PUBLIC DOCUMENT

STATE OF MINNESOTA
Before the Public Utilities Commission

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In the Matter of the Review of the 2011-2012 Annual Automatic Adjustment Reports for All Electric Utilities

DOCKET NO. E999/AA-12-757

In the Matter of the Review of the 2012-2013 Annual Automatic Adjustment Reports for All Electric Utilities

DOCKET NO. E999/AA-13-599

REPLY COMMENTS OF THE OFFICE OF THE ATTORNEY GENERAL - RESIDENTIAL UTILITIES AND ANTITRUST DIVISION

I. INTRODUCTION

The Office of the Attorney General – Residential Utilities and Antitrust Division ("OAG") submits the following Reply Comments in response to the Commission's Notice of Additional Comment Period for the above-captioned matters regarding the annual review of electric utility fuel costs and recovery. The OAG's Reply Comments address two topics. First, while the OAG agrees with the Minnesota Department of Commerce's ("DOC's") conclusion that the utilities did not provide sufficient analysis to support their claims that business interruption insurance ("BII") is cost prohibitive, the OAG does not agree that BII would only be beneficial to ratepayers when it is accompanied by a fuel clause adjustment ("FCA") incentive mechanism.[1] The information provided by the utilities, however, is not sufficient to adequately determine if BII is reasonable. The Commission should order utilities to conduct further analysis on the costs and benefits of BII for ratepayers.

Second, the OAG agrees with the DOC on the need for an FCA incentive mechanism. The DOC discussed multiple types of incentive mechanisms.[2] The OAG provides additional analysis on the factors that influence fuel costs, how these factors are partially within the utilities' control, and discusses the potential benefits and detriments of some of the incentive mechanisms discussed by the DOC. The OAG continues to recommend that the Commission consider implementing a FCA incentive mechanism that protects ratepayers from avoidable, higher fuel costs.

II. THE COMMISSION SHOULD REQUIRE ADDITIONAL ANALYSIS OF BII BY THE UTILITIES AND IMPLEMENT BENEFICIAL RATEPAYER PROTECTIONS.

A. THE UTILITIES PROVIDED CONTRADICTORY AND MISLEADING INFORMATION ABOUT BII.

Multiple utilities provided Reply Comments in those dockets and additional information has been produced to the OAG by the utilities on the subject of BII. In general, the information provided by most utilities has been sparse and lacked detailed analysis. At best, the information is incomplete and insufficient to determine whether BII is affordable. In analyzing the comments and responses to information requests that have been provided, the OAG found that the utilities provided contradictory and possibly misleading information. It appears that most

[1] *See* DOC's Response to Reply Comments at 6-7 (December 31, 2014). Although the DOC does not explicitly state that BII would not benefit ratepayers, it argues that the risk/responsibility structure would be flawed without a fuel clause incentive mechanism. BII would function better with a fuel clause incentive mechanism. Even without a FCA incentive mechanism, however, BII would provide benefits to ratepayers.

[2] *Id.* at 14-15.

utilities have not fully analyzed the costs and benefits of BII to ratepayers. Those utilities with incomplete analyses should be ordered by the Commission to conduct further analysis to ensure that ratepayers are paying reasonable rates, and not taking on unreasonable risks, for the service they are receiving.

In Xcel's November 10, 2014 Trade Secret Reply Comments, the company estimated that insuring its non-nuclear fleet would cost **[XCEL TRADE SECRET BEGINS]**

[XCEL TRADE SECRET ENDS]. However, in its response to OAG Information Request 6, Xcel noted that "(t)he above-noted cost estimate includes our 20 largest units across the entire Xcel Energy service territory, not just generators in the NSP System. The cost share for NSPM would likely be at the lower end of the noted range."[3] This was not explained in its comments filed with the Commission. Moreover, Xcel did not provide any documentation to support the original claimed cost. When the OAG sought additional information regarding the basis for Xcel's estimate of NSPM costs, it revealed that the company calculated the figures based on a verbal estimate from its broker.[4] Xcel estimated that NSPM's portion of the costs would be in the range of **[XCEL TRADE SECRET BEGINS]**

[XCEL TRADE SECRET ENDS].

Xcel's claimed costs for BII are questionable. For comparison purposes, the OAG calculated each of the responding utility's cost according to both premium cost per $100 of coverage and by premium cost per megawatt. Xcel estimated BII to cost **[XCEL TRADE SECRET BEGINS]**

[3] *See* Xcel's response to OAG Information Request 6, attached as Exhibit A.
[4] *See* Xcel's response to OAG Information Request 21, attached as Exhibit B.

[XCEL TRADE SECRET ENDS].[5] By comparison, Otter Tail Power ("OTP") received a verbal quote[6] from its insurer of $0.55 to $1.20 per $100 of coverage for BII.[7] Minnesota Power ("MP") pays **[MP TRADE SECRET BEGINS]**

[MP TRADE SECRET ENDS][8] for BII that is currently in place. MP's cost is the only cost that was actually provided by an insurance company in writing, while OTP and Xcel relied on verbal quotes. Xcel's estimate is **[TRADE SECRET BEGINS]**

[TRADE SECRET ENDS].[9]

The utilities have also not taken the steps necessary to sufficiently evaluate BII. The OAG has attached two excerpts from the *Market Power Review* and an article from *Power Engineering Internationa*l that discuss the communication process and informational exchange that can be followed to procure an accurate quote for BII.[10] These articles describe basic steps that utilities should take in evaluating BII. For example, a common first step would be for the utility's broker to send an engineer to meet station managers and carry out a risk assessment to compile a risk report.[11] It is not clear utilities have completed this initial step or any of the subsequent recommended steps as outlined in these articles. Moreover, a key conclusion that the

[5] *See* Xcel's response to OAG Information Request 6, attached as Exhibit A.
[6] *See* OTP's response to OAG Information Request 10, attached as Exhibit C.
[7] OTP did not provide enough information to make the dollars per megawatt calculation. For OTP's estimate, see its response to OAG Information Request 9, attached as Exhibit D.
[8] *See* MP's response to OAG Information Request 13 and 14, attached as Exhibit E.
[9] While the OAG recognizes that comparing the different estimated BII cost information that has been provided from different utilities is not a direct comparison, it is the best comparison possible with the information provided by the utilities.
[10] *Power Market Review* (Summer 2010). Global Markets International. Found at: http://www.willis.com/Documents/Publications/Industries/Renewables/PowerMarketReview.pdf (attached as Exhibit F) and *Power Engineering International*, Power and insurance – an effective partnership (2011). Found at: http://www.powerengineeringint.com/articles/print/volume-19/issue-5/features/power-and-insurance-an-effective-partnership.html (attached as Exhibit G).
[11] *Power Engineering International* (2011).

Power Engineering International article comes to is that if a company is quoted a high premium, the company is either not providing enough information or it has a risk management problem that is being identified by the insurer.

Utilities have also provided contradictory information regarding the different types of BII, the restrictions that insurance companies may or may not apply to BII policies, and how these factors could impact affordability. OTP included the following summary on the different types of BII coverage:

> Otter Tail found that the coverage is specific to each location, based on each location's unique factors. In addition Otter Tail found that BI, if available for a location, can be purchased in a range of coverages [sic] for a range of perils or exposures. The lowest cost coverage typically insures the differential cost between power generated at the location and power purchased on the open market with coverage for limited perils or exposures (for example equipment breakdown only, natural hazards, contingent BI for offsite assets such as transformers or power lines owned by others, etc…). The highest cost coverage insures 100 percent of the financial benefit that would have passed to the insured had the asset not been impaired and would cover the broadest range of perils and exposures.[12]

On the other hand, Xcel noted that BII "would not be available for purchase for a single plant, but would need to be purchased for a group of plants."[13] Xcel did not indicate whether a minimum number of generation facilities would be required in order to obtain a BII policy, nor did it substantiate the claim that BII cannot be purchased for fewer plants than Xcel's estimate included with information provided directly from an insurer or broker. For its part, MP insured fewer plants than Xcel stated it could, but **[MP TRADE SECRET BEGINS]**

[MP TRADE SECRET ENDS].[14] Each utility has provided limited analysis of differing types of BII and, except for MP, has not provided sufficient analysis

[12] *See* OTP's response to OAG Information Request 11, attached as Exhibit H.
[13] *See* Xcel's response to OAG Information Request 6, attached as Exhibit A.
[14] *See* MP's response to OAG Information Request 13 and 14, attached as Exhibit E.

to demonstrate whether the differing types of BII are prudent. OTP's, IPL's, and Xcel's methodologies do not rely on quotes from direct insurers[15] or any detailed analysis of the affordability of BII. Failure to consider this basic information is unreasonable.

B. THE UTILITIES FAILURE TO PURCHASE BII IS INFLUENCED BY THE LACK OF INCENTIVE TO MINIMIZE FUEL COSTS.

Evidence suggests that regulated utilities are failing to minimize fuel costs to the detriment of ratepayers. A recent report found that deregulated coal generation plants pay 12% less for coal than do regulated plants, primarily because regulated generators pass through costs directly to ratepayers and have no incentive to "shop around" for lower coal prices.[16] The same report found that regulated utilities choose to spend more money on coal scrubber technology to comply with regulation, instead of simply substituting cheaper low-sulfur coal to accomplish the same result, in order to make additional returns on their capital improvements.[17] Each of these findings support the claim that regulated utilities do not minimize their fuel costs without having an incentive to do so.

The fact that regulated utilities do not have an incentive to minimize their fuel costs could impact whether or not they consider BII to be a profit-maximizing business decision. Since both fuel and replacement fuel costs are passed directly through to ratepayers, utilities' interest in obtaining BII is lower than it would be if utilities internalized some fuel cost risk. Evidence suggests that regulated utilities do not consider BII to be necessary for their businesses. In

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[15] Xcel and OTP used verbal quotes from brokers to make calculations. The complexity of BII, including the numerous options available and types of generation, make verbal quotes a questionable method to receive accurate and complete information. While such a quote may have been an acceptable bases to provide an initial response to the Commission, a more thorough analysis and a more transparent methodology are required so that the Commission can control for variables affecting cost and protection for ratepayers.

[16] NBER, *When Does Regulation Distort Costs? Lessons From Fuel Procurement in U.S. Electricity Generation*. Cicala (2014).

[17] *Id.*

OTP's response to OAG Information Request 10, the company stated that its "insurer notes that less than five percent of regulated utilities purchase business interruption insurance."[18] Given that regulated utilities do not have an incentive to minimize fuel and replacement fuel costs, this statement should not be a surprise. It should also not be surprising that unregulated electricity generators commonly purchase BII because those generators retain the risk of replacement fuel costs associated with forced outages.[19] Given that regulated utilities do not minimize fuel costs and that unregulated electricity generators purchase BII due to the risk of replacement power costs, it is likely that regulated utilities are not purchasing BII because they have no incentive to minimize the costs BII would insure against.

For this reason, the DOC indicated that the effectiveness of BII will be greatly compromised unless utilities have an incentive to minimize fuel and replacement fuel costs. Specifically, the DOC stated "(e)ven if, say, a utility bought business interruption insurance on behalf of its customers and charged ratepayers for those costs in the FCA, the mechanism would be flawed because the party that would bear the risk (ratepayers) would not be the party that could manage the risk (utilities) by abiding by inspection and repair guidelines, hold contractors accountable for their missteps, etc. . . ." For this reason, the DOC suggests that a mechanism to incent utilities to reduce their fuel costs must come before the utility obtains BII.

BII would be more beneficial if a FCA incentive mechanism were in place, but BII could be a prudent cost without such a mechanism. First, BII could require the utility to prove that an

[18] *See* OTP's response to OAG Information Request 10, attached as Exhibit C.
[19] *See* Law360 *Underwriting the Wind*, December 20, 2010, and NREL, *Insuring Solar Photovoltaics: Challenges and Possible Solutions* (2010) for information on BII for wind and solar. Exelon Generation is an example of a firm that insures its solar and wind generation facilities. See Part I, Item 1 at 15, February 21, 2013 of 10-K report. See *Power Engineering International* article for a discussion of BII in the (mostly unregulated) electric generation sector in other countries, attached as Exhibit F.

interruption, such as a forced outage, was not caused by its negligence. Second, BII is often a policy that guards against catastrophic incidents. A FCA incentive mechanism would ensure that utilities are minimizing their costs under normal conditions, but stops far short of insuring that catastrophic events do not occur and provides no protection for ratepayers if such an event were to occur. Regardless, the FCA incentive mechanism and BII complement one another and it is clear that ratepayers would be less likely to pay inflated fuel costs with a FCA incentive mechanism. It is also clear that utilities need to conduct further analysis on the costs and benefits of BII. The Commission should require additional analysis of BII by the utilities and implement beneficial ratepayer protections.

III. A FCA INCENTIVE MECHANISM IS NEEDED TO ENSURE RATEPAYERS ARE CHARGED REASONABLE RATES.

The changes in electricity markets and regulation since the FCA was first implemented have exacerbated the perverse economic incentives within the FCA. The FCA incentivizes utilities to substitute capital for increased fuel efficiency, choose suboptimal fuel mixes across the generating fleet, and skew short- and long-term planning. The lack of incentive to minimize fuel costs has created a scenario in which each utility's poor performance is likely increasing fuel costs for Minnesota ratepayers. At a recent energy forum Xcel Energy's CEO, Mr. Ben Fowke, stated that "incentives do work."[20] Given the utilities' recent interest in performance based regulation ("PBR"), the Commission should implement a FCA incentive mechanism to ensure that Minnesota ratepayers are receiving reasonable rates and utilities are incented to improve performance.

[20] Center for Energy and Environment's 35th Anniversary Policy Forum. Video available on CEE's website.

A. Utilities Control Multiple Factors That Directly Influence Fuel Costs.

Utilities control multiple factors that directly influence fuel costs over the short- and long-run. Regulators should not be forced to micro-manage each and every decision that impacts fuel costs, nor can regulators possibly review or have knowledge about even a small portion of all these decisions. Since the factors that impact fuel costs are partially controlled by the utilities' performance, utilities need to be provided with an incentive to minimize fuel costs to provide reasonable rates.

Xcel's August 26, 2013 comments in Docket No. 12-757, included a table that listed the main factors impacting the FCA from 2008 to 2012. Xcel updated this list of factors to include 2013 to 2014 in its response to an information request.[21] The list of factors that occurred at least once between 2008 to 2014 can be simplified as follows:

1. Higher natural gas, coal and nuclear fuel prices,
2. Additional purchased power agreements ("PPAs") and general purchases for biomass and wind,
3. Increased company owned wind,
4. Higher rail prices to transport coal,
5. Retired coal generation,
6. MISO market price and related expenses, and
7. Planned and forced outages.

Other than nuclear costs, which are unique to Xcel, each of the above factors can influence fuel costs for any electric utility in Minnesota. Whether each factor is controlled or influenced by the

[21] See Xcel's response to OAG Information Request #2 attached as Exhibit I. Xcel's original table is included within its response, which details costs by year.

utility helps to inform whether or not an FCA incentive mechanism is prudent. Therefore, the OAG analyzed the utilities' control over the above factors. The OAG's analysis demonstrates that utilities have significant control over many of these factors.

