The Roles Generation And Transmission Cooperatives Play In DER Implementation

Recommendations for overcoming the challenges in bringing distributed energy resources to the wholesale market and their member-owners: a case for Great River Energy

Humphrey School Capstone Report

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PA 8081 Capstone Workshop
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Spring 2023

Great River Energy

HUMPHREY SCHOOL OF PUBLIC AFFAIRS
UNIVERSITY OF MINNESOTA

GREAT RIVER ENERGY™

Subject Keywords: distributed energy resources, generation and transmission cooperatives, distribution cooperatives, wholesale energy, valuation

Abstract

Distributed energy resources have large and increasing potential to contribute to a renewable and resilient energy grid in the United States. Great River Energy, a generation and transmission electric cooperative in Minnesota, is interested in helping to expand distributed energy resources within its service territory and that of its member-owner distribution cooperatives.

In this report, we analyze and describe the part that U.S. generation and transmission cooperatives have in expanding distributed energy resources, applied to the case of Great River Energy. Through literature review, analysis of case studies, conversations with referred experts and our capstone partner, and data analysis, we synthesize and give a set of recommendations for Great River Energy to consider investigating to meet its goal for increasing its generation of and support for renewable energy.

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Acknowledgements

The authors thank our capstone partner, Great River Energy, for providing an educational and rewarding capstone project, as well as for being supportive collaborators. We also thank all of our interviewees for their time and for sharing their experiences and wisdom to our questions. We are grateful for their contribution to this project. We would also like to thank our project advisor Steve Kelley, who helped us guide and facilitate our capstone work. Thank you to our respective Humphrey School of Public Affairs program staff, faculty, and fellow students for giving us a wonderful graduate school experience.

All errors are our own.

Executive Summary

In this report, we analyze and describe the part that generation and transmission cooperatives in the U.S. have in expanding distributed energy resources (DERs), applied to the case of Great River Energy in Minnesota. We give eight recommendations for Great River Energy to consider investigating to meet its goal for increasing its generation of and support for renewable energy.

Recommendation One: GRE to develop a common valuation system for DERs. Determining the value of DERs has critical importance to their growth, but the lack of a standard market valuation and compensation framework has created a gap in determining their full benefits as well as equity issues. Such a framework could streamline valuation, better inform the consumer benefits of DERs, and help determine whether to pursue a DER project.

Recommendation Two: GRE to develop new power supply contracts between its member-owner cooperatives. GRE can develop new, more flexible power supply contracts to ease integration of distributed generation.

Recommendation Three: GRE to apply for the Inflation Reduction Act (IRA) and Infrastructure Investment and Jobs Act (IIJA) and help member-owners to do so as well. The IRA and IIJA present historical financing opportunities to build out renewable and zero-carbon energy technologies, including DERs. GRE should apply for these funding opportunities, and encourage its member-owners to also pursue them.

Recommendation Four: GRE to help their distribution member-owner cooperatives adopt DERs. GRE can help provide market access for DER owners by ensuring that they meet the participation requirements, and can navigate the market system. GRE can also sponsor and facilitate distributed projects and lower cost power supply contracts to more easily finance them by leaning on their higher capacities.

Recommendation Five: GRE to develop integrated distribution resource plans (IDRPs). IDRPs are a framework for co-ops to more holistically plan and operate distributed energy. GRE can use IDRPs to evaluate their member-owners' current distribution system and analyze their impact on the grid to help evaluate risks associated with new grid investments as well as meeting grid performance requirements.

Recommendation Six: Collaborate with their member-owners to aggregate or bundle DERs through GRE. By working with their member-owners to implement their own distributed energy projects, GRE can collect and aggregate output from multiple sources. This can make it easier to integrate DERs into the wholesale market and ensure a reliable supply of electricity.

Recommendation Seven: Use Our Price Predicting Algorithms to Improve Efficiency of Market Participation. GRE can utilize its closeness to the MISO market to build algorithms that can forecast market electricity price fluctuations within a variety of ranges. These pose to give GRE more market strategies and more access to better battery storage strategies for its member-owners' development in DERs.

Recommendation Eight: GRE should apply the lessons learned from our analyzed case studies to DER implementation best practices. These lessons include using tax credits and other available incentives, using rate restructuring as a tool to increase transparency and promote DERs and renewable energy, seeking out more public private partnerships, and embracing the unique business model given by DERs where ownership is held at the consumer level.

Introduction

As opposed to traditional energy or utility scale energy, distributed energy resources (DERs) most often refer to small-scale, decentralized energy generation technologies under 10 MW increasingly sourced from renewable energy. These can be located on an electric utility's distribution system, a subsystem of the utility's distribution system, or behind a consumer's meter. DERs include energy storage, distributed generation, demand response, energy efficiency, thermal storage, electric vehicles, heat pumps, and distributed wind and solar.[1] These technologies are becoming significant contributors to energy production and resilient energy grids, including in the eyes of electric utilities and cooperatives (alternatively called co-ops).

One such interested cooperative is Great River Energy (GRE). GRE is a generation and transmission cooperative (G&T co-op or G&T) owned by 27 members that are themselves called electric distribution cooperatives (often referred to as member-owners). The service territories of GRE and its member-owners serve about a third of Minnesotans. GRE traditionally has produced energy at large energy facilities such as coal and gas plants or wind farms in North Dakota and Minnesota, but is now transitioning to primarily wind and other renewable energy sources that are utility scale. GRE also acknowledges the growing value of distributed energy resources, particularly with the adoption of FERC Order 2222 which permits DERs to partake in regional organized wholesale markets alongside traditional resources, thereby creating an opportunity for novel energy sources and grid services to enter U.S. organized wholesale markets. GRE members have historically delivered electricity using a top down approach and are now in a time where the bottom up approach of generating electricity provides increasing value. For various reasons, the main one being how the current electric system and markets are designed for centralized and large-scale generation, distributed energy resources face barriers including local fees as well as policy, technological, and social hurdles. Still, they give many benefits, such as increased grid resilience against supply disruptions caused by the human-caused climate crisis, as well as reducing pressure on the transmission grid.

GRE has gathered a capstone team to identify the barriers to and opportunities involved in expanding DERs, examine GRE's role in expanding DERs, and to give recommendations for what the cooperative can do regarding DER expansion and its role in this space. We begin our analysis through the lens of three central, guiding research questions: **(1**) What are some of the barriers other utility co-ops in the Midwest and nationwide have identified for implementing DERs? **(2)** How have these utility co-ops turned these barriers to DER integration into opportunities? **(3)** What could be GRE's role as a generation & transmission co-op in increasing DERs on the distribution side?

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[1] FERC Order No. 2222: Fact Sheet. (September 20, 2020). Federal Energy Regulatory Commission.

Methods and Report Structure

Our report is built on literature and document review, interviews with industry professionals, and analysis of an electricity market dataset. Throughout our report, we give our recommendations within their pertinent sections, structured this way to achieve our intended goal of accessibility and clarity.

We begin this report by offering an overview of the benefits and barriers of distributed energy resources, including the technological, financial, societal benefits and barriers ("Overview of Benefits and Barriers of DERs"). We then give an overview of current policies relevant to the implementation of DERs ("Overview of Current Policies Relating to DERs"). Next, we discuss how to value DERs and the common flaws in DER valuation ("Valuing DERs"). We view this section as helpful particularly because DERs are a quickly emerging, expanding, and changing umbrella of technology being applied to contexts, such as wholesale electricity markets, not before seen. We then discuss how DERs can fit into wholesale electricity markets ("Distributed Energy Resources in Wholesale Markets"). This section includes the benefits of wholesale DERs, the challenges of incorporating them into wholesale markets, and wholesale DERs in the context of Minnesota. We then give case studies relevant to G&T co-ops implementing DERs and summarize the lessons learned from them, from which GRE can readily apply to their needs ("Case Studies"). Specifically for this report, we only consider distributed energy resources as those that are powered by renewable or zero-carbon energy due to energy trends and the goals of GRE.

Overview of Benefits and Barriers of DERs

Technological and Financial Benefits

According to a number of organizations, there are many general benefits of DERs. The ACEEE identifies that at least two of these benefits include reduced cost for consumers and increased reliability. The reduced cost to consumers is one of the most important benefits for cooperative consideration and support from GRE's member co-ops. If properly planned and executed, DERs can boost energy efficiency which in turn decreases energy consumption without negatively affecting energy service. Additionally, DERs can increase reliability from the grid by providing the system with more flexibility, voltage control, congestion management, frequency control, energy, capacity, and net load flattening.[2] For example, generation, demand response, and energy efficiency provide a certain amount of extra capacity during system peaks and this reduces risk of brownout and blackouts. Moreover, DERs can be employed to establish microgrids. This form

[2] Trabish, H. (2022). High electricity rates impede crucial but costly technology investments to manage rising DER levels: utilities. Utility Dive.

of resilience is particularly valuable following severe weather events, guaranteeing the availability of power to essential infrastructure, including hospitals and other emergency services.[3]

A system-wide analysis of the benefits of DER integration into the grid was conducted by Vibrant Clean Energy (VCE) and released in December of 2020 with the intent of answering two primary questions:[4]

1. Can DERs lower costs across the entire electricity system compared with alternatives, while maintaining resource adequacy, reliability, and resilience?
2. Can DERs provide support and benefits for clean electricity goals across the entire electricity system?

To answer these questions, VCE developed four scenarios and used modeling software initialized and aligned with historical data from 2018 to analyze fifteen nationwide simulations that evolved the electricity system across the contiguous United States from 2020 through 2050 in 5-year investment periods.[5]

To summarize their findings, despite significant changes to the electricity system in modeling scenarios, total system costs decrease in all scenarios through 2050 due to the use of low-cost renewables and natural gas, which lower wholesale electricity costs. While there are expenses associated with upgrading the distribution infrastructure, there are also savings from delaying upgrades to the transmission-distribution interface and removing excessive utility-scale capacity reserved for peak usage. When the researchers ran the model with DERs included, peak energy use in the system was reduced by 16% in 2050. Lower peak energy use meant a 30% reduction in costs and potentially lower utility rates. A lower electricity rate could also result in more disposable income for customers.[6]

Many of the additional financial benefits of DERs come in the form of avoided costs. One avoided cost comes from avoiding grid-related expenditures on wire-based grid updates which can be avoided with the implementation of DERs. This cost will not be avoided for existing lines, but will be avoided as DERs become more widespread.[7] To demonstrate the value proposition of DERs as cost avoidant alternatives, it is necessary to assess the expected increase in demand in a specific region, estimate the expenses associated with capacity infrastructure upgrades to accommodate the growth, evaluate the required load reductions to avoid those investments, analyze the feasibility, reliability, and cost of using DERs to achieve those load

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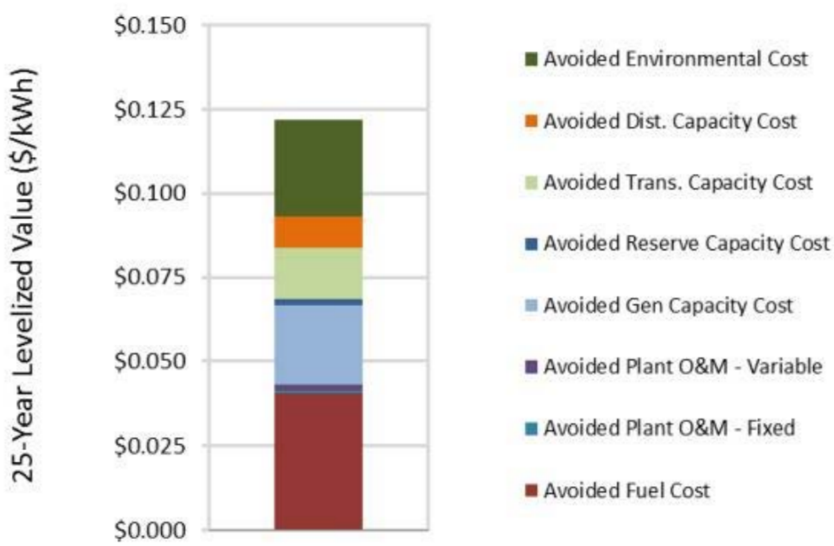
[3] American Council for an Energy-Efficient Economy. Distributed Energy Resources
[4] Clack et al. December 1, 2020. Why Local Solar For All Costs Less: A New Roadmap for the Lowest Cost Grid.
[5] Ibid.
[6] Ibid.
[7] Hausman, N. (March 2020). State Strategies for Valuing Distributed Energy Resources in Cost-Effective Locations.

reductions, and compare the costs between the conventional infrastructure upgrade and the DER alternative approach.[8]

Additional avoided costs may include avoided energy and fuel costs, avoided transmission and distribution losses, avoided operations and maintenance costs, and other avoided capital intensive infrastructure costs. Avoided energy and fuel costs occur as DERs reduce the need for electricity from other generators and do not require ongoing fuel expenditures. Because DERs are located near the electricity loads that they serve, they avoid transmission and distribution losses that occur when transporting electricity from generation to end user. Typically these losses are estimated to be between 8 and 15 percent, with that much potentially being saved with DER proximity to the end-user. If DERs are not owned by the cooperatives but by third party developers, the operation and maintenance costs can potentially be avoided for the co-ops and their consumers. DERs can also add value when they avoid investment into new infrastructure, which can potentially be an option if existing DERs are aggregated (see Recommendation: Aggregate DERs under GRE). In this case, avoided costs include capital for land, equipment, construction and regulatory costs. While there is potential that the intermittency of DERs can increase the variability of system loads, certain DERs, such as battery storage, can also be used to reduce system peak loads and help with power quality issues. The figure below from the Minnesota PUC shows an example of how these avoided costs can add up per kWh.



