Re: PUC docket number 22-75

Dear PUC members,

I write as a member-owner of the Cooperative Light and Power Association of Lake County, itself a member-owner of the Great River Energy cooperative.

GRE's initial IRP is unfortunately out of date in many respects already.

New directive from the PUC

On July 27th you adopted decision option 13a in docket 22-624, which stated:

> Require utilities to maximize the benefits of the IRA in future resource acquisitions and RFPs in the planning phase, petitions for cost recovery through riders and rate cases, IRPs, Gas IRPs, IDPs, and NGIA Innovation Plans. In such filings, utilities shall discuss how the plan to capture and maximize the benefits of the IRA, and how the IRA has impacted planning assumptions including (but not limited to) the predicted cost of assets and projects, and the adoption rates of electric vehicles, distributed energy resources, and other electrification measures. Reporting will continue until 2032.

While obviously GRE had no directive in March to go into depth on how the IRA has impacted this IRP, it does now. As it stands, the IRA is only mentioned 3 times in the IRP plus once in the Form Energy white paper that is Appendix F.

Projections are based on an outdated EIA AEO

Great River Energy's 2023-2037 Integrated Resource Plan was initially filed on March 31st, only 15 days after the EIA's 2023 Annual Energy Outlook was released. The latter was the first AEO to account for the (substantial) impacts of the 2022 Inflation Reduction Act, but GRE's IRP as filed depends upon the projections in the 2021 edition of the AEO.

For example, Appendix C Section 1.3.2's Figure 12 (page 16; pdf page 23) shows a curious inflection point of behind-the-meter solar PV adoption among GRE's current 27 distribution coops after 2021; the MN DER reports it is based upon do not show a deceleration in 2022; rather, they show a 42% higher installed capacity among commercial and residential distributed PV generation than in 2021, blowing past the IRP's projection for 2022-2025 growth in a single year (and noting that the vast majority of those newly-interconnected in 2022 were planned prior to the legislative surprise that was the IRA, in a year that the ITC had begun declining from its last).

Figure 12 implies an approximately three-fold growth of solar PV capacity between 2021 and 2038. The 2021 AEO's reference case in table 16 starts from a base of 101.9GW in 2021 and grows to 353.2GW in 2038, a 3.47x increase. Given the application, GRE might mean the 2021 AEO's "End-Use Sector" which grows from 39.8GW to 107.6GW, or 2.70x. This seems more likely since a 3.47x figure would grow the initial 34.8MW to 120.6MW, which disagrees with the chart.

The chart isn't labeled, although one might assume that the red line is total BtM solar PV and the blue line the same but with a residential filter.

While the 2023 AEO starts its forecasts from the 2022 base, the EIA's Electricity Data Browser says that "small scale solar photovoltaic" (distinguished from utility-scale) grew by 19% from 2021 to 2022, implying a 2021 to 2038 growth of 3.40x in the 2023 reference scenario for the same End-Use Sector. The same calculation for total solar PV capacity would see it grow by 6.26x nationally.

GRE's PV forecast therefore ought to be made more specific about the AEO references as well as being updated with the more recent edition.

The DER total of 49,167kW of BtM solar PV in the GRE area in 2022 multiplied out by the 2023 AEO forecast for End User solar PV national growth would take it to 140,520kW, or by the unqualified national solar growth rates would become 307,785kW.

I will say that I think the AEO only moving from 2.63x growth to 3.40x growth for BtM solar PV seems very pessimistic given the IRA's extension of the 30% ITC for the majority of the forecast period.

Other solar considerations

The Inflation Reduction Act's direct pay option for tax credits and financing assistance helps to make exercising the newly-increased 10% Renewable Member Resource Option extremely attractive to the 27 distribution coops - that would allow for the generation of up to 1,141GWh by distribution coops (10% x $899m billed to members / 78.80 mills per kWh, data from charts on pages 13-14 of the GRE 2022 Annual Report), which would take about 690,000kW of single-axis solar PV capacity in our climate and latitude.

If even a fraction of that is taken advantage of then there would be huge impacts on the IRP.

Other outdated data

Appendix C also contains many model outputs based on fitting historical data from 2011 to 2021 or 2022; due to the IRA's extension to many existing tax credits and addition to other areas one can expect a significant drift away from forecasts based on those.

BEV+PHEV estimates are inconsistent and incorrectly calculated

Appendix C Section 1.3.1 forecasts a 54% increase in the number of light duty BEVs+PHEVs in GRE's service territory, from 9,972 to 15,362. The accompanying figure 10 shows a 2038 EV figure of around 15,362, but a 2021 figure of approximately 5,000, not 9,972.

