2021

INTEGRATED RESOURCE PLAN

Your Energy Partner®

OPPD

Omaha Public Power District

DISCLOSURE

The 2021 IRP is based on the best information available at the time of development and contains forward-looking statements. Future conditions may differ materially from those discussed. OPPD will continually monitor changing conditions and reevaluate outcomes.

Acknowledgement

Resource planning is an ongoing process at Omaha Public Power District (OPPD). By design, the integrated planning process evaluates supply and demand-side options to optimally meet forecasted electrical demands for OPPD's service territory, minimizing cost and maintaining reliability. The planning process aligns OPPD's resources with its Board of Director's Strategic Directives. These are designed to guide efforts to address current and future challenges, mitigate risks, pursue strategic opportunities and optimize service to OPPD's customer-owners. Specifically, the planning process supports the following directives:

Strategic Directive 1: Strategic Foundation
Strategic Directive 2: Rates
Strategic Directive 4: Reliability
Strategic Directive 5: Customer Satisfaction
Strategic Directive 7: Environmental Stewardship
Strategic Directive 9: Resource Planning
Strategic Directive 11: Economic Development
Strategic Directive 13: Stakeholder Outreach & Engagement
Strategic Directive 15: Enterprise Risk Management

OPPD prepares, files and publishes an Integrated Resource Plan (IRP) every five years with the Western Area Power Administration (WAPA) because of OPPD's long-term contract to receive hydroelectric power from WAPA. OPPD expects that the experience gained over the next few years will likely modify the long-term outlook as the industry experiences rapid change. As part of the process, OPPD invited customer-owner participation and directly incorporated feedback. OPPD management and its board of directors value the knowledgeable input, comments and discussion provided by the customer-owners and other stakeholders collected during the process. Beyond this report, OPPD looks forward to continuing the ongoing resource planning process collaboratively with our stakeholders. You can learn more about OPPD's resource planning process here.

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Acronyms

ACM - Assessment of Corrective Measures
ACE - Affordable Clean Energy
BESS - Battery Energy Storage System
BRIGHT - Battery Research Innovation Guided by High-Potential Technologies
BTA - Best Technology Available
CAA - Clean Air Act of 1970
Capacity - Nameplate Capacity
CCCT - Combined-Cycle Combustion Turbine
CCR - Coal Combustion Residual
CCS – Cass County Station
CFS- Cubic Feet a Second
CPP - Clean Power Plan
CO2 - Carbon Dioxide
COD – Commercial Operation Date
CT - Combustion Turbine
CWA - Clean Water Act
CWIS - Cooling Water Intake Structure
DA - Day Ahead Market
DAC - Direct Air Capture
DER – Distributed Energy Resource
DOE - Department of Energy
DR – Demand Response
DSM - Demand-Side Management
E3 - Energy + Environmental Economics
EE - Energy Efficiency
EIA - Energy Information Administration
ELCC – Electric Load Carrying Capacity
EPA - Environmental Protection Agency
EPC - Engineering, Procurement and Construction
EPCRA - Emergency Planning and Community Right to Know Act
ERM - Enterprise Risk Management
ERS - Essential Reliability Services
EV - Electric Vehicles
FCITC - First Contingency Incremental Transfer Capability
FCS - Fort Calhoun Station
FPL - Federal Poverty Level
FERC - Federal Energy Regulatory Commission
GHG – Greenhouse Gases
GREEN - Growing Renewable Energy and Efficiency Now
GWh - Gigawatt-Hour
H2 - Hydrogen
Hg – Mercury

IAP2 - International Association of Public Participation
ICAP – Installed Capacity
IM - Integrated Marketplace
IRP - Integrated Resource Plan
ITC - Investment Tax Credit
JSS - Jones Street Station
kWh - Kilowatt-Hour
kW – Kilowatt
LOLE – Loss of Load Expectation
MATS - Mercury and Air Toxics Standard
MISO - Midwest Independent System Operator
MMBtu - One Million British Thermal Units
MRO - Midwest Reliability Organization
MUD - Metropolitan Utilities District
MWh - Megawatt-Hour
MW – Megawatt
NAAQS - National Ambient Air Quality Standard
NC1 - Nebraska City Station Unit No 1
NC2 - Nebraska City Station Unit No 2
NCS - Nebraska City Station
NDEE – Nebraska Department of Environment and Energy
NDEQ – Nebraska Department of Environmental Quality
NERC - North American Electric Reliability Corporation
NO1, NO2, NO3, NO4 and NO5 - North Omaha Station Units 1, 2, 3, 4 and 5
NOS - North Omaha Station
NOx - Nitrogen Oxide
NPA - Nebraska Power Association
NPDES - National Pollution Discharge Elimination System
NPPD – Nebraska Public Power District
NPRB - Nebraska Power Review Board
NPV - Net Present Value
NRC - U.S Nuclear Regulatory Commission
NREL - National Renewable Energy Laboratory
O&M - Operation and Maintenance
OATT - Open Access Transmission Tariff
OPPD - Omaha Public Power District
PC – Planning Coordinator
PDM – Product Development and Marketing
PHEV - Plug-In Hybrid Electric Vehicle
PPA - Power Purchase Agreement
PRM - Planning Reserve Margin
PTC - Production Tax Credit
PV – Photovoltaic
PWP – Power with Purpose

RC - Reliability Coordinator
RCRA - Resource Conservation & Recovery Act
REC - Renewable Energy Certificate
RES - Renewable Energy Standard
RFP - Request for Proposal
RH BART - Regional Haze Best Available Retrofit Technology
RPS - Renewable Portfolio Standard
RT - Real Time Market
RTO - Regional Transmission Organization
SAIDI - System Average Interruption Duration Index
SAMP - Strategic Asset Management Plans
SCCT - Simple-Cycle Combustion Turbine
SCED - Security-Constrained Economic Dispatch
SCR - Selective Catalytic Reduction
SCS - Sarpy County Station
SD - Strategic Directives
SEC - Securities Exchange Committee
SNCR - Selective Non-Catalytic Reduction
SIP - State Implementation Plan
SO2 - Sulfur Dioxide
SPP - Southwest Power Pool
TRI - Toxics Release Inventory
TRL- Technology Readiness Level
TSCA - Toxic Substances Control Act regulations
TW- Terawatt
TWh- Terawatt hours
UCAP – Unforced Capacity
USACE - United States Army Corps of Engineers
US - United States
WAPA - Western Area Power Administration

1. Executive Summary

Omaha Public Power District's 2021 Integrated Resource Plan (IRP) represents one of the most comprehensive and transformative resource planning studies undertaken in its 75-year history, solving for near-term load growth while providing a planning foundation for achieving the goal of net-zero carbon in the lowest cost manner and without sacrificing reliability or resiliency. The 2021 IRP supports OPPD's mission of providing affordable, reliable and environmentally sensitive energy services to customers.

The 2021 IRP supports the near-term needs of the growing community while fulfilling OPPD's commitment to retire North Omaha Units 4 and 5 from coal and reducing greenhouse gas emissions. The Power with Purpose project, included in the 2021 IRP, includes the region's largest utility-scale solar investments in addition to modern, flexible, firm resources that will provide a foundation of reliability and resiliency that will enable OPPD's transistion to a Net Zero Carbon future.

The Pathways to Decarbonization study, which is the basis of this IRP, includes industry leading modeling approaches and a robust stakeholder engagement process to identify pathways for OPPD's energy portfolio to achieve net-zero. The study highlights the growing role of the electrification in supporting community-wide decarbonization; the need for significant additions of renewable resources, energy storage, energy efficiency, and load flexibility; and the corresponding cessation of coal and reduction of fossil generation. The study evaluated a range of scenarios including load growth, pace of decarbonization, advancements in emerging technology, to identify 'no regret' resource additions throughout the study horizon.

The 2021 IRP outlines Advanced Feasibility Studies to begin in 2022 as OPPD's next steps to evaluate specific actions and opportunities to continue its progress towards decarbonization. A summary of OPPD's Pathways to Decarbonization: Energy Portfolio workshops can be found on OPPDCommunityConnect.com or in this video.

1.1. Introduction

In November 2019, OPPD's publicly elected board of directors approved revisions to OPPD's Strategic Directives, setting a goal for the utility to achieve net-zero carbon by 2050. In support of this goal, OPPD launched its Pathways to Decarbonization Strategic Initiative. As part of this initiative, in 2020 OPPD began work on a broad resource planning effort to identify potential pathways to achieve net-zero along with associated impacts to affordability and reliability. The study takes a holistic approach, considering the impacts of economy-wide decarbonization on the role of the electric utility. Energy & Environmental Economics (E3) was hired to support this analytical work alongside OPPD staff. The 2021 IRP reflects the key findings of this study as well as the next steps and areas requiring further examination.

Between its 2016 IRP and 2021 IRP, OPPD undertook a nearer-term resource planning effort to support emergent growing electric demand. This effort, known as Power with Purpose (PWP), identified 400-600MW of utility-scale solar and up to 600MW of natural gas capacity as the least cost option to serve growing demand while preserving reliability and enabling the repowering of North Omaha Units 4 and 5 from coal to natural gas. These resources are included in OPPD's near-term action plan. However, all of OPPD's resources were evaluated as part of its Pathways to Decarbonization Study.

1.2. Integrated Resource Plan Approach

The 2021 IRP includes the key components of traditional resource planning, including load forecasting, technology forecasting, scenario analysis and least-cost optimization, but also includes studies that extend beyond traditional planning. These advanced studies include an analysis of shifting energy demands across OPPD's service territory, a complex analysis of resource adequacy to ensure there are sufficient resources to serve electric demand under a variety of weather and load conditions, and a resiliency analysis that identifies potential threats related to severe weather events and climate change. The IRP also leverages knowledge gained through OPPD's most recent renewable sourcing activities, including technical grid support capabilities, near-term supply chain logistics and representative transmission interconnection assumptions.

Multi-sector analysis is included in the study and evaluates the impacts of decarbonization across the economy, not just the electric system. This study analyzes how energy consumption may shift across sources within OPPD's service territory to efficiently lower carbon emissions. A key shift is the increasing electrification of end uses such as building heating and transportation. These shifts will cause increased demand on the future electric system. The Multi-Sectoral Study provides a range of scenarios for electric load growth and how that will affect OPPD's future energy portfolio needs.

Resource adequacy is a core requirement for electric system reliability. Failure to maintain the demand balance between supply and demand can result in unexpected brownouts or blackouts of the bulk electric system, which can severely impact the health and safety of our communities. As part of its study, OPPD incorporated industry-leading quantitative approaches to ensure resource adequacy across all of its potential future pathways. This includes methods for simulating the resource adequacy contribution of renewables as they increasingly saturate the bulk electric system over a long-term horizon and ensures that OPPD maintains the right mix of resources to meet customer demand predictably over a wide range of potential weather conditions.

Lastly, OPPD incorporated a review of the resilience of its pathways to certain extreme scenarios, such as extreme summer heat, extreme winter cold, extended periods of low renewables, and extreme localized events. These scenarios consider regional challenges, such as those experienced with Winter Storm Uri in February of 2021, and challenges posed by increasing weather volatility outside of historically observed conditions. OPPD recognizes that, as customers increasingly rely on electricity for their daily lives, it is essential to preserve and strengthen the resiliency of the electric grid.

1.3. Study Highlights

Within the five-year timeframe of the 2021 IRP, OPPD's currently forecasted load obligations are fully satisfied by the Power with Purpose resource additions. The Power with Purpose resource additions have received regulatory approval and are required to support the near-term needs of OPPD's growing communities, while maintaining system reliability and resiliency. The Power with Purpose plan results in significant near-term environmental benefits by enabling the retirement of North Omaha Units 4 and 5 from coal and supplying large amounts of renewable energy.

Over the extended long-term time horizon, OPPD's Pathways to Decarbonization Study provides key insights for the direction of OPPD's energy portfolio and sets a foundation for future decision-making. Specifically, the study confirms that OPPD can maintain affordability and reliability while reducing its dependence on fossil resources. The study identifies commonalities across a range of potential scenarios that are "no regret" and identifies key findings that support OPPD's net-zero decarbonization goal.

1.3.1. Near-Term Actions

The 2021 IRP confirms that OPPD's Power with Purpose plans, which include 400-600MW of utility-scale solar and up to 600MW of natural gas capacity continue to be an important component of OPPD's near-term resource plans. The combination of new utility-scale solar and modernized natural gas enables OPPD to meet its 2014 commitments to cease coal operations at North Omaha Station. OPPD is underway sourcing, procuring and constructing these facilities.

OPPD's sourcing of 400MW to 600MW new utility-scale solar is currently in progress. As part of this sourcing, Nebraska's first utility-scale solar installation, the 81MW Platteview Solar Project, is scheduled to be online in 2023. OPPD remains focused on sourcing the additional PWP utility-scale solar as part of the near-term resource plan.