Source: Minnesota PUC Briefing Papers, 2014.

[8] Ibid.

Societal Benefits

Beyond the technological financial benefits of DERs are a few societal benefits as well. These may include resilience benefits, avoided public safety costs, avoided health and environment costs, and economy-wide and social benefits. The resilience benefits of DERs can occur if DERs are set up to respond quickly and flexibly to grid disruptions and can respond to critical needs during outages. Ratepayers may benefit from avoided public safety costs if DERs are successful at reducing peak electricity loads in which case, they can reduce fire risks and reduce insurance costs as a result. However, the Clean Energy State Alliance (CESA) also notes that certain DERs such as battery storage systems can be a potential fire risk due to their chemical composition. Avoided health and environmental costs can be measured by the cost of reduced GHG emissions, avoided air quality costs, avoided land use costs, and avoided water quality costs. These all can be associated with having a cleaner form of energy that many DERs represent. The economic and social benefits come in the form of economic development, job opportunities, tax revenue, energy democratization, and equity benefits. The CESA does admit that there is not strong evidence for how these economic and social benefits compare to counterfactuals.[9]

Technological and Financial Challenges and Barriers

Unfortunately there are also some obstacles to DER adoption, the primary and most relevant to this project is that adoption requires a change to operational and planning frameworks and business models. This holds true for both cooperatives and utilities that have to adjust from a centralized grid-system. Examples can include separate funding sources, out of sync timelines to realize funds, differing capitalization eligibility, competing resource constraints, and disconnected internal teams.[10] Some of the concerns with DER implementation in the co-op space are the potential diminished ability for co-ops to plan for integrated resource and distribution planning if there is not an integrated business model that ties DERs into this process. Because DERs are often not owned or controlled by cooperatives, it is difficult without the proper performance measurement equipment and methods in place to have the level of insight into DER performance that is required to make sure they are implemented in a beneficial manner. In a business-as-usual approach to planning around a centralized grid-system, some DERs will lead to a reduction in kWh sales and potentially will not meet capacity requirements.[11]

A technical and well-known challenge of DERs is that when they source or generate renewable or zero-carbon energy, they are non-constant energy sources. For example, wind and solar power require the elements to be cooperative, and generate power intermittently when conditions are right. Energy storage is the primary workaround to this, but storage capacity will need to be greatly expanded. Another technical challenge of DERs is that their rapid introduction into the

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[9] Ibid.

[10] McPhail, D. (December 19, 2019). Maximizing Value from DERs Through Value Stacking. Smart Power Electric Alliance.

[11] Trabish, H. (November 9, 2022). High electricity rates impede crucial but costly technology investments to manage rising DER levels: utilities. Utility Dive.

grid may cause stress on aging grid systems and lead to electrical and voltage issues that may increase blackouts and brownouts if not properly managed. Additionally, distribution lines might struggle with disruptions and overloading if the aggregation of independent DERs is not properly managed. This is a particular challenge with an increase in EV charging stations because they pull energy quickly and heavily from the grid often during peak times, causing opportunities for grid destabilization. This is generally a negative for cooperative consumers who will suffer from reduced service quality if the grid is not equipped to handle the challenges DERs present.[12] At the same time, EVs, including electric school buses, can help balance grid systems by acting as energy reservoirs. Since this give-and-take balance requires smart infrastructure and software, this still presents a significant challenge.

While there is the potential for reduced costs to consumers with DERs, if not adopted properly, there is also the possibility that costs could increase for members if distribution systems have to make costly changes to accommodate DER aggregations. Additionally, there may be increased capital and operational costs for communications between MISO, third-party aggregators, and multiple DERs as well as administrative costs for the member co-ops to determine a new rate structure to allocate these costs between all member-consumers. There are also equity concerns that will be discussed further in the DER valuation section.

[12] Carranza, 2021.

Overview of Current Policies Relating to DERs

Renewable energy resources play increasingly important roles in the US's energy system with the rapidly decreasing cost of renewables in recent years. However, the rapid growth of renewable energy does not guarantee an equally bright future for the deployment of DERs.[13] To adapt to this changing market, federal and state policies have been implemented to allow for easier DER implementation.

Federal Energy Regulatory Commission Order No. 2222

FERC issued Rule No. 2222 in September 2020 to enable distributed energy resources to compete with traditional energy resources in wholesale energy markets by requiring regional transmission operators (RTOs) and independent system operators (ISOs) to accommodate DERs as an official category of market participant.[14] Order 2222 allows DER aggregators to participate in the RTO and ISO capacity, energy, and ancillary service markets. Such an order changes the assumption that DERs operate independently from the wholesale electricity market.[15] Before the order, the many different rules for market participation in the six deregulated energy markets prevented DERs from fair competition, a particularly cumbersome barrier for small energy projects. The order is designed to increase grid resiliency, lower costs for consumers by enhancing competition, and create more innovation within the electric industry.[16]

For example, in California prior to Order 2222, aggregated DERs could only participate using two pathways unique to California ISO (CAISO). The first is through DER providers (DERP) who aggregate eligible DERs to participate on their behalf in the wholesale market. However, there are cumbersome barriers by going through a DERP that make it less profitable, such as discouraging the use of multiple value streams that DERs depend on, paying twice (at both the retail and wholesale rate), and a requirement for installing expensive telemetry in each individual DER, which undermines the financial case for aggregating hundreds or thousands of connected DERs. The other pathway is through a model of load curtailment called a Proxy Demand Response. Order 2222 makes these pathways more financially feasible for wholesale market participation.

In New England, solar-plus-storage systems can be bid to ISO New England's market by being designated as a renewable technology resource. This allows a limited number of qualified

[13] Paidipati et al. (February 2008). Rooftop Photovoltaics Market Penetration Scenarios.
[14] U.S. Electric Grid Moving Toward Distributed Energy Resources to Address New Realities. (February 16, 2022).
[15] Zhou et al. (September 2021).
[16] Putting Distributed Energy Resources to Work in Wholesale Electricity Markets. (September 2019).

resources to participate in the capacity auction without having to meet the requirements of ISO New England's minimum-offer price rule. Since there is only a limited capacity for renewable technology resource designation in ISO-NE's wholesale market, future larger aggregations of DERs would have likely found it impossible to participate if not for Order 2222.

Implementing FERC Order 2222

Most of the remaining challenges for Order 2222 implementation are at the state regulatory and distribution utility level because the interconnection of DERs with the grid remains subject to local utility interconnection rules. These rules can encourage or discourage regional DER activity. Although these gaps are mostly at the distribution level, it will require G&T cooperatives in particular to help fill these gaps since they generally have the staff and technological capacity that smaller distribution cooperatives might lack. They are also positioned to collaborate between their member distribution cooperatives and state public utility commissions.

Valuing DERs

Recommendation 1: GRE to develop a common valuation system for DERs

The valuation of DERs is a challenging, but necessary process to determine how to develop a DER implementation plan that provides the most benefit to consumers as possible.[17] Determining a consistent method of DER valuation can help streamline this process and also provide concrete evidence to consumers on how they can benefit from DERs, as well as help determine whether to pursue a DER project.

According to a report by the Energy Systems Integration Group (ESIG), there is currently a gap in the valuation of DERs full benefits to society because there is no overarching market framework for valuation and compensation benefits. Without an overarching valuation framework, companies are focused on the "behind-the-meter market" for consumers who are able to afford DERs at their residences. This leads to issues with equity as the cost of remaining on the grid increases and DER costs decline, tempting those energy consumers who can afford it to consider leaving the system. Their departure would erase the possibility of society-wide benefits that could come from having an aggregated system of DERs that are properly valued to entice consumers to participate with DERs on the grid.[18]

[17] Orrell, A. Et al. (May 2021). Value Case for Distributed Wind in Rural Electric Cooperative Service Areas.
[18] Kristov, L. 2021. "Valuing and Compensating Distributed Energy Resources." ESIG.

DER valuation first requires an understanding of what benefits GRE wants to measure and for whom. Cost Effectiveness tests are one method of determining this. For example, a Ratepayer Impact Measurement (RIM) test asks if utility rates will decrease as a result of DER implementation and considers the costs and benefits of a DER program on utility rates. This compares to a Participant Test (PT) or Program Administrator Cost Test (PAC) which are answering slightly different questions and therefore measures costs and benefits for slightly different groups (See Table 1). While these tests originally were developed for the valuation of energy efficiency, they can also be used for other DERs.[19] Once a method of valuation has been determined, GRE can continue with DER system planning for the benefits they wish to prioritize.

Table 1.

Test Name	**Question Answered**	**Summary of Approach**
Participant Test (PT)	Will costs decrease for the person or business participating in the program?	Only considers the costs experienced by program participants
Ratepayer Impact Measurement (RIM)	Will utility rates decrease?	Considers the costs and benefits that affect utility rates, including program administrator costs and benefits, and utility lost revenue
Program Administrator Cost Test (PAC)	Will the utility's total costs decrease?	Considers the costs and benefits experiences by the program or utility administrator
Total Resource Cost Test (TRCT)	Will the sum of the utility's total costs and the participant's total cost (or energy related costs) decrease?	Considers the costs and benefits experienced by all utility customers
Resource Value Test (RVT)	Will utility system costs be reduced while achieving applicable policy goals?	Considers the utility system costs and benefits plus those costs and benefits associated with achieving energy policy goals

[19] Shenot, J. (May 2020). Quantifying and Maximizing the Value of Distributed Energy Resources. Oregon Public Utility Commission Investigation Into Distribution System Planning (Docket UM 2005).

Common Flaws In DER Valuation

There are two common flaws in how DERs are currently valued: the inconsistency across DERs and inconsistency between DERs and Utility Infrastructure. The inconsistency across DERs comes from using a different valuation model for each type of DER or applying the tests differently between DERs. The second inconsistency between the DERs and infrastructure assumes that the least-cost/best-fit procurement for utility investments is equal to the cost-effectiveness for DER decisions. These inconsistencies lead to an incomplete and varied understanding of the real value of DER implementation.[20]

Recommendation

Given the benefits from valuing DERs coupled with the setbacks that result from valuing them inconsistently, we recommend GRE collaborate with its member-owner co-ops to develop a common valuation system for DERs. This system would preferably be progressively shared with other G&T co-ops in the Midwest and eventually farther throughout MISO's territory.

[20] Ibid.

DERs In Wholesale Markets

Benefits of Wholesale DERs

Beyond their base benefits, DERs can also provide benefits when they participate in wholesale markets if the rules governing their participation are structured properly. There are benefits for transmission grid and wholesale market operators, distribution utilities, state energy goals, utility ratepayers, and aggregators.[21]

Transmission grid and wholesale market operators: DERs are fast responding and flexible, which can significantly improve energy reliability and grid resilience by meeting the needs of the larger grid. When aggregated DERs participate in wholesale markets, RTOs and ISOs have improved visibility of DERs and are better able to track their current and predicted behavior. This better visibility can also improve coordination and dispatch instructions between transmission and distribution cooperatives. Distributed generation resources are often put in areas that experience inconsistent service or long down times, and their integration into wholesale markets can relieve grid congestion while improving system resilience. Allowing DERs to fully participate in wholesale markets improves wholesale competition and encourages just and reasonable rates, as was the intent of FERC Order 2222.

Distribution utilities: When DERs participate in wholesale markets, DERs also provide utilities information that can help guide them to plan in a more informed way, such as better real-time load management and the ability to reduce local congestion.

States: DERs bid into wholesale markets support a number of state goals, such as reducing carbon dioxide pollution emissions, improving distribution grid resilience, and addressing energy equity. They also allow greater consumer choice in managing electricity supply.

DER consumers and utility ratepayers: DERs participating in wholesale markets lower energy costs for consumers even more than they normally do, and they can provide revenue back to consumers. Wholesale market participation can also increase the value of DERs, which can lower rates for all customers by limiting the need for other higher-cost resources or infrastructure.

Developers and aggregators: DER wholesale market participation will add new revenue streams, allowing developers to pass on cost savings and accelerate deployment. Additionally,

[21] Putting Distributed Energy Resources to Work in Wholesale Electricity Markets. (September 2019).

the ability to participate in wholesale markets can limit the risk that asset managers face from possible curtailment due to limits of distribution infrastructure.

