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**STATE OF MINNESOTA**
**PUBLIC UTILITIES COMMISSION**

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**In the Matter of Great River Energy's 2014 Integrated Resource Plan**

**MPUC Docket No. ET2/RP-14-813**

# ENVIRONMENTAL INTERVENORS' INITIAL COMMENTS ON GREAT RIVER ENERGY'S COOPERATIVE'S INTEGRATED RESOURCE PLAN

## I. INTRODUCTION

Great River Energy ("GRE") is required by Minn. Stat. § 216B.2422, subd. 2, to "file a resource plan with the commission periodically in accordance with rules adopted by the commission." Accordingly, GRE filed its 2014 Integrated Resource Plan ("IRP") on November 1, 2014, with the Public Utilities Commission ("Commission"). On December 2, 2014, the Minnesota Department of Commerce ("DOC") found that the IRP is significantly complete relative to the scope of contents required by Minn. Stat. § 216B.2422 and Minn. R. 7843.0400, and thus is ready for review on its merits.

The Minnesota Center for Environmental Advocacy ("MCEA") submits comments on the IRP on behalf of itself and the following clean energy nonprofit organizations: Fresh Energy, the Izaak Walton League of America – Midwest Office, the Sierra Club, and Wind on the Wires (collectively "Environmental Intervenors"). We appreciate this opportunity to comment, and recognize the efforts of GRE and its staff to ensure that its members and their supporting ratepayers have safe, reliable, and affordable electric service.

Environmental Intervenors assert that the IRP has a number of critical flaws that must be adequately addressed prior to a final advisory decision, including the following:

- GRE's preferred plan will not adequately reduce $CO_2$ emissions.
- GRE overestimates the costs associated with increased energy efficiency savings.
- GRE overestimates costs associated with utility-scale solar.
- GRE's excess capacity position and increasing costs are significant risk factors.
- GRE's promotion of electric vehicles is not sufficiently tied to state energy goals.
- GRE selects a Preferred Plan that is based on unrealistic parameters.

Given these deficiencies, Environmental Intervenors respectfully request that the Commission order GRE to submit a revised IRP that adequately plans for a clean energy future.

## II. GRE'S PREFERRED PLAN DOES NOT ADEQUATELY REDUCE $CO_2$ EMISSIONS.

GRE's Preferred Plan will not comply with Minnesota's greenhouse gas reduction targets in Minn. Stat. § 216H.02 or reduce emissions in line with the 30% reduction targeted by the Environmental Protection Agency's Proposed Clean Power Plan to regulate existing emission sources under section 111(d) of the Clean Air Act. GRE's preferred plan purports to reduce the Company's $CO_2$ emissions levels from 2005 by roughly 27% by 2029.

The state greenhouse gas reduction goal is a reduction of at least 15% by 2015 followed by a reduction of at least 30% by 2025. *See* Minn. Stat. § 216H.02. GRE implies that it would surpass the 2015 goal (GRE IRP at 40, Table 4-1) and overlooks the 2025 goal in favor of the end date of its planning period, i.e., 2029. But GRE's System Optimizer modeling output shows that the "preferred" plan only results in a reduction in emission levels from 2005 of approximately **[TRADE SECRET BEGINS…** [redacted] **…TRADE SECRET ENDS]** by 2029, not the 27% claimed by GRE.

The difference between the 27% and **[TRADE SECRET BEGINS…** [redacted] **…TRADE SECRET ENDS]** reduction arises largely from two modifications that GRE made to its modeling results after the fact. It *reduced* the emissions from **[TRADE SECRET BEGINS…** [redacted] **…TRADE SECRET ENDS]** and *increased* the emissions reduction associated with **[TRADE SECRET BEGINS…** [redacted] **…TRADE SECRET ENDS]**. It does not make sense to claim one part of the planning exercise is realistic and another is not.

GRE's changes also illustrate how important **[TRADE SECRET BEGINS…** [redacted] **…TRADE SECRET ENDS]**. This is unrealistic and puts the Company in a situation in which its ability to reduce on-system emissions is largely outside of its control. The Commission should not endorse such an approach.

## III. ENERGY EFFICIENCY COSTS ARE OVERESTIMATED.

GRE prepared three different energy efficiency savings trajectories for its IRP. Those savings are shown in Table 8-3 of the IRP which is replicated as Table 1 here:

