Minnesota Center for
Environmental Advocacy

Using law, science, and research to protect Minnesota's environment, its natural resources, and the health of its people.

26 East Exchange Street - Suite 206
Saint Paul, MN 55101-1667

651.223.5969
651.223.5967 fax

info@mncenter.org
www.mncenter.org

January 4, 2016

Daniel Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

VIA ELECTRONIC SERVICE

Re: *In the Matter of Minnesota Power's Application for Approval of its 2015-2029 Resource Plan*
PUC Docket No. E015/RP-15-690

Dear Mr. Wolf:

In connection to the above-captioned docket, please find attached PUBLIC and NON-PUBLIC versions of the Initial Comments of Clean Energy Organizations. Also attached is an Affidavit of Service.

Sincerely,

/s/ Elizabeth Goodpaster
Elizabeth Goodpaster
Contract Attorney

EG/em

Enclosures

cc: Attached Service List

PUBLIC VERSION
TRADE SECRET DATA EXCISED

STATE OF MINNESOTA
BEFORE THE PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's Application for Approval of its 2015-2029 Resource Plan	PUC Docket No. E015/RP-15-690

CLEAN ENERGY ORGANIZATIONS' INITIAL COMMENTS

On Behalf Of

Fresh Energy
Minnesota Center for Environmental Advocacy
Sierra Club
Wind on the Wires

January 4, 2016

TABLE OF CONTENTS

INTRODUCTION

These comments on the Minnesota Power 2015 Integrated Resource Plan ("IRP") are being offered on behalf of Fresh Energy, Minnesota Center for Environmental Advocacy, Sierra Club, and Wind on the Wires ("Clean Energy Organizations" or "CEO"). Overall, Clean Energy Organizations recognize the recent important steps that Minnesota Power has taken toward using a cleaner portfolio of generation resources to serve its customers. Decisions to retire Taconite Harbor Unit 3, to refuel Laskin Energy Center with natural gas, and to gradually phase out its purchase from Square Butte Cooperative's coal plant are important results from earlier resource plans. In addition, Minnesota Power has reached early compliance with the Minnesota Renewable Energy Standard ("RES") with its significant wind power investments.

However, with the 2015 IRP, Minnesota Power's clean energy progress stagnates. The IRP overstates Minnesota Power's future resource needs, short-changes energy efficiency, wind, and solar potential, and exposes its customers to financial risks from operation of unneeded and uneconomic coal generation.

Our comments first identify problems on the load forecasting side. Second, we show that Minnesota Power's modeling (based on the flawed load forecast) gives unwarranted value to operating the oldest two Taconite Harbor units and the remaining small coal units at Boswell, and pushes premature acquisition of new fossil fuel generation.

The Commission should order Minnesota Power to immediately retire—not "idle"—Taconite Harbor Units 1 and 2, which are coal assets that Minnesota Power admits its customers do not need. In addition, as we discuss in these comments, the Commission should order Minnesota Power to correct problems in its load forecasting and modeling that create bias against zero-carbon resources, and prevent energy efficiency from deferring new energy and capacity. Finally, the Commission should order Minnesota Power to proactively seek ways to increase conservation by its CIP-exempt customers.

II. MINNESOTA POWER'S LOAD FORECAST OVERSTATES FUTURE NEEDS BASED ON FLAWED ASSUMPTIONS.

Because an IRP is driven by customer demand, it is essential to examine the utility's load forecast assumptions. Minnesota Power's load forecast for the 2015 IRP contains problematic and inconsistent assumptions that make it an unreliable foundation for planning decisions.

Much of Minnesota Power's Strategist modeling uses a load forecast from Minnesota Power's "AFR 2014" or Annual Forecast Report 2014, which was issued in July 2014. A smaller subset of modeling in the IRP uses the AFR 2015 issued in July 2015. The complete set of forecasts, including sensitivities, used in Strategist modeling is shown in Figure 1 along with actual sales through 2014.

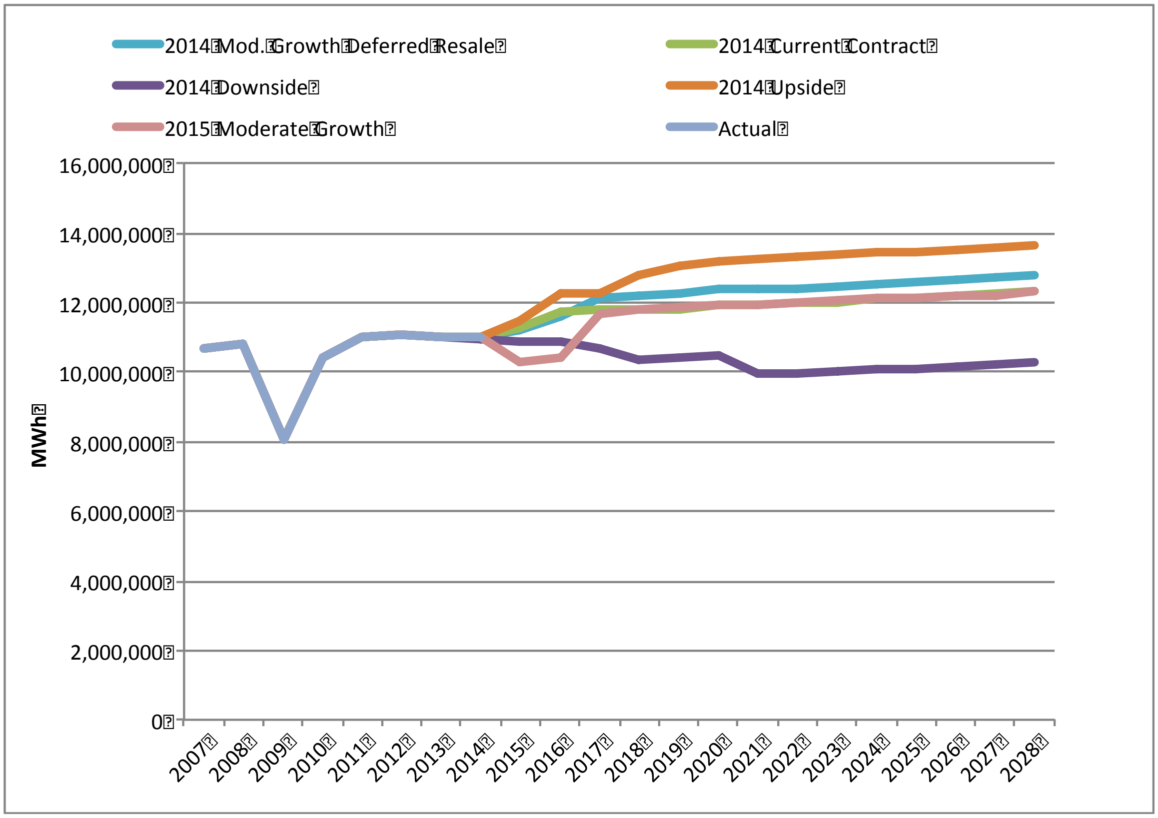


Figure 1. Load Forecasts Used in 2015 IRP Modeling

AFRs 2014 and 2015 differ from each other in substantive ways, and in fact, differ significantly from prior AFRs as well. What these differences generally show is a downward trend in projected demand. In places, Minnesota Power seems to acknowledge this trend, for example, when it states in the AFR 2014 that:

> Since the recession, Minnesota Power has observed a divergence of economic indicators and energy sales. Although economic conditions have improved, employment has rebounded, and population growth in the region has resumed, there has been little to no growth in electricity use by several customer classes.
>
> For example, Residential customer count has grown by just 97 customers or 0.08 percent (net) since 2009 and sales have stagnated as well. However, key economic and demographic indicators continued to grow in this timeframe.[1]

[1] Minnesota Power 2015 IRP at Appendix A, 12-13.

The trend towards lower rates of consumption and a changing relationship between economic growth and electricity consumption is not unique to Minnesota Power.[2]

A. Residential Class Post-2020 Growth Assumptions Ignore Downward Demand Trend.

Despite Minnesota Power's observations of little-to-no growth in the residential customer class, the AFR 2014 forecasts essentially infinitely increasing residential energy sales. This forecast is shown in Figure 2.

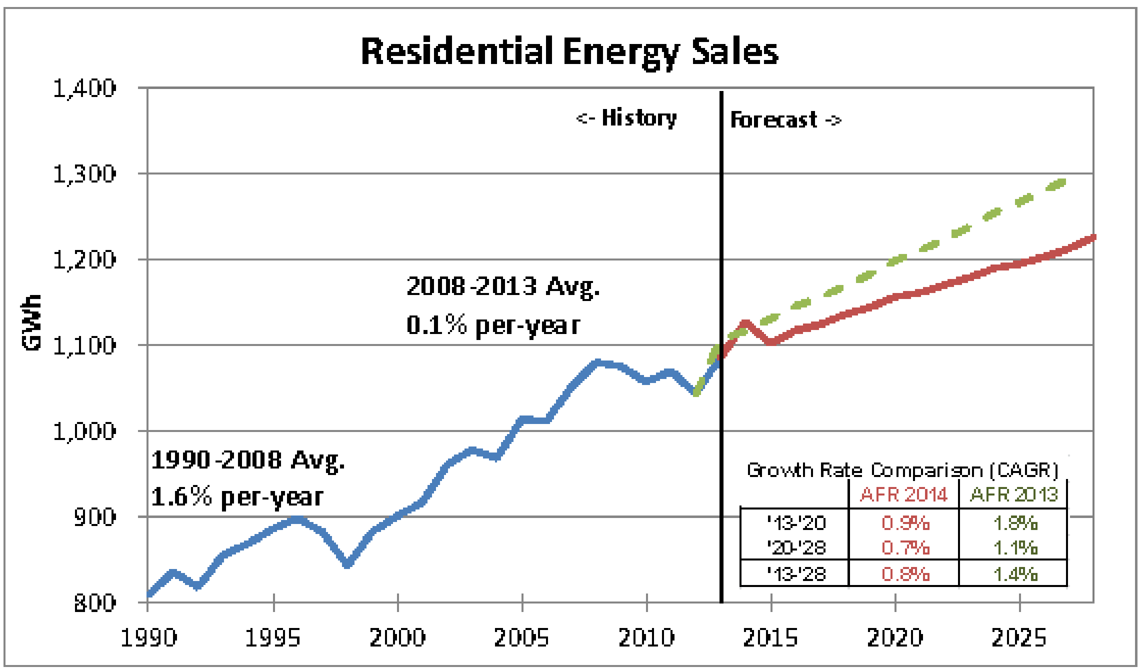


Figure 2. Residential Energy Sales from the AFR 2014 Moderate Growth Case[3]

---

[2] *See, e.g.*, https://www.eia.gov/todayinenergy/detail.cfm?id=10491.

[3] As an example of one of many contradictions in the Company's IRP, the AFR 2014 at page 1 says that the Moderate Growth Case is Minnesota Power's expected scenario. But the first page of Appendix A, which largely consists of the AFR 2014, says that the scenario that forms the base case for the 2015 IRP is the Moderate Growth with Deferred Resale forecast. Despite Minnesota Power's claim that this scenario "is identical to the Moderate Growth scenario except it assumes a one-year deferment in the start-up of the new industrial facility in the City of Nashwauk," (App. A at 44) there are differences between the two scenarios in other customer classes. These differences are small enough

The AFR 2015 moderated the near-term growth trend, but post-2020, the rate of growth remains the same, again leading to effectively infinitely increasing sales.

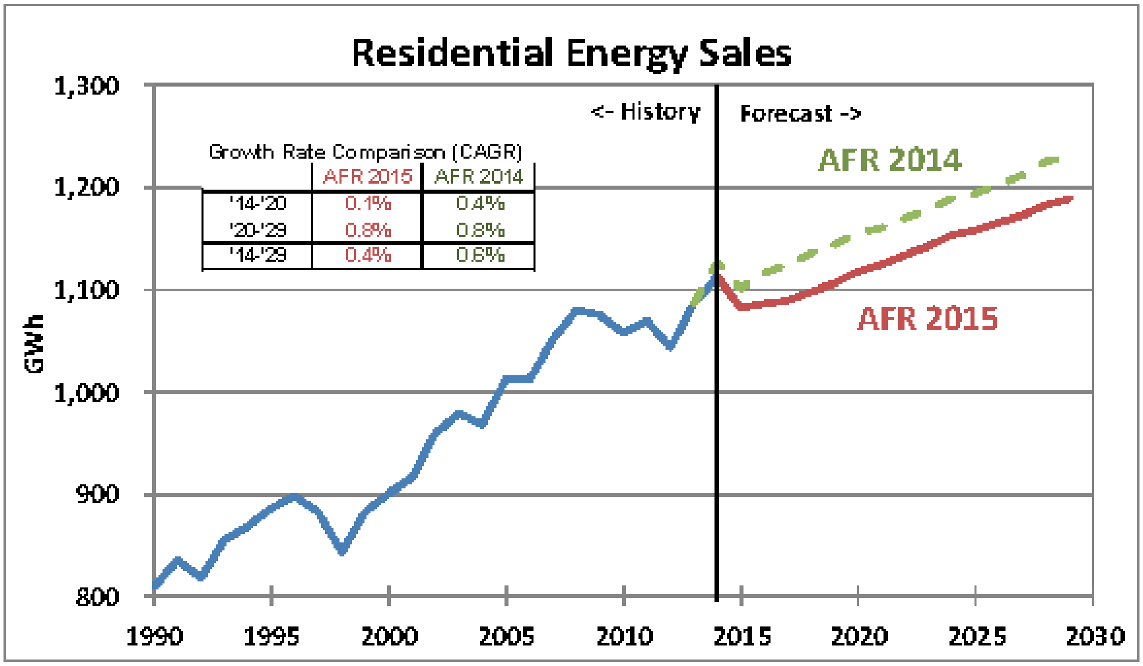


Figure 3. Residential Energy Sales from the AFR 2015 Moderate Growth Case

Note that in Figure 2, the dashed green line represents AFR 2013, whereas the dashed green line represents AFR 2014 in Figure 3. Although the current AFR 2015 rate of residential sales growth through 2020 is, on average, consistent with levels experienced since 2008, our concern again is the trend post 2020. Indeed, the only AFR 2014 scenario in which the post-2020 average annual growth rate is lower than post-2008 trends (and even then only **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]** rather than 0.8%) is when the period prior to 2020 includes a much higher rate of growth than AFR 2014's 0.4%. This is concerning because post-2020

---

that they did not outweigh the convenience of using the graphs in Figures 2 through 9 in these comments.

sales growth assumptions can have a significant impact on resource planning decisions made for a planning period through 2034.

None of Minnesota Power's load forecast scenarios contemplate residential sales growth in line with recent historic trends.

B. Commercial Rate Class Growth Assumptions Contradict Recent Trends.

Similarly, AFR 2014 projects very optimistic growth in commercial sales.

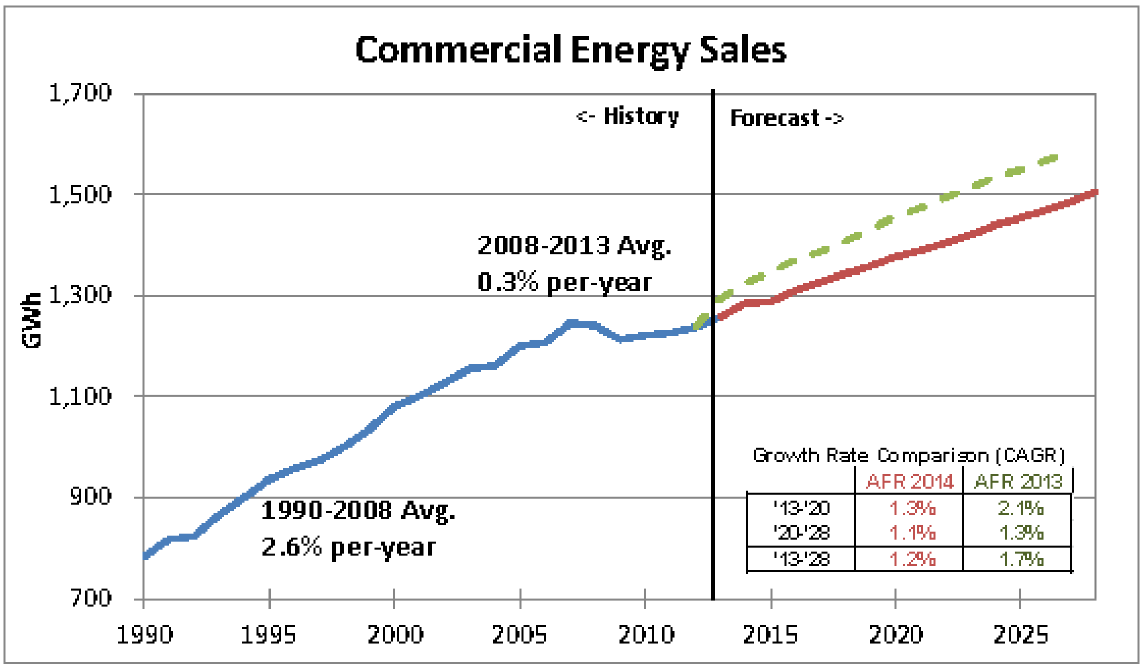


Figure 4. Commercial Energy Sales from the AFR 2014 Moderate Growth Case

And the optimism remains in the AFR 2015.

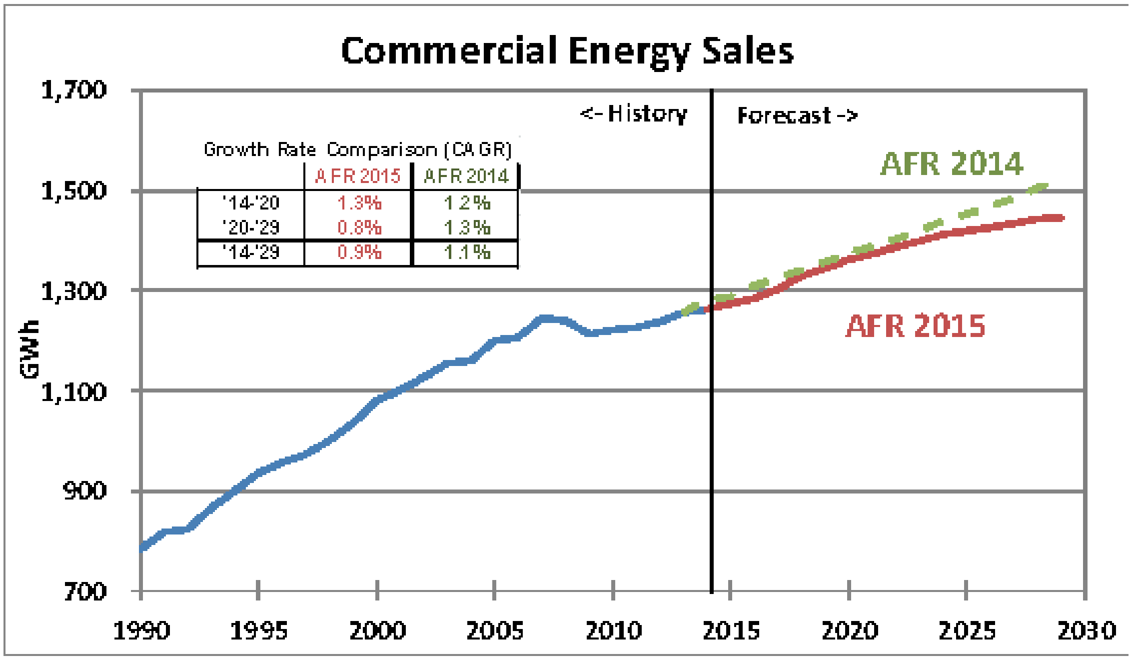


Figure 5. Commercial Energy Sales from the AFR 2015 Moderate Growth Case

The near-term growth assumption of 1.3% per year through 2020 is especially troubling. Since 2008, Minnesota Power commercial sales have only grown an average of 0.3% per year. And data from the Energy Information Administration through the third quarter of 2015 put commercial sales at 75% of 2014 commercial sales, meaning that unless sales have picked up in the fourth quarter of 2015, there will be *no* growth in commercial sales in 2015. No AFR 2014 forecast sensitivity assumes near-term commercial growth rates as low as the 0.3% rate experienced since 2008; each scenario is much higher.

Our point is not that residential and commercial sales must be in line with recent trends; as with everything else in utility planning, the past is not a perfect indicator of the future. Rather, the point is that each of Minnesota Power's load forecast scenarios used in this IRP fails to account for the possibility that sales growth in these sectors will approximate recent trends. Thus, none of the load forecast scenarios appropriately accounts for the real possibility of continued anemic sales in the residential and commercial sectors.

C. Large Industrial Rate Class Projections May Be Overstated.

The mining, paper, pipeline, and resale classes have their own idiosyncrasies and trends that seem to be more influenced by specific customer additions and losses than general economic factors. For example, the Company forecasts a significant drop in sales in the mining sector followed by a significant rise in 2017.

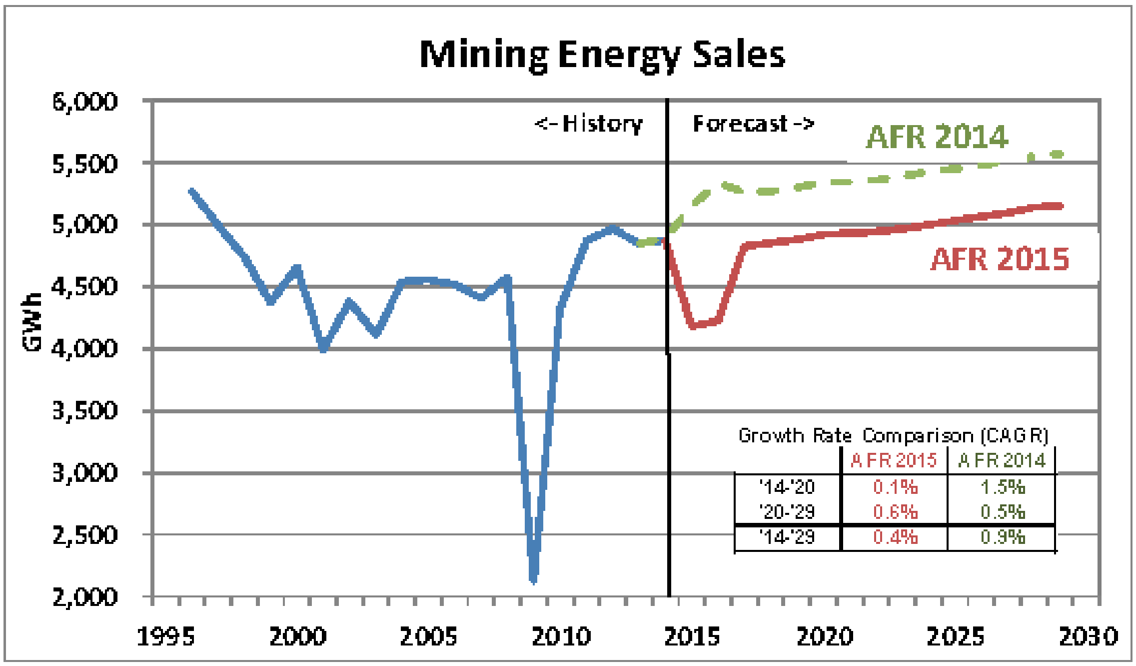


Figure 6. Mining Energy Sales from the AFR 2015 Moderate Growth Case

The uptick in sales after 2015 is driven in large part by the addition of the proposed Polymet nickel-copper mining operation. Even in the Moderate Growth with Deferred Resale scenario, Minnesota Power assumes Polymet starts operations in

[TRADE SECRET BEGINS

TRADE SECRET ENDS]—this is despite the fact that the final EIS for the project was only delivered in November 2015 and it has yet to go through permitting, let alone begin construction.