The 600MW of new, modern natural gas capacity will be met with the addition of the resources at two new power stations: Turtle Creek Station consisting of two simple-cycle turbine (CT) units totaling 450MW and Standing Bear Lake Station consisting of 9 reciprocating internal combustion engine (RICE) units and totaling 150MW. These units will provide the system with fast-ramping flexibility, maintaining reliable operations of the grid as North Omaha Units 4 and 5 are converted from coal to natural gas. The units are intended to provide reliability to the system and are expected to operate at low capacity factors, providing significant emissions reductions when compared to operating North Omaha Units 4 and 5 as baseload coal units. All units are scheduled to be online in 2023.

No additional resources beyond the Power with Purpose assets are required to meet-near-term load obligations. However, OPPD's load growth is always subject to change. Additional load growth above OPPD's load forecast may require additional resources to satisfy capacity obligations of SPP and reliability.

OPPD has identified the need for advanced feasibility studies to support incremental supply and demand side resource decisions supporting decarbonization and will begin these studies in 2022.

Table 1-1 Five-Year Supply-Side Resource Actions

Resource	Nameplate Capacity	Technology	Fuel	Action	Year
BRIGHT	1 MW	Battery Energy Storage	Li-Ion	New Build	2022
Standing Bear Lake Station	150 MW	Reciprocating Internal Combustion Engines	Natural Gas, with Fuel Oil Backup	New Build	2023
Turtle Creek Station	450 MW	Combustion Turbine	Natural Gas, with Propane Backup	New Build	2023
Platteview Solar	81 MW	Photovoltaic Solar	Solar	New PPA	2023
Additional Power with Purpose Solar	up to 519 MW	Photovoltaic Solar	Solar	New Facilities	Ongoing Sourcing
North Omaha 1,2,3	241 MW	Steam Turbine	Gas	Retire	Fall 2023
North Omaha Station Units 4&5	278 MW	Steam Turbine	Coal	Repower to Natural Gas	Spring 2024
Ainsworth PPA	10 MW	Wind Turbine	Wind	PPA Expiration	2025

Table 1-2 Five-Year Demand-Side Action Plan

Program	Description	Action	Year
HVAC Tune up Rebate	Residential incentive to cover a portion of cost to have their HVAC system professionally tuned-up	New	2022
SMB Building Management Systems	Incentive for the installation of a business management system for small and medium business customers	New	2022
Solar Incentives	Residential incentives for the purchase and installation of solar panels	New	2022
Smart Thermostat Expansion	Expansion of eligible manufacturer's smart thermostats units which can participate in OPPD's current Smart Thermostat program	Expansion	2022
Energy Star Appliance Rebates	Residential customer adoption of Energy Star rated appliances through incentives, education, and marketing provided by OPPD	New	2023

Outdoor Commercial Lighting Rebates	Commercial incentive for installation or replacement of outdoor high efficiency lighting	New	2023
Residential Lighting/Controls	Residential incentive for the purchase of high efficiency lighting and lighting controls	New	2023
Smart Thermostat EE	Expansion of current OPPD Smart Thermostat program allowing customer to receive an incentive for the purchase of a smart thermostat without participation in Demand Response program	New	2024
Expanded Eco 24/7 Efforts	Expansion of the current Eco 24/7 offering both in terms expanding offering for smaller customers and available technologies offered as solutions	Expansion	2024
Heat Pump Water Heater Rebates	Residential incentive for the purchase and installation of a heat pump water heater	New	2025
Weatherization Residential Rebates	Residential rebates for the purchase and installation of home weatherization measures such as high efficiency windows and door, insulation, home sealing, etc.	New	2025
Commercial Food Service Rebates	Commercial customer incentives for purchase and installation of high efficiency commercial food service equipment	New	2026

1.3.2. Long-term Horizon

A key finding of the Pathways to Decarbonization Study is that OPPD can achieve net zero while maintaining both affordability and reliability. OPPD identified several optimal pathways in which to reach its decarbonization goals under a variety of scenarios. These pathways share many commonalities including increased energy efficiency, integration of large amounts of new renewable and energy storage resources, and the ultimate cessation of coal generation. The modeling also demonstrated the continued role of firm, dispatchable generation in maintaining system resource adequacy and resilience, enabling the transition.

The pathways results highlight a minimum incremental investment in 1,100MW of solar, 500MW of wind, and 150MW of energy storage resources by 2030 growing to 3,000MW of solar, 3,800 MW of wind, and 800MW of energy storage resources by 2050. These are above OPPD's current PWP solar additions and are considered "no regret," as they are selected to be built across all load and pace of decarbonization scenarios. While resources required by 2030 are more certain than those required by 2050, OPPD will need to continue to monitor the environment and regularly update its plans.

The recent events of Winter Storm Uri highlight the critical role of the electric system and underscore the need for continued focus on system reliability and resilience. OPPD worked extensively to include these aspects in the 2021 IRP. The analysis found that, despite significant investments in renewables and energy storage, firm dispatchable resources will continue to play a central role in supporting the system, especially during extreme conditions. Although these resources are expected to generate less often, it is important that they receive adequate investment to ensure availability when they are needed most.

Cessation of coal generation occurs in all pathways and is required to reach the decarbonization goals. The study indicates that repowering NCS to natural gas may be a cost effective option for reducing near-term emissions while maintaining firm, dispatchable capacity.

All pathways point to a significant transition of OPPD’s energy portfolio. In 2022, OPPD will begin the next steps in its decarbonization journey, building from the 2021 IRP findings with advanced supply and demand-side feasibility studies. These advanced feasibility studies will evaluate further areas of investigation, including more detailed engineering of supporting infrastructure, to enable future decision making.

2. Background

2.1. Company Background

OPPD was created in 1946 under the authority of the Enabling Act as a public corporation and political subdivision of the State of Nebraska (State). The laws of the state provide that OPPD, either alone or jointly with other entities lawfully empowered to do so, may acquire, by purchase, lease or otherwise, and may operate, improve and extend electric properties and facilities and otherwise carry on the business of generating, transmitting and distributing electric power and energy within or beyond the boundaries of OPPD, and may also do such other things as are necessary to carry on a fully integrated electric power business.

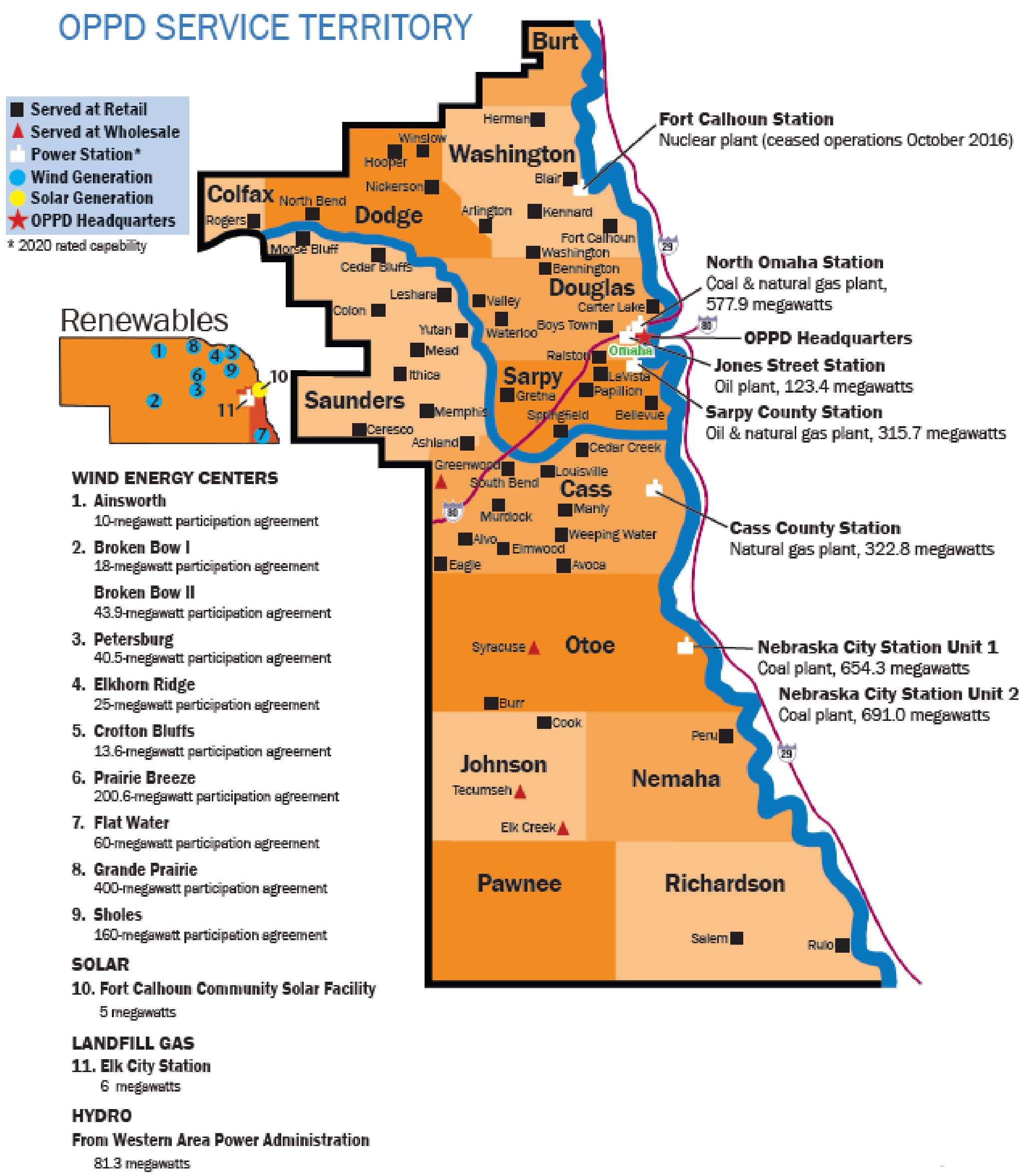


Figure 2-1 OPPD Service Territory

OPPD provides electric service in the city of Omaha, Nebraska and adjacent territory comprising all of Douglas, Sarpy and Washington counties. It also serves portions of Cass, Saunders, Dodge, Otoe, Nemaha, Johnson, Pawnee, Richardson, Burt and Colfax counties. The service territory also includes the community of Carter Lake, Iowa, which is served directly from OPPD's Omaha distribution system. The service area is approximately 5,000 square miles in size, with an estimated population of 849,000 as of December 31, 2020. Omaha, with an estimated population of 486,000, from a 2020 Census, is the largest city in the state. OPPD also serves 47 cities and villages at retail and five municipalities at wholesale.

For the 12 months ending July 31, 2021, the average number of customers served by OPPD was 393,316, which included 344,976 residential, 48,185 commercial, 142 industrial and 13 customers located outside of OPPD's service area (i.e., off-system customers). For the 12 months ending December 31, 2020, OPPD's approximate retail revenue (i.e., excluding wholesale and off-system customers) was derived from 44% of sales to residential customers, 32% from sales to commercial customers and 23% from sales to industrial customers.

2.2. Strategic Directives

In 2015, the OPPD Board of Directors established 15 strategic directives to provide clear and transparent performance expectations for OPPD management. These policies guide the organization's efforts to effectively and efficiently address current and future challenges, mitigate risks, pursue strategic opportunities and optimize services for the utility's customer-owners. Specifically, the board and senior management believe these directives are critical to maintain the value of public power for customers-owners. As a result, the 2021 IRP supports these policies and aligns closely with the following:

SD-1 Strategic Foundation – OPPD's mission is to provide affordable, reliable and environmentally sensitive energy services to its customer-owners. Through its strategic initiatives and broader planning efforts, OPPD will strive to "Lead The Way" it powers the future.

SD-2 Rates - OPPD has established a rate target of 20% below the West North Central Regional average published rates on a system average basis. Accordingly, OPPD uses a low-cost optimization approach to its resource planning.

SD-4 Reliability - Generation and delivery systems must perform at a high level to provide reliable service to customer-owners. This directive identifies the key metrics of unit availability, system average interruption duration index (SAIDI), and requires a reliable transmission and distribution system. As the composition of OPPD's generation portfolio shifts away from fossil generation to renewable generation and other demand-side solutions, the resource planning process remains sensitive to maintaining reliability.

SD-5 Customer Satisfaction – Customer satisfaction is key to OPPD's vision. OPPD listens to and incorporates customer feedback to continually enhance its processes and outcomes in all of its activities, including its resource planning efforts.

SD-7 Environmental Stewardship - Managing its interactions with the environment is essential to OPPD's ability to serve customers, create value for stakeholders and contribute to the well-being of the communities it serves and its employees. The OPPD Board of Directors recognizes the scientific consensus that climate change is occurring and that greenhouse gas emissions, including carbon dioxide, from human activity contribute to climate change impacts. Consequently, the Board of Directors has set a decarbonization goal of net-zero carbon production by 2050.

SD-9 Resource Planning - The Board of Directors recognizes that OPPD will have to adapt to the rapidly changing electric utility environment. As a result, OPPD's resource planning organization will provide the resources and analytical capability to adequately assess OPPD's Integrated Resource Portfolio (or Supply and Demand Portfolio) to ensure reliable, competitive, cost-effective and environmentally sensitive service for our customers.

