analysis**

Increasing Xcel's avoided rates to 100% results in an additional 331 MW of CHP potential moving from paybacks of greater than 10 years to paybacks less than 10 years when compared to the base case scenario. This is a significant amount of capacity that, when combined with the $4.50/MMBtu estimate represents 67% of Xcel's technical CHP potential. Though Xcel's standby rates already have high avoided rates, this analysis demonstrates that further improvements could significantly impact the payback period of CHP projects. This potential could increase above that which was modelled depending on the specific operational schedules of the customer generator. See Appendix B – 1 for a more detailed account of Xcel's CHP technical potential.

# Alliant Energy

*Note: On September 3, 2013 Alliant Energy announced that they will be selling their electric and natural gas operations and infrastructure in Minnesota. If approved by the Minnesota Public Utility Commission, Alliant will sell their natural gas business to Minnesota Energy Resources Corporation. The electric side of the business will be sold to twelve adjacent cooperative utilities, the largest being the Freeborn-Mower cooperative.*

## 4.1 Description of Standby Tariff – Rider 1S

Alliant Energy offers a standby rider under revised sheet 30, which is applicable to any customer on the Large Power and Lighting tariff (sheet 21) that owns their own generating equipment and executes a contract with Alliant for an initial term not less than five years. Rider 1S is divided into two service offerings:

1. Firm Standby
2. Non-Firm Standby

## 4.2 Description of Standby Charges

Rider 1S includes six charges:

1. Daily Administrative Charge
2. Generation Service Reservation Charge
3. Transmission Service Reservation Charge
4. Distribution Service Reservation Charge
5. Demand Charges for when standby is actually used
6. Energy Charges for when standby is actually used

Alliant offers both firm and non-firm standby service. Under the firm standby rate a customer would pay the generation, transmission and distribution reservation fees while the non-firm standby customer would only pay for the distribution reservation fee. Firm customers are allotted 964 hours annually for use of backup service during which they are not assessed demand usage charges. The reservation fees are calculated against the contracted standby capacity which is the maximum amount of standby service the utility is obligated to supply. The tariff is unclear if the contracted standby capacity may be less than the nameplate capacity rating. According to the tariff a standby customer must state both the total capacity requirements which Alliant shall be required to supply in the event of an outage and the capacity of the power source for which Alliant will be providing standby power and to which the standby service charge applies. The tariff does state that the contracted standby capacity may be different between the summer and winter seasons.

Both demand and energy charges are priced using the rate to which this standby rider is attached, in all cases this will be the Large Power and Light tariff. Firm standby customers only pay for standby energy during the first 964 hours of backup service while non-firm customers must pay for both demand and energy during outages. The standby usage demand shall be calculated as the lesser of (i) the amount of contracted standby capacity minus the actual demand supplied by the customer's generator, or (ii) the amount of actual capacity supplied by the company.

Rider 1S states that maintenance service must be scheduled to avoid both summer and winter peak periods and be scheduled at least 30 days in advance. The rider makes no mention of how maintenance service is to be billed and if it is included under the 964 hour grace period or separate altogether.

### 4.3 Assessment of Alliant Energy's Standby Rates

Alliant Energy's standby rate does not include transparent price signals that encourage DG customers to use standby service efficiently or with regards to the cost of maintaining grid reliability. Similar to Xcel Energy, Alliant Energy also employs a 964 hour grace period of backup service exempt from demand charges no matter if customers need that level of service. This represents an 11% FOR which is generally greater than most reliable CHP generators. Not only does this grace period not encourage customers to reduce the duration of forced outages it in fact incentivizes standby customer to go offline when they otherwise might not. Instead of a grace period rate structure, Alliant should employ an on-peak, per day kW charge in order to efficiently recover costs associated with backup service. Similarly to Xcel Energy, this should be combined with a lower reservation rate that is calculated using a customer-generator's FOR.

Distribution cost recovery should be more transparent for non-firm standby customers. The use of the large power and light tariff to assess demand and energy charges during outages seems to enable the double billing of distribution services for non-firm customers. These customers must pay a monthly distribution reservation charge but also pay the full demand charge found in the Large Power and Light tariff when taking standby service. Rider 1S contains no stipulation by which the demand charge in the otherwise applicable tariff is pro-rated based on the already paid distribution reservation charge.

Rider 1S does not include any specification for how maintenance service should be billed or whether or not a non-firm customer may take maintenance service. The standby rate should provide clear and concise mechanisms for how maintenance service is billed and scheduled. Since maintenance service is scheduled ahead of time during off-peak periods it should largely be exempt from demand and reservation charges.

Alliant Energy requires a minimum standby contract not less than five years with potential penalties issued if a customer ends standby service within ten years. The cancellation fee is to cover the cost of installation and removal of facilities; however, this could be more properly addressed under an interconnection agreement. The standby rate should transparently explain how costs within exit fees incurred.

The rider lacks clarity as to how the standby reservation capacity is calculated. While it seems that a standby customer is able to choose a contract capacity less than the nameplate capacity of their generator the language remains vague.

### 4.4 Potential Recommendations to Alliant Energy's Standby Rate

Following are suggested modifications to Alliant Energy's standby tariffs for consideration:

Transparency

1. *The method in which scheduled maintenance service is billed should be specified.* Since customers have flexibility with when they schedule maintenance service (typically falls on off-peak periods during off-peak months) a customer should not have to pay either the generation, transmission or shared distribution portion of the reservation fee or the backup demand rates for such service. If needed, a demand charge reflecting the off-peak nature of the service would be more appropriate.

2. *Alliant should remove exits fees from its standby rate.* These fees, if necessary, belong in a customer's interconnection agreement. Furthermore, the components to which the utility is assessing fees should be clearly stated.

3. *Remove the distribution reservation charge from demand purchases for non-firm standby customers.* Standby usage charges for non-firm customers are taken directly from the full-requirements tariff even though non-firm customers are already paying to reserve distribution service. Alliant energy should remove the distribution cost component from the full-requirements tariff when non-firm standby customers use standby service.

Flexibility

4. *Remove the grace period for firm backup power and instead tie the reservation charge to the customer's FOR.* The generation, transmission and shared distribution portions of the reservation charge should be calculated using the customer's own FOR. This would incentivize the customer to reduce the duration of outages and would further allow standby customers to minimize monthly charges.

Efficient Consumption

5. *A daily on-peak, as-used demand charge should replace the grace period and additional demand charges found in the full-requirements tariff.* This variable pricing would be implemented in conjunction with the calculation of the reservation rate using a customer's FOR. The daily, on-peak charge would be structured such that the customer would pay the

same amount as the supplemental rate if they took backup service for the entire month. The decrease in the monthly, fixed charges in combination with the addition of a variable usage charge would encourage the efficient consumption of grid resources. Since the costs of generation and shared distribution components are incurred during peak periods, standby demand charges for those services should apply only during on peak periods.

### 4.5 Avoided Rate Modeling of Standby Tariffs

Out of the four IOUs in Minnesota, Alliant Energy has the most burdensome standby rates. The analytic model found Alliant to have the lowest avoided rates in the state (Table 8). Since Alliant will shortly be leaving the state it is unclear how standby mitigation might affect potential CHP sites. Needless to say, the market uncertainty for CHP in Alliant's territory will likely hinder development until customers are familiar with their new electric utility.

| | 500 kW | 1000 kW | 3000 kW | 10000 kW |
|---|---|---|---|---|
| Voltage | Secondary | Primary | Primary | Transmission |
| Rate | Large Power and Light | Large Power and Light | Large Power and Light | Large Power and Light |
| Purchased Energy | 4,380,000 kWh | 8,760,000 kWh | 26,280,000 kWh | 87,600,000 kWh |
| | | | | |
| Customer Charge | $3,000.00 | $3,000.00 | $3,000.00 | $3,000.00 |
| Demand Charge | $66,880.00 | $131,486.08 | $394,458.24 | $1,337,600.00 |
| Energy Charge | $205,334.40 | $403,687.43 | $1,211,062.29 | $4,106,688.00 |
| Misc. Riders | $9,723.60 | $19,447.20 | $58,341.60 | $194,472.00 |
| Credits (Energy + Voltage) | -$18,133.20 | -$41,186.40 | -$123,559.20 | -$515,064.00 |
| | | | | |
| Total | $266,804.80 | $516,434.31 | $1,543,302.93 | $5,126,696.00 |
| per kWh | $0.06 | $0.06 | $0.06 | $0.06 |
| | | **Standby Rates** | | |
| Purchased Energy | 219,000 kWh | 438,000 kWh | 1,314,000 kWh | 4,380,000 kWh |
| Availability | 95% | 95% | 95% | 95% |
| | | | | |
| Additional Customer Charge | $780.00 | $780.00 | $780.00 | $780.00 |
| RSVP Charge | $56,700.00 | $113,400.00 | $340,200.00 | $1,134,000.00 |
| Demand Charge | $0.00 | $0.00 | $0.00 | $0.00 |
| Energy Charge | $10,266.72 | $20,184.37 | $60,553.11 | $205,334.40 |
| Misc. Riders | $486.18 | $972.36 | $2,917.08 | $9,723.60 |
| Credits (Energy + Voltage) | ($906.66) | ($3,043.32) | ($9,129.96) | ($56,233.20) |
| | | | | |
| Total | 70,326.23 | 135,293.41 | 398,320.23 | 1,296,604.79 |
| per kWh | 0.32 | 0.31 | 0.30 | 0.30 |
| | | | | |
| Avoided Cost | 196,478.56 | 381,140.90 | 1,144,982.70 | 3,830,091.20 |
| Avoided kWh | 4,161,000 kWh | 8,322,000 kWh | 24,966,000 kWh | 83,220,000 kWh |
| Avoided Rate | $0.047 | $0.046 | $0.046 | $0.046 |
| | | | | |
| % Avoided Rate of Full Requirements Rate | 77.52% | 77.69% | 78.10% | 78.64% |

Table 8: Alliant Energy Avoided Rate Analysis

### 4.6 Economic potential Analysis

**Technical Analysis**

The entire CHP technical potential within Alliant's electric territory is found in high load factor heating only applications. The only marginally significant source of CHP technical potential is found in the chemical sector (35 MW). The majority of capacity in this sector is found in systems ranging from 1 – 5 MW in capacity.

| | Payback >10 Years | Payback <10 Years | Payback 0-5 Years | Total Potential, MW |
|---|---|---|---|---|
| Base Rate - $4.50/MMBtu | 52 | 5 | 0 | 57 |
| Base Rate - $6.00/MMBtu | 57 | 0 | 0 | 57 |
| 100% Avoided Rate - $4.50/MMBtu | 52 | 5 | 0 | 57 |
| 100% Avoided Rate - $6.00/MMBtu | 52 | 5 | 0 | 57 |

**Table 9: Alliant Energy Technical Potential Payback**

**Economic Analysis**

As can be seen from Table 9 above, low natural gas prices have the same impact as modified standby rates on lowering the payback window for potential CHP projects. Though Alliant Energy is not a significant source of CHP economic potential in Minnesota with projects resulting in paybacks less than 10 years, this could change depending on the rate policies and structures of the future utilities serving this territory.

# 5. Minnesota Power

## 5.1 Description of Standby Tariff – Rider for Standby Service (RSS)

Minnesota Power (MN Power) offers a standby rider under page 61, 4th revision which is applicable to any customer on the residential, general, large light and power, municipal pumping or large power service rates who has entered into a parallel interconnection agreement with the utility and who executes a contract of not less than one year. Rider for Standby Service is divided into two service offerings:

1. Firm Standby
2. Non-Firm Standby

## 5.2 Description of Standby Charges

RSS is includes five charges:

1. Standby Reservation Fee
2. Standby Usage Fee – Summer Peak
3. Standby Usage Fee – Winter Peak
4. Standby Usage Fee – Off-Peak
5. Standby Energy

The standby reservation fee only applies to firm standby customers and is calculated using the contracted standby demand. The contracted standby demand shall be specified by the customer as the maximum amount of standby service MN Power is obligated to serve.

If a customer opts for firm standby service and pays the monthly standby reservation fee, they are exempt from any standby usage demand fees if (i) the contracted standby demand equals the nameplate capacity rating or (ii) the actual demand supplied by the generator is greater than the difference between the nameplate capacity rating of the generator and the contracted standby demand. This means that if a customer intends to use load shedding to address a portion of their standby needs, they must generate more than the difference between the nameplate capacity and the amount of capacity available to shed during an outage. If a customer's generation unit goes offline completely and their contracted standby demand is less than the nameplate capacity, they must pay a standby demand usage fee no matter the amount of capacity they are able to shed.