**Table 1. Energy Requirement, Efficiency, Distributed Generation & Electric Vehicle Forecasts**

| Year | Energy Requirement Forecast (MWh) | High Energy Forecast (MWh) | Low Energy Forecast (MWh) | Medium High Conservation & Electrical Efficiency Forecast (MWh) | High Conservation and Electrical Efficiency Forecast (MWh) | Increased Distributed Generation Forecast (MWh) | Increased Electric Vehicles Forecast (MWh) |
|---|---|---|---|---|---|---|---|
| 2015 | 13,041,357 | 13,041,357 | 13,041,357 | 13,017,966 | 12,994,634 | 13,029,319 | 13,041,609 |
| 2016 | 13,144,629 | 13,359,430 | 13,049,770 | 13,121,031 | 13,097,492 | 13,120,256 | 13,145,012 |
| 2017 | 13,266,644 | 13,696,246 | 13,076,927 | 13,242,727 | 13,218,869 | 13,229,783 | 13,267,222 |
| 2018 | 13,433,966 | 14,078,368 | 13,149,390 | 13,409,645 | 13,385,385 | 13,384,277 | 13,434,840 |
| 2019 | 13,294,368 | 14,153,571 | 12,820,075 | 13,269,660 | 13,245,014 | 13,231,515 | 13,295,690 |
| 2020 | 13,477,294 | 14,551,298 | 13,003,000 | 13,452,152 | 13,427,073 | 13,400,801 | 13,479,299 |
| 2021 | 13,683,226 | 14,972,031 | 13,114,074 | 13,657,588 | 13,632,014 | 13,592,942 | 13,686,252 |
| 2022 | 13,837,053 | 15,340,659 | 13,173,043 | 13,811,047 | 13,785,106 | 13,732,440 | 13,841,630 |
| 2023 | 14,036,623 | 15,755,029 | 13,277,753 | 14,010,139 | 13,983,722 | 13,917,207 | 14,043,545 |
| 2024 | 14,245,825 | 16,179,032 | 13,392,097 | 14,218,845 | 14,191,932 | 14,111,039 | 14,256,323 |
| 2025 | 14,650,331 | 16,798,339 | 13,701,745 | 14,622,835 | 14,595,408 | 14,500,171 | 14,666,163 |
| 2026 | 14,878,688 | 17,241,496 | 13,835,242 | 14,850,645 | 14,822,673 | 14,712,670 | 14,902,628 |
| 2027 | 15,134,544 | 17,712,154 | 13,996,240 | 15,105,890 | 15,077,307 | 14,952,297 | 15,170,744 |
| 2028 | 15,355,688 | 18,148,098 | 14,122,525 | 15,326,508 | 15,297,401 | 15,156,579 | 15,410,570 |
| 2029 | 15,591,718 | 18,598,928 | 14,263,696 | 15,561,969 | 15,532,295 | 15,375,938 | 15,661,021 |
| 5-Year CAGR | 0.48% | 2.07% | -0.43% | 0.48% | 0.48% | 0.39% | 0.48% |
| 10-Year CAGR | 0.99% | 2.42% | 0.30% | 0.99% | 0.98% | 0.89% | 0.99% |
| 15-Year CAGR | 1.28% | 2.57% | 0.64% | 1.28% | 1.28% | 1.19% | 1.32% |

The Energy Requirement Forecast includes what GRE terms 1.5% energy efficiency savings. That percentage is measured against GRE's All Requirements members and includes 0.5% savings from supply-side energy efficiency measures.

The "Medium High" and "High" Efficiency Forecasts are connected to Appendix D – "Conservation Plan Scenario Analysis" prepared for GRE by LADCO Services. The Medium High Forecast Corresponds to 1.75% annual savings and the High Forecast corresponds to 2% annual savings. LADCO's analysis looked at the program-incentive and administrative costs that it believes would be necessary to increase demand-side energy savings from the current 1% level to 1.25%, 1.5%, and 2% savings per year as well the attendant rate impacts associated with those savings levels. However, LADCO's approach to estimating these costs is simply not reflective of reality.

LADCO used "Utility Net Benefit correction factors" agreed to in Docket No. E,G999/CI-08-133 to escalate the incentive and administrative costs. Those factors were intended to correct for non-linear benefits of energy efficiency[1] under the assumption that the rate of increase in net benefits from implementing energy efficiency programs would flatten as savings increased since the cost of those programs would increase non-linearly. Because the financial incentives for energy savings are calculated based on net benefits, without this adjustment, the incentives would accrue at a slower rate as greater penetration of savings was achieved.[2] However, two years later, the Commission removed this adjustment after the DOC concluded that the increase in net benefits did not in fact slow as greater savings were achieved.

Despite this change, LADCO used the outdated correction factors in its cost analysis. LADCO assumed that the relationship between net benefits and savings established in the 2010 order would apply to GRE, with some modifications. Since it knew the benefits of achieving differing levels of savings, based on GRE's avoided cost, it could infer what the cost of the programs ought to be given what the net benefits "ought" to be. This approach resulted in program and administrative costs that rise dramatically:

[1] Order in Docket No. E,G999/CI-08-133 issued on January 27, 2010.
[2] Order in Docket No. E,G999/CI-08-133 issued on March 30, 2012.

**Table 2. LADCO Projected Incentive Costs Under Differing Savings Levels**

| | Project Incentive Costs | | | |
|---|---|---|---|---|
| **Project Description** | **Base Case** | **1.25%** | **1.50%** | **2.00%** |
| Commercial/ Industrial/Agricultural | $3,167,011 | $6,442,357 | $11,648,448 | $23,138,174 |
| Income Eligible | $1,398,225 | $1,398,225 | $1,398,225 | $1,398,225 |
| Residential | 33,229,144 | $6,759,494 | $12,221,866 | $24,277,197 |
| Total | $7,888,150 | $14,600,076 | $25,268,539 | $48,813,596 |
| Increase Over Base | | 185% | 320% | 619% |
| *Cost per First Year MWh* | *$77.05* | *$106.15* | *$153.09* | *$221.81* |