The 2021 AEO's table 39 shows a reference case total in 2021 of 1.43 million BEV+PHEV cars (100 mile electric, 200 mile electric, 300 mile electric, plug-in 10 gasoline hybrid, plug-in 40 gasoline hybrid) and 0.27 million BEV+PHEV light trucks, growing to 5.75 million cars and 4.45 million light trucks in 2038, for an aggregate growth rate of (5.75+4.45)/(1.43+0.27) - 1 = +500%, not +54%.

The 2023 AEO's table 39 reference case has those numbers growing from 2.46 million BEV+PHEV cars and 0.53 million light trucks in 2022 to 16.39 million cars and 14.19 million light trucks in 2038 for an aggregate growth of +923% nationally between 2022 and 2038.

The BEV+PHEV figures are inconsistently shown in the IRP for 2021; they are incorrectly calculated from the 2021 AEO; and when corrected and using the 2023 AEO growth rates, the 9,972 vehicles becomes 101,988 over the IRP period. Not counting the actual growth from 2021 to 2022.

The failure of GRE to apply a basic smell test to their results here gives cause to doubt the robustness of their other conclusions.

Unexamined potential for less conventional resources

In 2021 Minnesota's 5,511,960 vehicles traveled 57,171 million miles, so the average vehicle was driven 10,372 miles. 101,988 vehicles being driven 10,372 miles at an average of around 3 miles per kWh would be a 352,612MWh annual demand in 2038.

Given that the EV charging profile in Appendix C figure 11 shows a peak in the 2.5-3.5kW range, the ability to load control the charging of 100,000 such vehicles would be extremely significant. Since GRE is now required by the PUC to maximize the benefits of the IRA in its IRP, it should now be looking at IRA grants available to help create a virtual power station out of this enormous resource.

GRE's Director of Resource Planning has also recently expressed that utility-scale solar PV is "valueless" due to its winter ELCC MISO default capacity credit being only 5% of nameplate (in contrast to 50% the other three seasons), or a firm capacity of 6% per Appendix H. The reason for this is that in MISO Zone 1 we have a unimodal daily demand curve 3 seasons of the year, centered around solar PV's peak generation times, while in winter the demand curve becomes bimodal with peaks at 8-9am and 6-8pm.

Obviously combining it with short-term storage would bump solar PV's winter ELCC considerably - and therefore its value, too. I believe it would benefit the IRP if it included an examination of the IRA's effect on the winter bimodal demand curve: would those peaks be reduced or exacerbated by the tax benefit of replacing resistive heat with heat pumps vs replacing or augmenting propane heating systems with heat pumps; would the ITC for BtM storage enable a smoothing of that double-hump, and therefore make solar more valuable; would incentivizing the time-shifting of EV charging do much to flatten them?

Unexplained alteration to Rainbow PPA

The preferred plan as described in Table 2 on page 10 / pdf page 12 shows that the PPA with Rainbow Energy Center, LLC steps down from 1050MW to 550MW in 2023, to 350MW in 2025, and finally to 0MW in 2031. This is at odds with the PPA described to the distribution coops in January 2022 in the attached file <Rainbow_PPA_68MW_redacted.pdf> in which the initial 1050MW drops to 368MW in 2023. No change was mentioned in the News & Initiatives section of GRE's website, nor was there any mention of such a change to Cooperative LIght & Power's Board.

Informally the GRE Director of Planning Resources has said that this additional 200MW hedge was needed due to delays in bringing wind projects online, but it would behoove GRE to put the reason(s) on the record.

Good thing to say

As a member-owner of a GRE-owning cooperative, I am pleased that GRE is plotting a path to a low-carbon future and initiated its move towards a renewables-heavy portfolio at a financially opportune time.

In conclusion

I humbly suggest that the PUC require the follow changes prior to accepting GRE's IRP:

1. Update projections to use those from the EIA's 2023 AEO and decrease reliance on pre-IRA data where possible.
2. Figure out how the EV fleet size forecast became so inconsistent.
3. Address the IRA in accordance with the PUC-adopted decision option 13a of docket 22-624.
4. Address the potential to load control the early evening charging of 100,000 EVs, particularly in winter.
5. Address the potential of the winter bimodal demand curve in MISO Zone 1 to be flattened due to the effects of the IRA and thus the value of utility-scale solar PV investment.
6. Include estimates of distribution coop takeup of 10% self-generation given the significant incentives now available.

Yours sincerely,

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