The standby usage fees are calculated as a $/kW per month charge during months in which a generator is offline for both backup or maintenance service. The Standby usage demand fees are divided between summer-peak, winter-peak and off-peak periods, though these names are misleading since they only refer to months and not time periods during those months. The Standby demand used to calculate the usage fee shall be determined as the smaller of the following two amounts: (i) nameplate capacity minus the actual demand supplied by the generator minus the contracted standby demand, or (ii) the amount of actual capacity supplied by MN Power minus the contracted standby demand, but in neither case less than zero. The standby usage demand fees are separated by rate class and then divided into voltages categories.

The per kWh rate for standby usage energy charges are provided in the standby rider and are determined as the summation of the smaller of the following two amounts for each 15 minute period in the outage: (i) the nameplate capacity rating of the generator minus the actual demand supplied by the generator, or (ii) the actual capacity supplied by MN Power.

The standby rider contains no provisions for scheduled maintenance service nor does the rider state how many hours a standby customer is entitled to be offline. The rider only states that the customer should operate their generator in a manner agreed to by the company.

### 5.3 Assessment of Minnesota Power's Standby Rate

A general concern with Minnesota Power's rider for standby service is that it lacks sufficient detail as to the proper function of many of its rate components. The standby rider is opaque with regards to rate functions such as the calculation of the usage fee, maintenance demand specifications, allowed backup hours, and the charges that inhabit the reservation and demand fees. This rate is structured in such a way that implies that a firm standby customer reserving their entire nameplate capacity could go offline indefinitely without any additional monthly charges. The rate should be more transparent to allow customers to understand how their standby rate assesses charges.

Though the modelling suggests that Minnesota Power's standby rate allows customers to avoid a large percentage of their full-requirements charges, the results are uncertain because of opaque rate functions. Regardless, the modelling results of Minnesota Power's standby rates are structured without adequate price signals that would incentivize more efficient consumption. The standby rate fails to account for load diversity and time-of-use cost components, resulting in unclear signals to standby customers regarding the cost drivers behind utility investments. Furthermore, the tariff does not incorporate daily as-used demand charges that would give standby customers an incentive to reduce the duration of their generation unit outages.

Finally, Minnesota Power's standby tariff does not provide the standby customer with adequate flexibility to meets its standby requirements though alternative means such as load shedding.

### 5.4 Potential Recommendations to Minnesota Power's Standby Rate

Following are suggested modifications to Minnesota Power's standby tariffs for consideration:

Transparency

1. *The reservation and usage rates should be unbundled into corresponding generation, transmission and distribution cost components while the overarching mechanics should be made more transparent.* Under Minnesota Power's standby tariff, it is difficult to see the level of transmission and generation charges being included in the reservation fee. Unbundling the rates would make them more transparent. Additionally, the mechanics stipulating the use, duration and pricing of standby service should be made clear.

2. *Minnesota Power should specify how maintenance is treated and billed.* Since customers have flexibility with when they schedule maintenance service (typically falling on off-peak periods during off-peak months) a customer should not have to pay either the reservation fee or the forced outage usage demand rates for such service. By sending clear and specific price signals, Minnesota Power can help shift maintenance service towards those times when their marginal costs are low and thus minimizing the cost of providing standby service.

3. *Standby reservation charges and demand usage charges should reflect load diversity.* The standby reservation charges and the standby demand usage rates are greater than the demand charges in the full-requirements rates even though the coincident factor of standby customer is far less than that of full-requirements customers. Under this structure a standby customer pays more to reserve capacity than a full-requirements customer pays to use that same capacity even though the standby customer is using shared infrastructure far less. Charges for shared infrastructure should reflect load diversity and load diversity can be recognized by designing shared infrastructure demand charges on a coincident peak basis.

Flexibility

4. *The standby reservation charge should incorporate a customer's FOR to allow self-generating customers to avoid a greater amount of the fixed monthly charges.* Currently the standby reservation fee allows the customer to use an undefined amount of standby service. A better approach would be to tie the reservation rate to a customer's FOR to allow well operating customers to decrease their monthly fixed charges.

Efficient Consumption

5. *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. Additionally, the inclusion of a daily standby demand rate would encourage standby customer to limit their use of backup service.

6. *Standby energy usage fee 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.

## 5.5 Avoided Rate Analysis

Minnesota Power's standby rates allow customers to avoid a significant portion of the full-requirements rate with avoided rates ranging between 90 and 97% (Table 10).

| | 500 kW | 3000 kW | 10,000 kW | 10,000 kW |
|---|---|---|---|---|
| Voltage | Secondary | Primary | Primary | Transmission |
| Rate | General Service | General Service | Large Light and Power | Large Light and Power |
| Purchased Energy | 4,380,000 kWh | 26,280,000 kWh | 87,600,000 kWh | 87,600,000 kWh |
| | | | | |
| Customer Charge | $126.00 | $126.00 | $0.00 | $0.00 |
| Demand Charge | $35,160.00 | $210,960.00 | $2,424,840.00 | $2,424,840.00 |
| Energy Charge | $232,402.80 | $1,394,416.80 | $3,276,240.00 | $3,276,240.00 |
| Fuel Clause | $51,128.34 | $306,770.04 | $899,067.95 | $899,067.95 |
| Transmission Recovery | $1,445.40 | $8,672.40 | $26,988.00 | $26,988.00 |
| Misc. Riders | $22,854.84 | $137,129.04 | $482,272.80 | $482,272.80 |
| Credits (Energy + Voltage) | $0.00 | -$63,000.00 | -$210,000.00 | -$458,784.00 |
| | | | | |
| Total | $343,117.38 | $1,995,074.28 | $6,899,408.75 | $6,650,624.75 |
| per kWh | $0.08 | $0.08 | $0.08 | $0.08 |
| | | | | |
| | | **Standby Rates** | | |
| Purchased Energy | 219,000 kWh | 1,314,000 kWh | 4,380,000 kWh | 4,380,000 kWh |
| Availability | 95% | 95% | 95% | 95% |
| | | | | |
| Additional Customer Charge | $0.00 | $0.00 | $0.00 | $0.00 |
| RSVP Charge | $41,580.00 | $169,200.00 | $736,800.00 | $369,600.00 |
| Demand Charge | $0.00 | $0.00 | | |
| Energy Charge | $3,416.40 | $3,416.40 | $68,766.00 | $68,766.00 |
| Fuel Clause | $2,556.42 | $2,556.42 | $44,953.40 | $44,953.40 |
| Transmission Recovery | $72.27 | $72.27 | $569.40 | $569.40 |
| Misc. Riders | $1,142.74 | $1,142.74 | $19,613.64 | $19,613.64 |
| Credits (Energy + Voltage) | $0.00 | $0.00 | ($12,439.20) | ($12,439.20) |
| | | | | |
| Total | $48,893.83 | $176,513.83 | $858,263.24 | $491,063.24 |
| per kWh | $0.22 | $0.13 | $0.20 | $0.11 |
| | | | | |
| Avoided Cost | $294,223.55 | $1,818,560.45 | $6,041,145.52 | $6,159,561.52 |
| Avoided kWh | 4,161,000 kWh | 24,966,000 kWh | 83,220,000 kWh | 83,220,000 kWh |
| Avoided Rate | $0.071 | $0.073 | $0.073 | $0.074 |
| | | | | |
| % Avoided Rate of Full Requirements Rate | 90.26% | 95.95% | 92.17% | 97.49% |

Table 10: Minnesota Power Avoided Rate Analysis

## 5.6 Economic potential Analysis

### Technical Analysis

Minnesota Power has the second largest technical potential of CHP capacity of investor owned utilities in Minnesota with 236 MW (Table 11). Of this technical potential 201 MW is found in high load factor heating only applications. By far the largest source of this potential exists in the paper sector (120 MW) and within that from sites with a CHP capacity greater than 20 MW (81.2 MW). Though the largest customers by capacity already experience high avoided rates, even marginal improvements may have a noticeable impact on decreasing system payback.

| | Payback >10 Years | Payback <10 Years | Payback 0- 5 Years | Total Potential, MW |
|---|---|---|---|---|
| Base Rate - $4.50/MMBtu | 95 | 141 | 0 | 236 |
| Base Rate - $6.00/MMBtu | 236 | 0 | 0 | 236 |
| 100% Avoided Rate - $4.50/MMBtu | 95 | 141 | 0 | 236 |
| 100% Avoided Rate - $6.00/MMBtu | 95 | 141 | 0 | 236 |

**Table 11: Minnesota Power Technical Potential Payback**

### Economic Analysis

Because of uncertainties within Minnesota Power's standby rate, the avoided rates as presented in Table 10 reflect the uppermost estimation of avoided rate percentages. As a result the economic potential by payback category presented in Table 11 reflects the lower end of potential CHP capacity. As currently modelled, reduced natural gas prices have a similar effect on payback potential as do modified standby rates. In fact, the base case scenario with gas at $4.50/MMBtu lowers the payback windows for the same amount of capacity as does the scenario with 100% avoided rates; though one can assume that modified standby rates further reduce CHP payback within the less than 10 year payback category. However, capturing 141 MW of economic potential through standby mitigation represents a significant portion of Minnesota Power's technical potential. While the model estimates Minnesota Power to have high avoided rates, it demonstrates that even marginal improvements to standby can have a significant effect on CHP's economic potential. The effect on economic potential would be even more pronounced if the avoided rates were lower than currently modelled.

# 6. Otter Tail Power Company

## 6.1 Description of Standby Tariff –Standby Service (SS)

Otter Tail Power offers standby service under section 11.01 of the sixth revised tariff sheet which is applicable to any customer that request to become a firm standby customer that uses an extended parallel generation system and who has entered into a contract for standby service. Rate SS is divided into two service offerings:

1. Firm Standby
2. Non-Firm Standby

## 6.2 Description of Standby Charges

Rate SS has five charges:

1. Firm Standby Fixed Charges
2. Firm Standby On-Peak Demand Charges – Summer expressed on a daily basis
3. Firm Standby Off-Peak Demand Charges – Winter expressed on a daily basis
4. Firm Standby Energy Charges – Summer
5. Firm Standby Energy Charges – Winter

The five charges listed above are applied to both the firm and non-firm standby options and are further divided into a transmission, primary and secondary service voltage categories.

The firm standby fixed charge is broken out into a customer charge of $199/month for all voltages, a summer reservation charge per month per kW, a winter reservation charge per month per kW and a standby facilities charge per month per kW. Non-firm customers avoid all of these charges except for the customer charge.

All three reservation charges are calculated using the contracted backup demand figure which is the amount of capacity selected to back up the customer's generation, not to exceed the capability of the customer's generator. This figure may be less than the nameplate capacity if the customer opts to use load shed to self-supply a portion of standby service. Firm standby service allows the customer to use back-up service no more than 120 on-peak hours in the summer and 240 on-peak hours in the winter. If the customer exceeds those limits they may be required to take service under a standard, non-standby rate schedule.

Non-firm standby customers are not allowed to use backup service during any on-peak period. The service is only available in the summer and winter shoulder and off-peak periods.

When firm back-up service is taken the customer is charged for the metered demand and energy used during an outage. Though Backup Demand is charged on a per day on-peak basis the Backup Demand Charge, as further defined in attachment number one, is the sum of the ten highest daily Backup Demands multiplied by the applicable Backup Demand Charge. There is no demand charge when using standby service in the shoulder or off-peak periods.

The Standby Energy Charges are divided between summer and winter seasons and between on-peak, off-peak and should periods. Non-firm standby customers are not allowed to use standby energy during the on-peak periods.

Scheduled Maintenance Service does not require a reservation charge ("Firm Standby Fixed Charge"). The daily on-peak backup demand charge will be waived for a maximum continuous period of 30 days per calendar year to allow for the maintenance of a customer's generator. This waiver shall only be granted in the months of April, May, October and November. All other standby energy charges apply.

If supplemental service is needed it shall be supplied under standard rate schedule 10.06.

### 6.3 Assessment of Otter Tail's Standby Rate

Otter Tail's standby rate has the greatest avoided rates of all Minnesota electric utilities included in this report. This is largely due to the use of daily on-peak demand charges associated with backup service. The use of daily demand charges incentivizes DG customers to reduce the duration of their generating unit outages in order to save more money. Furthermore, the time-of-use price signals encourage customers to shift their use of utility resources to off-peak or shoulder periods.

Though the hourly limit for on-peak backup service may at first seem limiting, this figure only captures the number of hours a generator is offline during on-peak periods and not cumulatively. The summer on-peak period spans only 6 hours a day Monday to Friday while the Winter Peak spans only 9 hours a day. Therefore, the maximum allowed backup time during the summer and winter are, respectively, 20 and 26 week days.