**Table 3. LADCO Projected Administrative Costs Under Differing Savings Levels**

| **Project Description** | **Base Case** | **1.25%** | **1.50%** | **2.00%** |
|---|---|---|---|---|
| Commercial/ Industrial/Agricultural | $1,577,040 | $4,179,157 | $5,519,642 | $7,885,202 |
| Income Eligible | $157,888 | $157,888 | $157,888 | $157,888 |
| Residential | $3,430,021 | $9,089,555 | $12,005,072 | $17,150,103 |
| Total | 5,164,949 | 13,426,600 | 17,682,602 | 25,193,194 |
| Increase Over Base | | 260% | 342% | 488% |
| *Cost per First Year MWh* | *$50* | *$98* | *$107* | *$114* |

These increases are extraordinary and are not supported by the experience of the investor-owned utilities in Minnesota nor of other utilities that have ramped up their energy efficiency programs. Indeed, one study of several utilities across multiple states found that as savings increased the cost per MWh of achieving those savings decreased.[3] As the Cost per First Year MWh line shows in both tables above, instead LADCO is predicting significantly increasing costs per unit of energy saved as total savings increase.

Despite this flawed analysis of program and administrative costs, Table 4 below demonstrates that achieving 2% savings would be very cost-effective.

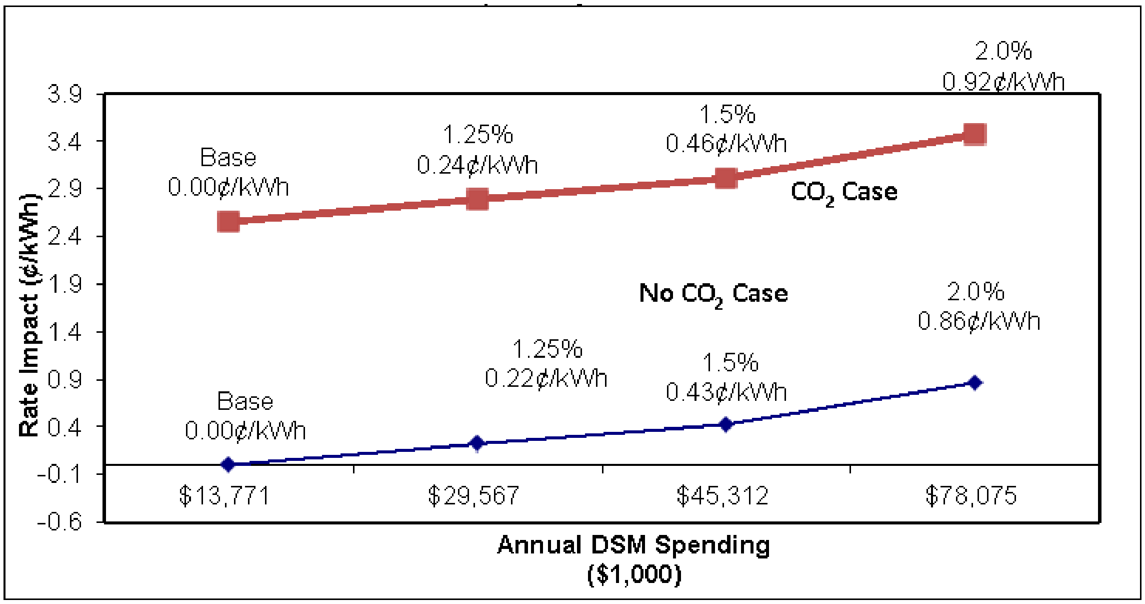
[3] *See* The Sustainability and Costs of Increasing Efficiency Impacts: Evidence from Experience to Date, (Aug. 2008) *available at*: http://synapse-energy.com/sites/default/files/SynapsePresentation.2008-08.0.Sustainability-and-Costs-of-Efficiency-Impacts.S0051.pdf.

**Table 4. Benefit-Cost Results by Scenario with $CO_2$ Cost Starting in 2019**

| Test Perspective | Benefits (Thousand Dollars) | Costs (Thousand Dollars) | Net Benefits (Thousand Dollars) | B/C Ratio |
|---|---|---|---|---|
| **Base Case Scenario** | | | | |
| Societal | $1,479,040 | $379,180 | $1,099,860 | 3.90 |
| Utility | $971,257 | $147,827 | $823,430 | 6.57 |
| Ratepayer Impact Measure | $2,687,460 | $3,609,254 | ($921,794) | 0.74 |
| Participant | $2,232,373 | $286,953 | $1,945,420 | 7.78 |
| **1.25% Scenario** | | | | |
| Societal | $1,956,758 | $578,365 | $1,378,393 | 3.38 |
| Utility | $1,280,905 | $302,670 | $978,235 | 4.23 |
| Ratepayer Impact Measure | $3,539,827 | $4,855,464 | ($1,315,637) | 0.73 |
| Participant | $2,980,137 | $374,874 | $2,605,263 | 7.95 |
| **1.5% Scenario** | | | | |
| Societal | $2,330,329 | $706,600 | $1,623,729 | 3.30 |
| Utility | $1,523,046 | $457,006 | $1,066,040 | 3.33 |
| Ratepayer Impact Measure | $4,206,091 | $5,863,053 | ($1,656,962) | 0.72 |
| Participant | $3,627,005 | $443,640 | $3,183,365 | 8.18 |
| **2.0% Scenario** | | | | |
| Societal | $3,163,442 | $984,147 | $2,179,295 | 3.21 |
| Utility | $2,048,671 | $796,657 | $1,252,014 | 2.57 |
| Ratepayer Impact Measure | $5,643,135 | $8,053,720 | ($2,410,585) | 0.70 |
| Participant | $5,143,716 | $614,763 | $4,528,953 | 8.37 |

Because Minnesota preferentially uses the Societal Test to screen energy efficiency programs, it is certainly noteworthy that even the 2% level never falls below a benefit-cost ratio of 3.21. Despite this fact, LADCO (and GRE) seems to dismiss increased savings on the basis of rate impacts. (GRE IRP at 60.) Using the results of the rate impact test, it created the following chart.