First, as referenced above, a recent National Bureau of Economic Research study found that deregulated coal generators paid 12% less for coal than coal generators under cost-of-service regulation.[22] The study, however, found that the same sample considered in the coal analysis did not pay a different amount for natural gas purchases. The discrepancy between the findings regarding natural gas and coal costs was primarily attributed to information asymmetry—natural gas prices are settled in a transparent open market, while coal contracts are primarily confidential bilateral contracts.[23] The study indicates that regulated utilities have poor performance with respect to confidential bilateral fuel contract negotiation. Moreover, regulators cannot police and readily compare the confidential bilateral contracts in the same way that they can review natural gas costs, which provides the regulated utility less incentive to minimize the fuel costs for coal. This finding indicates that ratepayers could save significantly, perhaps tens of millions of dollars, if the incentive was given to Minnesota utilities to lower their coal costs through better negotiation and procurement strategies.[24]

Second, utilities also have some control over the cost that company-owned wind and wind curtailments cause within their system. As the DOC pointed out in a previous AAA filing, Xcel has increased the cost of wind curtailments by not curtailing the cheapest wind resources

[22] Utilities make a comparison of average coal costs in AAA filings. Comparing simple averages does not provide enough information to determine if coal costs are prudent because they do not take into account the numerous variables that impact coal costs for each utility such as location, type of coal, quantity purchased, transportation costs, among many other things.
[23] NBER (2014) at 3.
[24] *See* tonnage purchased and average prices paid by each Minnesota utility in Docket No. 13-599.

first, which increased the fuel costs over the short-run for ratepayers.[25] Utilities also have control of the planning and integration of these facilities, which contributes to the costs of curtailments and operation within MISO (such as congestion costs) that flow through the FCA.

Third, like wind curtailments, utilities have control over planned outages, and the DOC has pointed out multiple cases where utilities have had some control over forced outages.[26] For example, utilities have caused outages due to their employee's own human error and poor oversight of their vendors.[27] These mistakes were obviously under the control of and caused by the utility, but utilities still attempted to pass through these costs to ratepayers. Utilities do not have proper incentive to minimize the time or frequency of these outages because they do not pay any replacement fuel costs.

Fourth, utilities have some control over MISO related costs that flow through the FCA, which have increased dramatically over the last decade. There are many costs associated with MISO (such as NSP's "proprietary resource trading methods") that are far too complex, making it difficult to determine whether or not they are reasonable. On the other hand, there are costs within MISO that are clearly partially under the control of utilities, such as congestion costs. For example, annual revenue rights are allocated each year as a hedge for congestion costs, which means a better hedging strategy will lower congestion costs, all else constant. This demonstrates some costs are too complex for regulators to effectively manage because of information asymmetry. For these costs to be minimized, the Commission should rely on a FCA incentive mechanism.

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[25] *See* the DOC's comments filed June 1, 2012 at 14.
[26] *See* the DOC's comments filed June 1, 2012.
[27] *Id.*

Fifth, the fuel costs related to coal transportation are similar to the issues posed by coal contract negotiation. Coal transportation costs are partially dictated by the utilities' ability to negotiate the lowest reasonable price. However, the utilities have no incentive to obtain the lowest price because the cost flows through the FCA. Utilities also do not have an incentive to achieve the most beneficial terms within the contract. Since utilities do not pay for replacement fuel costs, they are not significantly impacted financially by whether their generation plants run or not. Additionally, utilities have no reason to hold rail companies accountable for causing replacement power costs because utilities do not pay these costs. Utilities are likely paying too much for poor service from their rail providers, while ratepayers pick up the tab for the transportation and the replacement power costs due to low supplies of coal.

As discussed above, natural gas is procured in a relatively transparent market. However, natural gas hedging can impact the risk associated with prices. When addressing the FCA incentive mechanism in Xcel's 2012 electric rate case, a company witness, Mr. Allen Krug, stated "that an incentive mechanism would likely cause increases in hedging costs that the Company would have to incur to protect against fuel and purchased power cost volatility."[28] The fact that Xcel would increase hedging costs if it were to have an incentive to minimize its costs demonstrates that Xcel is willing to expose ratepayers to a higher level of risk than its stockholders with respect to fuel and purchased power cost volatility. Xcel and other utilities expose ratepayers to too much risk with regard to fuel and purchased power costs.

[28] *See* Krug Rebuttal at 22 in Docket No. 12-961.

B. A FCA Incentive Mechanism Is A Performance Based Regulation That Would Help Deliver Reasonable Fuel Costs.

The above analysis demonstrates that, based on both economic theory and the results of empirical studies, utilities have significant control over numerous factors that influence fuel costs. Since utilities have some control over fuel costs, they should internalize some of the risk associated with fuel costs in order to minimize costs. A FCA incentive mechanism would not only minimize fuel costs but would also reward utilities for improved performance. Most FCA incentive mechanisms are therefore a form of PBR, which has been requested by multiple Minnesota utilities. The OAG and DOC have suggested that these same utilities implement a FCA incentive mechanism that is similar, if not the same, to other metrics that could be developed under PBR for over a decade, without success.

The OAG is concerned that utilities may only want to pursue PBR when utilities are virtually assured of benefitting from the mechanism implemented. Structuring PBRs this way will not provide an effective or equitable mechanism. PBR requires that utilities take on more risk than traditional regulation in order to be eligible for larger rewards. If utilities are only willing to adopt PBR mechanisms that are designed with asymmetric information, the benefits for ratepayers will be eliminated or minimized.

C. Hindsight Analysis Of Possible FCA Incentive Mechanisms Demonstrate Reasonable Outcomes For Utilities And Ratepayers.

The OAG conducted hindsight analysis on two types of FCA incentive mechanisms to determine whether either would produce reasonable results. The OAG's analysis demonstrates both methods would provide outcomes that are better than the current model. The first analysis was conducted on a FCA incentive mechanism that sets fuel costs within a rate case with a band adjustment of 2%. This "band mechanism" would set the base cost of fuel in a rate case with a tolerance band of 2% and be trued-up annually when necessary. This would allow utilities to benefit from their improved performance up to 2% by lowering fuel prices and would punish utilities for poor performance up to 2% for higher fuel prices. Any costs above 2% would be deferred and addressed in a special proceeding where utilities would have to demonstrate why these costs were necessary and, therefore, should be recovered from ratepayers. Any costs that fall below 2% would go back to ratepayers. The second analysis was conducted on a FCA incentive mechanism that shares a percentage of the costs and benefits associated with increasing and decreasing fuel costs. This "sharing mechanism" would provide a 10 percent/90 percent sharing of costs and benefits between the utilities and ratepayers, respectively. These mechanisms were selected to demonstrate that there are reasonable FCA incentive mechanisms that can minimize fuel costs, and because both of these mechanisms have been implemented in other states.[29] These two mechanisms are not presented as the only possibilities, as the DOC provided additional options in previous comments (and noted that mechanisms can be combined).[30] The following analyses demonstrate that each of the FCA incentive mechanisms have benefits and detriments associated with them, but both provide outcomes superior to having no FCA incentive mechanism.

The OAG's analysis for each FCA incentive mechanism was conducted using similar methodologies, by incorporating data provided by Xcel[31] and data on the base cost of energy set in Xcel's previous rate cases. Each analysis uses the base cost of energy for Xcel's system and compares it to the actual cost of fuel within Xcel's system to determine whether there would

[29] FCA incentive mechanisms have been implemented in Washington, Idaho, Oregon, Missouri, and Wisconsin.
[30] The OAG has not addressed the possible need for statutory or rule changes to implement such mechanisms.
[31] *See* Xcel's response to OAG Information Request 2, attached as Exhibit I.

have been an over- or under-collection. The two mechanisms differ by the way in which the over or under collection is dealt with, as explained above.

Table 1, below, summarizes how the band mechanism would have worked over the 2011 to 2014 time period.[32]

Table 1

Band Mechanism				
(1)	**(2)**	**(3)**	**(4)**	**(5)**
Year	**% Over/Under Collected**	**$ within Tolerance Band**	**$ Over (Under) Band**	**Total**
2011	2.40%	$16,626,703	$3,331,643	$19,958,347
2012	-0.89%	($7,493,441)	$0	($7,493,441)
2013	-8.79%	($18,423,077)	($62,531,428)	($80,954,505)
2014	-0.16%	($1,329,348)	$0	($1,329,348)
Total		($10,619,162)		

Table 1, above, displays the percentage that was over or under collected in column 2, how much of the over or under collection was within the 2% tolerance band in column 3, how much was outside of the band that would be deferred by the utility or returned to ratepayers in column 4, and the total over or under collection that occurred in the given year in column 5.

The results in Table 1 demonstrate that Xcel would have been outside of the 2% tolerance band in two out of the last four years, and would have under-collected fuel costs slightly for two years. Total under-collection over the four year period would have been approximately $10 million, or 0.31% of total fuel costs. The band mechanism results also demonstrate that the company and consumers are protected by providing consumers with benefits some years and

[32] The OAG chose to use the 2011 to 2014 time period because in Xcel's 2008 rate case the base cost of energy was increased by approximately 50%, a historically unprecedented increase. This increase was over 25% greater than the actual cost of fuel experienced by Xcel in 2009 and 2010. The OAG considers these years outliers due to the uncharacteristically unreliable estimate that was used as the base cost of fuel for those years.

protecting the utility from large market disruptions that can lead to significant under-collections. One drawback to the band mechanism is that ratepayers would not immediately receive benefits from a utility's improved performance. Rather, ratepayers' benefits would accrue overtime as utilities hold costs below what they would be otherwise. The band mechanism may require regulators to affirmatively reset the base cost of energy on a regular basis to ensure the band is providing a strong incentive if the actual cost of energy is consistently under the base cost of energy and utilities avoid rate cases.

In contrast to the band mechanism, the sharing mechanism would provide benefits for ratepayers immediately. Table 2, below, displays the results of a 10 percent/90 percent sharing mechanism.

Table 2

Sharing Mechanism				
(1)	**(2)**	**(3)**	**(4)**	**(5)**
Year	**% Over/Under Collected**	**10% Sharing w/ Utility**	**90% Sharing w/ Consumer**	**Total**
2011	2.40%	$1,995,835	$17,962,512	$19,958,347
2012	-0.89%	($749,344)	($6,744,097)	($7,493,441)
2013	-8.79%	($8,095,451)	($72,859,055)	($80,954,505)
2014	-0.16%	($132,935)	($1,196,413)	($1,329,348)
Total		**($6,981,895)**		

Table 2, above, displays similar information to Table 1 except for columns 3 and 4, which summarize the sharing of over- or under-collection. Xcel would have under-collected by approximately $7 million, or 0.2% of total actual fuel costs, over the last four years.

Table 2 demonstrates that ratepayers and utilities would share in the costs and benefits every year. The sharing mechanism, under most circumstances, would not provide as strong of an incentive to the utility as the band mechanism since the utility would share in the costs and benefits with ratepayers. For example, in 2011, Xcel would have been able to retain over $16 million due to the lower cost of fuel under the band mechanism but less than $2 million under the sharing mechanism; ratepayers would have received a greater benefit under the sharing mechanism. The sharing mechanism also does not acknowledge that utilities may not have control over large fluctuations in energy prices, such as a 10% swing in fuel costs within one year.

The OAG's analyses of the band and sharing mechanisms results in a variation of fuel cost recovery of between 0.2% to 0.3% for Xcel over a four year period. These analyses demonstrate that a there is more than one option to ensure that utilities have incentive to control factors that influence the price of energy. The Commission should consider implementing a FCA incentive mechanism that protects ratepayers from paying avoidable, higher energy costs.

IV. CONCLUSION

In the OAG's December 30, 2014 comments, it made multiple recommendations for additional BII analysis to be completed by each of the utilities. MP had already completed a similar analysis that incorporated many of the recommendations made by the OAG concerning BII.[33] The fact that MP had already done this analysis demonstrates that the OAG's recommendations were reasonable. Xcel, OTP, and IPL, however, have not conducted any analysis that reasonably weighs the costs and benefits of BII for their ratepayers. The Commission should order Xcel, OTP, and IPL to conduct a meaningful analysis on whether BII is in the interest of ratepayers that incorporates, at a minimum, the recommendations in the OAG's previous comments.

[33] *See* MP's response to OAG Information Requests 13-16, attached as Exhibit E.

Additionally, the OAG submitted comments recommending that the Commission should consider implementing a FCA incentive mechanism. The OAG's analysis demonstrates that a utility's performance assuredly has some impact over the fuel costs passed through to ratepayers under the current FCA. The OAG also provided examples of reasonable FCA incentive mechanisms that would protect ratepayers and utilities from paying unreasonable fuel costs. The OAG recommends that the Commission consider implementing one of the FCA incentive mechanisms in order to protect ratepayers.

In addition, for the reasons stated in the OAG's previous comments, the OAG recommends that the Commission defer any decision on the recovery of Sherco 3 energy replacement cost until there is a sufficient record to determine if recovery is appropriate.

Dated: February 11, 2015

Respectfully submitted,

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ATTORNEY GENERAL – RESIDENTIAL
UTILITIES AND ANTITRUST DIVISION

☐ **Non Public Document – Contains Trade Secret Data**
☒ **Public Document – Trade Secret Data Excised**
☐ **Public Document**

Xcel Energy			
Docket No.:	E999/AA-13-599		
Response To:	Office of Attorney General	Information Request No.	6
Requestor:	Ian Dobson		
Date Received:	December 11, 2014		

<u>Question:</u>
Reference: Reply Comments at 10

Xcel claims that business interruption insurance would be **[TRADE SECRET BEGINS TRADE SECRET ENDS]** for non-nuclear generators. Please provide the insurance estimates or other information that supports this claim. Include in your response, but do not limit it to, a list of assumptions that were used to create the estimate and if Xcel has priced individual generators separately or aggregated all generators in this estimate.

<u>Response:</u>
Please see Attachment A to this response, which is a copy of an indicative term sheet issued in September 2013, and Attachment B, which shows how this term sheet has been applied to seven key units on the NSP system to support the cited estimate for purchasing business interruption insurance for non-nuclear generators. We note that we do not have a firm bid for business interruption insurance because a firm bid is only issued if there is a commitment to purchase the insurance. The Company has never found this type of insurance to be practical or cost-effective, so we have not solicited firm bidding prices, only periodic indicative term sheets to confirm this business practice remains sound.

We note that this type of insurance would not be available for purchase for a single plant, but would need to be purchased for a group of plants. If we were to obtain replacement power coverage, we would likely choose to insure only our 20 largest and most critical units. The above-noted cost estimate includes our 20 largest units across the entire Xcel Energy service territory, not just generators in the NSP System. The cost share for NSPM would likely be at the lower end of the noted range.

Preparer:	Robert Miller
Title:	Manager
Department:	Hazard Insurance
Telephone:	612-215-5371
Date:	December 23, 2014

Attachment A

This attachment is Trade Secret in its entirety.

Northern States Power Company
Electric Operations - State of Minnesota

Estimated Premium of Business Interruption Insurance

[TRADE SECRET BEGINS

Unit Name	Insured Capacity (MW)	Estimated Price * ($/MW)	Estimated Annual Business Interruption Fee Base

Range of Annual Business Interruption Insurance Premium Estimate			
	Fee Rate	Fee Base	Estimated Premium
High Estimate			
Low Estimate			

TRADE SECRET ENDS]

☐ **Non Public Document – Contains Trade Secret Data**
☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy			
Docket No.:	E999/AA-13-599		
Response To:	Office of Attorney General	Information Request No.	21
Requestor:	Ian M. Dobson		
Date Received:	January 14, 2015		

Question:
Reference: Response to OAG IR 6 – Attachment B

Confirm that the estimated premium is Xcel's estimate and not a broker's or insurance company's. If this is Xcel's estimated premium, explain why an estimate has not been obtained from a primary source.

Response:
The estimated insurance premium is a broker's estimate provided by Marsh. Xcel Energy analysts formatted Attachment B to show the calculations by plant based on the fee rate of 4 to 10 percent provided verbally by Marsh.

Preparer:	Robert Miller
Title:	Manager
Department:	Hazard Insurance
Telephone:	612-215-5371
Date:	January 27, 2015

OTTER TAIL POWER COMPANY
Docket No: E999-AA-13-599

Response to: Office of Attorney General
Analyst: Ian M. Dobson
Date Received: 12/11/2014
Date Due: 12/23/2014
Date of Response: 01/16/2015
Responding Witness: Stuart Tommerdahl, Manager Regulatory Administration, 218 739-8279

Information Request:

Reference: Reply comments at 4 – Business Interruption Insurance

Please provide the quote from the insurance company with any and all supporting documents.

