2024-2033 RESOURCE PLAN

Published December 2023




Acknowledgments

Connexus Energy staff and leadership extend their appreciation to the following organizations for their contributions to the resource planning process:

- **Connexus Energy Board of Directors,** for their guidance and input into this first-ever resource plan for Connexus Energy.
- **Members of the resource planning stakeholder working group,** for engaging in the planning process and sharing their expertise and insights:
  - Anoka Area Chamber of Commerce
  - Center for Energy and Environment
  - Citizens Utility Board of Minnesota
  - Clean Up the River Environment
  - Cooperative Finance Corporation
  - Fresh Energy
  - Minnesota Center for Environmental Advocacy
  - Minnesota Precision Manufacturing Association
  - Minnesota Solar Energy Industries Association
  - Sherburne County
- **Great River Energy,** for collaboration and coordination on load and resource forecasting.

All errors in this report are solely the responsibility of Connexus Energy.

Welcome Letter

On August 30, 2022, when Connexus Energy signed a new contract with our provider of wholesale power supply and transmission services, we ushered in a new era for the cooperative. Our *customer* contract—a first-of-its-kind approach to the relationship between wholesale electric cooperatives and the retail electric cooperatives they serve—offers Connexus a new degree of independence as an *integrated* utility and better positions us to serve our members. It does this in part by giving us the flexibility and autonomy to plan our future power supply portfolio.

The resource roadmap laid out in the following pages leverages that flexibility to ensure we can continue to deliver electric service with top-tier reliability at affordable rates, all while leading and innovating at the grid edge. The planned portfolio additions also set us on a trajectory consistent with Minnesota's carbon-free standard of 100 percent by 2040.

The development of our plan was guided by many voices, including those of our members, our Board, our employees, and key industry stakeholders. Our planning process employed trade standard analytics and modeling tools, shaped by context specific to our membership. It also contemplated continued industry transformation, examining emerging trends like growing adoption of electric vehicles and rooftop solar.

For our inaugural resource plan, we elected to study a ten-year horizon. We recognize that a lot can change over the course of the decade, so our plan is designed to be robust in the face of uncertainty. Portfolio additions are incremental and adaptable to our members' evolving needs.

To our members: This plan represents our dedication to affordable, reliable, and sustainable electric service today and in the future.

To our stakeholders: We are grateful for your engagement and your expert input.

And, to others reviewing our plan, stay tuned—this is just the start of our new journey as an independent utility.

Greg Ridderbusch
President & CEO

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1 - Executive Summary

On August 30, 2022, Connexus Energy executed a new set of contracts with our wholesale provider of transmission and power supply services, Great River Energy (GRE). These contracts facilitated Connexus Energy's transition on January 1, 2023, from GRE *member* to GRE *customer*. The change in status introduced new opportunities and new responsibilities for our utility, including the flexibility to procure new power supply resources and the ownership of long-term resource planning activities.

In recognition of this newfound autonomy, the Connexus Energy Board of Directors directed Connexus leadership and staff to develop a long-term resource plan. The key deliverables were to include 1) a ten-year roadmap for resource procurement, and 2) an associated short-term procurement action plan. The ultimate outcome for the first of those deliverables is the "preferred plan" shown in Table 1.

The preferred plan includes the addition of 100 MW of solar, 50 MW of nuclear, and 30 MW of four-hour battery energy storage to our existing resource portfolio, comprised of natural gas and oil generating assets, as well as wind, hydro, solar, storage, and other contracted resources. The solar resources in the preferred plan represent a mix of "local" (distribution-interconnected) and "bulk system" (interconnected to the high-voltage transmission system) assets. The nuclear power purchase agreement (or PPA) is intended to be an offtake agreement with an existing, licensed nuclear facility operating in the region. The storage assets are modeled as locally sited, distributed batteries.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
Solar	10 MW Local Solar	10 MW Local Solar	10 MW Local Solar	20 MW Bulk System Solar	10 MW Local Solar	10 MW Local Solar	20 MW Bulk System Solar	10 MW Local Solar			**100 MW**
Nuclear							50 MW Nuclear PPA				**50 MW**
Storage					15 MW 4-hr Storage			15 MW 4-hr Storage			**30 MW**
Total Annual Additions	**10 MW**	**10 MW**	**10 MW**	**20 MW**	**25 MW**	**10 MW**	**70 MW**	**25 MW**	**0 MW**	**0 MW**	**180 MW**

Table 1. Preferred plan resource additions by year and resource type

These portfolio additions will put us on a trajectory that aligns with Minnesota's carbon-free and renewable energy mandates, while ensuring we can continue to provide affordable and reliable electricity to our members in coming years.

The preferred plan was approved by the Connexus Energy Board of Directors on November 16, 2023, along with a short-term procurement action plan, to be executed by Connexus leadership and staff in the 12-24 months following plan approval. These actions include:

» Issue a request for proposal for 10 MW of local solar, to be owned or contracted by Connexus, with a target commercial in-service date of December 2024 – *completed November 17, 2023*.

» Identify sites and perform feasibility analysis for an incremental 20 MW of local solar, with targeted commercial in-service dates in 2025 (+10 MW) and 2026 (+10 MW).

» Identify and engage partners for an offtake agreement for 20 MW of bulk system solar, with a target commercial in-service date in 2027.

The development of our plan was guided by our Board of Directors and informed by advice and insights solicited from industry experts—including Connexus Energy members—through a stakeholder engagement process beginning in March 2023. Resource selections in the plan, including type, timing, and amount (MWs), were informed by industry standard analytics and modeling, as well as market and regulatory considerations.

We recognize that emerging trends and regulatory, market, and technological developments will continue to drive transformation in the electric power industry. With this in mind, we will periodically review and refresh our long-term plan, under guidance from our Board.

Finally, “preferred plan” is the term used by investor-owned utilities (IOUs) in the state for the plan they submit to the Minnesota Public Utilities Commission for consideration and approval. Throughout this report, we draw parallels between the state-mandated integrated resource planning process for Minnesota IOUs and the planning process Connexus developed to best serve its membership. Those who have been involved in the integrated resource plan (IRP) process will recognize the key steps we have taken to develop this plan. For readers new to resource planning, we hope the following sections help to clarify why we undertook this process, how we developed our plan, and how we will use the information gained through the planning process to better prepare for the future.

2 - Introduction to Connexus Energy

Based in Ramsey, Connexus Energy is Minnesota's largest retail electric cooperative, providing electricity and related products to more than 144,000 residents and businesses in portions of eight counties in the north metro.

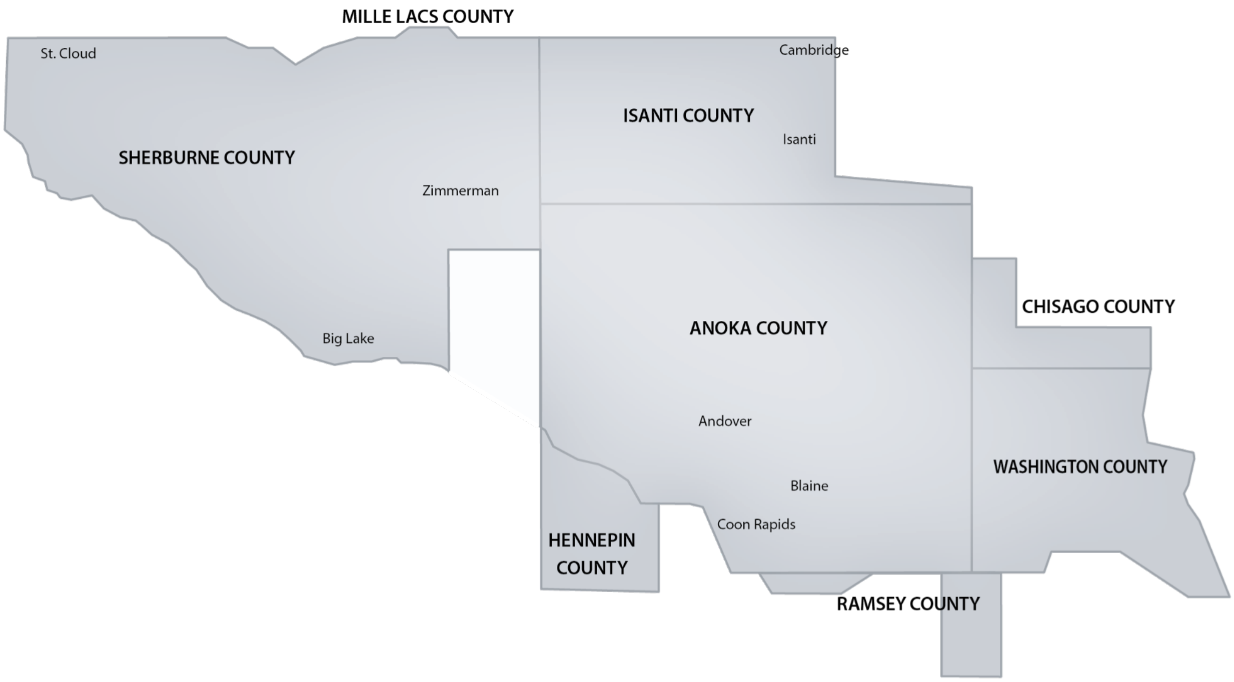

Figure 1. Map of Connexus Energy service territory as of December 2023

Our membership is approximately 90 percent residential and 10 percent commercial and industrial (C&I) by number of accounts. On an energy sales basis, the breakdown is 75 percent residential and 25 percent C&I on average. We serve fifteen members per mile of line.

We have been a trusted partner for our member communities for more than 85 years, going back to our start in 1937 as the Anoka County Cooperative Light and Power Association. Over the years, our business has evolved, but we remain as committed today as ever to providing excellent service to our membership and to ensuring access to safe, reliable, affordable, and sustainable electricity.

Our vision is simple—Connexus Energy is your most powerful membership®. Everything we do is for the benefit of our membership. That commitment is evidenced in key cooperative achievements and activities.

- **Reliability:** Consistently meeting top-tier reliability metrics.
- **Affordability:** Keeping rates flat for five of the past six years.
- **Sustainability:** Commissioning one of the first grid-scale solar plus storage installations in the Midwest and incorporating pollinator plantings into a growing local solar portfolio.
- **Optionality:** Providing members with program offerings like behavioral demand incentives (peak-time rebate) and a monthly electric vehicle (EV) charging subscription.

» **Innovation:** Employing non-wire alternatives to serve marginal load growth.

» **Community Engagement:** Supporting our member communities through educational campaigns, volunteer activities, and economic development.

Figure 2. Connexus Energy community engagement (clockwise from above left: Adopt-a-Highway cleanup crew, Anoka Area Chamber of Commerce breakfast, solar training for local emergency medical professionals)

Governance

As a cooperative, our members have a voice and a vote. Members elect our Board of Directors in annual elections, choosing from member candidates who reside in and are served by Connexus. The Board is governed by the cooperative's bylaws, which are adopted by the membership. The board establishes utility rates, sets the cooperative's goals and strategic direction, provides financial oversight, and acts as the policy-making body of Connexus Energy. Additionally, the Board served as the governing entity for review and approval of the long-term resource plan presented in this report. For information on current Board members, see our website.[1]

[1] See: www.connexusenergy.com.

Distribution Infrastructure

We maintain nearly 9,500 miles of 12.47 kV three-phase distribution lines, two-thirds of which are underground, along with 48 distribution substations. This infrastructure delivers more than 2 million megawatt-hours (MWh) of electricity to our members each year and more than 525 megawatts (MW) during periods of peak demand.

Our line crews maintain this infrastructure throughout the year, consistently providing service with reliability in the top 5 percent of electric utilities nationwide.[2]

Our distribution system interconnects with the "bulk"[3] electric system via GRE and Xcel Energy transmission substations (Figure 3).

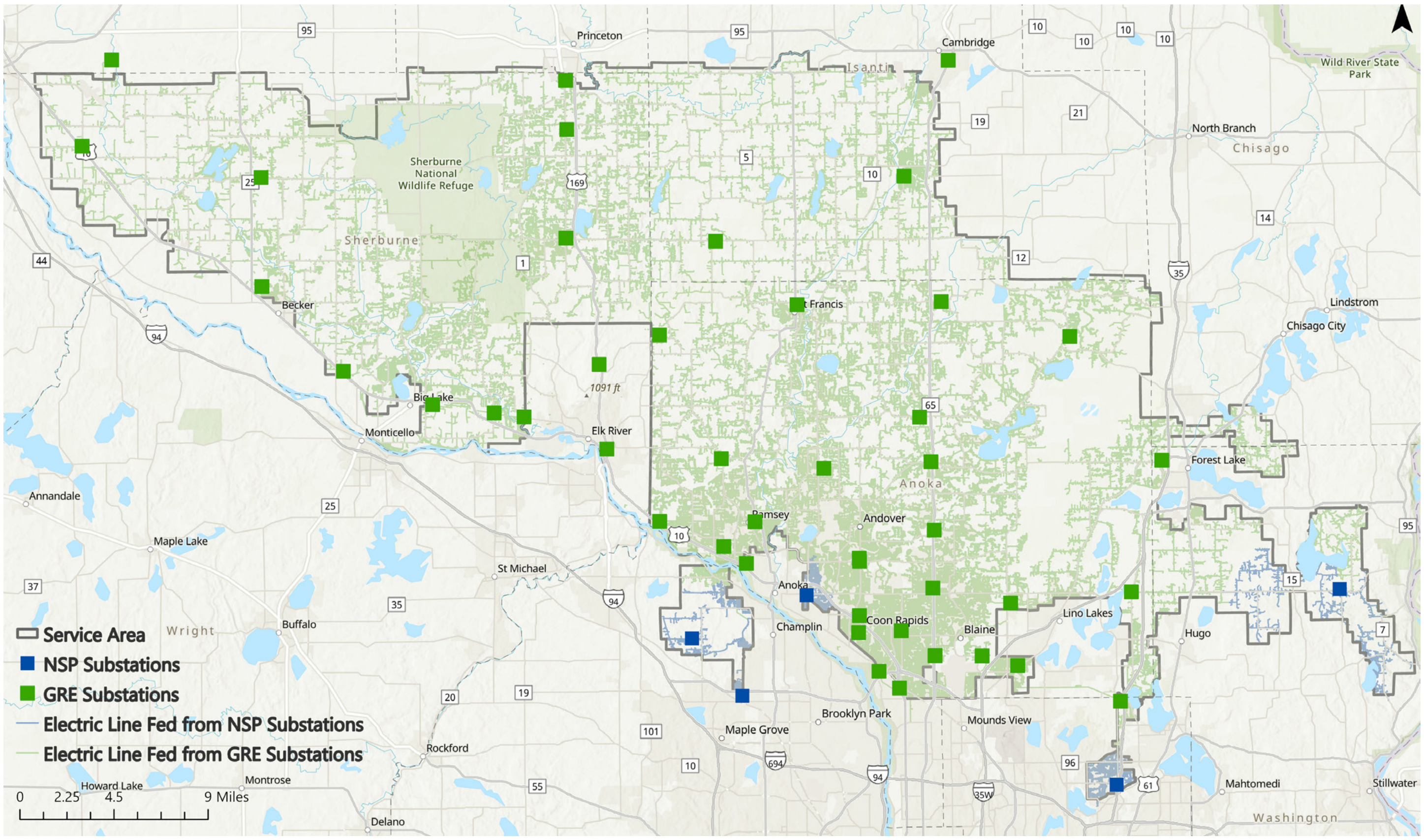

Figure 3. Map of Connexus substations (GRE = Great River Energy, NSP = Northern States Power/Xcel)

Power Supply Portfolio

Connexus Energy participates in the Midcontinent Independent System Operator (MISO)[4] wholesale energy, ancillary services, and capacity markets via Great River Energy (GRE). As a member of MISO (via GRE), the energy that is delivered to Connexus substations, and subsequently to Connexus Energy members' homes and businesses, is purchased from the MISO energy market by Connexus. The energy generated by the resources in our power supply portfolio is sold in the MISO energy market by or on behalf of Connexus Energy.[5] The revenues from these sales help offset and mitigate the volatility of market energy costs to serve load; i.e., these resources "hedge" our load costs.