To attain this directive, OPPD shall:

- Periodically assess, for strategic and integrated resource plans, OPPD's mix of generation assets, demand-side management programs, purchased power agreements and renewable energy resources.
- Utilize multiple scenarios to properly evaluate the range of risks posed by varying future assumptions such as, but not limited to, fuel costs, economic growth, regulations and emerging technologies.
- Ensure all integrated resource strategic plans support and align with OPPD's Strategic Directives.

***SD-11 Economic Development* -** A critical component of a region's growth is low-cost and reliable electricity delivery. As a result, OPPD deploys a low-cost optimization approach to its resource planning to partner to facilitate the growth of current customers as well as attract prospective customers looking to locate in the service territory.

***SD-13 Stakeholder Outreach and Engagement* -** As a publicly owned utility, OPPD is committed to engaging its customer-owners, the community and other stakeholders. We share context with customer-owners for key decisions and projects, including the Integrated Resource Plan, and provide meaningful ways for customer-owners to participate and provide feedback.

SD-15 Enterprise Risk Management – In support of OPPD's Enterprise Risk Management efforts, the IRP team performed stochastic modeling and established well-reasoned, risk-based parameters to identify, understand and mitigate risks.

2.3. Pathways to Decarbonization Strategic Initiative

Amid a changing industry and evolving customer expectations, Omaha Public Power District continues to move toward the future. OPPD has several strategic initiatives underway that will inform and build a foundation for change. Among these is OPPD's Pathways to Decarbonization initiative, which is focused on meeting the goal of being a net-zero carbon producer by 2050 and whose foundation is set by Strategic Directive 7 (Environmental Stewardship). This initiative has significant influence on OPPD's long-term integrated resource planning, but also includes a holistic evaluation of opportunities for environmental stewardship within the community, non-generation operations, and how OPPD supports customers in meeting their individual goals.

As OPPD transforms itself through this period of dynamic change, OPPD also understands that many of the assumptions made in the 2021 IRP will continue to evolve over time as regulations, technology and customers' preferences evolve. In light of this fluid environment, OPPD is committed to being vigilant in its planning efforts to not only make responsible financial choices, but also ensure the choices reflect the desires of our customers and the forward-looking view of our leadership and board of directors.

2.4. Integrated Resource Plan Requirement

An Integrated Resource Plan (IRP) is the planning process for energy resources that systematically evaluates the full range of supply options, including current and new generating capacity, power purchases, energy conservation and efficiency, cogeneration, and district heating and cooling applications, and renewable energy resources to provide adequate and reliable service at a reasonable cost to our customer-owners. This is a business-planning tool that supports informed decision-making around resource planning. The 2021 IRP meets federal regulations on behalf of four additional entities: Peru State College, City of Syracuse, City of Tecumseh and the University of Nebraska at Omaha. These entities are full customers of OPPD and receive energy obligations from WAPA. This planning cooperative also submits annual IRP progress reports to WAPA. OPPD solicits annual updates from these entities to complete the annual progress report.

The content required in the IRP is addressed in Federal Regulation 10 – Energy Chapter III – Department of Energy Part 905- Energy Planning and Management Program (10 CFR 905) and is submitted to the Western Area Power Authority every five years.

2.4.1. IRP Components

Per the requirements of 10 CFR 905, the Integrated Resource Plan (IRP) must comprise several basic components that highlight the systematic planning process, including:

- A load forecast shall be conducted that includes data reflecting the size, type, resource conditions and demographic nature of OPPD using an accepted load-forecasting method.
- Evaluating energy supply - OPPD compares resource options of existing and future supply and demand-side resources based on OPPD's size, type, resource needs, geographic area and competitive situation.
- Supply-side options including, but not limited to, purchase power contracts, conventional and renewable generation options.
- How demand-side options alter the customer's use pattern to provide for an improved combination of energy services to OPPD and the customer.

- Considerations around developing potential resource options including cost, market potential, consumer preferences, environmental impacts, demand or energy impacts, implementation issues, revenue impacts, and their commercial availability.
- Accounting for features of system operations including diversity, reliability, dispatchability and other risk factors, and to support customer goals and schedules.
- Public participation plays a key role in shaping and influencing this planning process and its outcomes. OPPD shall provide ample opportunity for public participation in preparing and developing the IRP, and include descriptions of the stakeholder engagement activities, including how OPPD gathered information from the public, identified public concerns, shared information and responded to public comments.
- An action plan will be created describing specific actions OPPD will take to implement its IRP, including time period covered. This plan must be updated and resubmitted annually. Actions include how OPPD expects to accomplish goals set forth, milestones by which they will be evaluated, and estimated energy and capacity benefits for those actions.
- A brief description of the measurement strategies for options identified in the IRP to determine if objectives are being met.

3. Public Participation

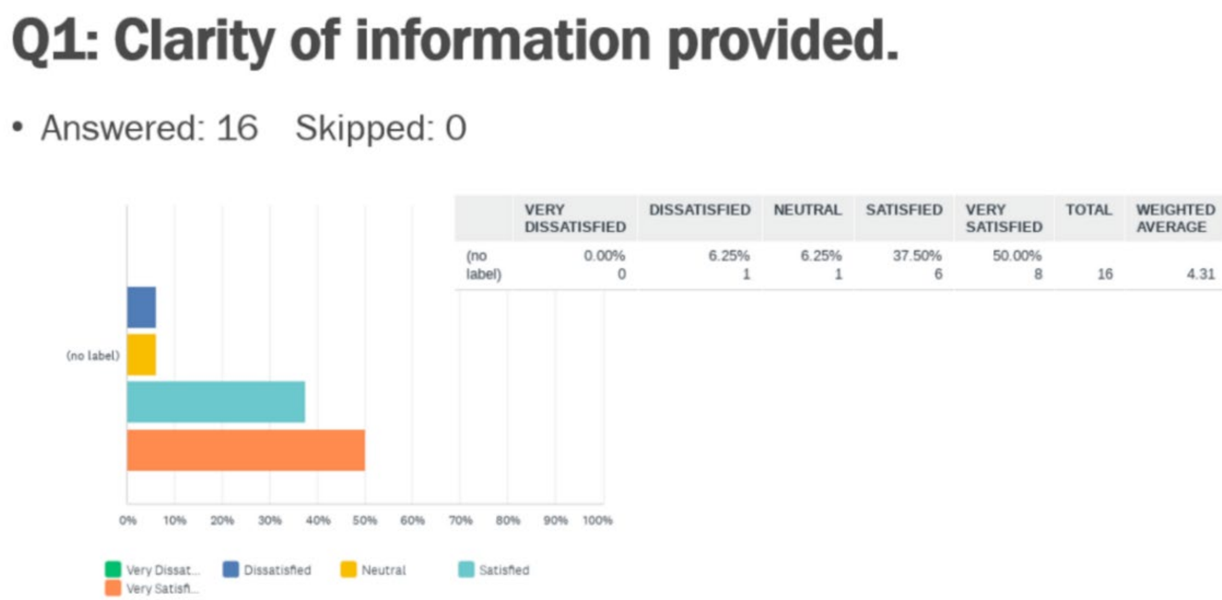
OPPD engages stakeholders in important matters that support our mission to provide affordable, reliable and environmentally sensitive energy services to our customers. OPPD also operates its business around a number of strategic directives, including SD-13 Stakeholder Outreach and Engagement. Through this directive, OPPD is committed to engaging its customers, the community and other stakeholders around key decisions and providing meaningful ways for customer-owners to participate and provide feedback.

Stakeholder outreach and communication for the 2021 Integrated Resource Plan (IRP) closely aligns with and was executed in conjunction with OPPD's Pathways to Decarbonization initiative. In November 2019, OPPD's Board of Directors approved revisions to the environmental stewardship strategic directive, SD-7. The revisions included a goal of net-zero carbon production by 2050. The Pathways to Decarbonization project looked at four specific areas of impact, including OPPD's Energy Portfolio. The energy portfolio work stream resulted in a completed study in December 2021, and provided recommendations for meeting the 2050 goal and supported OPPD's 2021 IRP.

OPPD is a member of International Association of Public Participation (IAP2) and utilizes the organization's engagement spectrum to help with transparency, understanding and consistency around levels of engagement. Levels of engagement for this project varied from Inform and Consult to Involve and Collaborate. This provided opportunities for stakeholders to better understand the study, its outcomes, and to provide opportunities for input and clarification throughout the process.

To build a meaningful plan, OPPD assembled a collaborative team, including the project team, outreach, corporate communications, relationship owners, subject-matter experts and executive sponsors.

Communication and relationships were key to the multi-faceted plan. At each stage, OPPD provided context to remind stakeholders of where the process started, where the process is currently and where it is going. OPPD recognizes that stakeholders may not want to engage at the same level, nor may they agree with the outcome. However, OPPD built a plan with multiple opportunities for stakeholders to be informed, engaged and provide feedback. This approach serves OPPD well, and ensures stakeholders are heard and understand the "why," which enables OPPD to maintain and foster an environment of trust.



	VERY DISSATISFIED	DISSATISFIED	NEUTRAL	SATISFIED	VERY SATISFIED	TOTAL	WEIGHTED AVERAGE
(no label)	0.00% 0	6.25% 1	6.25% 1	37.50% 6	50.00% 8	16	4.31

Figure 3-1 Tracking of Customer Feedback through post Workshop Surveys

Outreach objectives were set for all approaches, from broad communication to discovery sessions and workshops. At a high level, goals varied and included, but were not limited to:

- Ensure all customers had a base understanding of OPPD initiatives, including Pathways to Decarbonization and how it would support the IRP
- Invite and give opportunity for customers and other stakeholders to have a voice and participate in the process of OPPD redefining its energy portfolio and customer offerings
- Create multiple forums for communicating to and gathering feedback from stakeholders
- Seek feedback along the way to help shape the plan
- Loop back with stakeholders to show how feedback was used, or why it was not used
- Provide a deep dive, for those who want it, and provide summaries for those who only desired awareness

Throughout the stakeholder process, OPPD communicated IRP information through social media, OPPD websites, The Wire, customer emails and workshops. Through these efforts, OPPD was able to educate and collect feedback from a number of customer-owners and stakeholders.

OPPD outreach included multiple facets. The sections below will provide an overview of efforts and the results of each.

3.1. Stakeholder Workshops

3.1.1 Discovery Listening Sessions

Stakeholder engagement began in December 2019 with discovery listening sessions. During the 2016 IRP outreach, some of OPPD's most engaged stakeholders had thoughtful feedback on how OPPD could improve the process. OPPD wanted to hear from them about what could be done better this time around and to better understand what success looked like to them.

During these sessions, OPPD learned:

- Stakeholders sometimes feel unaware. They need upfront communication, time to digest information and provide input before final decisions are made.
- The need for a “layered” approach – understanding that not all stakeholders are engaged at the same level, including their own membership.
- Lean on them, help them translate technical information to their organizations, and provide shareable information (i.e., newsletter & social media copy, infographic, etc.).
- Maintain transparency in how feedback was used or not used, assumptions made behind the decisions, and timeline relative to decision points.
- Feedback – be clear on what OPPD is seeking from them.
- Utilize new and “outside the box” communication tactics (i.e. text messaging, board member social media communications, Nextdoor app).
- OPPD is doing better than most utilities at engagement and accessibility of information.
- Stakeholders appreciated the opportunity to be engaged early in the process.

OPPD took this feedback to develop the 2021 stakeholder engagement plan for the energy portfolio. Below are multiple examples of outreach and how feedback was incorporated.

3.1.2 Deep-Dive Workshops

In partnership with E3 (Energy + Environmental Economics), OPPD hosted a series of six virtual workshops, one informative session and a data release to take stakeholders on the Pathways to Decarbonization Energy Portfolio journey, which supports the IRP. The topics for the workshops and sessions included:

- Workshop #1 (April 7, 4-6 pm): Decarbonization Pathways Planning 101
- Workshop #2 (April 28, 4-6 pm): Multi-Sectoral Modeling
- Workshop #3 (May 12, 4-6 pm): Developing Key Assumptions & Scenarios
- Workshop #4 (May 26, 4-6 pm): Developing Modeling Approach
- Data Release (June 18): OPPD released a detailed set of assumptions and scenarios
- Informative Session: (August 4, 4-6 p.m.): Interim Modeling Update
- Workshop #5 (October 27, 4-6 p.m.): Initial Results
- Workshop #6 (December 9, 4-6 p.m.): Final Results

These workshops provided a forum for customers to walk through a series of technical presentations, engage with subject-matter experts about the process, have questions answered and provide feedback on topics presented.