Attachments: 0

Response:

Otter Tail relied on verbally communicated product descriptions and ranges as a basis for its analysis, as noted in our response to Information Request No. MN-OAG-09. Our insurer notes that less than 5 percent of regulated utilities purchase business interruption insurance.

OTTER TAIL POWER COMPANY
Docket No: E999-AA-13-599

Response to: Office of Attorney General
Analyst: Ian M. Dobson
Date Received: 12/11/2014
Date Due: 12/23/2014
Date of Response: 01/16/2015
Responding Witness: Stuart Tommerdahl, Manager Regulatory Administration, 218 739-8279

Information Request:

Reference: Business Interruption Insurance

In Otter Tail's reply comments at 4, it states that "Otter Tail determined that the cost of the additional premium for such coverage outweighed the benefit of adding that coverage."

1. Please provide the analysis that Otter Tail relied on to support this conclusion.

   a. If it was simply that Otter Tail has never experienced an outage of more than 60 days, please discuss how Otter Tail quantified the probability that it would not have one in the future.

Attachments: 0

Response:

For its evaluation, Otter Tail relied on insurance industry rate ranges, as provided by the insurer, for business interruption insurance. Costs range from $0.55 to $1.20 per $100 of limit purchased with a minimum 60 day deductible. These rates could result in an annual premium ranging from $275,000 to $600,000 for $50 million of coverage. The range in pricing is due to varying levels and types of business interruption insurance available and location-specific factors that would be considered in underwriting. Based upon these premium levels and Otter Tail's historic performance experience, it was determined that purchasing such insurance would not be a reasonable value.

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

OAG No. 13

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:

Christopher Anderson
Minnesota Power
30 W. Superior Street
Duluth, MN 55802-2191

MPUC Docket No.
E999/AA-13-599

In the Matter of 2013 Electric Company's Annual Adjustment Reports (AAA)

By: Ian M. Dobson
Telephone: (651) 757-1432

Date of Request: December 11, 2014
Due Date: December 23, 2014

Reference: Reply comments at 3 – Business Interruption Insurance

Please provide the "detailed risk assessment" that MP performed on its Bison wind assets and DC Line converter stations with all supporting data and documents referenced or used within the assessment.

Response: The attached risk summary was compiled in April – May 2013 and summarizes potential worst case scenarios surrounding an extended DC Line outage. The analysis assumes that no alternate transmission (i.e. AC system) is available and that generation must be curtailed versus delivering to different delivery point, causing a complete loss of Production Tax Credits (PTCs). Through our review of available business interruption coverage for this specific risk, we identified G-Cube as a potential new insurer for MP's Bison wind assets. G-Cube was also able to provide business interruption for our Bison wind assets when we switched our property policies for Bison over to them. We updated our analysis in 2014 as part of our annual insurance review and renewal. The potential worst case exposure recently increased due to the completion of Bison 4 and the resulting substantial increase in projected wind generation for Minnesota Power.

Response by: Jered Granley
Title: Director
Department: Risk Management
Telephone: 218-355-3856

Exhibit E

CONFIDENTIAL

Business Interruption Insurance Evaluation – DC Line

May 9, 2013

Executive Summary

The Company is currently reviewing insurance options for our DC Line Transmission assets. In addition to property insurance, providers have offered business interruption coverage. This additional insurance could help offset the replacement cost of energy and the lost value of Production Tax Credits (PTCs) in an extended outage event.

[TRADE SECRET DATA EXCISED]

Our current policy with FM Global does not include business interruption insurance and would not cover the potential exposure summarized above. FM is not able to offer additional coverage on the DC Line at this time. **[TRADE SECRET DATA EXCISED]**

Risk Assessment

Past DC Line outages have been relatively short in duration. The table below includes historical forced outage information. In an average year, about 2 outages occur, with the total outage duration of 80 hours. Over the last 11 years, the most outage hours occurred in 2002, when the DC line was out for 214 total hours or about 9 days.

DC Line
Forced Outages
2001-2011

Year	# of Events	Outage Hours
2001	3	13
2002	2	214
2003	1	125
2004	4	41
2005	1	40
2006	0	0
2007	2	195
2008	1	64
2009	0	0
2010	2	87
2011	3	97
Avg	**2**	**80**
Max	**4**	**214**

The outages in the table above are generally related to storm damage on relatively small sections of the line. None of the past forced outages have been related to the transformers or converters. After discussion with Lynn Crane and Peter Schommer, System Operations Engineers, the most significant outage risk surrounds a failure or loss of the transformers or converters. This equipment is over 35 years old and British Columbia Hydro recently had a catastrophic converter failure that lasted over a year in duration. **[TRADE SECRET DATA EXCISED]**

Outage Scenario	Duration	Replacement Energy	Lost PTC's	Total Exposure
[TRADE SECRET DATA EXCISED]				
[TRADE SECRET DATA EXCISED]				

[TRADE SECRET DATA EXCISED]

Our current policy with FM Global does not include business interruption insurance and would not cover the potential exposure summarized above. We reviewed business interruption coverage from GCube to potentially mitigate the business interruption risk. **[TRADE SECRET DATA EXCISED]**

2013 North Dakota Energy Projections

Purchases	Annual MWH	Purchase Price ($/MWH)	Total $
Oliver 1	[TRADE SECRET DATA EXCISED]		
Oliver 2	[TRADE SECRET DATA EXCISED]		
Square Butte	[TRADE SECRET DATA EXCISED]		
Total Purchases	[TRADE SECRET DATA EXCISED]		

Wind Generation	Annual MWH	Generation Cost ($/MWH)	Total $
Bison 1	[TRADE SECRET DATA EXCISED]		
Bison 2	[TRADE SECRET DATA EXCISED]		
Bison 3	[TRADE SECRET DATA EXCISED]		
Total Wind Generation	[TRADE SECRET DATA EXCISED]		

Annual Risk and 2 week risk based on 2013 MWH's and prices

Replacement Power Price	[TRADE SECRET DATA EXCISED]	CERA 7x24 forecasted price

Purchases	Annual MWH	Replacement Cost $/MWH	Total $ (Annual)	Total $ (1 week)	Total $ (30 days)
Oliver 1	[TRADE SECRET DATA EXCISED]			[TRADE SECRET DATA EXCISED]	
Oliver 2	[TRADE SECRET DATA EXCISED]			[TRADE SECRET DATA EXCISED]	
Square Butte	[TRADE SECRET DATA EXCISED]			[TRADE SECRET DATA EXCISED]	
Total Exposure - Replacement Power Purchases			[TRADE SECRET DATA EXCISED]	[TRADE SECRET DATA EXCISED]	

Wind Generation	Annual MWH	Replacement Cost $/MWH	Total $ (Annual)	Total $ (1 week)	Total $ (30 days)
Bison 1	[TRADE SECRET DATA EXCISED]			[TRADE SECRET DATA EXCISED]	
Bison 2	[TRADE SECRET DATA EXCISED]			[TRADE SECRET DATA EXCISED]	
Bison 3	[TRADE SECRET DATA EXCISED]			[TRADE SECRET DATA EXCISED]	
Total Exposure - Replacement Power Purchases			[TRADE SECRET DATA EXCISED]	[TRADE SECRET DATA EXCISED]	

Production Tax Credits	Annual MWH	PTC ($/MWH)	Total $ Lost PTC	Total $ (1 week)	Total $ (30 days)
Bison 1	[TRADE SECRET DATA EXCISED]			[TRADE SECRET DATA EXCISED]	
Bison 2	[TRADE SECRET DATA EXCISED]			[TRADE SECRET DATA EXCISED]	
Bison 3	[TRADE SECRET DATA EXCISED]			[TRADE SECRET DATA EXCISED]	
Total Exposure - Lost PTC	[TRADE SECRET DATA EXCISED]			[TRADE SECRET DATA EXCISED]	

Total	[TRADE SECRET DATA EXCISED]	[TRADE SECRET DATA EXCISED]
18 months	[TRADE SECRET DATA EXCISED]	
24 months	[TRADE SECRET DATA EXCISED]	
30 months	[TRADE SECRET DATA EXCISED]	

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

OAG No. 14

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:

Christopher Anderson
Minnesota Power
30 W. Superior Street
Duluth, MN 55802-2191

MPUC Docket No.
E999/AA-13-599

In the Matter of 2013 Electric Company's Annual Adjustment Reports (AAA)

By: Ian M. Dobson
Telephone: (651) 757-1432

Date of Request: December 11, 2014
Due Date: December 23, 2014

Reference: Reply comments at 3 – Business Interruption Insurance

Please provide MP's business interruption insurance policy for its Bison wind assets and DC Line converter stations.

Response: Please see attached *Trade Secret* copy of the requested insurance policy.

Response by: Jered Granley
Title: Director
Department: Risk Management
Telephone: 218-355-3856

OAG IR 14

ATTACHMENT:

LLOYDS'S CERTIFICATE IS

TRADE SECRET IN ITS ENTIRETY

OAG IR 14

ATTACHMENT:

ENDORSEMENT TO LLOYDS'S CERTIFICATE IS

TRADE SECRET IN ITS ENTIRETY

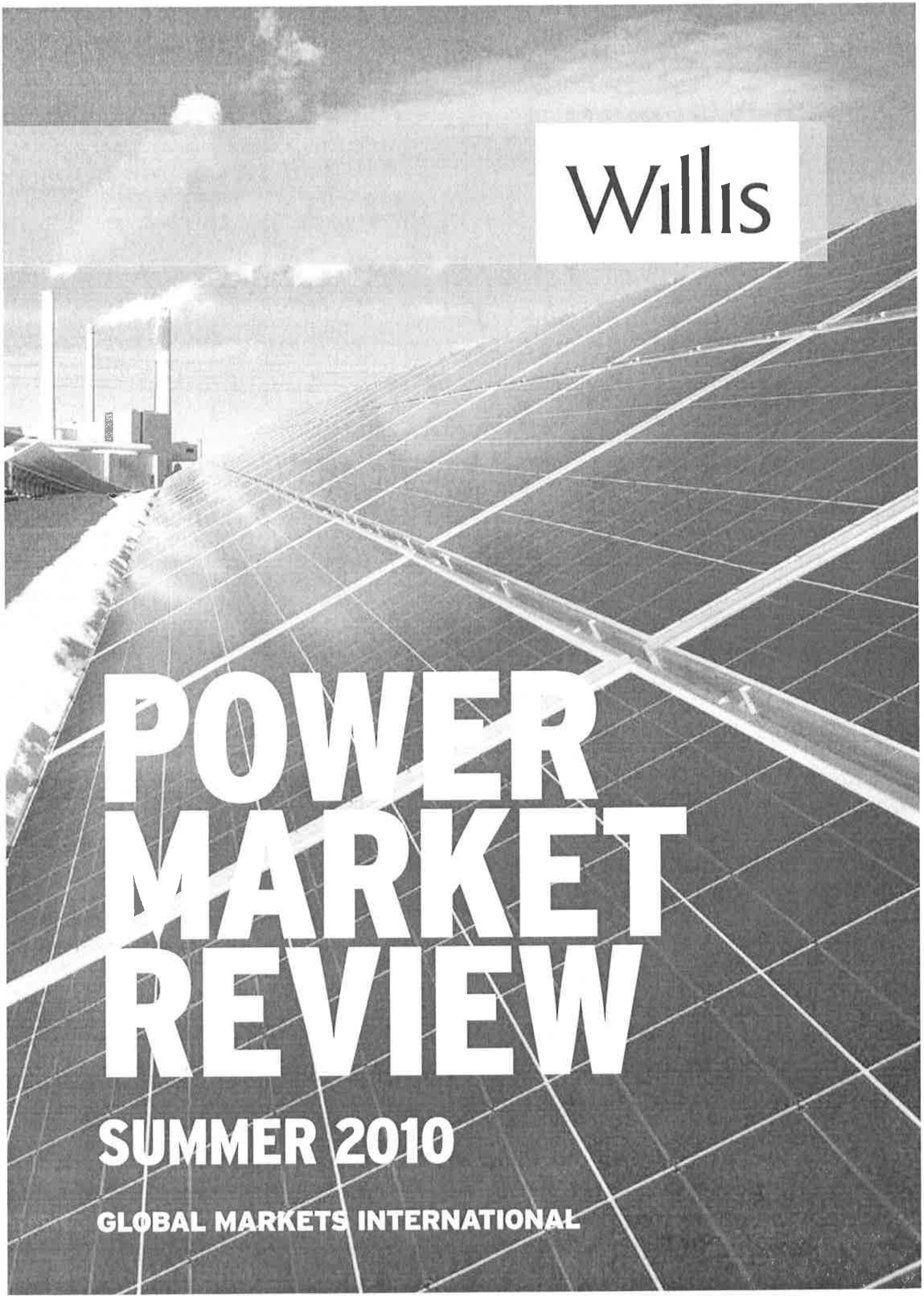
Willis
POWER
MARKET
REVIEW
SUMMER 2010
GLOBAL MARKETS INTERNATIONAL

Exhibit F

This has the outcome of creating an auction effect, giving buyers the freedom to select which limited number of insurers they wish to partner with out of the many quotations received in this area of the programme. It is here that the majority of risk losses will fall and hence where the majority of premium will be allocated.

ASSET VALUATIONS

Costs for new power plants and generation of electricity continue to rise and this also remains a key area of underwriting focus. Whilst engineering information is critical for underwriting review, this will not always be able to provide an accurate evaluation of the current replacement cost of assets. Correct asset valuation remains vital for underwriters when assessing risk exposure, PML limits and in calculating premium based on applied rates to asset values. Where insureds are unable to provide recent asset appraisal, underwriters will often either impose Average to the policy or adjust the premium they charge to reflect what they believe to be the correct level for the exposure – or both.

BUSINESS INTERRUPTION

Business Interruption is one area where power underwriters are focusing particular attention when assessing potential risk. One manifestation of this is that the technical underwriters are making greater efforts to fully understand the risks they are being asked to underwrite and their maximum monetary exposure in the event of a loss.

This is not always a straightforward task, since Business Interruption in the power sector is a particularly complex field of insurance. Different types of generator have different risk exposures: a portfolio generator may face potentially large additional costs of generation to replace the capacity of a damaged unit from elsewhere in its portfolio, while an Independent Power Producer (IPP) may only require cover for its fixed costs; a merchant producer will have a different, and more volatile, risk profile to one that sells under a power purchase or tolling agreement; some generators may have contractual obligations that they wish to insure, such as 'take or pay' fuel purchase commitments or penalties for non-performance; others may have significant contingent Business Interruption risks; and so on.

The measure of an underwriter's task in assessing the risks he or she is underwriting can be illustrated by the example of a portfolio generator with a monopoly or dominant position in its territory. In the event of damage to one of its merit order units, it will want to replace the lost capacity from its generating fleet. The replacement capacity will usually be more costly to run than the damaged unit (otherwise it would already have been running instead of the damaged one) and, for the purpose of this example, let us imagine that the reason for the difference is that the two plants run on different fuels. The generator therefore requires its Business Interruption insurance to provide indemnity for the increase in the costs it incurs for fuel as a result of a loss.

SO FAR, SO SIMPLE. BUT IN THE EVENT OF A LOSS, HOW MUCH MIGHT THESE ADDITIONAL COSTS BE?

This will depend not only on the duration of the outage, but also on:

- The market cost of the replacement fuel at the time of the outage, relative to what it would have cost to buy fuel for the damaged unit;
- Whether the generator is locked into a 'take or pay' fuel purchase contract in respect of the damaged unit, and is unable to store or use the contracted fuel elsewhere or sell it to a third party;
- The level of demand at the time of the outage (itself dependent on such factors as the weather and the economy), which will determine how much of the generator's portfolio is already running and how much is therefore spare;
- General plant availability – how much of the generator's portfolio is unavailable due to planned maintenance and/or other forced outages.

Few of these factors can be known at inception, since they are mostly conditional on the circumstances that apply at the time of the loss. Yet underwriters are increasingly seeking certainty over this kind of information, so that they can measure their exposure and cap it if necessary by limiting their line size or imposing caps or sublimits to the cover (or by doing both). If the insured generator submits estimated Business Interruption values per unit or plant based on expected circumstances, underwriters may try to limit their coverage for each unit or plant to these declared values – even though they may prove to be lower than the actual loss sustained due to factors beyond the Insured's control, such as increased fuel prices or unseasonal weather.