[2]As measured via key reliability metrics including SAIFI (System Average Interruption Frequency Index), SAIDI (System Average Interruption Duration Index), and CAIDI (Customer Average Interruption Duration Index). These metrics measure the frequency and duration of service interruptions, along with time to restore.
[3]As defined by the North American Electric Reliability Corporation (NERC). See: [Bulk Electric System (BES) Definition, Notification, and Exception Process (nerc.com)](nerc.com).
[4]See www.misoenergy.org.
[5]Local solar, which is included in the "solar" category, is an exception. This solar is interconnected behind the substation meter and has the effect of reducing metered load at the substation.

Our current power supply portfolio includes locally sited solar and battery storage assets, as well as GRE "legacy" wind, hydro, natural gas, oil, and other resources. These "legacy" GRE resources were built or procured on behalf of GRE members, previously including Connexus.

The portfolio breakdown by resource type, on an energy-basis (2023, projected MWhs) is approximately 45 percent non-resource-specific energy contracts (includes Rainbow Energy Contract), 37 percent wind, 5 percent natural gas and oil, and 2 percent solar. The remaining 11 percent of energy needs are "unhedged;" i.e., we do not own or contract for resources to help defray the cost of this last 11 percent of energy purchases for load in the MISO market.

We also operate a portfolio of load management resources and programs that help serve 40-50 MW of load during peak summer demand periods and 20-25 MW during the winter. This demand reduction is achieved via dynamic control of feeder voltage by using radio or Wi-Fi signal to control air conditioners, water heaters, irrigation systems and dual fuel heating systems, and through utility-directed dispatch of backup diesel generators.

Additional details on our power supply portfolio are provided in the Resource Forecasting – Modeling Inputs section.

Customer Contract

In August 2022, Connexus Energy executed new power supply and transmission contracts with our wholesale service provider, Great River Energy (GRE). These agreements transitioned Connexus from GRE member to GRE customer, starting January 1, 2023.

Notably, our customer contract for power supply services grants Connexus Energy full autonomy to plan for and procure our own power supply resources. It also retains rights to our members' historical investments in "legacy" GRE resources. As a customer, we own 21.7 percent of the benefits of each legacy resource, including the energy, capacity, and environmental attributes and related revenues. We also have an obligation to cover 21.7 percent of the costs.

As GRE legacy resources retire and contracts expire, our need for new resources grows. To prepare for portfolio transition, the Connexus Energy Board directed Connexus staff and leadership to develop and implement a long-term resource planning process in 2023, with a final recommendation for a ten-year resource plan to be delivered to the Board for consideration by November 16, 2023.

Additional details of our customer contracts are available on our website.[6]

[6] See https://www.connexusenergy.com/company/news-center/news/connexus-announces-approval-new-customer-agreements-great-river-energy.

3 - Resource Planning Process Overview

Scope and Timeline

At its core, the resource planning process is designed to answer two questions:

- How much load will the utility need to serve in the future?
- What is the optimal portfolio of assets to serve those future load needs?

We kicked off efforts to answer these two questions in January 2023, with a directive from the Connexus Energy Board of Directors to develop the cooperative's first long-term resource plan. The planning process was organized into four stages—project scoping, forecasting and analysis, draft plan development, and plan finalization—with on-going opportunities for stakeholder engagement (Figure 4).

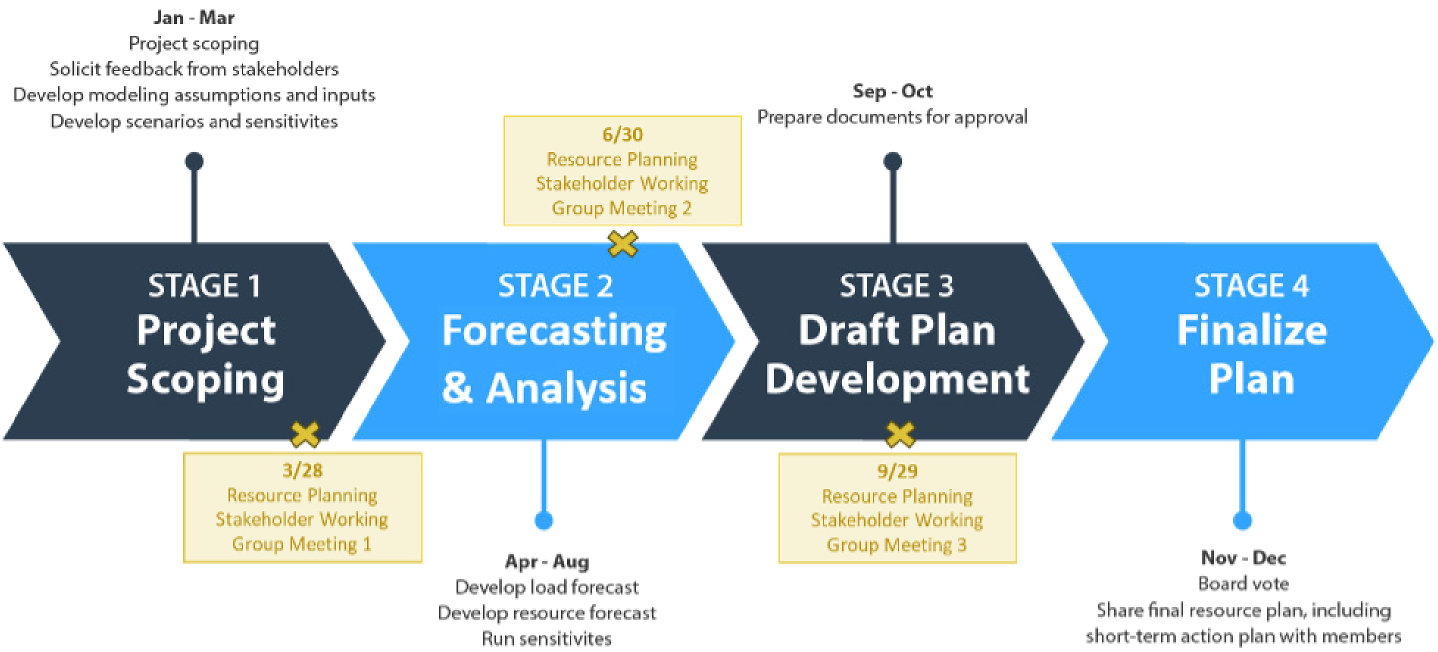

Figure 4. Resource planning process timeline

In designing the scope for this process, we borrowed from the state-mandated integrated resource planning process for investor-owned electric utilities (IOUs) in Minnesota. Minnesota IOUs must periodically submit an integrated resource plan (IRP) to the Minnesota Public Utilities Commission (Commission) for consideration and approval. State statute dictates requirements for the planning process and for the associated plan reports filed with the Commission. Connexus is not currently subject to the requirements of this statute,[7] but we recognize the value to our membership of certain, key components of the IRP process and have incorporated these into our planning process, including:

- Process oversight and plan approval by a jurisdictional governing body.
- Opportunities for impacted and/or interested parties to provide feedback.
- The use of industry standard tools, methodologies, and analytics.
- The resultant development of a long-term "preferred plan"[8] and a short-term action plan.

[7] See MN Statute Section 216B.2422, Subdivision 1.
[8] See "preferred plan" section for more details.

» The summarization of work efforts into a comprehensive, publicly available report.

» The periodic review and refresh of the plan as needs change over time.

The scope for our planning process was also guided by direction and input from our Board of Directors. Specifically, the Board directed Connexus Energy leadership and staff to develop a recommendation for a ten-year, least-cost plan to evolve our power supply portfolio to meet future load needs, while complying with MISO obligations and applicable state statute.[9] The final plan recommendation was to be presented to the Board in 2023, with regular updates from staff and with opportunities for our members and others to engage in the process.

Stakeholder Engagement

The integrated resource planning process for Minnesota IOUs includes opportunities for interest groups, other utilities, and the public to comment on the utility's proposed plans to build, procure, and/or retire resources. We likewise built avenues for stakeholder feedback into our process.

Key stakeholders include our members, the Connexus Energy Board, and Connexus Energy employees. We provided monthly updates to our Board starting in January 2023 and quarterly updates to our employee project team.

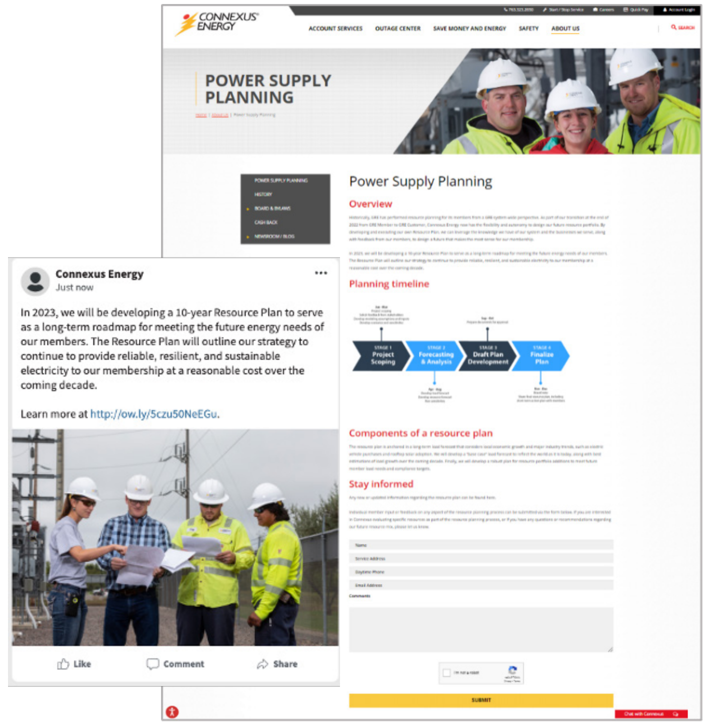

Figure 5. (from left to right) Connexus LinkedIn post, Connexus website

Beginning in March, we leveraged social media to create awareness among our membership about our power supply portfolio, the drivers for our planning process, and ways to get involved. We also sent information directly to our commercial and industrial members in the form of on-bill messaging, and we emailed key accounts with details about the process and engagement opportunities. Finally, we created a new page for power supply planning on our website with a contact form for feedback and questions (Figure 5), and we shared updates about the planning process at our annual meeting and via our annual report.

We also engaged a diverse group of stakeholders, representing different organizations, interests, and industries, recognizing the potential for our planning decisions to have impacts beyond our service territory. Each group represents local interests in long-term rate impacts, as well as planning and development impacts. We hosted three meetings for these stakeholders, with discussion facilitated by former Minnesota Public Utilities Commissioner, Dan Lipschultz. These sessions were attended by individuals from the following:

» Anoka Area Chamber of Commerce

» Center for Energy and Environment

» Citizens Utility Board of Minnesota

» Clean Up the River Environment

» Cooperative Finance Corporation

» Fresh Energy

» Minnesota Center for Environmental Advocacy

» Minnesota Precision Manufacturing Association

» Minnesota Solar Energy Industries Association

» Sherburne County

[9]Including Minnesota Renewable Energy Standard, Minnesota Carbon-Free Standard, and Energy Conservation and Optimization Act requirements.

Key topics covered in these meetings include an overview of our planning process, load forecast development with a focus on impacts of rooftop solar and electric vehicle adoption, modeling methodology and results, plan development, and next steps.

We also invited this external stakeholder group to observe our August 2023 board meeting, at which we presented our draft ten-year resource plan and our short-term resource procurement action plan. Ellen Anderson, former Minnesota Public Utilities Commission Chair, representing the Minnesota Center for Environmental Advocacy (MCEA) in the stakeholder group, spoke on behalf of the stakeholders at the August board meeting, sharing feedback on the process.

4 - Resource Planning Analytics

Forecasting and Modeling Overview

In the state of Minnesota, IOUs commonly use load forecasting and resource forecasting models to inform the development of their long-term resource plan. We similarly designed the scope of our resource planning analytics around the application of and results from these two types of models.

The **load forecasting model** helps to answer the first question of resource planning: How much load will the utility need to serve in the future? This model requires inputs of historic meter data (metered electric usage or "load") and historic weather data, along with projections for future economic and household growth to forecast future load needs by consumer class (e.g., residential, small commercial, large commercial). Typically, the hourly load forecast by consumer class is aggregated to produce a single, hourly load profile for the whole service territory of the utility.

Inputs to the load forecast may be modified to represent variations on future growth and/or weather. These variations can help characterize reasonable upper and lower bounds of future energy and demand requirements and subsequently help the utility create a more robust resource plan.

The load forecast serves as a crucial input to the second key analytical tool used in the resource planning process, which is the **resource forecasting model**. This model helps to answer the second question of resource planning: What is the "optimal" (typically, lowest net present value of system costs) resource portfolio that will meet long-term energy and demand needs? Usually, the model user will define the utility's existing power supply portfolio and the cost and operational characteristics of new resource options. Model outputs include the type, timing, and amount (MW) of new resource additions to the utility's existing power supply portfolio.

Resource forecasting is an iterative process in which a reference or base case (intended to reflect a moderate or baseline view of the future) is first modeled. After the base case outputs are reviewed and confirmed as reasonable, the model is run again, this time with variations on one or more base case inputs, producing a "change case" or "sensitivity." Each change case represents a different version of the future and has an associated distinct set of outputs. In combination, the base case and change cases help provide a more comprehensive picture of the type of portfolio that will meet load needs under a variety of outcomes, at the lowest cost possible.

The timeframe allotted for our resource planning process necessitated the use of consultants for forecasting and modeling activities. External experts were leveraged for analytics, and the scope of analytics performed to inform plan development was designed by Connexus staff with input from the Connexus Energy Board and the stakeholder group. Model selection and methodologies are covered in detail the following sections.

Load Forecasting Methodology and Results

The load forecast was developed in three stages, by member class,[11] using industry-standard models. First, monthly sales (energy, kWh) by class were forecast, then aggregated to produce system energy sales by month. Second, monthly system peaks (demand, kW) were modeled. Third, an hourly usage profile was developed and shaped by monthly energy and monthly demand. The key inputs into the forecasting process include weather data, economic data, and regional consumer appliance data and usage trends.

[11]As defined in the USDA's "Financial and Operating Report – Electric Distribution," previously known as "Form 7." Defined classes include residential, small commercial, large commercial, irrigation, public street and highway lighting, other sales to public authorities, and sales for resale. See [Financial and Operating Report - Electric Distribution | Rural Development (usda.gov)](usda.gov).

The resultant forecast represents moderate future load growth in Connexus Energy's service territory. In statistical terms, "moderate" growth is a "P50" forecast, which means that the likelihood that actual future load is higher than forecast is equal to the likelihood that actual future load comes in lower than forecast.

To quantify uncertainty around future load growth, two economic scenarios were modeled, representing low- and high-growth futures. The forecast inputs that were altered for these two include: local population, (number of) households, income, employment, and regional gross domestic product. Similarly, mild and extreme temperature scenarios representing 1-in-10-year conditions were modeled to capture uncertainty associated with future weather.

Figure 6 shows the forecast for annual energy sales for each of the scenarios in gigawatt hours (GWh), where 1 GWh = 1,000 megawatt hours (MWh) = 1,000,000 kilowatt hours (kWh). A typical residential member uses approximately 800 kWh per month.