Challenges that Wholesale DERs Bring

DERs can present several challenges when participating in wholesale markets. Some of these challenges include:

- **Technical integration:** DERs often have different technical characteristics, such as varying output and control capabilities, which can create difficulties with integrating them into wholesale markets that were originally designed for larger, centralized power plants. DERs can also impact the reliability and stability of the grid if not properly integrated, especially if their output is intermittent or variable. This requires careful coordination between cooperatives and MISO to ensure that DERs are appropriately dispatched and managed to maintain grid stability.

- **New expertise:** With DERs on the wholesale market, cooperatives and MISO will have to learn how to effectively manage them on the market and will need access to necessary information as they navigate the new complexities of DER participation. This will require a heightened degree of staff capacity, expertise, and collaboration.

- **Market design:** Wholesale markets are not quite designed to fully recognize and value the unique attributes and capabilities of DERs, such as their ability to provide flexibility and grid services. This can limit the realized value that DERs can provide to the grid and create disincentives for their participation in wholesale markets.

The benefits that DERs bring when integrated in wholesale markets are generally considered to outweigh their associated challenges, as long as the challenges are addressed in reasonable time. However, this isn't to say that these challenges are minor; they present both opportunities and significant barriers.

DERs Participating In Wholesale Markets

A report by the Energy Systems Integration Group examines the changes in regulation, market rules, planning, and operating practices needed to better integrate DERs into U.S. wholesale markets and operations. Its focus is on nearer-term implementation of the FERC's Order 2222, the order's implications for electricity distribution systems, and the broader gaps related to DER integration in wholesale markets and distribution systems.

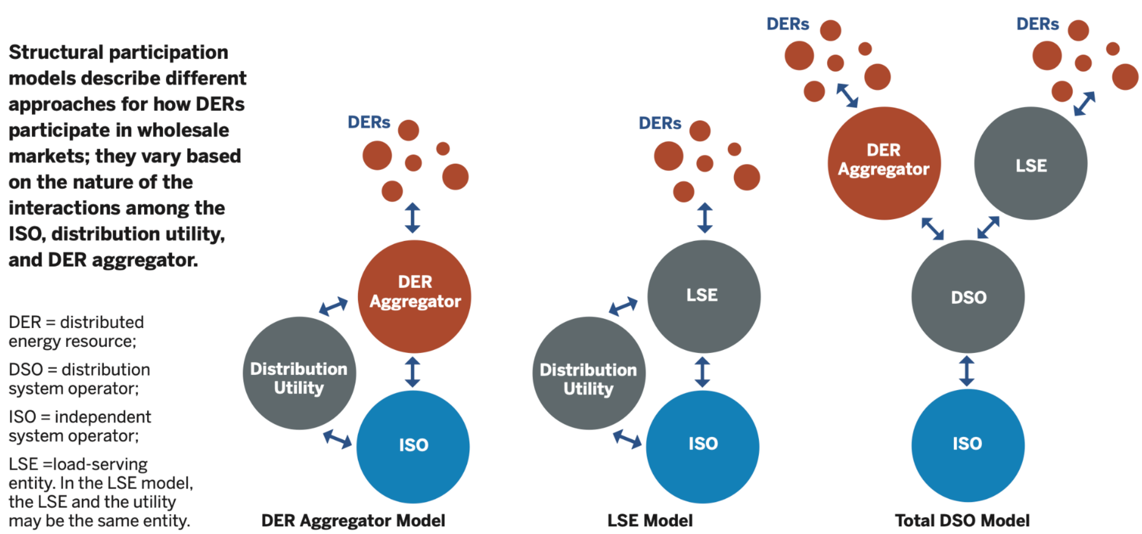
In the report, the authors organize the integration and participation of distributed energy resources in wholesale markets into a series of models. These models are organized around the functions of a distribution utility or distribution operator, a load-serving entity (which may also be the distribution utility), a DER aggregator, and the independent system operator[22]. These models are shown graphically in Figure 1 below.

- In the **DER aggregator model**, which Order 2222 has now broadened, a DER aggregator and distribution utility facilitate participation of DERs on the supply side of ISO markets. G&T cooperatives can also partner with these aggregators and provide them with access to their distribution network, which would allow the aggregators to connect with more DERs and increase their market participation.

- In the **load-serving entity model**, load-serving entities make demand bids to ISO markets, and DERs passively or actively participate in these markets through these bids. Most DERs currently interact with ISO markets through this model.

- The **total distribution system operator model** combines the above models and addresses their shortcomings. In this model, an independent distribution system operator ensures that DER supply offers and demand bids from DER aggregators and load-serving entities do not go above the limits of the distribution system before the offers are submitted to the ISO markets.

FIGURE 1
Three Structural Participation Models for DER Participation in Wholesale Markets



Source: Energy Systems Integration Group.

[22] Kahrl et al. (January 2022). DER Integration into Wholesale Markets and Operations

Regardless of the model, direct participation of DERs in ISO markets via aggregators, and encouraged by Order 2222 promise to bring significant value to stakeholders and renewable energy consumers. For customers, DERs can be tailored to their needs while making up for some of their costs by being compensated for distribution-level and wholesale market benefits. On the distribution level, effective implementation and operation of DERs can reduce the need for distribution infrastructure upgrades while still supporting rising amounts of generation, increased renewable energy sourcing, and resilience to extreme weather. In wholesale markets, DERs can provide new sources of flexibility and competition, reduce energy and market costs, and increase energy capacity.

Wholesale DERs in Minnesota

Despite the potential that FERC Order 2222 gives, the interconnection of DERs with the grid remains subject to local utility interconnection rules set and governed by state legislatures and state public utility commissions. The existing rules at the state jurisdictional level can either encourage or discourage DER market participation.

In law and policy, Minnesota is a fairly friendly state to DERs. Over the last couple decades, advocates and lawmakers have chartered research to study the capacity of the transmission and distribution system to handle new distributed energy connections, and they have designed several laws and programs to encourage distributed energy, such as the Community-Based Energy Development Law. Despite this expressed support by many stakeholders, few wholesale distributed energy projects have been implemented.

In practice, Minnesota hasn’t built out DERs to the scale that should be expected. Minnesota state and federal laws allow customers to install DERs and use the electricity they generate to offset electricity that customers would otherwise purchase from their utility, including cooperatives and municipal utilities. For example, the 2001 Minnesota statute 216B.1611[23] established that the Minnesota Public Utilities Commission should develop utility tariffs “for the interconnection and parallel operation of distributed generation fueled by natural gas or a renewable fuel, or another similarly clean fuel or combination of fuels of no more than ten megawatts of interconnected capacity” to be adopted by municipal and cooperative utilities. While this does include DERs powered by fossil fuels, it is an encouraging statute that “promote[s] the use of distributed energy resources[…]” for wholesale markets. At the time, this tariff was meant to maximize wholesale distributed energy projects. However, this tariff hasn't been implemented and no development has happened as a direct result of it.[24,25]

[23] Sec. 216B.1611. Interconnection Of On-Site Distributed Generation. MN Statutes. (2001).
[24] Landmark FERC decision opens market for distributed energy resources. (June 15, 2021).
[25] Mccoy & Farrell. (October 1, 2020). Updating Minnesota’s Dated Distributed Generation Tariff. Institute for Local Self-Reliance.

The gap of wholesale distributed generation may be filled with recent federal actions if they are successfully implemented. As mentioned before, the Inflation Reduction Act and Infrastructure Investment and Jobs Act are forecast to support rapid and sustained adoption of a variety of DERs through direct financial incentives, grants, loans, and rebates. Together with Minnesota policies that support DERs and FERC Order 2222, IIJA, and IRA should create the environment to accelerate DER adoption and participation in the MISO wholesale market.[26]

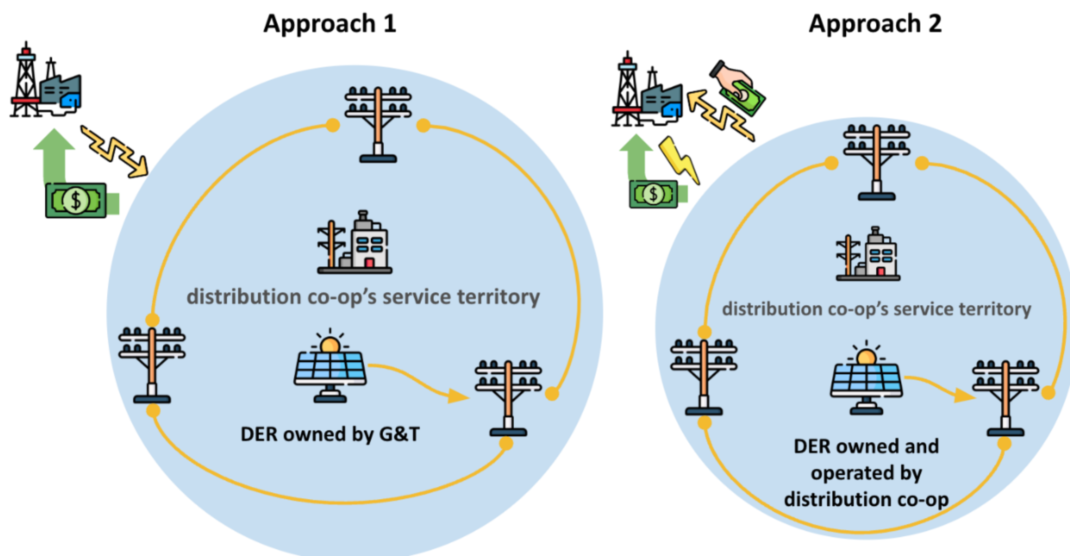
Recommendation 2: GRE to develop new power supply contracts between its member-owner cooperatives

A major barrier to cooperatives expanding DERs is the rigidity of wholesale power supply contracts, many of which have a long lifetime. Most all-requirements contracts between G&Ts and their member-owners – with or without energy supply carve outs – run until the 2040s (GRE has twenty of this type of contract). These contractual agreements constrain distribution cooperatives from expanding distributed energy resources, but some aspects of the rigidity of these contracts are challenged by new opportunities presented in evolving wholesale markets and new considerations of the value of DERs. And yet, it may be difficult to negotiate more flexibility in these contracts. The authors in Chan et al. (2019) recommend focusing on adapting or re-structuring power supply contracts to overcome this barrier.[27] Schmitt et al. (2021) suggest that G&T's can collaborate with their member distribution cooperatives to modify those contracts allowing their members to develop their own renewable power projects. If the wholesale power supply contract cannot be changed within a reasonable timeframe to accommodate new distributed energy projects, Schmitt et al. suggest the following two approaches to work around this constraint (these approaches are graphically represented in Figure 2 below:

1) One approach is that G&T cooperatives own a distributed energy project, but the project is located within the distribution cooperative's territory. The energy from that project stays within that distribution cooperative's grid, and the G&T is paid for that energy as part of the wholesale power purchasing contract. With this strategy, the distribution cooperative isn't adding generation capacity to its portfolio, avoiding the risk of exceeding its contracted generating limit. Also, the G&T cooperative can meet its priorities and obligations that G&Ts typically self-impose: prioritizing community benefits and protecting overall affordability and reliability of local energy.

[26] Richmond-Crosset & Greene. (September 30, 2022). How Distributed Energy Resources Can Lower Power Bills, Raise Revenue in US Communities.
[27] Chan et al. (February 2019). Barriers and Opportunities for Distributed Energy Resources in Minnesota's Municipal Utilities and Electric Cooperatives.

2) A second approach is for a distributed energy project to be owned and operated by a distribution cooperative within its own territory, but the G&T purchases the energy and sells it back to the distribution cooperative via a power purchasing agreement.



Recommendation

Given the barrier that certain conditions within power supply contracts present for expanding DERs, we recommend that GRE develop new power supply contracts to ease integration of distributed generation. In cases when this is not an option within a reasonable timeframe, we suggest following the strategies given by Schmitt et al. (2021)[28].

Recommendation 3: GRE to apply for Inflation Reduction Act (IRA) and Infrastructure Investment and Jobs Act (IIJA) federal funding and provide assistance to member cooperatives to do so as well

The Inflation Reduction Act

The Inflation Reduction Act (IRA) offers funding, programs, and incentives to all kinds of entities, including electric cooperatives, to accelerate the transition to a clean energy future for the US. The IRA provides **direct payments** to cooperatives when they implement a wide range of clean and zero emission energy technologies, including solar, wind, carbon capture, clean energy components manufacturing, nuclear, and battery storage. Before the legislation, cooperatives have been excluded from federal tax incentives because as nonprofit organizations, they generally do not pay federal income taxes. These payments are tax credits that cooperatives

[28] Schmitt, N. (August 2021). Financing Distributed Wind Projects in Rural Electric Cooperative Service Areas.

can trade as cash refunds after completing annual tax returns. This gives cooperatives equal opportunity as for-profit and investor-owned utilities, which have long enjoyed tax credits to develop renewable energy projects. The Act provides additional bonuses for investment in low-income and other marginalized communities.