Similar issues apply to merchant IPPs (i.e. those that do not have a standard PPA but do their business in the electricity marketplace), whose Gross Profit estimates will be based on predicted market prices.

If actual market prices at the time of a loss are higher than the level predicted at the start of the insurance period, the traditional principle of Business Interruption insurance – to do for the business what the business would have done for itself had no loss occurred – dictates that the policy indemnity should be based on the actual market price (adjusted for the extent to which the absence of the damaged unit itself affects the market price). However, if underwriters have introduced sublimits based on the estimated values declared at renewal, this may deny the Insured a full indemnity.

The desire for certainty may be understandable from the viewpoint of underwriters who want to be sure of the extent of their financial exposure (and also want the indemnity provided to reflect the premium paid), but it places the Insured in a difficult position. Not only does the Insured have to produce a large amount of data (typically, the estimated Gross Profit or additional cost of generation for each generating unit on a month-by-month basis to identify seasonal or other variations) – but may then find that the policy limits are insufficient to provide a full indemnity.

SO WHAT CAN GENERATORS DO TO ENSURE THAT THEIR COVER BEST REFLECTS THEIR NEEDS?

As in the case of engineering information, they should provide as much Business Interruption underwriting information as they can, in the format requested by insurers. If certain details have not been requested by underwriters in previous years, it does not follow that there is no need to provide them when asked to do so today. Underwriters are more likely to commit their capacity to business that they can assess and measure than to exposures that are unclear to them. Some have declined to write or renew business, even where the general risk quality is acknowledged to be good, because they have not been given the information they feel necessary to properly underwrite the Business Interruption risk. The time and effort involved in producing the more detailed information requested by underwriters should be rewarded by underwriters' greater willingness to offer terms.

As to policy limits, the indemnity under an insurance policy is always limited to the policy limit or sum insured, and this can affect any company that operates in a business environment in which revenues or costs can be volatile. Such volatility can sometimes be catered for by allowing a margin in the sum insured and making the insurance retrospectively adjustable based on actual revenue (or some other measure), but adjustable policies are not to the liking of all Insureds.

Where revenue or costs can be volatile, it is important that any *per diem* or *per mensem* sublimits are based on the estimated exposure for the periods of the year when the monetary exposure is at its highest (usually mid-winter and/or mid-summer), rather than just averaging the annual exposure throughout the year. The amounts of any sublimits are usually negotiable, and Insured and broker should work together to identify the key areas of exposure and the limits which the Insured feels necessary, before negotiations with underwriters take place. It is often beneficial for the Insured to be involved directly in such discussions.

Power Engineering International

Power and insurance - an effective partnership

01/05/2011

The damaged dam of the Sayano-Shushenskaya hydroelectric power station near the Siberian village of Cheryomushki Source: Reuters

Experts from the energy division of international reinsurance broker UIB list the ten essential facts that all power company managers and engineers should understand about the world of insurance.

Mark Ritson, UIB, UK

The fields of insurance and power engineering have a long relationship that has developed into a much closer bond over recent years.

The large international insurance companies that offer insurance to power installations have come to understand power risks on a more granular level and offer risk management advice based on their experience of losses and engineering accidents around the world as well as on their experience of seeing best practices in the industry. It is not uncommon for organizations in developing countries to ask reinsurance brokers how insurance is purchased in developed countries.

But the relationship is in continuous flux: new techniques from the power industry and premium price changes from the insurer can lead to misunderstandings on either side. It is the insurance broker's role to bring the sides together whenever there is a stalemate. The following ten points outline the current landscape of power industry

Exhibit G

insurance.

Why engineers need an effective dialogue with insurers or insurance brokers

There are several advantages for an engineer in knowing when, why and how to communicate with an insurance company or broker. The first and most obvious advantage is that open dialogue can keep insurance costs to a minimum. Another advantage is that insurers can provide valuable advice on risk management and improved efficiency, via brokers.

So how and when do power engineers interact with the world of insurance? When a power station needs a new insurance contract, it will usually be done via a broker company which will send its own engineer to meet the station managers and speak with engineers and everyone concerned in risk mitigation. The broker's engineer will carry out a risk assessment and compile a risk report. The visit might last up to three days, concluded by a wrap-up meeting. Subsequent annual visits need not take so long, but it is essential that a strong link continues between the insurance broker and power engineers – they have to keep each other informed of any changes in procedures or risk management techniques.

Any change that is not disclosed by the client might make an insurance policy invalid. Alternatively, any change that reduces the likelihood of a loss could result in improved insurance terms for the client by way of reduced deductibles or reduced premium. Many international (re)insurers will not look at an account if it does not have a recent survey report.

In most cases the plant manager and his team will know more about their plant than any outside engineer would ever know. That is why a good insurance engineer will never tell a plant manager how to run his plant.

How insurers and brokers have helped reduce power station risks

The fact that insurance brokers, such as UIB, now employ engineers has prompted a significant step forward in the overall management of risks in the power and energy industries. International insurers involved in the power industry also employ their own engineers and many underwriters come from an engineering background.

Officials check children from the evacuation area near the Fukushima Daini nuclear plant Source: Reuters

In today's world there are more conferences and seminars regarding power generation than ever before. Some of the major turbine manufacturers such as GE and Siemens also hold regular conference calls with the insurance market to discuss technological matters. There is a greater information flow today than at any other time in history. Brokers and insurers have much greater understanding of risk so not only provide balance sheet protection from a fiscal aspect but also can assist in providing a form of enterprise risk management in conjunction with the client's plant engineers.

Risk reports now look much different from just 15 years ago, when only a handful of insurers and brokers employed engineers. Reports are now more detailed and extensive, and they also reference international standards much more keenly. In addition, these reports contain far more details generated by questions from the broker and insurer rather than offered by the owners of the power facility.

The loss record in downstream energy, power and refining has improved in recent years and many people, including those in the power industry itself, credit the greater involvement and risk management advice of the insurance industry for this change. It was no one moment that brought in this change, but a general increase in the professionalism of the insurance market in tandem with a heightened awareness on risk management and loss mitigation. This shift was triggered initially by hurricane losses in the US – especially Hurricane Andrew – although it took several years to take hold.

How insurers insure power stations

To understand the needs of an insurer or insurance broker, it is useful to look at the structure of that part of the international insurance market that serves the power industry.

Insurers pride themselves on making risky corporate ventures possible by softening the blow of any potential accident or loss. The scale of potential losses in power is so huge that insurers naturally have a large role to play. However, this scale usually means that a power facility cannot be managed by a single insurer.

Smaller power facilities can be written by one insurer on their own, but this would generally be when there is insufficient premium to be shared between numerous insurers. Most power facilities will be written by more than one insurer. Either way, the potentially large losses that could arise from a power station claim would be absorbed in a manageable way without the risk of sinking an entire insurance company. Depending on the territory, insurance policies can be placed on either a direct basis or on a reinsurance basis. The territory and local insurance law will dictate the basis on which the policy is placed.

Most developed countries will have a direct policy because they will have a local insurance market capable of writing the risk. Countries that do not have a strong enough local insurance market will often use a local company to manage the risk but this insurer will then spread the risk into the international market with reinsurers through a facultative reinsurance programme.

The nuclear insurance market operates separately from the rest of the power generation insurance markets and consists of a network of country risk 'pools' which are overseen by international agreements and the International Atomic Energy Agency, which requires that insurance and risk management operations are adequate. Nuclear insurance capacity from the global reinsurance markets stands at €2-3 billion ($3-4.5 billion).

New and emerging technologies in renewable energy also demand so called 'expert capacity' from insurers and reinsurers which have developed specific skills and products in this area.

Power facilities owned by governments – usually in developing countries – will often be insured partly or entirely by the government or by a government-backed insurer. In this case, the facility might lose the benefits brought by the risk management requirements of the international power insurance markets. In the event of a large loss, the government would be in the same position as a company in that if they do not have sufficient insurance then the cost of repair or replacement of a facility would have to come from raising funds by different means.

How insurers and brokers bring international expertise to power engineering

The broker's main role in power insurance is to represent the customer and place a power facility's insurance contract in the insurance market. But when this is not possible or when an insurer poses questions before agreeing to provide insurance, it is the broker's role to reach a solution with the owners of the facility.

A broker can thus help to find the best solution at the minimum cost to the policyholder. For example, if an insurer calls for a $2 million investment in staff, hardware or procedures before insurance can be granted, the customer cannot always expect a $2 million saving in insurance premium.

Many times, an insurer's demands or questions can be satisfied by a full explanation of current procedures. An insurer will understand that not all power facilities look the same, but a broker's insight is required to prevent an insurer becoming nervous about a risk and withdrawing an offer of cover. If an insurer has gone so far as to make demands, it often shows that the insurer is interested in the risk. But it is worth remembering that a power insurer has many more risks to choose from and does not need to insure a risk for which the risk report is inadequate or out of date.

The power sector and the insurance sector have been closely aligned for many years. In the past, insurers such as National Vulcan and British Engine had very close ties to the power generators and many of their staff were formerly in the power industry. Later, the ties became even greater. At a global level, the Merrett Syndicate at Lloyd's of London provided coverage for power companies around the world alongside and often in conjunction with larger insurers such as Swiss Re, Munich Re and Hartford Steam Boiler. Then there was the emergence of Cox Power, another Lloyd's insurer whose aim was to work in tandem with the power industry in order to respond to its insurance needs.

When the insurance industry was unable to satisfy the needs of the power sector, insurance mutuals came into play, such as AEGIS, USICO and others. These mutuals were and are owned by the power sector.

How power station premiums are calculated

A dizzying number of financial factors contribute to an insurer's calculations on premium pricing.

The size of the facility and the power company's risk management and claims record will be the obvious first steps. The insurer will also consider the previous year's premium, the industry norms and the administration costs of providing the insurance policy.

Power and energy risks are computer-modelled by specialist teams within insurance companies to assess the likelihood and potential cost of a loss. The exposure to natural catastrophes such as earthquakes, tsunamis and windstorms are also taken into account.

Then, insurance company managers will ask their pricing, reserving and actuarial teams to decide on whether their prices should go up or down in certain lines of business or certain geographical zones. When business interruption insurance is calculated, the insurer must evaluate the revenues of the power facility and the expected duration for bringing the facility back to working order.

The insurer will also consider its own capital position and risk appetite and whether certain power facility risks provide good 'risk diversification' for the company. The role of actuaries – the back office mathematicians of insurance companies – has become more central in the pricing process for all lines of insurance business and not just power, thus moving the pricing process away from the individual decision-making of insurance underwriters. Of course, all of this is gauged and adjusted on a rolling basis by all the interlinked 'cogs' in the machinery of an insurance company.

Therefore, when a broker approaches an insurer for a premium quote, the broker will know from experience whether the quote represents a margin of error, as well as how the price compares to other companies and whether an insurer is financially robust enough to pay the claim without complications or delays.

However, power industry professionals might be disturbed to know that the price of their premium is dictated by the claims history of the rest of the power industry, which is why there is a need for differentiation between clients. Facilities with a clean loss record and good risk management will earn credits in their insurance compared with the rest of the industry but the underlying foundation of a price will be influenced by the loss record and catastrophe exposures as a whole.

In addition, the pricing of power industry premiums is also dictated by major insurance losses around the world such as the earthquakes in Chile and Japan. A significant claim in one part of the world may inflate premiums in another part of the world, if not straight away then within 12 to 18 months when the insurers and reinsurers have had a chance to reconsider their costs, capacity and terms. It might seem unfair, but if insurance capacity – the amount of money held in reserve by insurers and reinsurers – is squeezed by losses, there is naturally a higher demand for the capacity that remains and insurers can set their prices higher.

In the past few years most power risks will have benefited from this system and should have received years of premium reductions and improved coverage. The current market has a surplus of capacity in power insurance. While 'soft' market conditions are still in evidence there is a gradual tightening in premiums, terms and conditions as losses bite into profitability.

Why an insurance broker can be a power engineer's best friend

A broker can be instrumental in securing a favourable deal for a power company. As a result, the strength, leverage and expertise of a broker are important. An effective broker will demonstrate to the insurer the merits of a customer's equipment and standards and will do so in an efficient way for all parties concerned, saving time and costs.

There are frequent stalemates in insurance contract negotiations, but an effective broker will provide its power industry customer with a complete checklist of what the insurer requires, as well as any recent updates to regulations. The broker should also highlight for the customer any new concerns among insurers resulting from recent claims elsewhere in the power industry.

An insurer's questions over standards do not usually need a major investment in equipment or procedures as might appear at first inspection. Insurers' questions can often be satisfied by a thorough explanation of procedures and service history of the power facility. It is the role of a good broker to explain all of this.

A reliable broker will also be open with power industry managers with no fear of causing offence about their internal communication standards. It is essential that a broker can speak to a power industry customer honestly on this subject, because it is such an essential part of a risk report. This is where the clarity of information between grassroots power engineers and power company managers is important. When staff and managers at a power facility can prove they are responsive to risk and implement change, it will go in their favour. The best risks for brokers to deal with are those where you have faith that engineers, managers and financial controllers all operate in unison.

An effective broker will also call customers proactively whenever a change in insurance pricing is predicted. If a rise in industry-wide insurance pricing is anticipated – e.g. after a major insurance industry loss such as an earthquake or hurricane – securing contracts early can save money.

Emerging risks in power engineering

New technologies inevitably present new risks for insurers, developers and engineers to tackle jointly. But there are also a number of developing risks which continually change the risk landscape when insurers are evaluating power industry risks.

Debris at the scene of an accident at
Russia's biggest hydroelectric plant
Source: EPA

These can be political risks that prevent the power company from recruiting the correct staff or place pressure on company finances. Terrorism and war are often excluded from standard insurance contracts and would require additional coverage which has to be purchased through specialist insurers.

Another interesting emerging risk – the risk of cyber attack – has already impacted power stations, particularly in Iran. The Stuxnet computer virus is thought to have temporarily disabled nuclear processing plants in Iran. Although this was fairly isolated, it shows the danger to power plants from malicious software.

At present computer controls at power plants are involved in the monitoring rather than the functioning of hardware. But power machinery will soon be automated and computerized to improve efficiency, potentially putting power generation at risk from computer viruses.

At present, insurers do not cover damage or losses caused by computer viruses because all policies have what is known as a 'cyber exclusion'. This exclusion began life as the Y2K clause in the 1990s, in which insurers said they would not pay claims related to losses caused by software malfunction.

In most cases cyber risks insurance is just not available, which is understandable because at present the risk cannot be controlled or monitored. In many cases, it is also difficult to prove as a genuine risk.

Insurers have no reason to insure against this risk and at present there is little or no demand, but I would expect that in the future, as technology advances, it will become a more relevant issue. The big insurance and reinsurance companies will have already explored the possibility of providing this type of insurance.

Self-insurance for power companies – how it works

Power companies often self-insure by forming their own insurance company, known as a 'captive'. The benefits of creating a captive can include cost savings, the ability to tailor insurance placement, greater control, increased cash flow and a competitive advantage. In addition, establishing a captive can improve a company's claims service, help build up a capacity surplus, create a new profit centre and ensure access to new risk financing options.

By establishing a captive, a power company will reduce its exposure to premium rate fluctuations. As mentioned previously, insurers and reinsurers are looking for rate increases at the moment to recoup underwriting losses from the previous year and group investment losses. None of these were caused by the power industry, but its insurance costs will be influenced by them. When we are experiencing a 'hardening' market like this, power companies could insure more of their assets or perils through their captives, thus reducing their exposure to the rate increases. Under a 'soft' facultative market where premium rates were falling power companies could do the opposite, if it were more cost effective than using the captive.