**Figure 1. Rate Impacts by Scenario in the Year 2019**




It is likely that this figure suffers from the same problem as most rate impact analyses of energy efficiency—it ignores the fact that the energy consumed by customers also changes in each scenario. That is, while lost revenues arise from decreased sales, those decreased sales are not reflected on the customer side of equation in this figure. To put it another way, if a customer purchased 2,500 kWh per month at 8.00 cents per kWh, but would purchase 2,000 kWh per month at 8.92 cents per kWh, then she  would save money despite rising rates. Figures such as Figure 1 do not account for such a dynamic.

Even if increased savings resulted in increased total costs to customers, on a percentage basis, these increases are quite small. The 2013 and 2014 GRE wholesale rate was $0.704 per kWh.[4] An increase of $0.0092 and $0.0086 per kWh is equal to an increase of 1.3% and 1.2%, respectively. Of course, even these increases overstate the rate impact because, as discussed above, program incentive and administrative costs assumed here are significantly higher than GRE is likely to incur. As a result, the LADCO study actually supports the idea that GRE should be expanding its efforts to save energy on the customer-side of the meter. Indeed, achieving 2% savings per year would be well worth the benefit to customers.

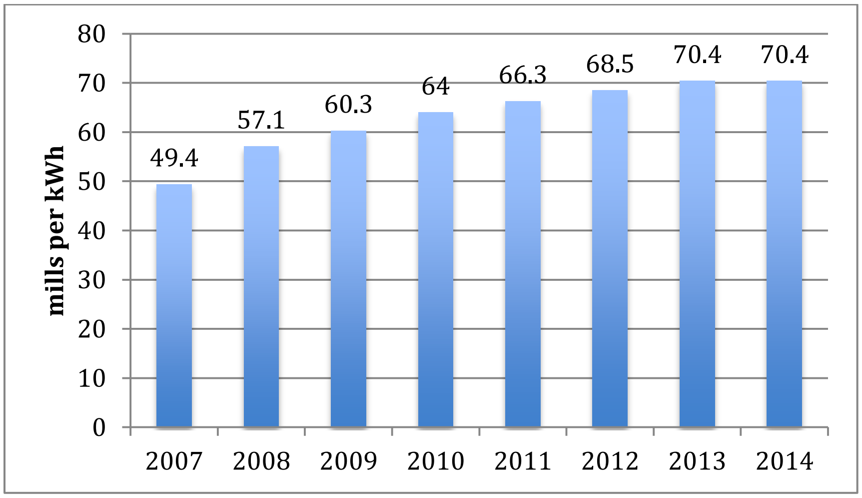
We should make clear that these 2% savings would be over and above any supply-side savings that might occur. GRE says in several instances throughout the IRP that it will get 0.5% savings annually from supply-side measures, however, no further information about where those savings might come from or what their cost might be is given. At page 60 of the IRP, GRE states "[b]ased on the results of [the LADCO] study, the current capacity need and the known challenges associated with increased levels of efficiency," it declines to pursue any higher level savings. GRE's members and this Commission should be very concerned with such statements. It ignores some key benefits of energy efficiency including:

1. GRE's capacity need will change over time and failure to take advantage of cost-effective savings potential now will result in higher costs for customers in the future.

2. The benefits of energy efficiency to customers are not limited to those periods when capacity is needed. Aggressive energy efficiency that impacts the broadest number of customers possible will also reduce bills. This would have the effect of offsetting the large rate increases in GRE's wholesale rate. (*see* Figure 2 demonstrating a 43% increase since 2007.)

[4] GRE 2013 Annual Report at page 24.

**Figure 2. GRE's Wholesale Rate by Year**[5]




3. Many other utilities including several in Minnesota have been able to achieve 1.5% savings on a regular basis. We see no reason why GRE would have "unique challenges" that would preclude it from increasing its savings level.

## IV. SOLAR COSTS ARE OVERESTIMATED.

GRE included solar PV as a potential resource in its modeling at 10 MW in size. It is not clear how many blocks of solar were available for the model to select, but in none of the 32 cases did System Optimizer choose solar. Certainly GRE's lack of need for new capacity is a reason for that and GRE used wind to comply with the RES, not solar.[6] But given that GRE is much closer to being deficient in energy rather than capacity, it is worth commenting on the cost assumptions made by GRE.