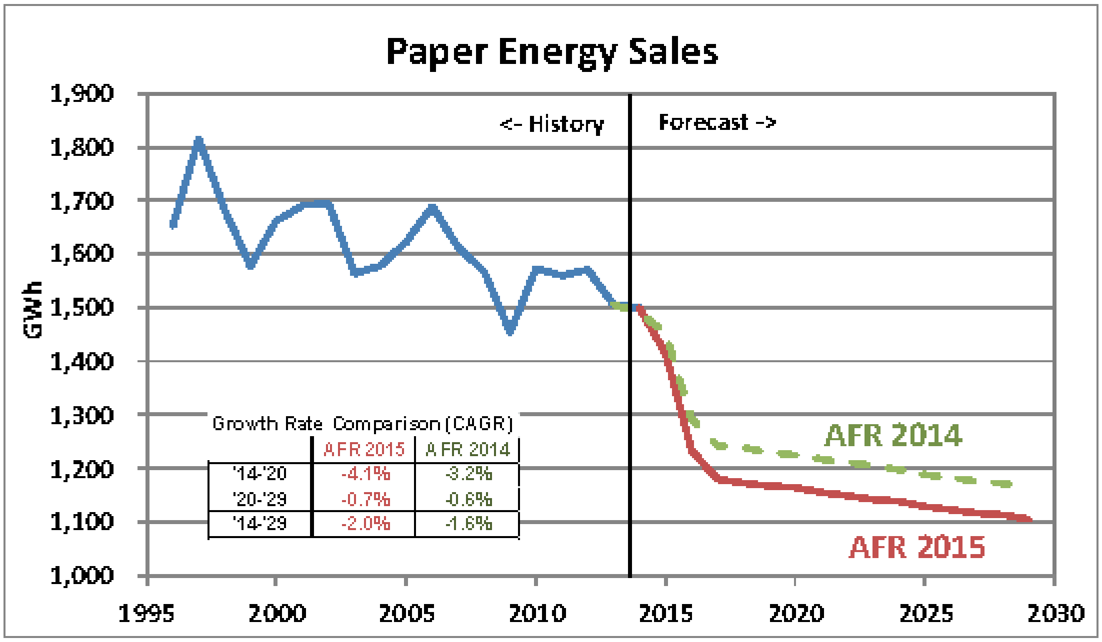


Figure 7. Paper Energy Sales from the AFR 2015 Moderate Growth Case

Both the AFRs 2014 and 2015 project declining sales to paper mills.

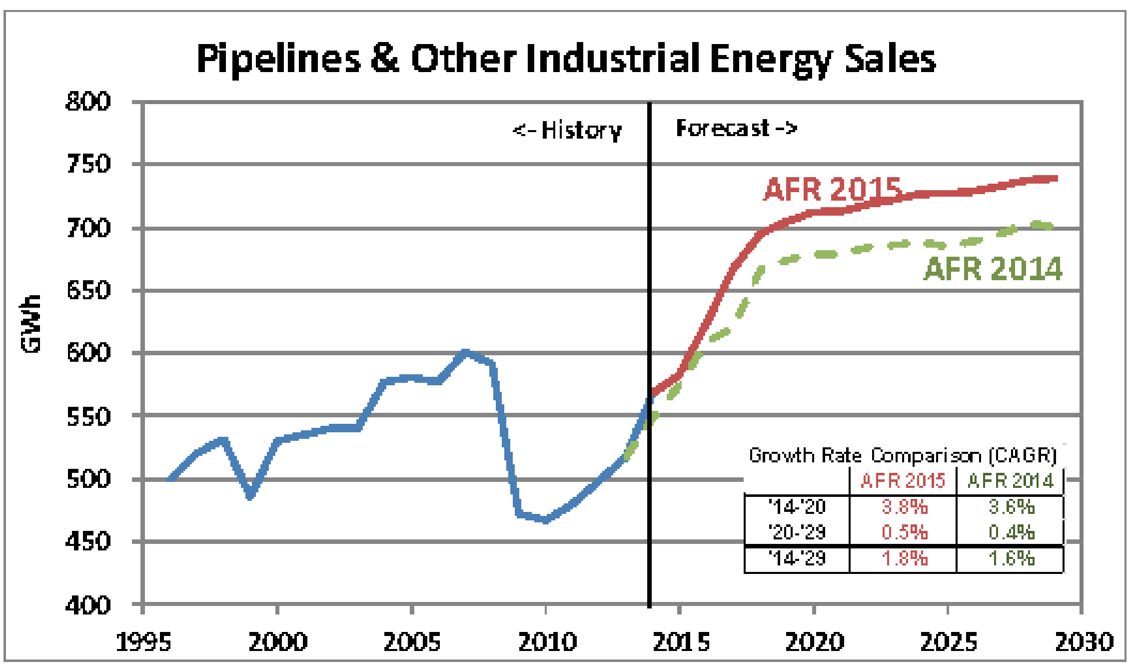


Figure 8. Pipeline Energy Sales from the AFR 2015 Moderate Growth Case

The Company forecasts an increase in sales in the pipeline sector, although this may depend in part on the Sandpiper pipeline[4] for which the Commission just declined to set a January 2017 deadline for approval of a certificate of need or route permit. It could well be mid-2017 before construction can even begin, if at all.

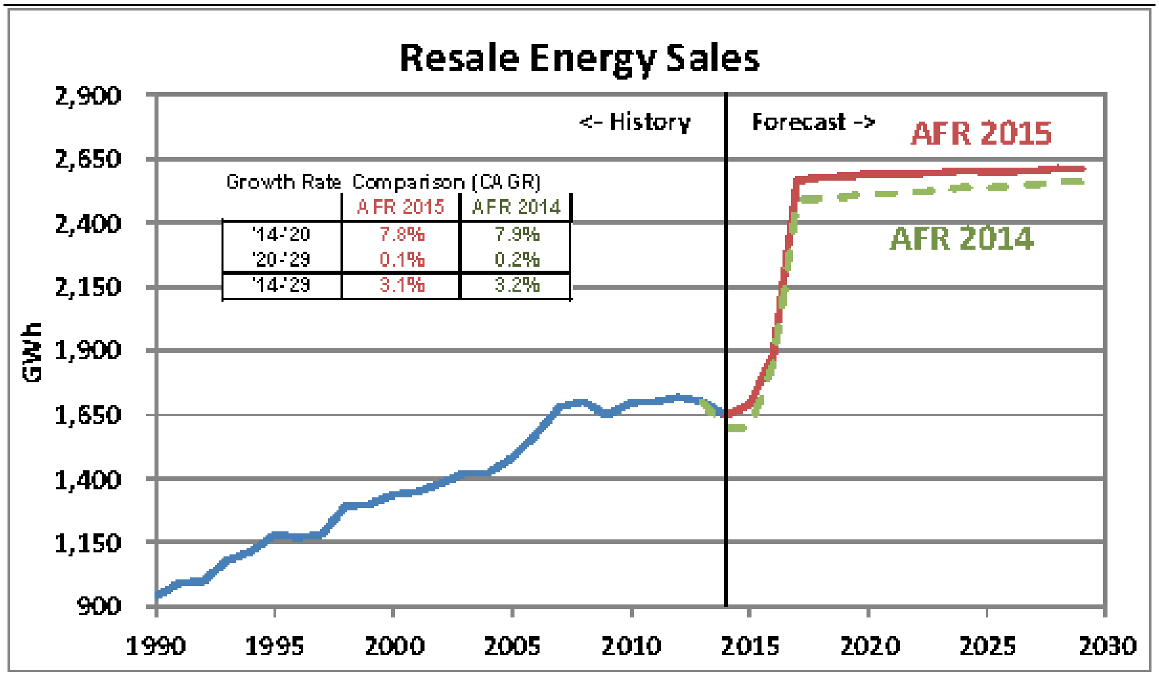


Figure 9. Resale Energy Sales from the AFR 2015 Moderate Growth Case

The jump in resale sales has largely to do with the Essar Steel project coming online. That project, currently under construction, has faced problems paying its contractors. The project also owes the state over $66 million, though Governor Dayton's spokesman, Matt Swenson, has said, "[Dayton is] sympathetic to the concerns of some vendors, who have expressed that more strident demands (by the state) at this time could

[4] The Company includes what seems to be a new **[TRADE SECRET BEGINS TRADE SECRET ENDS]** load coming online in **[TRADE SECRET BEGINS TRADE SECRET ENDS]** and ramping up to full load in **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. It is not clear if that represents Sandpiper or not.

jeopardize the future of the project, and limit the company's ability to make timely payments on any outstanding and future obligations."[5] The project is currently scheduled to come online by late 2016, though that date could reasonably be delayed. But assuming it does come online at some point, we believe that Minnesota Power could be overestimating demand from Essar. The forecast used in much of the Company's modeling assumes Essar Steel starts operations in **[TRADE SECRET BEGINS TRADE SECRET ENDS]** and ramps up to full output by **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. Minnesota Power then assumes that through **[TRADE SECRET BEGINS TRADE SECRET ENDS]** Minnesota Power makes this assumption despite the economic woes that have depressed production at other taconite facilities in the region.

Assumptions made about Essar Steel's demand are not inconsequential. As Figure 9 shows, it is responsible for a huge jump in sales. And production at full capacity would add 110 MW of demand, or a more than 5% increase in system peak.[6] This level of demand appears to be based on not-yet-finalized expansion plans, however:

---

[5] Myers, John. "Mark Dayton backs off as Essar Steel pays some bills." *Pioneer Press*. 4 Dec. 2015, http://www.twincities.com/localnews/ci_29203869/essar-steel-makes-payments-buys-time-from-state.

[6] Another area of inconsistency in Minnesota Power's IRP is how it treated the potential new load represented by Essar Steel. In Minnesota Power's Current Contract scenario, which it describes as including "additional loads served by Minnesota Power and its wholesale customers that are highly likely, i.e. the customer has a signed service agreement or is otherwise bound by contract to change its load," Minnesota Power shows **[TRADE SECRET BEGINS TRADE SECRET ENDS]** of load for Essar rather than **[TRADE SECRET BEGINS TRADE SECRET ENDS]** it uses as its base case scenario.

> Construction activities are well underway for the initial 4.1 million ton-per-year plant; permits have been finalized for the expansion to a 7 million ton-per-year production rate. While Essar continues to work on the financing for the larger production tonnage, mining operations are slated to start in 2015. The facility will result in up to 110 MW of new additional load to Minnesota Power.[7]

If the current facility under construction will produce only a maximum of 4.1 million tons per year, then it does not make sense to include load associated with the full 7 million tons of production in the base case forecast.

Given the uncertainty in the mining, pipeline, and resale sectors, and the declining load for the paper sector, the demand from large industrial customers is likely overstated—particularly in the short term.

D. Minnesota Power's Regression Models Cannot Be Relied Upon For Long-Term Projections Of Sales.

We also have concerns about Minnesota Power's load forecasting methodology. Minnesota Power's unexplained year-to-year shifts in the key "drivers" that determine its load forecasts raise questions about the reliability of its load forecasts for long-run projections.

Minnesota Power uses regression modeling techniques to produce forecasts of customer counts by class and customer use by class. As a general matter, the product of those two categories, summed among all classes, plus any known load additions/subtractions, provides the Company's load forecast. These regression models are premised on the idea that information about demographic, economic, and other variables such as weather explain why customers have consumed the level of energy they did in the past and will continue to explain the level of energy consumption in the future.

[7] ALLETE 2014 Annual Report published on April 1, 2015.

Minnesota Power purchases future projections of these variables from vendors such as IHS Global Insight, but Minnesota Power does not use each variable in its regression modeling, or at least each variable is not "key."

Indeed, the key explanatory variables or "drivers" as the Company terms them, have changed, entirely in some instances, between the AFR 2014 and the AFR 2015.

Table 1. Key Drivers by Modeling Output

Output	AFR 2014	AFR 2015
Residential Per-Customer Use	Wage Distribution; Employment in Public Sector	Weather, Appliance Saturation; "Seasonal Trend" variables
Commercial Per-Customer Use	Employment in Finance; Employment in Manufacturing	Total Non-Farm Employment
Paper Monthly Sales	Industrial Production Index for Paper; Gross Regional Product per capita, Per-capita Total Personal Income	Industrial Production Index for Paper; Employment in Wholesale Trade (Duluth MSA[8])
Pipeline and Other Monthly Sales	Employment in Trade, Transportation, & Utilities	Population; Gross Regional Product per Capita (Duluth MSA)
Public Authorities Per-Day Use	Employment in Other Services (Duluth MSA); Employment in Construction, Natural Resources, and Mining	Total Non-Farm employment
Street Lighting Per-Day Use	Population (Duluth MSA); Employment in Retail Trade	Total Personal Income (Duluth MSA); Employment in Education & Health
Resale Monthly Sales	Unemployment Rate (Duluth MSA); Housing Starts (Duluth MSA)	Employment in Education & Health

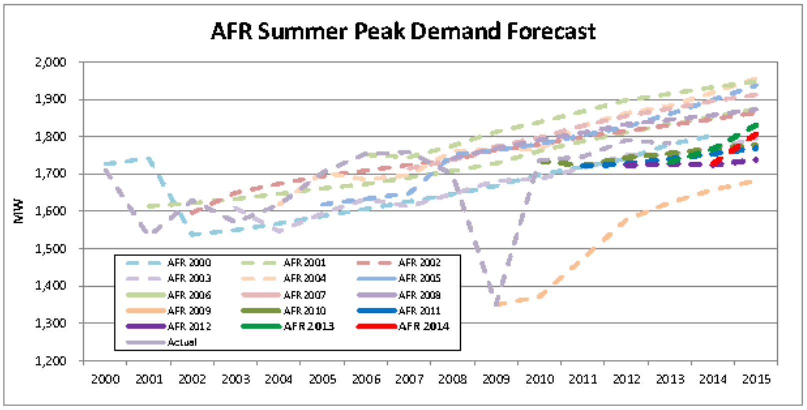
Shifts in key drivers like these suggest to us that the Company's regression models cannot be relied upon for long-term projections of sales. This is particularly

[8] The Duluth Metropolitan Statistical Area includes St. Louis County, MN, Carlton County, MN, and Douglas County, WI.

concerning because the point of an IRP is to do just that, to make resource addition and retirement decisions now, based on the best available long-term information.

E. Minnesota Power's Peak Load Forecast Ignores Significant Customer-Owned Generation.

The Company's AFR 2014 touts its "solid record of accurate forecasting"[9] and provides among other data, the following to back that assertion up.



Summer System Peak Error

Forecast	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Average Error of AFR	Avg. Error Year-Ahead
AFR 2000	**0.9%**	**13.7%**	-5.6%	-1.3%	-3.1%	**-6.8%**	-8.5%	-7.5%	-3.1%	23.6%	-2.2%	-1.6%	-2.8%	-0.2%	-0.3%	13.7%
AFR 2001		**5.2%**	**-0.5%**	4.0%	1.8%	-2.5%	**-4.6%**	-3.8%	0.5%	28.0%	1.4%	2.4%	1.2%	2.9%	2.8%	0.5%
AFR 2002			**-2.0%**	**5.0%**	3.5%	-0.6%	-2.6%	**-1.9%**	2.3%	30.7%	2.4%	3.1%	1.4%	2.7%	3.7%	5.0%
AFR 2003				**2.4%**	**-4.4%**	-6.4%	-6.9%	-8.2%	**-3.1%**	24.6%	-2.9%	-1.7%	-2.2%	-1.7%	-1.0%	4.4%
AFR 2004					**0.0%**	**0.0%**	-3.9%	-3.5%	3.7%	**30.8%**	1.7%	4.8%	4.1%	5.6%	4.3%	0.0%
AFR 2005						**-5.0%**	**-6.9%**	-6.3%	3.1%	30.7%	**2.5%**	3.3%	2.0%	4.4%	3.1%	6.9%
AFR 2006							**-0.2%**	**-0.7%**	4.5%	34.3%	5.9%	**7.0%**	6.0%	7.5%	8.0%	0.7%
AFR 2007								**-2.4%**	**2.2%**	31.4%	3.5%	4.8%	**3.6%**	5.2%	6.9%	2.2%
AFR 2008									**2.5%**	**31.0%**	3.2%	3.7%	2.4%	**3.6%**	7.7%	31.0%
AFR 2009										**0.0%**	**-21.1%**	-15.6%	-11.9%	-8.9%	-11.5%	21.1%
AFR 2010											**-0.1%**	**-1.4%**	-2.6%	-1.5%	-1.4%	1.4%
AFR 2011												**-1.5%**	**-3.5%**	-2.4%	-2.4%	3.5%
AFR 2012													**-3.7%**	**-3.0%**	-3.4%	3.0%
AFR 2013														**-2.8%**	-2.8%	

Figure 10. "Accuracy" of Minnesota Power's Summer Peak Forecast

We leave it to the reader to decide whether a 5-year error rate (in blue) of between –4.8% and 30.8% is accurate or not.

Setting that issue aside, through discovery, we learned that peak data differs between documents in this IRP depending on whether it is adjusted to be coincident with

---

[9] AFR 2014 at page 41.

the MISO peak and/or whether it accounts for customer-owned generation.[10] Customer-owned generation, the Company reports, has been between 120 and 180 MW "on any given monthly peak."[11] And indeed, the difference between the Company's estimated summer peak including customer-owned generation, and load delivered only by Minnesota Power has been 140 to 184 MW from 2005 to 2014. These two peaks are shown in Figure 11.

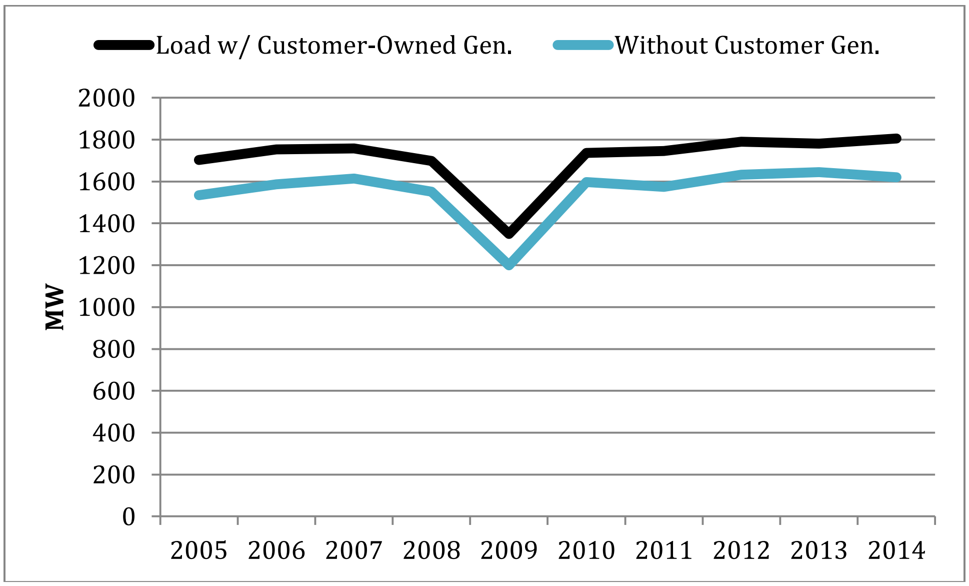


Figure 11. Minnesota Power's Historic Summer Peak Demand with and without Customer Generation[12]

Despite this fact, the Company seems to include only **[TRADE SECRET BEGINS TRADE SECRET ENDS]** of customer-owned generation in its Strategist modeling. This means that peak demand could be overestimated by as much as **[TRADE SECRET BEGINS TRADE SECRET ENDS]** for this reason alone.

[10] Minnesota Power's Response to CEO IRs 40 and 41.
[11] Minnesota Power's Response to CEO IR 41.
[12] EIA Form 861 and CEO IR 39 Attachment.

F. The Downside Scenario May Not Capture The Full Potential For Decreasing Sales.

As Figure 1 demonstrates, all the load forecasts used in Minnesota Power's modeling reflect increases in sales over the long-term with the exception of the AFR 2014 Downside scenario. That forecast shows a drop in sales of about 1 million MWh by 2021. The losses appear to be due to the idling or slowing down of production at [**TRADE SECRET BEGINS**

[13] **TRADE SECRET ENDS]**. The Downside scenario includes moderately less growth in the residential and commercial sectors, but still a faster rate than has occurred since 2008.

At least in the near term, the AFR 2014 Downside scenario does not seem likely to capture the full potential for declining sales. Since that forecast was produced, "A glut of overseas steel has pushed ore prices to a 10-year low and shuttered more than half the 11 major mining operations on Minnesota's Iron Range."[14]

Among the announcements made in 2015:

- "Feb. 24: Magnetation LLC announced it would idle its Keewatin plant, affecting 49 workers.
- March 12: U.S. Steel Corp. said it would idle its iron taconite plant in Keewatin in May, laying off up to 412 workers.
- March 31: U.S. Steel Corp. announced it would idle parts of its Minntac taconite plant in Mountain Iron in June. About 400 workers were laid off, and most have been called back.

[13] Spreadsheet "Expect14_Down" provided on the July 31, 2015 CD.
[14] Brooks, Jennifer. "On boom-or-bust Iron Range, this downturn feels different." *Star Tribune.* 28 Nov. 2015. http://www.startribune.com/on-boom-or-bust-iron-range-this-downturn-feels-different/357307601/#1.

- May 24: Steel Dynamics announced the immediate idling its Mesabi Nugget plant in Hoyt Lakes and Mining Resources in Chisholm. Some 200 workers laid off for two years.
- July 29: Cliffs Natural Resources said it would idle United Taconite operations in Eveleth and Forbes, laying off 420 employees.
- Nov. 17: Cliffs Natural Resources said it will idle Northshore Mining in Silver Bay in December, laying off most of its 540 workers there."[15]
- Nov. 18: Magnetation LLC announces possible production curtailment at Plant 2 in Bovey.[16]

It is not clear whether the load reduction assumptions regarding **[TRADE SECRET BEGINS TRADE SECRET ENDS]** are consistent with these idling plans or represent some other operational change. For example, in the AFR 2014 Downside scenario **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. But **[TRADE SECRET BEGINS TRADE SECRET ENDS]** do not appear to be included at all.

Because of this and because robust residential and commercial sales are still assumed, it is entirely possible that the Downside scenario does not reflect *enough* of a downside.

These issues and uncertainties should make Minnesota Power proceed with great caution when it comes to resource planning additions in particular.

[15] *Id.*
[16] Magnetation press release: http://www.magnetation.com/home/wp-content/uploads/2015/11/Press-Release-Magnetation-LLC-potential-P2-Curtailment.pdf.

III. TACONITE HARBOR ENERGY CENTER UNITS 1 AND 2 SHOULD NOT CONTINUE TO OPERATE.

In this IRP, Minnesota Power proposes to begin a "near-term economic idle" of Taconite Harbor Energy Center ("THEC") Units 1&2 "by the end of 2016." Based on the information provided in the IRP, Minnesota Power seems to believe that the decision to "idle" these units would cut their generation in about **[TRADE SECRET BEGINS TRADE SECRET ENDS]** in 2017 and 2018. The response to CEO IR 31 appears to confirm that Minnesota Power intends to operate the units regardless of whether they clear the MISO capacity auction or not. The reduction in generation in 2017 and 2018 seems to be achieved in Strategist by greatly extending **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. We are not aware, however, of any real-life mechanism that would allow Minnesota Power to do this.

Regardless of whether Minnesota Power's proposal is feasible or not, it does not resolve the fact that these units are probably not economic to operate currently, and will have a worsening economic picture in the future. These units do not cover their operating costs through MISO revenue let alone their fixed costs.