By utilizing a captive in this way power companies can control their insurance costs more effectively, which could aid budgeting and cost controls on a group basis, as the premium cost year-on-year would be more constant. Rather than declare what is to be insured and then negotiate the price for these assets, power companies could declare what price they want to pay and then move the assets and perils accordingly between the facultative market and captive to achieve the desired price.

How insurers and brokers are facilitating the rise of renewable energy

The next few years will see twice as many gas powered energy installations built than anything else – there are more resources available in this area of energy generation and it is cleaner. Politics and the need for governments to pursue greener power sources are also greatly influencing the power market. Twenty per cent of power in the EU must come from green power sources by 2020 – and insurers and brokers have risen to this challenge.

Insurers are working with technology developers, power and energy companies and governments in multi-party negotiations to develop renewable energy facilities. The ability of power companies to develop and use new technologies depends upon the involvement and understanding of insurers to support these risks. In addition, international insurers and brokers have also been active in providing loss data, weather information and indications of climate change to persuade politicians to take action.

Why 'new' is not always 'best' for power station insurers

Insurers are often intimidated by unproven equipment or technology. This is understandable – in order to provide insurance on a piece of power industry hardware they need extensive documentation on operational history and safety. Even when a known piece of hardware is being used, underwriters will say they wish to see it running for a couple of years before they are prepared to insure the risk at an optimal price.

The latest technologies and trends in power generation and power station engineering not only come under the purview of insurers but also require the participation and input of insurers at the development stage.

OTTER TAIL POWER COMPANY
Docket No: E999-AA-13-599

Response to: Office of Attorney General
Analyst: Ian M. Dobson
Date Received: 12/11/2014
Date Due: 12/23/2014
Date of Response: 01/16/2015
Responding Witness: Stuart Tommerdahl, Manager Regulatory Administration, 218 739-8279

Information Request:

Reference: Reply comments at 4 – Business Interruption Insurance

Please discuss the different types of business interruption insurance you explored. For example, did you inquire about the cost of only insuring the generator that produces the cheapest energy?

Attachments: 0

Response:

Otter Tail worked with its insurer to understand the Business Interruption (BI) products available. Otter Tail found that the coverage is specific to each location, based on each location's unique factors. In addition Otter Tail found that BI, if available for a location, can be purchased in a range of coverages for a range of perils or exposures. The lowest cost coverage typically insures the differential cost between power generated at the location and power purchased on the open market with coverage for limited perils or exposures (for example equipment breakdown only, natural hazards, contingent BI for offsite assets such as transformers or power lines owned by others, etc…). The highest cost coverage insures 100 percent of the financial benefit that would have passed to the insured had the asset not been impaired and would cover the broadest range of perils and exposures.

☐ **Non Public Document – Contains Trade Secret Data**
☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy
Docket No.: E999/AA-12-757
Response To: Office of Attorney General Information Request No. 2
Requestor: Ryan Barlow
Date Received: January 12, 2015

Question:
Reference: FCA Incentive Proposal

Please provide any and all data used to replicate Xcel's analysis within Table 3. Include a description of the analysis so that the analysis can be replicated from the data provided.

In addition, include similar data for the most recent 5 year period available such that the analysis can be updated.

Response:
Table 3 below has been updated with data for 2013. Complete data for 2014 is not yet available.

Table 3-Updated: Impact of Department's Proposal

	Change to FCA Recovery ($M)	**Actual ROE Weather Normalized (%)**	**Realized W/N ROE Under DOC FCA Incentive Proposal (%)**	**Difference (%)**
2008	**-$94.5**	10.19	7.78	-2.41
2009	**+$54.4**	10.18	11.46[1]	+1.26
2010	**+$32.8**	8.78	9.48	+0.70
2011	**-$26.5**	9.08	8.56	-0.52
2012	**-$63.1**	8.20	7.05	-1.15
2013	**-$112.1**	8.22	6.32	-1.90

Change to FCA Recovery: Please see Attachment A for data supporting these calculations. Attachment A shows the DOC's FCA Incentive Mechanism utilizing a

[1] In Table 3 as originally filed, we reported this ROE to be 11.44. Upon subsequent analysis, we discovered that this ROE should be 11.46. We have made the correction in this response.

Exhibit I

three-year average to calculate the fuel cost factors as compared to the actual fuel cost factors. The resulting difference is calculated in Attachment A and included in Table 3 above.

Actual ROE, Weather Normalized: See Attachment B "Actual" tabs by year for data supporting the actual ROE. The actual ROEs included in Attachment B are as filed with the PUC in the following Electric Jurisdictional Annual Reports:

E,G999/PR-09-4, filed May 1, 2009
E,G999/PR-10-4, Update filed May 28, 2010
E,G999/PR-11-4, filed May 2, 2011
E,G999/PR-12-4, Revision filed May 23, 2012
E,G999/PR-13-4, filed May 1, 2013
E,G999/PR-14-4, filed May 1, 2014

Realized Weather Normalized ROE Under DOC FCA Incentive Proposal: See Attachment B "DOC Proposal" tabs by year for data supporting the resulting ROE under the DOC FCA Incentive Proposal. To calculate the change in ROE, we used the original ROE calculations and adjusted the revenue by the FCA amounts as listed in Attachment A.

Difference: This is calculated by subtracting the Realized W/N ROE Under DOC FCA Incentive Proposal from the Actual ROE, Weather Normalized.

We have also updated Table 4 from our Reply Comments submitted on August 23, 2013 in this docket to provide the main factors impacting the FCA in 2013 and 2014.

Table 4-Updated: Main Factors Impacting FCA from 2008-2014

2008	2009	2010	2011	2012	2013	2014
• Additional biomass purchases (Fibrominn & Laurentian)	• Additional biomass purchases (Fibrominn, Laurentian and Rahr Malting)	• Additional biomass purchases (Fibrominn, Laurentian and Rahr Malting)				
• Additional wind purchases (Fenton, MinnDakota, CBED)	• Additional wind purchases (Fenton, MinnDakota, CBED)	• Additional wind purchases (Fenton, MinnDakota, CBED)	• Additional wind purchases - CBED (generally higher prices)	• Additional wind purchases - CBED & Prairie Rose (generally higher prices)	• Additional wind purchases - CBED & Prairie Rose (generally higher prices)	• Additional wind purchases - CBED & Prairie Rose (generally higher prices)
	• Grand Meadow wind online	• Grand Meadow and Nobles wind online	• Grand Meadow and Nobles wind online	• Grand Meadow and Nobles wind online	• Grand Meadow and Nobles wind online	

2008	2009	2010	2011	2012	2013	2014
• Higher coal prices due to increased transport cost (diesel surcharge)	• Higher coal prices due to increased transport cost (diesel surcharge)	• Higher coal and rail prices	• Higher coal and rail prices	• Higher coal and rail prices	• Higher wind curtailment costs	• Higher wind curtailment costs
• Higher nuclear fuel prices	• Higher nuclear fuel prices	• Higher nuclear fuel prices	• Higher nuclear fuel prices	• Higher nuclear fuel prices	• Higher coal and rail prices	• Increased rail transport cost and diesel surcharge at King and Black Dog
• Higher natural gas prices					• Higher nuclear fuel prices	
• High Bridge and Riverside retired from coal use in 2007 and 2008.	• High Bridge and Riverside retired from coal use in 2007 and 2008.	• High Bridge and Riverside retired from coal use in 2007 and 2008.				• Higher natural gas prices in Q1 2014 due to extreme cold
• Lower cost MISO market purchases as operations become smoother	• Lower natural gas and MISO market prices	• Lower natural gas and MISO market prices	• Lower natural gas and MISO market prices	• Lower natural gas and MISO market prices	• Higher MISO costs (mainly congestion)	• Higher MISO costs (mainly congestion)
		• More planned coal maintenance	• More planned coal maintenance		• More planned coal maintenanc e	
		• One nuclear refueling outage (2 nuclear refueling other yrs in period)	• More planned nuclear maintenance	• More planned nuclear maintenance	• More planned nuclear maintenanc e	• One nuclear refueling outage (vs. 2 in other yrs) and less planned maintenance
			• Sherco 3 forced outage near year-end	• Sherco 3 forced outage	• Sherco 3 forced outage	• Sherco 3 in service
						• Mild summer weather; lower load

Preparer:	David Horneck	John Chow	Jeff Hafner
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Date:	January 23, 2015		

Northern States Power Company
Electric Operations - State of Minnesota
FCA Incentive Proposal - Update of Table 3 (Impact of Department's Proposal)