The Act also creates **loan and grant programs** specifically for electric cooperatives to apply for funds to buy or build clean energy systems. Under the USDA Financial Assistance for Clean Energy program, cooperatives are eligible to receive funding for up to 25% of their project costs, with a maximum of $970 million going to any one cooperative. Clean energy systems can be renewable energy, energy storage, carbon capture, nuclear, and generation and transmission system efficiency improvements. The bill does not mandate reductions in carbon dioxide emissions or require closures of existing power plants and improvements to generation and transmission infrastructure. Through the USDA Rural Development program, the Act gives funding to help eligible entities such electric cooperatives purchase renewable energy and zero-emission systems and make energy-efficiency improvements on their infrastructure. The USDA can forgive up to 50% of the loan amount.[29,30,31]

The Infrastructure Investment and Jobs Act

The Infrastructure Investment and Jobs Act (IIJA) also provides a large amount of funding opportunities for electric cooperatives to help them expand the portfolio of renewable and zero-carbon energy technologies. Among the funding opportunities are: money allocated towards electric vehicle charging infrastructure to create and expand charging networks in rural areas, as well as funding for electric school buses[32,33]; clean energy research and development; carbon capture and storage projects; wind and solar, including funding for respective research and development; and energy storage.[34]

Recommendation

The IRA and IIJA present historical financing opportunities to build out renewable and zero-carbon energy technologies, including DERs. These opportunities will expire, and GRE will miss out on them if it doesn't apply as soon as possible. We thus recommend that GRE apply for the funding opportunities given by the IRA and IIJA, and it should encourage its member-owners to also pursue them to develop DERs in their respective territories, depending on the ownership agreement of DER projects.

[29] Meyers, C. (September 1, 2022). Co-ops benefit from Inflation Reduction Act.
[30] Thomas, H. (September 16, 2022). Inflation Reduction Act of 2022.
[31] USDA Seeks Public Input on Ways to Make Funds Available Through the Inflation Reduction Act to Advance Clean Energy for People in Rural America: Stakeholder Announcement. (Oct. 28, 2022).
[32] Levinson, M. (January 26, 2022). How to Help Your Community Fund Electric School Buses in the US.
[33] Kelly, E. (April 29, 2020). Flipping the Switch on Electric School Buses.
[34] Kelly, E. (November 15, 2021). House Passes Infrastructure Bill With Billions for Broadband, Energy R&D.

Recommendation 4: GRE to help their distribution member-owner cooperatives adopt DERs

Support for Wholesale Market Participation

G&T cooperatives can also play a role in providing market access for DER owners by ensuring that they meet the requirements of the wholesale market, are eligible to participate in energy markets, and can navigate the market system. This can help to incentivize the adoption of DERs and promote the growth of a more distributed, sustainable energy system.

It can be advantageous to have G&T cooperatives involved in the development of larger distributed energy projects, such as with distributed wind energy. Due to G&T's larger sizes, more assets, and robust credit history, G&Ts are often granted lower borrowing rates. Having the G&T be a project's sponsor can lower project costs. G&T's can also facilitate more and larger projects than their member cooperatives alone can, which allows them to receive more tax rebates. A G&T can also facilitate lower cost power supply contracts if they are contracting for multiple projects on behalf of their cooperative members. If member distribution cooperatives would rather they own a project, G&Ts can still assist with other project management tasks for which they may have additional staff and resource capacity, such as with planning, engineering, communications, and legal work.[35]

Support for General DER Implementation

Some member-owner distribution cooperatives have their own peak management programs, but without a G&T tariff structure that aligns costs with member rates, distribution cooperatives end up reducing their own bills by more than they lower total system costs. This unintentionally shifts costs away from them and onto other cooperatives. With their typically larger sizes and capacities, G&T cooperatives must juggle many and sometimes conflicting member-owner demands. Ultimately, the G&T combines the forecast of available load flexibility with historical data and makes their own forecasts to identify the DERs that will deliver equal cost savings, bolster reliability, and provide services that benefit the entire system. The key is centralized (G&T) coordination with decentralized (distribution member cooperative) control.

Each distribution cooperative aggregates local flexible resources at every transmission-distribution interface and shares a forecast of the total available capacity for DER dispatch by resource type. The total available capacity should be limited to the capacity that the distribution cooperatives and its members want to make available to their respective G&T after considering distribution constraints and other value streams for that energy source. Each

[35] Orrell et al. (May 2021). Value Case for Distributed Wind in Rural Electric Cooperative Service Areas.

distribution cooperative also shares a net load forecast for each substation, telling the G&T what they expect their load to be for the next 24 hours. This information sharing and coordination between transmission and distribution planning is consistent with the suggestion by Kahrl et al. (2022). The G&T then uses the distribution-level data to strengthen their own net load forecasts and integrates it into their supply curve. In places along the grid where it's economically advantageous, the G&T can send a request to the distribution co-op to dispatch local resources to shift or shed energy load. The distribution co-op dispatches its local resources and is paid by the G&T for doing so. Because the resource should be lower cost than the next-best source of energy or capacity, the entire membership pays less in supply costs.[36]

This strategy will likely end up favoring large distribution co-ops. Due to valid financial constraints, smaller co-ops may not be as technologically progressive and lack more software required to optimally interlink and manage DERs, such as advanced metering infrastructure. They might also lack staff capacity and skill sets. To avoid creating this inequitable gap, GRE as a G&T co-op should remember that they have the responsibility, opportunity, and capability to ensure their member co-ops have equal access to implementing DERs in the communities they serve.

Recommendation

Based on the capacities and role that GRE has in supporting its member-owners, we recommend that GRE provide any needed assistance to its member-owners in expanding DERs in their respective territories as well as providing any support for their member-owners with integrating DERs in the wholesale market should they be interested in doing so.

Recommendation 5: GRE to develop integrated distribution resource plans (IDRPs)

The increasing variety and amount of distributed energy resources being added in different ways creates an ever demanding need to understand the complex interconnections of the grid. Integrated resource plans that cooperatives design help to manage and plan around this complexity. Along with integrated resource plans, the National Rural Electric Cooperative Association suggests also creating integrated *distribution* resource plans (IDRPs)[37]. IDRPs are a framework for co-ops to more holistically plan and operate distributed energy for the future. This is done by considering the uncertainties in traditional planning (such as load growth, grid infrastructure changes, and power generation) and including DERs in the plans and acknowledging a downstream and upstream interaction in power supply. Cooperatives can use IDRPs to evaluate their current distribution system, consider the impact of distributed energy on

[36] Brisley, S. (January 20, 2023). How G&Ts Can Leverage DERs To Benefit All Members.
[37] Integrated Distribution Resource Planning for Electric Cooperatives. April 2020.

transmission infrastructure and on bulk power supply, and then reflect the impact of changes in wholesale power infrastructure on the distribution grid. Creating these scenarios using IDRPs and analyzing their impact on the grid helps cooperatives evaluate risks associated with new grid investments as well as meeting grid performance requirements.

Recommendation

We echo the advice by the National Rural Electric Cooperative Association when we recommend that GRE develop integrated distributed resource plans, as well as assist its member-owners in designing their own IDRPs. In their IDRPs, cooperatives can consider including DER growth over time, determining the infrastructure needed to properly integrate DERs into the grid, identifying the best locations of DERs along transmission and distribution networks, and other aspects of grid operations, such as safety, security, and protocols for gathering and analyzing data.

IDRP's include the role of emerging technologies, such as sensors and anomaly detection, along with the availability of data science and sophisticated analytics tools in operations planning. With their limited operational capacity, small cooperatives might not see the use in including the role of emerging technologies, nor have access to the latest data analytics tools. Developing IDRPs presents in general a key opportunity for further collaboration between G&T co-ops and their distribution member-owners.

Recommendation 6: GRE to work with their member-owners to aggregate or bundle DERs through GRE

Generation and transmission (G&T) cooperatives can help to address the challenges of integrating DERs into the wholesale market in a variety of ways. One way is by serving as aggregators of DERs by using sophisticated software packages such as DER Management Systems (DERMS) and virtual power plants to manage collections of DERs such as microgrids and community solar gardens.[38,39] By working with the distribution co-op members to implement their own distributed energy projects, G&T co-ops can collect and aggregate output from multiple sources, which can help to smooth out grid fluctuations. This can make it easier to integrate DERs into the wholesale market and ensure a reliable supply of electricity.

[38] Reilly & Joos. (2019). Integration And Aggregation Of Distributed Energy Resources – Operating Approaches, Standards And Guidelines.
[39] IEEE Guide for Distributed Energy Resources Management Systems (DERMS) Functional Specification. (April 29, 2021).

Aggregating DERs to participate on MISO's wholesale market offers an opportunity for GRE to meet the capacity needs of their members through a connection of smaller sources. Unfortunately, the process of aggregation is difficult because it requires management of numerous new distribution systems as well as the software capabilities to match these DERs to grid needs.

Value Stacking

One method of maximizing the value of DERs is through value stacking. Value stacking is defined as the bundling of grid applications, creating multiple value streams, which can improve the economics for distributed energy resources. An example of value stacking is the use of smart thermostats by utilities to deliver both demand response (DR) and energy efficiency (EE) benefits. While DR events provide value to the utility by shifting load from peak periods, they only occur around 10-12 times during the summer. However, optimizing HVAC operation on non-DR event days can provide additional value for both utilities and customers through reduced energy consumption. AEP Indiana Michigan Power was recognized for achieving an 80% load shed during DR events and up to 50% runtime reduction of HVAC on EE days while still maintaining customer comfort.

Utilities can further optimize the operating schedules of distributed energy resources (DERs) through time-of-use (TOU) rates for residential customers. This approach can deliver a combination of DR capability, rate optimization, cost savings, and increased customer satisfaction. By coordinating multiple DERs at a household, utilities can co-optimize schedules to avoid coincident operation and subsequent peaks.

Utilities can also leverage analytics to disaggregate household load into end-uses and appliances using smart meter/AMI interval data. By identifying times when non-controlled appliances, such as pool pumps, dishwashers, or dryers, are operating, an intelligent home energy management system can limit coincident peaks by curtailing or pausing the appliances it can control.

To bundle use cases in a single demand-side management program, utilities need a comprehensive plan that includes effective customer engagement, activation, and orchestration tools. Despite the challenges of DER value stacking, innovative utilities are realizing the benefits and moving beyond pilots into full implementations. Ultimately, DER value stacking will be critical for planning and operating a modern grid in the face of increasing DER deployment.

Virtual Power Plants for Electric Cooperatives

Virtual Power Plants provide an option for a method of DER aggregation. VPPs are a connected aggregation of DERs that store and supply power during grid stress or excess. The responsibility of delivering a contracted amount of energy to the grid falls on the DER aggregator, which has the potential to be GRE. The aggregator is tasked with selecting the resource to activate and determining the amount to request from each resource. Additionally, the off-taker or utility requires information on the participating resources, placing the responsibility on the aggregator to not only deliver but also report.[40]

VPPs are a valuable and largely overlooked resource for advancing key grid objectives:[41] The benefits that VPPs could potentially bring to the grid are increased reliability and resilience, affordability, decarbonization, economy-wide electrification, positive health and equity impacts, and consumer empowerment. In terms of reliability, VPPs could reduce peak demand in the US by 60 GW by 2030, and more than 200 GW by 2050. This is a significant reduction in peak demand that would have a positive impact on the grid's ability to meet capacity needs. VPPs are also a cost-effective resource that are estimated to help reduce annual power sector expenditures by $17 billion in 2030. They also would provide revenue streams that could incentivize electrification. This reliability and affordability make them a great resource for assisting with the decarbonization of the energy sector. They also help with overall health and equity issues by decreasing the reliance on natural gas plants which are still disproportionately impacting the health of people of color and low-income communities. Lastly, VPPs empower customers to play an active role in energy distribution and consumption.

Recommendation

Given the need for DER aggregation and bundling, as well as the benefits that can come from GRE getting involved, we recommend that GRE itself act as an aggregator of DERs in a reasonable way that matches its capabilities. By working with the distribution co-op members to implement their own distributed energy projects, GRE can collect and aggregate output from multiple sources. This can make it easier to integrate DERs into the wholesale market and ensure a reliable supply of electricity. Aggregating DERs to participate on MISO's wholesale market offers an opportunity for GRE to meet the capacity needs of their members through a connection of smaller sources.

Recommendation 7: Use price predicting algorithms to improve efficiency of market participation

GRE can provide technical and market assistance to their distribution member-owners who want to experiment with DERs and participate in the wholesale market, a process that they may have not had exposure to before. A method that can help member co-ops navigate fluctuations in future prices in the wholesale market will help them to better balance risks and increase returns

[40] Brehm et al. (2023). Clean Energy 101: Virtual Power Plants: Virtual power plants may be our most important and most overlooked domestic energy resource.
[41] Brehm et al. (2023). Virtual Power Plants, Real Benefits: How aggregating distributed energy resources can benefit communities, society, and the grid.

back to their stakeholders. By using a market electricity price forecasting algorithm, GRE can aid distribution co-ops interested in DER implementation to decide when to sell electricity to improve market participation efficacy. Predicting market price can also help GRE to better optimize its own electricity market strategy.