Otter Tail incentivizes customer's to self-supply standby reserves though multiple methods including the negation of reservations fees for customers with a physical assurance load limiting device, allowing customers to contract for backup capacity less than their nameplate capacity and by offering non-firm standby service. Customers who are able to self-supply standby reserves during on-peak periods whether through load shedding, physical assurance or other generation options will experience increased savings through Rate SS.

There are a few drawbacks in Rate SS, one of which is that it does not use a customer's FOR when calculating the reservation charges. Customers with widely differing FORs will all pay the same reservation charge for firm standby service. This remains a minor point due to the miniscule price of the reservation charges (all <$1.00 / kW) and the use of a daily on-peak demand charge to recover costs incurred during forced outages.

The rate is slightly complicated with regards to scheduled maintenance service and the backup demand charge. Though the rate never precludes the use of maintenance service for non-firm standby customers it doesn't affirm it either. The rate is unclear if a customer must pay a reservation charge to access the 30 day on-peak demand waiver. The method in which backup demand is charged is less transparent than it ought it be. A potential standby rate customer must read the details of attachment one in order to understand how specifically the backup demand is charged.

### 6.4 Potential Recommendations to Otter Tail's Standby Rate

The following are suggested modifications to Otter Tail's Standby Rate for consideration:

Transparency

1. *The reservation charges should be unbundled into generation, distribution and transmission cost components.* With the current standby rate structure it is difficult to assess the level of generation and transmission charges that a standby customer is paying in the reservation fee. While the reservation charges are small this in no way prevents them from being unbundled. Unbundling the reservation charge would make the rate design of Rate SS more transparent.

2. *Clearly state whether non-firm standby customers may take scheduled maintenance service.* This will add transparency and remove misunderstandings from the rate.

Flexibility

3. *The FOR should be used in the calculation of a customer's reservation charge.* The inclusion of a customer's FOR further incentivizes the customer to limit their use of backup service. The FOR would be applied to the unbundled generation and transmission components and any shared distribution infrastructure.

### 6.5 Avoided Rate Analysis

Otter Tail Power has the greatest avoided rates currently in place of all IOUs in Minnesota with rates in the 96-96% range (Table 12).

| | 500 kW | 1,000 kW | 3,000 kW | 10,000 kW |
|---|---|---|---|---|
| Voltage | Secondary | Primary | Primary | Transmission |
| Rate | General Service | Large General | Large General TOU | Large General TOU |
| Purchased Energy | 4,380,000 kWh | 8,760,000 kWh | 26,280,000 kWh | 87,600,000 kWh |
| | | | | |
| Customer Charge | $228.00 | $480.00 | $720.00 | $720.00 |
| Facilities Charge | $3,600.00 | $1,440.00 | $4,320.00 | $0.00 |
| Demand Charge | $6,520.00 | $73,800.00 | $221,400.00 | $612,400.00 |
| Energy Charge | $313,856.20 | $412,274.80 | $1,198,136.49 | $3,719,934.00 |
| Misc. Riders | $5,518.80 | $4,692.00 | $14,076.00 | $46,920.00 |
| | | | | |
| Total | $329,723.00 | $492,686.80 | $1,438,652.49 | $4,379,974.00 |
| per kWh | $0.08 | $0.06 | $0.05 | $0.05 |
| | | | | |
| | | **Standby Rates** | | |
| Purchased Energy | 219,000 kWh | 438,000 kWh | 1,314,000 kWh | 4,380,000 kWh |
| Availability | 95% | 95% | 95% | 95% |
| | | | | |
| Customer Charge | $2,388.00 | $2,388.00 | $2,388.00 | $2,388.00 |
| Facilities Charge | $4,335.60 | $6,339.60 | $19,018.80 | $0.00 |
| RSVP Charge | $550.20 | $1,049.60 | $3,148.80 | $9,704.00 |
| Demand Charge | $6,656.38 | $12,680.10 | $38,040.30 | $117,000.75 |
| Energy Charge | $10,216.86 | $19,733.13 | $59,199.38 | $185,996.70 |
| Misc. Riders | $275.94 | $551.88 | $1,655.64 | $5,518.80 |
| | | | | |
| Total | $24,422.99 | $42,742.31 | $123,450.92 | $320,608.25 |
| per kWh | $0.11 | $0.10 | $0.09 | $0.07 |
| | | | | |
| Avoided Cost | $305,300.01 | $449,944.49 | $1,315,201.57 | $4,059,365.75 |
| Avoided kWh | 4,161,000 kWh | 8,322,000 kWh | 24,966,000 kWh | 83,220,000 kWh |
| Avoided Rate | $0.073 | $0.054 | $0.053 | $0.049 |
| | | | | |
| % Avoided Rate of Full Requirements Rate | 97.47% | 96.13% | 96.23% | 97.56% |

**Table 12: Otter Tail Electric Avoided Rate Analysis**

## 6.6 Economic Potential Analysis

### Technical Analysis

Otter Tail Power has 63 MW of CHP technical potential within its territory (Table 13), 27 MW of which is found in the industrial sector and 36 MW in the commercial sector. Of the CHP technical potential within Otter Tail Power's electric territory 55 MW is found in high load factor heating and cooling only applications. Additionally, 45% (28 MW) of total technical potential is found in institutional and governmental sectors. The majority of all technical potential is in systems with a capacity less than 5 MW. There are no individual market sectors that have any significant technical potential.

| | Payback >10 Years | Payback <10 Years | Payback 0- 5 Years | Total Potential, MW |
|---|---|---|---|---|
| Base Rate - $4.50/MMBtu | 63 | 0 | 0 | 63 |
| Base Rate - $6.00/MMBtu | 63 | 0 | 0 | 63 |
| 100% Avoided Rate - $4.50/MMBtu | 57 | 6 | 0 | 63 |
| 100% Avoided Rate - $6.00/MMBtu | 57 | 6 | 0 | 63 |

**Table 13: Otter Tail Power Technical Potential Payback**

### Economic Analysis

Unlike the previous three utilities, modifications to Otter Tail Power's standby rates affect CHP payback windows to a greater extent than natural gas prices with 9.5% of the CHP projects moving from paybacks of greater than 10 years to paybacks less than 10 years (Table 13). This corresponds to the fact that most of the technical potential is found in the size categories that have the lowest avoided rates. Though the amount of CHP potential is low for projects with paybacks less than 10 years, it would be misleading to assume that there would be no market penetration since Otter Tail Power has a high percentage of technical potential within sectors that have a tolerance for increased payback (e.g. institutional facilities).

# 7. Net Metering Rates

## 7.1 Definition of Key Concepts

Though net metering was originally implemented in order to encourage private investment in renewable energy resources such as solar and wind, it can provide a needed incentive for smaller CHP projects to become financially feasible.[41]

Net metering allows for the flow of electricity both to and from the customer – typically through a single, bi-directional meter – allowing qualified DG 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 kilo-watt hours (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.[42] 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.

## 7.2 Successful Approaches in Net Metering Design

The successful approaches presented in this section were created to address net metering stipulations in Minnesota's newly passed House File 729. The following recommendations were pulled together from successful state practices and recommendations from the Regulatory Assistance Project (RAP) and Interstate Renewable Energy Council (IREC).

[41]Wan, Yih-hue and H. James Green, "Current experience with net metering programs," Green Power Report, 1998. Accessible at http://apps3.eere.energy.gov/greenpower/resources/pdfs/current_nm.pdf
[42] Applicable for demand billed customers. Residential customers usually pay no demand charges.

### Aggregate Caps

Net metering should be offered on a first come first serve basis to all qualified customer-generators who are interconnected and operated in parallel with the grid pursuant to the interconnection agreement provided.

State and utility aggregate generating caps should be removed for net metering customers as they arbitrarily limit potential capacity to a sales percentage. However, if the mechanisms to create a cap exist, the utility must first demonstrate that additional net metering capacity will increase costs on other customers before a cap should be enforced.

### Net Excess Generation Credits

The value of net excess generation (NEG) is perhaps the most disputed aspect of net metering policies. On one hand, utilities argue that net metering generation does not displace underlying grid costs or any administrative costs, but only displaces avoided power costs (usually the price of fuel). On the other hand, net metered customers argue that their generation displaces the marginal costs to add new capacity which can usually be quite more expensive than the fuel in existing coal or nuclear plants. Additionally, NEG is delivered at the distribution voltage level which avoids transmission, generation and sometimes distribution related capacity costs.

A central question to the pricing of NEG is the extent that net metered generation can help a utility avoid the need for new capacity. In general, DG customers on a net metering rate offer a product that comes with a service life of twenty years – significant enough to reduce the utility's need for new marginal capacity.[43] Under such a situation NEG should be priced to reflect the long run marginal costs to add new generation resources. Whether the rate of NEG compensation equals the utility's retail rate depends largely on if the retail rate incorporates longer run marginal costs. If the retail rate is lower than the long run marginal costs of added capacity, then the utility and non-generating customers are reaping a greater share of benefits provided by net metering customers. If the converse holds true, then non-generating customers are largely subsidizing net metering customers.

Three states provide examples of successful approaches to crediting NEG of net metered customers (Table 14):

[43] Regulatory Assistance Project, "Designing Distributed Generation Tariffs Well: Fair Compensation in a Time of Transition, (2014), 31.

| State | Net Excess Generation (NEG) Policy for Net Metering Customers |
|---|---|
| California | Customer may choose one of the following:<br>• NEG carried forward to customer's next bill indefinitely.<br>• Customer is financially compensated for NEG each billing period. Compensation calculated with the 12-month average spot market price for the hours of 7 am to 5 pm for the year in which the surplus energy was generated. |
| Pennsylvania | • NEG is carried forward as a kWh credit.<br>• Customer is financially compensated for any NEG remaining at the end of the year. Compensation is calculated with the "price -to-compare" (includes the generation and transmission components, but not the distribution component, of utility's retail rate). |
| New York | • NEG for solar PV and wind carried forward as a kWh credit; at the end of a year all NEG is monetized at the utility's avoided rate. NEG for micro CHP is credited at the utility's avoided rate and carried over indefinitely. |

**Table 14: Successful Approaches to Crediting NEG**

Successful approaches in most states credit Net Excess Generation on a 1:1 kWh basis and either roll over credits indefinitely or monetize credits annually at a pre-determined rate (the most common being a market rate, a PURPA avoided rate or a retail rate). The rate at which NEG is monetized should reflect the full costs that net metered generation helps the utility avoid. No matter the method in which net excess generation is credited, those credits should not reduce any fixed monthly customer charges imposed by the utility. For example, net metering credits will only apply to charges that use kWh as the billing determinant.[44] Furthermore, utilities should provide net metering customers service at non-discriminatory rates that are identical in rate structure to the rates these customer would be on but for any on-site generation and net metering implementation.

### Standby Requirements

A concern with net metering rates is that they allow customer-generators to avoid capacity and reserve costs which can shift the burden to non-generating customers. Though net metering rates for larger customers (those not on a residential rate) include a demand charge this mechanism might not cover the incurred costs from all net metered generators. The ability of a demand charge to adequately recover utility costs depends largely on the load factor of the generator in question. Load factor refers to the ratio of a generator's average load over their maximum load over a set period of time. For

[44] Interstate Renewable Energy Council, "Net Metering Model Rules," 2009.

example, the yearly load factor of solar PV will be low due to the fact that the sun may not shine during an overcast day in which the customer needs generation. In such an occurrence, the customer must then purchase their full capacity from the utility through the demand charge in the regular rate.

In contrast, a CHP system has a much higher load factor because it is not reliant on an intermittent resource: it can generate night, day and during overcast periods. A higher load factor generator still needs the grid during the occasional outage, but since these outages happen less frequently, the demand charge in the regular rate might not adequately cover the costs to provide capacity during outages. Under such a circumstance, a standby rate may be a warranted approach to recover the utility's capacity related costs. Standby rates should be applied only when demand charges in the regular rate fail at recovering the incurred costs from net metered generators.