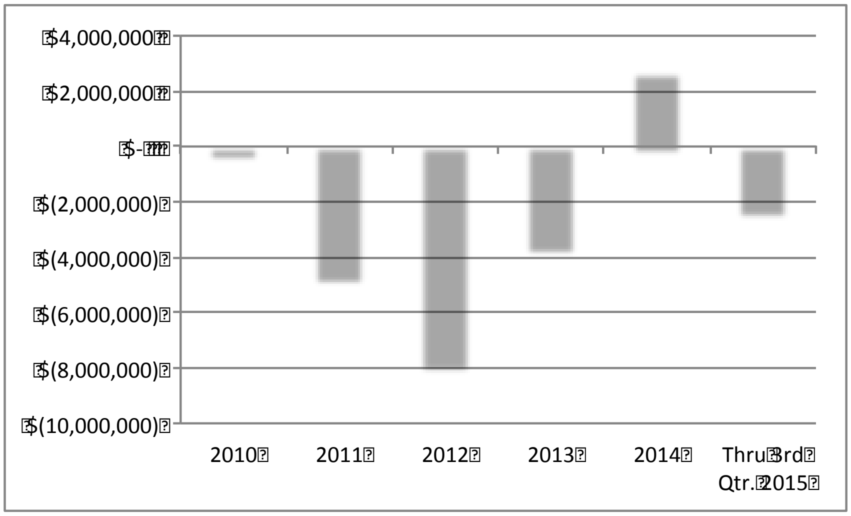


Figure 12. Taconite Harbor Net Revenue, 2010 – Third Quarter 2015[17, 18]

THEC has likely been losing money on its operations since at least 2010,[19] a problem that is unlikely to have been solved by the retirement of Taconite Harbor 3 in May 2015. The MISO clearing price that results in most of the units' revenue is on a steady to declining trajectory (Figure 13).

[17] Based on MISO, EIA, and FERC Form 1 data.

[18] Even if the units had been receiving MISO capacity auction revenue rather than the more likely situation in which they were part of a Fixed Resource Adequacy Plan (FRAP) they would only have brought in about $300,000 in additional revenue during the 2014/2015 Planning Year (June 1, 2014 – May 31, 2015) and less in the prior year when clearing prices were even lower.

[19] For many marginal coal units in MISO, the very high prices associated with severe winter weather in 2014 turned around what would otherwise have been another year of net loss.

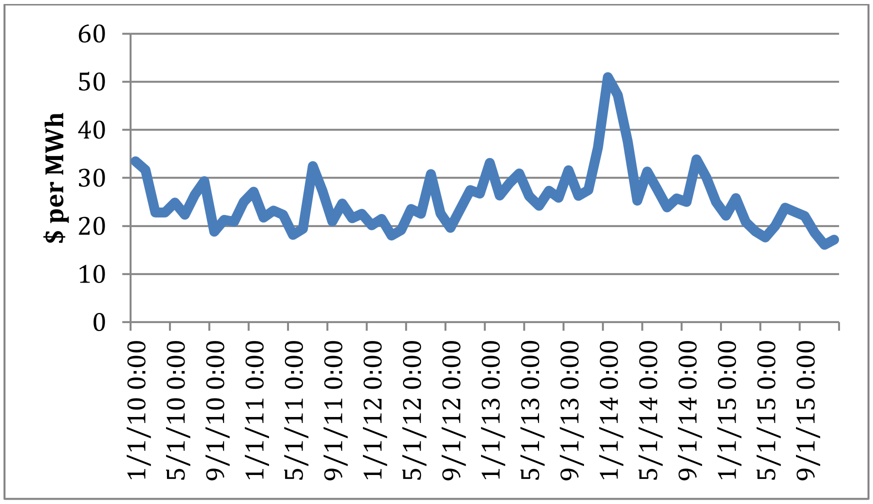


Figure 13. Taconite Harbor 1 and 2 Day-Ahead Monthly Average Locational Marginal Price

And Minnesota Power's response to CEO IR 3 showed that the units will increase in variable cost. For example, THEC 1 is modeled as having a 2015 variable cost of **[TRADE SECRET BEGINS TRADE SECRET ENDS]** per MWh, that increases to **[TRADE SECRET BEGINS TRADE SECRET ENDS]** per MWh in 2016. As discussed below, this increasing variable cost is due, in part, to increasing environmental compliance costs, and may actually underestimate those costs.

The only solution to this problem is to retire the units. Otherwise, Minnesota Power will continue to incur significant fixed costs and will continue to operate the units without fully recovering their variable costs through MISO revenue. From the standpoint of ensuring just and reasonable rates, the need to retire the units is particularly urgent. Through its plan to idle the units and to decline to use the Zonal Resource Credits associated with them to meet its resource adequacy obligations, the Company has signaled that these units are not important to meeting its customers' needs. That means that customers will be covering the losses associated with operating units that are not useful to them. That being the case, there is double the rationale to retire them as quickly as possible.

IV. THERE IS SIGNIFICANT RISK THAT THE CONTINUED OPERATION OF TACONITE HARBOR WILL VIOLATE HEALTH-BASED AIR QUALITY STANDARDS FOR SULFUR DIOXIDE.

Even if the continued operation of THEC Units 1 & 2 were economical (which it is not), Minnesota Power's plan to continue operating the units will likely result in violations of the U.S. Environmental Protection Agency's ("EPA") health-based, 1-hour National Ambient Air Quality Standard ("NAAQS") for sulfur dioxide ("SO_2").[20] Indeed, Minnesota Pollution Control Agency ("MPCA") modeling demonstrates that Minnesota Power's current permit causes significant exceedances of the 1-hour SO_2 NAAQS in the communities, parks, and recreation areas surrounding the power plant.[21] Even after accounting for the emission reductions required under a consent decree between EPA and Minnesota Power, modeling carried out by several of the CEOs shows that THEC will likely continue to violate the 1-hour NAAQS for SO_2.[22]

Indeed, Minnesota Power's own modeling predicts that THEC Units 1 & 2 will, by themselves, account for 100% of the allowable SO_2 emissions in the area, leaving no

---

[20] *See* Primary National Ambient Air Quality Standard for Sulfur Dioxide Final Rule, 75 Fed. Reg. 35,520, 35,525 (June 22, 2010).

[21] *See* http://www.pca.state.mn.us/index.php/view-document.html?gid=17612 (attached as Exhibit 01).

[22] *See U.S. EPA et al. v. Allete, Inc.*, No. 0:14-cv-2911-ADM-LIB, Consent Decree at 24-25 (D. Minn. filed July 16, 2014) (Doc. 3-1), *available at* http://www.epa.gov/sites/production/files/2014-07/documents/minnesotapower-cd.pdf; *see also* Klafka, *Taconite Harbor Energy Center, Schroeder, Minnesota, Evaluation of Compliance with the 1-hour NAAQS for SO_2* (Sept. 29, 2014) [hereinafter, "Klafka Report"] (attached as Exhibit 02).

room for error or for emissions from nearby facilities such as Northshore Mining.[23] Moreover, Minnesota Power's plan to run the units periodically could actually increase the risk of violations of the 1-hour SO_2 standard because the Company's most-recent Title V permit application proposes a 30-day rolling average emission limit, which would allow wide variations in short-term emissions. As a result, Minnesota Power's plan to continue operating the units carries significant risk for customers and Minnesotans living, working, and recreating near the power plant.

The continued operation of THEC Units 1 & 2 is not only a public health risk, but presents significant risk for Minnesota Power customers, who will bear the economic burden of additional pollution reduction measures that will likely be required to comply with EPA's 1-hour SO_2 standard. Indeed, Minnesota Power's own SO_2 compliance plan indicates that it will need to achieve additional SO_2 reductions—ranging from 33 to 45 percent—from the injection of sodium bicarbonate into its pollution control system in order to comply with EPA's 1-hour standard.[24] As an initial matter, it is not clear that Taconite Harbor can even achieve those emission reductions because the Company has not conducted any stack testing and there are no other facilities in the country that operate similar controls.[25] In any case, it does not appear that the company has evaluated the cost implications of the additional sodium bicarbonate or lime sorbent that might be required to comply with the more stringent 1-hour SO_2 standard. Nor has the Company evaluated

[23] *See* Minnesota Power's Response to CEO IR Nos. 033.4 at 6 of 11 & 033.3 at 16 of 31.
[24] *See* Pre-Protocol Letter from Minnesota Power to Minnesota Pollution Control Agency at 6 (Feb. 13, 2015) (attached as Exhibit 03).
[25] *See* Resp. to CEO IR 33 at 1-2. The U.S. Energy Information Administration's Form 860 data, which contains unit-level specific information about environmental equipment at existing power plants, indicates that there are no other facilities in country that utilize sodium bicarbonate injection in addition to lime injection, as Minnesota Power plans with Taconite Harbor. *See* https://www.eia.gov/electricity/data/eia860/.

whether that increased sorbent injection will result in any costs to control increased particulate matter emissions.

V. THE *ENERGYFORWARD* STRATEGY IS NOT ROBUST RESOURCE PLANNING.

Minnesota Power continues to promote its strategy of moving its energy mix to one-third coal, one-third natural gas, and one-third renewables. Moving away from coal and toward a more diverse fuel mix better positions the Company to meet federal environmental regulations and reduces risk to customers. However, simply dividing one's energy mix evenly between three different "fuels" is neither solid resource planning nor any guarantee that the strategy is optimal for ratepayers.

A. Energy*Forward* Leads Minnesota Power To Pursue Unneeded Fossil Fuel Resource Additions.

The Energy*Forward* strategy, dominated by fossil fuel resources, appears to prompt the Company to pursue resource additions that may not be in the best interests of customers nor even needed. For example, in this resource plan Minnesota Power proposes to add 200 – 300 MW of natural gas CC capacity by 2024. Despite that date being nearly 8 years in the future, Minnesota Power is already accepting bids from companies to construct such a facility,[26] a fact that it fails to mention in its IRP. As Xcel did when the Commission identified a need on its system, bids for new capacity should be fuel-neutral not fuel-specific, should arise from an order by the Commission certifying

[26] Myers, John. "Minnesota Power seeks bids for first big gas plant." *Duluth News Tribune*. 5 Dec. 2015. http://www.duluthnewstribune.com/news/3897552-minnesota-power-seeks-bids-first-big-gas-plant.

that there is need,[27] and should occur in a reasonable timeframe prior to the identified need. On top of that, given the many deficiencies in the Company's load forecast and in its Strategist modeling (see section B below), Minnesota Power has not adequately demonstrated the need for this facility.

B. Minnesota Power's Approach To Modeling In This IRP Is Biased Against The Small Coal Early Exit Scenario.

Quality resource planning arises from a solid foundation of accurate inputs and sound methodological approaches. Given the many problems with the Company's load forecast, it is difficult to view any of the Company's four expansion plan scenarios (Preferred Plan, Small Coal Through Mid-2020s, Small Coal Gas Refuel, and Early Small Coal Exit) as providing a realistic build-out scenario. As this Commission well knows, capacity additions and retirements are highly dependent on the load forecast. Further, as we explain in the following subsections, the Company's methodological approach to its Strategist modeling is problematic. It does not allow resources to compete on a level playing field, unnecessarily constrains the expansion plan and does not flow from a clear or logical set of criteria.

In response to our CEO IR 3, Minnesota Power delivered a number of Strategist modeling files divided into four groups: Base Case, Step 2 – Detailed Coal Analysis, Step 3 – Detailed Resource Analysis, and Step 4 – Swim Lane Comparative Analysis. We address each of these steps in turn.

---

[27] We recognize that in Docket No. 13-53, the Commission required Minnesota Power to "obtain approximately 200 MW, subject to need, of intermediate capacity (and associated energy) in the 2015 – 2017 timeframe by constructing the resource itself, by sharing in the ownership of the resource, or by procuring the resource through bilateral contracts, whichever option is most cost-effective." However, because timing is inextricably linked to need, we don't believe the Commission intended to authorize procurement of intermediate capacity at any point in time rather than in the 2015-2017 timeframe.

1. Base Case.

The "Base Case" contains two runs that appear to reflect the resource choices outlined on pages 28 and 29 of the IRP (they are not repeated here for brevity) with either no MISO market interaction or the ability to both purchase from and sell energy into MISO. Where there are capacity needs, they seem to be filled in with short-term market capacity purchases.

2. Step 2.

The IRP describes the Step 2 - "Detailed Coal Analysis" as determining "if a small coal-fired generation facility should be closed/shutdown prior the accounting end of life rather than move forward with the cost effective option(s) from Step 1." Since Step 1 was simply a levelized cost analysis of new resource choices, this would seem to imply that shutdown of Minnesota Power's small coal facilities is being weighed by Strategist against the resource choices that passed screening in Step 1.

However, examination of several of the runs (closely examining all 72 runs performed in this step is just not possible given CEO's resources) shows that at least some resource choices were turned off—including **[TRADE SECRET BEGINS**

TRADE SECRET ENDS]. And renewables were modeled at higher than realistic prices. On December 18, 2015, Congress passed a five-year extension of the wind PTC (albeit with declining values each year after December 2016) and the solar ITC, which would begin to be drawn down after 2019.[28] Wind was modeled without the

[28] Bade, Gavin. "UPDATED: Congress passes $1.1T omnibus spending bill with solar, wind tax credit extensions." *Utility Dive*. 18 Dec. 2015. http://www.utilitydive.com/news/updated-congress-passes-11t-omnibus-spending-bill-with-solar-wind-tax-c/411115/.

PTC at a levelized price of **[TRADE SECRET BEGINS** [29] **TRADE SECRET ENDS]** per MWh. In contrast, Xcel has told investors that it is signing contracts for wind in the $20 per MWh range.[30] Wind was also constrained in this step to the addition of just one unit beginning in **[TRADE SECRET BEGINS TRADE SECRET ENDS]** and then a second unit in **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. And curiously, the Company does not seem to assign any accredited capacity to wind.[31]

Similarly, while the Company's solar cost assumptions apparently did include a 30% ITC, the cost of solar was still estimated at **[TRADE SECRET BEGINS** [32] **TRADE SECRET ENDS]** per MWh for a 50 MW farm. And Strategist could only take one solar farm starting in **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. Xcel has been signing contracts for solar in the $75 per MWh range.[33]

Minnesota Power does not explain how it weighed the results of Step 2 or what criteria it used to pass options on to Step 3. However, Appendix K leaves the impression that Minnesota Power's preferred approach to its small coal units was dependent on the percentage of time that Strategist chose:

1. Shutdown of THEC 1&2 and BEC 1&2 by 2019;
2. Idle by 2017 & Shutdown by 2020 (THEC 1&2 Only);
3. Refuel with Natural Gas by 2019 (BEC 1&2 Only);
4. Continue Coal Operations.

[29] CEO IR 18.1 Attachment; the exception being the sensitivities in which alternative wind prices were modeled.
[30] UBS Global Research. "Upside from the Analyst Day." 7 December 2015.
[31] *See*, for example, the Step 2-Case 1-24 GAF Loads and Resources Detail Report provided in response to CEO IR 3.
[32] CEO IR 18.1 Attachment; the exception being the sensitivities in which alternative solar prices were modeled.
[33] UBS Global Research. "Upside from the Analyst Day." 7 December 2015.

Figures 10 and 11 of Appendix K of Minnesota Power's IRP show the percentage of time that these four options were chosen across what is likely to be the base plus sensitivity runs performed by the Company. In turn, this seems to imply that the Company weighed the results of each sensitivity equally, except that it preferred those scenarios without a CO_2 price because refueling BEC 1&2 was chosen in nearly 90 percent of runs with a CO_2 price. Table 2 lists the sensitivities performed in Step 2:

Table 2. List of Sensitivities Performed in Step 2

AFR 2015 Load Forecast	$35 Wind Price
$9 per ton CO_2	$45 Wind Price
$34 per ton CO_2	$55 Wind Price
Social Cost of Carbon	$65 Wind Price
$21.5 per ton CO_2 starting in 2025	$75 Wind Price
Low Coal	$75 Solar Price
High Coal	$80 Solar Price
Gas at 50% Below Forecasted Price	$85 Solar Price
Gas at 25% Below Forecasted Price	$90 Solar Price
Gas at 25% Above Forecasted Price	20% Less Wind Capacity Accreditation
Gas at 50% Above Forecasted Price	AFR 2014 Downside
Gas at 100% Above Forecasted Price	AFR 2014 Upside
Market Prices at 50% Below Forecasted	AFR 2014 Current Contract
Market Prices at 25% Below Forecasted	2% Increase in MISO Planning Reserve Margin
Market Prices at 25% Above Forecasted	2% Increase in MISO Coincident Peak
Market Prices at 50% Above Forecasted	2% Decrease in MISO Coincident Peak
No MISO Market	"40% Renewable"[34]
New Generation Capital Cost 30% Lower	Winter MISO Coincident Peak Demand
New Generation Capital Cost 30% Higher	

It is not at all clear why the Company would choose this particular set of sensitivities. For example, eight of the nine renewable sensitivities examine prices that are too high in today's market, and analyzing a two percent increase in the MISO PRM,

[34] This sensitivity does not seem to be discussed anywhere in the IRP and it is not clear from the Strategist files what it is intended to represent. It does *not* seem to be a 40% RPS requirement, however.

higher than the PRM has ever been, when MISO is forecasting a fairly stable PRM through at least 2025,[35] is not realistic.

What the Company seems to be saying is that it views the AFR 2014 Downside sensitivity as having an equal probability of occurring as, say, increasing natural gas costs by 100 percent. This approach does not provide much meaningful information and allows the modeler to bias the "percent of selection" in favor of the resource choices s/he favors, because the modeler chooses which, and how many, sensitivities are performed.

3. Step 3.

The Company then moved to Step 3, which seems to evaluate non-coal related resource choices in the context of four different coal-related alternatives:

1. Preferred Plan – "idle" THEC 1&2 in 2016 and retire by 2020; continue operating BEC 1&2 on coal through 2024
2. Small Coal – continue operating THEC 1&2 through 2026 and BEC 1&2 through 2024
3. Small Coal Gas Refuel – "idle" THEC 1&2 in 2016 and retire by 2020; refuel BEC 1&2 with natural gas by 2019
4. Early Small Coal Exit – "idle" THEC 1&2 in 2016 and retire by 2020; shutdown BEC 1&2 in 2019

As with Step 2, the only criterion to select resources for further analysis seems to be the percent of time those resources were selected using the same sensitivities listed in Table 2. The point of Step 3 seems to be to create a portfolio of non-coal options to accompany each of the four coal-related alternatives.[36] The combination of non-coal resources seems to change between Case 1 (no CO_2) and Case 2 ($21.5 per ton cost) as shown in Figures 13 and 14 of Appendix K of Minnesota Power's IRP.

[35] *See* https://www.misoenergy.org/Library/Repository/Study/LOLE/2016%20LOLE%20Study%20Report.pdf at 32.
[36] *See* Appendix K at 16.

The same Step 2 issues regarding solar and wind availability and cost also plague this step. And the level of energy efficiency seems to be fixed in these runs at the **[TRADE SECRET BEGINS TRADE SECRET ENDS]** level.[37]

It is not clear what the Net Present Value ("NPV") total in Tables 6 and 7 of Appendix K are supposed to represent. What is noticeable is that despite all of these modeling flaws, which generally bias the model against zero-carbon resources, there are small differences in cost between each of the four Step 3 portfolios. The most costly plan in Table 6 (Small Coal Through Mid-2020s) is only 0.5 percent more than the least-cost alternative in Table 6 (Preferred Plan). And the three least costly plans (Preferred Plan, Small Coal Gas Refuel, Early Small Coal Exit) in Table 7 (includes a $21.50 CO_2 price) differ by no more than 0.4 percent.

4. Step 4.

Step 4 repeats most of the same sensitivities from Step 3 and adds a few more, such as Higher Revenue Requirements due to EPA Regulations and additional energy efficiency. All levels of energy efficiency other than the "11 GWh" level are also treated as sensitivities. And all resource choices are fixed. So the Early Small Coal Exit portfolio has exactly the same level of capacity resources whether "9 GWh" of energy efficiency is included or "30 GWh" of energy efficiency. This is not a meaningful evaluation of energy efficiency because it does not allow it to defer capacity, only energy. Avoided capacity costs are typically a very significant, even majority portion of the avoided cost of energy efficiency.

[37] Response to CEO IR 3.

Fixing all capacity resources also biases the modeling towards the "Preferred Plan" and the "Small Coal Refuel" because those plans seem to have the least amount of excess capacity (Small Coal Refuel is not identified on Figure 14 below because it is virtually identical to the Preferred Plan). Figure 14 compares the reserve margin for each of these portfolios in the "CO_2 in Base" sensitivity against the modeled reserve margin requirement.

[TRADE SECRET BEGINS

TRADE SECRET ENDS]
Figure 14. Reserve Margin of Three Step 4 Alternatives

The Small Coal Early Exit portfolio has so much excess capacity starting in 2021 because of the forced addition of **[TRADE SECRET BEGINS TRADE SECRET ENDS]** MW of CC capacity. This capacity is also forced into the Preferred Plan in 2024, which explains the purple line's jump in reserve margin in that year. Not only is at least some of the capacity unnecessary, but the Company inexplicably switched from analyzing a **[TRADE SECRET BEGINS TRADE SECRET ENDS]** MW block of CC capacity in Step 3 to forcing in **[TRADE SECRET BEGINS TRADE SECRET ENDS]** MW of CC capacity in Step 4.

This excess capacity likely contributes to a notably bigger difference in NPV between the Preferred Plan and the Small Coal Early Exit plan (Table 8 of Appendix K). The differences on a percentage basis are in the noise, however, when CO_2 is considered.

In sum, the Company's modeling approach does not provide a logical path towards its preferred expansion plan. It seems to choose resources based on an arbitrary selection of sensitivities with differing probabilities of occurring. In addition, certain resources are either unfairly restricted, too expensive, and/or left out entirely.

VI. MINNESOTA POWER'S STRATEGY IS INCONSISTENT WITH STATUTORY ENERGY SAVINGS PRIORITIES.

In response to Minnesota Power's 2013 Resource Plan, the Commission ordered Minnesota Power to do more rigorous analysis of energy savings as a resource.[38] The Company's modeling approach to energy efficiency, however, causes it to underestimate the savings Minnesota Power can achieve. Secondarily, Minnesota Power incorrectly models efficiency cost.[39] Third, Minnesota Power continues to ignore the possibility of additional energy savings from its CIP-exempt customers.

[38] Order Approving Resource Plan, Requiring Filings, and Setting Date for Next Resource Plan, November 12, 2014, Docket No. E-015/RP-13-53 at 8, ¶ 12.
[39] This critique is in addition to the problem discussed in Section B, *infra*, that higher levels of energy efficiency were only analyzed for cost-effectiveness *after* a supply-side plan had been fixed.

As a result, Minnesota Power underestimates the ability for additional energy savings to defer capacity additions that can create significant economic benefits for utility ratepayers.

A. Minnesota Power's Interpretation Of "Embedded Efficiency Savings" Places A Significant Bias Against Energy Efficiency.

For this IRP, Minnesota Power produced estimates of "embedded" efficiency savings arising from CIP programs as well as activities by CIP-exempt customers. We first address the embedded savings Minnesota Power estimated for CIP customers.

Minnesota Power uses the term "embedded" savings to mean something more than what is normally intended by the phrase. Normally, embedded savings would be the savings arising from measures that have already been installed. Minnesota utilities can expect there to be savings that "persist" beyond the year in which an energy efficiency measure was installed. If significant enough, when those savings are not explicitly accounted for, there is a possibility that the load forecast will result in too low a growth rate since the projection will be dampened by the "embedded" savings present in historical sales figures.[40]

Minnesota Power takes this interpretation a step further, however. Embedded savings in Minnesota Power's analysis are not just savings that persist from *prior* years, but also include a base level of savings that it believes will be achieved going forward. This base level is determined entirely by just five years of data. Specifically, the CIP

[40] Recall that the load forecasts in this IRP are produced using information about historical relationships between sales and economic, demographic, and assume those relationships will explain sales into the future.

savings achieved from 2010-2014 that the Company believes are replicable are assumed to be embedded in the load forecast, at least through 2028 and perhaps beyond.

These “embedded” savings are not used to make any adjustment to the load forecast. Instead, the future “embedded” savings only come into play when Minnesota Power considers increasing levels of energy efficiency. In those cases, the future “embedded” savings are subtracted from the trajectory of increased savings.