The price bids for electricity in their respective markets are rapidly increasing with the proliferation of renewable energy sources. According to MISO's retail electricity prices change in MISO's Minneapolis Hub, in the last five years, Minnesota's annual average electricity prices decreased from 2018 to 2020. Then, from 2020 to 2022, electricity prices rose rapidly and standard deviation indicates the electricity price became more unstable. These trends have been reflected in both the Day Ahead electricity market and the Real-Time electricity market (Tables 2 and 3). The Day Ahead Market experienced a nearly five times jump from 2020 to 2021 but a slight decline in 2022. In the Real Time Market, electricity price volatility steadily rose from 2020 to 2022.

More disaggregated DER ownership brought to the market by lower entry barriers may increase uncertainty in the electricity market. These individual owners may make uninformed or individually driven decisions, thereby increasing the volatility of the entire market. The higher potential for market fluctuation provides evidence for the value of a market forecasting system. Under an aggregated DER system, GRE could provide the necessary technological resources to provide more accurate forecasts.

Table 2. Day Ahead Market Electricity Price Change from 2018 to 2022

Year	Average Electricity Price [$/MWh]	Standard Deviation [$/MWh]
2018	29.9763	11.6903
2019	22.5323	8.1926
2020	17.4893	6.9603
2021	37.3197	33.4709
2022	45.24	23.0387

Table 3. Real Time Market Price Change from 2018 to 2022

Year	Average Electricity Price [$/MWh]	Standard Deviation [$/MWh]
2018	26.5758	15.4589
2019	21.9713	16.9616
2020	17.5789	13.1071
2021	36.6134	35.7117
2022	44.1158	49.1084

The volatility of electricity prices between different hours makes it possible to arbitrage[42] or reduce overall generation costs. Therefore, predicting the fluctuation of electricity prices in the electricity market may become increasingly important for the expansion of DERs in the future.

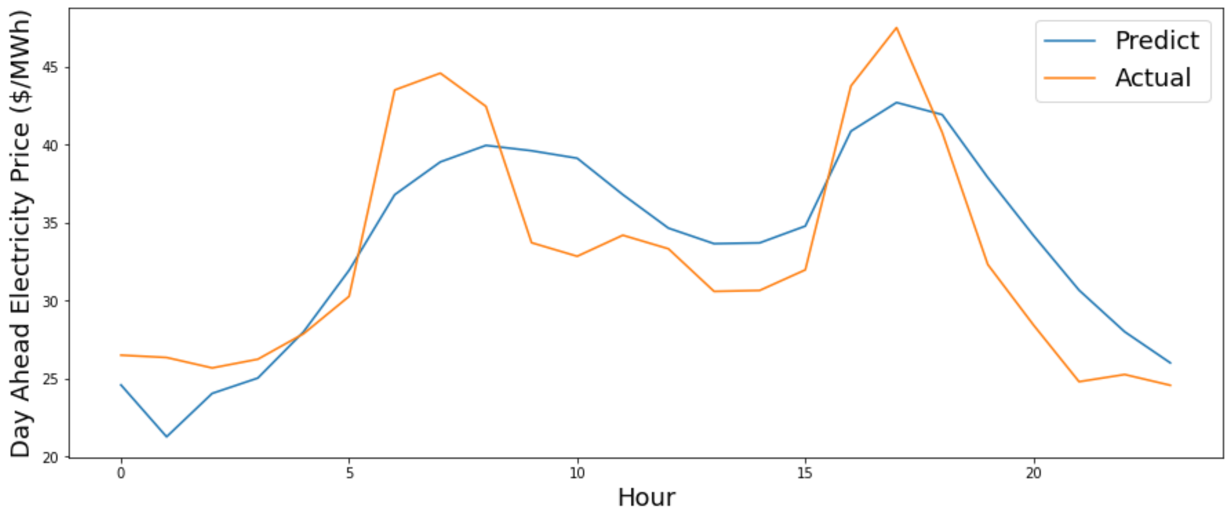
Table 4. Cross comparison of current market and future market scenarios

	Current electricity market	**Future electricity market with more independent participants**	**Future electricity market with more participants under co-ops' umbrella**
Goods	Electricity (no long-term storage)	Electricity (distributed energy resources allow longer term storage)	Electricity (distributed energy resources allow longer term storage)
Entry Barriers	High regulated, higher barriers for entry	Less regulated, lower barriers for more DER entry	Less regulated, lower barriers for more DER entry
Participant	Monopoly players, not open to public	Potentially more distributed sources with monopoly players (depends on integration mode)	Potentially more distributed sources under monopoly players (depends on integration mode)
Trade Method	Real Time trade with Day ahead trade	Real Time trade with Day Ahead trade	Real Time trade with Day Ahead trade
Market Rationality	Less biased and mature	Biased and irrational	Less biased and irrational than working parallelly

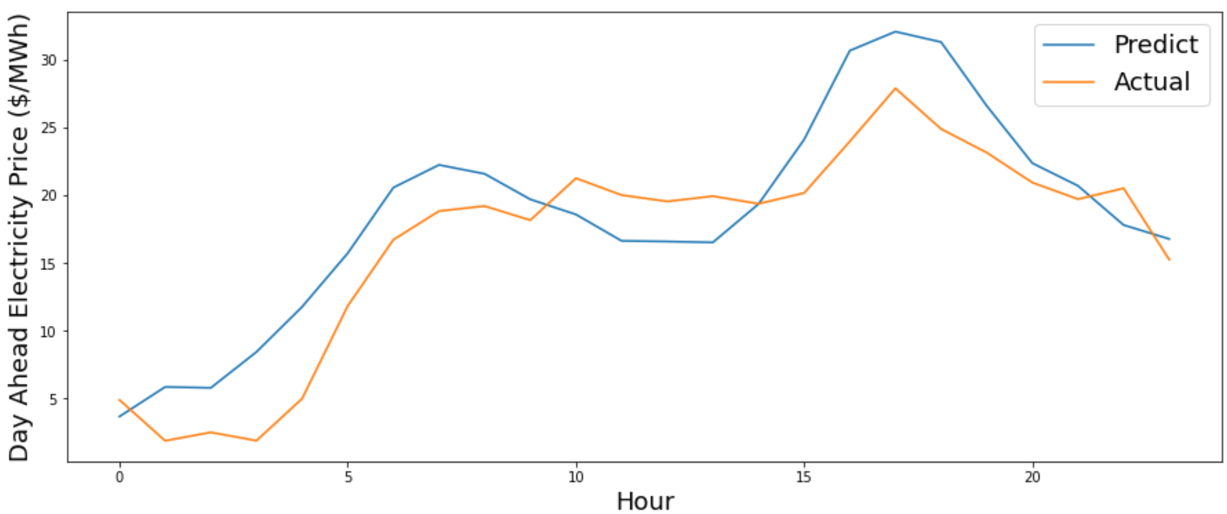
We used supervised machine learning to build two similar algorithms for predicting electricity prices in the Day Ahead and Real Time Market. The electricity prices on the Day Ahead market are the prices set in advance. The Day Ahead market prediction requires at least 24 hours forecasting capability to implement. Compared with the Day Ahead market, the Real Time electricity market usually has more price fluctuation and uncertainty. Thus the 1-hour predictive capability can balance accuracy while ensuring applicability.

[42] Bradbury et al. (2014). Economic viability of energy storage systems based on price arbitrage potential in real-time U.S. electricity markets.

Example comparison of predicted vs. actual price for Day Ahead market (from 2023/1/31 1:00 a.m. to 2023/2/1 0:00 a.m.)



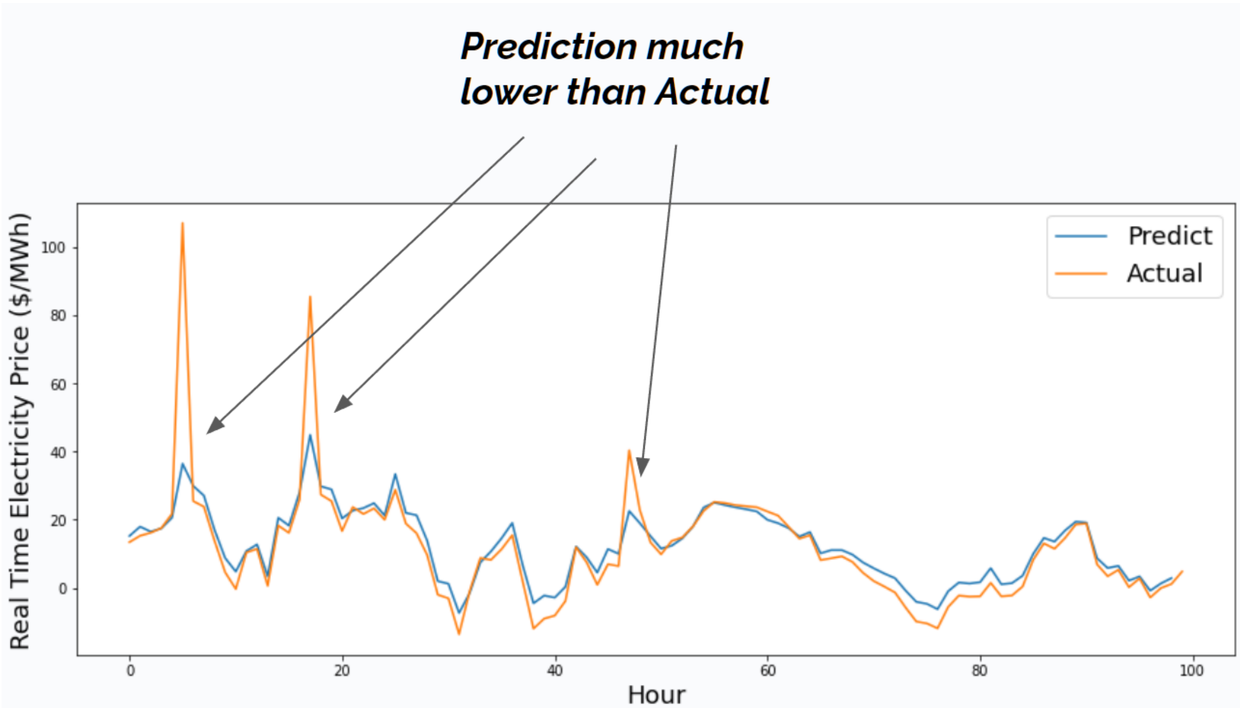
Example comparison of predicted vs. actual price for Day Ahead market (from 2023/2/7 1:00 a.m. to 2023/2/8 0:00 a.m.)



The Day Ahead market prediction algorithm uses 168 hours of electricity price change data snippets to predict electricity price for the next 24 hours. The trend of price changes in the energy market is easily estimated, but the actual value of electricity prices is difficult to predict. Adding time positioning variables will allow the model to reflect weekly and seasonal change of electricity prices.

The Real time market algorithm uses 24 hours of electricity price change snippets to predict electricity price for the next 24 hours. The real time prediction comparison shows that even in the current electricity market, the fluctuation of electricity prices can be predicted within a reasonable range. However, the predicted value of electricity prices are sometimes far lower than the actual value. Such outliers may be due to severe supply market shortages.

Example Comparison of predicted vs. actual price for Real Time market (from 2023/2/7 12:00 a.m. to 2023/2/26 11:00 p.m.)



Recommendation

We recommend that GRE build algorithms that can forecast Day Ahead and Real Time market electricity price fluctuations within reasonable ranges. GRE has the capacity to develop algorithms that are able to predict wholesale electricity market price changes within a reasonable range. GRE has an IT department with experienced staff and a large amount of accumulated operational and MISO market data. That data will provide the necessary foundation to develop machine learning-based predictive algorithms. GRE could hire 1-2 employees with relevant experience. By doing so, GRE can have **more market strategies**. GRE members will also have access to **better battery storage strategies** for their DER development. Detailed recommended steps on developing a forecasting algorithm and source code for the proof-of-concept forecasting models are given in Appendix A.

Case Studies

Recommendation 8: GRE should apply the lessons learned from case studies to DER implementation best practices

The distribution grids were traditionally modeled and designed for one way flow of electrons. Voltage regulators were deployed based on this one way flow of energy. With DERs now in play, the entire infrastructure needs to be redesigned to accommodate the two way flow of energy, storage, asset placement, and sizing. Smart designing and planning is necessary in order to maintain reliable, safe and cost effective power distribution. We looked at case studies to understand how utilities and other U.S. co-ops are adapting to integrate DERs into their current structure and business plans and how GRE can utilize and consider some of their learnings.

RADWIND Case Studies

Wind energy is a prominent part of GRE's renewable energy portfolio. The National Rural Electric Cooperative Association (NRECA) compiled a list of case studies that looked specifically at distributed wind energy projects and how various U.S. cooperatives incorporated these into their plans. All these projects were part of a DOE funded initiative through the Wind Energy Technology Office (WETO). These projects are collectively known as the Rural Area Distributed Wind Integration Network Development (RADWIND)[43]. They vary in scale and scope but the main focus was to identify technical risks, barriers to market deployment and ultimately develop a toolkit that consumers and cooperatives can use to assess the need, costs as well as feasibility of wind energy as a viable DER.