The following two tables (Table 15 and Table 16) list 17 states that exempt net metered customers from standby rates:

| **Net-Metering and Standby Rates for States with CHP Inclusion in Net-Metering Policy:** | | |
|---|---|---|
| **State** | **Standby** | **Capacity Limit** |
| Arizona | Arizona Public Service net metering rate EPR-6 stipulates that customer demand be charged using the full-requirements tariff. | • Systems cannot exceed 125% of customer's annual electricity consumption |
| Florida | At a customer's discretion | • 2 MW |
| Maine | Exempt | • 660 kW for IOU customers |
| Maryland | Exempt | • 2 MW<br>• 30 kW for Micro-CHP<br>• Systems cannot exceed 200% of customer's baseline electricity consumption |
| New York | Exempt | • Solar: 2 MW for non-residential<br>• Wind: 2 MW for non-residential<br>• Micro-CHP: 10 kW (residential only)<br>• Micro-hydroelectric: 2 MW for non-residential |
| Oklahoma | Exempt | • The lesser of 100 kW or 25,000 kWh/year |
| Pennsylvania | Exempt | • 5 MW for micro-grid and emergency systems<br>• 3 MW for non-residential<br>• 50 kW for residential |
| Utah | Exempt | • 2 MW for non-residential |

| Net-Metering and Standby Rates for States with CHP Inclusion in Net-Metering Policy: | | |
|---|---|---|
| **State** | **Standby** | **Capacity Limit** |
| | | • 25 kW for residential |
| Vermont | Exempt | • 2.2 MW for military systems<br>• 20 kW for micro-CHP<br>• 500 kW for all other systems |
| Washington | Exempt | • 100 kW |

Table 15: Standby Exemption in States that make CHP eligible under Net Metering Rates

| Net-Metering and Standby Rates for States that Do Not Include CHP in Net Metering: | | |
|---|---|---|
| **State** | **Standby** | **Capacity Limit** |
| Alaska | Exempt | • 25 kW |
| California | Exempt | • 1 MW<br>• 5 MW Government or University |
| Delaware | Exempt | • 500 kW to 2 MW non-residential (varies by utility)<br>• 25 kW residential |
| Michigan | Exempt | • 150 kW |
| Nevada | Exempt | The lesser of,<br>• 1 MW<br>• 100% of the customer's annual requirements for electricity |
| North Carolina | Exemption only for non-residential customers up to 100 kW | • 1 MW |
| Rhode Island | Exempt | • 5 MW (systems must be sized to not exceed 100% of customer's annual electricity consumption) |

Table 16: Standby Exemption in States that do not include CHP under Net Metering Rates

**Meter Aggregation**

Meter aggregation should be available upon request only when the additional meters are located on the customer's contiguous property and are used to measure electricity only for the customer's requirements. Net metering customers reserve the right to designate the order in which NEG credits shall apply to individual meters.

## 7.3 Minnesota Net Metering Rules

In 1983, Minnesota instituted one of the nation's first net metering policies that set the generating capacity cap at 40 kilowatts (kW). This size cap existed until 2013 when the Minnesota legislature passed House File 729, which, among other provisions, increased net metering capacity to 1 megawatt (MW) for customers served by IOUs.

**Capacity Constraints**

Utilities may petition the Minnesota Public Commission to limit additional net metering facilities when the cumulative generation has reached 4% of annual retail electric sales. However, each utility must demonstrate that additional net metering facilities would cause significant rate impacts, require significant reliability measures or raise significant technical issues in order to limit net metering capacity. There is no limit of statewide capacity.

Qualified CHP net metering customers must limit their generation capacity to 120% of their on-site annual electric consumption; however, there are no minimum efficiency requirements for CHP.

**Net Excess Generation**

Under current Minnesota law, a qualifying net metering facility is defined as an electric generation facility constructed for the purpose of offsetting energy use through the use of renewable energy systems or distributed generation systems with a minimum efficiency of 40%. Eligible distributed generation projects are limited to those that consume natural gas, renewable fuel, or a similarly clean fuel. [45] Net metering customers may elect to receive a credit for any NEG or they may elect to roll over their kilowatt-hour (kWh) credits to future bills. NEG credits for systems sized below 40kW are priced at the "average retail utility energy rate," while credits for larger systems, up to 1 MW, are priced at the avoided costs as defined in the Code of Federal Regulations. At this time, it is unclear if Minnesota law allows customers to receive a check for their net excess generation or if it may only be issued as a credit on an electric bill.

**Meter Aggregation**

Customers may request meter aggregation if the meters are located on contiguous property owned by the customer requesting the aggregation. The total of all aggregate meters is subject to the size limitation for single meters. Meter aggregation only affects the kilowatt-hour sales and not other

[45] Minnesota, House File 729, Article 9, Section 2, Subdivisions (h)(i)

charges that may apply to multiple meters. An aggregate meter customer may designate the order in which NEG credits apply.

**Standby**

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. 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. As of writing, all Minnesota utilities have included systems greater than 100 kW under standby provisions. In order to alleviate the financial burden of exceeding the 964 hour standby demand grace period Xcel Energy has included a $5.15 per kW of installed capacity credit for solar units. This credit is applied to the cost of purchasing backup demand when the unit exceeds the grace period.

## 7.4 Assessment of Minnesota Net Metering Rates

The net metering rates updated though House File 729 are largely in line with successful approaches used in other states and those proposed by the Interstate Renewable Energy Council and the Regulatory Assistance Project. A possible impediment concerns the imposition of standby rates on larger, low load factor 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. However, HF 729 can be interpreted to require net metering customers with low load factor generator units - who would otherwise pay for their demand through a full-requirements rate - to contract for standby service for a forced outage every time the sun went down or the wind slowed. Since Xcel's current standby rate allows for a maximum of 964 hours of time offline, these customers would be required to pay for both standby service and regular demand service to cover the same capacity. This potential practice of double charging net metering customers for capacity requirements is considered unfair and would significantly hinder Minnesota's ability to achieve its policy goals as stated in House File 729 Article 12. Standby rates can be justified for net metering customers with high availability and reliability, like those running CHP systems if the demand purchased during their infrequent outages doesn't cover capacity related expenses. Since traditional net metering technologies (i.e. solar and wind) go offline more frequently, the regular demand charge within the existing electric rate should provide adequate cost recovery for the utility.

## 7.5 Recommendations for Net Metering Rates

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.

### 7.6 Net Metering Potential

The CHP technical potential for net metering customers was determined by analyzing the number of industrial and commercial facilities with CHP systems sized 1 MW and less. The CHP technical potential for these customers with systems 1 MW and less totaled 242.5 MW for industrial customers and 410.1 MW for commercial sectors, representing 33% of the state's total CHP potential. The commercial sector has a larger potential due to the greater number of facilities where the technical fit of a CHP system would be 1 MW or less, corresponding to the updated net metering threshold. See Appendix C for a detailed list of the net metering technical potential of CHP installations in Minnesota.

The two significant barriers to CHP in the current net metering rates are the inclusion of standby rates and the low NEG credit price. According to HF 729, it is unclear if standby rates will apply to larger net metering customers above 100 kW. Though standby avoidance would certainly help the financial situation of net metering eligible CHP systems it does not decrease any payback windows below the 10 year range.

Without standby rates playing a factor, increasing CHP's economic potential depends largely on the NEG credit price utilities are willing to offer and if they would issue a check instead of a credit on a bill.

Under the current law all net metering customers with a capacity greater than 40 kW shall receive NEG credits priced at the PURPA avoided rate. In their current filing, Xcel proposes to offer these systems $0.02623/kWh for all NEG credits that are a year old.[46] This credit would appear as a line item on the customer's bill instead of a check.

Such a proposal will not increase the economic potential of CHP for two reasons. The first is that a payment of $0.02623/kWh is far too low to be worth the additional fuel needed to generate above a customer's electric load. Most CHP customers would not run their systems for excess generation because the rates are too low to meaningfully reduce the simple payback. The second is that even were the price to suffice, since a customer can never receive a check for NEG there is no way to use NEG credits to reduce system payback.[47]

[46] Minnesota Public Utility Commission Docket E002/M-13-642

[47] It should be noted that most CHP is sized and operated to follow the thermal load. This does mean that there might be times in which the customer needs to generate excess electricity in order to meet an on-site thermal

Net metering rates are designed to aid generation like wind and solar that are dependent on factors outside of human control. When the wind slows down or stops or the sun goes down a customer may use NEG credits against electricity purchased during these times. However, the availability rates for CHP systems are far greater than for wind and solar DG technology. CHP customers on a net metering rate, especially those sized at 120% of their electric load, can easily become net exporters depending on the number of hours they operate their CHP system. Without a greater price and a more direct way to monetize NEG credits, net metering rates do not substantially affect the economic potential of CHP.

requirement or vice-versa. In those circumstances NEG credits could be applied to periods when the generator is not covering the on-site electric load. However, under such a circumstance the customer would still pay the demand charges incurred on the utility.

# 8. Discussion and Conclusions

Today, there is an installed CHP generating capacity base of 918.5 MW in Minnesota currently ranking the state 5th amongst the 12 Midwest states. Yet there still remains 1,975 MW of unrealized CHP technical potential in the State of which 1,798 MW resides within the four major investor owned utilities of Alliant Energy, Minnesota Power, Otter Tail Power, and Xcel Energy. These figures represent the upward most limits for CHP capacity unrestrained by economic paybacks, operating costs, energy costs or other such costs that factor into a major investment decision. The technical potential figures are useful when gauging the efficacy of policy and rate mitigations to encourage the development CHP projects. This study looked specifically at how standby rates and, to a lesser extent net metering rates, affect the economic potential of CHP projects today and what recommendations, if any, should be considered to reduce the barriers that these factors impose on CHP development.

## 8.1 Standby Rates

Standby rates in Minnesota have been perceived as a significant barrier to CHP development. Yet with the passage of HF 729 and the approval of Xcel's new standby rates the landscape has changed. However, there are still modifications that can be made to standby rates that would allow CHP generators to avoid a greater portion of their full-requirements rates.

Though the standby suggestions for each utility are somewhat unique, Table 17 outlines the most reoccurring standby modifications for IOUs in Minnesota grouped by functional criteria:

| 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. |

| Principle | Analysis and Recommendation |
|---|---|
| **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 17: Standby Rate Policy Recommendations**

While the financial effects these modifications might have are largely dependent on customer specific metrics including CHP capacity, operating hours, voltage classification, etc., the suggested modifications should increase the avoided rate of each utility. In order to gauge the effect standby rates have on CHP economic potential, our analytic model analyzed the avoided rates as they currently exist and then as they exist were they to avoid 100% of the full-requirements rate.

### 8.2 Net Metering Rates

The new net metering rates will help very small CHP systems (<40 kW) to a greater extent than larger systems because the net excess generation credit for smaller systems equals the retail rate while the larger systems only receive the PURPA avoided rate. NEG credits should be the same for all net metering customers. The primary benefit to larger customers, those between 100 kW and 1 MW, would be through standby avoidance; however, it seems that IOUs in Minnesota are currently attempting to include those customers on standby rates. As demonstrated in section 7.2, seventeen states – even those that include CHP as an eligible net metering technology – exempt net metering customers from standby rates. Whether Minnesota utilities should exempt standby rates depends largely on the ability of the demand charge in the regular rate to recover the incurred capacity costs from net metering customers. The load factor of net metered customers provides one way of dividing customers between those requiring standby service to recover incurred costs and those able to stay on the full-requirements rate.

### 8.3 Economic Potential Analysis

ERC worked in conjunction with ICF International in order to develop the overall economic analysis potential of CHP generating capacity in Minnesota (not including CHP systems installed within electric municipality and cooperative service territories). The ICF model analyzed the impact of avoided rates (as modified through standby and net metering policy recommendations) on simple project payback rates to determine the payback windows for potential CHP installations. The avoided rates used in the economic potential model include the baseline rates and the increased rates from standby and net metering recommendations. Simple paybacks were modeled using current utility electric prices, natural gas rate estimates based on average prices from the EIA for the commercial and industrial sector, and industry average CHP equipment cost and performance characteristics.