This approach is flawed. Minnesota Power uses sales data going back to 1990 to produce its load forecast, a period of time in which Minnesota Power almost certainly did not achieve close to the level of savings that it has in the past few years. Yet the Company assumes that the last five years of CIP savings are the only years that are indicative of the level of savings embedded in its load forecast going forward. This overestimates the level of embedded savings that actually exist and probably has the net effect of making the load forecast overly optimistic.

To our knowledge, there are no savings data going back to 1990, but Minnesota Power’s 2014 CIP Status Report shows that the level of CIP savings achieved prior to 2010, the last historical year included in the embedded savings calculation, was much lower than the most recent 5-year period.

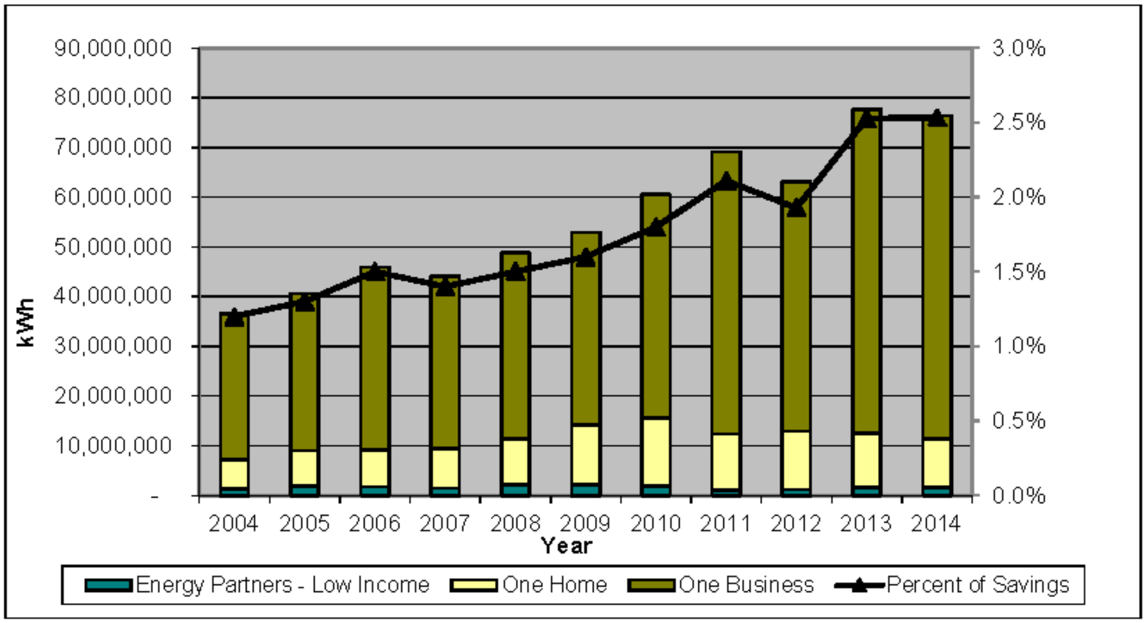


Figure 15. Minnesota Power's 2004 – 2014 CIP Achievements[41]

The Company does say that, "Minnesota Power recognizes that embedded conservation is not something that can be estimated with a high degree of certainty regardless of the method used, and will caution against placing excessive confidence in these estimates."

We agree that there will necessarily be uncertainty in the estimates, but there are improvements that can and should be made. These include limiting "embedded" savings to those arising from previously installed measures. Because Minnesota Power already collects data on its CIP program, it could use savings and measure life data to estimate how those embedded savings will decay into the future.

All future savings would then be modeled explicitly as a decrement to load. Xcel, for example, takes a similar approach. This approach is much less likely to underestimate savings and should be more accurate.

[41] Minnesota Power Conservation Improvement Filing on April 1, 2015 in Docket No. E015/CIP-13-409.01.

The impact of this change could be significant. Currently, Minnesota Power assumes embedded CIP savings will constitute **[TRADE SECRET BEGINS TRADE SECRET ENDS]** GWh of new, incremental savings.[42] This base plan level of savings is simply not modeled in Strategist. If additional energy efficiency scenarios are modeled, then Minnesota Power subtracts its base level savings from those scenarios. The net result is that the majority of future savings are assumed to be embedded.

Three of the additional EE scenarios are shown in Figure 16 to demonstrate this. The solid lines are the total savings the Company believes it is modeling both explicitly (increased savings beyond the base) and implicitly (embedded savings going forward) through the load forecast. The dotted lines are the savings modeled explicitly in Strategist. The true level of future savings contained in the modeling would be somewhere in between.

[42] "MP-OrderPT-12_A&B" provided on the July 31, 2015 CD.

[TRADE SECRET BEGINS]

[TRADE SECRET ENDS]

Figure 16. Implicit and Explicit Levels of Savings Included in Three Energy Efficiency Sensitivities[43]

The net effect is that there is much less energy efficiency in its IRP than the Company states. Had it been modeled correctly, energy efficiency would have much more of an impact in avoiding new capacity additions.

B. Minnesota Power Assumes Dramatic, Unjustified Cost Increases For New Energy Savings.

In order to correct its modeling of energy efficiency, the Company would also likely need to modify the costs assigned to energy efficiency. The program costs modeled in Strategist are inexplicably higher than what is given in Table 14 of Appendix K. And

[43] Note that Figure 16 (above) and future energy efficiency start in 2017, but the majority of the Company's modeling uses a load forecast based on historical data through only 2013. That means that savings achieved in 2014 and 2015 and yet to be achieved in 2016 are essentially ignored. This further biases the load forecast upwards.

neither source is consistent with the costs given in a workbook provided on the Company's July 2015 CD.[44]

Taking the three sensitivities shown in Figure 16 above, the following chart shows how the cost in Table 14 of Appendix K (solid line), in Strategist (dotted line), and in the July 2015 workbook (line with diamonds) compare.

[TRADE SECRET BEGINS]

[TRADE SECRET ENDS]
Figure 17. Energy Efficiency Cost Projections Differ by Source of Data

The reason for the differences in the three sources is not known.

Moreover, any of the three data sources probably contains estimates of energy efficiency costs that are well above what Minnesota Power has historically experienced.

[44] This workbook is described by the Company as the source for the cost of additional energy efficiency programs; *see* Minnesota Power's Response to CEO IR No. 20.

Table 3. Minnesota Power's 2007 – 2014 CIP Achievements and their First Year Cost[45]

Year	Achieved CIP Energy Savings (GWh)	Average First Year Cost per kWh Saved
2007	44.2	$ 0.09
2008	48.9	$ 0.10
2009	52.9	$ 0.10
2010	60.5	$ 0.09
2011	69.1	$ 0.09
2012	63.2	$ 0.11
2013	77.6	$ 0.08
2014	76.3	$ 0.09

Table 3 above shows Minnesota Power's CIP achievements and first year unit costs for 2007 through 2014. The lifetime costs of the CIP savings, which is a more appropriate comparison to supply side costs, are much lower still. These extremely cost effective energy savings benefit all of Minnesota Power's ratepayers and these costs should be reflected in resource planning.

However, Minnesota Power, regardless of which costs it assumes, seems to be using much higher conservation costs in the current IRP.

[45] From Docket No. E015/M-14-233.

Table 4. IRP Incremental Energy Savings Costs[46]

Incremental Savings Per Year (GWh)	First Year Incremental Program Cost ($000) (Table 14 of Appendix K)	Average Cost of Incremental Savings ($/kWh)
3	$ 511	$ 0.17
6	$ 1,199	$ 0.20
9	$ 2,034	$ 0.23
11	$ 2,665	$ 0.24
12	$ 2,988	$ 0.25
15	$ 4,064	$ 0.27
18	$ 5,206	$ 0.29
21	$ 6,438	$ 0.31
24	$ 7,725	$ 0.32
27	$ 9,057	$ 0.34
30	$ 10,525	$ 0.35

Table 4 above shows the minimum incremental energy savings costs for additional savings above Minnesota Power's existing plan (which appears to be the savings levels in the CIP Triennial Plan, which is 46.5 GWh in 2016).[47,48] In 2014, the Company achieved 76.3 GWhs of savings at an average first-year cost of $0.09 per kWh. The difference between the Company's 2014 achievements and minimum CIP goal is 29.8 GWh. Yet, in the IRP the Company is assuming an incremental cost of 3.9 times the

[46] This table shows the same data represented by the line with diamonds in Figure 17.
[47] Appendix B – Part 2, Page 6 states "The Existing Plan used the assumptions developed for Minnesota Power's 2016 CIP Plan."
[48] Minnesota Power defines incremental cost as "the difference between the cost of a standard efficiency measure and a high-efficiency measure. It is important to this study because the incremental cost was used as the reference point for the variation in plan incentives. Existing Plan incremental costs were permitted to escalate 2.0 percent per year after 2016." Appendix B – Part 2, Page 7.

2014 average cost to achieve the incremental 30 GWhs above the Company's CIP minimum goal. These increases are not supported by any documentation yet provided by the Company.

In sum, CIP energy savings are not properly analyzed in Minnesota Power's IRP. There are likely significant savings missing from the analysis, the cost increases are unsubstantiated, and energy efficiency is not allowed to compete with supply-side resources in a meaningful way.

C. Minnesota Power Did Not Comply With The Commission's Order To Analyze Greater Energy Savings Potential By Customers Exempt From CIP.

Of the electric utilities in the state, Minnesota Power has the greatest percentage of large industrial load. Nearly all of those customers have been exempted from paying the costs of utility conservation programs in their rates. Minnesota Power has not recognized that improved energy savings from its largest customers are a resource that would result in system-wide benefits.

In Minnesota Power's 2013 IRP the Commission stated:

> The Commission agrees with the Environmental Intervenors that the energy savings goals described in Minn. Stat. §§ 216B.2401 and 216C.05 do not exclude consideration of savings that may be achieved by Minnesota Power's CIP-exempt customers. A significant amount of demand on Minnesota Power's system comes from CIP-exempt customers, but Minnesota Power's resource plans—which must consider energy conservation as an energy resource—serve CIP and CIP-exempt customers alike. Accordingly, resource planning should reflect the possibility of energy conservation among all of Minnesota Power's customers.
>
> The Commission will therefore require Minnesota Power's next resource plan filing to include more detailed information concerning system-wide energy conservation. Specifically, analysis and aggregated energy savings data for CIP-exempt customers will be required. This information will

help paint a more complete picture of the possibilities for energy conservation on Minnesota Power's system.[49]

The Commission ordered Minnesota Power, in its next resource plan, to:

a. Identify the amount of energy savings embedded in each year of its load forecast, in terms of total savings (kWh) and as a percentage of non-CIP-exempt retail sales;

b. Identify the amount of system-wide energy savings, including aggregate data for CIP-exempt customers, embedded in each year of its load forecast;

c. Evaluate additional conservation scenarios for its CIP-exempt and non-CIP-exempt customers, that would achieve greater energy savings beyond those in the base case; and

d. Provide cost assumptions for achieving every 0.1 percent of savings above 1.5 percent of non-CIP-exempt retail sales.

Responding to Order point 12.b, Minnesota Power provided a high-level estimate of embedded energy savings both from customers that participate in CIP, and from customers that are exempt from CIP. In response to CEO IR 23, the Company stated that it did not conduct any evaluation, measurement, or verification procedures on the historical CIP-exempt savings it reported.

And contrary to Order point 12.c, Minnesota Power did not analyze any additional conservation scenarios for CIP-exempt customers. As it did with CIP customer savings, the Company simply assumed that the savings its CIP-exempt customers say were realized in recent years, would continue to occur at the same levels and be embedded in the load forecast similar to the approach taken with CIP savings.

We don't believe the Commission should deem these efforts sufficient to comply with its 2013 IRP Order. If real, the savings achieved by CIP-exempt customers were

[49] Order Approving Resource Plan, Requiring Filings, and Setting Date for Next Resource Plan, November 12, 2014, Docket No. E-015/RP-13-53.

nearly equal to the CIP base level of savings.[50] This makes it essential to continue to leverage those savings, rather than passively assume they will somehow materialize in the future; and to verify these savings using the same evaluation, measurement, and verification (EM&V) techniques used to verify CIP savings.

CONCLUSION

Clean Energy Organizations have identified numerous problems with Minnesota Power's 2015 Resource Plan. The problems range from the lack of sound load forecast assumptions and methodology; to bias created by unreasonable cost assumptions for clean energy resources; to a flawed modeling approach that does not justify continued operation of Taconite Harbor Units 1 & 2 or support any need to procure new fossil fuel resources.

Clean Energy Organizations ask the Commission to order Minnesota Power to:

1. Immediately retire Taconite Harbor Units 1 and 2;
2. Correct the identified problems in its load forecasting and modeling that create bias against clean energy resources;
3. Suspend its pending natural gas power plant procurement;
4. Time future supply additions closer to demonstrated need, using a fuel-neutral resource acquisition process;
5. Proactively seek ways to increase conservation by its CIP-exempt customers.

In addition, Clean Energy Organizations urge the Commission to convene a technical conference that would allow interested parties to develop a better approach to modeling energy efficiency in IRPs, and hopefully one that creates greater linkages between CIP and resource planning. The current modeling approaches employed by

[50] Spreadsheet "Energy Savings and Program Cost Results_Disc1_2015IRP" provided on the July 31, 2015 CD.

many Minnesota utilities, including Minnesota Power, do not result in an optimal level of cost-effective savings. Instead modelers are forcing in pre-selected levels of conservation into the model. As a result, utility IRPs are not optimizing energy savings as a resource, as directed by Minnesota Statutes § 216B.2401.

Dated: January 4, 2016

Respectfully submitted,

/s/ Elizabeth Goodpaster
Elizabeth Goodpaster
Leigh Currie
Minnesota Center for Environmental Advocacy
26 E. Exchange Street, Ste. 206
St. Paul, MN 55101
(651) 287-4873

Attorneys for Fresh Energy, Minnesota Center for Environmental Advocacy, Sierra Club, and Wind on the Wires

STATE OF MINNESOTA
BEFORE THE PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's
Application for Approval of its 2015-2029
Resource Plan

AFFIDAVIT OF SERVICE

PUC Docket No. E015/RP-15-690

STATE OF MINNESOTA)
)ss.
COUNTY OF RAMSEY)

Erin Mittag being duly sworn, says that on the 4th day of January, 2016 she served via U.S. mail and e-dockets the following:

- Public and Non-public versions of the Initial Comments of Clean Energy Organizations

on the following persons, in this action, by filing through e-dockets or mailing to them a copy thereof, enclosed in an envelope, postage prepaid, and by depositing the same in the post office at St. Paul, Minnesota, directed to said persons at the last known mailing address of said persons:

Attached Service List.

E Mittag
Erin Mittag

Subscribed and sworn to before me
this 4th day of January, 2016

Karen E Moss
Karen Moss

KAREN E. MOSS
NOTARY PUBLIC - MINNESOTA
My Commission Expires 01/31/2021

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_15-690_RP-15-690
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	Yes	OFF_SL_15-690_RP-15-690
William A.	Blazar	bblazar@mnchamber.com	Minnesota Chamber Of Commerce	Suite 1500 400 Robert Street North St. Paul, MN 55101	Electronic Service	No	OFF_SL_15-690_RP-15-690
Jon	Brekke	jbrekke@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 553694718	Electronic Service	No	OFF_SL_15-690_RP-15-690
Christina	Brusven	cbrusven@fredlaw.com	Fredrikson Byron	200 S 6th St Ste 4000 Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_15-690_RP-15-690
Emma	Fazio	emma.fazio@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-690_RP-15-690
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_15-690_RP-15-690
Dave	Frederickson	Dave.Frederickson@state.mn.us	MN Department of Agriculture	625 North Robert Street St. Paul, MN 551552538	Electronic Service	No	OFF_SL_15-690_RP-15-690
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_15-690_RP-15-690
Benjamin	Gerber	bgerber@mnchamber.com	Minnesota Chamber of Commerce	400 Robert Street North Suite 1500 St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_15-690_RP-15-690

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Barbara	Gervais	toftemn@boreal.org	Town of Tofte	P O Box 2293 7240 Tofte Park Road Tofte, MN 55615	Electronic Service	No	OFF_SL_15-690_RP-15-690
Michael	Greiveldinger	michaelgreiveldinger@alliantenergy.com	Interstate Power and Light Company	4902 N. Biltmore Lane Madison, WI 53718	Electronic Service	No	OFF_SL_15-690_RP-15-690
Janice	Hall	N/A	Cook County Board of Commissioners	411 W 2nd St Court House Grand Marais, MN 55604-2307	Paper Service	No	OFF_SL_15-690_RP-15-690
Lori	Hoyum	lhoyum@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	Yes	OFF_SL_15-690_RP-15-690
Eric	Jensen	ejensen@iwla.org	Izaak Walton League of America	Suite 202 1619 Dayton Avenue St. Paul, MN 55104	Electronic Service	No	OFF_SL_15-690_RP-15-690
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-690_RP-15-690
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_15-690_RP-15-690
Chad T	Marriott	ctmarriott@stoel.com	Stoel Rives LLP	900 SW 5th Ave Ste 2600 Portland, OR 97204	Electronic Service	No	OFF_SL_15-690_RP-15-690
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_15-690_RP-15-690
Daryl	Maxwell	dmaxwell@hydro.mb.ca	Manitoba Hydro	360 Portage Ave FL 16 PO Box 815, Station Main Winnipeg, Manitoba R3C 2P4 Canada	Electronic Service	No	OFF_SL_15-690_RP-15-690

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Marion Ann	McKeever	N/A	Satellites Country Inn	9436 W Hwy 61 Schroeder, MN 55613	Paper Service	No	OFF_SL_15-690_RP-15-690
Herbert	Minke	hminke@allete.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	Yes	OFF_SL_15-690_RP-15-690
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	Yes	OFF_SL_15-690_RP-15-690
Andrew	Moratzka	apmoratzka@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-690_RP-15-690
David W.	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	Suite 300 200 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-690_RP-15-690
Thomas L.	Osteraas	N/A	Excelsior Energy	150 South 5th Street Suite 2300 Minneapolis, MN 55402	Paper Service	No	OFF_SL_15-690_RP-15-690
Britt	See Benes	britt@ci.aurora.mn.us	City of Aurora	16 W 2nd Ave N PO Box 160 Aurura, MN 55705	Electronic Service	No	OFF_SL_15-690_RP-15-690
Ron	Spangler, Jr.	rlspangler@otpco.com	Otter Tail Power Company	215 So. Cascade St. PO Box 496 Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_15-690_RP-15-690
John Linc	Stine	john.stine@state.mn.us	MN Pollution Control Agency	520 Lafayette Rd Saint Paul, MN 55155	Electronic Service	No	OFF_SL_15-690_RP-15-690
Eric	Swanson	eswanson@winthrop.com	Winthrop Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_15-690_RP-15-690

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_15-690_RP-15-690
Charles	Zelle	charlie.zelle@state.mn.us	Department of Transportation	MN Dept of Transportation 395 John Ireland Blvd St. Paul, MN 55155	Electronic Service	No	OFF_SL_15-690_RP-15-690

Exhibit 01

To CEO Initial Comments

In the Matter of Minnesota Power's Application for Approval of its 2015-2029 Resource Plan

Docket No. E015/RP-15-690

FACILITY NAME	Nearby Source	COUNTY	Urban (U) and/or Rural (R)	Met Data	Background ug/m^3	Compliance	Culpable	Target Value	n
Flint Hills Resources LP - Pine Bend		Dakota	U / R	MSPMPX5Y	55.89	N	Y	31.11	4
Gopher Resource LLC							Y		
Xcel Energy - Inver Hills Generating Plt							Y		
Marathon Petroleum Co LLC		Washington					Y		
Seneca Wastewater Treatment Plant		Dakota	U / R	MSPMPX5Y	55.89	N	Y	12.44	10
Sanimax amx LLC							Y		
Xcel Energy - Black Dog							Y		
NRG Energy Center Minneapolis LLC		Hennepin					Y		
Owens Corning Roofing & Asphalt LLC Mpls							Y		
	HERC						N		
	University of MN - Twin Cities						Y		
	Gerdau Ameristeel US Inc - St Paul Mill						Y		
3M - Administrative Offices - Maplewood		Ramsey					N		
District Energy St Paul Inc-Hans O'Nyman							Y		
Metropolitan Wastewater Treatment Plant							Y		
Waldorf Corp - A Rock-Tenn Co							Y		
Xcel Energy - Allen S King Generating		Washington	R	MSPMPX5Y	39.15	Y			
Verso Paper Corp - Sartell Mill		Benton	R	STCMPX5Y	39.15	N	Y	70.59	2
	St Cloud State University						Y		
Xcel Energy - Sherburne Generating Plant		Sherburne					N		
Order of St Benedict/St John's Abbey		Stearns					Y		
Anchor Glass Container Corp - Shakopee		Scott	R	MSPMPX5Y	39.15	N	Y	70.59	2
Rahr Malting Co - Shakopee							N		
	CertainTeed Corp						Y		
Bongards' Creameries		Carver	R	MSPMPX5Y	23.58	N	Y	156.74	1
Wausau Paper Mills LLC		Crow Wing	R	BEDMPX5Y	23.58	N	Y	156.74	1
3M - Hutchinson Tape Manufacturing Plant		McLeod	R	MSPMPX5Y	39.15	N	Y	141.17	1
Associated Milk Producers - Paynesville		Stearns	R	STCMPX5Y	39.15	N	Y	141.17	1
Melrose Dairy Proteins LLC		Stearns	R	STCMPX5Y	39.15	Y			
Corn Plus		Faribault	R	FSDABR5Y	23.58	Y			
ADM - Red Wing		Goodhue	R	MSPMPX5Y	23.58	N	Y	78.37	2
Xcel Energy - Red Wing Generating Plant							N		
USG Interiors Inc - Red Wing							Y		
Austin Utilities - NE Power Station		Mower	R	RSTMPX5Y	39.15	N	Y	70.59	2
Hormel Foods Corp/QPP - Austin							Y		
Sappi Cloquet LLC		Carlton	R	DLHINL5Y	23.58	N	Y	156.74	1
American Crystal Sugar - Moorhead		Clay	R	FARABR5Y	23.58	N	Y	78.37	2
Busch Agricultural Resources - Moorhead							Y		
Minnesota Power - Tac Harbor Energy Ctr		Cook	R	DYTINL5Y	23.58	N	Y	156.74	1
Boise White Paper LLC - Intl Falls		Koochiching	R	INLINL5Y	23.58	Y			
Otter Tail Power Co - Hoot Lake Plant		Otter Tail	R	FARABR5Y	23.58	N	Y	156.74	1
	Ottertail Energy								
American Crystal Sugar - Crookston		Polk	R	GFKABR5Y	23.58	N	Y	156.74	1
	University of Minnesota - Crookston								
American Crystal Sugar - E Grand Forks		Polk	R	GFKABR5Y	23.58	N	Y	156.74	1

FACILITY NAME	Nearby Source	COUNTY	Urban (U) and/or Rural (R)	Met Data	Background ug/m^3	Compliance	Culpable	Target Value	n
Minnesota Power Inc - Hibbard Renewable Energy Ctr							Y		
Duluth Steam Cooperative Association							Y		
Georgia-Pacific - Duluth Hardboard		St. Louis	U	DYTINL5Y	23.58	N	Y	52.25	3
	ME Global								
	Lyle & Tate								
	Northern Constructors								
ADM - Mankato							Y		
CHS Oilseed Processing - Mankato							Y		
Xcel Energy - Key City/Wilmarth		Blue Earth	R	RWFMPX5Y	23.58	N	Y	52.25	3
	Mankato Energy Center								
	Katolite								
Willmar Municipal Utilities		Kandiyohi	R	RWFMPX5Y	23.58	N	Y	156.74	1
ADM Corn Processing - Marshall		Lyon	R	RWFMPX5Y	39.15	N	Y	141.17	1
	McLaughlin & Schulz, Plant 596, HMA								
Interstate Power & Light - Fox Lake		Martin	R	RSTMPX5Y	23.58	N	Y	156.74	1
	Buffalo Lake Energy								
Olmsted Waste-to-Energy Facility							Y		
IBM - Rochester							Y		
St Marys							Y		
Associated Milk Producers Inc - Rochester		Olmsted	U	RSTMPX5Y	39.15	N	Y	20.12	7
Rochester Public Utilities - Silver Lake							Y		
Rochester Public Utilities Cascade Creek							Y		
Mayo Medical Center Rochester							Y		
Southern Minnesota Beet Sugar Coop		Renville	R	RWFMPX5Y	23.58	N	Y	156.74	1
Fibrominn Biomass Power Plant		Swift	R	RWFMPX5Y	23.58	Y			
Hibbing Public Utilities Commission		St. Louis							
Mesabi Nugget Delaware LLC		St. Louis							
Minnesota Power - Laskin Energy Center		St. Louis							
Virginia Dept of Public Utilities		St. Louis							
Blandin Paper/Rapids Energy Center		Itasca							
Minnesota Power Inc - Boswell Energy Ctr		Itasca							

SIL = EPA recommended interim significant impact level (SIL) of 4% of standard
Compliance = modeled 4th high for modeling domain is below the SO_2 1-hr standard of 196 ug/m^3.
Culpable = facility modeled above the Significant Impact Level (SIL) at receptors where the standard is exceeded.
Target Value = [Standard – (2*SIL) - background] / n
n = number of facilities within the modeling domain whose impacts exceed the SIL
Facilities that modeled below the SIL at receptors where the standard is exceeded

Monitoring site for Background Concentrations	ug/m^3	Years
Blaine	55.89	2005-2007
Rosemount (423)	39.15	2008-2010
Duluth	23.58	2008-2010

Exhibit 02

To CEO Initial Comments

In the Matter of Minnesota Power's Application for Approval of its 2015-2029 Resource Plan

Docket No. E015/RP-15-690

Taconite Harbor Energy Center

Schroeder, Minnesota

Evaluation of Compliance with the 1-hour NAAQS for SO_2

September 29, 2014

Conducted by:

Steven Klafka, P.E., BCEE

Wingra Engineering, S.C.