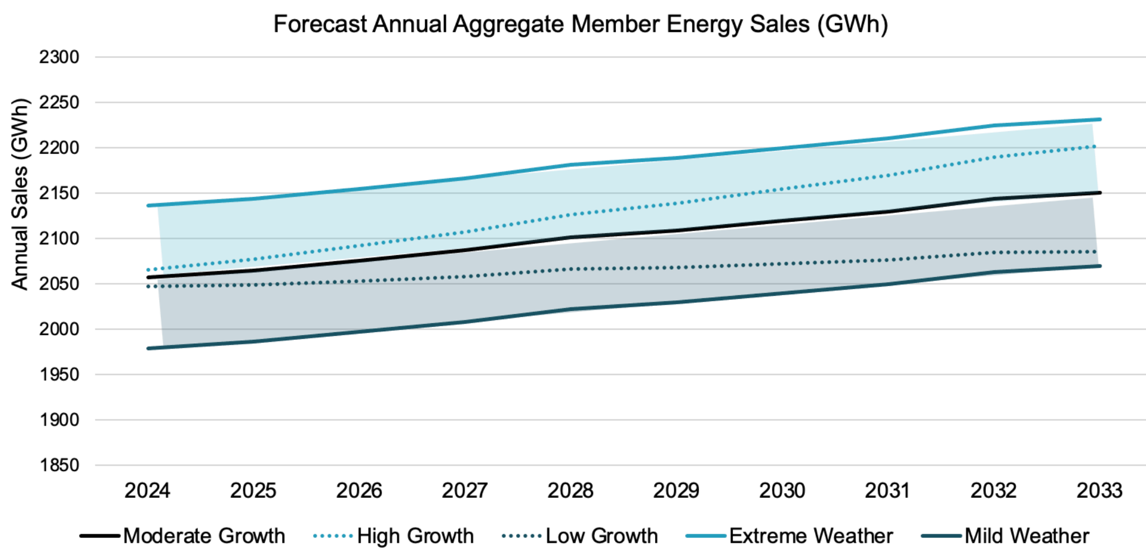

Figure 6. Forecast annual energy sales (GWh) by scenario (colored bands reflect the reference point of the moderate case for the weather scenarios)

The ten-year (2024-2033) compound annual growth rate for energy sales in the moderate growth scenario is 0.5 percent. Total energy sales forecast in 2024 and 2033 are 2,057 GWh and 2,151 GWh, respectively. The growth rates for the low- and high-economic growth scenarios are 0.2 percent and 0.7 percent, respectively. Energy sales in the mild and extreme weather scenarios are ± 3.8 percent from the moderate case in each year of the study horizon. For comparison, energy sales across all member classes over the past decade (2013-2022) have grown 0.7 percent per year, on average.

The Connexus Energy system is a summer-peaking system, meaning that the highest coincident demand[12] occurs during the summer months. Figure 7 shows forecast demand for low, moderate, and high growth scenarios, as well as mild and extreme weather scenarios.

[12]Peak demand on a member-by-member basis is measured as the average of the four highest consecutive fifteen-minute intervals of usage (kilowatts, kW). On a system-wide basis, the coincident peak demand occurs during the hour with the highest aggregate load (megawatts, MW).

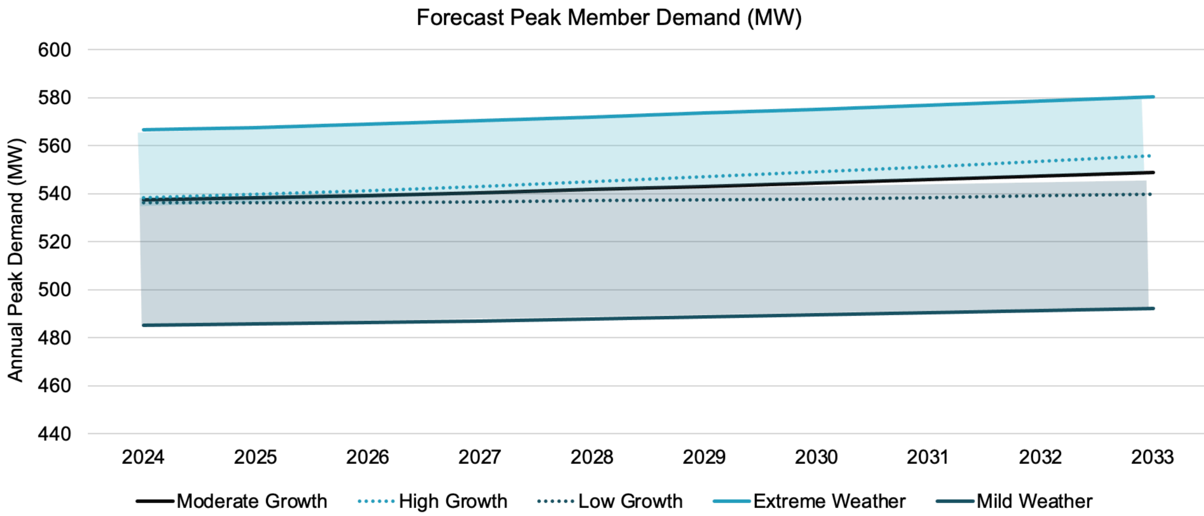

Figure 7. Forecast annual system peak demand (MW) by scenario (colored bands reflect the reference point of the moderate case for the weather scenarios)

The ten-year (2024-2033) compound annual growth rate for peak demand in the moderate growth scenario is 0.2 percent. The peak summer forecast for 2024 is 527 MW; the peak summer forecast for 2033 is 549 MW. The growth rates for the low- and high-economic growth scenarios are 0.1 percent and 0.4 percent, respectively. Peak demand in the mild weather scenarios is 10 percent (rounded to the nearest 1 percent) lower than the moderate case in each year of the study horizon. The extreme weather scenario peak demand is 6 percent (rounded) higher than the moderate case each year. For reference, the average annual system peak from 2013 through 2022 was 510 MW.

The load forecasting process as described does not explicitly account for significant future growth in member rooftop solar or electric vehicles (EV). Given that historic trends are likely not indicative of future growth, we developed separate hourly forecasts for the potential impacts on load of rooftop solar generation and EV charging.

Rooftop Solar Adoption Forecast

For both rooftop solar and EV adoption forecasts, we needed to project, 1) the total number of adopters, and 2) the class average hourly impact of each adopter for each year of the study horizon. In both instances member meter data was leveraged where possible to inform long-term adoption trends and hourly profile development.

To forecast the number of member solar adopters each year, we used a standard tech adoption s-curve model, informed by recent member solar adoption trends and an estimation of feasible rooftop space.[13] The "base case" in Figure 8 represents gradual adoption, in line with Connexus Energy member adoption trends over the past five years. The "high case" represents a future in which rooftop solar costs continue to decline and/or incentives are increased, and adoption subsequently increases at a much higher rate during the next five years.

[13]From NREL, "Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment," see: Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment (nrel.gov).

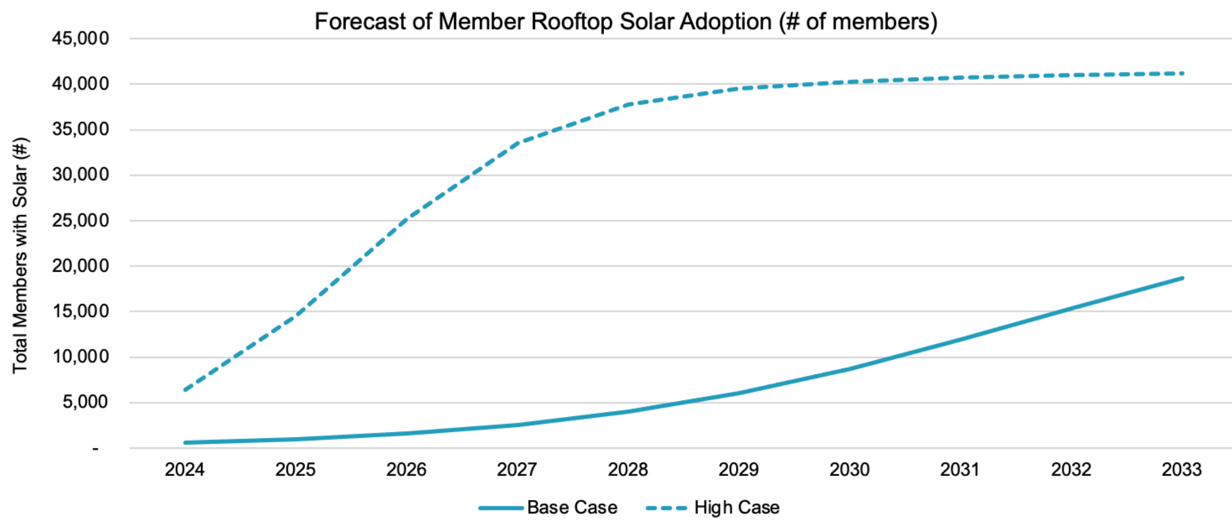

Figure 8. Forecast of total members with rooftop solar (number of members)

The total number of members with solar forecast in the base case in 2033 is 18,700 or approximately 13 percent of all members. The high case reaches 19,000 adopters in mid-2025 and projects more than 40,000 members (28 percent of all member accounts) with solar by 2033. As of December 2023, there were more than 1,000 member solar systems in our service territory, totaling nearly 11 MW of capacity. Both base and high cases represent a significant uptick in solar adoption over the coming decade.

The average member array size was assumed to be 7 kW, informed by the average member array size to-date, with a slight derate under the assumption that future member adoption may include smaller rooftops as per-unit solar costs decline. A class average hourly generation profile per kW-installed was estimated based on meter data from members with solar. This class average profile, with an annual production factor of 13.4 percent, was applied to all forecast member solar adoption.

For additional insights into future solar growth, we used the National Renewable Energy Laboratory's (NREL) Distributed Generation Market Demand (dGen) model[14] to forecast adoption. This model uses pre-built representative customer profiles (agents) to simulate localized adoption of rooftop solar, considering local electricity costs, solar costs, and neighborhood adoption effects, along with other key variables. The dGen model simulates adoption of rooftop solar by Connexus members at approximately 30 percent of the rate forecast using the standard s-curve model. In concert, these two models produce potential bounds on reasonable projections for adoption.

Electric Vehicle (EV) Adoption Forecast

The forecast for EV adoption was informed by historic member EV ownership trends and industry projections for growth. For context, as of January 2023, there were 1,232 EVs registered in the Connexus Energy service territory.[15] On average, EV ownership among Connexus members has grown 5 percent each month since early 2019, with annual growth between 40-80 percent. We estimate there are between 1,700 and 2,000 EVs registered in the Connexus Energy service territory as of December 2023.[16]

In the **Base Case**, members are projected to own 14,000 EVs in 2033. This translates to EVs accounting for 1 in every 13 new vehicle purchases. Base case annual adoption projections result in EVs comprising 5.5 percent of overall vehicle ownership in 2033. The base case projections are derived from a trendline of historic member EV ownership.

[14]See https://www.nrel.gov/analysis/dgen/.
[15]See Electric Vehicles / Public Utilities (mn.gov).
[16]Connexus members with electric vehicles are not required to report ownership to the utility.

In the **High Case**, adoption is quadrupled, with total EV ownership projected to be just under 54,000 vehicles in 2033 or more than 20 percent of all vehicles on the road. In the high case, 1 in every 3 new vehicles purchased by the membership is electric in 2033. To develop the high case projections, 2 national industry projections for EV adoption[17] were averaged, then pro-rated and adjusted based on local EV ownership, vehicle lifespan (10.5 years), vehicles per household (1.9), and annual growth in number of households (+0.5 percent).

Figure 9 shows both base and high case forecasts for EV adoption in the form of total projected member EV owners per year through 2033.

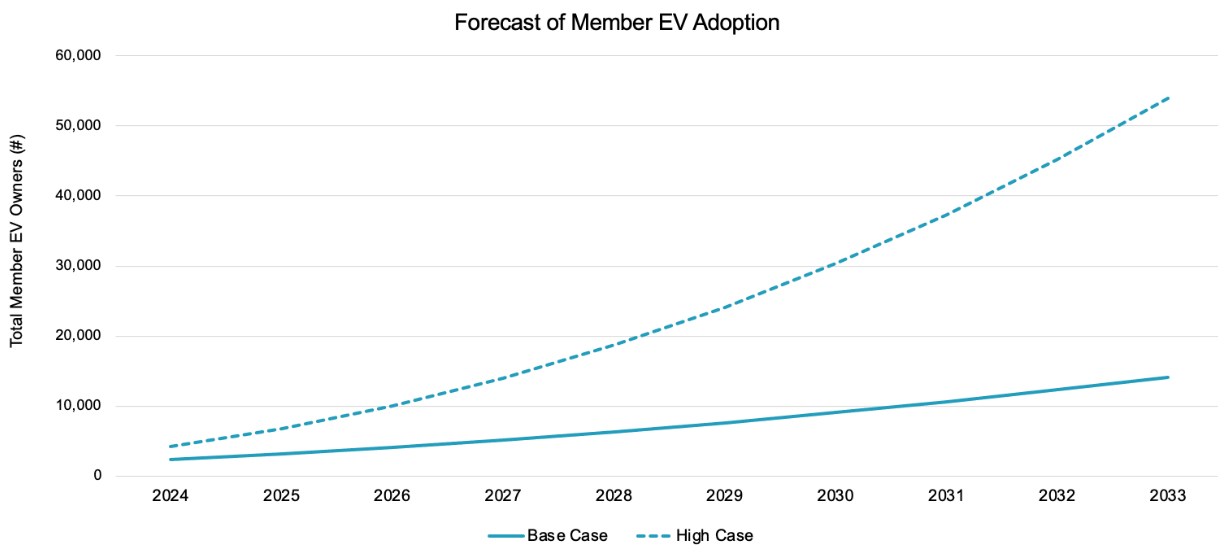

Figure 9. Base and high case forecasts of member EV adoption (total member EV owners per year)

To forecast the class average hourly impact of each EV adopter, for each year of the study horizon, we needed to project EV charging behaviors. To do this, member EV owner charging behavior was categorized as either "controlled" or "uncontrolled." The "controlled" group represents members enrolled in one of Connexus Energy's special EV rates, which incentivize charging during off-peak hours.[18] The "uncontrolled" group represents EV-owning members who are not on a special rate and have no utility rate incentive to charge during off-peak hours.

The "controlled" profile was developed using meter data from known EV owners (known to Connexus because they have signed up for a special EV rate tariff). The "uncontrolled" profile was built using meter data from likely EV owners, identified through EV "fingerprint" analytics. The resultant profiles are shown in Figure 10.

[17]Goldman Sachs Research, see Electric Vehicles are Forecast to Be Half of Global Car Sales by 2035 (goldmansachs.com); and IHS Markit forecast, as summarized by Axios, see Electric vehicles forecast to overtake gas engines within a decade (axios.com).
[18]See www.connexusenergy.com.

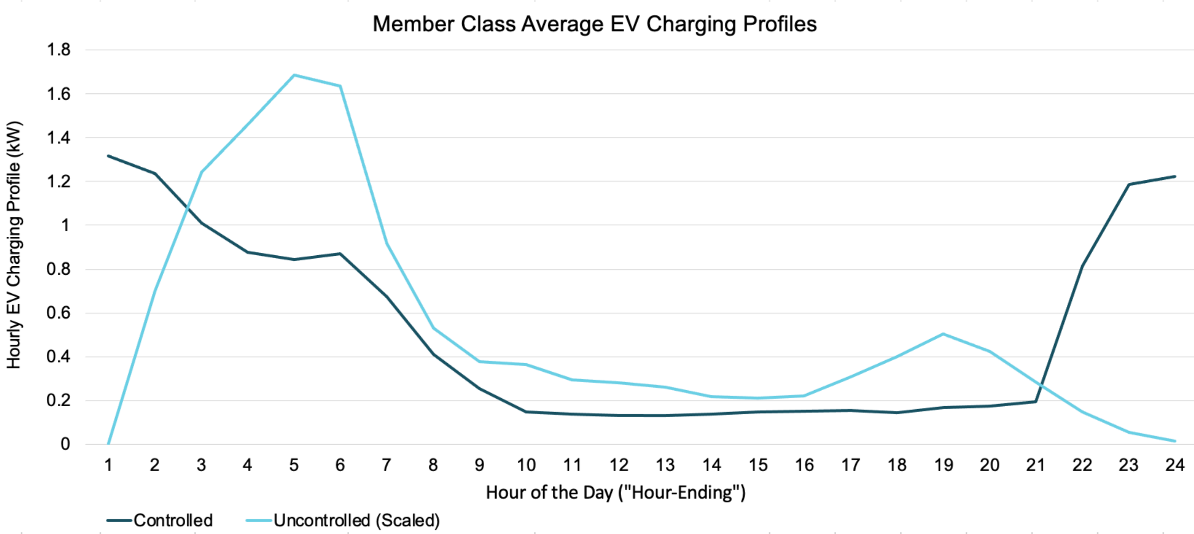

Figure 10. Forecast of member EV-charging profiles (hourly kW)

As a simplifying assumption, both class average hourly charging profiles were held constant for each 24-hour period throughout the 10-year study period. While it is unlikely that future charging behavior will be static, it is difficult to project exactly how charging behavior will change in the face of evolving electric vehicle (EV) charging technology and rates. Further, observed member charging behavior is relatively consistent, even from weekday to weekend and from one season to the next.