From an overall technical potential of 1,798 MW residing in the four major investor owned utilities, the base case modeling results indicated 780 MW of new CHP generating capacity with a simple payback of 10 years or less. Table 18 and Table 19 show the overall economic potential in payback periods compared to the overall technical potential in the Base Case and 100% Avoided Rate Case scenarios. Table 20 and Table 21 provide a more detailed breakout of the economic potential residing in each of the four major investor owned electric utilities for the standby rate scenarios and the baseline natural gas price scenario compared to an increased price in natural gas.

| | Payback >10 Years | Payback <10 Years | Payback 0-5 Years | Total Potential, KW |
|---|---|---|---|---|
| Alliant | 52 | 5 | 0 | 57 |
| MN Power | 95 | 141 | 0 | 236 |
| Northern States | 809 | 633 | 0 | 1,442 |
| Otter Tail | 63 | 0 | 0 | 63 |
| Total | 1,019 | 779 | 0 | 1,798 |

**Table 18: CHP Economic Potential per Utility (Base Case)**

| | Payback >10 Years | Payback <10 Years | Payback 0-5 Years | Total Potential, KW |
|---|---|---|---|---|
| Alliant | 52 | 5 | 0 | 57 |
| MN Power | 95 | 141 | 0 | 236 |
| Northern States | 479 | 964 | 0 | 1,442 |
| Otter Tail | 57 | 6 | 0 | 63 |
| Total | 682 | 1,116 | 0 | 1,798 |

**Table 19: CHP Economic Potential per Utility (100% Avoided Rate)**

| | Payback >10 Years | Payback <10 Years | Payback 0-5 Years | Total Potential, KW |
|---|---|---|---|---|
| Alliant | 57 | 0 | 0 | 57 |
| MN Power | 236 | 0 | 0 | 236 |
| Northern States | 1,442 | 0 | 0 | 1,442 |
| Otter Tail | 63 | 0 | 0 | 63 |
| Total | 1,798 | 0 | 0 | 1,798 |

**Table 20: CHP Economic Potential per Utility (Base Case & Increased Natural Gas Prices)**

| | Payback >10 Years | Payback <10 Years | Payback 0-5 years | Total Potential, KW |
|---|---|---|---|---|
| Alliant | 52 | 5 | 0 | 57 |
| MN Power | 95 | 141 | 0 | 236 |
| Northern States | 809 | 633 | 0 | 1,442 |
| Otter Tail | 57 | 6 | 0 | 63 |
| Total | 1,013 | 785 | 0 | 1,798 |

**Table 21: CHP Economic Potential per Utility (100% Avoided Rate & Increased Natural Gas Prices)**

Due to recent standby modifications and updated net metering policies, these issues are not as significant of a barrier to CHP development as they were previously perceived; however, there still remain opportunities for improvement within the existing rate structures that can greatly impact the overall economic potential of new CHP generating capacity within the State of Minnesota. Standby rates should promote efficiency, fairness, transparency, and system reliability while net metering rates should offer a similar generation credit to all eligible customers and exempt low load factor generators from standby charges.

The economic potential analysis resulting in the various payback periods only factored varied avoided rates and the price of natural gas. It should be noted though that the modeling results showed no CHP projects would experience a payback less than 5 years when modeling improved standby rates. This would indicate that standby rates are not the sole barrier to CHP development in the State of Minnesota for policy makers to consider. Like many states, standby rates are one of several barriers that impair the development of CHP projects.

The economic potential analysis only factored varied avoided rates and the price of natural gas. Other factors that should be considered when developing CHP projects that can positively impact project simple paybacks and overall economic potential are, but not limited to:

- Grid Congestion due to environmental pressures on coal fired utility power plants shutting down and the ability of CHP systems to relieve grid constrain by providing generation in specified locations of the utility grid.
- Energy Resiliency and the capability of properly installed CHP systems to maintain facility operations due to grid outages from man-made disasters (i.e. terrorist attacks) and natural disasters (i.e. heavy rain and snow storms, tornadoes, etc.).
- Microgrid advancements and the development of district energy systems with CHP centered as the primary generation technology.

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# Appendix A – CHP Technical Potential Methodology

This section describes the methodology for estimating the technical market potential for combined heat and power (CHP) in the industrial and commercial/institutional market sectors. Two different types of CHP markets (traditional CHP and combined cooling heating and power) were included in the evaluation of technical potential. Both of these markets were evaluated for high load factor (80% and above) and low load factor (51%) applications resulting in four distinct market segments that are analyzed.

### Traditional CHP – Heating Only

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

- High load factor applications: This market provides for continuous or nearly continuous operation. It includes all industrial applications and round-the-clock commercial/institutional operations such colleges, hospitals, hotels, and prisons.
- Low load factor applications: Some commercial and institutional markets provide an opportunity for coincident electric/thermal loads for a period of 3,500 to 5,000 hours per year. This sector includes applications such as schools, and laundries.

### CHP with Heating and Cooling

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

- Low load factor applications: These represent markets that otherwise could not support CHP due to a lack of thermal load. This sector includes applications such as commercial office buildings.
- Incremental high load factor applications: These markets represent round-the-clock commercial/institutional facilities that could support traditional CHP, but with cooling, incremental capacity could be added while maintaining a high level of use of the thermal energy from the CHP system.

All of the market segments in this category are also included in the high load factor traditional market segment, so only the incremental capacity for these markets is added to the overall totals.

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

- Identification of applications where CHP provides a reasonable fit to the electric and thermal needs of the user. Target applications were identified based on reviewing the electric and thermal energy consumption data for various building types and industrial facilities.

- Quantification of the number and size distribution of target applications. Several data sources were used to identify the number of applications by sector that meets the thermal and electric load requirements for CHP.

- Estimation of CHP potential in terms of megawatt (MW) capacity. Total CHP potential is then derived for each target application based on the number of target facilities in each size category and sizing criteria appropriate for each sector.

- Subtraction of existing CHP from the identified sites to determine the remaining technical market potential.

The technical market potential does not consider screening for economic rate of return, or other factors such as ability to retrofit, owner interest in applying CHP, capital availability, natural gas availability, and variation of energy consumption within customer application/size class. The technical potential as outlined is useful in understanding the potential size and size distribution of the target CHP markets in the state. Identifying technical market potential is a preliminary step in the assessment of economic potential. The basic approach to developing the technical potential is described below:

- Identify existing CHP in the state. The analysis of CHP potential starts with the identification of existing CHP. The U.S. currently has 4,100 CHP sites totaling 81.8 GW of capacity. Of this existing CHP capacity, 31% of the sites and 80% of the capacity are in the industrial sector. This existing CHP capacity is deducted from any identified technical potential.

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

- Quantify the number and size distribution of target applications. Once applications that could technically support CHP were identified, the Hoovers database from Dun & Bradstreet and the Major Industrial Plant Database (MIPD) from IHS were used to identify potential CHP sites by SIC code or application, and location. The Hoovers database is based on the Dun & Bradstreet financial listings and includes information on economic activity (8 digit SIC), location (metropolitan area, county, electric utility service area, state) and size (employees) for commercial, institutional and industrial facilities. In addition, for select SICs limited energy consumption information (electric and gas consumption, electric and gas expenditures) is provided based on data from Wharton Econometric Forecasting (WEFA). MIPD has detailed energy and process data for 16,000 of the largest energy consuming industrial plants in the United States. The Hoovers database and MIPD were used to identify the number of facilities in target CHP applications and to group them into size categories based on average electric demand in kilowatt-hours.

Total CHP potential is then derived for each target application based on the number of target facilities in each size category. It was assumed that the CHP system would be sized to meet the average site electric demand for the target applications unless thermal loads (heating and cooling) limited electric capacity. There are two distinct applications and two levels of annual load making for four market segments in all. In traditional CHP, the thermal energy is recovered and used for heating, process steam, or hot water. In cooling CHP, the system provides both heating and cooling needs for the facility. High load factor applications are assumed to operate at 80% load factor and above; low load factor applications operate at an assumed average of 4500 hours per year (51%) load factor. The high load factor cooling applications are also applications for traditional CHP, though the cooling applications have 25-30% more capacity than traditional.

# Appendix B – CHP Technical Potential by Utility and Sector

## B – 1: Xcel Energy – Northern States

### Industrial Sector

| SIC | Application | 50 - 500 KW Sites | Capacity | 500 kW - 1 MW Sites | Capacity | 1 - 5 MW Sites | Capacity | 5 - 20 MW Sites | Capacity | > 20 MW Sites | Capacity | Total Sites | Capacity |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 20 | Food | 125 | 23.4 | 23 | 15.5 | 33 | 69.0 | 5 | 35.0 | 2 | 71.9 | 188 | 214.9 |
| 22 | Textiles | 12 | 2.4 | 1 | 0.8 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 13 | 3.2 |
| 24 | Lumber and Wood | 79 | 12.2 | 9 | 6.7 | 5 | 7.0 | 1 | 6.2 | 0 | 0.0 | 94 | 32.2 |
| 25 | Furniture | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 26 | Paper | 54 | 11.9 | 23 | 15.2 | 10 | 20.3 | 3 | 31.3 | 1 | 41.3 | 91 | 120.0 |
| 27 | Printing | 11 | 1.5 | 1 | 0.7 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 12 | 2.2 |
| 28 | Chemicals | 120 | 20.3 | 26 | 18.1 | 33 | 78.2 | 11 | 76.2 | 0 | 0.0 | 190 | 192.7 |
| 29 | Petroleum Refining | 0 | 0.0 | 2 | 1.4 | 1 | 3.5 | 1 | 6.5 | 2 | 203.0 | 6 | 214.4 |
| 30 | Rubber/Misc. Plastics | 138 | 20.5 | 12 | 7.9 | 1 | 1.9 | 0 | 0.0 | 0 | 0.0 | 151 | 30.2 |
| 32 | Stone/Clay/Glass | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 33 | Primary Metals | 24 | 5.7 | 7 | 4.9 | 6 | 15.3 | 1 | 6.5 | 0 | 0.0 | 38 | 32.4 |
| 34 | Fabricated Metals | 52 | 5.6 | 1 | 0.5 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 53 | 6.1 |
| 35 | Machinery/Computer Equip | 9 | 1.1 | 0 | 0.0 | 1 | 1.3 | 0 | 0.0 | 0 | 0.0 | 10 | 2.4 |
| 37 | Transportation Equip. | 25 | 3.7 | 3 | 1.8 | 3 | 7.2 | 1 | 8.3 | 0 | 0.0 | 32 | 21.0 |
| 38 | Instruments | 3 | 0.2 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 3 | 0.2 |
| 39 | Misc. Manufacturing | 8 | 0.9 | 0 | 0.0 | 1 | 1.3 | 0 | 0.0 | 0 | 0.0 | 9 | 2.2 |
| | **Total** | **660** | **109.4** | **108** | **73.5** | **94** | **205.0** | **23** | **170.0** | **5** | **316.2** | **890** | **874.1** |

Table 22: Xcel Energy Industrial Sector CHP Technical Potential

## Commercial Sector

| SIC | Application | 50 - 500 KW | | 500 kW - 1 MW | | 1 - 5 MW | | 5 - 20 MW | | > 20 MW | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Sites | Capacity | Sites | Capacity | Sites | Capacity | Sites | Capacity | Sites | Capacity | Sites | Capacity |
| 43 | Post Offices | 3 | 0.3 | 0 | 0.0 | 1 | 1.1 | 0 | 0.0 | 0 | 0.0 | 4 | 1.4 |
| 52 | Retail | 298 | 31.8 | 9 | 6.1 | 1 | 1.3 | 0 | 0.0 | 0 | 0.0 | 308 | 39.3 |
| 4222 | Refrigerated Warehouses | 11 | 1.7 | 2 | 1.1 | 0 | 0.0 | 1 | 6.7 | 0 | 0.0 | 14 | 9.5 |
| 4581 | Airports | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 19.1 | 0 | 0.0 | 1 | 19.1 |
| 4952 | Water Treatment | 7 | 0.6 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 7 | 0.6 |
| 5411 | Food Stores | 125 | 28.7 | 17 | 10.6 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 142 | 39.4 |
| 5812 | Restaurants | 402 | 42.1 | 0 | 0.0 | 1 | 1.4 | 0 | 0.0 | 0 | 0.0 | 403 | 43.4 |
| 6512 | Commercial Buildings | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 6513 | Multifamily Buildings | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 7011 | Hotels | 171 | 25.3 | 11 | 7.0 | 5 | 7.6 | 1 | 7.8 | 0 | 0.0 | 188 | 47.8 |
| 7211 | Laundries | 13 | 2.2 | 4 | 2.7 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 17 | 4.9 |
| 7374 | Data Centers | 32 | 5.7 | 3 | 2.0 | 5 | 9.7 | 1 | 6.1 | 0 | 0.0 | 41 | 23.5 |
| 7542 | Car Washes | 24 | 1.7 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 24 | 1.7 |
| 7832 | Movie Theaters | 1 | 0.1 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.1 |
| 7991 | Health Clubs | 39 | 5.2 | 4 | 2.3 | 2 | 4.0 | 0 | 0.0 | 0 | 0.0 | 45 | 11.5 |
| 7997 | Golf/Country Clubs | 90 | 9.9 | 2 | 1.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 92 | 10.9 |
| 8051 | Nursing Homes | 180 | 24.9 | 7 | 4.3 | 4 | 5.4 | 0 | 0.0 | 0 | 0.0 | 191 | 34.6 |
| 8062 | Hospitals | 34 | 7.0 | 18 | 12.5 | 21 | 45.8 | 1 | 5.8 | 0 | 0.0 | 74 | 71.1 |
| 8211 | Schools | 181 | 13.9 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 181 | 13.9 |
| 8221 | College/Univ | 45 | 8.3 | 13 | 10.0 | 16 | 35.1 | 9 | 80.3 | 1 | 21.0 | 84 | 154.7 |
| 8412 | Museums | 7 | 1.3 | 1 | 1.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 8 | 2.2 |
| 9100 | Government Buildings | 137 | 20.7 | 13 | 10.0 | 9 | 12.8 | 0 | 0.0 | 0 | 0.0 | 159 | 43.5 |
| 9223 | Prisons | 4 | 0.4 | 1 | 0.9 | 8 | 17.0 | 0 | 0.0 | 0 | 0.0 | 13 | 18.2 |
| 9711 | Military | 5 | 0.9 | 0 | 0.0 | 2 | 5.1 | 0 | 0.0 | 0 | 0.0 | 7 | 6.1 |
| | **Total** | **1,809** | **232.6** | **105** | **71.5** | **75** | **146.3** | **14** | **125.8** | **1** | **21.0** | **2,004** | **597.2** |