Madison, Wisconsin

1. Introduction

Wingra Engineering, S.C. was hired by the Sierra Club to conduct an air modeling impact analysis to help USEPA, state and local air agencies identify facilities that are likely causing violations of the 1-hour sulfur dioxide (SO_2) national ambient air quality standard (NAAQS). This document describes the results and procedures for an evaluation conducted for the Taconite Harbor Energy Center located in Schroeder, Minnesota. This 252 megawatt facility is owned and operated by Minnesota Power.

The dispersion modeling analysis predicted ambient air concentrations for comparison with the 1-hour SO_2 NAAQS. The modeling was performed using the most recent version of AERMOD, AERMET, and AERMINUTE, with data provided to the Sierra Club by regulatory air agencies and through other publicly-available sources as documented below. The analysis was conducted in adherence to all available USEPA guidance for evaluating source impacts on attainment of the 1-hour SO_2 NAAQS via aerial dispersion modeling, including the AERMOD Implementation Guide; USEPA's Applicability of Appendix W Modeling Guidance for the 1-hour SO_2 National Ambient Air Quality Standard, August 23, 2010; modeling guidance promulgated by USEPA in Appendix W to 40 CFR Part 51; and USEPA's March 2011 Modeling Guidance for SO_2 NAAQS Designations.[1]

2. Compliance with the 1-hour SO_2 NAAQS

2.1 1-hour SO_2 NAAQS

The 1-hour SO_2 NAAQS takes the form of a three-year average of the 99th-percentile of the annual distribution of daily maximum 1-hour concentrations, which cannot exceed 75 ppb.[2] Compliance with this standard was verified using USEPA's AERMOD air dispersion model, which produces air concentrations in units of $\mu g/m^3$. The 1-hour SO_2 NAAQS of 75 ppb equals 196.2 $\mu g/m^3$, and this is the value used for determining whether modeled impacts exceed the NAAQS.[3] The 99th-percentile of the annual distribution of daily maximum 1-hour concentrations corresponds to the fourth-highest value at each receptor for a given year.

2.2 Modeling Results

Modeling results for Taconite Harbor Energy Center are summarized in Table 1. It was determined that based on either currently permitted emissions, proposed allowable emissions, or measured actual

---

[1] http://www.epa.gov/scram001/so2_modeling_guidance.htm.
[2] USEPA, Applicability of Appendix W Modeling Guidance for the 1-hour SO_2 National Ambient Air Quality Standard, August 23, 2010.
[3] The ppb to $\mu g/m^3$ conversion is found in the source code to AERMOD v. 13350, subroutine Modules. The conversion calculation is $75/0.3823 = 196.2\ \mu g/m^3$.

emissions, the Taconite Harbor Energy Center is estimated to create SO_2 concentrations which exceed the 1-hour NAAQS.

For the modeling results presented in Table 1, the evaluated emission rates include the allowable and actual. "Allowable" is the peak emission rate from each unit either as approved by the current air quality operation permit for the facility (identified as "Current" limitations), or the emission rates proposed in a recent Consent Decree between the USEPA, Minnesota Pollution Control Agency and Minnesota Power.[4] Proposed limitations include those effective upon the Date of Entry of the Consent Decree (identified as "2014" limitations) and those effective December 31, 2015 (identified as "2016" limitations). "Actual" are the measured emissions for each hour between June 1, 2010 and December 31, 2013 as taken from USEPA *Air Markets Program Data*.[5]

Anticipating the retirement of Boiler 3 in 2015, concentrations were predicted for two scenarios: Current operation of all three boilers and stacks S01, S02 and S03, and future operation of two boilers and stacks S01 and S02.

Air quality impacts in Minnesota are based on a background concentration of 5.2 μg/m^3. This is the 2010-12 design value for Lake County, Minnesota—the lowest measured background concentration in the state. This is the most recently available design value.

Table 1 - SO_2 Modeling Results for Taconite Harbor Energy Center Modeling Analysis

Stacks	Emission Rates	Averaging Period	99th Percentile 1-hour Daily Maximum (μg/m^3)				Complies with NAAQS?
			Impact	Background	Total	NAAQS	
S01, S02 & S03	Allowable (Current)	1-hour	2,420.0	5.2	2,425.2	196.2	No
	Allowable (2014)	1-hour	1,754.4	5.2	1,759.6	196.2	No
	Allowable (2016)	1-hour	648.2	5.2	653.4	196.2	No
	Actual	1-hour	1,127.8	5.2	1,133.0	196.2	No
S01 & S02	Allowable (Current)	1-hour	1,685.3	5.2	1,690.5	196.2	No
	Allowable (2014)	1-hour	1,080.5	5.2	1,085.7	196.2	No
	Allowable (2016)	1-hour	648.2	5.2	653.4	196.2	No
	Actual	1-hour	701.8	5.2	707.0	196.2	No

[4] *U.S. EPA et al. v. Allete, Inc.*, No. 0:14-cv-2911-ADM-LIB, Consent Decree at 24-25 (D. Minn. filed July 16, 2014) (Doc. 3-1).
[5] http://ampd.epa.gov/ampd/.

The current and proposed allowable emissions used for the modeling analysis are summarized in Table 2.

Table 2 - Modeled SO_2 Emissions from Taconite Harbor Energy Center [6, 7]

Stack ID	Unit ID	Current Allowable Emissions 3-hour Average (lbs/hr)	2014 Allowable Emissions 30-day Average (lbs/hr)	2016 Allowable Emissions 30-day Average (lbs/hr)
S01	SV001M (Boiler 1)	581.1	410	224
S02	SV002M (Boiler 2)	581.1	335	224
S03	SV003M (Boiler 3)	581.1	522	0
Stack Total	All Units	1,743.3	1,267	447

Based on the modeling results, emission reductions from current allowable rates considered necessary to achieve compliance with the 1-hour NAAQS were calculated and presented in Table 3.

The actual hourly emissions measured from June 2010 to December 2013 were reviewed to determine the hours when total facility emissions exceeded the required total facility emission rate considered necessary to achieve compliance with the 1-hour NAAQS. Table 3 presents the percentage of time during this 3.5 year period when actual emissions exceeded the required rate.

Based on current allowable emissions, predicted exceedances of the 1-hour NAAQS for SO_2 extend throughout the region to a maximum distance of 50 kilometers. Based the 2014 allowable emissions, exceedances extend to a maximum distance of 45 kilometers. Based on the 2016 allowable emissions, exceedances extend to a maximum distance of 16 kilometers.

Table 4 summarizes sensitive locations near the Taconite Harbor Energy Center. Based on either current allowable or actual hourly emissions, predicted concentrations at the Sawbill Trail located east north east of Carlton Peak exceed the 1-hour NAAQS for SO_2 of 196.2 $\mu g/m^3$.

Figures 1 and 2 show the extent of NAAQS violations based on current allowable emissions from all three boilers. Figure 1 provides a regional view of all violations and Figure 2 provides a local view.

Figures 3 and 4 show the extent of NAAQS violations based on proposed 2014 allowable emissions from all three boilers. Figure 3 provides a regional view of all violations and Figure 4 provides a local view.

---

[6] Minnesota Pollution Control Agency, Air Emission Permit No. 03100001-008, October 19, 2009. Each boiler is limited to 0.78 lbs of SO_2 per mmbtu (3-hour average). This is the limitation with the shortest averaging period.

[7] In the July 16, 2014 Consent Order, the 2014 allowable emission rates for Unit 1 is 0.550 lbs/mmbtu, Unit 2 is 0.450 lbs/mmbtu, and Unit 3 is 0.700 lbs/mmbtu. The 2016 allowable emission rates for Unit 1 is 0.300 lbs/mmbtu, Unit 2 is 0.300 lbs/mmbtu, and Unit 3 is 0 lbs/mmbtu.

Figures 5 and 6 show the extent of NAAQS violations based on proposed 2016 allowable emissions from all three boilers. Figure 5 provides a regional view of all violations and Figure 6 provides a local view.

Figures 7 and 8 show the extent of NAAQS violations based on actual hourly emissions from all three boilers. Figure 7 provides a regional view of all violations and Figure 8 provides a local view.

Figures 9, 10, and 11 present the extent of NAAQS violations based on current, 2014 and 2016 allowable emissions from all three boilers, respectively. These figures include sensitive locations near the Taconite Harbor Energy Center, including the Lake Superior Hiking Trail.[8]

Table 3 - Required Emission Reductions for Compliance with the 1-hour NAAQS for SO_2

Permit Emission Rates	Stacks	Acceptable Impact (NAAQS-Background) 99th Percentile 1-hour Daily Max (µg/m^3)	Required Total Facility Reduction Based on Allowable Emissions (%)	Required Total Facility Emission Rate (lbs/hr)	Required Total Facility 1-hour Average Emission Rate (lbs/mmbtu)	Percentage of Time During June 2010 to 2012, that Required Rate was Exceeded
Allowable (Current)	S01, S02 & S03	191.0	92%	137.6	0.06	97%
	S01 & S02		89%	131.7	0.09	95%
Allowable (2014)	S01, S02 & S03		89%	137.9	0.06	97%
	S01 & S02		82%	131.7	0.09	95%
Allowable (2016)	S01, S02 & S03		71%	131.7	0.09	95%
	S01 & S02		71%	131.7	0.09	95%

Table 4 - Sensitive Locations

Location in Figures 9, 10 & 11	Sensitive Location	Easting (utm-m)	Northing (utm-m)
1	Sawbill Trail ENE of Carlton Peak	661757	5272665
2	Downhill ski area of Lutsen Mountain resort	670608	5281288
3	Carlton Peak	660903	5272222
4	Hidden Falls in Caribou State Park	659962	5269147
5	City of Schroeder center near Highway 61	658424	5267763
6	Caribou Falls near George H Crosby Manitou State Park	648348	5259149
7	Superior Hiking Trail in George H Crosby Manitou State Park	643089	5260438
8	The main historic Lutsen Lodge on shore of Lake Superior	672145	5278392

[8] http://www.shta.org/Trail/TrailGPS.php.

2.3 Conservative Modeling Assumptions

A dispersion modeling analysis requires the selection of numerous parameters which affect the predicted concentrations. For the enclosed analysis, several parameters were selected which under-predict facility impacts.

Assumptions used in this modeling analysis which likely under-estimate concentrations include the following:

- Allowable emissions are based on a limitation with an averaging period which is greater than the 1-hour average used for the SO_2 air quality standard. Emissions and impacts during any 1-hour period may be higher than assumed for the modeling analysis.
- No consideration of facility operation at less than 100% load. Stack parameters such as exit flow rate and temperature are typically lower at less than full load, reducing pollutant dispersion and increasing predicted air quality impacts.
- No consideration of off-site sources. These other sources of SO_2 will increase the predicted impacts.

2.4 Modeling Results without Flagpole Receptors

The modeling results presented in Table 1 incorporate the use of a flagpole receptor height of 1.5 meters to reflect a representative inhalation level. Since the use of flagpole receptors is not a typical practice, the SO_2 Modeling Results and Required Emissions Reductions analyses presented in Tables 1 and 3 of this report were repeated without the flagpole receptors. These alternative modeling results are presented in Table 1A and 3A in Appendix A of this report. It was determined that the use of flagpole receptors increased the predicted concentrations by 1 to 3%. Without the use of flagpole receptors, exceedances of the 1-hour NAAQS for SO_2 were predicted based on current and proposed allowable emissions, as well as actual hourly emissions.