To determine the ratio of EV owners in the "controlled" bucket versus the "uncontrolled" bucket, we again looked at historic and industry trends. In 2019, nearly 90 percent of member EV owners were enrolled in a special Connexus Energy EV rate tariff. That "capture rate" (percent of total EV owners in the Connexus service territory enrolled in a special EV program/rate) had decreased to 56 percent at the start of 2023. One potential reason for the drop is that early EV adopters may be more engaged in utility program offerings in general. Each year, EVs make up an increasingly larger portion of new car offerings; members purchasing EVs today may be doing so for different reasons (e.g., cost advantage) than those individuals who have purchased an EV in the past (e.g., environmental reasons, novel tech). For modeling purposes, we assumed that the current capture rate declines linearly to 50 percent in 2033. We also assume that all members on a special rate respond to the financial incentive to change their charging behavior (i.e., all are assigned the "controlled" profile), and the remaining EV adopters are assigned the "uncontrolled" charging profile.

Load Profile Impacts of Rooftop Solar and Electric Vehicle (EV) Adoption

After forecasts for rooftop solar and EV adoption were developed, hourly class average profiles were aggregated then applied to the "moderate growth" hourly load forecast to model net impacts of EVs and rooftop solar for each adoption scenario.

In the **Base Case**, the net impact of load *growth*, due to incremental EV charging and load *reduction* due to incremental rooftop solar generation, is a reduction in the ten-year compound annual load growth rate from 0.5 percent to approximately 0 percent.

The total projected energy generation from rooftop solar in 2033 is 153 GWh, which represents 7.1 percent of total forecast member energy sales in that year. The projected peak[19] generation from rooftop solar in 2033 is 130 MW. This represents 23.8 percent of peak summer demand in 2033.

[19]Highest single hour of production across all member rooftop arrays measured in MWs.

The total projected annual charging load and peak demand[20] from EVs in 2033 is 64 GWh and 18 MW, respectively. The peak charging load occurs between 4 a.m. and 5 a.m.

In the **High Case**, the net impact of load *growth*, due to incremental EV charging and load *reduction* due to incremental rooftop solar generation, is a reduction in the ten-year compound annual load growth rate from 0.5 percent to less than 0.1 percent.

The total projected energy generation from rooftop solar in 2033 in the high case is 338 GWh, which represents 15.7 percent of total forecast member energy sales in that year. The projected peak generation from rooftop solar in 2033 is 288 MW. This represents more than half of peak summer demand in 2033.

The total projected annual charging load and peak demand from EVs in 2033 in the high case is 224 GWh and 68 MW, respectively. The peak charging load occurs between 4 a.m. and 5 a.m., as in the base case.

Figures 11 and 12 illustrate the hourly load profile impacts of rooftop solar and EV charging assumptions for each scenario. These figures show the projected average hourly energy sales across all members in 2033. For example, "hour-ending 1" represents the average total load (MW) across all members for the hour starting at midnight and ending at 1 a.m. for each day of 2033. The figures highlight typical load patterns, including higher average load usage in the morning and evening periods and lower usage overnight and, to a lesser extent, during midday. These usage patterns shift across the ten-year study period, as both EV charging load and rooftop solar generation increase.

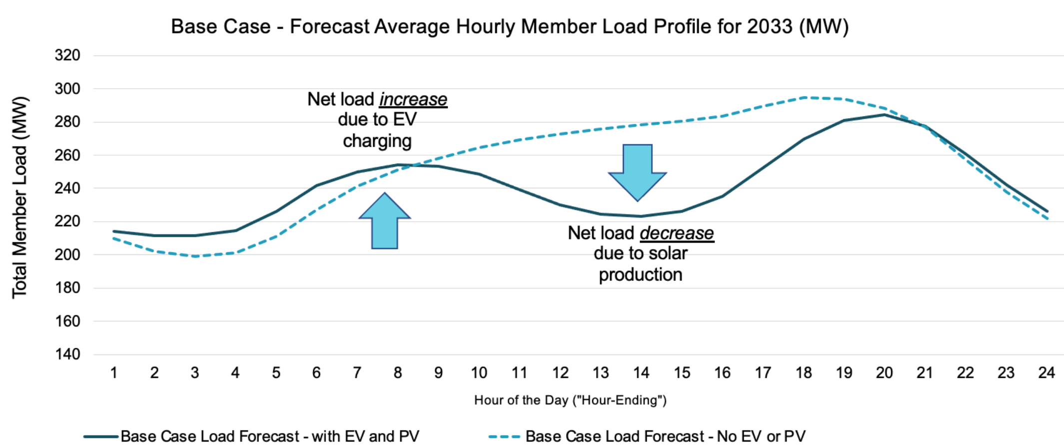

Figure 11. Modeled net load impacts of base case EV and rooftop solar photovoltaic (PV) assumptions in 2033 (MW)

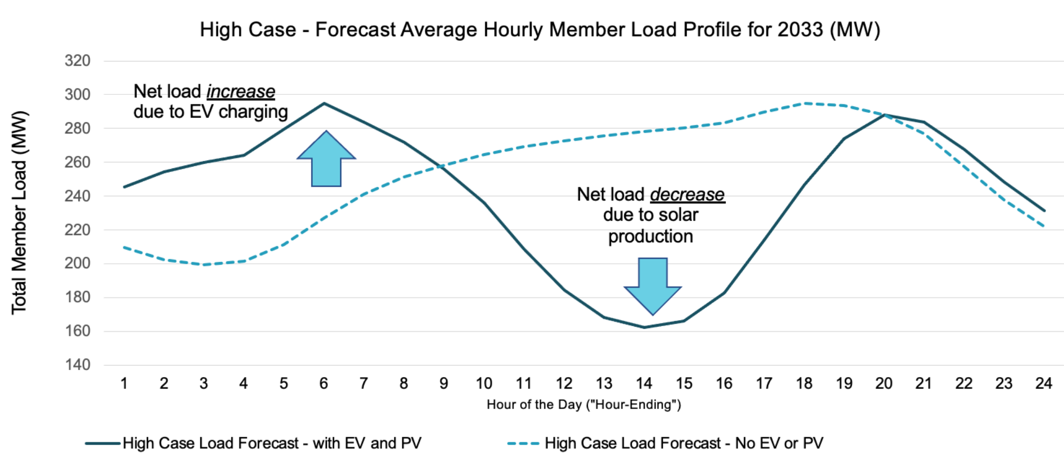

Figure 12. Modeled net load impacts of hgh case EV and rooftop solar (PV) assumptions in 2033 (MW)

[20]Highest single hour of charging across all member EV owners measured in MWs.

Figures 13 and 14 show the hourly load profile impacts of rooftop solar and EV charging assumptions for each of the base case and high case for each year of the study horizon.

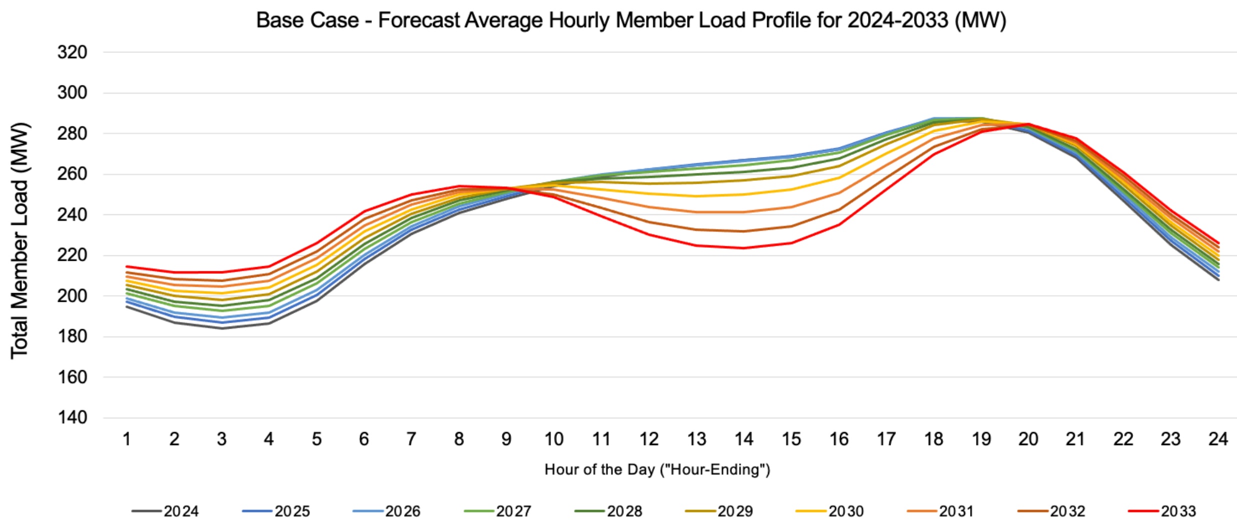

Figure 13. Modeled net load impacts of base case EV and rooftop solar (PV) assumptions, 2024-2033 (MW)

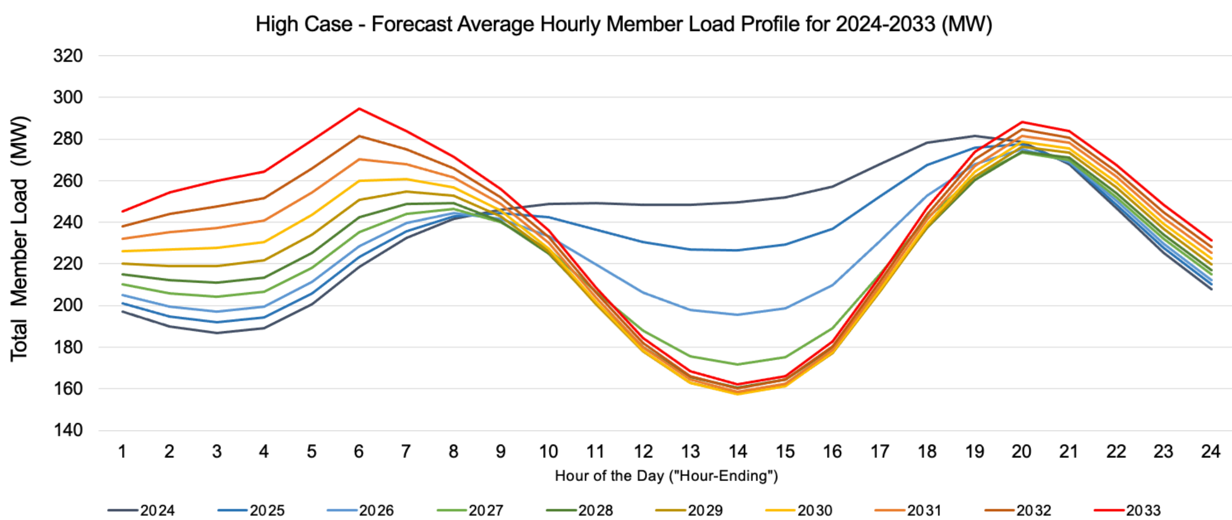

Figure 14. Modeled net load impacts of high case EV and rooftop solar (PV) assumptions, 2024-2033 (MW)

As a simplifying assumption, we modeled a single hourly charging pattern per each “controlled” EV and “uncontrolled” EV (Figure 10), every day throughout the ten-year study horizon. As a result, there are no specific seasonal net impacts of EV charging on modeled hourly load profiles. There are seasonal impacts on modeled net load from solar generation, given the variation of solar irradiance across the year. While solar generation is highest on average during the summer months, member load also increases during summer months, primarily due to air conditioning load. In the spring, solar generation is still relatively high, but mild temperatures lead to lower heating and cooling loads, and therefore, lower member load overall. Figure 15 shows the potential seasonal impact of high rooftop solar adoption during an average spring day (April or May), including net (i.e., total member load – member rooftop solar generation = total member net load) midday load dipping to 80 MW.

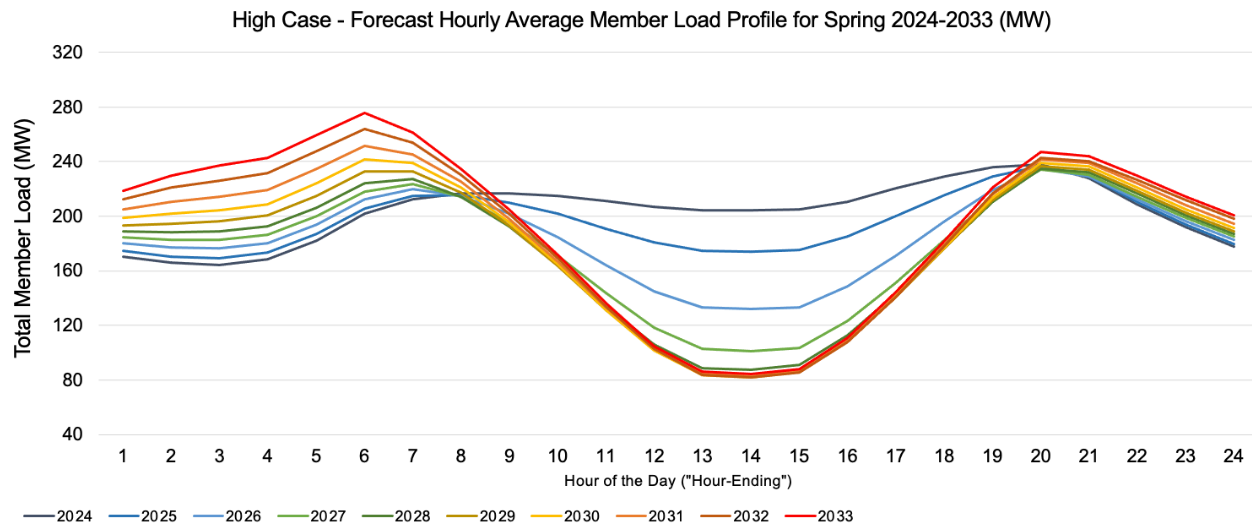

Figure 15. Seasonal net load impacts of high case EV and rooftop solar (PV) assumptions, April-May 2024-2033 (MW)

When we drill down into the hourly load forecast for the high case, we see nearly 270 hours in the months of April through early June from 2027 through 2033, in which the total rooftop solar generation exceeds the total system load. The potential for local solar generation to exceed load poses challenges for future distribution system planning.[21] See the "Planning Challenges and Opportunities" section for discussion of this topic. For purposes of the resource plan, the key concerns related to future growth in rooftop solar adoption are the hourly and seasonal impacts on total system resource requirements.

Resource Forecasting – Background Information

Resource forecasting for integrated resource planning is often performed using proprietary software designed to model the optimal portfolio of resources to serve future load needs for a defined system, e.g., a single utility or a group of utilities. Here "optimal" means the least-cost[22] portfolio that meets system energy and demand requirements, while complying with regulatory requirements, regional energy market obligations, and other constraints.

The model user defines the study horizon (the number of years or decades into the future the model simulates system operations), along with system parameters and economic indicators (Table 2). Key system parameters include the load forecast and the current resource portfolio, with definitions of the operational, financial, and environmental (e.g., emissions, environmental attributes) characteristics for each resource. Typically, electric generators, energy storage, a variety of energy and/or capacity contracts, demand response resources, and energy efficiency and conservation measures can all be represented as resources. The dispatch type for each resource is also user-defined, as economic, must-run, or pre-determined (via a user-input dispatch profile). The user also defines whether the model can add small amounts (e.g., 1 MW) of each resource to the portfolio to meet future needs or if the model can only add defined increments (e.g., 10-MW chunks of solar), which may be more representative of viable project sizes.

Future resource options are another set of key system parameters. In addition to defining operational, financial, and environmental characteristics of each resource, the model user may limit the total number of each type of resource added by the model per year and in total over the course of the simulated time horizon. For example, the user may include wind, solar, and storage as potential future additions to the existing resource portfolio. The wind option may not be available until three years into the study horizon, whereas solar and storage may be available in year one; this could reflect industry conditions, e.g., wind permitting challenges and in-service delays.

[21]See "Planning Challenges and Opportunities" for further discussion on this topic.
[22]Lowest net present value of portfolio costs, including capital and variable and fixed costs.