Table 23: Table 21: Xcel Energy Commercial Sector CHP Technical Potential

## B – 2: Alliant Energy

### Industrial Sector

| SIC | Application | 50 - 500 KW | | 500 kW - 1 MW | | 1 - 5 MW | | 5 - 20 MW | | > 20 MW | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Sites | Capacity | Sites | Capacity | Sites | Capacity | Sites | Capacity | Sites | Capacity | Sites | Capacity |
| 20 | Food | 6 | 1.5 | 1 | 0.7 | 4 | 8.0 | 0 | 0.0 | 0 | 0.0 | 11 | 10.2 |
| 22 | Textiles | 0 | 0.0 | 0 | 0.0 | 1 | 1.8 | 0 | 0.0 | 0 | 0.0 | 1 | 1.8 |
| 24 | Lumber and Wood | 2 | 0.2 | 0 | 0.0 | 1 | 1.2 | 0 | 0.0 | 0 | 0.0 | 3 | 1.3 |
| 25 | Furniture | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 26 | Paper | 2 | 0.4 | 1 | 0.8 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 3 | 1.2 |
| 27 | Printing | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 28 | Chemicals | 15 | 2.6 | 1 | 0.9 | 8 | 26.2 | 1 | 5.2 | 0 | 0.0 | 25 | 35.0 |
| 29 | Petroleum Refining | 0 | 0.0 | 1 | 0.7 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.7 |
| 30 | Rubber/Misc. Plastics | 4 | 0.6 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 4 | 0.6 |
| 32 | Stone/Clay/Glass | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 33 | Primary Metals | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 34 | Fabricated Metals | 1 | 0.1 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.1 |
| 35 | Machinery/Computer Equip | 1 | 0.1 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.1 |
| 37 | Transportation Equip. | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 38 | Instruments | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 39 | Misc. Manufacturing | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| | **Total** | **31** | **5.5** | **4** | **3.2** | **14** | **37.1** | **1** | **5.2** | **0** | **0.0** | **50** | **51.0** |

Table 24: Alliant Energy Industrial Sector CHP Technical Potential

## Commercial Sector

| SIC | Application | 50 - 500 KW | | 500 kW - 1 MW | | 1 - 5 MW | | 5 - 20 MW | | > 20 MW | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Sites | Capacity | Sites | Capacity | Sites | Capacity | Sites | Capacity | Sites | Capacity | Sites | Capacity |
| 43 | Post Offices | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 52 | Retail | 3 | 0.3 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 3 | 0.3 |
| 4222 | Refrigerated Warehouses | 1 | 0.1 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.1 |
| 4581 | Airports | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 4952 | Water Treatment | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 5411 | Food Stores | 2 | 0.4 | 1 | 0.6 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 3 | 1.0 |
| 5812 | Restaurants | 2 | 0.2 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 2 | 0.2 |
| 6512 | Commercial Buildings | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 6513 | Multifamily Buildings | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 7011 | Hotels | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 7211 | Laundries | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 7374 | Data Centers | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 7542 | Car Washes | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 7832 | Movie Theaters | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 7991 | Health Clubs | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 7997 | Golf/Country Clubs | 1 | 0.1 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.1 |
| 8051 | Nursing Homes | 22 | 2.3 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 22 | 2.3 |
| 8062 | Hospitals | 1 | 0.2 | 1 | 0.9 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 2 | 1.0 |
| 8211 | Schools | 2 | 0.1 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 2 | 0.1 |
| 8221 | College/University | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 8412 | Museums | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 9100 | Government Buildings | 7 | 0.9 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 7 | 0.9 |
| 9223 | Prisons | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 9711 | Military | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| | **Total** | **41** | **4.5** | **2** | **1.5** | **0** | **0.0** | **0** | **0.0** | **0** | **0.0** | **43** | **5.9** |

**Table 25: Alliant Energy Commercial Sector CHP Technical Potential**

## B – 3: Minnesota Power

### Industrial Sector

| SIC | Application | 50 - 500 KW | | 500 kW - 1 MW | | 1 - 5 MW | | 5 - 20 MW | | > 20 MW | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Sites | Capacity | Sites | Capacity | Sites | Capacity | Sites | Capacity | Sites | Capacity | Sites | Capacity |
| 20 | Food | 5 | 1.0 | 1 | 0.6 | 1 | 1.6 | 0 | 0.0 | 0 | 0.0 | 7 | 3.1 |
| 22 | Textiles | 1 | 0.1 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.1 |
| 24 | Lumber and Wood | 27 | 5.0 | 2 | 1.5 | 3 | 4.8 | 2 | 21.0 | 0 | 0.0 | 34 | 32.2 |
| 25 | Furniture | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 26 | Paper | 3 | 0.5 | 0 | 0.0 | 2 | 6.1 | 4 | 32.4 | 2 | 81.2 | 11 | 120.1 |
| 27 | Printing | 2 | 0.3 | 1 | 0.5 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 3 | 0.9 |
| 28 | Chemicals | 5 | 1.0 | 0 | 0.0 | 4 | 8.3 | 0 | 0.0 | 0 | 0.0 | 9 | 9.3 |
| 29 | Petroleum Refining | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 30 | Rubber/Misc. Plastics | 11 | 2.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 11 | 2.0 |
| 32 | Stone/Clay/Glass | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 33 | Primary Metals | 4 | 0.7 | 1 | 0.9 | 1 | 1.4 | 0 | 0.0 | 0 | 0.0 | 6 | 3.0 |
| 34 | Fabricated Metals | 3 | 0.7 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 3 | 0.7 |
| 35 | Machinery/Computer Equip | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 37 | Transportation Equip. | 4 | 0.7 | 1 | 0.7 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 5 | 1.4 |
| 38 | Instruments | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 39 | Misc. Manufacturing | 1 | 0.3 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.3 |
| | **Total** | **66** | **12.3** | **6** | **4.2** | **11** | **22.2** | **6** | **53.4** | **2** | **81.2** | **91** | **173.1** |

Table 26: Minnesota Power Industrial Sector CHP Technical Potential

### Commercial Sector

| SIC | Application | 50-500 kW Sites | 50-500 kW MW | 500-1 MW Sites | 500-1 MW (MW) | 1-5 MW Sites | 1-5 MW (MW) | 5-20 MW Sites | 5-20 MW (MW) | >20 MW Sites | >20 MW (MW) | Total Sites | Total MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 43 | Post Offices | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 52 | Retail | 28 | 2.9 | 1 | 0.5 | 1 | 1.1 | 0 | 0.0 | 0 | 0.0 | 30 | 4.5 |
| 4222 | Refrigerated Warehouses | 2 | 0.1 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 2 | 0.1 |
| 4581 | Airports | 1 | 0.4 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.4 |
| 4952 | Water Treatment | 2 | 0.4 | 0 | 0.0 | 1 | 2.8 | 0 | 0.0 | 0 | 0.0 | 3 | 3.2 |
| 5411 | Food Stores | 26 | 4.1 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 26 | 4.1 |
| 5812 | Restaurants | 22 | 1.9 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 22 | 1.9 |
| 6512 | Commercial Buildings | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 6513 | Multifamily Buildings | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 7011 | Hotels | 41 | 5.9 | 1 | 0.7 | 1 | 1.5 | 0 | 0.0 | 0 | 0.0 | 43 | 8.1 |
| 7211 | Laundries | 2 | 0.2 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 2 | 0.2 |
| 7374 | Data Centers | 2 | 0.1 | 1 | 0.5 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 3 | 0.6 |
| 7542 | Car Washes | 1 | 0.1 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.1 |
| 7832 | Movie Theaters | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 7991 | Health Clubs | 1 | 0.1 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.1 |
| 7997 | Golf/Country Clubs | 13 | 1.1 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 13 | 1.1 |
| 8051 | Nursing Homes | 27 | 3.6 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 27 | 3.6 |
| 8062 | Hospitals | 13 | 3.0 | 5 | 3.3 | 6 | 8.7 | 0 | 0.0 | 0 | 0.0 | 24 | 14.9 |
| 8211 | Schools | 11 | 0.8 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 11 | 0.8 |
| 8221 | College/University | 6 | 1.5 | 3 | 2.1 | 1 | 1.3 | 1 | 6.7 | 0 | 0.0 | 11 | 11.6 |
| 8412 | Museums | 2 | 0.2 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 2 | 0.2 |
| 9100 | Government Buildings | 19 | 2.8 | 2 | 1.5 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 21 | 4.3 |
| 9223 | Prisons | 3 | 0.3 | 0 | 0.0 | 2 | 3.9 | 0 | 0.0 | 0 | 0.0 | 5 | 4.2 |
| 9711 | Military | 0 | 0.0 | 1 | 0.5 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.5 |
| | **Total** | **222** | **29.5** | **14** | **9.2** | **12** | **19.2** | **1** | **6.7** | **0** | **0.0** | **249** | **64.5** |

**Table 27: Minnesota Power Commercial Sector CHP Technical Potential**

## B – 4: Otter Tail Electric

### Industrial Sector

| SIC | Application | 50 - 500 KW | | 500 kW - 1 MW | | 1 - 5 MW | | 5 - 20 MW | | > 20 MW | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Sites | Capacity | Sites | Capacity | Sites | Capacity | Sites | Capacity | Sites | Capacity | Sites | Capacity |
| 20 | Food | 9 | 1.4 | 4 | 3.2 | 2 | 3.4 | 0 | 0.0 | 0 | 0.0 | 15 | 8.0 |
| 22 | Textiles | 1 | 0.2 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.2 |
| 24 | Lumber and Wood | 11 | 2.2 | 3 | 2.0 | 1 | 1.0 | 1 | 5.7 | 0 | 0.0 | 16 | 10.9 |
| 25 | Furniture | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 26 | Paper | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 27 | Printing | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 28 | Chemicals | 10 | 1.4 | 2 | 1.3 | 1 | 1.9 | 0 | 0.0 | 0 | 0.0 | 13 | 4.6 |
| 29 | Petroleum Refining | 0 | 0.0 | 1 | 0.7 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.7 |
| 30 | Rubber/Misc. Plastics | 2 | 0.2 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 2 | 0.2 |
| 32 | Stone/Clay/Glass | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 33 | Primary Metals | 0 | 0.0 | 0 | 0.0 | 1 | 1.8 | 0 | 0.0 | 0 | 0.0 | 1 | 1.8 |
| 34 | Fabricated Metals | 1 | 0.1 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.1 |
| 35 | Machinery/Computer Equip | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 37 | Transportation Equip. | 3 | 0.4 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 3 | 0.4 |
| 38 | Instruments | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 39 | Misc. Manufacturing | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| | **Total** | **37** | **5.9** | **10** | **7.2** | **5** | **8.2** | **1** | **5.7** | **0** | **0.0** | **53** | **27.0** |