Some key takeaways from these studies are the importance of public-private partnerships, IRA incentives available to co-ops such as tax credits for asset ownership, low cost capital for clean energy projects in coop territories, and extended tax credits for up to 10 years for small and medium size turbines[44].

Rocky Mountain Institute recently reported on how rural coops are redefining energy with DER's. They had four main takeaways to offer[45]:

- Co-op systems now have multiple options for providing reliable and low-cost energy and other services.
- DERs can create new value streams for co-op systems.

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[43] Creating Opportunities for Cooperative Distributed Wind. Rural Area Distributed Wind Integration Network Development (RADWIND).
[44] Newcomb & Schmitt. (January 2023). Distributed Wind Project Development Practices in Rural Electric Cooperative Service Areas.
[45] Transforming Electric Supply for Small-Town and Rural America. Microgrid Knowledge. (February 25, 2019).

- DERs will change the flow of energy and services between G&Ts, distribution co-ops, and their members.
- Multiple business models can effectively serve a transformed rural electric system

Cooperatives Using a Rate Control Approach

In another series of case studies compiled by the NRECA, rate control was emphasized as an important factor for successful incorporation of DERs into their business models. Six different U.S. co-ops were studied[46].

Bandera Electric Cooperative: Bandera is a Texas based transmission and distribution cooperative that has a partial requirements agreement for its power supply with the Lower Colorado River Authority (LCRA) under a market-based, cost-plus model. Bandera is a part of the ERCOT footprint, which features a competitive wholesale market with no demand charge. Bandera is billed based on a time-of-use (TOU) wholesale rate which attempts to follow market energy prices. In order to receive the hourly meter data that is necessary for the TOU wholesale rate, Bandera employs Aclara automated metering infrastructure (AMI) across its entire system. Like all cooperatives in Texas, Bandera distribution operations and rates are self-regulated; however, the transmission portion of its operations is regulated. The Cooperative's transmission costs are itemized separately and priced per kilowatt (kW) based on Bandera's contribution to ERCOT's coincident peak. They started to include a detailed break up of rates on bills, which included summer, non-summer, peak and off-peak rate charges.

One of the lessons learnt from this was the importance of early education and communication to members on what the rate charges meant and what the variations were for. It is important that the rate structure reflects the innovations in technology and not stick to the traditional methods.

Cobb Electric Membership Corporation: Cobb Electric is a Georgia based distribution cooperative and one of the top purchasers of solar energy among cooperatives nationwide[47]. In the period between 2010 and 2014, as Cobb was reaching new heights in performance, reliability and public service, it was falling short on kWh sales. This prompted the redesign of the rate structure and moved from a standard rate to a smart choice rate structure. This broke down the bill into a standard service rate, a peaking rate and an energy charge. This would eventually provide more flexibility to customers to manage their usage enduring peaking season/peak hours and also look into alternate options like solar installations to manage their usage.

A key takeaway from this study was also the importance of understanding customer usage and frequent communication to make changes that reflect modern day usage and taking into account technology like smart appliances and possibly DERs, to keep rates low for customers.

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[46] Rate Case Studies. (July 2016). National Rural Electric Cooperative Association.
[47] Shapiro, L. (2015). An Unlikely Coalition Leads a Georgia Co-Op From Coal to Solar.

Hoosier Energy Electric Cooperative: Hoosier Energy is an Indiana based G&T with 18 distribution coop members. Similar to GRE, their renewables mix is 5% which they intend to increase to 10% by 2025[48]. They were aiming to reduce costs by reevaluating their demand side management program. To better manage peak loading, they decided to revamp their billing structure and added more details into bills including an on peak and off peak rate as well as a summer and winter production demand component charge. This included members installing switched on air conditioners and water heaters for load control. Being intune to market demand and making proactive rate policy changes could provide room for DER implementation in the longer run.

Mid-Carolina Electric Cooperative: Mid-Carolina is a South Carolina based mostly rural cooperative. Amid facing lower sales, an unfair fixed cost recovery rate plan and realizing that their current rate structure did not provide an opportunity for customers to make changes to their energy use patterns to lower their bills, prompted them to reevaluate their rate structure. Some of the changes to their volumetric rate structure included going down to daily rate costs, introducing a demand charge by looking at on-peak and off-peak demand, and keeping the residential charge economica which still carefully balances the wholesale market prices to demand peaks. Taking equity into consideration, further thought was given on how to structure rates for net metering customers, this is an opportunity to include more DERs in terms of rooftop solar and other battery storage options. Key takeaways were the importance of considering all member classes when making rate changes and constant education for members and customers to keep them engaged and to not lose participation.

St. Croix Electric Cooperative: St. Croix is a mostly rural Wisconsin cooperative, focused on equitable net metering, especially with the context of more solar as a DER option. They offer community solar to their members and have accordingly made net metering changes to allow for time of use rates. As more solar gets added to the grid for GRE territory, this is a strategy that could be considered. One thing to keep in mind is to think about all the entire membership and how rate changes could affect all of them, and not just making changes for a select set of members.

Sioux Valley Energy Electric Cooperative: Sioux Valley is based in South Dakota, serving both South Dakota as well as Minnesota. A unique challenge facing this co-op was the merger of two co-ops that left various (41) rate tariffs in place which made it challenging and necessary to make rate changes to unify across all its members. The farm and rural residential rates were modified the most. A huge challenge facing them was cost recovery between the fixed and volumetric charges due to the merger. The main change included a move from a declining block structure to a fixed uniform rate structure. An incredible amount of energy was put into education efforts since there was a constant change for many years on rates to customers. Similar

[48] Annual Report (2016). Hoosier Energy Electric Cooperative.

to other co-ops, they also lay emphasis on constant education to board members, customers and members especially when it comes to rate conversation and suggest to include it in annual strategic meeting discussions.

Washington Electric Cooperative: Washington Electric is a Vermont-based G&T cooperative and unique in the fact that almost 100% of their energy generation comes from renewable sources. Their changes in rate structure were prompted by policy changes since they were already offering net metering and were exceeding the allowed 4%. Their main goal was to get a balance in rate for both net metered and non net metered customers. Equity was at the fore-front and this kind of an approach allows for DERs such as rooftop solar or a CSG to be successfully incorporated into the current business model and still charge fair rates to customers who are not net metered. A small amount of grid service fee was introduced to account for cross -subsidization if any and monetary credits were provided for excess generation.

California DER Action Plan

California provides an example for how plans for DERs might be developed and executed. In California, the Distributed Energy Resources Action Plan at the state level describes in detail how the public sector should adapt to DERs. These plans include: wider data sharing to promote more reasonable planning and investment, better connection performance, load flexibility and rates, greater transparency, better cybersecurity, and improved cost certainty. Specifically, the plan recommends that utilities develop or improve an existing data-sharing portal by 2023 to help governments and investors in DERs obtain more accurate and usable information. The plan also recommends utilities continue to conduct pioneering research to understand feasibility, safety, and cost confidence through a notification-only interconnection process and improve the cybersecurity of the interconnection. Many utilities currently in California use the interconnection portal to contractors and developers who are interested in DERs to find suitable locations for new projects. Information is generally displayed online in the form of maps, such information including current existing transmission lines and planning transmission lines, sub-transmissions, and service territories, etc.

Distributed Electric Storage Cases in Arizona and North Dakota

Energy cooperatives are increasingly expanding their offering of distributed electric storage. An Arizona energy cooperative, Trico Electric, is building a third battery project after a push from its members.[49] The cooperative will complete a new 10-megawatt/40-megawatt-hour battery system by the end of the year 2023. Part of the co-op's battery system deployment strategy includes pumping electricity into the wholesale electricity market during peak periods, then injecting the electricity into the market during the evening peak or when higher peak electricity

[49] Cash, C. (March 24, 2023). Trico Electric Cooperative to Install Third Battery System.

demand or prices are foreseen in a specific time range. This way, the battery storage reduces the co-op's peak resource needs and raises the technology's value.

Basin Electric Power Cooperative, a North Dakota electric cooperative, offers a trial rate policy that expands electricity storage technology for the 131 co-ops to which it supplies power.[50] Through this rate structure, all Basin contract members can try to use energy storage systems to understand this technology and reduce peak demand costs. These distribution co-op pilots can decide when their 150 kW batteries are charged and discharged, while the cost of transmitting the electricity to the grid must be paid to Basin.

Case Studies for DER Aggregation

The need for collaboration on DER integration into the grid is demonstrated in a 2017 report released by the California Independent System Operator (CAISO), Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E). The report was compiled by a working group led by think tank More Than Smart (MTS) which included the IOUs, CAISO, and DER providers. In 2017, this was an unprecedented collaboration between IOUs, CAISO and third-party DER providers in an attempt to develop a plan to streamline electric system communications with the development of more DERs in the system.[51]

The report centers around interconnection plans for the bulk transmission system to DERs through utility-operated distribution systems, thus providing a level of communication that will be required to operate and distribute DER energy. While previously this level of coordination was not needed between transmission and distribution operators, as more DERs come into play, using these resources in wholesale power markets requires more collaboration. Without it, ISOs may issue dispatch instructions to DERs that they cannot meet because of distribution system constraints.

The report developed by the working group looks at two time frames to consider the level of DER integration that will occur in the short term and mid-term. Based on this analysis, In the near term (1-year from 2017), there was expected to be a relatively low level of DER penetration, making DERs only a small factor in the wholesale market. However, it was estimated that by 2020, wholesale markets would see higher levels of DER and DER aggregation. From this analysis, they supposed that coordination would require the ISO (in California's case, CAISO) to develop ways to provide day-ahead DER dispatch schedules to the distribution operators so they can anticipate potential reliability or performance problems, potentially through DER Management Systems (DERMS). DERMs has been initiated and pilot tested by PG&E through funding under California's 2015-2017 EPIC program which was a

[50] Cash, C. (January 19. 2023). Co-ops Leverage Basin Electric's Rate to Build Grid-Level Battery Storage.
[51] Trabish, H. (June 22, 2017). Stop, collaborate and listen: California stakeholders want to open electric system communications

California PUC research portfolio designed to deliver projects that helped the state reach their climate and environmental goals.

Pilot programs such as those run by PG&E are an example of ways that ISOs, distribution operators, and DER providers can work together to test ways to communicate advisory information on current system conditions to DER providers in order to allow them to modify market bids when necessary. This may require ISOs to develop methods for providing day-ahead DER dispatch schedules to the operators which can be incorporated into a DERMs system. The providers also need to be able to communicate to the ISOs if there are any constraints on their end that might affect the market bid process. The report also argues that there should be an agreement between the distribution operators and DERs providers similar to an interconnection agreement so that it is clear who will take responsibility for any disruptions. The software for this communication will be a necessary component for agreement between the different collaborating groups in this process. The authors argue that “solutions for communications at the T-D interface ‘are the key technical and regulatory issues in distribution system operations and will be the foundation for integrating DER.’”

Lessons learned from case studies:

- Public-private partnerships create mutually beneficial opportunities for DER implementation
- IRA provides tax incentives to co-ops for asset ownership, low cost capital for clean energy projects in coop territories, and extended tax credits for up to 10 years for small and medium size turbines
- Rate restructuring is critical to a growing DER market to keep current customers and to also improve the co-ops service and satisfaction of clean energy demands
- DERs also offer a business model where all of the ownership is held at the customer level which gives co-ops a potentially different strategic opportunity to be a leader in clean energy
- Given that MISO is still relatively new and constantly changing to meet market demands, it is important for co-ops to consider how they can work with MISO and influence policies to benefit their own customers, especially in terms of rates
- It is also important to think about how to align costs to the wholesale market and how to align rates while still including some risk hedging, but ensuring that there are no prohibitive renewable energy subsidies from historical factors that could be negatively affecting customer rates.
- While thinking about restructuring rates, it is imperative to be inclusive and equitable and think of all members and customers. It is important to begin discussions early and often with distribution co-op members and encourage them to have concurrent discussions with their customers. Transparency and consistent language is important to move forward with

incorporating DERs as a business opportunity and influencing policy changes at the same time

Next Steps

In this report, we give many recommendations, but we suggest the following three to prioritize that GRE, by itself or in collaboration with a future student capstone group can consider investigating first:

- (Recommendation 1): Explore ideas for developing a common DER valuation system
- (Recommendation 3): Identify specific funding opportunities given by IRA and IIJA that GRE and its member-owners can benefit from
- (Recommendation 4): Help GRE's distribution member-owner cooperatives adopt DERs

We suggest these three because we see them as those that have the best combinations of feasibility, positive impact on expanding DERs from GRE's perspective, and their benefits are realized if acted upon sooner rather than later. Another possible next step, especially for a future capstone student group, is to design and conduct a survey intended for GRE members about their feedback on the direction and opportunities of DERs from a distribution cooperative perspective.