Docket No. E999/AA-12-757
Information Request No. OAG-2
Attachment A

					3 Year Average (Cents/kWh)			Current Monthly (Cents/kWh)			Difference in Cost			
Month	Actual Total Fuel Costs	Asset Based Margin Sharing	Non-Asset Based Margin Sharing	Actual Retail Sales MWH	Fuel Cost Factor	Refund Asset Based	Refund Non-Asset Based	Fuel Cost Factor	Refund Asset Based	Refund Non-Asset Based	Fuel Cost	Asset Based Refunds	Non-Asset Based Refunds	Total
Jan-05	39,598,376			2,601,733				1.522						
Feb-05	35,834,953			2,268,035				1.580						
Mar-05	45,395,357			2,360,653				1.923						
Apr-05	51,041,934			2,420,196				2.109						
May-05	51,211,954			2,318,332				2.209						
Jun-05	76,114,859			2,689,571				2.830						
Jul-05	76,430,159			3,122,147				2.448						
Aug-05	68,109,183			2,846,184				2.393						
Sep-05	66,529,683			2,596,787				2.562						
Oct-05	70,022,400			2,649,353				2.643						
Nov-05	55,639,357			2,535,978				2.194						
Dec-05	71,838,023			2,511,819				2.860						
Year 2005	707,766,238			30,920,788				2.273						
Jan-06	60,061,484			2,531,036				2.373						
Feb-06	49,673,400			2,313,619				2.147						
Mar-06	38,375,412			2,452,103				1.565						
Apr-06	34,954,507			2,314,868				1.510						
May-06	52,523,366			2,375,548				2.211						
Jun-06	66,245,748			2,618,409				2.530						
Jul-06	107,263,113			3,338,410				3.213						
Aug-06	78,741,252			2,887,468				2.727						
Sep-06	44,925,003			2,552,557				1.760						
Oct-06	54,269,764			2,594,157				2.092						
Nov-06	60,275,005			2,353,573				2.561						
Dec-06	61,506,260			2,541,581				2.420						
Year 2006	708,814,314			30,873,329				2.259						
Jan-07	71,665,400			2,672,088				2.682	0.000	0.000				
Feb-07	83,660,905	(3,474,288)		2,481,783				3.371	-0.144	0.000				
Mar-07	62,124,449	(1,220,986)		2,514,142				2.471	-0.050	0.000				
Apr-07	70,867,648	(2,540,787)		2,387,724				2.968	-0.093	0.000				
May-07	70,140,345	678,178		2,527,580				2.775	0.022	0.000				
Jun-07	78,459,706	(1,469,030)		2,829,416				2.773	-0.049	0.000				
Jul-07	98,785,601	(3,307,055)		3,196,945				3.090	-0.120	0.000				
Aug-07	89,562,972	(1,697,500)		3,161,418				2.833	-0.062	0.000				
Sep-07	63,277,000	(1,916,673)		2,775,307				2.280	-0.076	0.000				
Oct-07	71,880,058	358,601		2,712,455				2.650	0.013	0.000				
Nov-07	69,353,280	(924,368)		2,484,000				2.792	-0.034	0.000				
Dec-07	72,515,936	(2,425,996)	(101,483)	2,627,389				2.760	-0.093	-0.004				
Year 2007	902,293,300	(17,939,904)	(101,483)	32,370,247				2.787	-0.057	0.000				
Jan-08	67,208,838	(2,163,770)	(101,483)	2,693,741	2.195	0.000	0.000	2.495	-0.081	-0.004	($8,078,238)	$2,178,159	$102,147	($5,797,932)
Feb-08	72,185,879	(3,844,738)	(103,515)	2,562,509	2.395	-0.049	0.000	2.817	-0.156	-0.004	($10,813,810)	$2,734,122	$107,549	($7,972,139)
Mar-08	88,448,584	(2,374,344)	(103,323)	2,627,706	1.991	-0.017	0.000	3.366	-0.091	-0.004	($36,124,976)	$1,941,968	$103,558	($34,079,450)
Apr-08	58,335,572	(3,235,765)	(104,077)	2,404,599	2.202	-0.036	0.000	2.426	-0.115	-0.004	($5,379,450)	$1,915,666	$89,187	($3,374,597)
May-08	68,780,468	(8,477,876)	(107,894)	2,459,080	2.408	0.009	0.000	2.797	-0.265	-0.003	($9,571,642)	$6,754,433	$83,043	($2,734,166)
Jun-08	76,516,599	(2,463,544)	(109,357)	2,593,783	2.714	-0.018	0.000	2.950	-0.079	-0.004	($6,130,449)	$1,576,791	$90,782	($4,462,876)
Jul-08	106,338,159	(1,026,532)	(104,407)	3,108,394	2.925	-0.034	0.000	3.421	-0.039	-0.004	($15,418,620)	$138,343	$122,315	($15,157,962)
Aug-08	90,478,264	(288,136)	(104,466)	3,039,243	2.658	-0.019	0.000	2.977	-0.011	-0.004	($9,701,183)	($256,074)	$117,436	($9,839,821)
Sep-08	71,409,719	1,372,814	(103,485)	2,602,395	2.205	-0.024	0.000	2.744	0.054	-0.004	($14,029,165)	($2,029,769)	$105,553	($15,953,381)
Oct-08	66,952,161	(2,058,065)	(105,909)	2,589,024	2.466	0.005	0.000	2.586	-0.075	-0.004	($3,113,948)	$2,064,263	$100,221	($949,464)
Nov-08	62,234,194	(1,884,712)	(100,574)	2,573,788	2.513	-0.013	0.000	2.418	-0.070	-0.004	$2,434,733	$1,482,907	$96,337	$4,013,977
Dec-08	71,631,097	(2,513,754)	(14,664)	2,670,809	2.680	-0.032	-0.001	2.682	-0.101	-0.001	($48,174)	$1,843,038	($19,611)	$1,775,254
Year 2008	900,519,534	(28,958,422)	(1,163,155)	31,925,071	2.446	-0.019	0.000	2.807	-0.086	-0.004	($115,974,920)	$20,343,846	$1,098,517	($94,532,556)
Jan-09	74,211,667	(2,506,390)	(13,227)	2,658,011	2.519	-0.027	-0.001	2.792	-0.096	-0.001	($7,251,761)	$1,826,576	($20,656)	($5,445,841)
Feb-09	56,987,453	(1,211,351)	(12,709)	2,401,494	2.793	-0.099	-0.001	2.373	-0.050	-0.001	$10,090,756	($1,185,462)	($21,178)	$8,884,116
Mar-09	60,347,405	(759,217)	(12,290)	2,574,548	2.488	-0.047	-0.001	2.344	-0.030	0.000	$3,711,060	($439,904)	($22,414)	$3,248,741
Apr-09	55,534,047	(138,864)	(12,873)	2,281,596	2.310	-0.081	-0.001	2.434	-0.005	0.000	($2,835,082)	($1,739,365)	($22,734)	($4,597,180)
May-09	54,389,941	(826,806)	(12,754)	2,383,433	2.600	-0.106	-0.001	2.282	-0.027	0.000	$7,587,984	($1,881,753)	($25,014)	$5,681,216
Jun-09	61,265,325	305,356	(13,440)	2,473,368	2.751	-0.049	-0.001	2.477	0.010	0.000	$6,776,234	($1,460,618)	($22,579)	$5,293,037
Jul-09	64,602,598	(853,499)	(13,556)	2,725,848	3.239	-0.045	-0.001	2.370	-0.033	-0.001	$23,694,923	($333,583)	($15,364)	$23,345,977
Aug-09	68,165,219	(274,668)	(12,986)	2,817,909	2.847	-0.022	-0.001	2.419	-0.011	-0.001	$12,074,124	($313,060)	($18,076)	$11,742,987
Sep-09	63,817,001	(455,884)	(12,262)	2,588,925	2.265	-0.007	-0.001	2.465	-0.018	0.000	($5,180,672)	$290,658	($21,176)	($4,911,190)
Oct-09	58,845,259	(544,959)	(12,292)	2,526,632	2.446	-0.022	-0.001	2.329	-0.021	0.000	$2,948,072	($4,727)	($21,738)	$2,921,607
Nov-09	55,860,599	(202,995)	(12,662)	2,410,902	2.589	-0.038	-0.001	2.317	-0.008	0.000	$6,551,910	($726,003)	($21,000)	$5,804,907
Dec-09	64,316,237	377,589	(110,698)	2,619,806	2.623	-0.063	-0.001	2.455	0.016	-0.005	$4,406,584	($2,062,489)	$81,908	$2,426,003
Year 2009	738,342,751	(7,091,688)	(251,749)	30,462,472	2.623	-0.051	-0.001	2.421	-0.023	-0.001	$62,574,133	($8,029,732)	($150,020)	$54,394,380
Jan-10	67,178,750	(1,296,343)	(110,610)	2,687,150	2.656	-0.058	-0.001	2.500	-0.051	-0.004	$4,182,816	($199,643)	$77,991	$4,061,165
Feb-10	57,979,277	(512,102)	(114,408)	2,328,485	2.858	-0.115	-0.002	2.490	-0.022	-0.005	$8,579,355	($2,147,317)	$79,892	$6,511,929
Mar-10	59,198,385	(749,773)	(113,228)	2,502,045	2.733	-0.056	-0.001	2.366	-0.031	-0.005	$9,192,665	($629,775)	$80,634	$8,643,524
Apr-10	59,318,470	(231,929)	(112,994)	2,252,030	2.612	-0.084	-0.002	2.634	-0.009	-0.004	($506,110)	($1,683,368)	$60,146	($2,129,332)
May-10	74,194,527	(2,433,656)	(106,655)	2,490,585	2.623	-0.117	-0.002	2.979	-0.081	-0.004	($8,868,775)	($894,554)	$47,795	($9,715,535)
Jun-10	69,908,312	(2,312,700)	(106,655)	2,713,832	2.738	-0.046	-0.002	2.576	-0.078	-0.004	$4,407,964	$873,552	$55,578	$5,337,094
Jul-10	84,669,593	(1,130,964)	(104,173)	3,191,466	2.987	-0.057	-0.001	2.653	-0.044	-0.004	$10,647,058	($438,484)	$86,771	$10,295,345
Aug-10	90,711,688	(1,374,390)	(99,415)	3,281,899	2.752	-0.025	-0.001	2.764	-0.055	-0.004	($388,220)	$975,847	$87,353	$674,980
Sep-10	57,977,924	(634,123)	(115,835)	2,468,196	2.492	-0.013	-0.001	2.349	-0.025	-0.005	$3,521,891	$314,395	$78,170	$3,914,457
Oct-10	59,870,169	(507,740)	(112,919)	2,459,744	2.525	-0.029	-0.002	2.434	-0.020	-0.004	$2,243,921	($223,476)	$70,005	$2,090,451
Nov-10	61,607,340	(240,826)	(113,356)	2,456,433	2.510	-0.040	-0.002	2.508	-0.009	-0.004	$43,851	($766,588)	$68,236	($654,501)
Dec-10	65,480,333	(544,829)	(30,862)	2,669,398	2.633	-0.058	-0.003	2.453	-0.022	-0.001	$4,798,924	($942,526)	($42,762)	$3,813,636
Year 2010	808,094,768	(11,969,376)	(1,241,112)	31,501,263	2.677	-0.058	-0.002	2.559	-0.037	-0.004	$37,855,339	($5,761,936)	$749,808	$32,843,212
Jan-11	66,568,585	(850,960)	(31,664)	2,699,456	2.595	-0.074	-0.003	2.466	-0.033	-0.001	$3,478,856	($1,109,351)	($42,405)	$2,327,100
Feb-11	66,335,690	215,295	(34,406)	2,428,989	2.566	-0.076	-0.003	2.731	0.009	-0.001	($3,998,717)	($2,081,210)	($40,603)	($6,120,530)
Mar-11	66,764,445	(551,195)	(34,503)	2,547,289	2.700	-0.050	-0.003	2.621	-0.023	-0.001	$2,005,184	($702,842)	($39,287)	$1,263,054
Apr-11	65,328,969	(592,630)	(34,354)	2,298,697	2.496	-0.052	-0.003	2.842	-0.022	-0.001	($7,950,181)	($695,770)	($47,242)	($8,693,193)
May-11	68,044,546	(113,915)	(34,195)	2,418,072	2.691	-0.160	-0.003	2.814	-0.004	-0.001	($2,963,918)	($3,780,423)	($47,870)	($6,792,211)
Jun-11	69,889,920	(225,927)	(34,458)	2,709,962	2.669	-0.057	-0.003	2.579	-0.008	-0.001	$2,444,469	($1,353,522)	($48,857)	$1,042,089
Jul-11	95,173,509	(673,023)	(31,263)	3,317,306	2.832	-0.033	-0.002	2.869	-0.026	-0.001	($1,226,558)	($243,530)	($41,538)	($1,511,626)
Aug-11	80,403,548	(867,519)	(33,764)	3,046,743	2.728	-0.021	-0.002	2.639	-0.034	-0.001	$2,725,556	$398,731	($31,655)	$3,092,632
Sep-11	62,674,300	(205,799)	(34,406)	2,570,726	2.522	0.004	-0.003	2.438	-0.008	-0.001	$2,170,032	$308,313	($42,069)	$2,436,276
Oct-11	65,884,078	(254,699)	(35,058)	2,468,493	2.451	-0.041	-0.003	2.669	-0.010	-0.001	($5,383,095)	($776,884)	($42,728)	($6,202,708)
Nov-11	63,071,354	(423,858)	(34,840)	2,436,128	2.415	-0.031	-0.003	2.589	-0.016	-0.001	($4,239,186)	($377,959)	($42,587)	($4,659,732)
Dec-11	66,647,574	(448,649)	(85,560)	2,542,830	2.530	-0.034	-0.002	2.621	-0.018	-0.004	($2,301,408)	($389,327)	$39,169	($2,651,566)
Year 2011	836,786,518	(4,992,879)	(458,470)	31,484,691	2.600	-0.052	-0.003	2.657	-0.016	-0.001	($15,238,967)	($10,803,776)	($427,672)	($26,470,415)
Jan-12	69,148,575	(326,225)	(85,530)	2,573,449	2.585	-0.058	-0.002	2.687	-0.013	-0.003	($2,623,110)	($1,159,558)	$36,544	($3,746,125)
Feb-12	62,983,683	(540,045)	(87,424)	2,346,635	2.533	-0.021	-0.002	2.684	-0.023	-0.004	($3,554,642)	$55,247	$36,039	($3,463,356)
Mar-12	63,300,548	(244,922)	(88,955)	2,405,036	2.444	-0.027	-0.002	2.632	-0.010	-0.004	($4,526,970)	($404,787)	$38,530	($4,893,227)
Apr-12	58,661,916	(105,250)	(84,971)	2,281,677	2.637	-0.014	-0.002	2.571	-0.004	-0.003	$1,510,291	($232,502)	$18,549	$1,296,338
May-12	69,563,209	(600,281)	(82,529)	2,445,104	2.696	-0.046	-0.002	2.845	-0.020	-0.003	($3,631,715)	($641,485)	$15,858	($4,257,342)
Jun-12	77,569,194	(63,993)	(82,079)	2,753,610	2.546	-0.028	-0.002	2.817	-0.002	-0.003	($7,461,651)	($718,318)	$23,569	($8,156,401)

					3 Year Average (Cents/kWh)			Current Monthly (Cents/kWh)			Difference in Cost			
Month	Actual Total Fuel Costs	Asset Based Margin Sharing	Non-Asset Based Margin Sharing	Actual Retail Sales MWH	Fuel Cost Factor	Refund Asset Based	Refund Non-Asset Based	Fuel Cost Factor	Refund Asset Based	Refund Non-Asset Based	Fuel Cost	Asset Based Refunds	Non-Asset Based Refunds	Total
Jul-12	96,998,683	(1,637,168)	524,935	3,332,143	2.647	-0.029	-0.002	2.911	-0.065	0.021	($8,794,942)	$1,222,649	($753,245)	($8,325,538)
Aug-12	80,639,132	(441,830)	81,173	2,901,732	2.616	-0.028	-0.002	2.779	-0.018	0.003	($4,727,703)	($270,266)	($143,376)	($5,141,345)
Sep-12	63,548,942	(107,656)	3,222	2,485,293	2.418	-0.017	-0.002	2.557	-0.004	0.000	($3,445,472)	($310,608)	($56,277)	($3,812,357)
Oct-12	67,302,695	(665,401)	(1,728)	2,479,834	2.476	-0.018	-0.002	2.714	-0.026	0.000	($5,896,367)	$220,668	($51,602)	($5,727,300)
Nov-12	68,456,764	(111,246)	(118)	2,492,963	2.472	-0.012	-0.002	2.746	-0.004	0.000	($6,831,508)	($188,577)	($54,783)	($7,074,868)
Dec-12	73,325,609	(751,157)	5	2,511,151	2.508	-0.008	-0.003	2.920	-0.032	0.000	($10,340,577)	$613,782	($72,820)	($9,799,615)
Year 2012	851,498,950	(5,595,175)	96,002	31,008,627	2.548	-0.025	-0.002	2.739	-0.019	0.000	($60,324,368)	($1,813,754)	($963,014)	($63,101,136)
Jan-13	70,304,656	(1,006,032)	11	2,584,730	2.549	-0.031	-0.003	2.720	-0.041	0.000	($4,421,801)	$254,822	($77,434)	($4,244,413)
Feb-13	62,189,862	(588,568)	-	2,286,392	2.636	-0.012	-0.003	2.720	-0.026	0.000	($1,909,518)	$330,707	($74,454)	($1,653,264)
Mar-13	74,099,811	(500,004)	-	2,504,218	2.539	-0.021	-0.003	2.959	-0.021	0.000	($10,518,749)	$6,760	($79,387)	($10,591,376)
Apr-13	73,159,370	(826,260)	-	2,321,046	2.683	-0.014	-0.003	3.152	-0.031	0.000	($10,887,080)	$411,456	($78,921)	($10,554,545)
May-13	73,352,662	(719,020)	-	2,377,720	2.880	-0.043	-0.003	3.085	-0.024	0.000	($4,869,811)	($440,830)	($72,226)	($5,382,866)
Jun-13	80,109,945	(573,540)	-	2,601,817	2.658	-0.032	-0.003	3.079	-0.020	0.000	($10,949,822)	($310,318)	($71,013)	($11,331,154)
Jul-13	92,319,774	(262,505)	-	3,020,935	2.813	-0.035	0.004	3.056	-0.011	0.000	($7,335,701)	($737,708)	$119,567	($7,953,842)
Aug-13	85,825,677	(1,092,444)	-	3,010,371	2.727	-0.029	-0.001	2.851	-0.045	0.000	($3,719,140)	$467,869	($16,961)	($3,268,232)
Sep-13	78,918,790	(1,055,063)	-	2,623,630	2.448	-0.013	-0.002	3.008	-0.044	0.000	($14,689,405)	$820,600	($51,264)	($13,920,069)
Oct-13	75,077,407	187,889	-	2,443,926	2.606	-0.019	-0.002	3.072	0.008	0.000	($11,387,834)	($655,488)	($49,388)	($12,092,709)
Nov-13	76,934,789	(252,744)	-	2,422,380	2.615	-0.011	-0.002	3.176	-0.010	0.000	($13,588,238)	($15,942)	($48,646)	($13,652,825)
Dec-13	85,779,869	(230,481)	-	2,582,953	2.660	-0.023	-0.002	3.321	-0.010	0.000	($17,069,428)	($326,124)	($38,934)	($17,434,486)
Year 2013	928,072,612	(6,918,772)	11	30,780,118	2.651	-0.023	-0.002	3.017	-0.023	0.000	($111,346,527)	($194,193)	($539,061)	($112,079,781)
Jan-14	90,537,999	(1,911,296)	-	2,665,234	2.622	-0.028	-0.001	3.397	-0.079	0.000	($20,657,386)	$1,370,606	($39,747)	($19,326,528)
Feb-14	71,843,173	(382,186)	-	2,410,036	2.712	-0.013	-0.002	2.981	-0.017	0.000	($6,487,310)	$99,008	($41,577)	($6,429,878)
Mar-14	69,587,791	(884,481)	-	2,545,274	2.738	-0.017	-0.002	2.734	-0.038	0.000	$103,401	$526,558	($42,142)	$587,817
Apr-14	64,943,102	(850,008)	-	2,269,151	2.857	-0.022	-0.002	2.862	-0.033	0.000	($121,124)	$249,574	($39,233)	$89,217
May-14	61,709,308	(246,807)	-	2,378,008	2.913	-0.020	-0.002	2.595	-0.008	0.000	$7,572,941	($271,434)	($38,334)	$7,263,173
Jun-14	72,963,829	(531,286)	-	2,612,382	2.822	-0.011	-0.001	2.793	-0.019	0.000	$745,860	$203,903	($37,746)	$912,016
Jul-14	77,294,708	(718,620)	-	2,808,674	2.942	-0.027	0.005	2.752	-0.029	0.000	$5,333,364	$61,570	$143,383	$5,538,316
Aug-14	76,240,254	(379,720)	-	2,965,393	2.756	-0.027	0.001	2.571	-0.015	0.000	$5,473,585	($340,166)	$15,692	$5,149,112
Sep-14	63,166,406	(257,920)	-	2,502,631	2.671	-0.018	0.000	2.524	-0.011	0.000	$3,684,932	($176,662)	($10,162)	$3,498,108
Oct-14	67,788,476	(371,315)	-	2,427,954	2.817	-0.010	0.000	2.792	-0.015	0.000	$615,007	$115,884	($12,082)	$718,808
Nov-14	73,222,318	(80,030)	-	2,430,213	2.836	-0.011	0.000	3.013	-0.003	0.000	($4,309,679)	($185,374)	($11,556)	($4,506,609)
Dec-14	68,812,426		-	2,556,695	2.956	-0.019	-0.001	2.691		0.000	$6,765,241	($478,832)	($28,642)	$6,257,767
Year 2014	858,109,790	(6,613,670)	-	30,571,645	2.803	-0.018	-0.001	2.809	-0.024	0.000	($1,281,169)	$1,174,635	($142,147)	($248,681)

	Total Cost Difference in 2008 - 2014	**($203,736,479)**	**($5,084,910)**	**($373,588)**	**($209,194,977)**

Final December 2014 data not yet available. Preliminary data used.