The model will consider the operational and financial characteristics, and may also consider environmental[23] characteristics, of both the existing resource portfolio and future resource options, along with user-defined constraints, to determine the "optimal" resource mix and application in each time "bucket" modeled—e.g., hour, month, year. The model has perfect foresight, meaning that it will add resources to the portfolio at the optimal time, given what it knows about load, resources, and constraints across the entire study horizon. Constraints commonly include renewable energy standards or targets and planning reserve margin requirements.[24]

Model Inputs	Description
Load forecast	Hourly, aggregate load (MW) profile
Existing resource portfolio	Operational, economic, and environmental characteristics of the resources in the existing portfolio
Future resource options	Operational, economic, and environmental characteristics of the resources available for the model to select to meet future load needs
Fuel prices	May include natural gas price ($/MMBtu), coal price ($/ton), etc.
Energy market prices	Proxy for regional energy market interactions ($/MWh)
Planning reserve margin	Seasonal peak reserve capacity requirement (% applied to seasonal coincident peak load)
Escalators/inflators	May be universal or specific to individual model components (%)
Discount rate	For net present value calculations (%)
Compliance obligations	State-mandated renewable energy requirements (annually, as % of load)

Table 2. Resource forecasting model components and generic descriptions

Details typically *not* represented in the resource forecasting model include electric distribution and transmission wires (load and resources may be modeled as if they all exist at a single location or node), external systems (e.g., other utilities and their resource portfolios), and dynamic regional energy market interactions (a proxy for the energy market may be modeled as a fixed-price stream paired with monthly or annual buy/sell limits). These simplifications help limit computational requirements for the optimization and subsequently keep model simulation times in check, which can be especially important for complex portfolios and/or decades-long study horizons.

Once assumptions for key system parameters are established, a reference case or "base case," representing moderate growth or a status quo version of the system in the future, is built. Then a simulation of future load needs and future resource applications—which could include various activities such as storage charge/discharge, electric power generation, energy market purchases, or load reduction achieved through a demand response program—is carried out for the defined timeframe. The results of the system simulation (of the model "run") include the optimal type, timing, and number of new resources added to the existing portfolio. Additional outputs typically include system and resource-level costs, resource dispatch/use, and emissions generated.[25] Outputs may be available in hourly, monthly, annual, or other defined time "buckets". Contingent upon the software and the user-defined settings, the model may produce the top portfolio plus the five or ten next-best portfolios.

[23]Emissions and/or environmental attributes, such as renewable energy and/or carbon-free energy certificates.
[24]The Midcontinent Independent System Operator is a regional system operator and power pool formed in 2001. Participants in the MISO power pool have an obligation to make enough capacity available to the pool to serve load at all times during the year. To ensure that the capacity will cover load even in the event of extreme weather and system emergencies, MISO also mandates that participants carry a planning reserve margin—a capacity cushion beyond typical load requirements. The requirement for this capacity cushion is allocated across all members in MISO. Connexus is a participant in the MISO power pool via Great River Energy. As a result, Connexus Energy has a MISO capacity obligation. The amount (MW) of Connexus' capacity obligation, i.e., our planning reserve margin requirement, is determined by MISO based on historic Connexus Energy load during MISO system peaks, along with projected Connexus load growth. The obligation is seasonal, i.e., a specific number of MWs must be made available by Connexus Energy for each of summer, fall, winter, and spring. The obligation is recalculated each year to reflect changing system conditions.
[25]Carbon dioxide (CO2), nitrogen oxides (NOX), sulfur oxides (SOX), mercury (Hg), lead (Pb), and particulate emissions are typically modeled.

After the base case outputs are reviewed and validated, the model is typically run again, multiple times, with variations on one or more base case inputs, producing a “change case” or “sensitivity.” Each change case represents a different version of the future, and each simulation using a change case will produce a distinct set of outputs to compare against those from the base case. The suite of cases will help inform the formulation of a portfolio to meet future load needs economically under a variety of future outcomes.

Resource Forecasting – Model Inputs

Industry standard modeling tools were used in resource forecasting for Connexus Energy’s resource plan development.[26] The following section provides details of the model inputs.

Study Horizon

Per direction from the Connexus Energy Board of Directors, the study horizon was set to ten years, beginning in 2024.

System Definition

The system was defined as Connexus load and resources with a proxy representation of the MISO energy market. This definition aligns with industry standards used by Minnesota investor-owned utilities for integrated resource planning. No transmission or distribution delivery lines were represented; all load and generation were assumed to exist at a single node.

Economic Indicators

The discount rate was set at 5.5 percent, based on a projected average weighted cost of capital. The discount rate is used in the present value calculations of total portfolio costs.

Load Forecast

The “moderate” growth forecast shown in Tables 3 and 4, with embedded base case rooftop solar and base case electric vehicle adoption assumptions, was used for the base case model build. This load forecast represents hourly aggregate demand and energy needs across all member classes. The net load reduction achieved through Connexus Energy’s demand response programs is embedded in the load forecast, as are energy and demand savings from member energy efficiency and conservation measures.

Externalities

Externalities (costs assigned to emissions on a per-unit basis, e.g., \$/ton of CO_2) are not modeled. The only emitting resources in the portfolio are natural gas and fuel oil peakers.

Existing Resource Portfolio

Connexus Energy’s resource portfolio includes several local solar and battery energy storage assets contracted by Connexus (Table 3), along with legacy GRE natural gas and fuel oil assets, wind, hydro, and other contracts (Table 4).

The assets listed in Table 3 are located within our service territory, and we are the counterparty in long-term bilateral contracts for all energy, capacity, and environmental attributes from these resources. The nameplate capacity column lists the maximum instantaneous output (MW) of each resource.

[26]Anchor Power Solutions’ EnCompass model was employed by Great River Energy staff on behalf of Connexus Energy. This software product is also used by investor-owned utilities in Minnesota for state-mandated integrated resource planning. GRE provided model inputs for GRE legacy resources in Connexus Energy’s power supply portfolio. Connexus Energy staff provided the load profiles, future resource option definitions, and planning reserve margin requirement assumptions, as well as change case definitions and associated assumptions.

Resource Name	Resource Type	Location	Nameplate Capacity (MW)	In-Service Date	Contract End Date	Ownership Status
Anoka Solar	solar	Anoka County, MN	3.375	2018	2043	Connexus contracted
Anoka Storage	battery storage^	Anoka County, MN	6	2018	2043	Connexus contracted
Athens Solar	solar	Isanti County, MN	6.625	2018	2043	Connexus contracted
Athens 1 Storage	battery storage^	Isanti County, MN	6	2018	2043	Connexus contracted
Athens 2 Storage	battery storage^	Isanti County, MN	3	2018	2043	Connexus contracted
Baldwin Renewable Station	solar	Sherburne County, MN	3	2021	2046	Connexus contracted
Stanford Renewable Station	solar	Isanti County, MN	7.25	2021	2046	Connexus contracted

^Lithium-ion, 2-hr (can be used for longer dispatches at lower capacity) battery energy storage.

Table 3. Connexus Energy resource portfolio (assets associated with Connexus bilateral agreements)

Connexus Energy's existing storage resources are dispatched economically by the model as part of the portfolio optimization. In the model, they can charge using energy generated by portfolio resources or using energy purchased from the MISO market proxy; they are allowed to discharge energy to serve load. Energy sales to the market proxy are not allowed.

Connexus Energy's existing solar resources are represented with an hourly annual production profile, based on historic production data. These resources are automatically dispatched according to this pre-determined production profile each year.

Our existing resource portfolio also includes legacy GRE resources. These resources represent historic investments by GRE member cooperatives, including Connexus.[27] GRE's legacy portfolio encompasses natural gas and oil peaking plants owned and operated by GRE ("owned" status in Table 4), along with long-term bilateral contracts, including wind power purchase agreements (PPAs) ("contracted" status in Table 4). Several legacy wind resources are not yet in service; the underlying agreements for these resources were executed prior to Connexus Energy's conversion from member to customer.

Per the Connexus Energy customer contract with GRE, we have a right to 21.7 percent of the attributes (energy, capacity, renewable energy certificates) of legacy GRE resources, including planned wind resources, and we have an obligation to cover 21.7 percent of the costs. This pro-rata assignment of benefits and costs is captured in the resource forecasting model.

[27]Connexus was a member of Great River Energy until January 1, 2023.

Table 4 provides summary data for the legacy GRE resources in Connexus Energy's resource portfolio.

Resource Name	Resource Type	Location	Nameplate Capacity* (MW)	In-Service Date	Contract End Date	Ownership Status
Arrowhead Station	fuel oil	Cook County, MN	18	2009	N/A	owned
Ashtabula II Wind	wind	Griggs, Steele Counties, ND	51	2010	2035	contracted
Buffalo Ridge Wind	wind	Lincoln County, MN	106	2023	2048	contracted
Cambridge Station - Unit 1	fuel oil	Cambridge, MN	25	2007	N/A	owned
Cambridge Station - Unit 2	natural gas^	Cambridge, MN	156	2007	N/A	owned
Deuel Harvest Wind	wind	Deuel County, SD	200	*2023*	2048	contracted
Discovery Wind	wind	McLean County, ND	400	*planned in-service 2026-2051*		contracted
Dodge County Wind	wind	Dodge, Steele Counties, MN	259	*planned in-service 2025-2050*		contracted
Elk River Peaking Station	natural gas^	Elk River, MN	183	2009	N/A	owned
Elm Creek Wind	wind	Jackson, Martin Counties, MN	99	2008	2033	contracted
Emmons Logan Wind	wind	Emmons, Logan Counties, ND	200	2019	2044	contracted
Endeavor I Wind	wind	Osceola County, IA	100	2011	2036	contracted
Lakefield Junction (1-6)	natural gas^	Martin County, MN	488	2001	N/A	owned
Manitoba Hydro Contract	hydro^^	Manitoba/distributed	200	2013	2030	contracted
Maple Lake Station	fuel oil	Maple Lake, MN	20	pre-2007	N/A	owned
Pleasant Valley (1-3)	natural gas^	Mower County, MN	421	2001/2002	N/A	owned
Prairie Star Wind	wind	Mower County, MN	100	2008	2028	contracted
Rainbow Contract^^^	N/A	Delivery to Wright County, MN	368	2022	2030	contracted
Rock Lake Station	fuel oil	Pine City, MN	25	pre-2007	N/A	owned
Spiritwood Station	natural gas	Stutsman County, ND	99	2014	N/A	owned
St. Bonifacius Station	fuel oil	St. Bonifacius, MN	58	pre-2007	N/A	owned
Three Waters Wind	wind	Jackson, Dodge Counties, MN	280	*planned in-service 2026-2051*		contracted
Trimont Area Wind	wind	Jackson, Martin Counties, MN	100	2005	2030	contracted

*Connexus receives 21.7% of energy, (nameplate) capacity, and environmental attributes of each legacy GRE resource, per Connexus' Customer agreement.
^Natural gas peaker plants with fuel oil backup. As of Dec. 2023, fuel oil backup at Cambridge 2 is planned.
^^The Manitoba Hydro (MH) contract is a seasonal diversity exchange; 200 MW of summer capacity is provided to GRE in exchange for 200 MW of winter capacity to MH.
^^^The Rainbow Contract is an energy and capacity contract between GRE and Rainbow Energy Center, LLC (REC); REC purchased Coal Creek Station in 2022. Energy from this contract is delivered to the Dickinson Converter Station in Buffalo, MN, via high-voltage direct-current transmission.

Table 4. Connexus resource portfolio (legacy GRE resources)

GRE's natural gas and oil peaking plants are dispatched economically in the model to serve load (energy sales to the MISO market proxy are not allowed).

The bilateral contracts are all modeled with pre-defined hourly production profiles. The wind profiles are based on historical production. The Rainbow contract is an around-the-clock (24/7) energy contract; i.e., it provides 80 MW per hour for every hour through contract termination in mid-2030.

Future Resource Options – Definitions

The resource forecasting model can leverage a combination of 1) existing resources, 2) future resource options, and 3) (a proxy for) MISO energy market purchases[28] to meet future demand and energy needs. Future options were limited to carbon free resources, given recent changes to Minnesota statute that mandate electric utilities to procure 100 percent of their energy requirements from carbon-free energy sources by 2040. Details of future resource options are shown in (Table 5).

Resource Type	Nameplate Capacity (MW)	Interconnection	Ownership Status	First Available	Total Available
Nuclear	25	Bulk System	PPA	2031	3
Solar	10	Local	Owned	2024	5
Solar	10	Local	PPA	2024	10
Solar	20	Bulk System	PPA	2026	10
Storage	15 MW / 60 MWh	Local	Owned	2025	5
Wind	20	Bulk System	PPA	2027	5
Wind	40	Bulk System	PPA	2028	5

Table 5. Summary data for modeled future resource options

In Table 5, nameplate capacities reflect likely project availability. The model must add the full nameplate capacity for each resource addition to the portfolio; it is not allowed to add partial units.

"Local" solar represents Connexus-owned or contracted assets interconnected to Connexus Energy distribution lines. "Bulk System" solar represents Connexus-contracted assets interconnected with the high-voltage transmission system outside of the Connexus Energy service territory.

"Ownership Status" indicates whether Connexus owns the asset or contracts for the attributes of the asset in the form of a power purchase agreement (PPA).

"First Available" is the year in which the asset is first available to be added to the portfolio by the model. "Total Available" is the maximum number of units by resource type that can be added to the portfolio by the model (e.g., 3 x 25 MW nuclear PPAs can be added to the portfolio, starting in 2031) across the ten-year study horizon.

The "Nuclear" resource represents a PPA with an existing nuclear facility in the region. This resource is first available late in the study period to align with likely market availability.

The "Storage" resource represents lithium-ion, four-hour batteries. Storage is allowed to charge from either the MISO market proxy or portfolio resources. Storage may discharge to serve load; it may not discharge to sell energy to the market proxy.

[28]The resource forecasting model can purchase energy from the "market" in 1 MWh blocks in any hour of the simulation. The energy purchase price is pre-defined by the model user. For Connexus Energy's resource planning model, market purchases are priced off-peak and on-peak blocks ($/MWh). Market energy purchases were capped at ~15 percent of total annual energy needs. On-peak (6 a.m. to 10 p.m., weekdays) and off-peak (all other hours) energy purchases.

Future Resource Options – Pricing

Future resource options operational and financial characteristics were developed using a combination of publicly available industry data, asset performance data, and subject matter expert insights.[29] Table 6 shows annual PPA pricing ($/MWh) assumptions for contracted solar, wind, and nuclear resource options. Tiered pricing reflects a range of project availability.

Resource Type (Nameplate Capacity)	PPA Pricing ($/MWh) 2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Solar PPA, Local, 1st Tier Pricing (10 MW)	$ 50	$ 49	$ 48	$ 47	$ 46	$ 45	$ 44	$ 43	$ 43	$ 42
Solar PPA, Local, 2nd Tier Pricing (10 MW)		$ 54	$ 53	$ 52	$ 51	$ 50	$ 49	$ 48	$ 47	$ 46
Solar PPA, Bulk System, 1st Tier Pricing (20 MW)			$ 53	$ 52	$ 51	$ 50	$ 49	$ 48	$ 47	$ 46
Solar PPA, Bulk System, 2nd Tier Pricing (20 MW)				$ 53	$ 52	$ 51	$ 50	$ 49	$ 48	$ 47
Wind PPA (20 MW)				$ 38	$ 39	$ 40	$ 41	$ 42	$ 43	$ 44
Wind PPA (40 MW)					$ 40	$ 41	$ 42	$ 43	$ 44	$ 45
Nuclear PPA (25 MW)								$ 48	$ 50	$ 52

Table 6. Modeled future resource options: details on PPA pricing assumptions ($/MWh)

Pricing assumptions for future resource options modeled as Connexus-owned ("self-build") assets are shown in Tables 7 and 8.

Resource Type (Nameplate Capacity)	Capital Cost ($/kW-installed) 2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Solar Self-Build, Local (10 MW)		$1,090	$1,068	$1,046	$1,025	$1,005	$985	$965	$946	$927
Storage Self-Build, Local (15 MW / 60 MWh)		$814	$792	$771	$750	$730	$710	$691	$672	$654

Table 7. Future resource options – (overnight) capital costs, owned assets ($/kW-installed)

Resource Type (Nameplate Capacity)	Fixed Operation & Maintenance Cost ($/kW-yr) 2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Solar Self-Build, Local (10 MW)		$17	$16	$16	$16	$15	$15	$15	$14	$14
Storage Self-Build, Local (15 MW / 60 MWh)		$29	$28	$27	$27	$26	$25	$25	$24	$23

Table 8. Future resource options – fixed O&M costs, owned assets ($/kW-year)

In Tables 7 and 8, pricing assumptions are listed for the first year available, by resource, through the final year of the study period (2033).