Table 28: Otter Tail Electric Industrial Sector CHP Technical Potential

### Commercial Sector

| SIC | Application | 50 - 500 KW Sites | 50 - 500 KW Capacity | 500 kW - 1 MW Sites | 500 kW - 1 MW Capacity | 1 - 5 MW Sites | 1 - 5 MW Capacity | 5 - 20 MW Sites | 5 - 20 MW Capacity | > 20 MW Sites | > 20 MW Capacity | Total Sites | Total Capacity |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 43 | Post Offices | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 52 | Retail | 10 | 1.3 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 10 | 1.3 |
| 4222 | Refrigerated Warehouses | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 4581 | Airports | 1 | 0.1 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.1 |
| 4952 | Water Treatment | 1 | 0.1 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.1 |
| 5411 | Food Stores | 10 | 1.8 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 10 | 1.8 |
| 5812 | Restaurants | 9 | 0.8 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 9 | 0.8 |
| 6512 | Commercial Buildings | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 6513 | Multifamily Buildings | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 7011 | Hotels | 8 | 0.9 | 0 | 0.0 | 1 | 2.3 | 0 | 0.0 | 0 | 0.0 | 9 | 3.2 |
| 7211 | Laundries | 1 | 0.1 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.1 |
| 7374 | Data Centers | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 7542 | Car Washes | 1 | 0.1 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.1 |
| 7832 | Movie Theaters | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 7991 | Health Clubs | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 7997 | Golf/Country Clubs | 4 | 0.4 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 4 | 0.4 |
| 8051 | Nursing Homes | 28 | 2.9 | 2 | 1.8 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 30 | 4.7 |
| 8062 | Hospitals | 12 | 2.8 | 5 | 3.0 | 1 | 1.4 | 0 | 0.0 | 0 | 0.0 | 18 | 7.2 |
| 8211 | Schools | 3 | 0.2 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 3 | 0.2 |
| 8221 | College/University | 2 | 0.5 | 1 | 0.8 | 4 | 8.7 | 0 | 0.0 | 0 | 0.0 | 7 | 10.0 |
| 8412 | Museums | 1 | 0.2 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.2 |
| 9100 | Government Buildings | 15 | 2.1 | 1 | 1.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 16 | 3.1 |
| 9223 | Prisons | 0 | 0.0 | 0 | 0.0 | 1 | 3.0 | 0 | 0.0 | 0 | 0.0 | 1 | 3.0 |
| 9711 | Military | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| | **Total** | **106** | **14.3** | **9** | **6.6** | **7** | **15.3** | **0** | **0.0** | **0** | **0.0** | **122** | **36.2** |

Table 29: Otter Tail Electric Commercial Sector CHP Technical Potential

## B – 5: Municipalities / Cooperatives

### Industrial Sector

| SIC | Application | 50 - 500 KW | | 500 kW - 1 MW | | 1 - 5 MW | | 5 - 20 MW | | > 20 MW | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Sites | Capacity | Sites | Capacity | Sites | Capacity | Sites | Capacity | Sites | Capacity | Sites | Capacity |
| 20 | Food | 15 | 3.1 | 3 | 2.3 | 7 | 15.3 | 0 | 0.0 | 0 | 0.0 | 25 | 20.7 |
| 22 | Textiles | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 24 | Lumber and Wood | 18 | 3.8 | 3 | 2.3 | 2 | 3.0 | 1 | 6.5 | 0 | 0.0 | 24 | 15.4 |
| 25 | Furniture | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 26 | Paper | 0 | 0.0 | 1 | 0.8 | 2 | 4.1 | 1 | 8.4 | 1 | 20.7 | 5 | 34.0 |
| 27 | Printing | 5 | 0.9 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 5 | 0.9 |
| 28 | Chemicals | 10 | 2.1 | 1 | 0.5 | 7 | 20.2 | 0 | 0.0 | 0 | 0.0 | 18 | 22.8 |
| 29 | Petroleum Refining | 0 | 0.0 | 1 | 0.6 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.6 |
| 30 | Rubber/Misc. Plastics | 10 | 1.9 | 1 | 0.8 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 11 | 2.6 |
| 32 | Stone/Clay/Glass | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 33 | Primary Metals | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 34 | Fabricated Metals | 1 | 0.1 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.1 |
| 35 | Machinery/Computer Equip | 1 | 0.4 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.4 |
| 37 | Transportation Equip. | 4 | 0.5 | 2 | 1.4 | 1 | 1.9 | 0 | 0.0 | 0 | 0.0 | 7 | 3.9 |
| 38 | Instruments | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 39 | Misc. Manufacturing | 2 | 0.2 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 2 | 0.2 |
| | **Total** | **66** | **12.8** | **12** | **8.7** | **19** | **44.5** | **2** | **14.8** | **1** | **20.7** | **100** | **101.6** |

Table 30: Muni/Coop Industrial Sector CHP Technical Potential

## Commercial Sector

| SIC | Application | 50 - 500 KW | | 500 kW - 1 MW | | 1 - 5 MW | | 5 - 20 MW | | > 20 MW | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Sites | Capacity | Sites | Capacity | Sites | Capacity | Sites | Capacity | Sites | Capacity | Sites | Capacity |
| 43 | Post Offices | 1 | 0.1 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.1 |
| 52 | Retail | 32 | 3.8 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 32 | 3.8 |
| 4222 | Refrigerated Warehouses | 1 | 0.2 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.2 |
| 4581 | Airports | 1 | 0.3 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.3 |
| 4952 | Water Treatment | 1 | 0.1 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.1 |
| 5411 | Food Stores | 15 | 3.2 | 4 | 2.6 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 19 | 5.7 |
| 5812 | Restaurants | 25 | 2.2 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 25 | 2.2 |
| 6512 | Commercial Buildings | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 6513 | Multifamily Buildings | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 7011 | Hotels | 32 | 4.0 | 1 | 0.5 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 33 | 4.5 |
| 7211 | Laundries | 1 | 0.1 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.1 |
| 7374 | Data Centers | 1 | 0.1 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 1 | 0.1 |
| 7542 | Car Washes | 2 | 0.1 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 2 | 0.1 |
| 7832 | Movie Theaters | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 7991 | Health Clubs | 2 | 0.2 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 2 | 0.2 |
| 7997 | Golf/Country Clubs | 7 | 0.6 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 7 | 0.6 |
| 8051 | Nursing Homes | 38 | 4.3 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 38 | 4.3 |
| 8062 | Hospitals | 22 | 4.0 | 7 | 4.5 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 29 | 8.6 |
| 8211 | Schools | 13 | 0.9 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 13 | 0.9 |
| 8221 | College/University | 5 | 0.8 | 2 | 1.4 | 1 | 1.2 | 0 | 0.0 | 0 | 0.0 | 8 | 3.5 |
| 8412 | Museums | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| 9100 | Government Buildings | 26 | 4.2 | 3 | 2.4 | 1 | 1.1 | 0 | 0.0 | 0 | 0.0 | 30 | 7.7 |
| 9223 | Prisons | 0 | 0.0 | 0 | 0.0 | 1 | 1.8 | 0 | 0.0 | 0 | 0.0 | 1 | 1.8 |
| 9711 | Military | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| | **Total** | **225** | **29.0** | **17** | **11.5** | **3** | **4.2** | **0** | **0.0** | **0** | **0.0** | **245** | **44.7** |

Table 31: Muni/Coop Commercial Sector CHP Technical Potential

# Appendix C – Net Metering Technical Potential

| SIC | Application | Total Sites | Total MW | Total MWh |
|---|---|---|---|---|
| 20 | Food | 246 | 52.6 | 394,441 |
| 22 | Textiles | 16 | 3.5 | 26,219 |
| 24 | Lumber and Wood | 171 | 35.8 | 268,418 |
| 26 | Paper | 110 | 29.7 | 222,555 |
| 27 | Printing | 20 | 4.0 | 29,910 |
| 28 | Chemicals | 255 | 48.2 | 361,125 |
| 29 | Petroleum Refining | 9 | 3.4 | 25,779 |
| 30 | Rubber/Misc Plastics | 179 | 33.8 | 253,438 |
| 33 | Primary Metals | 45 | 12.2 | 91,411 |
| 34 | Fabricated Metals | 59 | 7.1 | 53,080 |
| 35 | Machinery/Computer Equip | 12 | 1.6 | 11,906 |
| 37 | Transportation Equip. | 47 | 9.2 | 69,057 |
| 38 | Instruments | 3 | 0.2 | 1,233 |
| 39 | Misc. Manufacturing | 12 | 1.4 | 10,261 |
| | **Industrial Sector Total** | **1,184** | **242.5** | **1,818,834** |
| 43 | Post Offices | 4 | 0.4 | 1,933 |
| 52 | Retail | 381.0 | 46.7 | 210,353 |
| 4222 | Refrigerated Warehouses | 17.0 | 3.1 | 23,513 |
| 4581 | Airports | 3.0 | 0.7 | 3,087 |
| 4952 | Water Treatment | 11.0 | 1.1 | 8,360 |
| 5411 | Food Stores | 200.0 | 52.1 | 234,246 |
| 5812 | Restaurants | 460.0 | 47.2 | 212,214 |
| 7011 | Hotels | 265.0 | 44.4 | 332,912 |
| 7211 | Laundries | 21.0 | 5.3 | 23,809 |
| 7374 | Data Centers | 39.0 | 8.4 | 63,270 |
| 7542 | Car Washes | 28.0 | 1.9 | 8,744 |
| 7832 | Movie Theaters | 1.0 | 0.1 | 273 |
| 7991 | Health Clubs | 46.0 | 7.8 | 35,154 |
| 7997 | Golf/Country Clubs | 117.0 | 13.1 | 58,807 |
| 8051 | Nursing Homes | 304.0 | 44.1 | 330,527 |
| 8062 | Hospitals | 118.0 | 41.2 | 308,976 |
| 8211 | Schools | 210.0 | 15.9 | 71,502 |
| 8221 | College/Univ | 77.0 | 25.5 | 191,544 |
| 8412 | Museums | 11.0 | 2.6 | 11,543 |
| 9100 | Government Buildings | 223.0 | 45.5 | 204,880 |
| 9223 | Prisons | 8.0 | 1.5 | 11,551 |
| 9711 | Military | 6.0 | 1.5 | 10,962 |
| | **Commercial Sector Total** | **2,550** | **410.1** | **2,358,160** |

Table 32: Net Metering Technical Potential

# Appendix D – Economic Payback Model Assumptions

## D –1: Electric Rates

### High Load Factor Retail Rates ($/kWh)

| Utility | Year | 50 kW-500 kW | 500 kW -1 MW | 1-5 MW | 5-20 MW | >20 MW |
|---|---|---|---|---|---|---|
| Alliant | 2013 | 0.0615 | 0.0607 | 0.0587 | 0.0585 | 0.0585 |
| MN Power | 2013 | 0.0823 | 0.0822 | 0.0668 | 0.0668 | 0.0638 |
| Xcel Energy | 2013 | 0.0672 | 0.0651 | 0.0631 | 0.0605 | 0.0596 |
| Otter Tail | 2013 | 0.0753 | 0.0725 | 0.0562 | 0.0542 | 0.0496 |
| Alliant | 2013 to 2017 | 0.0623 | 0.0615 | 0.0596 | 0.0593 | 0.0593 |
| MN Power | 2013 to 2017 | 0.0834 | 0.0834 | 0.0678 | 0.0677 | 0.0647 |
| Xcel Energy | 2013 to 2017 | 0.0682 | 0.0661 | 0.0640 | 0.0613 | 0.0604 |
| Otter Tail | 2013 to 2017 | 0.0764 | 0.0735 | 0.0570 | 0.0549 | 0.0503 |
| Alliant | 2018 to 2022 | 0.0646 | 0.0637 | 0.0617 | 0.0614 | 0.0614 |
| MN Power | 2018 to 2022 | 0.0864 | 0.0864 | 0.0702 | 0.0701 | 0.0669 |
| Xcel Energy | 2018 to 2022 | 0.0706 | 0.0684 | 0.0662 | 0.0635 | 0.0626 |
| Otter Tail | 2018 to 2022 | 0.0791 | 0.0761 | 0.0590 | 0.0569 | 0.0521 |
| Alliant | 2023 to 2027 | 0.0668 | 0.0660 | 0.0639 | 0.0636 | 0.0636 |
| MN Power | 2023 to 2027 | 0.0895 | 0.0894 | 0.0727 | 0.0726 | 0.0693 |
| Xcel Energy | 2023 to 2027 | 0.0731 | 0.0708 | 0.0686 | 0.0658 | 0.0648 |
| Otter Tail | 2023 to 2027 | 0.0819 | 0.0788 | 0.0611 | 0.0589 | 0.0540 |
| Alliant | 2028 to 2032 | 0.0692 | 0.0683 | 0.0661 | 0.0659 | 0.0659 |
| MN Power | 2028 to 2032 | 0.0926 | 0.0926 | 0.0752 | 0.0752 | 0.0718 |
| Xcel Energy | 2028 to 2032 | 0.0757 | 0.0734 | 0.0710 | 0.0681 | 0.0671 |
| Otter Tail | 2028 to 2032 | 0.0848 | 0.0816 | 0.0633 | 0.0610 | 0.0559 |