Northern States Power Company (MN)
Electric Utility - Minnesota Retail Jurisdiction
Cost of Service Study
2008 Actual Weather Normalized

Revenue Requirement & Return Summary

(Dollars in Thousands)

	Capital Structure	Rate	Ratio	Weighted Cost
1	Long Term Debt	6.6443%	47.9431%	3.1900%
2	Short Term Debt	4.5341%	1.2922%	0.0600%
3	Preferred Stock	0.0000%	0.0000%	0.0000%
4	Common Equity	10.5400%	50.7647%	5.3500%
5	**Required Rate of Return**			**8.6000%**

Composite Income Tax Rates		
State of Minnesota Tax rate		9.80%
Federal Statutory Tax rate	35.00%	
Federal Effective Tax Rate (1-State Rate * Fed Rate)		31.57%
Total Minnesota Composite Tax Rate		**41.37%**
Total Corporate Composite Tax Rate		**40.85%**

		Total Company Electric	Minnesota Retail Electric	All Other
	Rate of Return (ROR)			
6	Total Operating Income	431,011	382,508	48,503
7	Total Average Rate Base	5,197,705	4,541,555	656,150
8	**ROR** (Operating Income / Rate Base)	**8.29%**	**8.42%**	**7.39%**
	Return on Equity (ROE)			
9	Total Operating Income	431,011	382,508	48,503
10	Debt Interest (Rate Base * Weighted Debt Cost)	(168,925)	(147,601)	(21,325)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0	0
12	Earnings Available for Common	262,086	234,907	27,179
13	Equity Rate Base (Rate Base * Equity Ratio)	2,638,599	2,305,507	333,093
14	ROE (Earnings for Common / Equity Rate Base)	**9.93%**	**10.19%**	**8.16%**
	Revenue Deficiency			
15	Require Operating Income (Rate Base * Required Return)	447,003	390,574	56,429
16	Operating Income	431,011	382,508	48,503
17	Operating Income Deficiency	15,991	8,066	7,925
18	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.69056	1.70561	N/A
19	**Revenue Deficiency** (Income Deficiency * Conversion Factor)	**27,034**	**13,757**	**13,276**
	Total Retail Revenue Requirements			
20	Retail Related Revenues	2,907,838	2,605,035	302,803
21	Revenue Deficiency	27,034	13,757	13,276
22	**Total Retail Revenue Requirements**	**2,934,872**	**2,618,792**	**316,079**
23	**Percentage Increase (Decrease)**	**0.93%**	**0.53%**	**4.38%**

Northern States Power Company (MN)
Electric Utility - Minnesota Retail Jurisdiction
Cost of Service Study
2008 Actual Weather Normalized with FCA Incentive

Revenue Requirement & Return Summary

(Dollars in Thousands)

	Capital Structure	Rate	Ratio	Weighted Cost
1	Long Term Debt	6.6443%	47.9431%	3.1900%
2	Short Term Debt	4.5341%	1.2922%	0.0600%
3	Preferred Stock	0.0000%	0.0000%	0.0000%
4	Common Equity	10.5400%	50.7647%	5.3500%
5	**Required Rate of Return**			**8.6000%**

Composite Income Tax Rates		
State of Minnesota Tax rate		9.80%
Federal Statutory Tax rate	35.00%	
Federal Effective Tax Rate (1-State Rate * Fed Rate)		31.57%
Total Minnesota Composite Tax Rate		**41.37%**
Total Corporate Composite Tax Rate		**40.85%**

		Total Company Electric	Minnesota Retail Electric	All Other
	Rate of Return (ROR)			
6	Total Operating Income	431,011	327,083	103,928
7	Total Average Rate Base	5,197,705	4,541,555	656,150
8	ROR (Operating Income / Rate Base)	**8.29%**	**7.20%**	**15.84%**
	Return on Equity (ROE)			
9	Total Operating Income	431,011	327,083	103,928
10	Debt Interest (Rate Base * Weighted Debt Cost)	(168,925)	(147,601)	(21,325)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0	0
12	Earnings Available for Common	262,086	179,483	82,603
13	Equity Rate Base (Rate Base * Equity Ratio)	2,638,599	2,305,507	333,093
14	ROE (Earnings for Common / Equity Rate Base)	**9.93%**	**7.78%**	**24.80%**
	Revenue Deficiency			
15	Require Operating Income (Rate Base * Required Return)	447,003	390,574	56,429
16	Operating Income	431,011	327,083	103,928
17	Operating Income Deficiency	15,991	63,490	(47,499)
18	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.69056	1.70561	N/A
19	**Revenue Deficiency** (Income Deficiency * Conversion Factor)	**27,034**	**108,289**	**(81,255)**
	Total Retail Revenue Requirements			
20	Retail Related Revenues	2,907,838	2,510,502	397,336
21	Revenue Deficiency	27,034	108,289	(81,255)
22	**Total Retail Revenue Requirements**	**2,934,872**	**2,618,792**	**316,080**
23	**Percentage Increase (Decrease)**	**0.93%**	**4.31%**	**-20.45%**

Northern States Power Company (MN)
Electric Utility - Minnesota Retail Jurisdiction
Cost of Service Study
2009 Actuals Weather Normalized

Revenue Requirement & Return Summary

(Dollars in Thousands)

	Capital Structure	Rate	Ratio	Weighted Cost
1	Long Term Debt	6.5714%	46.3727%	3.0500%
2	Short Term Debt	0.9669%	1.3932%	0.0100%
3	Preferred Stock	0.0000%	0.0000%	0.0000%
4	Common Equity	10.8800%	52.2341%	5.6800%
5	**Required Rate of Return**			**8.7400%**

Composite Income Tax Rates		
State of Minnesota Tax rate		9.80%
Federal Statutory Tax rate	35.00%	
Federal Effective Tax Rate (1-State Rate*Fed Rate)		31.57%
Total Minnesota Composite Tax Rate		**41.37%**
Total Corporate Composite Tax Rate		**40.85%**

		Total Company Electric	MN Retail Electric	All Other
	Rate of Return (ROR)			
6	Total Operating Income	459,639	407,461	52,178
7	Total Average Rate Base	5,544,988	4,862,391	682,597
8	ROR (Operating Income / Rate Base)	**8.29%**	**8.38%**	**7.64%**
	Return on Equity (ROE)			
9	Total Operating Income	459,639	407,461	52,178
10	Debt Interest (Rate Base * Weighted Debt Cost)	(169,677)	(148,789)	(20,887)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0	0
12	Earnings Available for Common	289,962	258,672	31,290
13	Equity Rate Base (Rate Base * Equity Ratio)	2,896,375	2,539,826	356,548
14	ROE (Earnings for Common / Equity Rate Base)	**10.01%**	**10.18%**	**8.78%**
	Revenue Deficiency			
15	Require Operating Income (Rate Base * Required Return)	484,632	424,973	59,659
16	Operating Income	459,639	407,461	52,178
17	Operating Income Deficiency	24,993	17,512	7,481
18	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.69070	1.70561	N/A
19	Revenue Deficiency (Income Deficiency * Conversion Factor)	**42,256**	**29,869**	**12,387**
	Total Retail Revenue Requirements			
20	Retail Related Revenues	2,799,613	2,495,665	303,948
21	Revenue Deficiency	42,256	29,869	12,387
22	**Total Retail Revenue Requirements**	**2,841,869**	**2,525,534**	**316,335**
23	**Percentage Increase (Decrease)**	**1.51%**	**1.20%**	**4.08%**

Northern States Power Company (MN)
Electric Utility - Minnesota Retail Jurisdiction
Cost of Service Study
2009 Actuals Weather Normalized with FCA Incentive

Revenue Requirement & Return Summary

(Dollars in Thousands)

	Capital Structure	Rate	Ratio	Weighted Cost
1	Long Term Debt	6.5714%	46.3727%	3.0500%
2	Short Term Debt	0.9669%	1.3932%	0.0100%
3	Preferred Stock	0.0000%	0.0000%	0.0000%
4	Common Equity	10.8800%	52.2341%	5.6800%
5	**Required Rate of Return**			**8.7400%**

Composite Income Tax Rates		
State of Minnesota Tax rate		9.80%
Federal Statutory Tax rate	35.00%	
Federal Effective Tax Rate (1-State Rate*Fed Rate)		31.57%
Total Minnesota Composite Tax Rate		**41.37%**
Total Corporate Composite Tax Rate		**40.85%**

		Total Company Electric	MN Retail Electric	All Other
	Rate of Return (ROR)			
6	Total Operating Income	492,528	439,977	52,551
7	Total Average Rate Base	5,544,988	4,862,391	682,597
8	ROR (Operating Income / Rate Base)	**8.88%**	**9.05%**	**7.70%**
	Return on Equity (ROE)			
9	Total Operating Income	492,528	439,977	52,551
10	Debt Interest (Rate Base * Weighted Debt Cost)	(169,677)	(148,789)	(20,887)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0	0
12	Earnings Available for Common	322,851	291,187	31,664
13	Equity Rate Base (Rate Base * Equity Ratio)	2,896,375	2,539,826	356,548
14	ROE (Earnings for Common / Equity Rate Base)	**11.15%**	**11.46%**	**8.88%**
	Revenue Deficiency			
15	Require Operating Income (Rate Base * Required Return)	484,632	424,973	59,659
16	Operating Income	492,528	439,977	52,551
17	Operating Income Deficiency	(7,896)	(15,004)	7,108
18	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.69070	1.70561	N/A
19	**Revenue Deficiency** (Income Deficiency * Conversion Factor)	**(13,350)**	**(25,590)**	**12,240**
	Total Retail Revenue Requirements			
20	Retail Related Revenues	2,854,007	2,550,059	303,948
21	Revenue Deficiency	(13,350)	(25,590)	12,240
22	Total Retail Revenue Requirements	**2,840,657**	**2,524,469**	**316,188**
23	Percentage Increase (Decrease)	**-0.47%**	**-1.00%**	**4.03%**

Northern States Power Company (MN)
Electric Utility - Minnesota Retail Jurisdiction
Cost of Service Study
2010 Actuals WN

Revenue Requirement & Return Summary

(Dollars in Thousands)

	Capital Structure	Rate	Ratio	Weighted Cost
1	Long Term Debt	6.3100%	47.2400%	2.9800%
2	Short Term Debt	0.9200%	0.7700%	0.0100%
3	Preferred Stock	0.0000%	0.0000%	0.0000%
4	Common Equity	10.8800%	51.9900%	5.6600%
5	**Required Rate of Return**			**8.6500%**

Composite Income Tax Rates		
State of Minnesota Tax rate		9.80%
Federal Statutory Tax rate	35.00%	
Federal Effective Tax Rate (1-State Rate*Fed Rate)		31.57%
Total Minnesota Composite Tax Rate		**41.37%**
Total Corporate Composite Tax Rate		**40.87%**

		Total Company Electric	MN Retail Electric	All Other
	Rate of Return (ROR)			
6	Total Operating Income	456,326	398,236	58,091
7	Total Average Rate Base	5,982,975	5,270,870	712,105
8	ROR (Operating Income / Rate Base)	**7.63%**	**7.56%**	**8.16%**
	Return on Equity (ROE)			
9	Total Operating Income	456,326	398,236	58,091
10	Debt Interest (Rate Base * Weighted Debt Cost)	(178,891)	(157,599)	(21,292)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0	0
12	Earnings Available for Common	277,435	240,637	36,799
13	Equity Rate Base (Rate Base * Equity Ratio)	3,110,549	2,740,325	370,223
14	ROE (Earnings for Common / Equity Rate Base)	**8.92%**	**8.78%**	**9.94%**
	Revenue Deficiency			
15	Require Operating Income (Rate Base * Required Return)	517,527	455,930	61,597
16	Operating Income	456,326	398,236	58,091
17	Operating Income Deficiency	61,201	57,695	3,506
18	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.69110	1.70561	N/A
19	**Revenue Deficiency** (Income Deficiency * Conversion Factor)	**103,497**	**98,405**	**5,092**
	Total Retail Revenue Requirements			
20	Retail Related Revenues	2,962,258	2,650,381	311,877
21	Revenue Deficiency	103,497	98,405	5,092
22	**Total Retail Revenue Requirements**	**3,065,755**	**2,748,786**	**316,969**
23	**Percentage Increase (Decrease)**	**3.49%**	**3.71%**	**1.63%**

Northern States Power Company (MN)
Electric Utility - Minnesota Retail Jurisdiction
Cost of Service Study
2010 Actuals WN with FCA Incentive

Revenue Requirement & Return Summary

(Dollars in Thousands)

	Capital Structure	Rate	Ratio	Weighted Cost
1	Long Term Debt	6.3100%	47.2400%	2.9800%
2	Short Term Debt	0.9200%	0.7700%	0.0100%
3	Preferred Stock	0.0000%	0.0000%	0.0000%
4	Common Equity	10.8800%	51.9900%	5.6600%
5	**Required Rate of Return**			**8.6500%**

Composite Income Tax Rates		
State of Minnesota Tax rate		9.80%
Federal Statutory Tax rate	35.00%	
Federal Effective Tax Rate (1-State Rate*Fed Rate)		31.57%
Total Minnesota Composite Tax Rate		**41.37%**
Total Corporate Composite Tax Rate		**40.87%**

		Total Company Electric	MN Retail Electric	All Other
	Rate of Return (ROR)			
6	Total Operating Income	475,748	417,492	58,256
7	Total Average Rate Base	5,982,975	5,270,870	712,105
8	ROR (Operating Income / Rate Base)	**7.95%**	**7.92%**	**8.18%**
	Return on Equity (ROE)			
9	Total Operating Income	475,748	417,492	58,256
10	Debt Interest (Rate Base * Weighted Debt Cost)	(178,891)	(157,599)	(21,292)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0	0
12	Earnings Available for Common	296,857	259,893	36,964
13	Equity Rate Base (Rate Base * Equity Ratio)	3,110,549	2,740,325	370,223
14	ROE (Earnings for Common / Equity Rate Base)	**9.54%**	**9.48%**	**9.98%**
	Revenue Deficiency			
15	Require Operating Income (Rate Base * Required Return)	517,527	455,930	61,597
16	Operating Income	475,748	417,492	58,256
17	Operating Income Deficiency	41,780	38,439	3,341
18	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.69110	1.70561	N/A
19	**Revenue Deficiency** (Income Deficiency * Conversion Factor)	**70,654**	**65,561**	**5,093**
	Total Retail Revenue Requirements			
20	Retail Related Revenues	2,995,101	2,683,224	311,877
21	Revenue Deficiency	70,654	65,561	5,093
22	**Total Retail Revenue Requirements**	**3,065,755**	**2,748,785**	**316,970**
23	Percentage Increase (Decrease)	**2.36%**	**2.44%**	**1.63%**

Northern States Power Company (MN)
Electric Utility - Minnesota Retail Jurisdiction
Cost of Service Study
2011 WN

Revenue Requirement & Return Summary

(Dollars in Thousands)

	Capital Structure	Rate	Ratio	Weighted Cost
1	Long Term Debt	6.1187%	46.9000%	2.8700%
2	Short Term Debt	3.0636%	0.4300%	0.0100%
3	Preferred Stock	0.0000%	0.0000%	0.0000%
4	Common Equity	10.3700%	52.6700%	5.4600%
5	**Required Rate of Return**			**8.3400%**

Composite Income Tax Rates		
State of Minnesota Tax rate		9.80%
Federal Statutory Tax rate	35.00%	
Federal Effective Tax Rate (1-State Rate*Fed Rate)		31.57%
Total Minnesota Composite Tax Rate		**41.37%**
Total Corporate Composite Tax Rate		**40.78%**

		Total Company Electric	MN Retail Electric	All Other
	Rate of Return (ROR)			
6	Total Operating Income	499,684	441,991	57,693
7	Total Average Rate Base	6,530,772	5,770,216	760,556
8	ROR (Operating Income / Rate Base)	**7.65%**	**7.66%**	**7.59%**
	Return on Equity (ROE)			
9	Total Operating Income	499,684	441,991	57,693
10	Debt Interest (Rate Base * Weighted Debt Cost)	(188,086)	(166,182)	(21,904)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0	0
12	Earnings Available for Common	311,598	275,809	35,789
13	Equity Rate Base (Rate Base * Equity Ratio)	3,439,758	3,039,173	400,585
14	ROE (Earnings for Common / Equity Rate Base)	**9.06%**	**9.08%**	**8.93%**
	Revenue Deficiency			
15	Require Operating Income (Rate Base * Required Return)	544,666	481,236	63,430
16	Operating Income	499,684	441,991	57,693
17	Operating Income Deficiency	44,982	39,245	5,738
18	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.68858	1.70561	N/A
19	**Revenue Deficiency** (Income Deficiency * Conversion Factor)	**75,956**	**66,937**	**9,019**
	Total Retail Revenue Requirements			
20	Retail Related Revenues	3,093,329	2,756,335	336,994
21	Revenue Deficiency	75,956	66,937	9,019
22	**Total Retail Revenue Requirements**	**3,169,285**	**2,823,272**	**346,013**
23	Percentage Increase (Decrease)	**2.46%**	**2.43%**	**2.68%**