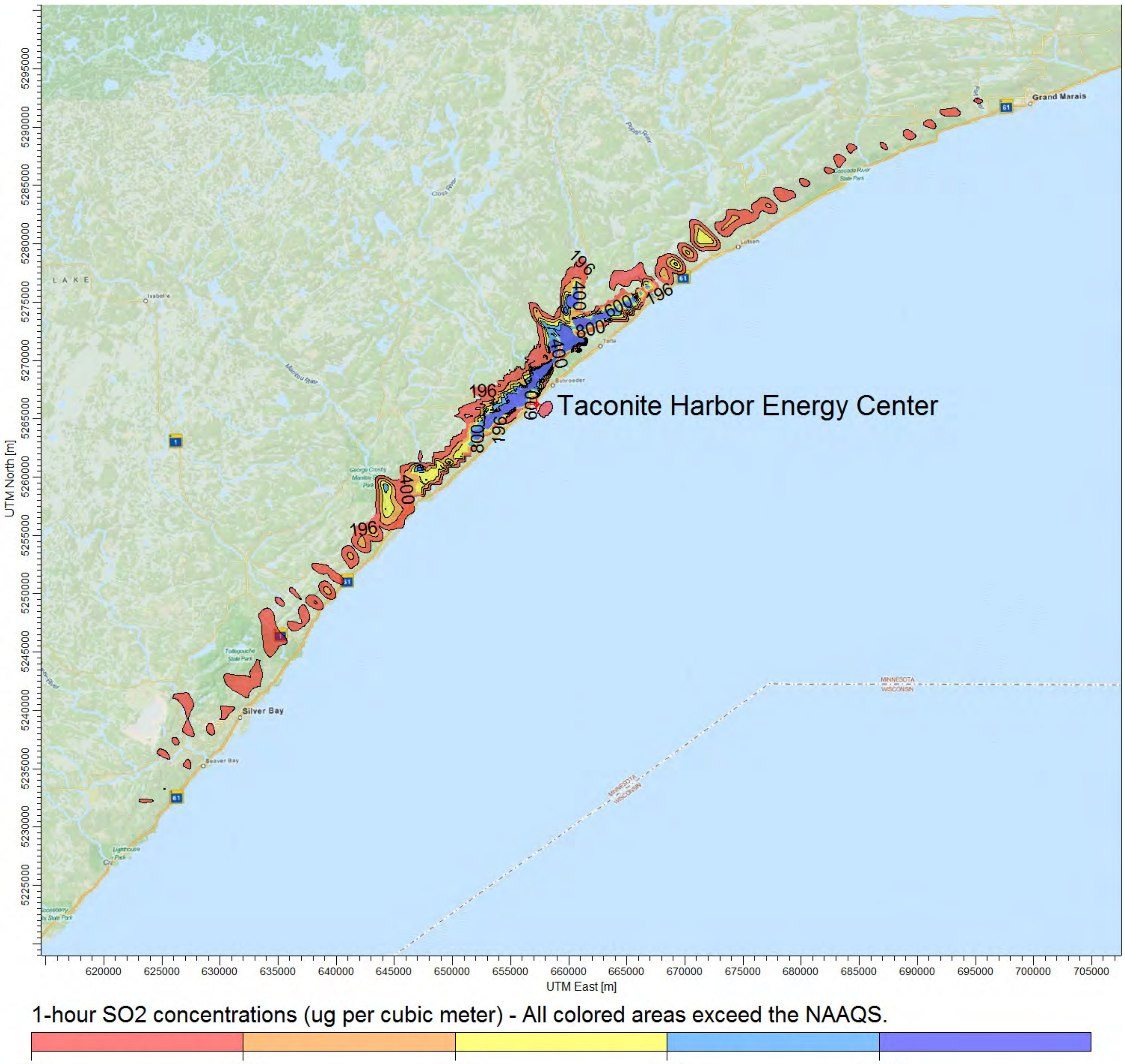


Figure 1 - Concentrations Based on Current Allowable Emissions

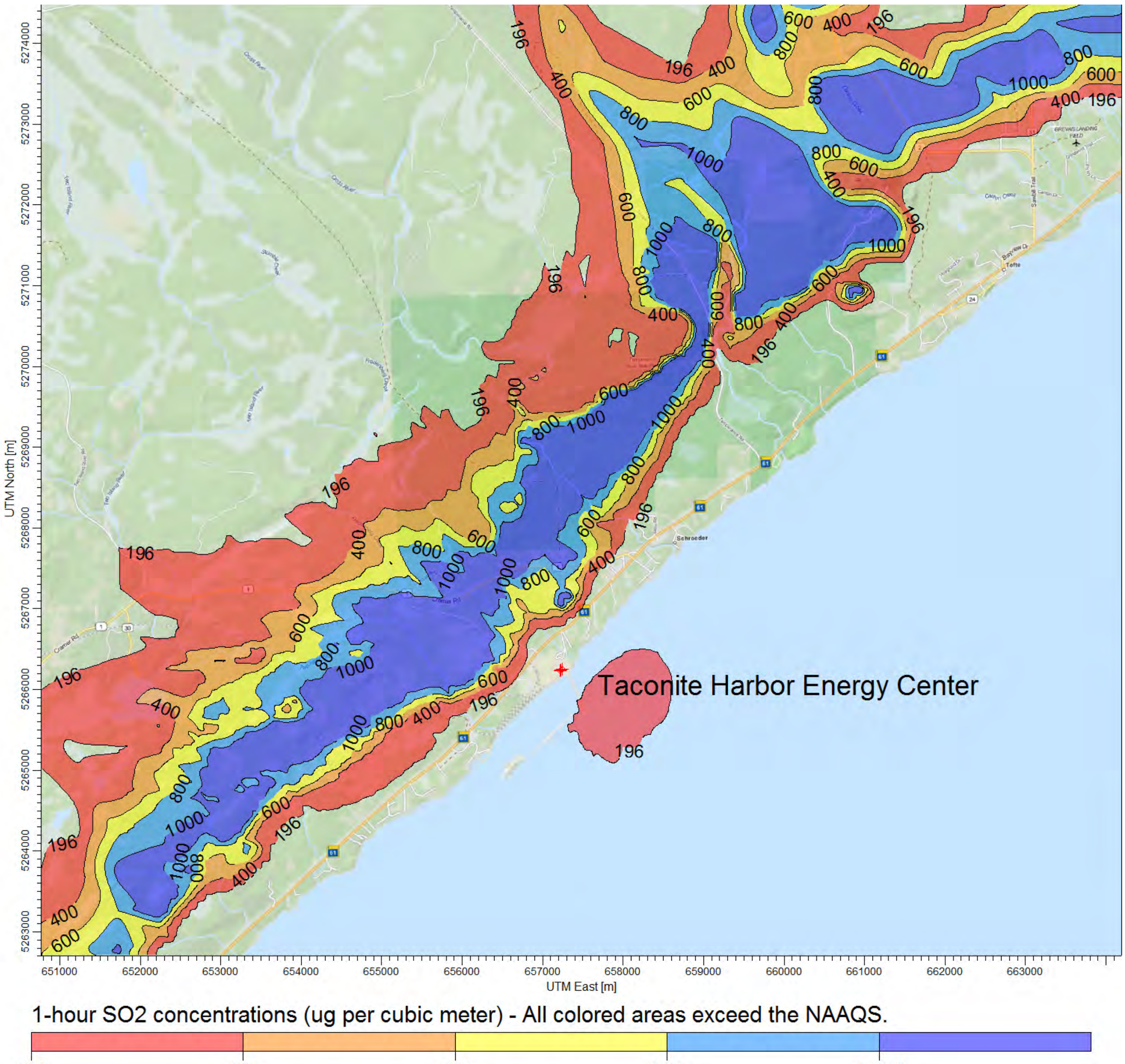


Figure 2 - Concentrations Based on Current Allowable Emissions

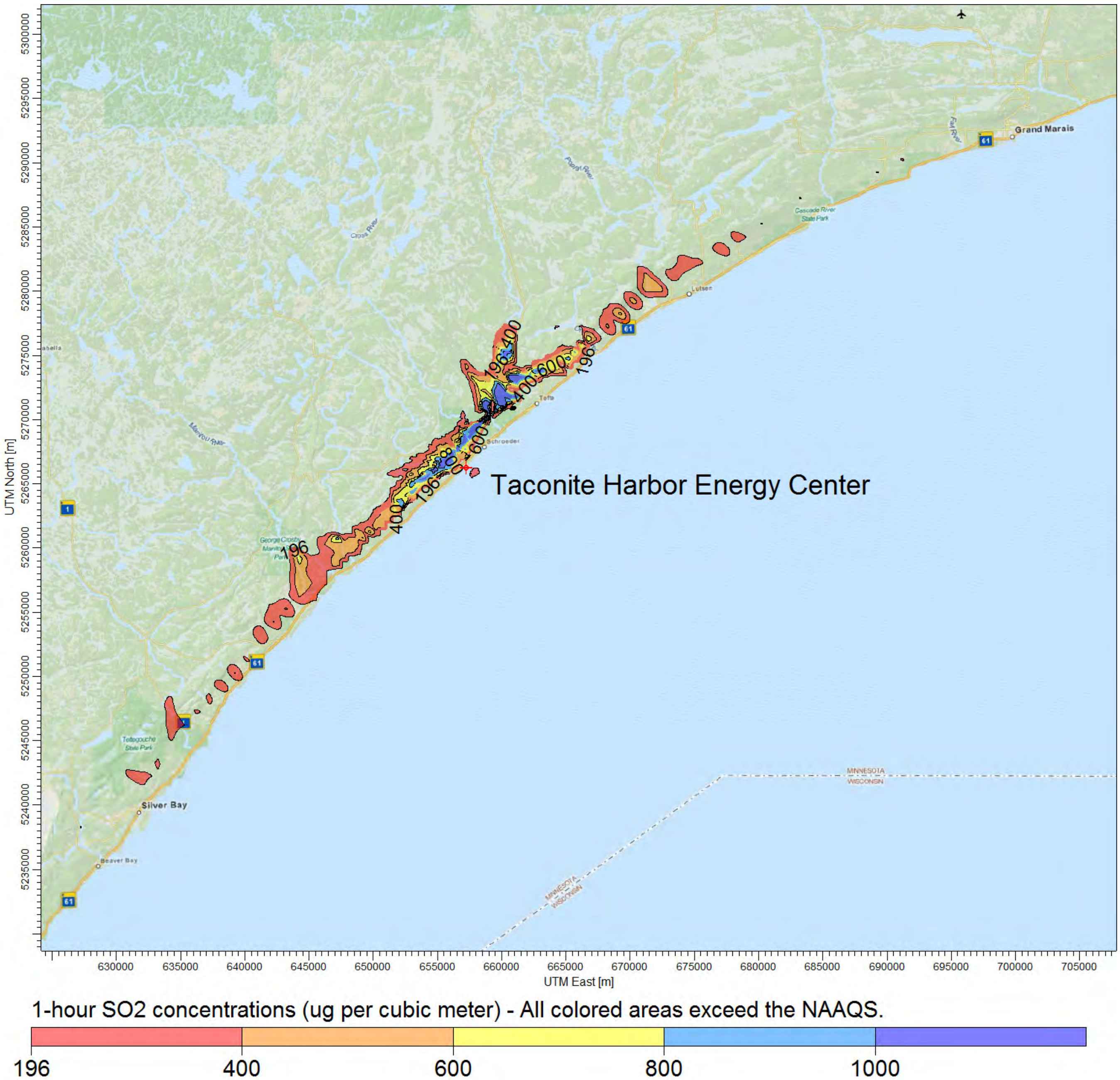


Figure 3 - Concentrations Based on 2014 Allowable Emissions

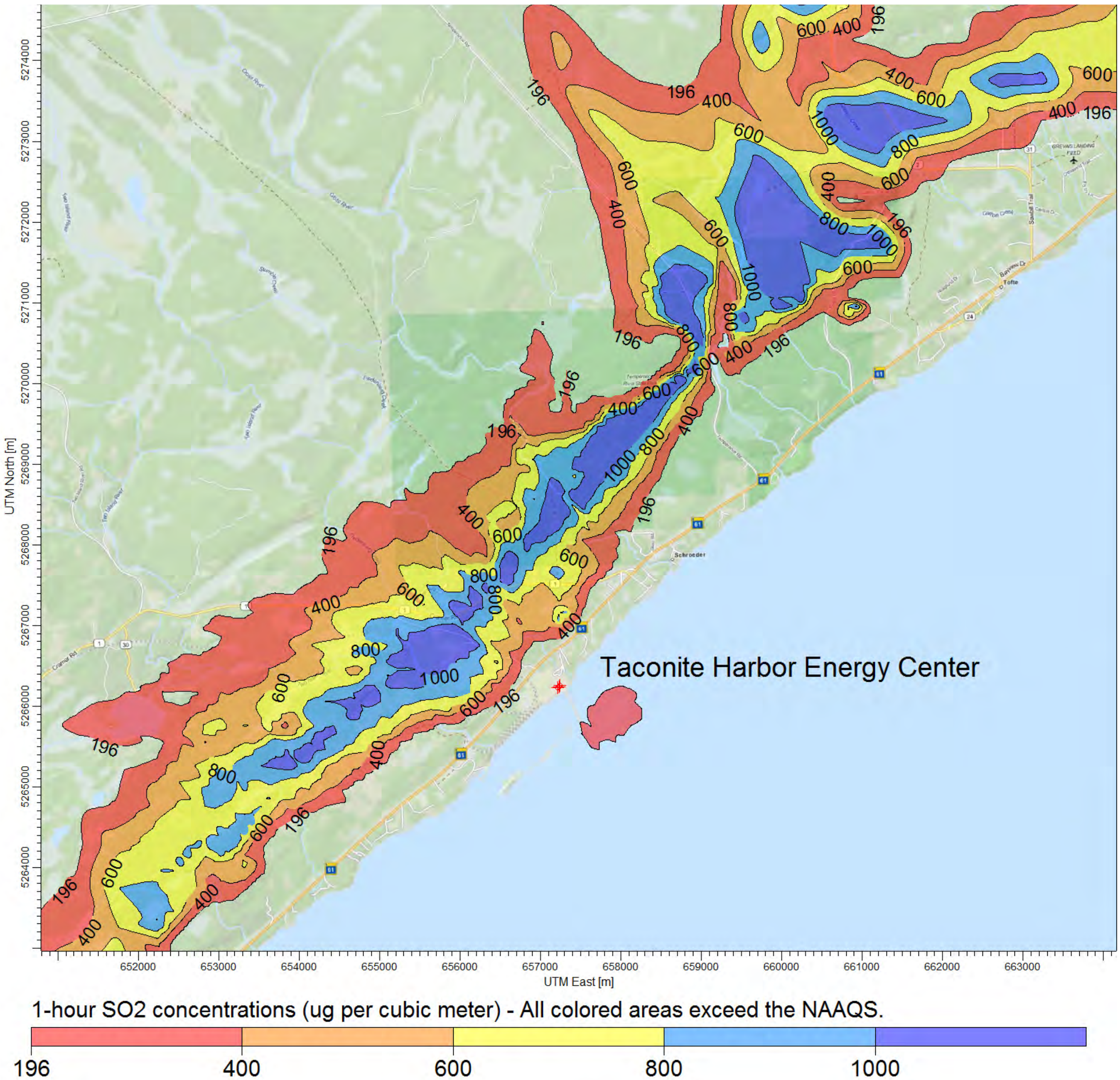


Figure 4 - Concentrations Based on 2014 Allowable Emissions

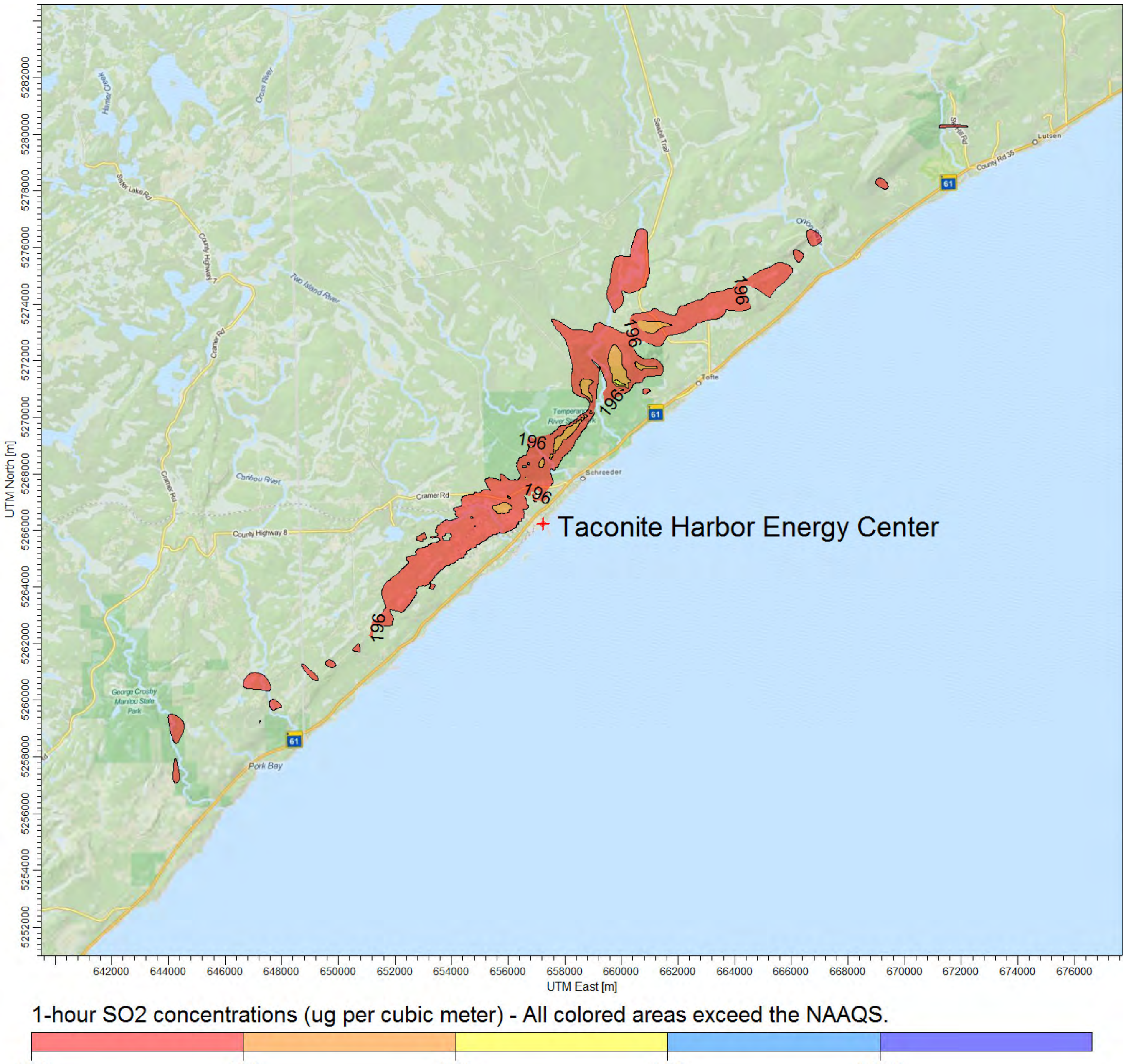


Figure 5 - Concentrations Based on 2016 Allowable Emissions

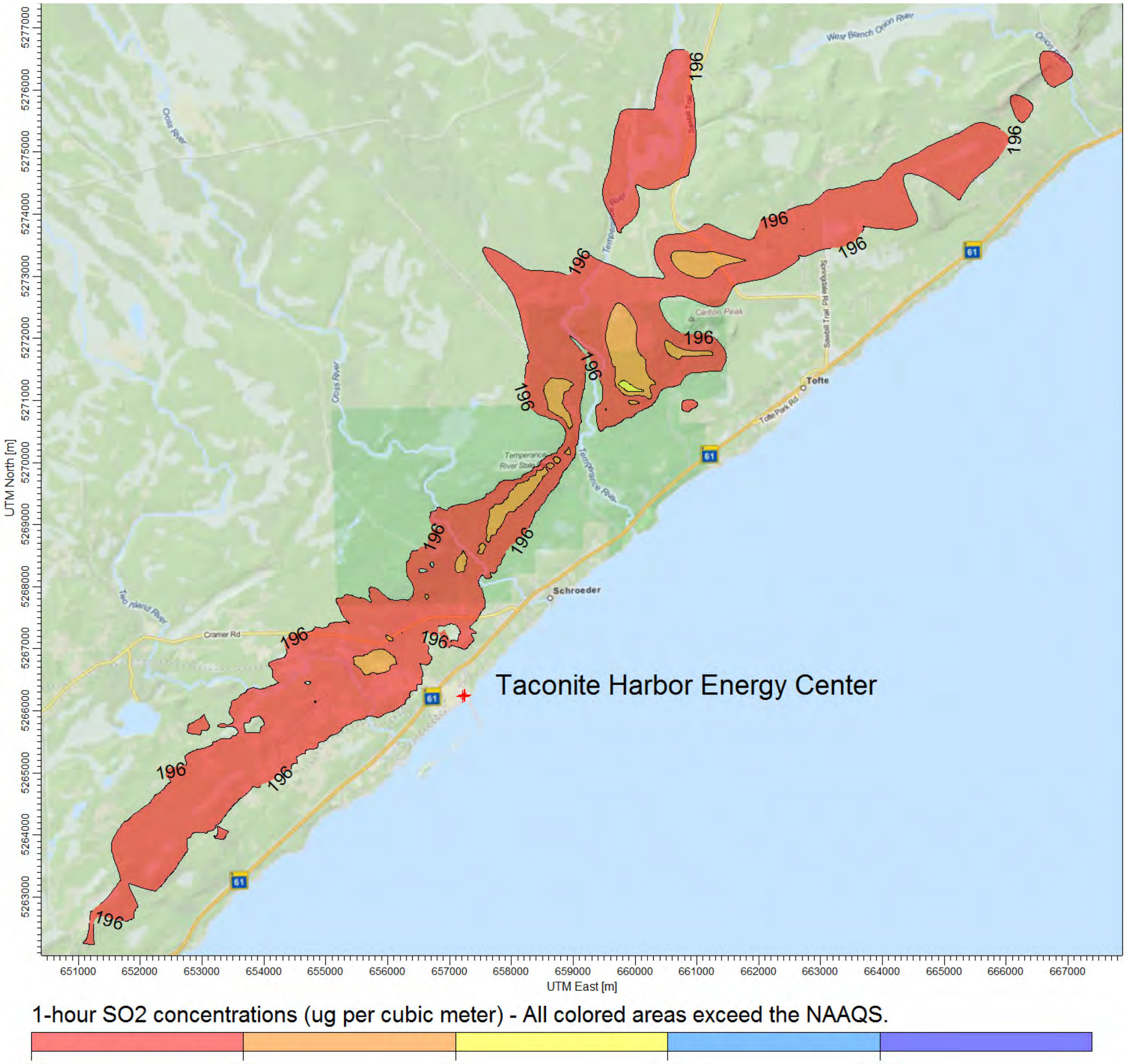


Figure 6 - Concentrations Based on 2016 Allowable Emissions

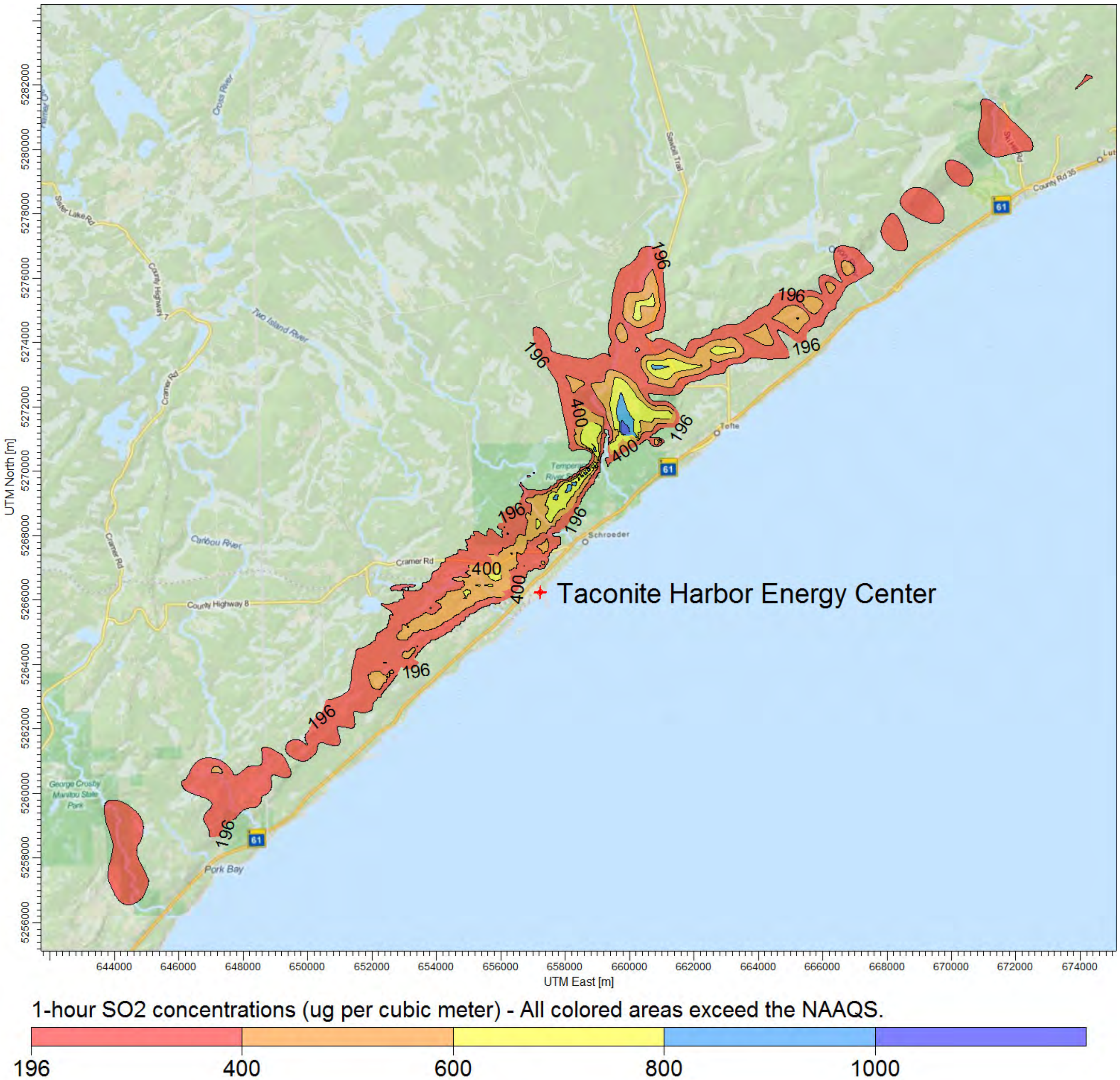
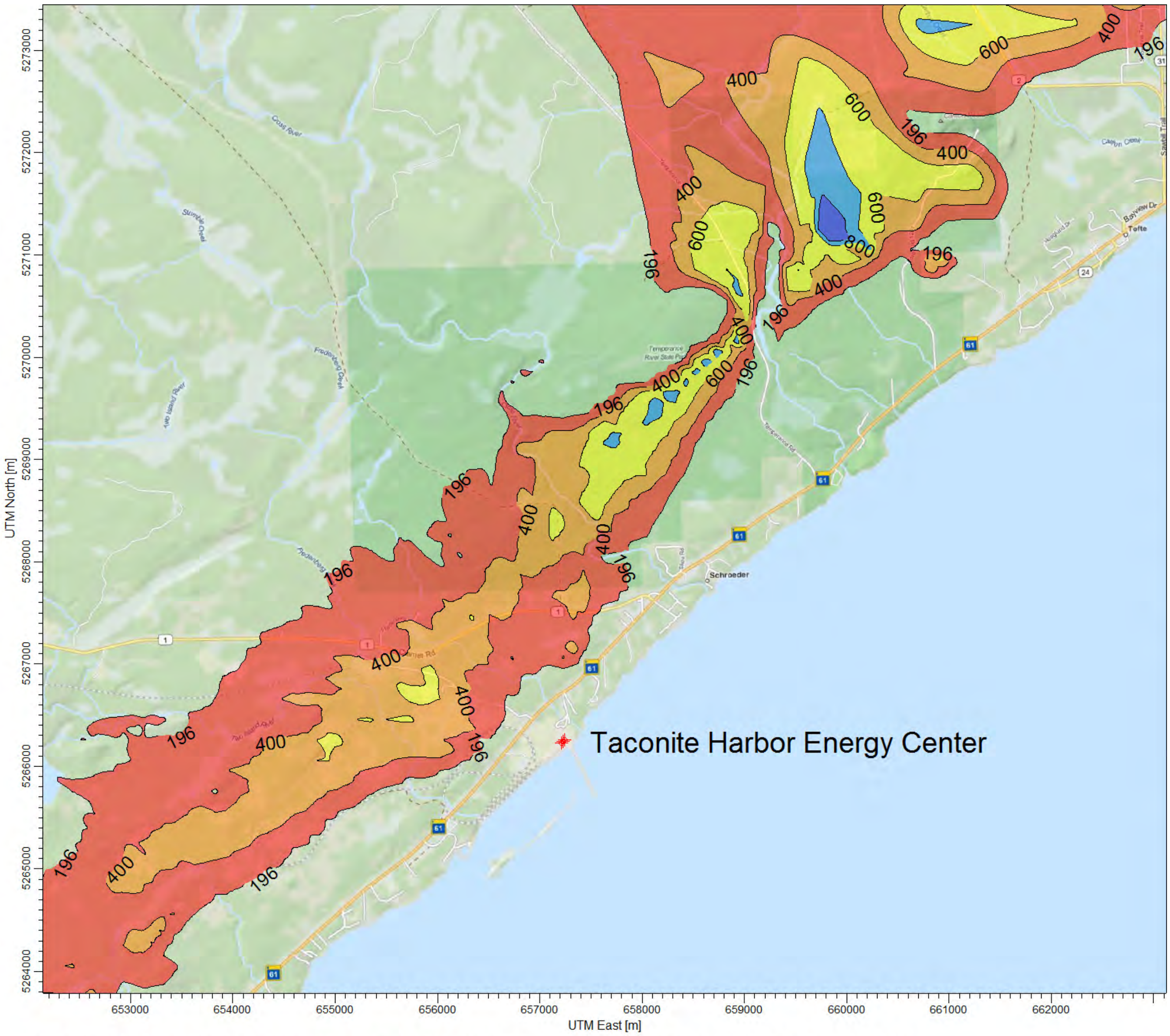


Figure 7 - Concentrations Based on Actual Emissions



1-hour SO2 concentrations (ug per cubic meter) - All colored areas exceed the NAAQS.