Appendix A. Machine Learning Model

The following is the methodology for the suggested machine learning approach to predict the Day Ahead changes of wholesale electricity market prices. Those models were inspired by a time series forecasting model from the CSDN. Other variables can be added to improve the models' predictability, such as relative position of the forecasted hours, electricity demand and supply, energy consumption, fuel price changes, weather, and temperature.

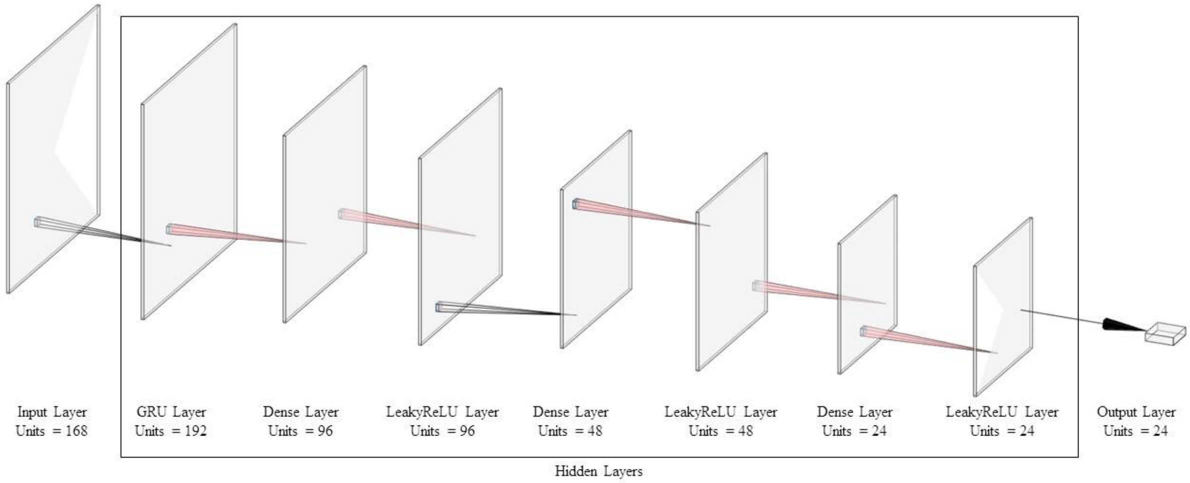
Due to limitations in computing power, both of the electricity price prediction models use gated recurrent units (GRU) instead of the long short-term memory units (LSTM) to build multi-layers deep learning neural networks models that predict electricity changes in the Day Ahead and Real Time Market. GRU is usually considered a cheaper computation solution with propinquity performance than LSTM. In general, the gate recurrent units use a gating mechanism that has an update gate and a reset gate. The update and reset gates decide what information will be passed to the output or the next layer. The GRU could be trained to remember long-term information without washing the data through time or removing irrelevant data. Such abilities make GRU useful in time series prediction.

The Day Ahead model is trained using MISO Day Ahead Minneapolis Hub electricity market price data from 0:00 a.m. on January 1, 2018 to 11:00 p.m. on February 6, 2023. The Day Ahead model uses data from 12:00 a.m. on February 7, 2023 to 11:00 p.m. on February 26, 2023 as the validation dataset. The Real Time model using MISO Real Time Minneapolis Hub electricity market price data from 0:00 a.m. on January 1, 2018 to February 7 2023 to train the model and use February 8, 2023 to February 12, 3:00 am data to validate.

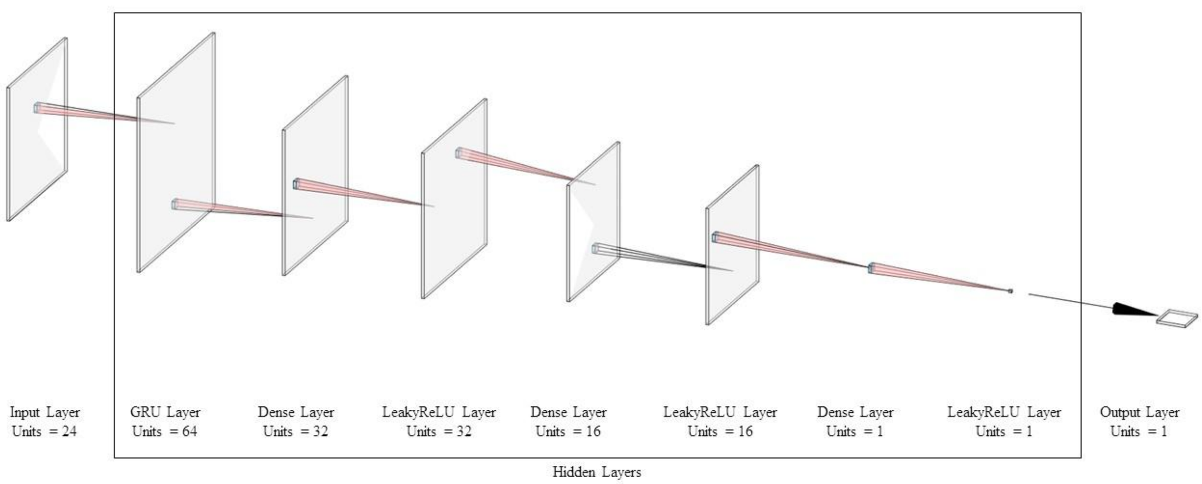
We used the following steps to develop the forecasting algorithms:

1. Find the parameters that have the greatest impact on electricity prices (such as weather, temperature, specific dates or events)
2. Create and compare different models with various variables
3. Conduct a sensitivity analysis on the models
4. Determine the model (benchmarking)
5. Train the data using various ranges of wholesale market prices to then feed to the model (such as the nearest 24 hours or 168 hours)
6. Determine the variables used by the model

Schematic diagram of neural network structure for **Day Ahead Market** prediction:



Schematic diagram of neural network structure for **Real Time Market** prediction:



Source code for the **Day Ahead Market proof of concept** forecasting model:
Step 1: Import Packages and Create Dataframe

```
## Import Package
import pandas as pd
import numpy as np
import math
from matplotlib import pyplot as plt
from matplotlib.pylab import mpl
import tensorflow as tf
from sklearn.preprocessing import MinMaxScaler
from keras import backend as K
from keras.layers import LeakyReLU
from sklearn.metrics import mean_squared_error
from keras.callbacks import LearningRateScheduler
from keras.callbacks import EarlyStopping
from tensorflow.keras import Input, Model,Sequential
import warnings

warnings.simplefilter(action='ignore', category=pd.errors.PerformanceWarning)

path_name = 'F:/HHH_UMN/2023 Spring/Capstone/Data/'
file_name = 'Node_DA.csv'
new_file_name = 'test_1.csv'
df_DA = pd.read_csv(path_name + new_file_name)


df_DA['ds'] = pd.to_datetime(df_DA["ds"])

indexed_df = df_DA.set_index(["ds"], drop=True)
indexed_df.head()

shifted_df = pd.DataFrame()
num_hour = 168 + 23
for i in range(num_hour,0,-1):
    shifted_df['t-'+str(i)]= indexed_df.shift(i)
shifted_df['t'] = indexed_df.values
concat_df = shifted_df.dropna()
concat_df.index = range(len(concat_df))
concat_df.head()
```

	t-191	t-190	t-189	t-188	t-187	t-186	t-185	t-184	t-183	t-182	...	t-9	t-8	t-7	t-6	t-5	t-4	t-3	t-2
0	36.21	30.88	31.05	30.67	32.11	31.20	34.18	44.37	45.18	50.58	...	34.44	32.29	33.38	39.29	54.89	42.00	34.49	33.38
1	30.88	31.05	30.67	32.11	31.20	34.18	44.37	45.18	50.58	55.45	...	32.29	33.38	39.29	54.89	42.00	34.49	33.38	29.90
2	31.05	30.67	32.11	31.20	34.18	44.37	45.18	50.58	55.45	56.33	...	33.38	39.29	54.89	42.00	34.49	33.38	29.90	25.94
3	30.67	32.11	31.20	34.18	44.37	45.18	50.58	55.45	56.33	51.77	...	39.29	54.89	42.00	34.49	33.38	29.90	25.94	22.96
4	32.11	31.20	34.18	44.37	45.18	50.58	55.45	56.33	51.77	49.80	...	54.89	42.00	34.49	33.38	29.90	25.94	22.96	21.23

5 rows × 192 columns

Step 2: Data Normalization and Randomization

```
## Data Normalized
data = concat_df
pot = len(data) - 672#divide train data and test data
train = data[:pot]
pd.DataFrame(np.random.shuffle(train.values))
test = data[pot:]
scaler = MinMaxScaler(feature_range = (0,1)).fit(train)
train_norm = pd.DataFrame(scaler.fit_transform(train))
test_norm = pd.DataFrame(scaler.transform(test))

test_norm.shape, train_norm.shape
```

```
((672, 192), (44377, 192))
```

Step 3: Data processing and Matrix Deformation

```
# Create Input & Output
X_train=train_norm.iloc[0:44376, :168]
X_test=test_norm.iloc[:, :168]
Y_train=train_norm.iloc[0:44376,168:]
Y_test=test_norm.iloc[:,168:]

# Keep Original Data
source_x_train=X_train
source_x_test=X_test

# Reshape Matrix
X_train=X_train.values.reshape([X_train.shape[0],24,7]) #from shape (:, 168) to (:, 24, 7)
X_test=X_test.values.reshape([X_test.shape[0],24,7])  #from shape (:, 168) to (:, 24,7)

# Keep Value Info only
Y_train=Y_train.values
Y_test=Y_test.values

# Check
print(Y_test)
Y_train.shape

```

```
[[0.05379009 0.05354552 0.05245308 ... 0.05101825 0.05176827 0.05064323]
 [0.05354552 0.05245308 0.05336616 ... 0.05176827 0.05064323 0.0475942 ]
 [0.05245308 0.05336616 0.05602387 ... 0.05064323 0.0475942  0.04645285]
 ...
 [0.03278929 0.03375128 0.04094177 ... 0.04832793 0.04718658 0.04126787]
 [0.03375128 0.04094177 0.03945802 ... 0.04718658 0.04126787 0.03880582]
 [0.04094177 0.03945802 0.04033849 ... 0.04126787 0.03880582 0.03989826]]

(44376, 24)
```

Step 4: Reduce Learning Rate Function

```
## Reduce Learning Rate Function
def scheduler(epoch):
    # Every 50 epochs, the learning rate is reduced to 1/10 of the original
    if epoch % 50 == 0 and epoch != 0:
        lr = K.get_value(gru.optimizer.lr)
        if lr>1e-5:
            K.set_value(gru.optimizer.lr, lr * 0.1)
            print("lr changed to {}".format(lr * 0.1))
    return K.get_value(gru.optimizer.lr)

reduce_lr = LearningRateScheduler(scheduler)
```

Step 5: Early Stop Function

```
## Early Stop Function
# Call Early Stop Function
early_stopping = EarlyStopping(monitor='loss',
                               patience=20,
                               min_delta=1e-5,
                               mode='auto',
                               restore_best_weights=False, ## Whether to restore model weights from
                               # the epoch with the best value for the number of monitors
                               verbose=2)
```

Step 6: Deep Learning Neural Network Construction

```
# Feature number
input_dim = X_train.shape[2]
print(input_dim)
# Time step: How many time steps of data are used to predict the value of the next moment
time_steps = X_train.shape[1]
print(time_steps)
batch_size = 48

gru = Sequential()
input_layer =Input(batch_shape=(batch_size,time_steps,input_dim))
gru.add(input_layer)
gru.add(tf.keras.layers.GRU(192))
gru.add(tf.keras.layers.Dense(96))
gru.add(tf.keras.layers.LeakyReLU(alpha=0.3))
gru.add(tf.keras.layers.Dense(48))
gru.add(tf.keras.layers.LeakyReLU(alpha=0.3))
gru.add(tf.keras.layers.Dense(24))
gru.add(tf.keras.layers.LeakyReLU(alpha=0.3))
# define optimizer
nadam = tf.keras.optimizers.Nadam(learning_rate=1e-3)
gru.compile(loss = 'mse',optimizer = nadam,metrics = ['mae'])
gru.summary()
```

```
7
24
Model: "sequential"
_________________________________________________________________
 Layer (type)                Output Shape              Param #
=================================================================
 gru (GRU)                   (48, 192)                 115776

 dense (Dense)               (48, 96)                  18528

 leaky_re_lu (LeakyReLU)     (48, 96)                  0

 dense_1 (Dense)             (48, 48)                  4656

 leaky_re_lu_1 (LeakyReLU)   (48, 48)                  0

 dense_2 (Dense)             (48, 24)                  1176

 leaky_re_lu_2 (LeakyReLU)   (48, 24)                  0

=================================================================
Total params: 140,136
Trainable params: 140,136
Non-trainable params: 0
```