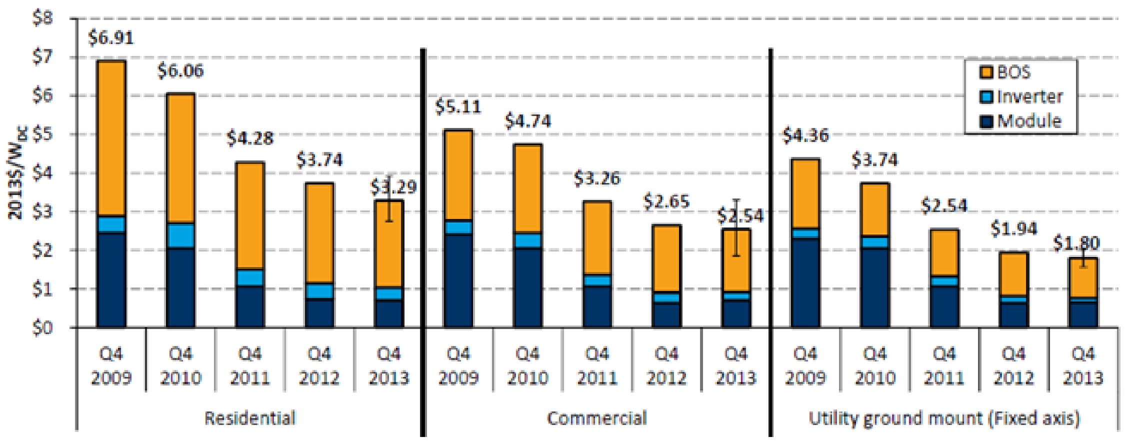
The source of the installed cost is reported as the "Annual Energy Outlook," a publication by the Energy Information Administration ("EIA"). No date is given, but an April 2013 report by the EIA called "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants" reports the same overnight cost that GRE used, i.e., $4,183 per KW. GRE did not use the

[5] GRE's 2011 and 2013 Annual Reports.

[6] It is our understanding the GRE hardcoded those wind resources that it felt were necessary to comply with the existing RES in those cases that assumed future RES compliance.

regional cost adjustment that EIA applied to solar PV in the MRO-W region, of which Minnesota is a part. That adjustment is 95%. However, the bigger issue is that this cost is simply out of date. The cost of solar PV has fallen dramatically in the past couple of years (*see* Figure 3).

**Figure 3. NREL's Cost Based Estimate for PV System Prices**[7]




As Figure 3 demonstrates, by the end of the fourth quarter of 2013, installed costs of utility-scale, ground-mounted PV systems were estimated at $1,800 per kW. This number is not directly comparable to GRE's assumption because the EIA estimate assumed single-axis tracking technology, which is slightly more expensive than fixed axis. Even so, GRE's cost is much too high relative to the current state of the technology. On a levelized basis, this translates into $267 per MWh. That is much, much higher than such a system would reasonably cost. Even the lower cost sensitivity with a 30% reduction in installed cost is too high at $187 per MWh. As the Environmental Intervenors discussed in their comments on OTP's most recent resource plan in Docket No. E017/RP-13-961, a more reasonable levelized cost, while the 30% ITC is still available, would be $115 per MWh. This does not include the future reductions in PV cost that are widely expected.

[7] Presentation to UBS Electric Utilities & IPPs on February 11, 2015.

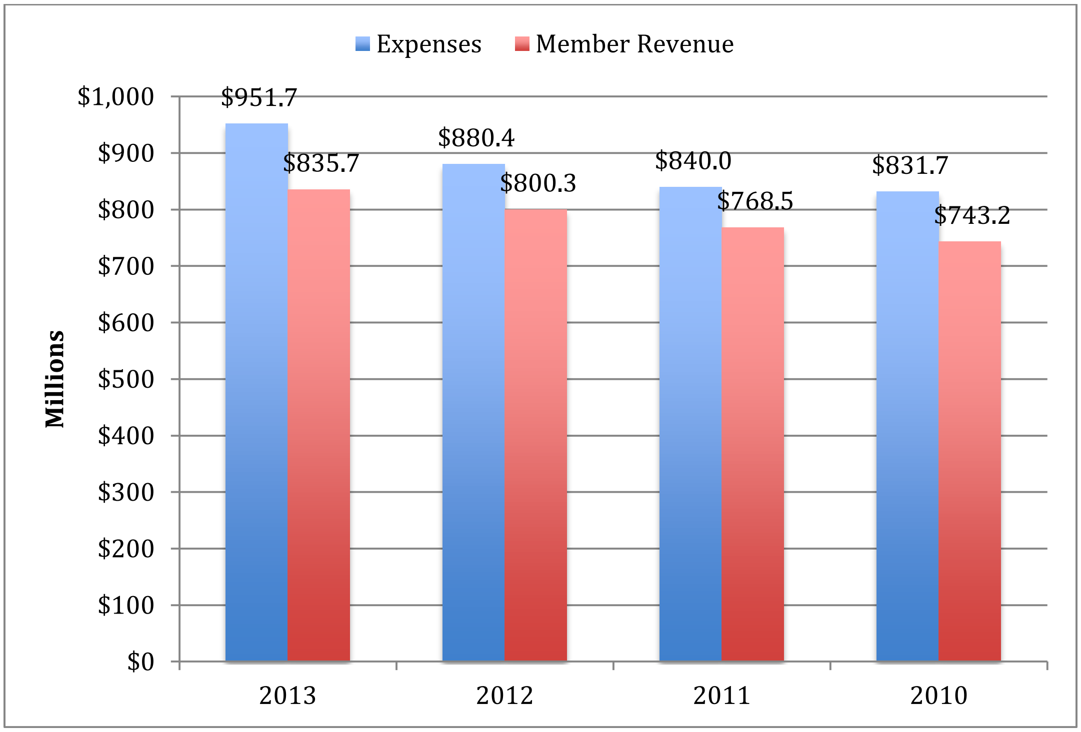
In addition, transmission interconnection costs are too high. After discussion with GRE, we learned that the transmission cost for solar was based on GRE's estimate for wind and adds an additional **[TRADE SECRET BEGINS…** [redacted] **…TRADE SECRET ENDS]**. About half of the cost comes from the assumption that **[TRADE SECRET BEGINS…** [redacted] **…TRADE SECRET ENDS]** and simply serves to make solar look much more expensive than it is.