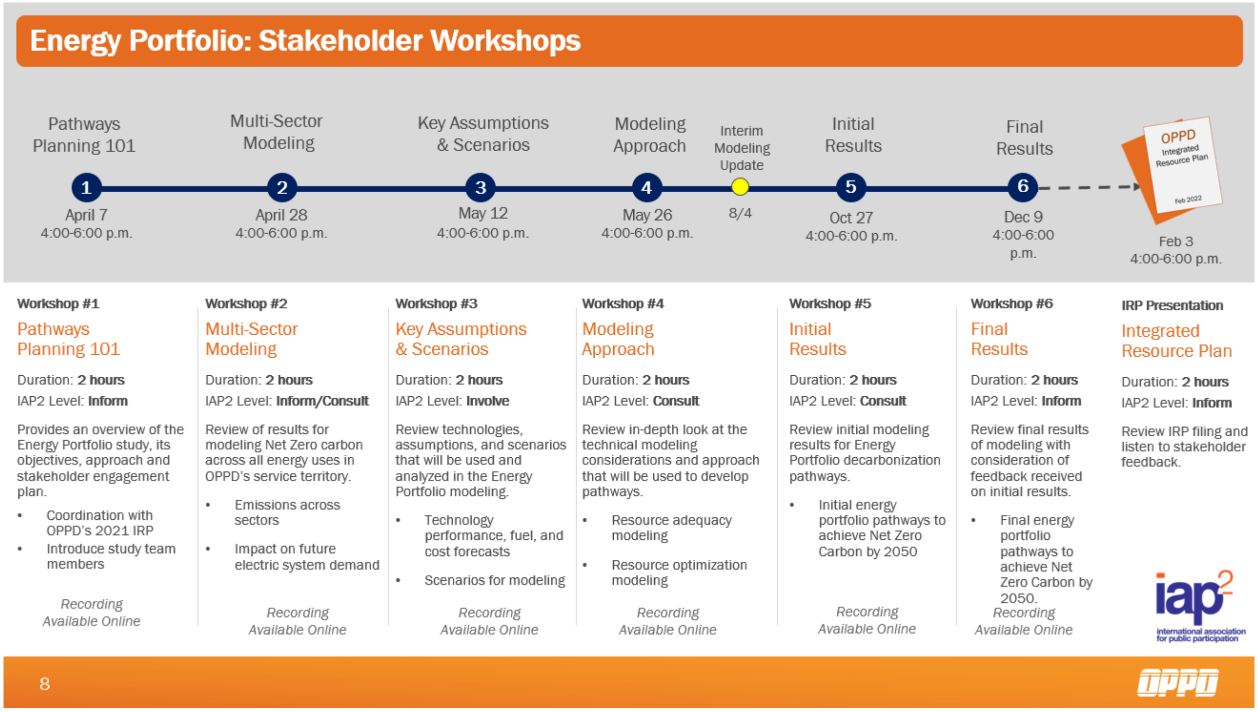


Figure 3-2 Pathways to Decarbonization Energy Portfolio Workshop Timeline

Each workshop was well-attended. The workshops were recorded and posted on OPPD's Community Engagement Platform, OPPDCommunityConnect, following each event.

People who were unable to attend the workshop could watch the recording online, and feedback and questions were accepted online for a period following each workshop.

Figure 3-3 Pathways to Decarbonization: Energy Portfolio Multi-Sector Modeling Workshop

Nearly 100 OPPD customers, including members of the public, advocacy groups, local and state government, universities and colleges, private businesses, and OPPD employees, attended the first workshop. The following workshops became more and more technical so the attendance numbers held steady at about 30 stakeholders.

Interest peaked for the last couple of workshops with more stakeholders interested in learning about the initial and final results with 48 and 70 stakeholders attending the last two workshops, respectively.

In addition to providing these workshop opportunities for external stakeholders, each workshop was first presented to OPPD employees. These workshops were well received with more than 100 employees attending each.

Each workshop provided many opportunities for stakeholders to provide feedback and ask questions. The WebEx technology platform provided ways for stakeholders to ask questions and comments through the Q&A tool, or to speak verbally by raising their hands.

OPPD also utilized Poll Everywhere to give stakeholders the opportunity to provide input through multiple-choice questions, word clouds or Q&A. The virtual workshop format was well received, surveys were collected at the end of each workshop and the majority of respondents were satisfied or very satisfied.

3.1.3 Speakers Bureau

OPPD’s Speakers Bureau offers free presentations to businesses, organizations and schools on a variety of topics. OPPD also responded to stakeholder requests for additional communication and met these stakeholders where they were. Throughout 2021, OPPD presented to many organizations and provided opportunities for additional engagement, input and Q&A.

Figure 3-4 OPPD presenting in the public

3.1.4 IRP Virtual Presentation

The 2021 IRP draft and supporting materials were shared on OPPDCommunityConnect between January 21 and February 20, 2022. Stakeholders were able to review a summary video of the decarbonization workshops for understanding of how that outreach supported the IRP. They also had the opportunity to review the IRP draft and provide feedback and questions during the 30 day comment period, Jan. 21 – Feb. 20, 2022.

After having time to review and digest the draft, external stakeholders are invited to attend a virtual presentation held on February 3, 2022 to provide comments and ask questions. Employees were invited to attend a similar presentation on February 1, 2022. Approximately 80 external stakeholders and 275 employees attended their respective session and participated in feedback and Q & A opportunities throughout the events.

3.2. Electronic Efforts

Electronic efforts were very important for the 2021 IRP outreach, as COVID guidelines turned what would normally be in-person workshops and meetings into online events. OPPD electronic efforts were concentrated on use of its new customer engagement platform, oppdcommunityconnect.com, social media and email campaigns.

OPPDCommunityConnect.com – OPPD's new customer engagement platform is where customers can learn about our goals, concerns and efforts about Pathways to Decarbonization, the IRP and other OPPD projects. In addition to learning more about the projects, customers are invited to share input, insights and ideas with us. Each Pathways to Decarbonization workshop was recorded and posted to this site, and it provided an opportunity for those who were unable to attend the workshop live to view the workshop after the fact, and provide comments, questions and ideas for a specified period following each event. Supplemental materials such as the data release, summary videos and written executive summaries were posted on the site for additional context. At the time of submission, there were approximately 11,700 total visits on the pages that were dedicated to Pathways to Decarbonization and the IRP. On the page dedicated to feedback from the Pathways to Decarbonization workshops and the IRP, the team received more than 100 comments and questions, resulting in excellent engagement from stakeholders.

OPPDtheWire.com – This is OPPD's brand journalism website, and its stories help provide more context and transparency around company efforts, as opposed to more traditional websites. There were two stories in 2021 highlighting the Pathways to Decarbonization initiative and the IRP. The first in April 2021, was about the workshops announcement. The story had 160 page views and 148 unique page views, with an average time on the page of 2 minutes 10 seconds. In December 2021, a second story was published about the Pathways to Decarbonization findings. As of Feb. 21, 2022, there were 112 page views and 101 unique page views on this story, with an average time on the page of 5 minutes 59 seconds.

Social Media –
OPPD promoted the Pathways to Decarbonization Workshops and IRP outreach efforts on social media through paid ads on Facebook, (6) and organic posts on Facebook, Twitter, and LinkedIn, (75 total at no cost).

- **Highest Reach** (the number of people who saw the ad at least once, estimated): 15,420 *paid*
- **Total Impressions** (The number of times the ads and posts were on screen): 233,896
- **Total Comments** (The number of comments on the ads and posts): 56
- **Total Reactions** (The number of reactions on the ads and posts. The reactions button on the post allow people to share different reactions to its content: Like, Love, Haha, Wow, Sad or Angry): 488
- **Total Shares/Retweets** (The number of shares of the posts/ads. People can share ads or posts on their own or friends' timelines, in groups and on their own page): 272
- **Total Clicks** (The number of clicks on the posts and ads): 4,539
- **Total Link Clicks** (The number of clicks on links within the ad or post that led to specified destinations, such as OPPDCommunityConnect, on or off Facebook): more than 3,250

Figure 3-5 OPPD Social Media Public Engagement

Email Campaign – OPPD relationship owners sent emails to their contacts inviting them to attend the decarbonization and IRP events. These emails included a PDF invitation, which they were asked to further share with their contacts and organizations. These emails were sent to many contacts, including elected officials, community leaders and advocacy groups. This group included state senators, congressional representatives, mayors, city council members, county commissioners, area chambers of commerce, customers and environmental partners. Those who attended previous workshops or showed interest in the project via OPPDCommunityConnect also received email invitations to subsequent workshops.

Pathways to Decarbonization VIDEO – A summary video was created to document the content provided in the workshops in an easy-to-understand manner. This video could also be easily shared with organizations so others could catch up on our journey without watching hours and hours of technical content in the workshops. The video was updated throughout the year to include all workshops, and there have been more than 700 views on YouTube.

3.3. Written Efforts

OPPD's written efforts included OPPD's monthly bill-insert newsletter, Outlets, as well as press releases and executive summaries for stakeholders to learn about the process at a glance.

Outlets – This OPPD newsletter is distributed with physical bills and reaches 215,000 customers. It promotes *oppdcommunityconnect.com* as a source for more information and a forum to provide feedback.

Press Releases – The Pathways to Decarbonization and IRP journey were featured in the board meeting press releases along the way. Eleven press releases were sent to 79 unique email addresses for local and national news outlets:

- 69 local newspapers, radio, and television stations & Associated Press-Omaha.
- 10 national/regional publications, including Bloomberg, S&P Global, Platts, Energy Central, Energy News Network/Midwest Energy News and APPA, among others.
- At the time of IRP submittal, there were seventeen total news stories that referenced "OPPD or Omaha Public Power District" and "decarbonization." Of these, 11.8% were positive, 88.2% were neutral and none had a negative sentiment.

Executive Summaries – Following each workshop, executive summaries were created, posted on OPPDCommunityConnect and distributed to stakeholders to share with their constituents, organizations and memberships. The summaries translate technical information (as we heard in the discovery sessions) and provide education for those not interested in joining the technical workshops.

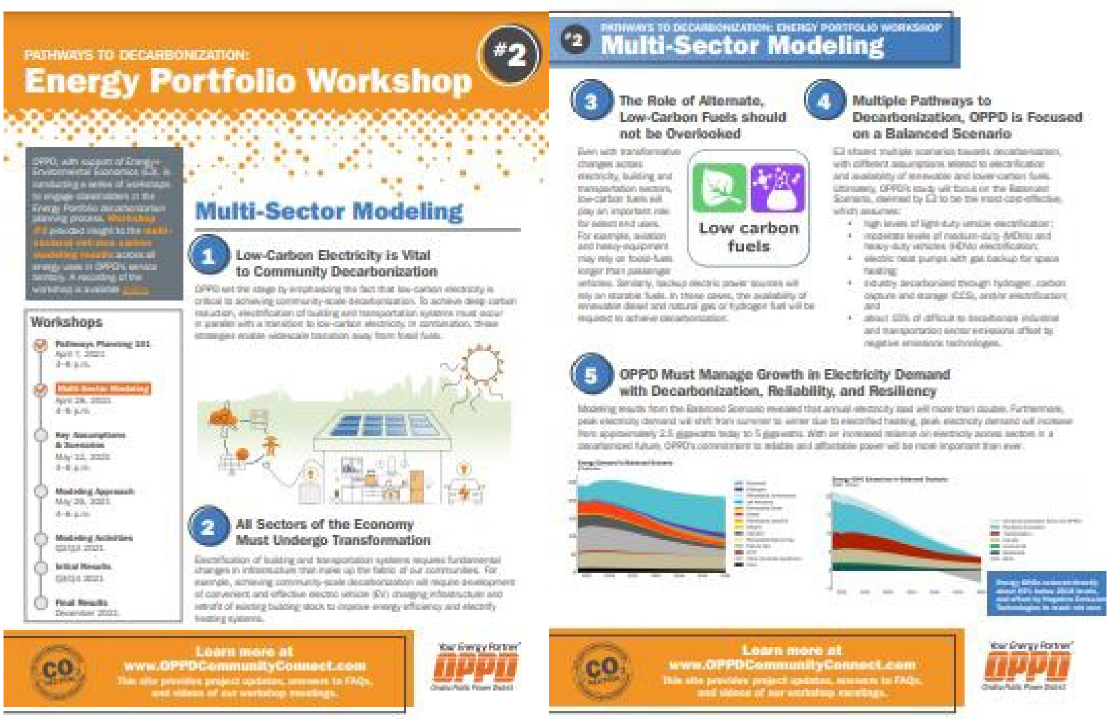


Figure 3-6 Executive Summary Example

Overall, customer expectations are aligned with OPPD’s stated mission of providing affordable, reliable and environmentally sensitive energy services to our customers. This process thoroughly evaluated feasible options, considered stakeholder input and provided the board of directors with a fair, equitable and informed recommendation.

Additionally, the Integrated Resource Plan is a public document, and the public is invited to offer their input on an ongoing basis by visiting OPPDCommunityConnect.com or oppd.com/about/energy-portfolio. The meetings of OPPD’s board of directors are also open to the public, and input is encouraged.