Northern States Power Company (MN)
Electric Utility - Minnesota Retail Jurisdiction
Cost of Service Study
2011 WN with FCA Incentive

Revenue Requirement & Return Summary

(Dollars in Thousands)

	Capital Structure	Rate	Ratio	Weighted Cost
1	Long Term Debt	6.1187%	46.9000%	2.8700%
2	Short Term Debt	3.0636%	0.4300%	0.0100%
3	Preferred Stock	0.0000%	0.0000%	0.0000%
4	Common Equity	10.3700%	52.6700%	5.4600%
5	**Required Rate of Return**			**8.3400%**

Composite Income Tax Rates		
State of Minnesota Tax rate		9.80%
Federal Statutory Tax rate	35.00%	
Federal Effective Tax Rate (1-State Rate*Fed Rate)		31.57%
Total Minnesota Composite Tax Rate		**41.37%**
Total Corporate Composite Tax Rate		**40.78%**

		Total Company Electric	MN Retail Electric	All Other
	Rate of Return (ROR)			
6	Total Operating Income	484,008	426,472	57,536
7	Total Average Rate Base	6,530,772	5,770,216	760,556
8	ROR (Operating Income / Rate Base)	**7.41%**	**7.39%**	**7.57%**
	Return on Equity (ROE)			
9	Total Operating Income	484,008	426,472	57,536
10	Debt Interest (Rate Base * Weighted Debt Cost)	(188,086)	(166,182)	(21,904)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0	0
12	Earnings Available for Common	295,922	260,289	35,632
13	Equity Rate Base (Rate Base * Equity Ratio)	3,439,758	3,039,173	400,585
14	ROE (Earnings for Common / Equity Rate Base)	**8.60%**	**8.56%**	**8.90%**
	Revenue Deficiency			
15	Require Operating Income (Rate Base * Required Return)	544,666	481,236	63,430
16	Operating Income	484,008	426,472	57,536
17	Operating Income Deficiency	60,659	54,764	5,894
18	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.68858	1.70561	N/A
19	**Revenue Deficiency** (Income Deficiency * Conversion Factor)	**102,427**	**93,407**	**9,020**
	Total Retail Revenue Requirements			
20	Retail Related Revenues	3,066,859	2,729,865	336,994
21	Revenue Deficiency	102,427	93,407	9,020
22	**Total Retail Revenue Requirements**	**3,169,286**	**2,823,272**	**346,014**
23	Percentage Increase (Decrease)	**3.34%**	**3.42%**	**2.68%**

Northern States Power Company (MN)
Electric Utility - Minnesota Retail Jurisdiction
Cost of Service Study
2012 Actual W/N

Revenue Requirement & Return Summary

(Dollars in Thousands)

	Capital Structure	Rate	Ratio	Weighted Cost
1	Long Term Debt	5.7072%	45.3838%	2.5900%
2	Short Term Debt	0.9830%	1.8365%	0.0200%
3	Preferred Stock	0.0000%	0.0000%	0.0000%
4	Common Equity	10.3700%	52.7797%	5.4700%
5	**Required Rate of Return**			**8.0800%**

Composite Income Tax Rates		
State of Minnesota Tax rate		9.80%
Federal Statutory Tax rate	35.00%	
Federal Effective Tax Rate (1-State Rate*Fed Rate)		31.57%
Total Minnesota Composite Tax Rate		**41.37%**
Total Corporate Composite Tax Rate		**40.90%**

		Total Company Electric	MN Retail Electric	All Other
	Rate of Return (ROR)			
6	Total Operating Income	477,099	422,757	54,341
7	Total Average Rate Base	6,809,326	6,091,145	718,181
8	ROR (Operating Income / Rate Base)	**7.01%**	**6.94%**	**7.57%**
	Return on Equity (ROE)			
9	Total Operating Income	477,099	422,757	54,341
10	Debt Interest (Rate Base * Weighted Debt Cost)	(177,723)	(158,979)	(18,745)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0	0
12	Earnings Available for Common	299,375	263,778	35,597
13	Equity Rate Base (Rate Base * Equity Ratio)	3,593,942	3,214,888	379,054
14	ROE (Earnings for Common / Equity Rate Base)	**8.33%**	**8.20%**	**9.39%**
	Revenue Deficiency			
15	Require Operating Income (Rate Base * Required Return)	550,194	492,165	58,029
16	Operating Income	477,099	422,757	54,341
17	Operating Income Deficiency	73,095	69,407	3,688
18	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.69207	1.70561	N/A
19	**Revenue Deficiency** (Income Deficiency * Conversion Factor)	**123,682**	**118,382**	**5,300**
	Total Retail Revenue Requirements			
20	Retail Related Revenues	3,107,514	2,752,488	355,026
21	Revenue Deficiency	123,682	118,382	5,300
22	**Total Retail Revenue Requirements**	**3,231,196**	**2,870,870**	**360,326**
23	Percentage Increase (Decrease)	**3.98%**	**4.30%**	**1.49%**

Northern States Power Company (MN)
Electric Utility - Minnesota Retail Jurisdiction
Cost of Service Study
2012 Actual W/N with FCA Incentive

Revenue Requirement & Return Summary

(Dollars in Thousands)

	Capital Structure	Rate	Ratio	Weighted Cost
1	Long Term Debt	5.7072%	45.3838%	2.5900%
2	Short Term Debt	0.9830%	1.8365%	0.0200%
3	Preferred Stock	0.0000%	0.0000%	0.0000%
4	Common Equity	10.3700%	52.7797%	5.4700%
5	**Required Rate of Return**			**8.0800%**

Composite Income Tax Rates		
State of Minnesota Tax rate		9.80%
Federal Statutory Tax rate	35.00%	
Federal Effective Tax Rate (1-State Rate*Fed Rate)		31.57%
Total Minnesota Composite Tax Rate		**41.37%**
Total Corporate Composite Tax Rate		**40.90%**

		Total Company Electric	MN Retail Electric	All Other
	Rate of Return (ROR)			
6	Total Operating Income	439,806	385,761	54,045
7	Total Average Rate Base	6,809,326	6,091,145	718,181
8	ROR (Operating Income / Rate Base)	**6.46%**	**6.33%**	**7.53%**
	Return on Equity (ROE)			
9	Total Operating Income	439,806	385,761	54,045
10	Debt Interest (Rate Base * Weighted Debt Cost)	(177,723)	(158,979)	(18,745)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0	0
12	Earnings Available for Common	262,083	226,782	35,301
13	Equity Rate Base (Rate Base * Equity Ratio)	3,593,942	3,214,888	379,054
14	ROE (Earnings for Common / Equity Rate Base)	**7.29%**	**7.05%**	**9.31%**
	Revenue Deficiency			
15	Require Operating Income (Rate Base * Required Return)	550,194	492,165	58,029
16	Operating Income	439,806	385,761	54,045
17	Operating Income Deficiency	110,387	106,404	3,984
18	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.69207	1.70561	N/A
19	**Revenue Deficiency** (Income Deficiency * Conversion Factor)	**186,783**	**181,483**	**5,300**
	Total Retail Revenue Requirements			
20	Retail Related Revenues	3,044,413	2,689,387	355,026
21	Revenue Deficiency	186,783	181,483	5,300
22	**Total Retail Revenue Requirements**	**3,231,196**	**2,870,870**	**360,326**
23	Percentage Increase (Decrease)	**6.14%**	**6.75%**	**1.49%**

Northern States Power Company

NSPM JCOS MN Elec: 2013 Actual - Annual Report - W/N,

NSPM - 04 Revenue Deficiency Schedule	2013 MN Electric	2013 MN Electric with DOC FCA Incentive Proposal	Difference
Weighted Cost of Capital			
Cost of Short Term Debt	0.77%	0.77%	0.77%
Cost of Long Term Debt	5.01%	5.01%	5.01%
Cost of Common Equity	9.83%	9.83%	9.83%
Ratio of Short Term Debt	1.96%	1.96%	1.96%
Ratio of Long Term Debt	45.37%	45.37%	45.37%
Ratio of Common Equity	52.67%	52.67%	52.67%
Weighted Cost of STD	0.02%	0.02%	0.02%
Weighted Cost of LTD	2.27%	2.27%	2.27%
Weighted Cost of Debt	2.29%	2.29%	2.29%
Weighted Cost of Equity	5.18%	5.18%	5.18%
Required Rate Of Return	**7.47%**	**7.47%**	**7.47%**
Composite Income Tax Rate			
State Tax Rate	9.80%	9.80%	9.80%
Federal Statuatory Tax Rate	35.00%	35.00%	35.00%
Federal Effective Tax Rate	31.57%	31.57%	31.57%
Composite Tax Rate	**41.37%**	**41.37%**	**41.37%**
Rate of Return (ROR)			
Total Operating Income	444,727,290	379,014,914	(65,712,376)
Total Rate Base	6,719,451,520	6,719,451,520	-
ROR (Operating Income / Rate Base)	**6.62%**	**5.64%**	**(0.98%)**
Return on Equity (ROE)			
Total Operating Income	444,727,290	379,014,914	(65,712,376)
Debt Interest (Rate Base * Weighted Cost of Debt)	(153,875,440)	(153,875,440)	
Earnings Available for Common	290,851,850	225,139,474	(65,712,376)
Equity Rate Base (Rate Base * Equity Ratio)	3,539,135,116	3,539,135,116	-
ROE (earnings for Common/Equity Rate Base)	**8.22%**	**6.36%**	**(1.86%)**
Revenue Deficiency			
Required Operating Income (Rate Base * Required Return)	501,943,029	501,943,029	
Total Operating Income	444,727,290	379,014,914	(65,712,376)
Operating Income Deficiency	57,215,739	122,928,114	65,712,376
Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.7056	1.7056	1.7056
Revenue Deficiency (Income Deficiency * Conversion Factor)	**97,587,820**	**209,667,601**	**112,079,781**
Total Revenue Requirements			
Total Retail Revenues	2,889,764,488	2,777,684,707	(112,079,781)
Revenue Deficiency	97,587,820	209,667,601	112,079,781
Total Revenue Requirements	**2,987,352,308**	**2,987,352,308**	**0**

STATE OF MINNESOTA
OFFICE OF THE ATTORNEY GENERAL

LORI SWANSON
ATTORNEY GENERAL

SUITE 1400
445 MINNESOTA STREET
ST. PAUL, MN 55101-2131
TELEPHONE: (651) 296-7575

February 11, 2015

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

**RE: In the Matter of the Review of the 2011-2012 Annual Automatic Adjustment Reports for All Electric Utilities
Docket No. E999/AA-12-757**

**In the Matter of the Review of the 2012-2013 Annual Automatic Adjustment Reports for All Electric Utilities
Docket No. E999/AA-13-599**

Dear Mr. Wolf:

Enclosed and e-filed in the above-referenced matters please find Reply Comments of the Office of the Attorney General - Residential Utilities and Antitrust Division **[PUBLIC and TRADE SECRET VERSIONS]**.

By copy of this letter all parties have been served with the public version of the document. Affidavits of service are enclosed. In addition, representatives of Xcel Energy and Minnesota Power have been provided with individual versions of the document that disclose the trade secret information regarding the company of the recipient.

Sincerely,

s/ James W. Canaday

JAMES W. CANADAY
Assistant Attorney General
Manager, Residential Utilities
and Antitrust Division

(651) 757-1421 (Voice)
(651) 296-9663 (Fax)

Enclosures
cc: Tiffany Hughes, Xcel Energy
Christopher Anderson, Minnesota Power
Leann Oehlerking Boes, Minnesota Power
Service Lists

AFFIDAVIT OF SERVICE

RE: In the Matter of the Review of the 2011-2012 Annual Automatic Adjustment Reports for All Electric Utilities
Docket No. E999/AA-12-757

In the Matter of the Review of the 2012-2013 Annual Automatic Adjustment Reports for All Electric Utilities
Docket No. E999/AA-13-599

STATE OF MINNESOTA)
) ss.
COUNTY OF RAMSEY)

I, Deanna Donnelly, hereby state that on the 11th day of February, 2015, I efiled with eDockets **Reply Comments of the Office of the Attorney General – Residential Utilities and Antitrust Division [PUBLIC VERSION]** and served the same upon all parties listed on the attached service list via electronic submission and/or United States Mail with postage prepaid, and deposited the same in a U.S. Post Office mail receptacle in the City of St. Paul, Minnesota.

See Attached Service Lists

s/ Deanna Donnelly
Deanna Donnelly

Subscribed and sworn to before me
this 11th day of February, 2015.

s/ Patricia Jotblad
Notary Public
My Commission expires: January 31, 2020.

AFFIDAVIT OF SERVICE

RE: In the Matter of the Review of the 2011-2012 Annual Automatic Adjustment Reports for All Electric Utilities
Docket No. E999/AA-12-757

In the Matter of the Review of the 2012-2013 Annual Automatic Adjustment Reports for All Electric Utilities
Docket No. E999/AA-13-599

STATE OF MINNESOTA)
) ss.
COUNTY OF RAMSEY)

I, Deanna Donnelly, hereby state that on the 11th day of February, 2015, I efiled with eDockets **Reply Comments of the Office of the Attorney General – Residential Utilities and Antitrust Division [TRADE SECRET VERSION]** and served the same upon all parties listed on the attached service list via electronic submission and/or United States Mail with postage prepaid, and deposited the same in a U.S. Post Office mail receptacle in the City of St. Paul, Minnesota.

See Attached Service Lists

s/ Deanna Donnelly
Deanna Donnelly

Subscribed and sworn to before me
this 11th day of February, 2015.

s/ Patricia Jotblad
Notary Public
My Commission expires: January 31, 2020.

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_12-757_Official
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_12-757_Official
Michael	Greiveldinger	michaelgreiveldinger@alliantenergy.com	Interstate Power and Light Company	4902 N. Biltmore Lane Madison, WI 53718	Electronic Service	No	OFF_SL_12-757_Official
Tiffany	Hughes	Regulatory.Records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_12-757_Official
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_12-757_Official
Andrew	Moratzka	apmoratzka@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_12-757_Official
Leann	Oehlerking Boes	lboes@mnpower.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	OFF_SL_12-757_Official
Randy	Olson	rolson@dakotaelectric.com	Dakota Electric Association	4300 220th Street W. Farmington, MN 55024-9583	Electronic Service	No	OFF_SL_12-757_Official
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_12-757_Official
Stuart	Tommerdahl	stommerdahl@otpco.com	Otter Tail Power Company	215 S Cascade St PO Box 496 Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_12-757_Official

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_12-757_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_13-599_13-599
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_13-599_13-599
Marie	Doyle	marie.doyle@centerpointenergy.com	CenterPoint Energy	800 LaSalle Avenue P O Box 59038 Minneapolis, MN 554590038	Electronic Service	No	OFF_SL_13-599_13-599
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_13-599_13-599
Bruce	Gerhardson	bgerhardson@otpco.com	Otter Tail Power Company	PO Box 496 215 S Cascade St Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_13-599_13-599
Michael	Greiveldinger	michaelgreiveldinger@alliantenergy.com	Interstate Power and Light Company	4902 N. Biltmore Lane Madison, WI 53718	Electronic Service	No	OFF_SL_13-599_13-599
Tiffany	Hughes	Regulatory.Records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_13-599_13-599
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_13-599_13-599
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_13-599_13-599
Leann	Oehlerking Boes	lboes@mnpower.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	OFF_SL_13-599_13-599
Stuart	Tommerdahl	stommerdahl@otpco.com	Otter Tail Power Company	215 S Cascade St PO Box 496 Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_13-599_13-599

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Gregory	Walters	gjwalters@minnesotaenergyresources.com	Minnesota Energy Resources Corporation	3460 Technology Dr. NW Rochester, MN 55901	Electronic Service	No	OFF_SL_13-599_13-599
Robyn	Woeste	robynwoeste@alliantenergy.com	Interstate Power and Light Company	200 First St SE Cedar Rapids, IA 52401	Electronic Service	No	OFF_SL_13-599_13-599
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_13-599_13-599