## V. GRE'S EXCESS CAPACITY POSITION AND INCREASING COSTS ARE SIGNIFICANT RISK FACTORS.

GRE has significant excess capacity on its system, particularly since Spiritwood came on line in November 2014. Spiritwood, coupled with low levels of load growth, has likely contributed to some risky courses of action that GRE has adopted in order to cover its increasing operating costs. For example, GRE has invested millions of dollars to build one of two ethanol plants that will use steam from Spiritwood and its lack of interest in retiring Stanton Station is likely due in part to the contribution that plant currently makes to off-system sales revenue.

GRE relies upon non-member sales (both contracted and in the spot market) to cover the costs of operating its units. According to GRE's Annual Reports (demonstrated in Figure 4), member revenue has consistently fallen short of expenses by $72 to $116 million per year. While non-member electric revenue has varied from $60 to $80 million, the balance of electric operating expenses are covered by transmission revenue, tipping fees at the Elk River Processing Plant, and other non-electric revenue.

**Figure 4. GRE Electric Operating Expense and Member Revenue by Year**




Relying on non-member sales to cover its operating costs is unnecessarily risky and should not be endorsed by the Commission as part of GRE's Preferred Plan.

## VI. GRE'S PROMOTION OF ELECTRIC VEHICLES IS NOT SUFFICIENTLY TIED TO STATE ENERGY GOALS.

GRE indicates that it is interested in electric vehicles as a way to absorb *existing* wind generation during low-demand hours. In addition, the forecasts in Tables 8-3 and 8-4 of its IRP suggest that increases in electric vehicle penetration will increase overall energy and capacity demand on GRE's system by roughly 69,303 MWh and 21 MW through 2029, respectively. In each case, it is important to point out the impacts of increasing numbers of electric vehicles on the utility's electric grid, and highlight policies to ensure those vehicles are meeting state energy goals.

Electric vehicles can play an important role in our transportation infrastructure and policy moving forward. Broadly speaking, as the negative health and environmental impacts of extracting, processing, and burning liquid transportation fuel resources increases, a cleaner electric system can provide better transportation solutions for our economy. However, as noted in a recent study by the University of Minnesota,[8] the impact of electric vehicles relative to gasoline vehicles depends largely on the generation resource used to meet vehicle demand. Significant air pollution and health benefits exist by switching from gasoline to electric vehicles powered by renewable generation resources. Conversely, switching to electric vehicles powered by coal-fired generation resources can have detrimental pollution and health effects.

Given these dynamics and existing state energy goals, it is important that policies and programs aimed at increasing electric vehicle adoption match the increased demand on the system with an increase in renewable generation resources. These can include time-of-use programs that encourage overnight charging when renewable penetration may be higher, tariff options that match vehicle charging with 100 percent renewable generation, and ultimately, an overall increase in the percentage of a utility's generation mix from renewable resources. As GRE plans for and even promotes greater electric vehicle adoption across its service territory, it should enact policies and programs that keep an increase in electric vehicles in step with an increase in renewable generation resources.

## VII. GRE SELECTS A PREFERRED PLAN THAT FAILS TO ADEQUATELY AND REALISTICALLY PLAN FOR A CLEAN ENERGY FUTURE.

The Commission should deny GRE's IRP if GRE continues to prefer Expansion Plan E that fails to adequately and realistically plan for a clean energy future. GRE's Preferred Plan, Plan E, seems to be GRE's preference in large part because it was the most frequently selected in

[8] Life Cycle Air Quality Impacts Of Conventional and Alternative Light-Duty Transportation in the United States (Nov. 2014), *available at*: http://www.pnas.org/content/111/52/18490.

System Optimizer. GRE offered the following additional explanations for selecting its Preferred Plan:

> Expansion Plans that reflected unexpected outcomes of high or low energy prices, high or low energy and demand growth, high externalities costs and high PVRRs were eliminated. This eliminated Expansion Plans A, F, G, H, I, J, K and L from consideration. Expansion Plan B was eliminated because it results from a case where new hydro is not allowed as a resource option and it has a higher PVRR than Expansion Plan E. Expansion Plan C was removed from consideration since it does not allow coal generation retirements or coal contract terminations. Expansion Plan D was eliminated because it did not meet Minnesota's Renewable Energy Standard requirement.

(GRE IRP at 130.) In other words, Expansion Plans A, F, G, H, I, J, K, and L arise out of parameters that are outside GRE's expected future (and as a result some had high PVRRs) and were therefore eliminated from further consideration.[9] Table 5 demonstrates that Plans A, B, C, D, F, G, I, J, K, and L all arise only from parameters outside GRE's expected future, not complying with Minnesota's RES, and/or no inclusion of externalities.