4. Political, Regulatory, and Operational Environment

OPPD plans its system within the context of a larger planning environment and is subject to a myriad of external factors spanning federal, regional and state boundaries. Among these are environmental policy, wholesale electric market dynamics and regional reliability planning considerations. All of these factors are considered as a part of the integrated resource planning process and its impact on economic, environmental and operational outcomes.

4.1. Federal Energy and Environmental Policy

The 117th U.S. Congress started its two-year legislative session in January 2021. Several bills were introduced that could have implications for energy, environment, and tax policy. Below is a more in-depth summary of those issues that can affect OPPD operations.

4.1.1. Tax-Exempt Financing

There have been repeated budget proposals that include provisions that would impose a “cap” on the tax value of municipal bond interest, a surtax on municipal bonds, or other onerous proposals to alter the use of tax-exempt financing. For more than 200 years, state and local governments and governmental entities, including OPPD, have relied on municipal bonds as a means of financing. Interest on these bonds issued by state and local governments (OPPD is a political subdivision of the state of Nebraska) have always been exempt from federal income tax. Historically, Congress has never taxed interest on municipal debt. Furthermore, the existing rules and regulations under the Internal Revenue Code and the Securities and Exchange Commission (SEC) appear sufficient to prevent abuse and have enforcement programs to ensure compliance. OPPD, like other public utilities, utilizes tax-exempt financing to fund the construction of electric generation, transmission and distribution assets as well as other related facilities necessary to provide low-cost, reliable electric service to our customers. Although OPPD will need to continue to adequately plan and serve its customers regardless of any changes to tax-exempt financing, new restrictions on tax-exempt financing of municipal bonds could lead to higher debt-service costs in the future and, therefore, affect the rates paid by OPPD’s customers.

4.1.2. Renewable Electricity Tax Credits

During the 114th Congress, the Consolidated Appropriations Act of 2016 was signed into law. This legislation addressed energy tax issues important to OPPD. The bill extends three renewable power tax credits, including a 2.3 cent per kilowatt-hour wind energy production tax credit (PTC), a 30% solar property investment tax credit (ITC), and a 30% residential energy efficient property credit that can apply to solar electric property. Specifically, the bill extended the PTC for wind energy at expired law levels through 2016 (having expired at the end of 2014). The credit would then be phased out as follows: 80% of credit value for 2017, 60% for 2018 and 40% for 2019. The credit would expire after 2019. The PTC has been important to the growth and development of renewable electricity resources, particularly wind. Although OPPD is a tax-exempt entity and only taxable entities can claim the PTC or ITC, OPPD is able to benefit from the PTC or ITC through PPAs with taxable entities. The taxable entities own the wind energy resources and pass through the PTC or ITC in the PPA. Similar to the PTC, OPPD may benefit from the ITC on solar projects that are part of the Power with Purpose initiative, including Platteview Solar.

4.1.3. Tax Issues

The 117th Congress is considering multiple proposals that would deploy energy tax provisions to pursue climate-related or infrastructure investment policy objectives. For instance, the Senate Finance Committee passed the Clean Energy for America Act. This legislation proposes tax credits for non-EPA house gas (GHG)-emitting electricity generating technologies, with the provisions phasing out once emissions reductions targets are achieved. The legislation also proposes tax incentives for clean fuels (as defined in the bill) and transportation electrification, as well as for building energy efficiency, and would provide various other tax incentives for "clean energy."

The Growing Renewable Energy and Efficiency Now (GREEN) Act (H.R. 7330), would have revised various investment tax credits and production tax credits and made them available to for-profit companies with little to no tax liability and to tax-exempt entities, equally. The bill would replace existing ITCs and PTCs with a technology-neutral tax credit and would allow utilities to elect to receive tax credits as direct payments, including public power utilities.

The Biden administration's "American Jobs Plan" also proposes substantial modifications to energy tax policy. The administration's proposal would expand and extend existing tax incentives supporting renewables, provide incentives for zero-emissions vehicles and electric vehicle infrastructure expand tax incentives for building energy efficiency, and provide various other "clean energy" tax incentives. Tax incentives supporting fossil fuels would be repealed.

Carbon tax/fee

There are numerous bills introduced to implement a carbon tax/fee. Most set a per-ton tax on the carbon dioxide content of leading fossil fuels (e.g., coal, oil, natural gas) upon extraction. These bills would use the funds from the tax/fee for various proposals like dividends back to customers, job training, community assistance and low-income assistance. Some form of this may be included in the Budget Reconciliation package.

Restore Tax-Exemption for Advance Refunding Bonds

In 2017, the ability to advance refund bonds was eliminated in the Tax Cuts and Jobs Act ("TCJA") (P.L. 115-97). Before January 1, 2018, municipal issuers were able to issue single, tax-exempt advance refunding bonds prior to 90 days before call. This critical tool allowed public power utilities to refinance their outstanding debt in order to take advantage of more favorable interest rate environments or covenant terms. Advance refunding bonds frequently provided issuers with the flexibility to lower debt servicing charges that would otherwise be a fixed cost. Legislation has been introduced to restore the tax exemption for advance refunding bonds. This would be beneficial to public power.

4.1.4. Infrastructure/ Energy/ Environmental Legislation

The 117th Congress in its current legislative session advanced a bipartisan infrastructure package and a budget reconciliation package. These packages have elements with provisions of interest to the utility sector and OPPD.

Bipartisan Infrastructure Package

In late 2021, the Senate voted 67-32 to advance the bipartisan infrastructure bill. The bill includes $73 billion to upgrade the nation's power infrastructure to include thousands of miles of new, resilient transmission lines to facilitate the expansion of renewable energy; investment in research and development for advanced transmission and electricity distribution technologies; and, investment in smart-grid technologies that focus on flexibility and resilience The bill also invests in demonstration projects and research hubs for next-generation technologies like advanced nuclear reactors, carbon capture, and clean hydrogen. Additionally, the bill creates a new Grid Deployment Authority. The authority would be a new federal entity to finance and encourage the development of high-voltage transmission lines.

Additional provisions of interest*:*

- $7.5 billion for building out a national network of electrical vehicle charging stations
- More than $50 billion to improve the resiliency of U.S. infrastructure to protect against droughts, floods and other natural disasters, as well as cyberattacks
- $21 billion to clean up polluted areas, including money to reclaim abandoned mines and cap orphaned gas wells
- $65 billion to improve access to broadband internet

OPPD could benefit from these provisions. OPPD will continue to pursue these opportunities as process and other fund distribution mechanisms are better understood.

Budget Reconciliation Package

The House and Senate approved S. Con. Res. 14, which is the $3.5 trillion budget resolution for fiscal year 2022 that instructs relevant committees to report legislation meeting specified entitlement spending and revenue targets. This is the legislative vehicle that will be used to move the "human infrastructure" package, which will include language to address climate change. Instructions given to House and Senate committees would provide funding for various programs including the following:

- A Clean Electricity Payment Program - Clean energy, manufacturing, and transportation tax incentives and grants
- New polluter fees (methane and carbon imports)

- Investments in climate, smart agriculture, and forest management for farmers and rural communities
- Coastal and ocean resiliency programs
- Investments in drought and wildfire prevention and the Department of the Interior
- New consumer rebates for home electrification and weatherization
- Environmental justice and climate resilience
- Investments in federal vehicle fleet and buildings electrification

As explained, this package could significantly affect OPPD operations and customer owners. The proposed legislation appears fluid and the outcome is unknown at the time of this report.

4.1.5. Environmental Legislation

The following includes Environmental Protection Agency rules that have been recently finalized or proposed:

Air Quality and the Clean Air Act Amendments

Greenhouse Gas Regulation - There is uncertainty regarding how the federal government will address greenhouse gas regulation in the coming years. The Environmental Protection Agency (EPA) finalized the Clean Power Plan (CPP) regulations in 2015 to specifically limit greenhouse gas (GHG) emissions from power plants. The CPP was challenged in court and never went into effect. The EPA published a final rule in the Federal Register on July 8, 2019, called the Affordable Clean Energy (ACE) Rule and at the same time repealed the CPP. The ACE rule included emission guidelines for existing electric utility generating units based on reducing GHG emissions by implementing heat rate improvements on the affected coal-fired units. The ACE rule was also challenged in the courts and on January 9, 2021, the District of Columbia Circuit Court vacated the ACE rule, remanding it back to the EPA. While there may still be legal proceedings relative to the ACE rule, EPA has indicated plans to undertake new rulemaking to replace the ACE Rule in the future.

National Ambient Air Quality Standard (NAAQS) for one-hour SO2 - On June 2, 2010, the EPA strengthened the NAAQS for SO_2. Following long delays in issuing the area designations, the EPA was sued and on March 2, 2015, the U.S. District Court for the Northern District of California accepted as an enforceable order an agreement between the EPA and Sierra Club and Natural Resources Defense Council to resolve litigation concerning the deadline for completing the designations. The court's order directed the EPA to complete designations in three additional rounds: the first round by July 2, 2016, the second round by December 31, 2017, and the final round by December 31, 2020. On September 5, 2019, the EPA issued a memorandum with additional guidance concerning the final round of SO_2 NAAQS.

In 2016, during the second round of area designations, air dispersion modeling showed the area surrounding NCS is in attainment with the SO_2 NAAQS. On July 1, 2016, the EPA designated Otoe County as unclassifiable/attainment for the 1-hour SO_2 NAAQS. After four years of ambient SO_2 monitoring near North Omaha Station showed ambient concentrations less than half of the 1-hour SO2 NAAQS, the EPA published the final rule on March 26, 2021, which revised the 2010 1-hour SO_2 NAAQS designation status for Douglas County to Attainment/Unclassifiable.

Regional Haze - OPPD received a regional haze information request from the NDEE on June 5, 2020, with a revision dated August 4, 2020, and a supplement dated September 29, 2020, for use in their preparation of a State Implementation Plan (SIP) submittal for the regional haze second implementation period. The information request asked for a regional haze analysis for NC1. OPPD provided NDEE with an initial response to the information request on November 4, 2020, and a second response on February 17, 2021. In response to a subsequent request for modeling information, OPPD provided a joint response with NPPD to the request on March 31, 2021. OPPD continues engagement with NDEE as the agency works to prepare the Nebraska Regional Haze SIP for submittal to the EPA

Hazardous and Toxic Materials Regulations

Chemical Reporting - The electric utility industry is subject to the Emergency Planning and Community Right to Know Act (EPCRA), the Toxic Substances Control Act regulations (TSCA) and the Resource Conservation & Recovery Act (RCRA), including applicable programs delegated to the NDEQ by the EPA. OPPD conducts environmental audits to monitor compliance with these regulations in conjunction with the proper management and disposal of applicable hazardous, toxic and low-level radioactive wastes.

The four major provisions of the EPCRA are emergency planning, emergency release notification, hazardous chemical storage reporting requirements and toxic chemical release inventory. The emergency planning section of the law is designed to help communities prepare for and respond to emergencies involving hazardous substances. Specifically, OPPD annually reports the presence, location and amount of hazardous substances at its facilities to local emergency responders and to local and state emergency planning committees. OPPD also annually reports the amounts of EPCRA chemicals that it releases to the environment at its coal-fired generating facilities to the State Emergency Response Commission and the EPA via the Toxics Release Inventory (TRI). The TRI is a publicly available EPA database that contains information on toxic chemical releases and other waste management activities reported annually by certain industry groups as well as federal facilities. Accidental or emergency releases of EPCRA chemicals above threshold amounts are reported to local agencies as well as the National Response Center.

OPPD manages TSCA waste (mainly asbestos and polychlorinated biphenyls from electrical transmission and distribution equipment) through a process involving reporting, sampling and analysis, and appropriate waste management to ensure compliance. RCRA waste is managed by characterizing, packaging and shipping radioactive and solid wastes to OPPD’s approved waste vendors to ensure compliance and minimize liability associated with waste disposal. In order to ensure compliance, OPPD remains active in reviewing applicable regulatory changes and modifying facility environmental management plans accordingly. Pollution prevention efforts have been effective in reducing environmental liabilities and reducing operating costs.

Clean Water Act

316(b) Fish Protection Regulations - On May 19, 2014, the EPA issued the final rule under Section 316(b) Rule of the Clean Water Act. Facilities are required to implement the best technology available (“BTA”) for entrainment and impingement. The NDEE sent a determination on June 8, 2020 that “the facility’s existing cooling water intake structure (CWIS) technology is best technology available (BTA) for entrainment.” OPPD submitted the proposed BTA determination for impingement in December of 2020. This submittal stated that OPPD intends to install and operate coarse mesh modified traveling screens with a fish return at Nebraska City Station and North Omaha Station intake structures providing flow for North Omaha Station Units 4 and 5. The BTA determination for entrainment and the compliance strategy and implementation timeline for impingement will be included in the renewed National Pollution Discharge Elimination System (NPDES) permits, now expected in Q1 of 2022.