Step 7: Train the Day Ahead Model

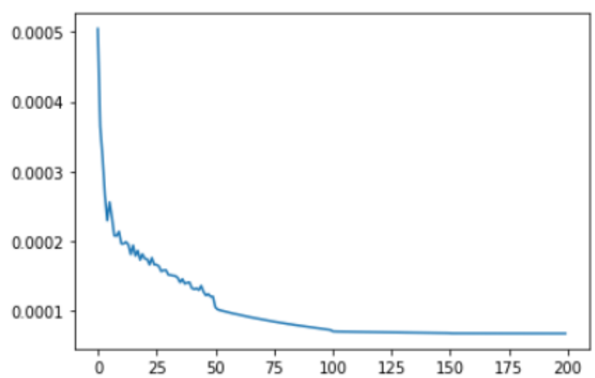
```
model=gru.fit(X_train,Y_train,validation_split=0.1,epochs=200,batch_size=48,callbacks=[reduce_lr])
```

```
Epoch 1/200
833/833 [==============================] - 14s 15ms/step - loss: 5.0486e-04 - mae: 0.0127 - val_loss: 7.68
57e-04 - val_mae: 0.0205 - lr: 0.0010
Epoch 2/200
833/833 [==============================] - 12s 15ms/step - loss: 3.6460e-04 - mae: 0.0103 - val_loss: 7.14
04e-04 - val_mae: 0.0200 - lr: 0.0010
Epoch 3/200
833/833 [==============================] - 12s 15ms/step - loss: 3.2049e-04 - mae: 0.0098 - val_loss: 6.31
47e-04 - val_mae: 0.0187 - lr: 0.0010
Epoch 4/200
833/833 [==============================] - 12s 15ms/step - loss: 2.6622e-04 - mae: 0.0093 - val_loss: 6.91
96e-04 - val_mae: 0.0192 - lr: 0.0010
Epoch 5/200
833/833 [==============================] - 12s 14ms/step - loss: 2.2979e-04 - mae: 0.0088 - val_loss: 6.19
78e-04 - val_mae: 0.0183 - lr: 0.0010
Epoch 6/200
833/833 [==============================] - 12s 15ms/step - loss: 2.5610e-04 - mae: 0.0091 - val_loss: 6.13
86e-04 - val_mae: 0.0181 - lr: 0.0010
Epoch 7/200
```

Step 8: Draw Loss Graph

```
model.history.keys()
plt.plot(model.epoch,model.history.get('loss')) #Draw the change graph of loss follow epoch move
```

```
[<matplotlib.lines.Line2D at 0x212e4af4c40>]
```



Step 9: Prediction through the Trained Day Ahead Model & Data revert

```
predict = gru.predict(X_test)

real_predict=scaler.inverse_transform(np.concatenate((source_x_test,predict),axis=1))
real_y=scaler.inverse_transform(np.concatenate((source_x_test,Y_test),axis=1))
real_predict=real_predict[:,168:193]
real_y=real_y[:,168:193]
```

```
21/21 [==============================] - 0s 5ms/step
```

Source code for the **Real Time Market proof of concept** Forecasting model

Step 1: Import Packages and Create Dataframe

```
## Import Package
import pandas as pd
import numpy as np
import math
from matplotlib import pyplot as plt
from matplotlib.pylab import mpl
import tensorflow as tf
from sklearn.preprocessing import MinMaxScaler
from keras import backend as K
from keras.layers import LeakyReLU
from sklearn.metrics import mean_squared_error
from keras.callbacks import LearningRateScheduler
from keras.callbacks import EarlyStopping
from tensorflow.keras import Input, Model,Sequential


path_name = 'F:/HHH_UMN/2023 Spring/Capstone/Data/'
file_name = 'Node_RT.csv'
new_file_name = 'test_2.csv'
df_RT = pd.read_csv(path_name + new_file_name)


df_RT['ds'] = pd.to_datetime(df_RT["ds"])

indexed_df = df_RT.set_index(["ds"], drop=True)
indexed_df.head()

shifted_df = pd.DataFrame()
num_hour = 24
for i in range(num_hour,0,-1):
    shifted_df['t-'+str(i)]= indexed_df.shift(i)
shifted_df['t'] = indexed_df.values
concat_df = shifted_df.dropna()
concat_df.index = range(len(concat_df))
concat_df.head()
```

	t-24	t-23	t-22	t-21	t-20	t-19	t-18	t-17	t-16	t-15	...	t-9	t-8	t-7	t-6	t-5	t-4	t-3
0	28.05	27.21	25.64	26.35	26.92	32.28	42.05	54.18	43.76	48.87	...	31.42	37.36	122.32	278.35	103.65	56.91	65.01
1	27.21	25.64	26.35	26.92	32.28	42.05	54.18	43.76	48.87	62.21	...	37.36	122.32	278.35	103.65	56.91	65.01	44.71
2	25.64	26.35	26.92	32.28	42.05	54.18	43.76	48.87	62.21	48.77	...	122.32	278.35	103.65	56.91	65.01	44.71	39.06
3	26.35	26.92	32.28	42.05	54.18	43.76	48.87	62.21	48.77	51.98	...	278.35	103.65	56.91	65.01	44.71	39.06	40.80
4	26.92	32.28	42.05	54.18	43.76	48.87	62.21	48.77	51.98	36.26	...	103.65	56.91	65.01	44.71	39.06	40.80	31.39

5 rows × 25 columns

Step 2: Data Normalization and Randomization

```
## Data Normalized
data = concat_df
pot = len(data) - 480#divide train data and test data
train = data[:pot]
test = data[pot:]
#pd.DataFrame(np.random.shuffle(train.values))
scaler = MinMaxScaler(feature_range = (0,1)).fit(train)
train_norm = pd.DataFrame(scaler.fit_transform(train))
test_norm = pd.DataFrame(scaler.transform(test))

test_norm.shape, train_norm.shape
```

```
((480, 25), (44712, 25))
```

Step 3: Data processing and Matrix Deformation

```
# Create Input & Output
X_train=train_norm.iloc[:,:24]
X_test=test_norm.iloc[:,:24]
Y_train=train_norm.iloc[:,24:]
Y_test=test_norm.iloc[:,24:]

# Keep Original Data
source_x_train=X_train
source_x_test=X_test

# Reshape Matrix
X_train=X_train.values.reshape([X_train.shape[0],24,1])
X_test=X_test.values.reshape([X_test.shape[0],24,1])

# Keep Value Info only
Y_train=Y_train.values
Y_test=Y_test.values

#Check
X_train.shape,Y_train.shape
```

```
((44712, 24, 1), (44712, 1))
```

Step 4: Reduce Learning Rate Function

```
## Reduce Learning Rate Function
def scheduler(epoch):
    # Every 50 epochs, the learning rate is reduced to 1/10 of the original
    if epoch % 50 == 0 and epoch != 0:
        lr = K.get_value(gru.optimizer.lr)
        if lr>1e-5:
            K.set_value(gru.optimizer.lr, lr * 0.1)
            print("lr changed to {}".format(lr * 0.1))
    return K.get_value(gru.optimizer.lr)

reduce_lr = LearningRateScheduler(scheduler)
```

Step 5: Early Stop Function

```
## Early Stop Function
# Call Early Stop Function
early_stopping = EarlyStopping(monitor='loss',
                               patience=20,
                               min_delta=1e-5,
                               mode='auto',
                               restore_best_weights=False, ## Whether to restore model weights from
                               # the epoch with the best value for the number of monitors
                               verbose=2)
```

Step 6: Deep Learning Neural Network Construction

```
# Feature number
input_dim = X_train.shape[2]
# Time step: How many time steps of data are used to predict the value of the next moment
time_steps = X_train.shape[1]
batch_size = 24

gru = Sequential()
input_layer =Input(batch_shape=(batch_size,time_steps,input_dim))
gru.add(input_layer)
gru.add(tf.keras.layers.GRU(64))
gru.add(tf.keras.layers.Dense(32))
gru.add(tf.keras.layers.LeakyReLU(alpha=0.3))
gru.add(tf.keras.layers.Dense(16))
gru.add(tf.keras.layers.LeakyReLU(alpha=0.3))
gru.add(tf.keras.layers.Dense(1))
gru.add(tf.keras.layers.LeakyReLU(alpha=0.3))
# define optimizer
nadam = tf.keras.optimizers.Nadam(learning_rate=1e-3)
gru.compile(loss = 'mse',optimizer = nadam,metrics = ['mae'])
gru.summary()
```

```
Model: "sequential"
_________________________________________________________________
 Layer (type)                Output Shape              Param #
=================================================================
 gru (GRU)                   (24, 64)                  12864

 dense (Dense)               (24, 32)                  2080

 leaky_re_lu (LeakyReLU)     (24, 32)                  0

 dense_1 (Dense)             (24, 16)                  528

 leaky_re_lu_1 (LeakyReLU)   (24, 16)                  0

 dense_2 (Dense)             (24, 1)                   17

 leaky_re_lu_2 (LeakyReLU)   (24, 1)                   0

=================================================================
Total params: 15,489
Trainable params: 15,489
Non-trainable params: 0
```

Step 7: Train the Real Time Model

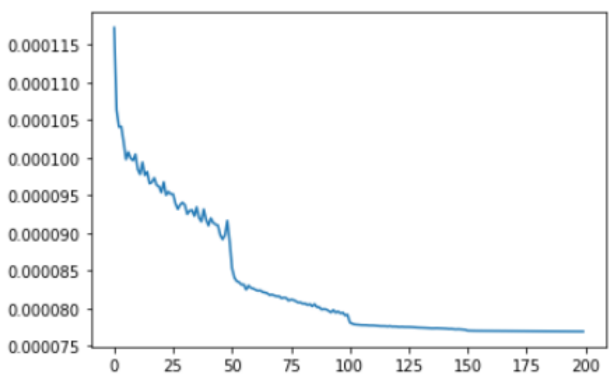
```
## Train the model
model=gru.fit(X_train,Y_train,validation_split=0.1,epochs=200,batch_size=24,callbacks=[reduce_lr])
```

```
Epoch 1/200
1677/1677 [==============================] - 11s 5ms/step - loss: 1.1726e-04 - mae: 0.0046 - val_loss: 5.5
380e-04 - val_mae: 0.0086 - lr: 0.0010
Epoch 2/200
1677/1677 [==============================] - 9s 5ms/step - loss: 1.0638e-04 - mae: 0.0042 - val_loss: 5.81
89e-04 - val_mae: 0.0082 - lr: 0.0010
Epoch 3/200
1677/1677 [==============================] - 9s 5ms/step - loss: 1.0409e-04 - mae: 0.0041 - val_loss: 5.67
65e-04 - val_mae: 0.0069 - lr: 0.0010
Epoch 4/200
1677/1677 [==============================] - 9s 5ms/step - loss: 1.0414e-04 - mae: 0.0040 - val_loss: 5.62
51e-04 - val_mae: 0.0070 - lr: 0.0010
Epoch 5/200
1677/1677 [==============================] - 9s 5ms/step - loss: 1.0209e-04 - mae: 0.0039 - val_loss: 5.84
56e-04 - val_mae: 0.0081 - lr: 0.0010
Epoch 6/200
1677/1677 [==============================] - 10s 6ms/step - loss: 9.9777e-05 - mae: 0.0039 - val_loss: 6.3
765e-04 - val_mae: 0.0074 - lr: 0.0010
Epoch 7/200
```

Step 8: Draw Loss Graph

```
model.history.keys()
plt.plot(model.epoch,model.history.get('loss')) #Draw the change graph of loss as epoch increases
```

```
[<matplotlib.lines.Line2D at 0x25dd159a9b0>]
```



Step 9: Prediction through the Trained Day Ahead Model & Data revert

```
predict = gru.predict(X_test)

real_predict=scaler.inverse_transform(np.concatenate((source_x_test,predict),axis=1))
real_y=scaler.inverse_transform(np.concatenate((source_x_test,Y_test),axis=1))
real_predict=real_predict[:,24]
real_y=real_y[:,24]
```

```
15/15 [==============================] - 0s 2ms/step
```

Appendix B. Methodology

The purpose of our research is to investigate the opportunities and barriers involved in G&T cooperatives expanding distributed energy resources, particularly by having them participate in wholesale markets. This project was done for Great River Energy, and we apply our findings and recommendations in the context of them.

The major sources of information for our project is through literature review and desktop research, which include academic articles, reports and white papers, state and federal statutes, agency websites, and other sources. Another source is our project collaborators, who are staff members at Great River Energy. We also interviewed industry experts on their knowledge and thoughts on various topics that our research questions touch on, such as the role G&T and distribution co-ops have with DERs, how the wholesale market plays into it and current trends, and the value addition to co-ops and end users. We then synthesized the information we gathered to offer a series of recommendations that are relevant to the various sections of our report.

In discussing the scope and interests by Great River Energy, we arrived at three questions that guided our research:

1. What are some of the barriers other utility co-ops in the Midwest have identified for DER?
2. How have these utility co-ops turned these barriers to DER into opportunities?
3. What could be GRE’s role as a transmission & generation utility co-op in increasing DER in the distribution side?

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