[9] This is not to say that the way a plan performs outside of the "expected" case is not useful or important information—it is. But the way GRE did its modeling means that some of that information is simply not available. For example, there is no Plan E measured against low load growth because the low load growth cases resulted in a different expansion plan. Or, in another example, the only time high "externalities" were used was in cases without any wholesale market representation. It thus becomes very difficult to know which parameter, high externalities or no wholesale market, was most influential on the expansion plan. For these reasons, the cases outside of the "expected" future are generally of limited value.

**Table 5. Parameters Outside of GRE's Expected Future by Plan**

| Plan | A | B | C | D | E | F | G | H | I | J | K |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | No. of Cases | High Prices | Low Prices | High Growth | Low Growth | High Externalities | No Externalities | Low Externalities | No Retirements | No RPS Compliance | No Market |
| ~~A~~ | 1 | | 1 | | 1 | | 1 | | | | |
| ~~B~~ | 1 | | | | | | 1 | | | | |
| ~~C~~ | 1 | | | | | | 1 | | 1 | | |
| ~~D~~ | 3 | | | | | | 2 | | | 3 | |
| E | 14 | | | | | | 9 | 3 | | | 6 |
| ~~F~~ | 1 | | 1 | | 1 | | | | | | |
| ~~G~~ | 2 | | | | | | | | | 2 | |
| H | 3 | | | | | | | | | | |
| ~~I~~ | 2 | 2 | | 2 | | | | | | | |
| ~~J~~ | 1 | | | | | 1 | | | | | |
| ~~K~~ | 2 | | | | | 2 | | | | | 2 |
| ~~L~~ | 1 | 1 | | 1 | | | | | | | 1 |

[a] *GRE uses the term "externalities" to refer to both the externality values established by the Commission in 1997 as well as the Commission's $CO_2$ regulatory values.*

In Table 5, "Case" refers to separate combinations of unique parameters, and "Plan" refers to the capacity plan arising from each case. Column A shows the number of cases that resulted in each of the plans A through L. Columns B through K shows some of the parameters that made up each case.[10]

Eliminating the plans that result from parameters outside of GRE's expected future leaves plans E and H. So that the reader will have some sense of how these plans differ, a version of Table 9-3 from GRE's IRP is reproduced below (with some modifications due to errors in the original table).

[10] Columns B through K will not necessarily add up to the number in Column A because some cases include more than one of the parameters listed in Columns B through K or include parameters not listed in this table.

**Table 6. Generation Additions and Retirements by Expansion Plan**

| Expansion Plan | Additions (MW) | | | | Retirements | | | |
|---|---|---|---|---|---|---|---|---|
| | Coal | Gas | Wind | Hydro | Genoa 3 | Stanton | Coal Creek 1 | Coal Creek 2 |
| **A** | 0 | 0 | 300 | 200 | Yes | No | No | No |
| **B** | 0 | 0 | 600 | 0 | Yes | No | No | No |
| **C** | 0 | 0 | 600 | 200 | No | No | No | No |
| **D** | 0 | 0 | 0 | 200 | Yes | No | No | No |
| **E** | 0 | 0 | 600 | 200 | Yes | No | No | No |
| **F** | 0 | 400 | 300 | 200 | Yes | Yes | Yes | No |
| **G** | 0 | 0 | 0 | 200 | Yes | Yes | No | No |
| **H** | 0 | 0 | 600 | 200 | Yes | Yes | No | No |
| **I** | 0 | 0 | 700 | 200 | Yes | No | No | No |
| **J** | 0 | 800 | 600 | 200 | Yes | Yes | No | No |
| **K** | 0 | 1200 | 600 | 200 | Yes | Yes | Yes | Yes |
| **L** | 0 | 0 | 1400 | 200 | Yes | No | No | No |

As Table 6 demonstrates, the major difference between Plans E and H is that H includes the retirement of Stanton Station[11] and Plan E does not. If one looks at the specific combinations of parameters that led to each of these two plans, plan H actually arises from the most likely combination of parameters. The Plan H cases include:

- Medium Prices/Growth, Medium Externalities, Retirements Possible
- Medium Prices/Growth, Medium Externalities, Retirements Possible & Low Solar Costs
- Medium Prices/Growth, Medium Externalities, Retirements Possible & High Hydro Costs

The Plan E cases include:

- Medium Prices/Growth & Medium Externalities & no Market & GRE Coin. Peak
- Medium Prices/Growth & Medium Externalities & no Market & MISO Coin. Peak
- Medium Prices/Growth & Low Externalities & no Market & GRE Coin. Peak
- Medium Prices/Growth & Low Externalities & no Market & MISO Coin. Peak
- Medium Prices/Growth & Low Externalities & Retirements
- Medium Prices/Growth & NO Externalities & no Market & GRE Coin. Peak
- Medium Prices/Growth & NO Externalities & no Market & MISO Coin. Peak
- Medium Prices/Growth & High PHEV & NO Externalities & Retirements
- Medium Prices/Growth & NO Externalities & Retirements
- Medium Prices/Growth & NO Externalities, Retirements & Low Solar Costs

[11] The Stanton Station is 189 MW in size and came online in April 1967.