Solid Waste

Coal Combustion Residuals (CCR) Regulations - On April 17, 2015, the EPA promulgated technical requirements for CCR landfills and surface impoundments for the safe disposal of coal combustion residuals under Subtitle D of the RCRA. The regulations provide design criteria, operating criteria, groundwater monitoring requirements, closure requirements and recordkeeping and notification requirements associated with CCR landfills and surface impoundments. The regulation became effective on October 19, 2015, and OPPD complies with the requirements.

Landfill-Specific Updates - On May 30, 2019, OPPD notified the NDEE that it had initiated Assessment of Corrective Measures (ACM) for the NOS landfill. Following hydrogeological modeling, groundwater monitoring, and engineering evaluations, OPPD has proposed long-term groundwater monitoring and post-closure capping as a final remedy. Per the requirements of the CCR rule, OPPD held a public meeting on September 22, 2021, to present remediation options and OPPD's preferred option. A public comment period was held until October 8, 2021. On December 13, 2021, OPPD published a final Selection of Remedy report and is in the process of seeking associated permitting for the selected final remedy. The NC1 landfill completed final closure activities in the fall of 2020 and has proceeded to post closure sampling. On December 14, 2020, OPPD initiated ACM for the NC2 landfill. Following hydrogeological modeling, groundwater monitoring, and engineering evaluations, OPPD identified wind-blown ash as the source has proposed source control through the application of a surface binder on the ash in the landfill, as well as operational changes in landfill construction (reduce the active area of the landfill to minimize dust) as a final remedy. Per the requirements of the CCR rule, OPPD held a public meeting on August 25, 2021, to present remediation options and OPPD's preferred option. A public comment period was held until September 7, 2021. On November 15, 2021, OPPD published a final Selection of Remedy report and is in the process of seeking associated permitting for the selected final remedy.

4.1.6. U.S. Army Corps of Engineers Oversight of Missouri River

During the spring and summer of 2011, all three of OPPD's baseload stations were threatened by prolonged, flood stage, water levels on the Missouri River as the Corps drained record Missouri River basin runoff from the six mainstream reservoirs. Gavin's Point Dam releases were at or above 160,000 cubic feet per second (cfs) for 74 continuous days. Previously, the highest rate of release from Gavin's Point was 80,000 cfs. Additional threats to OPPD's generation occurred in spring and summer of 2019. Many factors contributed to the flooding that year: a wet fall in 2018; an extremely cold and wet winter that resulted in deeply frozen ground, above-average snowfall and thick river ice; and the "Bomb Cyclone," which dumped rain and snow on frozen ground in Nebraska, Iowa, and South Dakota, and included a rapid warm-up that caused snow to quickly melt over frozen, fully saturated soil Fifty gages on the Missouri River and its tributaries in the region set new stage records. Nearly all of these new records were on unregulated areas of the Missouri Basin -- tributaries and the Missouri River downstream of Gavin's Point Dam. The years 2011 and 2019 highlighted the level of disruption the Missouri River can present to the operation of OPPD's generation stations and to all enterprises located in the river's historical flood plain. Contrarily, in drought years, low river levels may also lead to constriction in power generation limits.

4.2. Eastern Interconnection, SPP and the Integrated Marketplace

The Southwest Power Pool (SPP), based in Little Rock, Ark., was created in 1941 to provide electric reliability and coordination for 11 regional power companies. SPP has since expanded its scope of services and was approved as a Regional Transmission Organization (RTO) by the Federal Energy Regulatory Commission (FERC) in 2004. The services that SPP currently provides for its members include:

- Transmission tariff administration

- Transmission expansion planning
- Reliability coordination
- Wholesale energy market operations and Integrated Marketplace
- Consolidated balancing authority
- Generation reserve sharing

SPP expanded its services in the west in December 2019 when it launched its Western Reliability Coordination service on a contract basis, and in February 2021 with the successful launch of the Western Energy Imbalance Service (WEIS) Market. SPP employs approximately 600 employees and operates a system footprint spanning across 17 states.

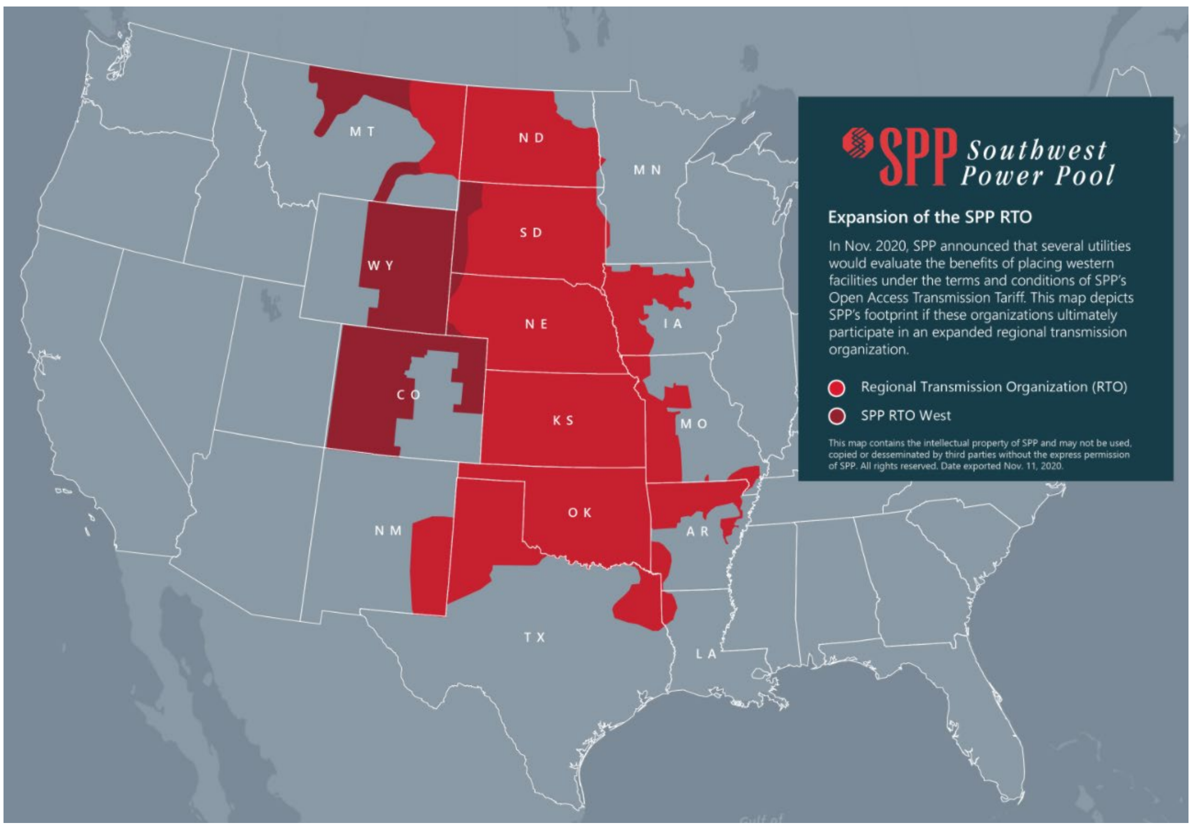


Figure 4-1 SPP Integrated Marketplace as of September 2021

4.2.1. Integrated Marketplace

OPPD participates as a market participant in the SPP Integrated Marketplace, offers its generation resources and bids its load into the market. The SPP Integrated Marketplace seeks to utilize the most economical generation resources to serve the electric system load in the SPP footprint while maintaining system reliability. The Integrated Marketplace has both a Day-Ahead (DA) Market and a Real-Time (RT) Market. For the subsequent day, market participants offer generation resources into the DA Market based on cost and availability, and bid in load based on forecasted demand. The SPP DA market engine simulates grid flows and generation resource commitments to most economically and reliably serve the load, resulting in binding financial obligations. In real time, generations resources are physically committed based on real-time system conditions to most economically and reliably serve the actual system load. Real-time system conditions may differ from projections entered into and settled in the DA Market. OPPD's fossil and renewable assets are very competitive within the SPP Integrated Marketplace.

On April 1, 2009, OPPD became a transmission-owning member of the Southwest Power Pool. OPPD actively participates in SPP working groups to develop improvements and amendments to SPP governing documents and to provide assistance in the development of transmission system study models for transmission expansion planning. At the time it joined, all of OPPD's transmission facilities were placed under the SPP Open Access Transmission Tariff. OPPD no longer grants new transmission service requests under its own transmission tariff. Transmission services granted prior to becoming a member of SPP remain on OPPD's tariff as 'Grandfathered Agreements' for the original term of service. Any extension of service will be under the SPP Tariff. New generation interconnection requests to connect to OPPD's transmission facilities must be submitted to SPP for approval.

In addition to OPPD, there are two Nebraska utilities (Lincoln Electric System and Nebraska Public Power District) that are members of SPP, and these utilities' transmission systems are under the SPP RTO authority. The SPP transmission planning processes identify new transmission projects across Nebraska and the SPP footprint that are expected to relieve congestion on the region's transmission system, improve reliability on the nation's energy grid and support future generation additions. These transmission additions identified through the SPP transmission planning processes should contribute to making additional renewable generation feasible concerning deliverability to OPPD's system.

4.2.2. Planning Reserve Margin

As stipulated in Section 5 of Attachment AA of the SPP Tariff, OPPD is required to maintain sufficient capacity to meet the resource adequacy requirement, which is equal to OPPD's net peak demand plus a Planning Reserve Margin (PRM) of 12%. The modeling results of the 2021 IRP assume the current 12% PRM will remain for the duration of the five-year study. OPPD's Load and Capability (L&C) report which reflects the planned reserve margin can be found in Appendix A.

This requirement is enforced to ensure load-serving entities have adequate capacity to serve the SPP Balancing Authority Area's peak demand. Failure to meet the resource adequacy requirement results in a deficiency payment as calculated in accordance with Section 14.2 of Attachment AA. To fulfill its resource adequacy obligations, OPPD submits an annual Resource Adequacy Workbook to SPP to demonstrate compliance. The PRM is determined via a probabilistic Loss of Load Expectation (LOLE) Study which analyzes the ability of the transmission provider to the reliably serve the SPP Balancing Authority Area's forecasted peak demand. The LOLE study is performed biennially. SPP studies the PRM such that the LOLE for the applicable planning year does not exceed one day in ten years. It should be noted that the PRM is currently being evaluated by SPP and may be revised upward in the future.

4.3. State(s) Policy and Legislation

The first session of the 107th Legislature began in January of 2021. Sessions of the Nebraska Legislature last for 90 working days in odd-numbered years and 60 working days in even-numbered years. Bills were introduced that could have implications for OPPD. Below is a more in-depth summary of those issues that can affect OPPD operations.

4.3.1. Nebraska Power Review Board

In 1963, the Nebraska Legislature enacted Chapter 70, Article 10, Reissue Revised Statutes of 1943 of Nebraska, as amended, establishing the Nebraska Power Review Board (NPRB). The NPRB consists of five members appointed by the governor subject to approval by the Legislature. The statute declares that it is the policy of the state to avoid and eliminate conflict and competition between retail suppliers of electricity and to facilitate the settlement of rate disputes between suppliers of electricity at wholesale. Subject to approval of the NPRB, retail suppliers of electricity in adjoining areas are authorized to enter into written agreements with each other, specifying either the service area or customers that each shall serve. Where agreements cannot be reached, the NPRB will determine the matter after a hearing. With NPRB approval, OPPD has entered into service-area agreements with all other suppliers whose territories adjoin that of OPPD. The construction of any transmission lines or related facilities outside OPPD's service territory generally carrying more than 700 volts, or the construction of most electric generation facilities is subject to the approval of the NPRB. Since the establishment of the NPRB, OPPD has received NPRB approval for the construction of all facilities requiring such approval. The NPRB is not responsible for approval of transmission facilities located within OPPD's service territory, the construction of privately developed renewable facilities, or the retirement of transmission and generation assets.

4.3.2. LIHEAP/Weatherization

LB306 made two important changes to the Low Income Home Energy Assistance Program (LIHEAP) in the State of Nebraska. The bill increased the annual income limit from 130% of the federal poverty level (FPL) to the federal maximum allowed of a 150% of the FPL. This legislation will also ensure that no less than 10% of LIHEAP funds are allocated to weatherization assistance programs enable low-income families to permanently reduce their energy usage by making their households more energy efficient while ensuring the residents' health and safety.

4.3.3. LB-436 Net Metering and LB 65 of 2003

Several bills have been introduced addressing net metering. The main one that would affect OPPD operations is LB683. This bill proposes material changes to the existing net-metering statutes for distributed energy systems and raises many questions and concerns about the ultimate purpose of the legislation as well as the operational impacts. Inclusion of any "form of technology" is allowed for net metering; including gas generators or other fossil-fueled generators in the bill is problematic. This has the potential to disrupt OPPD's distribution system in uncertain magnitudes, as well as work contrary to OPPD's strategic decarbonization goal in pursuit of net-zero carbon by 2050. While OPPD supports new solutions to changing energy needs, OPPD must also be thoughtful as to how it affects all of our customers. This legislation is not the right attempt to address net metering.