[29]Industry references for self-build future resource option pricing includes the National Renewable Energy Laboratory (NREL) 2022 Annual Technology Baseline and Q1 2022: US Solar PV System and Energy Storage Cost Benchmarks study. Wind pricing escalation assumptions were informed by the Department of Energy (DOE) Office of Energy Efficiency and Renewable Energy (EERE) 2022 Land-Based Wind Market Report. Of note: pricing assumptions were set in early 2023; between late 2022 and late 2023, market pricing for new resources has seen uplift on the order of 20-30 percent in many instances with a variety of drivers.

Future Resource Options – Operational Details

Each new solar power purchase agreement (PPA) or self-build solar asset is modeled with a user-defined annual hourly generation profile that has an equivalent annual capacity factor of 21.2 percent in year one of operation. The profile shape and capacity factor are based on average actual performance of single-axis solar facilities currently under contract by Connexus Energy. The shape of the hourly profile is static from one year to the next. The available capacity and energy from each solar PPA or self-build solar asset are decremented each year by 0.5 percent to reflect asset degradation over time.[30]

Each new wind PPA is modeled with a user-defined annual hourly generation profile that has an equivalent annual capacity factor of 40.4 percent in all years of operation. The profile shape is based on average historical performance from wind resources in Connexus Energy's portfolio. The capacity factor is informed by historic performance and industry averages for new wind facilities in the Midwest.[31] The shape of the hourly profile is static from one year to the next.

Each new nuclear PPA is modeled as an around-the-clock (24/7) energy resource. For example, if the model adds a 25 MW nuclear PPA to the portfolio, that PPA will provide 25 MW of energy in every hour for the remainder of the study horizon (through 2033).

Each new battery energy storage resource was modeled with an 85 percent roundtrip efficiency and with the capability to fully charge and discharge between 0 MW and 15 MW (up to 60 MWh). Battery augmentation over time is assumed; no battery degradation is modeled.

Future Resource Options – Capacity Accreditation

Each year, MISO "accredits" planning resource capacity based on each resource's historical availability to serve load during MISO system coincident peaks.[32] New resources are assigned a class average accreditation rate by resource type, which is converted into accredited MWs by season. For example, a 10 MW solar array in Connexus Energy's portfolio may be accredited at a rate of 0.5 for the summer season. The resultant 10 MW x 0.5 = 5 MW of summer accredited capacity can be counted towards the Connexus summer capacity obligation for the subsequent MISO planning year.[33]

In the model, each future resource option is assigned seasonal capacity accreditation factors, which are taken into consideration for portfolio optimization. Table 9 shows the capacity accreditation assumptions by future resource option type, season, and year.

Wind, storage, and solar accreditation trends reflect MISO projections for the future resource mix in the region.[34] In particular, distributed solar adoption is forecast to grow over the coming decades, which will shift net peak load hours to occur later in the day, especially during the summer season.

[30]Rate of degradation is industry standard assumption. See NREL source from 2015: Overview of Field Experience - Degradation Rates & Lifetimes (Presentation), NREL (National Renewable Energy Laboratory).
[31]See DOE EERE 2022 Land-Based Wind Market Report: https://www.energy.gov/sites/default/files/2022-08/land_based_wind_market_report_2202.pdf.
[32]Wind resource accreditation accounts for both individual resource performance and overall wind fleet saturation and performance. See MISO's PY 2023-2024 Wind and Solar Capacity Credit Report for additional details: https://cdn.misoenergy.org/2023%20Wind%20and%20Solar%20Capacity%20Credit%20Report628118.pdf.
[33]The MISO planning year runs June 1 through May 31.

	Seasonal Capacity Accreditation Factors									
Base Case Summer	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
New Solar	0.70	0.68	0.62	0.55	0.45	0.35	0.25	0.23	0.23	0.22
New Wind				0.16	0.16	0.16	0.16	0.16	0.16	0.15
Nuclear								0.97	0.97	0.97
New Storage		0.80	0.81	0.81	0.82	0.82	0.83	0.83	0.84	0.84
Base Case Fall	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
New Solar	0.40	0.40	0.39	0.39	0.38	0.38	0.37	0.37	0.36	0.36
New Wind				0.21	0.21	0.21	0.21	0.21	0.21	0.21
Nuclear								0.97	0.97	0.97
New Storage		0.80	0.81	0.81	0.82	0.82	0.83	0.83	0.84	0.84
Base Case Winter	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
New Solar	0	0	0	0	0	0	0	0	0	0
New Wind				0.35	0.35	0.35	0.34	0.34	0.34	0.34
Nuclear								0.97	0.97	0.97
New Storage		0.80	0.80	0.81	0.81	0.81	0.82	0.82	0.82	0.82
Base Case Spring	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
New Solar	0.50	0.50	0.50	0.50	0.50	0.50	0.49	0.49	0.49	0.49
New Wind				0.12	0.12	0.12	0.12	0.12	0.12	0.12
Nuclear								0.97	0.97	0.97
New Storage		0.80	0.80	0.79	0.79	0.78	0.78	0.77	0.77	0.76

Table 9. Future resource options seasonal capacity accreditation factors

Planning Reserve Margin Requirement

As a member of MISO's power pool,[35] Connexus Energy has an obligation to ensure the availability of a certain amount of capacity (MWs) to the pool each season for each planning year. This capacity obligation is called a planning reserve margin requirement or PRMR. At a high level, the PRMR is calculated using a forecast of Connexus load and a MISO-determined planning reserve margin or PRM.[36] The load forecast is designed to reflect future load needs under average conditions. The PRM is a capacity "cushion" to ensure that load across the MISO system can be served even under extreme conditions. The resultant seasonal PRMR is the amount (MWs) of capacity Connexus must have available per season for a specific planning year.

MISO's 2023-2024 PY seasonal PRM percentages—7.4 percent for summer, 14.9 percent for fall, 25.5 percent for winter, and 24.5 percent for spring[37]—were used for each year of the study.

[34]See MISO's 2022 Regional Resource Assessment: [MISO Report Template (misoenergy.org)](misoenergy.org).

Energy Market Prices

The MISO energy market is represented in the model with a forward price forecast. Energy can be purchased from the "market" by the model to serve load in any time step in 1 MWh blocks. Pricing is defined for peak (6 a.m. to 10 p.m., weekdays) and off-peak (all other hours, plus NERC holidays) periods. The forward price forecast is proprietary; it is informed by broker quotes, historic pricing trends, and other factors. Market energy purchases were capped at 15 percent of total annual energy needs. Market sales are not allowed.

Fuel Prices

Fuels explicitly represented in the model include natural gas and fuel oil. Modeled monthly natural gas prices represent fuel purchases at Ventura Hub. Both natural gas and fuel oil prices are based on proprietary forecasts. Economic dispatch of natural gas and fuel oil generators in the model accounts for the cost of fuel. The cost of nuclear fuel for the nuclear new resource option is embedded in the PPA rate. There are no coal-fired generators explicitly represented in the model.

Regulatory Requirements

The Minnesota Renewable Energy Standard (RES) requires electric utilities in the state to source 20 percent of energy for retail sales from renewable sources in 2020, 25 percent beginning in 2025, and 55 percent beginning in 2035.[38] Minnesota also recently enacted a carbon-free standard (CFS), which similarly requires electric utilities to source a certain percent of retail sales from carbon-free resources (existing nuclear facility qualify as carbon-free; existing nuclear is not defined as a renewable resource in Minnesota statute). The carbon- free standard threshold for electric cooperatives in 2030 is 60 percent (compared to 80 percent for investor-owned utilities); all electric utilities in Minnesota must source 90 percent of energy for retail sales from carbon-free sources beginning in 2035 and 100 percent beginning in 2040. Model constraints reflect RES requirements and rules, including the four-year bank for renewable energy certificates.[39] A post-simulation check was performed to ensure CFS compliance starting in 2030.

Sensitivity Case Inputs

The assumptions described in preceding sections were used to build the base case. We also included "change" cases or sensitivities in the model, in which one or two key input variables were altered per case to isolate the effects of specific future conditions (e.g., high energy market prices) on the optimal portfolio selected by the model. The key assumptions for the change cases are shown in Table 10. While the exact conditions that would produce materially different portfolio outcomes are not known, we can leverage market insights and subject matter expertise to help identify probable and high-impact future scenarios. Input from our Board, along with stakeholder feedback, shaped the set of sensitivities used for this resource plan.

[35]GRE serves as the MISO Market Participant on behalf of Connexus.
[36]See MISO Business Practice Manual 11 (Resource Adequacy) for additional details on PRMR determination: https://www.misoenergy.org/legal/rules-manuals-and-agreements/business-practice-manuals/.
[37]See MISO 2023/24 PY PRM and Local Reliability Requirements - Final Results.
[38]See Minnesota state statute section 216B.1691 for RES and CFS details: Sec. 216B.1691 MN Statutes.
[39]See Minnesota Renewable Standard: Utility Compliance report: 230009.pdf (mn.gov).

Resource Forecasting – Modeling Methodology

Industry standard methods informed our use of resource forecasting models in the development of our plan. The following section provides brief notes on model simulation settings and methodology.

Simulation Settings

Once the model build was completed, simulation settings were selected. These settings dictate treatment of time-series inputs,[40] end effects,[41] unit commitment, and planned and forced generator outages, for example. Settings were selected to balance the need for detailed results with the potential for increased model runtime.

Case Name	Key Assumption/s
High EV Adoption	Increased % of EV passenger vehicle purchases to 35% by 2033
High Solar Adoption	Increased % residential member rooftop solar adopters to 30% in 2033
High Solar Pricing	Increased prices by factor of 1.25x for solar PPAs and 1.1x for solar self-build
High Wind Pricing	Increased PPA prices by factor 1.25x
High Nuclear Pricing	Increased PPA prices by factor 1.5x
High Market Pricing	Increased both energy market and natural gas prices by 2x
Low Solar Capacity Credit	Decreased MISO capacity accreditation for existing and new solar by 0.3x to 0.1x

Table 10. Modeled "change" cases (sensitivities)

Modeling Methodology

The base case model was first run "open," i.e., without limitations on new resource additions. This run provides a point of reference to help ensure the model constraints are not so strict that they materially bias the results.

After results from this "open" run of the base case were validated, constraints were applied to new resource additions, and the base case was re-run. Modeled constraints on new resource additions reflect actual planning considerations, including risk management and supply chain limitations. Constraint assumptions are provided in the "Total Available" column of Table 5 (summary data for modeled future resource options).

Once the "constrained" base case results were validated, the "change" cases or sensitivities were simulated and results validated. In each of the base case and change case runs, the maximum number of new storage resource additions (5 x 15 MW/60 MWh batteries) was added to the portfolio by the model optimization. To examine the bounds of future outcomes, we removed storage as a new resource option and re-ran all cases. While a future without storage is unlikely, a future with less storage than the model is consistently selecting is probable, given the artificial bias from placing all resources and load at the same node as the storage. The total set of results, from runs with and without storage, better inform ultimate plan formulation.

Other methodologies and/or models may be employed in resource planning to examine portfolio risk (e.g., stochastic models) and/or to take a more granular look at the system or specific trends (e.g., production cost

[40]The model offers different options for treatment of time-series inputs, e.g., a monthly price forecast for market energy purchases or an hourly load profile. The "typical weeks" setting was used for our modeling. This option condenses hourly model inputs into representative seven-day profiles for each month of the ten-year horizon.
[41]"End effects" address the potential to bias the model towards new resources with distributed costs (e.g., power purchase agreement) and against a new resource with a large up-front capital cost (e.g., self-build solar). End effects were primarily addressed via model-calculated annualized economic carrying charges for capital projects.

models or distribution system analysis tools, including capacity hosting models). These types of models were not used in our resource planning process. We may leverage these tools in future resource planning cycles, contingent upon our planning needs.

Resource Forecasting – Model Outputs

Each model iteration ("run") produces a distinct set of outputs. Key outputs include resource additions, total portfolio costs, total costs by resource, total system capacity, energy (generated) by resource, total emissions, emissions by resource, storage charge and discharge, and energy market purchases. In combination, these results tell the story of each portfolio built by the model. The following sections summarize case results for resource additions, market energy purchases, and natural gas generation.

Base Case – Detailed Resource Additions

Resource additions in base case runs with and without storage are shown in Tables 11 and 12.

In the base case run with storage, the model adds the maximum amount of storage as soon as constraints allow (one 15 MW unit of storage is first available in 2025, two units per year are available beginning in 2026). When the model cannot add storage, it increases solar and nuclear additions.

In both runs, there is a large influx of new resources in 2031. This is driven by the August 2031 expiration of the Rainbow Energy Contract, a legacy GRE bilateral contract from which Connexus Energy gets 80 MW of capacity and 80 MW of energy around-the-clock (24/7).

Base Case w/Storage	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Solar								30 MW Local Solar		
								40 MW Bulk System Solar		
Nuclear								25 MW Nuclear PPA		
Storage		15 MW 4-hr Storage	30 MW 4-hr Storage	30 MW 4-hr Storage						
Total Annual Additions	**0 MW**	**15 MW**	**30 MW**	**30 MW**	**0 MW**	**0 MW**	**0 MW**	**95 MW**	**0 MW**	**0 MW**

Table 11. Base case with storage annual resource additions by resource type (MWs)

Base Case w/o Storage	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Solar	10 MW Local Solar	20 MW Local Solar		10 MW Local Solar	20 MW Local Solar					
					20 MW Bulk System Solar			40 MW Bulk System Solar		
Nuclear								75 MW Nuclear PPA		
Storage										
Total Annual Additions	**10 MW**	**20 MW**	**0 MW**	**10 MW**	**40 MW**	**0 MW**	**0 MW**	**115 MW**	**0 MW**	**0 MW**

Table 12. Base case without storage annual resource additions by resource type (MWs)

All Cases – Total Annual Resource Additions

Total annual resource additions by case are presented in Table 13. One evident trend is the concentration of resource additions in 2031. As discussed in the previous section, the model is adding enough resources to make up for the expiration of the Rainbow Energy Contract, which accounts for approximately one-third of our total energy portfolio and one-fifth of our accredited capacity through August 2031.

All Cases – Total Resource Additions by Type

Total resource additions by type are presented in Table 14. Local and bulk system solar portfolio additions are aggregated in the "solar" column. Key takeaways include:

- » The model adds the maximum allowed storage resources in cases with storage as a new resource option.
- » The model maxes out nuclear resources in most cases when storage isn't available—even when the price of the nuclear contract increases by 50 percent.
- » Most cases include at least 70 MW of solar resource additions. Exceptions occur when storage is available and 1) the shape of the system-wide load profile changes due to electric vehicle (EV) and rooftop solar adoption, or 2) the capacity credit for solar significantly declines, or 3) market energy purchases and natural gas generation costs increase—causing the model to lean less on these resources for peak needs in combination with solar and instead turning to additional nuclear resources.