- Medium Prices/Growth & High EE/Cons & No Externalities & Retirements
- Medium Prices/Growth & NO Externalities & Retirements High Hydro Costs
- Medium Prices/Growth & High DG (Customer Owned) & NO Externalities & Retirements
- Medium Prices/Growth & High (EE/Cons, EV, DG) & NO Externalities & Retirements

Plan E includes six Scenarios without a wholesale market representation, which are, of course, not representative of how GRE actually operates. And the lack of a wholesale market would tend to result in keeping existing baseload units because of the need for energy. Of the 8 cases that allow for wholesale market transactions, moreover, all but one do not include externalities, which is contrary to Minnesota law. *See* Minn. Stat. § 216B.243, subd. 3.

GRE enables both sales and purchases in those runs with a wholesale market representation. Typically, Minnesota utilities allow market purchases of electricity to be made in their planning models but not sales. The rationale for this is that small amounts of market purchases can avoid a situation in which the model builds otherwise unnecessary capacity. But market sales do not serve much function except to reduce the cost of a plan. Including sales will therefore tend to distort modeling results. This is exactly the dynamic that happens in a number of GRE's runs.

To understand how off-system sales influence the PVRR of Plan E and Plan H, we can roughly compare the Plan H cases to the "with market" Plan E cases. Table 7 attempts to make the "market on" Plan E and Plan H cases comparable ex post facto by removing sales revenue and adding externalities to those cases that did not include them. Because externalities necessarily affect the dispatch, building, and retirement decisions made by the model adding them in after the fact will not affect the outcome of the expansion plan. Accordingly, we also added a column that subtracted all externalities from each case.

**Table 7. Removing Sales Revenue and Putting Cases in Equal "Externality" Terms Shows Clear Preference for Retiring Stanton [PV OF SALES REVENUE IS TRADE SECRET]**

| Expansion Plan | Case | Case Description | PV of Sales Revenue (millions) | PVRR Increase above Case 7 w/ Externalities & w/o Sales Revenue | PVRR Increase above Case 7 w/o Externalities & w/o Sales Revenue | Retire Stanton? |
|---|---|---|---|---|---|---|
| **H** | **7** | Medium Prices/Growth & Medium Externalities & Retirements High Hydro Costs | [redacted] | 0.00% | 0.00% | Y |
| **H** | **4** | Medium Prices/Growth & Medium Externalities (Base Case) & Retirements | [redacted] | 0.22% | 0.27% | Y |
| **H** | **9** | Medium Prices/Growth & Medium Externalities & Retirements & Low Solar Costs | [redacted] | 0.22% | 0.27% | Y |
| **E** | **3** | Medium Prices/Growth & Low Externalities & Retirements | [redacted] | 7.81% | 1.05% | |
| **E** | **31** | Medium Prices/Growth & High (EE/Cons, EV, DG) & No Externalities & Retirements | [redacted] | 9.75% | 2.15% | |
| **E** | **30** | Medium Prices/Growth & High DG (Customer Owned) & No Externalities & Retirements | [redacted] | 9.81% | 2.22% | |
| **E** | **6** | Medium Prices/Growth & NO Externalities & Retirements High Hydro Costs | [redacted] | 9.98% | 2.30% | |
| **E** | **28** | Medium Prices/Growth & High EE/Cons & No Externalities & Retirements | [redacted] | 10.05% | 2.38% | |
| **E** | **29** | Medium Prices/Growth & High PHEV & No Externalities & Retirements | [redacted] | 10.31% | 2.57% | |
| **E** | **2** | Medium Prices/Growth & NO Externalities & Retirements | [redacted] | 10.20% | 2.58% | |
| **E** | **8** | Medium Prices/Growth & NO Externalities & Retirements & Low Solar Costs | [redacted] | 10.20% | 2.58% | |

As Table 7 makes clear, once sales revenue is removed, Plan H performs better than Plan E. In fact, in a world where carbon is regulated, Plan H is significantly less risky than Plan E.

Because the ability to sell electricity and capacity has been essential to positive net margins, it is noteworthy that many of GRE's bilateral contracts **[TRADE SECRET BEGINS…** [redacted]

[redacted] **…TRADE SECRET ENDS]** Figure 5 shows GRE's bilateral obligations at the peak period of each year through 2025.

**Figure 5. GRE's Bilateral Sales Obligation at the Time of Annual Peak**
**[TRADE SECRET BEGINS…**

[redacted]

**…TRADE SECRET ENDS]**

Thus, retiring Stanton would not only reduce regulatory risk but also reduce the risk that GRE will be unable to cover the expense of operating its own power plants.

GRE claims that retiring any additional baseload plants such as Stanton would "create unacceptable exposure to the market nearly every day of the year." (GRE IRP at 6.) GRE further states that "[t]aking our baseload resources out of our portfolio would remove [GRE's primary hedge against the price volatility of the MISO energy market] and leave our members with a large exposure to uncertain MISO energy market prices."[12] Environmental Intervenors agree that MISO market prices are uncertain, which is why continuing to operate power plants for the sole purpose of creating positive net margins through off-system sales is an inherently risky practice. If GRE were to retire Stanton Station, the response should not be to "do nothing" and allow

[12] Environmental Intervenors IR No. 23.

purchases of spot power to increase. Instead, a prudent utility would seek to bring resources online that as closely match the need of its customers as possible. For example, increased energy efficiency savings would exactly match the needs of customers.

## VIII. REQUESTED ORDER

Environmental Intervenors respectfully request that the Commission issue an order denying GRE's 2014 IRP as submitted requiring GRE to address these critical flaws.

Dated: March 2, 2015

Respectfully submitted,

/s/ Leigh Currie

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