Local control is an important aspect of the public power model, and OPPD will continue to manage a framework for customers to meet their renewable energy or sustainability goals. For customers interested in owning and operating their own renewable energy resources, such as solar panels, OPPD offers rider offerings for both net metering and small, power-producing customers that insufficiently, but more equitably, recover costs from all customers, net metering or otherwise.

4.3.4. LB-1048 Certified Renewable Export Facilities

A bill was introduced to establish a Renewable Energy Standard to promote the development and utilization of clean and renewable energy production. This bill had a hearing, but did not pass.

4.3.5. LR-136

OPPD and the other public power utilities took part in LR 136, an interim study to examine, understand and evaluate the causes, impacts and costs of rolling electrical power outages during the extreme weather events of February 2021. The study also discussed the benefits of public power district membership in the Southwest Power Pool (SPP) and the costs and benefits of SPP membership. This was the second interim study on the matter. The first was directly after the February storm and was focused on what happened. LR 136 was focused on the after action reports and what recommendations/actions are needed going forward. OPPD and SPP were well prepared, performed well during the event, and that there are lessons learned that will be applied going forward to improve performance even more. OPPD benefits from the resources within the SPP footprint.

5. Load and Resource Balance

This section assesses OPPD's load and resource balance, comparing forecasted electric demand to current and planned resources. Specifically, this section provides detail on OPPD's reference load forecast, including projected summer peak demand, winter peak demand and annual energy requirements. This forecasted electric demand is compared to OPPD's resources over the IRP's five-year action plan to demonstrate OPPD's plan to meet SPP's Planning Reserve Margin (PRM) requirements.

5.1. Load Forecasting

The load forecasting process is a fundamental component of the IRP modeling process, determining future system energy and capacity needs. OPPD's load forecasting utilizes a vast database of detailed historical information paired with regional macroeconomic forecasts and sophisticated load forecasting tools. This process produces best in-class accuracy, but is still subject to long-term uncertainty.

5.1.1. Load Forecasting Methodology

OPPD utilizes the Itron suite of load forecasting software to develop its load forecast including Forecast Manager, MetrixND and Metrix LT.

Producing OPPD's load forecast begins with collecting data from internal sources and external data provided by both public and proprietary sources. This data includes measures of OPPD customer growth and energy consumption, new economic development within the service territory, weather, economic and demographic data. This data is modeled at the individual rate class level, which comprises three main customer categories: Industrial, Commercial and Residential.

Models are created to establish a mathematical relationship between energy consumption and factors such as appliance end-use efficiency (heating, cooling, washing, drying, etc.), weather, building square footage, and household income growth. OPPD's largest industrial customer forecasts are additionally informed through discussions with account executives representing those customers. Models produce forecasts at the individual rate class level and are then aggregated and calibrated to a system peak forecast that includes transmission losses. The resulting output is a forecast file that contains system-wide hourly demand values over a 30-year time horizon (Net System Requirements). System peaks are derived from this NSR file.

5.1.2. Reference Load Forecast

The 2021-2031 Reference load Net System Requirements forecasts are provided in Appendix A. Compared to forecasts developed for previous IRP submissions, 2021 reference forecasts have been revised upward to reflect larger growth in our industrial customer base, including major load growth from data centers. Table 5-1 shows the differences between the 2016 IRP and the 2021 Reference load.

The 2021-2031 Peak Demand and Net System Requirements forecasts were input into the Multi Sectoral modeling study. The results of the study provided pathways of Peak

Demand and Net System Requirements utilized in the Pathways to Decarbonization: Energy Portfolio study.

Table 5-1 Load Forecast, Annual Peak Demand (MW)

Load Forecast, Annual Peak Demand (MW)			
Year	**2016 IRP**	**2021 IRP**	**Change**
2017	2,417		
2018	2,454		
2019	2,458		
2020	2,445		
2021	2,456	2,549	93
2022	2,455	2,663	208
2023	2,449	2,748	299
2024	2,434	2,863	429
2025	2,440	2,958	518
2026	2,436	2,988	552
2027	2,435	3,019	584
2028	2,425	3,039	614
2029	2,435	3,055	620
2030	2,437	3,058	621
2031	2,438	3,064	626

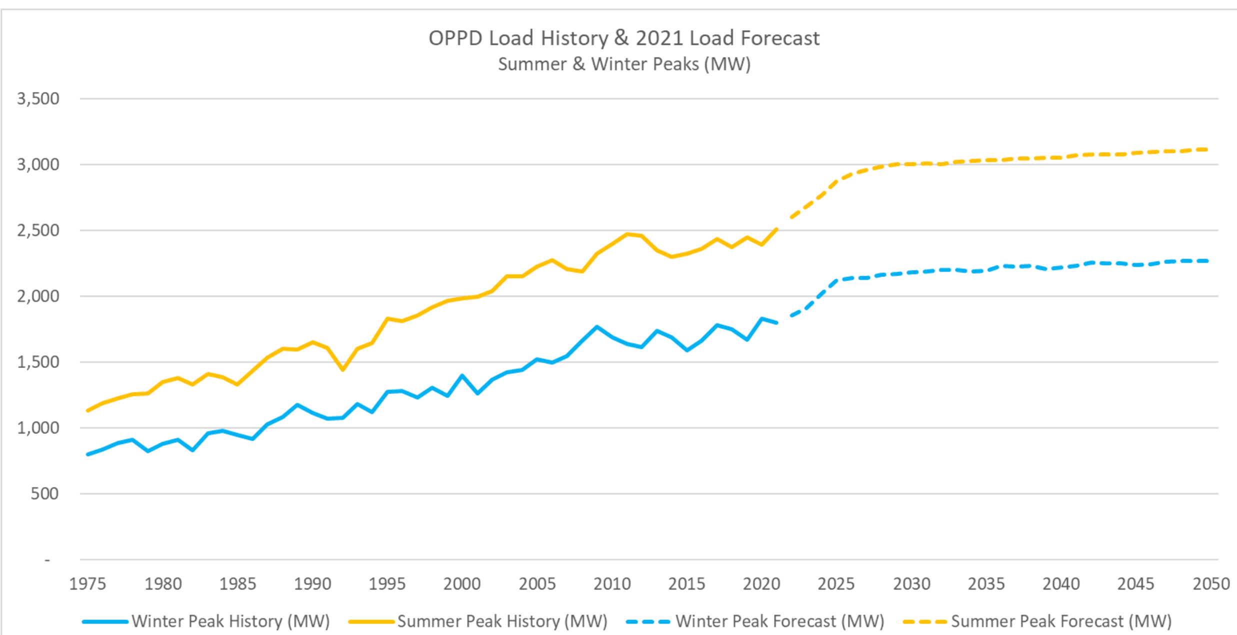


Figure 5-1 OPPD Load History and 2021 Load Forecast Summer and Winter Peaks (MW)

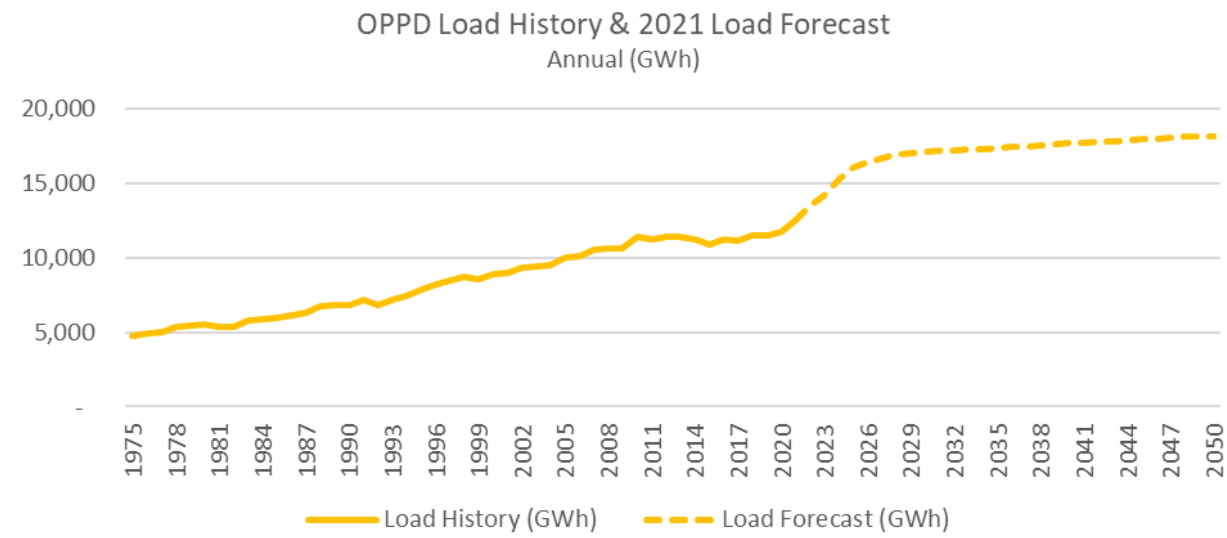


Figure 5-2 Historic and 2021 Load Forecast Annual (TWh)

5.1.3. Energy Efficiency

OPPD integrates two types of energy efficiency projections into its load forecast. The first type is based on data from the EIA Energy Outlook Reference case for the West North Central region. The energy projections contain estimates for energy usage intensities, device saturation rates, device energy efficiency and projected square footage for building structures. The second type of projection includes OPPD's Demand Side Management (DSM) Program that most recently includes energy efficiency measures unveiled in 2019.

5.1.4. Distributed Generation

Figure 5-3 Customer-owner Distributed Generation. Solar Panels

Distributed generation is a growing trend across the utility industry. OPPD anticipates that the number of distributed generation projects will continue to grow. OPPD customers who generate renewable energy with generators located behind their service meter are eligible for net-metering rates. At the end of 2016, OPPD had 59 customers and a total generating capacity of 538 kilowatts. In 2016, the total estimated amount of energy produced by these customer-owned distributed generation assets was 755,406 kWh. The net energy produced in excess of customer load was 32,857 kWh. From January to September 2021 (YTD 2021), OPPD had 230 customers among residential and commercial rate classes with a total generating capacity of 1,786 kilowatts, 1,762 KW of which belongs to solar generating assets and 26.6 KW to wind generating assets. In YTD 2021, the total estimated amount of energy produced by these customer-owned distributed generation assets was 1,442,204 kWh. The net energy produced in excess of customer load was 257,097 kWh.

Accordingly, OPPD will continue to monitor the trend of distributed generation participation as it develops ongoing future resource plans.

5.1.5. Electric Vehicles

OPPD has been preparing for expanding consumer use of electric vehicles (EV) within its service territory. Growth in EV technology and availability, coupled with policy and incentives from federal authorities to adopt EVs, reinforces our modeling of electrification in this sector. While the service territory is still in the early stages of EV adoption, OPPD is incorporating broader electrification within its long-term load forecasting.

EIA provides estimates for adoption through 2050 for the West North Central Region, which were scaled to OPPD's service territory population to arrive at an initial estimate for OPPD EV load growth. However, with federal initiatives targeting 50% of new vehicles to be electric-powered by 2030, there exists a large range of potential adoption over the next decade. The data on EV adoption OPPD can collect to date, along with federal initiatives, are being analyzed to inform a variety of potential load growth scenarios.

As of September 2021, OPPD is serving 1,138 electric passenger vehicles and 414 electric trucks for 1,552 EVs. A peak demand of 6.7MW was recorded in January 2021, for electric vehicle use.

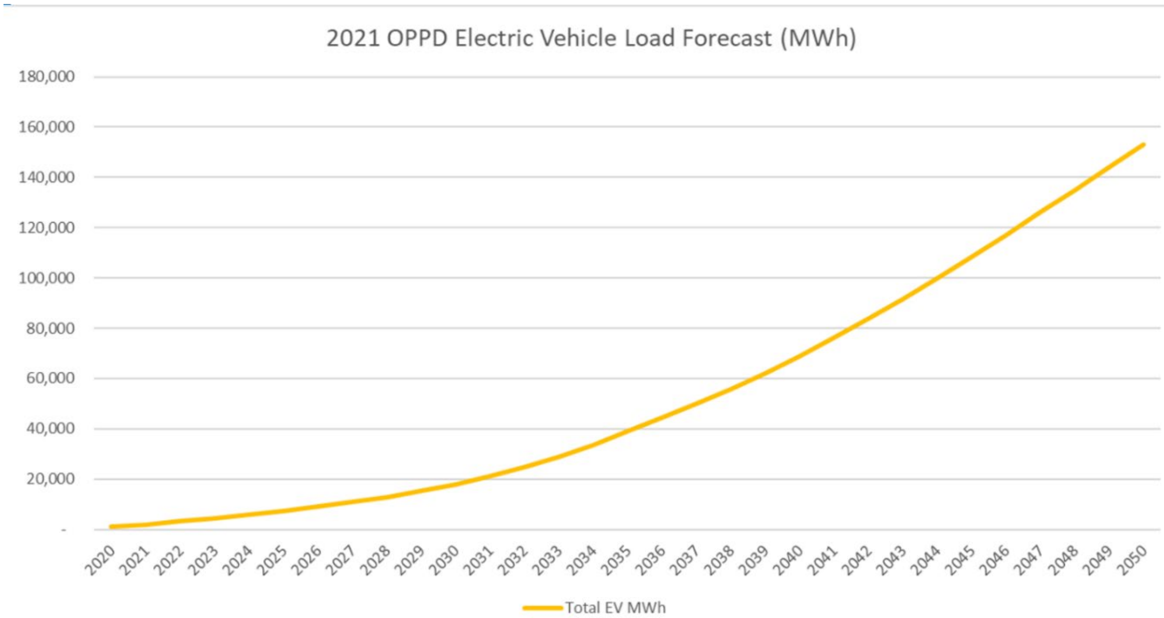


Figure 5-4 OPPD Electric Vehicle Load Forecast (MWh)

5.2. Current System Resources

OPPD's power requirements are provided from its generating facilities, leased generation and purchases of power. OPPD's all-time peak load is 2,509 MW, set on July 29, 2021. The following table summarizes the output and capability of OPPD's generation facilities displayed by energy source.