Case Name	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
Base Case	-	15	30	30	-	-	-	95	-	-	170
Base Case - No Storage	10	20	-	10	40	-	-	115	-	-	195
High EV Adoption	-	15	30	15	-	-	-	45	40	-	145
High EV Adoption - No Storage	10	10	-	30	10	-	60	50	25	-	195
High Solar Adoption	-	15	30	15	15	-	-	-	25	-	100
High Solar Adoption - No Storage	-	-	-	-	-	-	60	25	60	-	145
High Solar Pricing	-	15	30	30	-	-	-	95	-	-	170
High Solar Pricing - No Storage	10	20	-	10	40	-	-	115	-	-	195
High Wind Pricing	-	15	30	30	-	-	-	95	-	-	170
High Wind Pricing - No Storage	10	20	-	10	40	-	-	115	-	-	195
High Nuclear Pricing	-	15	30	30	-	-	-	95	-	-	170
High Nuclear Pricing - No Storage	10	20	-	10	40	-	-	115	-	-	195
High Market Pricing	10	15	30	30	-	-	-	50	10	-	145
High Market Pricing - No Storage	10	20	-	10	40	-	-	115	-	-	195
Low Solar Capacity Credit	-	15	30	30	-	-	-	50	-	-	125
Low Solar Capacity Credit - No Storage	10	30	-	20	60	-	-	135	-	-	255

Table 13. Total annual resource additions by case (MWs)

Case Name	Solar	Wind	Nuclear	Storage
Base Case	70	-	25	75
Base Case - No Storage	120	-	75	-
High EV Adoption	20	-	50	75
High EV Adoption - No Storage	120	-	75	-
High Solar Adoption	-	-	25	75
High Solar Adoption - No Storage	100	20	25	-
High Solar Pricing	70	-	25	75
High Solar Pricing - No Storage	120	-	75	-
High Wind Pricing	70	-	25	75
High Wind Pricing - No Storage	120	-	75	-
High Nuclear Pricing	70	-	25	75
High Nuclear Pricing - No Storage	120	-	75	-
High Market Pricing	20	-	50	75
High Market Pricing - No Storage	120	-	75	-
Low Solar Capacity Credit	-	-	50	75
Low Solar Capacity Credit - No Storage	180	-	75	-

Table 14. Total resource additions by case and resource type (MWs)

All Cases – Natural Gas Generation

Natural gas generators are one of several "dispatchable" resources modeled.[42] Natural gas generation (GWh) varies from one case to the next and across the study period. Natural gas generation as a percentage of total annual energy sales to members ranges from 1 percent to 6 percent. On average, in 2024 and 2025, natural gas accounts for 5 percent of total energy served. This drops to 1.5 percent on average across all runs starting in 2026, when planned legacy GRE wind comes online in the model. Gas generation jumps in 2031 for a few cases and otherwise slowly trends upward to between 1.5 percent and 3 percent in the last year of the study. Figure 16 shows annual natural gas generation by case (GWh). Total emissions by case are not presented in this report but could be extrapolated from natural gas generation trends, as natural gas peakers are the only emitting resource with measurable generation across all cases.

All Cases – Market Energy Purchases

Market energy purchases are also "dispatchable" in the model. Market purchases as a percentage of total annual energy sales to members range from 3 percent to 17 percent across all years and runs. On average, in 2024 and 2025, market energy accounts for approximately 15 percent of total energy served. This drops to 6 percent on average from 2026 to 2030 and ramps back up to around 9 percent for most cases in 2031 and to 10 percent in 2033. Figure 17 shows annual market energy purchases by case (GWh).

[42]The others are 1) fuel oil generators—which typically only operate during high-price periods in the regional energy market, 2) storage—for which discharge patterns are relatively consistent from one case to the next, and 3) energy market purchases—which are covered in the next section. Wind, solar, and other energy contracts are modeled as static production profiles. Excess renewable energy is curtailed at no cost.

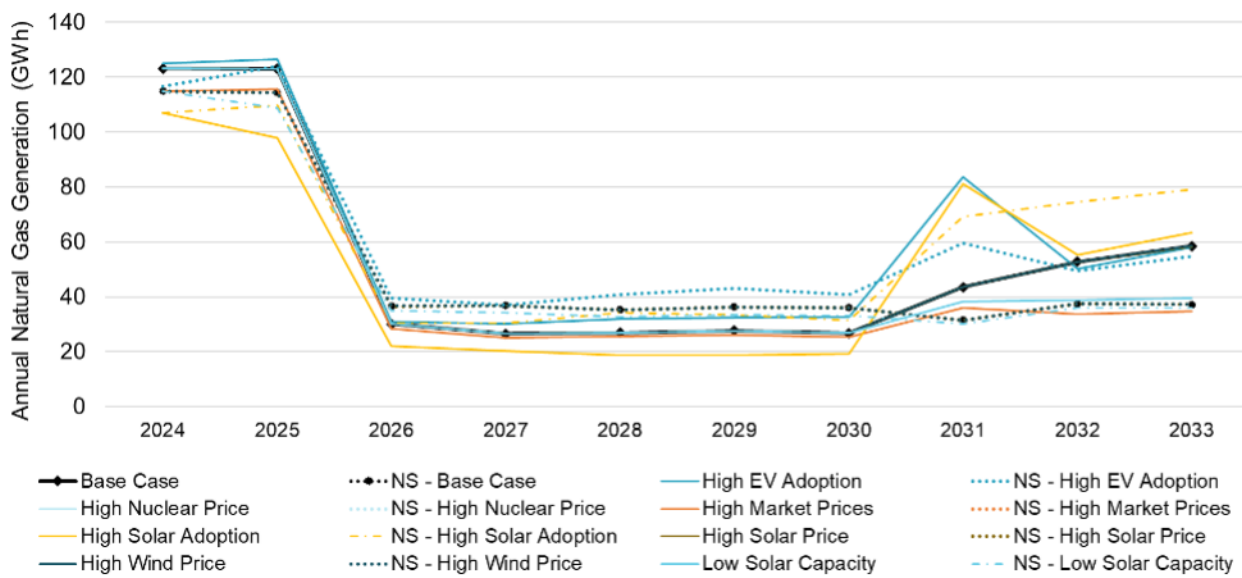

Figure 16. Annual natural gas generation by case (GWh) (NS = no storage option)

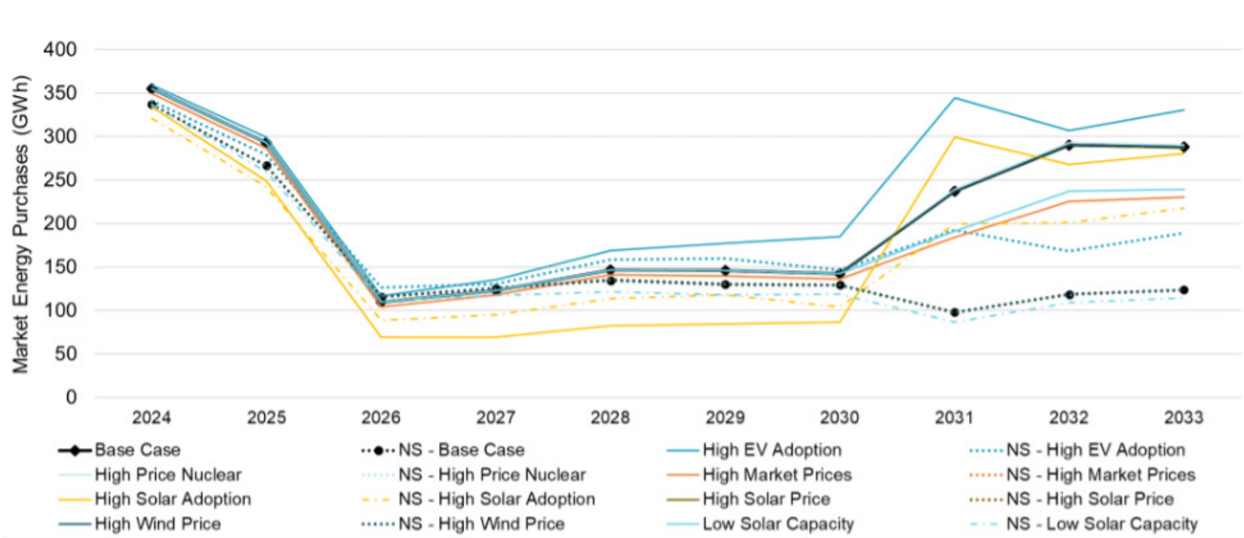

Figure 17. Annual market energy purchases by case (GWh) (NS = no storage)

Summary

The details of resource additions, natural gas generation, and market energy purchases examined together reflect the nuances of optimization decisions in the model. For example, in the high solar adoption case, the model adds 75 MW of storage and 25 MW of nuclear resources to the portfolio. No solar resources are added in this run. The model also leans more heavily on both natural gas generation and market energy purchases to meet demand and energy needs in 2031 than it does in nearly every other case run. The underlying driver for these outcomes is the high rate of rooftop solar adoption, which has the effect of decreasing net load,[43] especially during peak summer hours. Instead of adding solar resources to the portfolio—which would further depress net load during these same peak summer hours—the model looks to a combination of storage, market energy purchases, and natural gas generation to serve summer peaks, which now occur later in the evening.

The insights from resource forecasting modeling help us understand which resource combinations can meet future demand, energy, and capacity needs at least-cost, while complying with regulatory requirements—under a variety of scenarios. While the model represents a simplified version of our system and requires many assumptions about the future, it allows for a standardized approach to evaluation of resource portfolios for planning purposes.

[43]Net load is defined here as [total household load – solar production = net load].

5 - Preferred Plan

The concept of a "preferred plan" is borrowed from the state-mandated integrated resource planning process for investor-owned utilities in Minnesota.[44] The preferred plan lays out the combination of resource additions and retirements the utility projects over the next 15 years to meet statutory requirements, including forecasted demand and energy needs, renewable energy standards, and emissions reduction targets.[45] [46]

Connexus Energy's version of the preferred plan is a ten-year roadmap for portfolio evolution. This roadmap aims to minimize future costs to serve member load and meet changing consumer needs, while complying with MISO market obligations and regulatory requirements for electric cooperatives in Minnesota. Our preferred plan for 2024 through 2033 includes procurement of 100 MW of solar resources, 50 MW of nuclear resources, and 30 MW of four-hour battery energy storage. The planned solar additions are a mix of "local" solar sited within the Connexus Energy service territory and interconnected to Connexus distribution lines and "bulk system" solar interconnected with the high-voltage transmission system. Additionally, Connexus Energy will explore opportunities to include utility-supported development of a portion of the planned solar additions on dwellings for low-income and/or underserved populations. The planned nuclear additions are modeled as offtake agreements with existing, licensed nuclear power generating facilities in the region. The storage is modeled as locally sited, four-hour batteries, which may take the form of distributed assets. Table 15 shows the details of planned annual portfolio additions.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
Solar	10 MW Local Solar	10 MW Local Solar	10 MW Local Solar	20 MW Bulk System Solar	10 MW Local Solar	10 MW Local Solar	20 MW Bulk System Solar	10 MW Local Solar			**100 MW**
Nuclear							50 MW Nuclear PPA				**50 MW**
Storage					15 MW 4-hr Storage			15 MW 4-hr Storage			**30 MW**
Total Annual Additions	**10 MW**	**10 MW**	**10 MW**	**20 MW**	**25 MW**	**10 MW**	**70 MW**	**25 MW**	**0 MW**	**0 MW**	**180 MW**

Table 15. Preferred plan resource additions by year and resource type

The development of the preferred plan was informed by the results of resource forecasting modeling, input from the Connexus Energy Board, and other stakeholders, including Connexus Energy members and Connexus employees and resource and portfolio risk screens.[47] The final plan was checked for compliance with statutory requirements, including renewable and carbon-free energy mandates.

[44]See page 2 of Minnesota House Research Department's summary of Xcel Energy's approved 2020-2034 Integrated Resource Plan: Xcel's Approved 2020-2034 Integrated Resource Plan (mn.gov).
[45]See Resource Planning (IRP)/Public Utilities (mn.gov).
[46]See Minnesota Statute Section 216B.2422 for additional details on integrated resource planning and filing requirements for electric utilities in Minnesota.
[47]For additional details on preferred plan development, see Connexus Energy's Resource Planning Stakeholder Working Group Meeting #3 slide deck: www.connexusenergy.com.

Annual Energy Mix

The energy mix by resource and/or contract type projected for 2023 and as modeled in the preferred plan for 2024 through 2033 is shown in Figure 18.

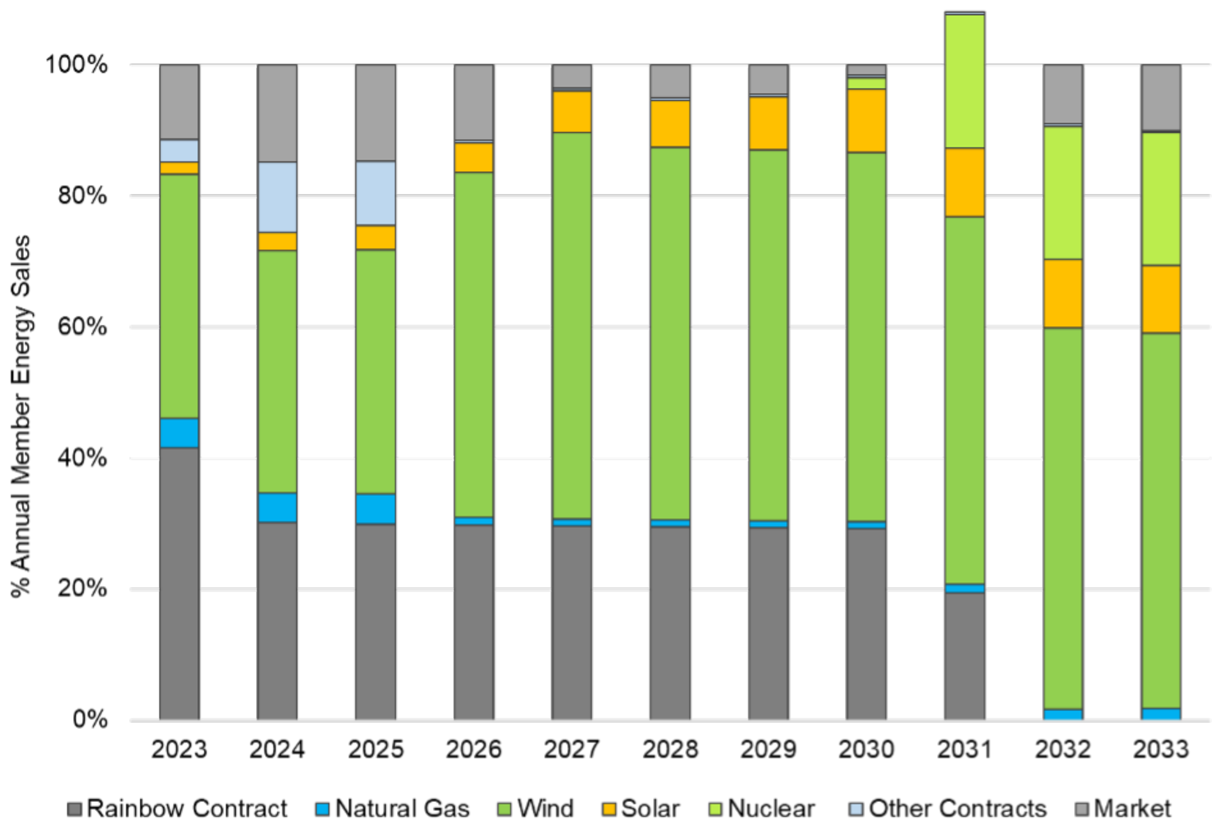

Figure 18. Projected (2023) and modeled (preferred plan, 2024-2033) annual energy mix by resource and/or contract type (as a % of total annual member energy sales)

As background, the energy that is delivered to Connexus Energy substations and subsequently to Connexus members' homes and businesses is *purchased from* the MISO energy market by Connexus Energy. The energy that is generated/provided by the different resource and/or contract types shown in Figure 18 is *sold into* the MISO energy market by or on behalf of Connexus.[48] The revenues from these sales help offset and mitigate the volatility of market energy costs to serve load, i.e., these resources "hedge" our load costs. The "Market" category represents energy purchases from the MISO energy market that are unhedged in the preferred plan.

The "Wind" category includes existing and planned legacy GRE wind resources (PPAs).

The "Solar" category includes both local and bulk system resources. It does not explicitly reflect member rooftop solar additions, which were forecast separately and embedded in the load forecast.

The "Other Contracts" category includes several bilateral, non-resource-specific energy contracts.

Total energy exceeds forecast member needs in 2031, due to a few months of overlap between the Rainbow contract end and the nuclear resource purchase power agreement (PPA) start date in the preferred plan. Actual contract timeframes for a future nuclear energy contract resource may differ.

[48]Local solar, which is included in the "solar" category, is an exception. This solar is interconnected behind the substation meter and has the effect of reducing metered load at the substation.

Annual Renewable Energy (%)

The portion of annual energy sales met with renewable energy resources as projected for 2023 and as modeled in the preferred plan for 2024 through 2033 is shown in Figure 19. The dashed black line in Figure 19 shows the Minnesota state mandate for renewable energy, i.e., the renewable energy standard (RES).[49] The RES requires that electric utilities, including independent cooperatives, source an equivalent of 20 percent of their energy sales from renewable resources, which are defined as solar, wind, biomass, small hydro, and hydrogen if generated from the previously listed sources. In 2025, the RES steps up to 25 percent and in 2035, it increases to 55 percent. Utilities must use renewable energy certificates (RECs) to comply with the statutory requirements. One REC is the environmental attribute associated with 1 MWh of renewable energy generation. RECs have a shelf-life of four years and can be retained in the utility's REC "bank" during this time. Utilities may purchase RECs or use the RECs produced from their owned or contracted resources. RECs are retired each year in the spring to meet compliance requirements for the previous calendar year.