196 400 600 800 1000

Figure 8 - Concentrations Based on Actual Emissions

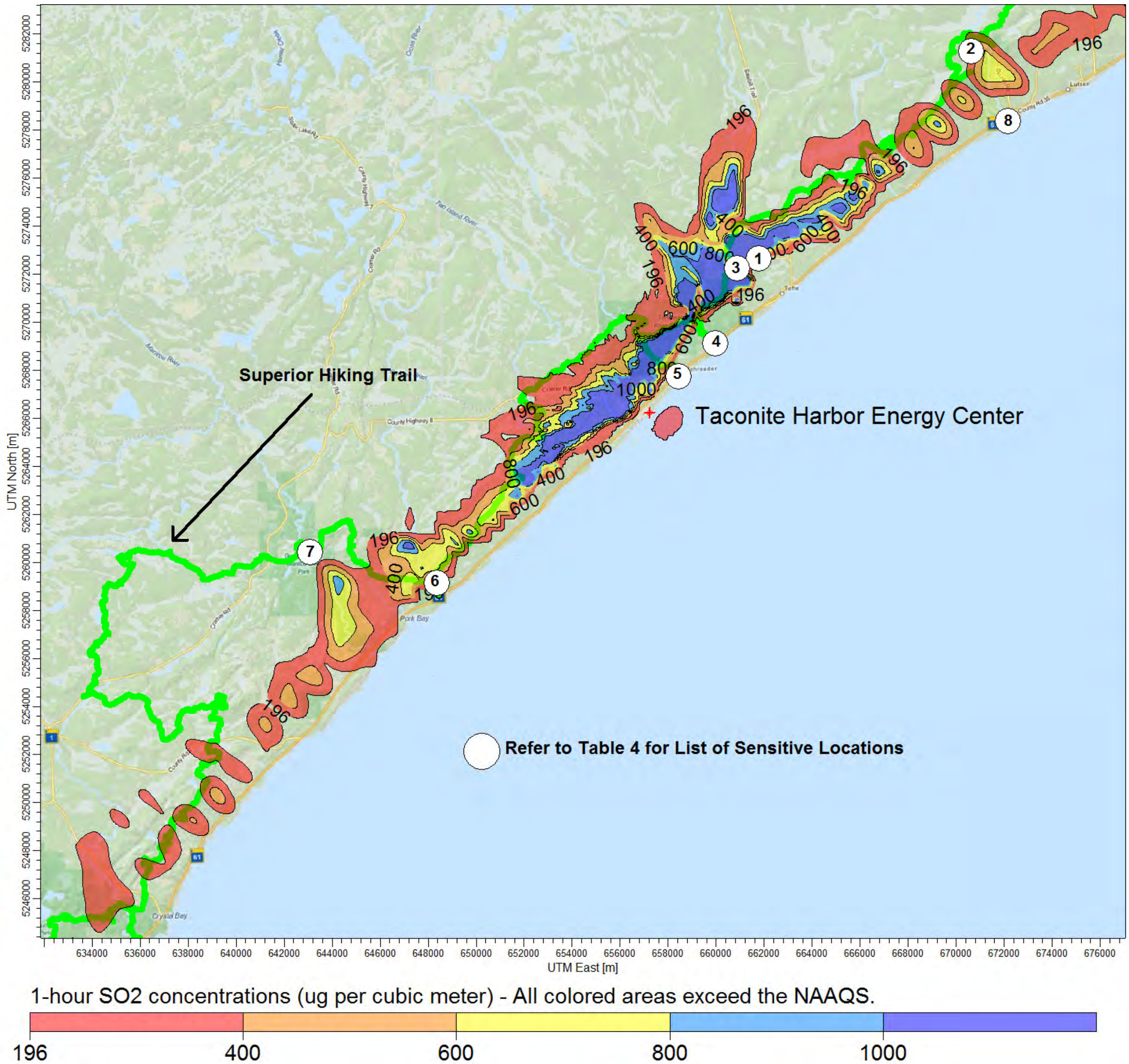


Figure 9 - Concentrations at Sensitive Locations Based on Current Allowable Emissions

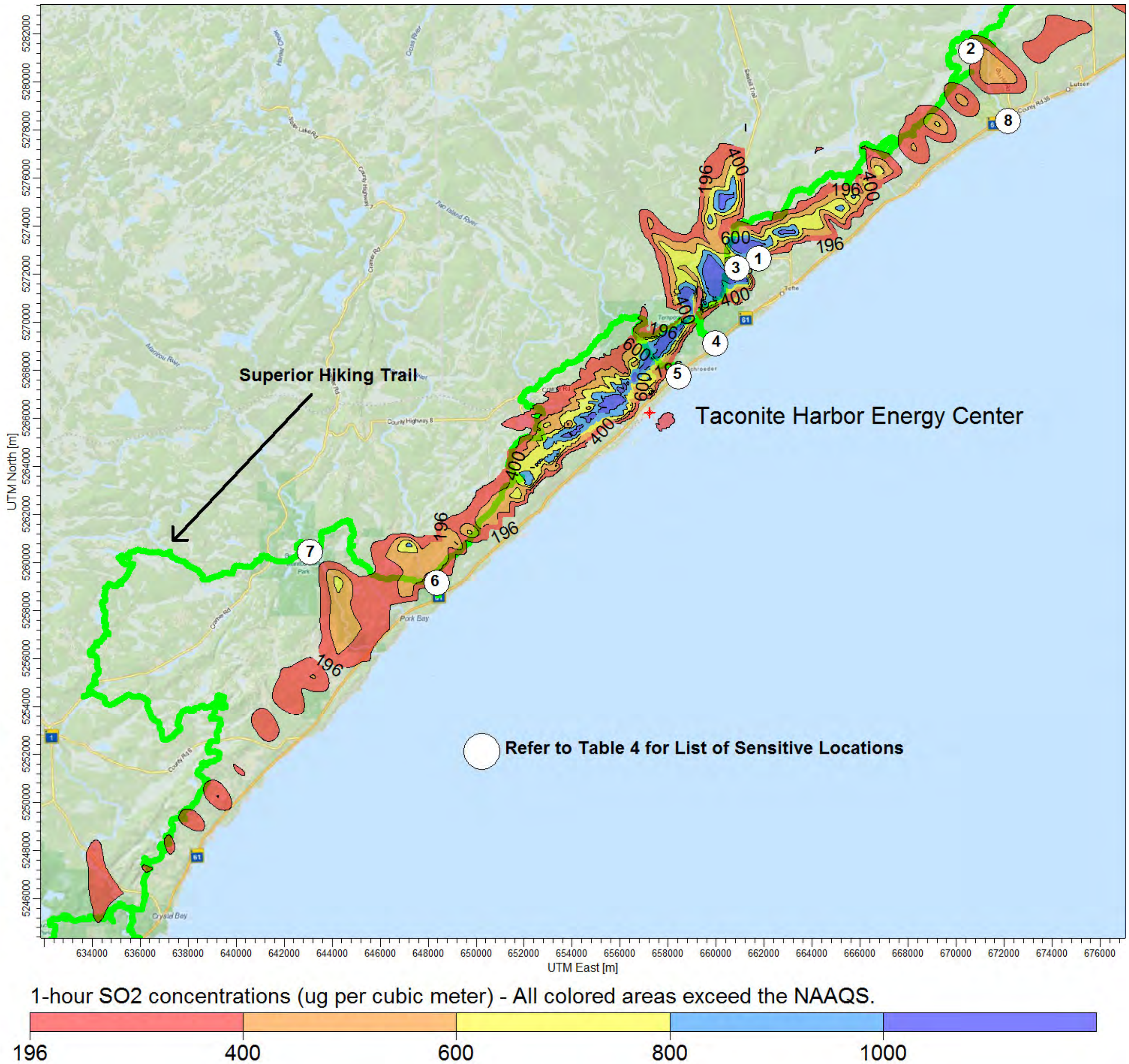


Figure 10 - Concentrations at Sensitive Locations Based on 2014 Allowable Emissions

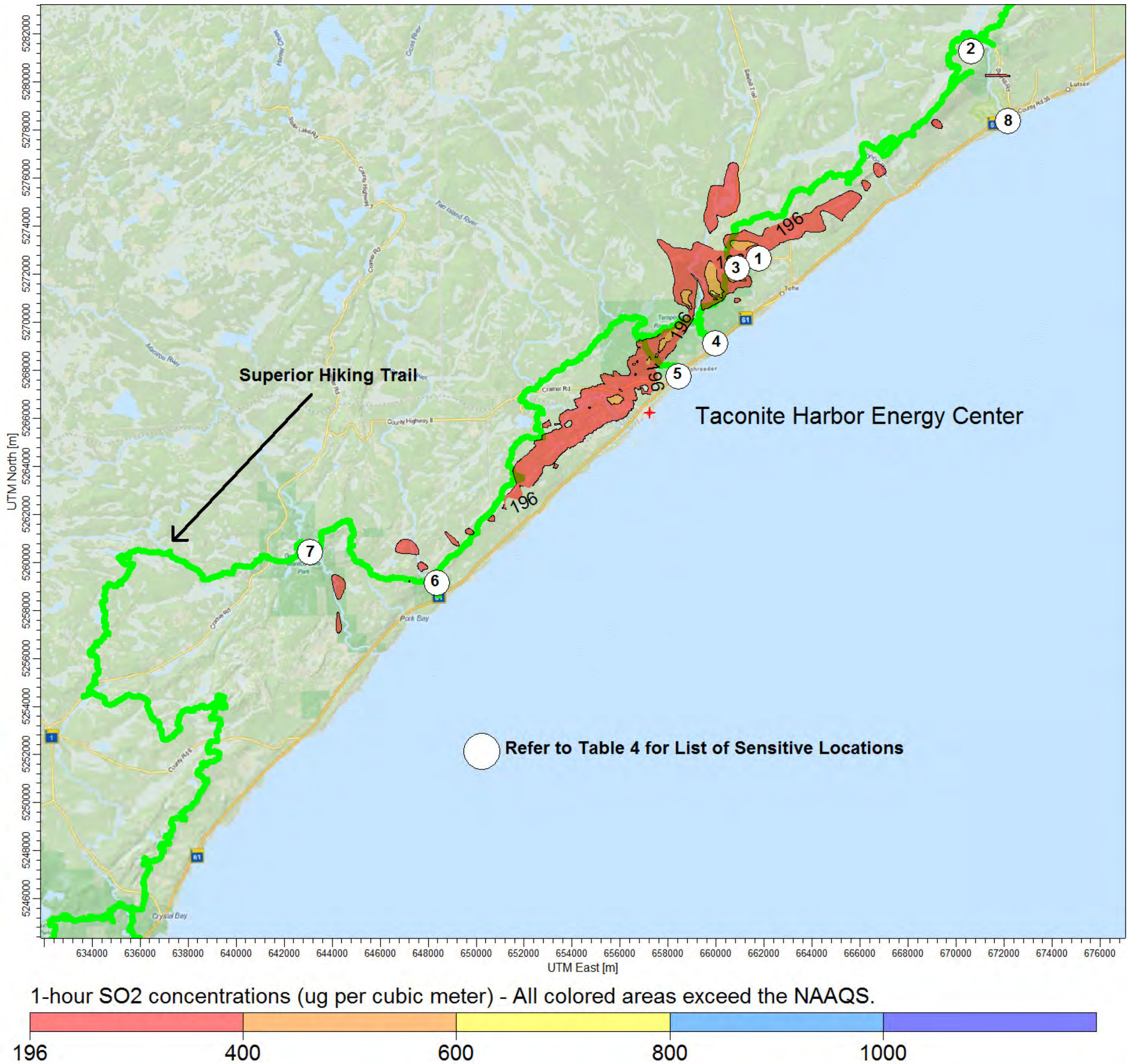


Figure 11 - Concentrations at Sensitive Locations Based on 2016 Allowable Emissions

3. Modeling Methodology

3.1 Air Dispersion Model

The modeling analysis used USEPA's AERMOD program, v. 13350. AERMOD, as available from the Support Center for Regulatory Atmospheric Modeling (SCRAM) website, was used in conjunction with a third-party modeling software program, *AERMOD View*, sold by Lakes Environmental Software.

3.2 Control Options

The AERMOD model was run with the following control options:

- 1-hour average air concentrations
- Regulatory defaults
- Flagpole receptors

To reflect a representative inhalation level, a flagpole height of 1.5 meters was used for all modeled receptors. This parameter was added to the receptor file when running AERMAP, as described in Section 4.4.

An evaluation was conducted to determine if the modeled facility was located in a rural or urban setting using USEPA's methodology outlined in Section 7.2.3 of the Guideline on Air Quality Models.[9] For urban sources, the URBANOPT option is used in conjunction with the urban population from an appropriate nearby city and a default surface roughness of 1.0 meter. Methods described in Section 4.1 were used to determine whether rural or urban dispersion coefficients were appropriate for the modeling analysis.

3.3 Output Options

The AERMOD analysis was based on 3.5 years of recent meteorological data. The modeling analyses used one run with three years of sequential meteorological data from June 2010 – December 2013. Consistent with USEPA's Modeling Guidance for SO_2 NAAQS Designations, AERMOD provided a table of fourth-high 1-hour SO_2 impacts concentrations consistent with the form of the 1-hour SO_2 NAAQS.[10]

Please refer to Table 1 for the modeling results.

---

[9] USEPA, Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions, Appendix W to 40 CFR Part 51, November 9, 2005.

[10] USEPA, Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards, Attachment 3, March 24, 2011, pp. 24-26.

4. Model Inputs

4.1 Geographical Inputs

The “ground floor” of all air dispersion modeling analyses is establishing a coordinate system for identifying the geographical location of emission sources and receptors. These geographical locations are used to determine local characteristics (such as land use and elevation), and also to ascertain source to receptor distances and relationships.

The Universal Transverse Mercator (UTM) NAD83 coordinate system was used for identifying the easting (x) and northing (y) coordinates of the modeled sources and receptors. Stack locations were obtained from facility permits and prior modeling files provided by the state regulatory agency. The stack locations were then verified using aerial photographs.

The facility was evaluated to determine if it should be modeled using the rural or urban dispersion coefficient option in AERMOD. A GIS was used to determine whether rural or urban dispersion coefficients apply to a site. Land use within a three-kilometer radius circle surrounding the facility was considered. USEPA guidance states that urban dispersion coefficients are used if more than 50% of the area within 3 kilometers has urban land uses. Otherwise, rural dispersion coefficients are appropriate.[11]

USEPA’s AERSURFACE v. 13016 was used to develop the meteorological data for the modeling analysis. This model was also used to evaluate surrounding land use within 3 kilometers. Based on the output from the AERSURFACE, approximately 3.0% of surrounding land use around the modeled facility was of urban land use types including Type 21 – Low Intensity Residential, Type 22 – High Intensity Residential and Type 23 – Commercial / Industrial / Transportation.

This is less than the 50% value considered appropriate for the use of urban dispersion coefficients. Based on the AERSURFACE analysis, it was concluded that the rural option would be used for the modeling summarized in this report. Please refer to Section 4.5.3 for a discussion of the AERSURFACE analysis.

---

[11] USEPA, Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions, Appendix W to 40 CFR Part 51, November 9, 2005, Section 7.2.3.

4.2 Emission Rates and Source Parameters

The modeling analyses only considered SO_2 emissions from the facility. Off-site sources were not considered. Concentrations were predicted for the scenarios shown in Tables 1 and 2:

1) current and proposed allowable emissions based on permits issued by the regulatory agency or the consent order between USEPA, MPCA and Minnesota Power, and

2) actual hourly emissions measured each hour between June 1, 2010 and December 31, 2013 as taken from USEPA *Air Markets Program Data*.[12]

Stack parameters and emissions used for the modeling analysis are summarized in Table 5.

Table 5 – Facility Stack Parameters and Emissions [13]

Stack	SV001M	SV002M	SV003M
Description	Unit 1	Unit 2	Unit 3
X Coord. [m]	657243.24	657228.67	657215.07
Y Coord. [m]	5266255.88	5266242.28	5266229.65
Base Elevation [m]	189.97	189.98	190.77
Release Height [m]	67.06	67.06	67.06
Gas Exit Temperature [°K]	435.93	435.93	435.93
Gas Exit Velocity [m/s]	25.74	25.74	25.74
Inside Diameter [m]	3.02	3.02	3.02
Current Allowable Emissions [g/s]	73.22	73.22	73.22
2014 Allowable Emissions [g/s]	51.63	42.24	65.71
2015 Allowable Emissions [g/s]	28.16	28.16	0
Actual Emission Rate [g/s]	-	-	-

The above stack parameters and emissions were obtained from regulatory agency documents and databases identified in Section 2.3. The analysis was conducted based on 100% operating load using maximum exhaust flow rates and temperatures. Operation at less than full capacity loads was not considered. This assumption tends to under-predict impacts since stack parameters such as exit flow rate and temperature are typically lower at less than full load, reducing pollutant dispersion and increasing predicted air quality impacts. Stack location, height and diameter were verified using aerial photographs, and flue gas flow rate and temperature were verified using combustion calculations.

---

[12] http://ampd.epa.gov/ampd/.
[13] MPCA AERMOD File: MNTACSIP.ADI, December 12, 2011.

4.3 Building Dimensions and GEP

Building dimensions from a prior downwash evaluation by the PCA were available. This modeling analysis did address the effects of downwash using the BPIP model.

4.4 Receptors

For Taconite Harbor Energy Center, three receptor grids were employed:

1. A 100-meter Cartesian receptor grid centered on Taconite Harbor Energy Center and extending out 5 kilometers.
2. A 500-meter Cartesian receptor grid centered on Taconite Harbor Energy Center and extending out 10 kilometers.
3. A 1,000-meter Cartesian receptor grid centered on Taconite Harbor Energy Center and extending out 50 kilometers, which is the maximum distance accepted by USEPA for the use of the AERMOD dispersion model.[14]

A flagpole height of 1.5 meters was used for all these receptors. As noted, however, since the use of a 1.5-meter flagpole receptor may not be common practice, this analysis was repeated without flagpole receptors. That analysis is presented in Appendix A.

Elevations from stacks and receptors were obtained from National Elevation Dataset (NED) GeoTiff data. GeoTiff is a binary file that includes data descriptors and geo-referencing information necessary for extracting terrain elevations. These elevations were extracted from 1 arc-second (30 meter) resolution NED files. The USEPA software program AERMAP v. 11103 is used for these tasks.

4.5 Meteorological Data

To improve the accuracy of the modeling analysis, recent meteorological data for the 2010-2013 period were prepared using the USEPA's program AERMET which creates the model-ready surface and profile data files required by AERMOD. Required data inputs to AERMET included surface meteorological measurements, twice-daily soundings of upper air measurements, and the micrometeorological parameters surface roughness, albedo, and Bowen ratio. One-minute ASOS data were available so USEPA methods were used to reduce calm and missing hours.[15] The USEPA software program AERMINUTE v. 11325 is used for these tasks.

---

[14] USEPA, Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions, Appendix W to 40 CFR Part 51, Section A.1.(1), November 9, 2005.

[15] USEPA, Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards, Attachment 3, March 24, 2011, p. 19.

This section discusses how the meteorological data was prepared for use in the 1-hour SO_2 NAAQS modeling analyses. The USEPA software program AERMET v. 13350 is used for these tasks.

4.5.1 Surface Meteorology

Surface meteorology was obtained for Sky Harbor Airport located near the Taconite Harbor Energy Center. Integrated Surface Hourly (ISH) data for the 2010-2013 period were obtained from the National Climatic Data Center (NCDC). The ISH surface data was processed through AERMET Stage 1, which performs data extraction and quality control checks.

4.5.2 Upper Air Data

Upper-air data are collected by a "weather balloon" that is released twice per day at selected locations. As the balloon is released, it rises through the atmosphere, and radios the data back to the surface. The measuring and transmitting device is known as either a radiosonde, or rawindsonde. Data collected and radioed back include: air pressure, height, temperature, dew point, wind speed, and wind direction. The upper air data were processed through AERMET Stage 1, which performs data extraction and quality control checks.

For Taconite Harbor Energy Center, the concurrent 2010-2013 upper air data from twice-daily radiosonde measurements obtained at the most representative location were used. This location was the International Falls, Minnestoa measurement station. These data are in Forecast Systems Laboratory (FSL) format and were downloaded in ASCII text format from NOAA's FSL website.[16] All reporting levels were downloaded and processed with AERMET.

4.5.3 AERSURFACE

AERSURFACE is a program that extracts surface roughness, albedo, and daytime Bowen ratio for an area surrounding a given location. AERSURFACE uses land use and land cover (LULC) data in the U.S. Geological Survey's 1992 National Land Cover Dataset to extract the necessary micrometeorological data. LULC data was used for processing meteorological data sets used as input to AERMOD.

AERSURFACE was used to develop surface roughness, albedo, and daytime Bowen ratio values in a region surrounding the meteorological data collection site. AERSURFACE was used to develop surface roughness in a one kilometer radius surrounding the data collection site. Bowen ratio and albedo was developed for a 10 kilometer by 10 kilometer area centered on the meteorological data

---

[16] Available at: http://esrl.noaa.gov/raobs/.

collection site. These micrometeorological data were processed for seasonal periods using 30-degree sectors.

The Minnesota Pollution Control Agency provides pre-processed meteorological data for modeling with AERMOD on its web site.[17] These data are provided for the 2006 to 2010 period using AERMET v. 11059 and AERSURFACE v. 08009. These data include AERSURFACE output files for average, wet and dry moisture conditions.

For this project, the meteorological data for the June 2010 to December 2013 period was re-processed using current versions of modeling software. For each year, moisture conditions were determined to be average, wet and dry. These were as follows:

- 2010 – Wet
- 2011 – Average
- 2012 – Wet
- 2013 – Average

When processing each year of meteorological data, the appropriate AERSURFACE output file from PCA was used.

4.5.4 Data Review

Missing meteorological data were not filled as the data file met USEPA's 90% data completeness requirement.[18] The AERMOD output file shows there were 1.76% missing data.

To confirm the representativeness of the airport meteorological data, the surface characteristics of the airport data collection site and the modeled source location were compared. Since the Sky Harbor Airport is located close to Taconite Harbor Energy Center, this meteorological data set was considered appropriate for this modeling analysis. [19] This weather station provided high quality surface measurements for the most recent 5-year time, and had similar land use, surface characteristics, terrain features and climate.

Additionally, this airport was previously used by the Minnesota Pollution Control Agency for modeling the Taconite Harbor Energy Center. As noted, the PCA provides these meteorological data for modeling with AERMOD on its web site.

---

[17] Refer to: http://www.pca.state.mn.us/index.php/air/air-monitoring-and-reporting/air-emissions-modeling-and-monitoring/air-dispersion-modeling/meteorological-data.html.
[18] USEPA, Meteorological Monitoring Guidance for Regulatory Modeling Applications, EPA-454/R-99-05, February 2000, Section 5.3.2, pp. 5-4 to 5-5.
[19] USEPA, AERMOD Implementation Guide, March 19, 2009, pp. 3-4.

5. Background SO_2 Concentrations

Background concentrations were determined consistent with USEPA's Modeling Guidance for SO_2 NAAQS Designations.[20] To preserve the form of the 1-hour SO_2 standard, based on the 99^{th} percentile of the annual distribution of daily maximum 1-hour concentrations averaged across the number of years modeled, the background fourth-highest daily maximum 1-hour SO_2 concentration was added to the modeled fourth-highest daily maximum 1-hour SO_2 concentration.[21]

Background concentrations were based on the 2010-12 design value measured by the ambient monitors located in Minnesota.[22]

6. Reporting

All files from the programs used for this modeling analysis are available to regulatory agencies. These include analyses prepared with AERSURFACE, AERMET, AERMAP, and AERMOD.

---

[20] USEPA, Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards, Attachment 3, March 24, 2011, pp. 20-23.
[21] USEPA, Applicability of Appendix W Modeling Guidance for the 1-hour SO_2 National Ambient Air Quality Standard, August 23, 2010, p. 3.
[22] http://www.epa.gov/airtrends/values.html

Appendix A
Modeling Results without Flagpole Receptors

Table 1A - SO_2 Modeling Results for Taconite Harbor Energy Center Modeling Analysis

Stacks	Emission Rates	Averaging Period	99th Percentile 1-hour Daily Maximum (µg/m^3)				Complies with NAAQS?
			Impact	Background	Total	NAAQS	
S01, S02 & S03	Allowable (Current)	1-hour	2,375.7	5.2	2,380.9	196.2	No
	Allowable (2014)	1-hour	1,714.0	5.2	1,719.2	196.2	No
	Allowable (2016)	1-hour	631.6	5.2	636.8	196.2	No
	Actual	1-hour	1,109.9	5.2	1,115.1	196.2	No
S01 & S02	Allowable (Current)	1-hour	1,642.1	5.2	1,647.3	196.2	No
	Allowable (2014)	1-hour	1,052.8	5.2	1,058.0	196.2	No
	Allowable (2016)	1-hour	631.6	5.2	636.8	196.2	No
	Actual	1-hour	694.7	5.2	699.9	196.2	No

Table 3A - Required Emission Reductions for Compliance with the 1-hour NAAQS for SO_2

Permit Emission Rates	Stacks	Acceptable Impact (NAAQS-Background) 99th Percentile 1-hour Daily Max (µg/m^3)	Required Total Facility Reduction Based on Allowable Emissions (%)	Required Total Facility Emission Rate (lbs/hr)	Required Total Facility 1-hour Average Emission Rate (lbs/mmbtu)	Percentage of Time During June 2010 to 2012 Required Rate was Exceeded
Allowable (Current)	S01, S02 & S03	191.0	92%	140.2	0.06	97%
	S01 & S02		88%	135.2	0.09	94%
Allowable (2014)	S01, S02 & S03		89%	141.1	0.06	97%
	S01 & S02		82%	135.2	0.09	94%
Allowable (2016)	S01, S02 & S03		70%	135.2	0.09	94%
	S01 & S02		70%	135.2	0.09	94%

Exhibit 03

To CEO Initial Comments

In the Matter of Minnesota Power's Application for Approval of its 2015-2029 Resource Plan

Docket No. E015/RP-15-690

minnesota power / 30 west superior street / duluth, minnesota 55802-2093 / 218-722-5642 / www.mnpower.com

February 13, 2015

VIA EMAIL ONLY

Ms. Shelley Burman, Mr. Jim Sullivan, Ms. Carolina Schutt, Mr. Steve Pak, and Mr. Don Smith
Minnesota Pollution Control Agency
Environmental Analysis & Outcomes Division – Air Assessment Section
Industrial Division – Air Quality Permits Section
520 Lafayette Road North
St. Paul, MN 55155-4194

Dear Shelley, Jim, Carolina, Steve, and Don,

Thank you for taking the time to meet with Minnesota Power (MP) and Wenck Associates (Wenck) on December 17, 2014 and for ongoing discussions since regarding 1-hour SO_2 NAAQS modeling for the Taconite Harbor Energy Center (THEC). As you know, the THEC facility located in Schroeder, Minnesota consists of three approximately 75 megawatt units, one of which (Unit 3) will be retired during 2015. The remaining two units, Unit 1 and Unit 2, are well-controlled units equipped with multi-pollutant control systems installed as part of Minnesota Power's Arrowhead Regional Emissions Abatement (AREA) Plan, approved by the MPCA on January 17, 2006.