Table 33: High Load Factor Electric Rate Model Inputs

**Low Load Factor Retail Rates ($/kWh)**

| Utility | Year | 50 kW-500 kW | 500 kW -1 MW | 1-5 MW | 5-20 MW | >20 MW |
|---|---|---|---|---|---|---|
| Alliant | 2013 | 0.0771 | 0.0755 | 0.0725 | 0.0714 | 0.0713 |
| MN Power | 2013 | 0.0903 | 0.0902 | 0.0772 | 0.0770 | 0.0740 |
| Xcel Energy | 2013 | 0.0753 | 0.0878 | 0.0847 | 0.0812 | 0.0795 |
| Otter Tail | 2013 | 0.0776 | 0.0743 | 0.0648 | 0.0749 | 0.0677 |
| Alliant | 2013 to 2017 | 0.0782 | 0.0766 | 0.0735 | 0.0724 | 0.0723 |
| MN Power | 2013 to 2017 | 0.0916 | 0.0915 | 0.0783 | 0.0781 | 0.0751 |
| Xcel Energy | 2013 to 2017 | 0.0764 | 0.0891 | 0.0859 | 0.0824 | 0.0807 |
| Otter Tail | 2013 to 2017 | 0.0787 | 0.0754 | 0.0658 | 0.0760 | 0.0687 |
| Alliant | 2018 to 2022 | 0.0810 | 0.0793 | 0.0761 | 0.0749 | 0.0749 |
| MN Power | 2018 to 2022 | 0.0948 | 0.0948 | 0.0810 | 0.0809 | 0.0778 |
| Xcel Energy | 2018 to 2022 | 0.0791 | 0.0922 | 0.0889 | 0.0853 | 0.0835 |
| Otter Tail | 2018 to 2022 | 0.0814 | 0.0781 | 0.0681 | 0.0787 | 0.0711 |
| Alliant | 2023 to 2027 | 0.0838 | 0.0821 | 0.0788 | 0.0776 | 0.0775 |
| MN Power | 2023 to 2027 | 0.0982 | 0.0981 | 0.0839 | 0.0838 | 0.0805 |
| Xcel Energy | 2023 to 2027 | 0.0819 | 0.0955 | 0.0921 | 0.0883 | 0.0865 |
| Otter Tail | 2023 to 2027 | 0.0843 | 0.0808 | 0.0705 | 0.0815 | 0.0736 |
| Alliant | 2028 to 2032 | 0.0868 | 0.0850 | 0.0816 | 0.0803 | 0.0803 |
| MN Power | 2028 to 2032 | 0.1017 | 0.1016 | 0.0869 | 0.0868 | 0.0834 |
| Xcel Energy | 2028 to 2032 | 0.0848 | 0.0989 | 0.0953 | 0.0915 | 0.0896 |
| Otter Tail | 2028 to 2032 | 0.0873 | 0.0837 | 0.0730 | 0.0844 | 0.0763 |

Table 34: Low Load Factor Electric Rate Model Inputs

## D – 2: Natural Gas Prices

**Low Estimate from EIA ($/MMBtu)**

| | Boiler Load (Therms/day) | | | | | CHP Load (Therms/day) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **354** | **660** | **2,419** | **8,815** | **35,206** | **667** | **1,499** | **5,645** | **21,639** | **81,429** |
| 2013 to 2017 | $5.00 | $5.00 | $4.50 | $4.50 | $4.50 | $5.00 | $5.00 | $4.50 | $4.50 | $4.50 |
| 2013 to 2017 | $5.00 | $5.00 | $4.50 | $4.50 | $4.50 | $5.00 | $5.00 | $4.50 | $4.50 | $4.50 |
| 2013 to 2017 | $5.00 | $5.00 | $4.50 | $4.50 | $4.50 | $5.00 | $5.00 | $4.50 | $4.50 | $4.50 |
| 2013 to 2017 | $5.00 | $5.00 | $4.50 | $4.50 | $4.50 | $5.00 | $5.00 | $4.50 | $4.50 | $4.50 |
| | | | | | | | | | | |
| 2018 to 2022 | $5.31 | $5.31 | $4.78 | $4.78 | $4.78 | $5.31 | $5.31 | $4.78 | $4.78 | $4.78 |
| 2018 to 2022 | $5.31 | $5.31 | $4.78 | $4.78 | $4.78 | $5.31 | $5.31 | $4.78 | $4.78 | $4.78 |
| 2018 to 2022 | $5.31 | $5.31 | $4.78 | $4.78 | $4.78 | $5.31 | $5.31 | $4.78 | $4.78 | $4.78 |
| 2018 to 2022 | $5.31 | $5.31 | $4.78 | $4.78 | $4.78 | $5.31 | $5.31 | $4.78 | $4.78 | $4.78 |
| | | | | | | | | | | |
| 2023 to 2027 | $5.63 | $5.63 | $5.07 | $5.07 | $5.07 | $5.63 | $5.63 | $5.07 | $5.07 | $5.07 |
| 2023 to 2027 | $5.63 | $5.63 | $5.07 | $5.07 | $5.07 | $5.63 | $5.63 | $5.07 | $5.07 | $5.07 |
| 2023 to 2027 | $5.63 | $5.63 | $5.07 | $5.07 | $5.07 | $5.63 | $5.63 | $5.07 | $5.07 | $5.07 |
| 2023 to 2027 | $5.63 | $5.63 | $5.07 | $5.07 | $5.07 | $5.63 | $5.63 | $5.07 | $5.07 | $5.07 |
| | | | | | | | | | | |
| 2028 to 2032 | $5.98 | $5.98 | $5.38 | $5.38 | $5.38 | $5.98 | $5.98 | $5.38 | $5.38 | $5.38 |
| 2028 to 2032 | $5.98 | $5.98 | $5.38 | $5.38 | $5.38 | $5.98 | $5.98 | $5.38 | $5.38 | $5.38 |
| 2028 to 2032 | $5.98 | $5.98 | $5.38 | $5.38 | $5.38 | $5.98 | $5.98 | $5.38 | $5.38 | $5.38 |
| 2028 to 2032 | $5.98 | $5.98 | $5.38 | $5.38 | $5.38 | $5.98 | $5.98 | $5.38 | $5.38 | $5.38 |

**Table 35: Low EIA Natural Gas Price Estimates**

**High Estimate from EIA ($/MMBtu)**

| | Boiler Load (Therms/day) | | | | | CHP Load (Therms/day) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **354** | **660** | **2,419** | **8,815** | **35,206** | **667** | **1,499** | **5,645** | **21,639** | **81,429** |
| 2013 to 2017 | $6.50 | $6.50 | $6.00 | $6.00 | $6.00 | $6.50 | $6.50 | $6.00 | $6.00 | $6.00 |
| 2013 to 2017 | $6.50 | $6.50 | $6.00 | $6.00 | $6.00 | $6.50 | $6.50 | $6.00 | $6.00 | $6.00 |
| 2013 to 2017 | $6.50 | $6.50 | $6.00 | $6.00 | $6.00 | $6.50 | $6.50 | $6.00 | $6.00 | $6.00 |
| 2013 to 2017 | $6.50 | $6.50 | $6.00 | $6.00 | $6.00 | $6.50 | $6.50 | $6.00 | $6.00 | $6.00 |
| | | | | | | | | | | |
| 2018 to 2022 | $6.90 | $6.90 | $6.37 | $6.37 | $6.37 | $6.90 | $6.90 | $6.37 | $6.37 | $6.37 |
| 2018 to 2022 | $6.90 | $6.90 | $6.37 | $6.37 | $6.37 | $6.90 | $6.90 | $6.37 | $6.37 | $6.37 |
| 2018 to 2022 | $6.90 | $6.90 | $6.37 | $6.37 | $6.37 | $6.90 | $6.90 | $6.37 | $6.37 | $6.37 |
| 2018 to 2022 | $6.90 | $6.90 | $6.37 | $6.37 | $6.37 | $6.90 | $6.90 | $6.37 | $6.37 | $6.37 |
| | | | | | | | | | | |
| 2023 to 2027 | $7.32 | $7.32 | $6.76 | $6.76 | $6.76 | $7.32 | $7.32 | $6.76 | $6.76 | $6.76 |
| 2023 to 2027 | $7.32 | $7.32 | $6.76 | $6.76 | $6.76 | $7.32 | $7.32 | $6.76 | $6.76 | $6.76 |
| 2023 to 2027 | $7.32 | $7.32 | $6.76 | $6.76 | $6.76 | $7.32 | $7.32 | $6.76 | $6.76 | $6.76 |
| 2023 to 2027 | $7.32 | $7.32 | $6.76 | $6.76 | $6.76 | $7.32 | $7.32 | $6.76 | $6.76 | $6.76 |
| | | | | | | | | | | |
| 2028 to 2032 | $7.77 | $7.77 | $7.18 | $7.18 | $7.18 | $7.77 | $7.77 | $7.18 | $7.18 | $7.18 |
| 2028 to 2032 | $7.77 | $7.77 | $7.18 | $7.18 | $7.18 | $7.77 | $7.77 | $7.18 | $7.18 | $7.18 |
| 2028 to 2032 | $7.77 | $7.77 | $7.18 | $7.18 | $7.18 | $7.77 | $7.77 | $7.18 | $7.18 | $7.18 |
| 2028 to 2032 | $7.77 | $7.77 | $7.18 | $7.18 | $7.18 | $7.77 | $7.77 | $7.18 | $7.18 | $7.18 |

**Table 36: High EIA Natural Gas Price Estimates**

## D – 3: Cooling, Retail Rates ($/kWh)

| | | 50 kW-500 kW | 500 kW - 1 MW | 1-5 MW | 5-20 MW | >20 MW |
|---|---|---|---|---|---|---|
| Alliant | 2013 | 0.1147 | 0.1115 | 0.1061 | 0.1029 | 0.1029 |
| MN Power | 2013 | 0.1076 | 0.1074 | 0.0994 | 0.0992 | 0.0962 |
| Xcel Energy | 2013 | 0.0926 | 0.1184 | 0.1128 | 0.1076 | 0.1042 |
| Otter Tail | 2013 | 0.0830 | 0.0789 | 0.0838 | 0.1015 | 0.0896 |
| | | | | | | |
| Alliant | 2013 to 2017 | 0.1163 | 0.1130 | 0.1076 | 0.1044 | 0.1043 |
| MN Power | 2013 to 2017 | 0.1091 | 0.1089 | 0.1008 | 0.1006 | 0.0975 |
| Xcel Energy | 2013 to 2017 | 0.0940 | 0.1200 | 0.1144 | 0.1091 | 0.1057 |
| Otter Tail | 2013 to 2017 | 0.0842 | 0.0800 | 0.0850 | 0.1029 | 0.0909 |
| | | | | | | |
| Alliant | 2018 to 2022 | 0.1205 | 0.1170 | 0.1114 | 0.1081 | 0.1080 |
| MN Power | 2018 to 2022 | 0.1130 | 0.1128 | 0.1044 | 0.1042 | 0.1010 |
| Xcel Energy | 2018 to 2022 | 0.0973 | 0.1243 | 0.1185 | 0.1130 | 0.1094 |
| Otter Tail | 2018 to 2022 | 0.0872 | 0.0829 | 0.0880 | 0.1065 | 0.0941 |
| | | | | | | |
| Alliant | 2023 to 2027 | 0.1247 | 0.1212 | 0.1153 | 0.1119 | 0.1119 |
| MN Power | 2023 to 2027 | 0.1170 | 0.1168 | 0.1081 | 0.1079 | 0.1046 |
| Xcel Energy | 2023 to 2027 | 0.1007 | 0.1287 | 0.1227 | 0.1170 | 0.1133 |
| Otter Tail | 2023 to 2027 | 0.0903 | 0.0858 | 0.0911 | 0.1103 | 0.0975 |
| | | | | | | |
| Alliant | 2028 to 2032 | 0.1292 | 0.1255 | 0.1194 | 0.1159 | 0.1158 |
| MN Power | 2028 to 2032 | 0.1211 | 0.1210 | 0.1120 | 0.1117 | 0.1083 |
| Xcel Energy | 2028 to 2032 | 0.1043 | 0.1333 | 0.1270 | 0.1211 | 0.1173 |
| Otter Tail | 2028 to 2032 | 0.0935 | 0.0889 | 0.0944 | 0.1142 | 0.1009 |

Table 37: Electric Cooling, Retail Rates

### D – 4: Growth Rates

**Technical Potential Yearly Growth Rates (%)**

| **Sector** | % |
|---|---|
| Industrial Growth Rate | 0.5% |
| Commercial/Other Growth Rate | 1.5% |

Table 38: Technical Potential Growth Rates

**Energy Price Growth Rates (%)**

| **Fuel** | % |
|---|---|
| Natural Gas | 1.2% |
| Electricity Prices | 0.7% |

Table 39: Energy Price Growth Rates