The preferred plan exceeds the renewable energy threshold in all years of the study horizon and positions Connexus Energy for compliance through the next decade.

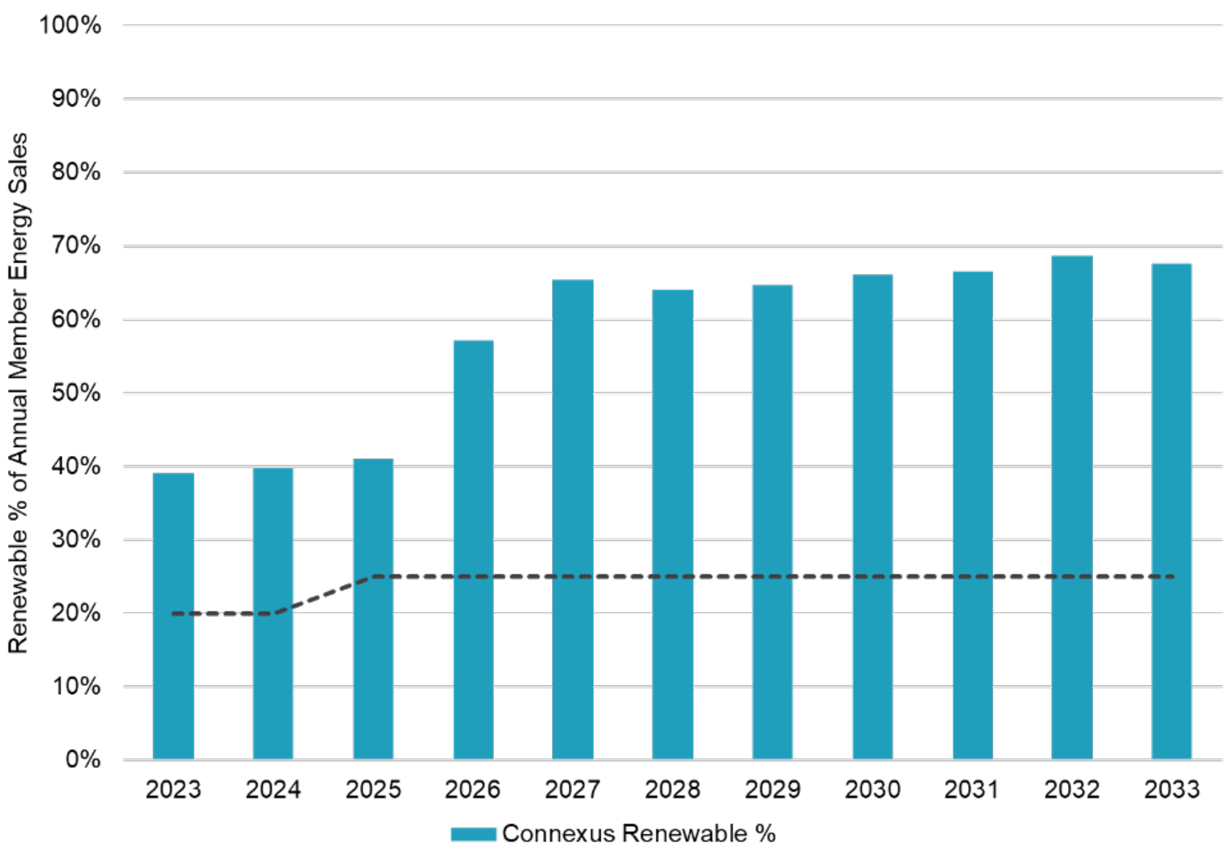

Figure 19. Projected (2023) and modeled (preferred plan, 2024-2033) renewable energy as a percentage of annual member energy sales

[49]See Sec. 216B.1691 MN Statutes.

Annual Carbon-Free Energy (%)

Carbon-free energy projected for 2023 and as modeled in the preferred plan for 2024 through 2033 is shown in Figure 20. The dashed black line in Figure 20 shows the Minnesota state mandate (as a % of energy sales) for carbon-free energy.[50] The carbon-free standard requires that electric utilities, including independent cooperatives, source an equivalent of 60 percent of their energy sales from carbon-free resources starting in 2030, 90 percent beginning 2035, and 100 percent beginning in 2040. Carbon-free resources are defined as solar, wind, biomass, small hydro, and hydrogen if generated from the previously listed sources.

The preferred plan as modeled would exceed the carbon-free energy threshold in 2030 and sets Connexus Energy on a path that aligns with the subsequent thresholds beyond the study horizon.

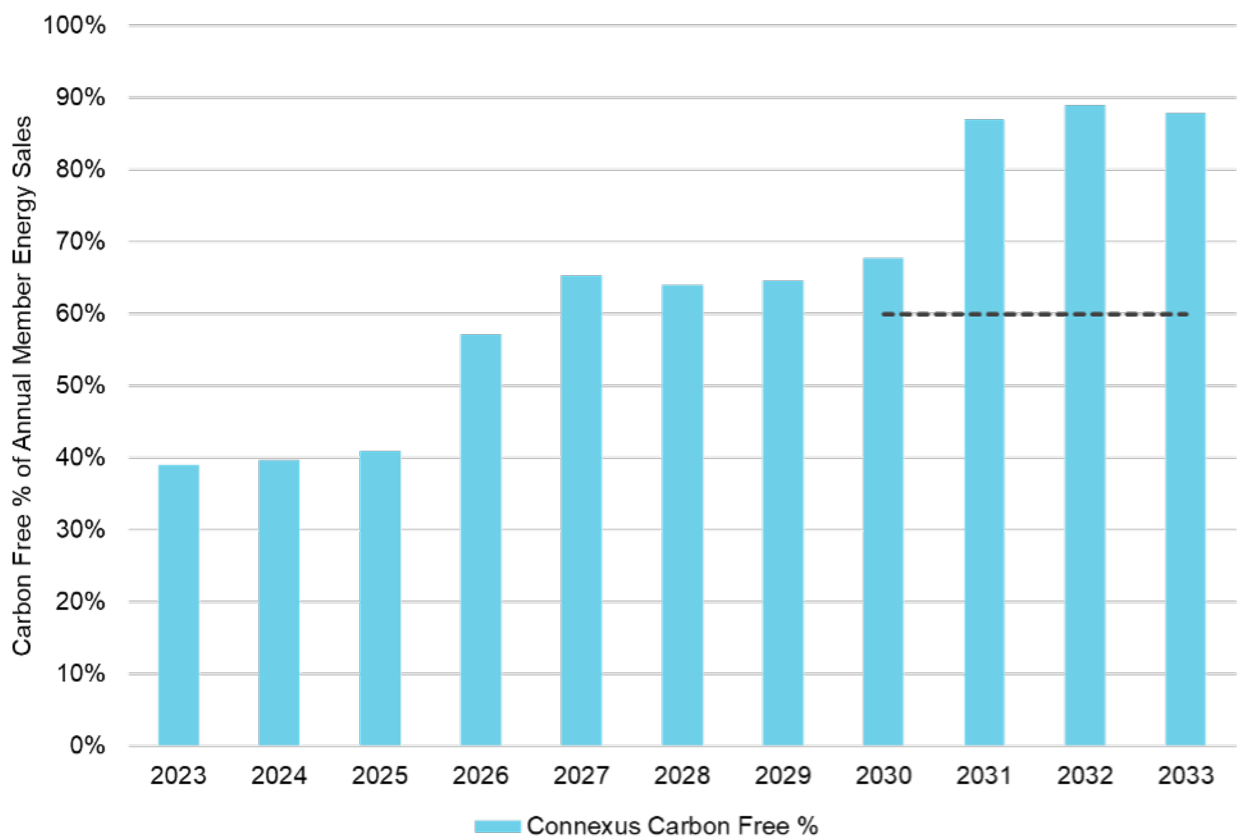

Figure 20. Projected (2023) and modeled (preferred plan, 2024-2033) carbon-free energy as a percentage of annual member energy sales.

[50]See Sec. 216B.1691 MN Statutes.

(Accredited) Capacity Mix

The capacity mix by resource and/or contract type in 2023 and as modeled in the preferred plan for 2030 and 2033 (as snapshots before and after the Rainbow Energy Contract expires) is shown in Figure 21. These MW values represent actual (2023) and projected MISO accredited capacity during the summer season. Accredited capacity reflects the resource's projected availability to provide capacity during periods of peak MISO system demand.

Most of Connexus Energy's accredited capacity comes from legacy GRE natural gas generators. Member-owned or contracted backup diesel generators registered as load modifying resources in MISO are the "demand response" resources shown across the study horizon.

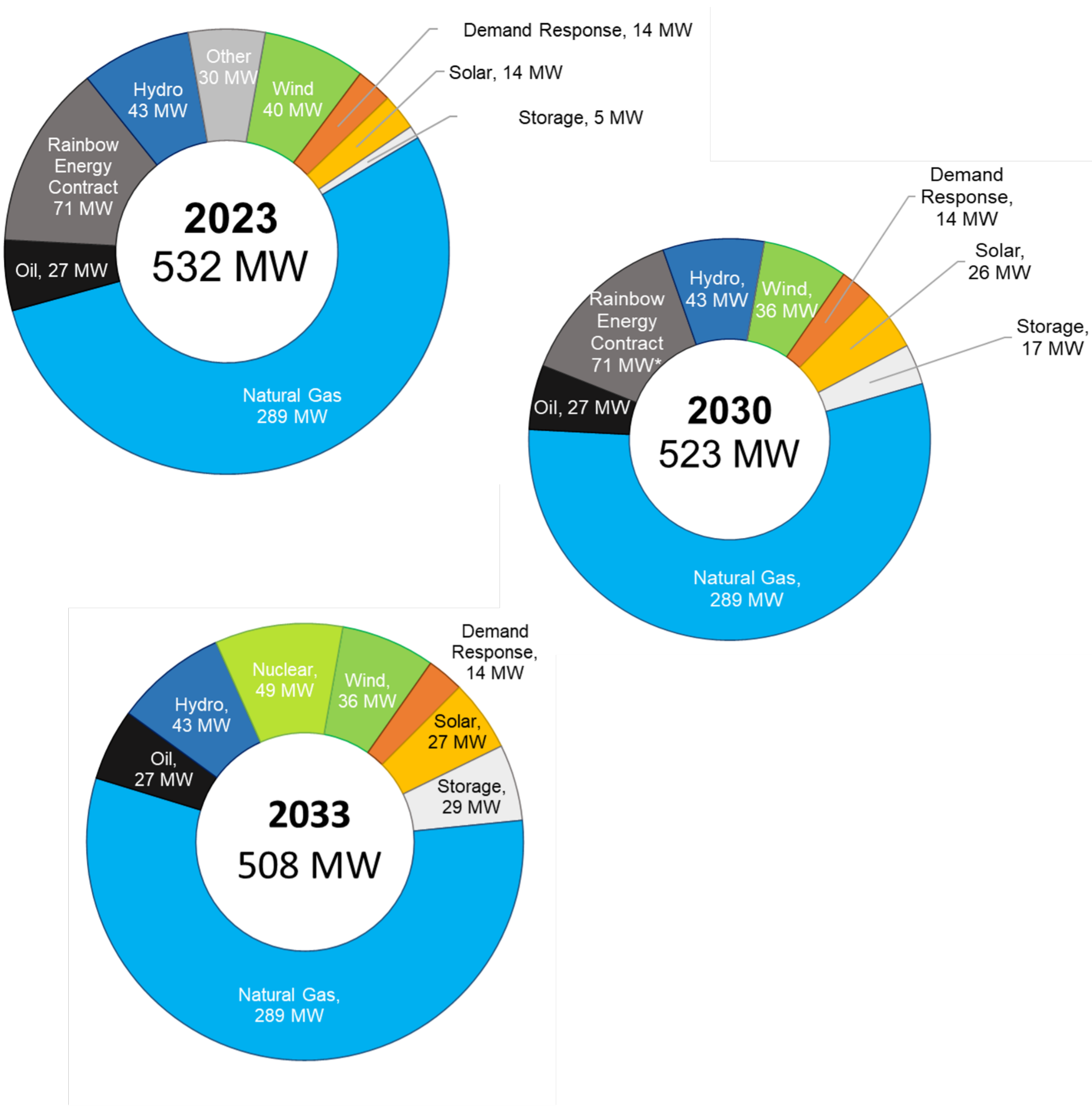

Figure 21. Summer season accredited capacity (2023; preferred plan: 2030, 2033)

6 - Short-Term Procurement Action Plan

To set ourselves on the path to meeting the procurement targets laid out in the preferred plan, we established an action plan for 2024 with three key steps:

Step 1: Issue request for proposal (RFP) for 10 MW of local solar energy arrays:

- RFP to be issued in fourth quarter 2023.[51]
- Vendors to be selected in first quarter 2024.
- Arrays to be commercially operational between fourth quarter 2024 and second quarter 2025.

Step 2: Perform a feasibility assessment for additional 20 MW of local solar

- To be completed by third quarter 2024.
- For assets to be commercially operational between 2025 and 2026.
- To include investigation into distributed solar, which may encompass member solar on single family and multi-family dwellings, with preference for low-income dwellings and/or businesses offering services to low-income members.
- To include identification of viable land for solar development.
- To include initial feasibility studies for distribution interconnection.

Step 3: Identify opportunities for procurement of 20 MW of bulk system solar

- To include identification by fourth quarter 2024 of large (100 MW+) projects with opportunity for small offtake (10-20 MW) by Connexus Energy within upper Midwest.
- Targeting projects currently in MISO generator interconnection queue.
- Targeting project commercial operation date in 2027.

In 2025 or as otherwise directed by the Connexus Energy Board, staff will revisit the preferred plan to ensure that procurement targets continue to align with member needs, compliance obligations, and statutory requirements. Resultant actions may include a plan refresh and/or project scoping for the next full resource planning cycle.

[51]Upon approval of the preferred plan and short-term procurement action plan by the Connexus Energy Board on November 16, 2023, an RFP was issued by National Renewables Cooperative Organization (NRCO) on behalf of Connexus for 10 MW of local solar.

7 - Next Steps

In the next decade, the electric power industry will experience continued transformation as artificial intelligence, smart appliances, residential energy storage, vehicle-to-grid, and other technologies mature and increasingly become accessible to our membership. These changes, along with market and regulatory evolution, and permitting and land use considerations, will present both opportunities and challenges for planning our future power supply portfolio and for our business overall.

Our ten-year resource roadmap is a good first step towards ensuring we are prepared for coming changes. Near-term actions to close out the 2023 resource planning process include:

- **Communicate the plan to members and stakeholders** – via the Connexus Energy website, member and stakeholder newsletters, social media, and other channels.
- **Implement the short-term procurement action plan** – including awarding bid/s in first quarter 2024 for 10 MW of local solar for development at identified sites with a target commercial operation date of December 2024.

Next steps in 2024 stem from specific planning needs identified as part of the 2023 planning process, including:

- **Re-evaluate our planning toolkit,** along with our interconnection queue management process for distributed solar and storage in recognition of potential future saturation of feeder capacity on select feeders.
- **Continue study of electric vehicle and rooftop solar adoption** and their impact on system costs, load profiles, distribution system infrastructure, and total resource needs.
- **Form an internal working group to identify key planning challenges and opportunities,** including those related to emerging technologies, with findings to feed into strategic plan development and risk management activities.
- **Identify parties to engage in a discussion of MISO tariff and business practices** regarding treatment of distribution-sited resources across MISO processes.

Appendix A – Acronyms

CFS - Carbon-Free Standard

EV - Electric Vehicle

GRE - Great River Energy

LMR - Load Modifying Resource

MH - Manitoba Hydro

MISO - Midcontinent Independent System Operator

NERC - North American Electric Reliability Corporation

PRM - Planning Reserve Margin

PRMR - Planning Reserve Margin Requirement

PRA - Planning Resource Auction

PV - Photovoltaic (solar)

PY - (MISO) Planning Year

RES - Renewable Energy Standard

RFP - Request for Proposal