During the AREA Project Units 1 and 2 were retrofitted with NOx control (ROFA), SO_2 control (Rotamix/FSI), and mercury control (currently activated carbon). The units also have electrostatic precipitators (ESPs) that were converted during the AREA Project from hot-side to cold-side for enhanced particulate removal. In 2015 the SO_2 and acid gas control on Units 1 and 2 will be improved further by incorporating sodium bicarbonate (SBC) injection in addition to the hydrated lime injection currently in use. This enhanced reduction in SO_2 emission rates will yield even lower expected concentrations for 1-hour SO_2 NAAQS modeling.

At the conclusion of the December 17 meeting it was agreed that Minnesota Power should document in an email the specific topics that could require additional review within the context of a modeling protocol. Our understanding from the meeting is that modelers and permitting staff at the Minnesota Pollution Control Agency (MPCA) would then be able to quickly review this pre-protocol documentation and provide concurrence or comments back to Minnesota Power on the proposed approaches.

The goal in submitting this pre-protocol letter on non-standard topics that could require additional review is to obtain expedited approval of the modeling protocol once it is submitted. As you know, the timeline for this project is under a compressed schedule, including an April 1 deadline for protocol submittal and a July 1 deadline for a modeling report submittal (following MPCA approval of the protocol). Therefore we are hopeful that submitting documentation in the form of a pre-protocol letter will indeed expedite MPCA approval of the modeling protocol.

This letter is comprised of five non-standard topics that could require additional review or for which we would like MPCA concurrence. The topics are:

1. Modeled Emission Rates
2. Proposed Permit Conditions
3. Meteorological Data
4. Nearby Sources
5. Modeled Emission Sources

1. Modeled Emission Rates

The proposed SO_2 emission limit for Boilers 1 and 2 (SV001 and SV002) is a **30-day average** limit of **271.6 pounds per hour (lb/hr)**. The 30-day average emission limit of 271.6 lb/hr is based on the procedure outlined by EPA in the April 23, 2014 *Guidance for 1-hour SO_2 Nonattainment Area SIP Submissions*[1] (hereafter referred to as the "EPA guidance"). The methodology to calculate this limit is explained in more detail in the next section: "2. Proposed Permit Conditions". An emission limit in lb/hr is relevant since it represents the rate of SO_2 emitted from the stacks on an hourly basis.

2. Proposed Permit Conditions

MP proposes to use a longer term SO_2 average emission limit (i.e., a 30-day average) that is comparably stringent to a 1-hour limit. In the EPA guidance document, EPA explains how to determine this 30-day average emission limit and EPA declares that long term average limits may provide adequate assurance that the 1-hour SO2 standard will be attained. More specifically, the EPA guidance provides a 6-step approach to determining a 30-day average that is comparably stringent to a 1-hour SO_2 emission limitation. The EPA guidance states (**emphasis** added):

> *Exceedances of the SO_2 NAAQS occur when emissions from relevant sources are sufficiently high on occasions when the meteorology is conducive for those emissions to cause elevated SO_2 concentrations. An illustrative example would be a case in which a single source has a dominant impact on area concentrations, and the source only causes an exceedance at a particular location with light southwest winds with limited dispersion. In this example, the likelihood of an exceedance at that location will be a function of the likelihood of elevated emissions occurring during times of light southwest winds with limited dispersion.* ***Stated more generally, the likelihood of an exceedance is a function of the likelihood of emissions being high when the meteorology is conducive for the source to cause an exceedance.*** *By extension, the likelihood of a violation is a function of the likelihood of emissions being high on a sufficient number of times with meteorology conducive to having exceedances to have the average of the 99th percentile daily maximum values exceed the NAAQS.*

[1] Stephen Page, "Guidance for 1-Hour SO_2 Nonattainment Area SIP Submissions", April 23, 2014 memorandum, http://www.epa.gov/oaqps001/sulfurdioxide/pdfs/20140423guidance.pdf.

> ***Viewed another way, the occasions when the meteorology is conducive for the source to cause an exceedance at a particular location are likely to be infrequent, and high concentrations are contingent on both emissions being sufficiently high and the meteorology being sufficiently conducive.*** *The NAAQS itself is based on relatively rare occurrences, being based on the 99th percentile of daily maximum concentrations.* ***Nevertheless, the point here is that the occurrence of high emissions will not cause an exceedance if it does not occur when meteorology is conducive to having an exceedance.*** *Furthermore, a source with rare occurrences of high emissions and with much more frequent occurrences of moderate emissions is more likely to have moderate emissions on those occasions with meteorology conducive for exceedances, and the design value for the source may be more prone to reflect the moderate emissions than the high emissions.*
>
> *…* ***EPA views its analyses as indicating that suitably adjusted longer term average limits can generally be expected to provide adequate confidence that the attainment plan will provide for attainment.***

This EPA guidance advises on how to determine a baseline 1-hour limit that is then adjusted downward to set a longer term average (e.g., a 30-day) limit. The resulting longer term average is a limit with comparable stringency to the corresponding 1-hr limit. The 6 steps in establishing a 30-day limit are summarized below:

> **Step 1:** Conduct dispersion modeling to determine a source's *critical emission value*, this is the hourly emission rate that results in modeled concentrations just below the 1-hr SO_2 NAAQS. This modeling analysis would include background concentrations and nearby sources.
>
> **Step 2:** Compile emissions data reflecting the distribution of emissions expected after the installation of control equipment or other similarly significant changes in operations.
>
> **Step 3:** Calculate a corresponding distribution of longer term emission averages (e.g., 30-day) from the distribution from Step 2. Hours with no operations are not to be included in the average calculations.
>
> **Step 4:** Calculate the 99th percentile value for the 1-hour distribution from Step 2 and from the 30-day averages distribution from Step 3.
>
> **Step 5:** Compute the ratio of the two 99th percentile values.
>
> **Step 6:** Multiply the ratio from Step 5 times the critical emission value from Step 1.

According to EPA, the result from Step 6 is a 30-day average emission limit which may generally be considered to have comparable stringency as a 1-hour limit at the modeled attainment level. The EPA believes that with the downward adjustment detailed in the 6 steps above, elevated emissions will be sufficiently rare that violations are very unlikely to occur.

MP is proposing to use this approach in determining a 30-day permit limit for Taconite Harbor Units 1 and 2 that is comparable in stringency to the 1-hour SO_2 limit. To determine this longer-term average limit, the six steps outlined by the EPA guidance were followed:

Step 1: Based on a 5-year modeled average of 99th percentile daily maximum hourly SO_2 concentrations, an emission rate of 380 lb/hr (47.9 g/s) for SV001 and SV002 results in concentrations at the level of the 1-hour SO_2 NAAQS (i.e., 196 µg/m^3). This analysis was performed in AERMOD by using Northshore Mining (NSM) met data and it includes a background of 2.5 ppb of SO_2. No nearby sources were included in this analysis per the justification provided in: "Section 4. Nearby Sources".

Step 2: As stated earlier, during 2015 THEC will be enhancing SO_2 controls on Units 1 and 2 by incorporating SBC injection in addition to the hydrated lime currently being utilized. This new sorbent will further reduce SO_2 emission rates, but it is not expected to change the fundamental <u>distribution</u> of emissions. Therefore, 2011-2014 CEMS (Continuous Emission Monitoring System) data collected from SV001 and SV002 was compiled to reflect the distribution of emissions expected after the use of SBC injection. The EPA Guidance states the following about this:

> *The data are used in a relative sense, so the magnitude of the emissions need not be the same…Where the control strategy does not significantly change the distribution, the source's current emission distribution may be the best indicator of the source's post-control emission distribution.*

Therefore, recent CEMS data was compiled in the form of hourly emissions in lb/hr that were also used to calculate rolling 30-day average emission levels. In should be noted that 2011 through 2014 were selected as the most recent available data set. It was not possible to use 2010 data as MP changed its Data Acquisition Historian System that year, and noncompliance data prior to the switchover became unrecoverable. However, MP and Wenck believe that four full years of hourly data (2011-2014) is more than sufficient to meet the EPA Step 2 guidance criteria instruction, which is to *compile emissions data reflecting the <u>distribution of emissions</u> that is expected once the attainment plan is implemented.*

Step 3: Based on the 2011-2014 CEMS data for SV001 and SV002, a 30-day emission average distribution was calculated.

Step 4 and 5: The 99th percentile values for the 1-hour distribution (from Step 2) and the 30-day averages distribution (from Step 3) were calculated along with the ratio of the two (Table 1).

Table 1. 99th percentile values for hourly and 30-day distributions.

2011-2014	**99th %(lb/hr)**	
	Unit 1 (SV001)	**Unit 2 (SV002)**
1-hr	457.9	385.5
30-day	369.8	275.6
99th Percentile 30-day to 1-hr ratio	**0.81**	**0.71**

Step 6: The ratio from Step 5 times the critical emission value from Step 1 was performed (Table 2). The ratio used was the most conservative (i.e., lower) from the two units (i.e., 71% from Unit 2). As a result, the 30-day average limit is 271.6 pounds per hour (lb/hr).

Table 2. Scaling of critical value based on 99th percentile ratios.

Critical Value*	380	lb/hr
Scaling factor	0.71	--
30-day limit	271.6	lb/hr

*Critical Value obtained through modeling of SV001 and SV002 at highest emission rate that produced a NAAQS-compliant run. Model run includes 2.5 ppb from background.

Therefore, using the modeled emission rate of 380 lb/hr for each boiler, MP proposes a 30-day rolling emission limit of 271.6 lb/hr.

Compliance with the proposed 30-day limit

Minnesota Power will assess compliance with the 30-day rolling 271.6 lb/hr limit through CEMS data. The 30-day rolling average is calculated from the daily averages from non-zero hours and based only on valid hours of SO_2 emissions. Based on an evaluation of the 2011-2014 CEMS data, compliance with this limit is not expected to be a problem at THEC. Figures 1 and 2 depict the histogram of 30-day rolling averages for Units 1 and 2 (i.e., SV001 and SV002).

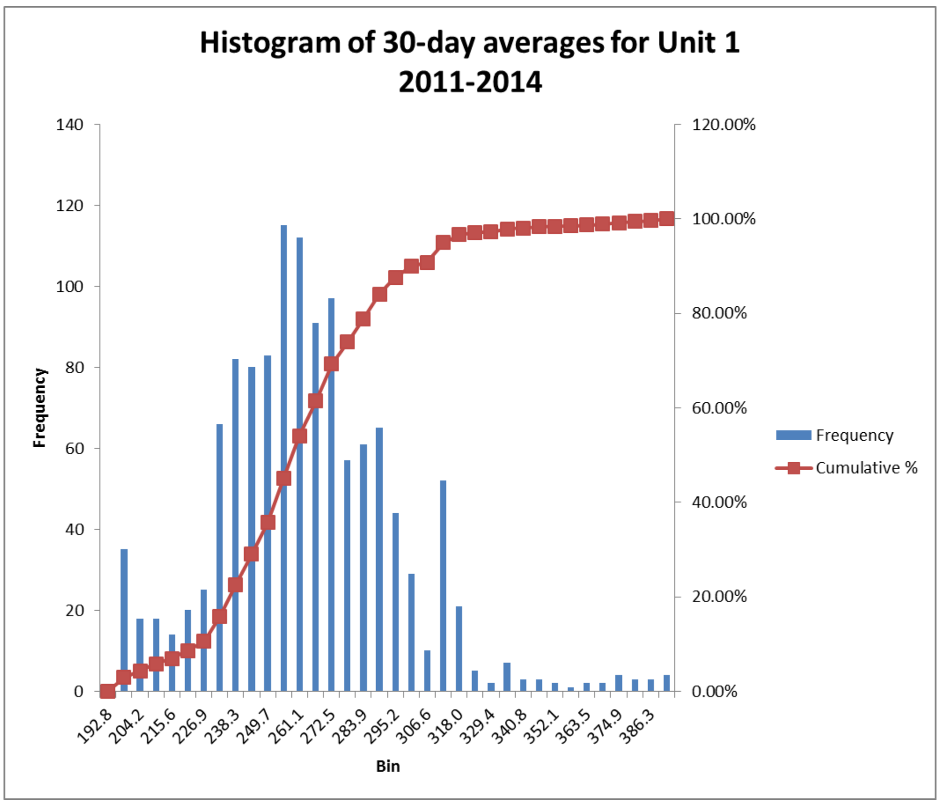


Figure 1. Histogram of 30-day rolling average values for Unit 1 (SV001) from THEC.

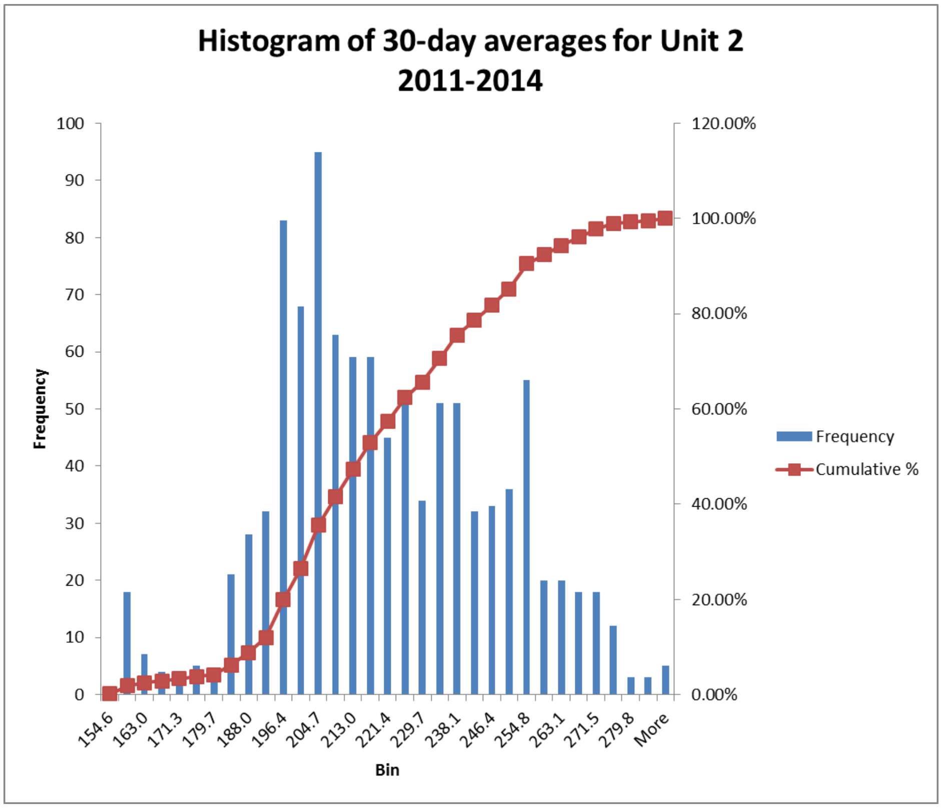


Figure 2. Histogram of 30-day rolling average values for Unit 2 (SV002) from THEC

For Unit 1, the maximum 30-day average emission rate is 392.0 lb/hr. For Unit 2, the maximum 30-day average emission rate is 288.2 lb/hr. However, since the two units will soon be controlled further with sodium bicarbonate (SBC), there will be an enhanced reduction in SO_2 emissions. This SO_2 reduction may range from 33 to 45 percent. If we conservatively assume the lower reduction of 33%, both units will have maximum emissions lower than 271.6 lb/hr based on a 30-day rolling average (Table 3). Therefore, Minnesota Power is expected to meet the proposed limit once the SBC injection project is in place.

Table 3. Current and expected maximum 30-day rolling average values based on the 2011-2014 CEMS data and an estimated SO_2 reduction from sodium bicarbonate (SBC) injection.

2011-2014	Max (lb/hr) 2011-2014		Estimate Further SO_2 Reduction with SBC	Max (lb/hr) Expected	
	Unit 1	Unit 2	%	Unit 1	Unit 2
30-day avg.	392.0	288.2	33	262.6	193.1

3. Meteorological Data

The use of the THEC onsite meteorological data collected in 1992 was proposed during the December 17, 2014 meeting. However, MPCA staff expressed concern with vintage of this data. MPCA held discussions with modeling staff from EPA Region V, who also expressed similar concerns. Mr. Jim Sullivan also mentioned that more recent meteorological data was available from Northshore Mining (NSM), in Silver Bay, MN. On December 19, 2014 Mr. Sullivan communicated to Sergio Guerra that the NSM meteorological data would be suitable for THEC's modeling evaluation. Furthermore, it was

communicated that, based on discussions with Randy Robinson from EPA Region V, the use of the NSM data would be acceptable for THEC. This data was sent by Ms. Melissa Sheffer to Sergio Guerra on December 19, 2014. The processed onsite meteorological data was collected at NSM from 2008-2012.
The use of the onsite NSM meteorological data is proposed for the THEC modeling analysis given its similarity in land use, location, and terrain which is a much better fit than either the National Weather Service (NWS) data from the Duluth International Airport (DLH) or the Duluth Sky Harbor Airport (DYT) data. The NSM data has also been accepted and used in other modeling evaluations reviewed by MPCA and EPA.

4. Nearby Source in THEC's Modeling Evaluation

MPCA's GIS tool was used to determine any nearby sources to include in the modeling analysis for THEC. Based on this tool, Northshore Mining was identified as a potential nearby source to include. However, upon closer inspection we believe that the likelihood of this source impacting THEC's modeling domain is highly unlikely. Therefore, MP requests that this nearby source be excluded from the modeling analysis of THEC.

The justification to exclude NSM from the modeling analysis relates to the distance between the two sites which is over 23 miles (about 38 kilometers). Given that SO_2 oxidizes and is removed from the atmosphere due to chemical reactions in the atmosphere and dry/wet deposition, the effects of SO_2 are highly localized. Therefore, it is not expected that the impacts from NSM would overlap with those from THEC. Furthermore, for the plumes from these two sites to overlap, the winds would have to come from the southwest direction, specifically from the 214°-236° wind vane (Figure 3).

Figure 3. Map showing Northshore Mining Co. (NSM) and Minnesota Power Taconite Harbor Energy Center (THEC) with the NSM's 2008-2012 wind rose plot.

Additionally, since we are dealing with the 1-hour standard, the winds would also have to be at least of 38 km/hr for the plume from NSM to reach the THEC site. When the winds originate from the southwest, the main impacts from THEC would occur at a distance from the site. Therefore, it is likely that the distance to the highest receptors would be even greater than 38 km, which would require even faster winds in order for the two plumes to overlap each other.

An analysis of the wind direction and speed revealed that from the 43,848 hours collected at NSM during the 5 year period available (2008-2012), only 75 hours had speeds greater than 10.5 m/s (37.8 km/hr) from the southwest (214°-236°) direction. This means that favorable conditions that would produce overlapping of impacts for NSM and THEC occurred only 0.17% of the time. Given that the 1-hour SO_2 NAAQS is the 99^{th} percentile, even if the overlapping of these two plumes produced maximum impacts, these impacts would be a higher percentile than the statistical form of the standard. Therefore, MP proposes not to include NSM as a nearby source in the modeling analysis.

5. Modeled Emission Sources

According to Table 17 from MPCA's Air Dispersion Modeling Guidance, emission units below a calculated lower bound emission rate can be excluded in a modeling evaluation. Emission units above a calculated upper bound emission rate must be modeled explicitly in a modeling evaluation. Emission units with emission rates between the upper and lower bounds must be consolidated into one area source represented by the smallest rectangular area source enclosing the emission sources with emission rates between the upper and lower bounds. The calculated 1-hour SO_2 lower bound is 0.131 lb/hr as shown in Table 4.

Table 4. Lower and upper bound ratios for 1-hour SO_2 in lb/hr.

SO_2 Ratio	NAAQS/150	196/150	1.307
SO_2 LB	*0.10 lbs/hr		**0.131**
SO_2 UB	*2.28 lbs/hr		2.98

Lower Bound = (1-hr SO_2 NAAQS)/(PM10 NAAQS) * 0.10 lb/hr = (196/150) * 0.10 lb/hr = 0.131 lb/hr
Upper Bound = (1-hr SO_2 NAAQS)/(PM10 NAAQS) * 2.28 lb/hr = (196/150) * 2.28 lb/hr = 2.98 lb/hr

Impacts from sources emission emitting less than the lower bound are assumed to be represented in the background concentration. There are six emission sources at the site currently:

1. Utility Boiler Units 1-3 (SV001-SV003),
2. Heating Boiler (SV004),
3. Cold Start Generator (SV005), and
4. 100 HP Fire Pump Engine (Insignificant Activity).

Modeled emission rates for Units 1 and 2 were discussed previously. SV003 will not be included in the modeling analysis because this Unit will be retired soon. The heating boiler, Cold Start Generator and the fire pump engine have SO_2 emissions of 0.053 lb/hr, 0.019 lb/hr, and 0.001 lb/hr, respectively (see attached IA Emission Calculations). All of these values are below the calculated lower bound for 1-hr SO_2 and therefore do not need to be included in the modeling analysis according to MPCA's modeling guidance (see Table 5). Thus, these three units (i.e., SV004, SV005 and the 100 HP engine) will be excluded from the modeling evaluation.

Table 5. Comparison of insignificant activities to Lower Bound limit.

Stack/Vent Number	Emission rate (lb/hr)	Modeling Insignificant Threshold (lb/hr)	Include in Modeling Eval?	Description
SV004	0.05325	0.131	NO	Heating Boiler
SV005	0.0194	0.131	NO	Cold Start Generator
N/A	0.0012	0.131	NO	100 HP Diesel Fire Pump Engine

We appreciate your prompt attention to this modeling pre-protocol submittal and look forward to continued cooperative work with the MPCA on this important project. If you have any questions, please contact Melissa Weglarz of Minnesota Power at mweglarz@allete.com or (218) 355-3321 or Jared Anderson of Wenck Associates at janderson@wenck.com (651) 294-4592.

Sincerely,

Melissa S. Weglarz

Melissa Weglarz
Air Quality Manager
ALLETE, Inc. dba Minnesota Power

Jared Anderson

Jared Anderson
Associate / Senior Air Dispersion Modeler
Wenck Associates, Inc.

Attachment: IA Emissions Calculations

MN Power - Tac Harbor Energy Center
Insignicant Activity Calculations

SV004M Heating Boiler

Throughput	35	MMBtu/hr
Emission Rate	0.213	lb/1000 gal
Emission Rate	0.05325	lb/hr

Sulfur content = 142 * S based on AP-42 Section 1.3 "Fuel Oil Combustion", Table 1.3-1 for Boilers less than 100 MMBtu/hr firing No. 2 oil; 35 MMBtu/hr * 142 * 15 ppm / 10^6 * 100 / 140,000 btu/gal * 10^3.

S = 15 ppm based on sulfur content in fuel shipments, heating value of 140,000 BTU/gal

SV005M Cold Start Generator

Throughput	1600	HP
Emission Rate	1.21E-05	lb/HP*hr
Emission Rate	0.0194	lb/hr

Sulfur content = 8.09E-03 * S based on AP-42 Section 3.4 " Large Stationary Diesel And All Stationary Dual-fuel Engines", Table 3.4-1 for Diesel Engines;

S = 15 ppm based on sulfur content in fuel shipments.

100 HP Diesel Fire Pump Engine

Throughput	100	HP
Emission Rate	1.21E-05	lb/HP*hr
Emission Rate	0.0012	lb/hr

Sulfur content = 8.09E-03 * S based on AP-42 Section 3.4 " Large Stationary Diesel And All Stationary Dual-fuel Engines", Table 3.4-1 for Diesel Engines;

S = 15 ppm based on sulfur content in fuel shipments.

Summary	Emission rate (lb/hr)	Mod. Insig. Threshold (lb/hr)	Include in Modeling Eval?	Description
SV004M	0.05325	0.131	NO	Heating Boiler
SV005M	0.0194	0.131	NO	Cold Start Generator
N/A	0.0012	0.131	NO	100 HP Diesel Fire Pump Engine