Table 5-2 OPPD Generation Summary as of December 31, 2020

	Initial Date in Service	Capability[1] (kW)	% of Total	Amount (MWh)	% of Total
Coal:					
Nebraska City Station Unit 1	1979	654,300	22.0	3,975,976.1	28.6
Nebraska City Station Unit 2[3]	2009	691,000	23.2	3,688,237.5	26.5
North Omaha Station[4, 7]	multiple	336,300	11.3	1,753,466.4	12.6
Subtotal Coal		1,681,600	56.4	9,417,680.0	67.7
Oil/Natural Gas:					
Cass County Station	2003	323,800	10.9	151,838.1	1.1
Jones Street Station	1973	123,400	4.1	1,529.2	0.0
North Omaha Station[4]	multiple	241,600	8.1	18,389.0	0.1
Sarpy County Station[5]	multiple	315,700	10.6	65,880.5	0.5
Subtotal Oil/Natural Gas		1,004,500	33.7	237,636.8	1.7
Other:					
Elk City Station (Methane Gas)		6,000	0.2	48,436.6	0.3
Total Owned Accredited Generation		2,692,100	90.3	9,703,753.4	69.8
Purchased/Leased Generation:					
City of Tecumseh, Nebraska (Oil)		6,500	0.2	15.2	
Western Area Power Administration (Hydro)		79,700	2.7	380,010.0	
Wind:[6]					
Ainsworth		1,000	0.0	20,543.6	
Broken Bow I		2,800	0.1	70,748.7	
Crofton Bluffs		2,400	0.1	55,484.7	
Elkhorn Ridge		2,200	0.1	59,239.2	
Flat Water		13,100	0.4	195,474.1	
Petersburg		8,000	0.3	168,261.0	
Broken Bow II		6,700	0.2	196,121.7	
Prairie Breeze		43,100	1.5	790,515.4	
Grande Prairie		64,500	2.1	1,552,418.1	
Sholes		58,300	2.0	706,927.1	
Subtotal Purchased/Leased Generation		288,300	9.7	4,195,758.8	30.2
Total Accredited Generation		2,980,400	100.0	13,899,512.2	
Solar					
Fort Calhoun Community Solar		5,000		9,287.3	
Total Non-accredited Generation		5,000		9,287.3	0.0
Total Generation Produced				13,908,799.5	100.00

(1) Maximum 2021 summer accredited net capability.
(2) Actual net production and availability factor as of December 31, 2020.
(3) 50% of the output is sold to seven participating utilities through long-term Participation Power Agreements.
(4) Station consists of five units placed in service in 1954, 1957, 1959, 1963 and 1968 North Omaha Units 1, 2, and 3 have been converted to natural gas fired peaking units.
(5) Station consists of five units placed in service in 1972, 1996 and 2000.
(6) Total wind accredited summer 2021 capability is 202.1 MW. Nameplate capacity for wind resources is 971.7MW.
(7) North Omaha Station Units 4 and 5 gain additional incremental summer capability using natural gas supplied on a firm basis as supplemental fuel

5.2.1. Firm Dispatchable Resources

Resources that are considered "firm dispatchable" can be turned on and off while having fuel sources that are generally dependable, reliable and readily available.

Nebraska City Station - Located approximately five miles southeast of Nebraska City, Neb., this facility consists of two, coal-fired steam generator units, NCS Unit No. 1 (NC1), and NCS Unit No. 2 (NC2).

NC1 was commissioned in 1979 and consists of coal pulverizers, subcritical reheat boiler with wall-fired low NOx coal burners, natural gas and fuel oil igniters, steam turbine and generator, steam condenser supplied by once-through cooling with river water, air preheaters, electrostatic precipitators for emissions control, dry sorbent injection for flue gas conditioning and emissions control, and activated carbon injection for mercury emissions control.

NC2 was commissioned in 2009 and consists of coal pulverizers, subcritical reheat boiler with wall-fired low NOx coal burners, natural gas and fuel oil igniters, steam turbine and generator, steam condenser supplied by cooling water from a cooling tower, air preheaters, SCR (selective catalytic reduction) with ammonia injection for NOx emissions control, dry scrubber with ash recycle for SO_2 emissions control, activated carbon injection for mercury emissions control, a baghouse for particulate emissions control, and pulse jet fabric filter for particulate emissions control.

OPPD retrofitted NC1 with dry sorbent injection and activated carbon injection emissions control systems in 2016 to comply with the Mercury and Air Toxics Standards (MATS).

OPPD owns, operates and maintains NC2. Fifty percent of the station's output is used by OPPD to meet customer load requirements. OPPD has executed long-term Power Purchase Agreements (PPAs) with seven public power and municipal utilities, known as the Participants, located in Nebraska, Missouri and Minnesota for the remaining 50% of the unit output.

The participants and their percentage share of NC2's output are as follows:

Table 5-3 Nebraska City Unit 2 Participants Share

Participants	Percentage Share
Central Minnesota Municipal Power Agency	2.17
City of Grand Island, Nebraska, Utilities Department	5.00
City of Independence, Missouri, Power & Light Department	8.33
Falls City, Nebraska, Utilities	0.83
Missouri Joint Municipal Electric Utility Commission	8.33
Nebraska City, Nebraska, Utilities	1.67
Nebraska Public Power NPPD	23.67
Participants' Total	50.00
Omaha Public Power OPPD	50.00
NC2 Total	100.00

North Omaha Station (including conversion) - North Omaha Station (NOS), located in the northeast section of the City of Omaha, consists of five steam generator units equipped for coal and natural gas firing. All five units have subcritical reheat boilers, natural gas igniters and burners, steam turbines, steam condensers supplied by once-through cooling with river water, air preheaters and electrostatic precipitators for emissions control. Maintenance and inspection outages are completed annually at NOS to improve station safety, efficiency and reliability. Units 4 and 5 are also equipped with coal pulverizers and coal burners.

NO1, NO2 and NO3 were retired from coal operation in April of 2016, and all coal supply-related equipment was disconnected from the units. As a result of the board of directors action related to Fort Calhoun Station in June 2016, OPPD is using existing natural gas generating capability for NO1, NO2, and NO3 for capacity accreditation purposes and these units remain available for gas operation, but operate on an infrequent basis as they are called upon by the market.

Retrofitting of NO4 and NO5 with dry sorbent injection and activated carbon injection emissions control systems was completed on April 16, 2016. This retrofit was completed to comply with the MATS rule.

In accordance with board of director's resolution, North Omaha Units 4 and 5 will cease coal operations by December 31, 2023. At that time, the units will undergo new burner and other updates to aid with burning natural gas. NOS Units 1, 2 and 3 will be retired but may be used as an alternate auxiliary steam supply source for seasonal building heating in case of challenges with the planned electric auxiliary boiler.

Cass County Station - Cass County Station (CCS), located near Murray, Neb., consists of two combustion turbine units equipped for natural gas firing. The combustion turbine units are tied into two natural gas transportation pipeline systems enhancing competition between fuel suppliers.

Jones Street Station - Jones Street Station (JSS), located near downtown Omaha, consists of two combustion turbine units equipped for oil firing and is used for reliability and peaking purposes and during situations when natural gas is not available to the other peaking stations.

Sarpy County Station - Sarpy County Station (SCS), located in Bellevue, Neb., consists of five combustion turbine units equipped for oil or natural gas firing, is used for balancing, reliability and peaking purposes. While the SCS units primarily operate on natural gas, their ability to operateon fuel oil provides fuel diversity in situations when natural gas may not be available.

In September 2020, OPPD announced the locations and capacity of two, new natural gas backup generation facilities (detailed below). These facilities will be owned and operated by OPPD. The sourcing for these natural gas generation assets began in September 2020.

Figure 5-5 SBLS Render Military Rd View

Standing Bear Lake Station - Standing Bear Lake in northwest Douglas County, will be comprised of reciprocating internal combustion engine (RICE) units and generate 150MW. These units can also run on light fuel oil and are capable of running on a blend of hydrogen/ natural gas in support of future technology advancements and as regional hydrogen markets develop. These units offer fast start-up to rapidly support the addition of intermittent resources such as wind and solar, as well as support the changing generation needs of the electrical grid. This station will be complete and the plant energized in 2023.

Turtle Creek Station - Turtle Creek Station in Sarpy County, will be comprised of two simple-cycle turbine (CT) units, and will generate a combined 450MW. These gas turbines will primarily operate on natural gas, but are designed with dual fuel capability with the ability to also run on light fuel oil. These units may also be capable of running on biofuel or a blend of hydrogen/ natural gas in support of future technology advancements and as regional hydrogen markets develop. This station will be completed and energized in 2023.

Figure 5-6 TCS Render Platteview Rd View

Landfill Gas - Elk City Station, located near Elk City, Neb., in western Douglas County, is a renewable energy facility that uses methane gas from the Douglas County Landfill to produce electricity. The nameplate capacity of the facility is 6.4MW and is limited by the methane production of the landfill.

Fuel Supply

This section provides detailed information on the three primary fuel sources utilized by OPPD for its current generation resources: coal, natural gas and fuel oil. OPPD manages fuel supply risk with a combination of inventories, company-owned rail lines and contractual agreements with railroad, coal mining, and natural gas utility and pipeline companies.

Coal Fuel Supply - OPPD currently has a term contract with Peabody Coal Sales through 2022, Bluegrass Commodities LP ("Bluegrass") through 2023 and Kiewit through 2024. Rail transportation services are provided under a 7-year contract with Burlington Northern Santa Fe ("BNSF") Railway beginning in January 2021. OPPD owns approximately 57 miles of rail line extending from NCS to Lincoln, Neb., known as the ("Arbor Line"). The Arbor Line provides competitive access to NCS from Union Pacific Railroad Company and BNSF Railway, as well as rail access to other third-party shippers. In order to maintain the Arbor Line, OPPD has a multiyear rail maintenance contract with Kelly Hill Company.

The average price per ton for coal delivered and the total amount delivered to OPPD's NCS for 2020 and 2019 were as follows:

Table 5-4 Nebraska City Average Delivered Coal Price per Ton

Year Ended	Average Price	Tons
2020	$23.28	4,901,862
2019	$24.12	4,005,246

The average price, per-ton, for coal delivered and the total amount delivered to OPPD's NOS for 2020 and 2019 were as follows:

Table 5-5 North Omaha Station Average Delivered Coal Price per Ton

Year Ended	Average Price	Tons
2020	$22.55	1,090,678
2019	$22.23	1,222,582

The coal for both NCS and NOS is delivered to the sites by seven, district-owned unit trains totaling 1,009 cars.

Natural Gas - Natural gas from Metropolitan Utilities District ("MUD") is available on an interruptible basis for power station fuel at NOS and SCS. Firm natural gas contracts were negotiated for the start-up process at NOS, and to generate electricity at NO1, NO2 and NO3 for the summers of 2019 through 2023, when market or grid conditions warrant. CCS and NCS are located outside of MUD's service territory and therefore do not receive natural gas services from MUD. CCS is connected to two natural gas transportation pipeline systems, Northern Natural Gas Company and Natural Gas Pipeline Company of America adjacent to the CCS site. These interconnections enhance competitive pricing between the two pipeline systems. OPPD has firm natural gas transportation for CCS during the summer months, and interruptible transportation available yearround. Nebraska City Utilities built and put into operation a natural gas pipeline to NCS to provide fuel for start-up in lieu of oil. In addition, OPPD contracts natural gas storage for hedging purposes.

Fuel Oil Supply - OPPD maintains fuel oil supplies at SCS and JSS, and has access to pipeline terminals in the area for immediate replenishment. The new firm dispatchable resources Turtle Creek Station and Standing Bear Lake Station will also have fuel oil tanks on-site. These tanks will increase energy assurance in events when the primary fuel of natural gas is unavailable. The on-site tanks will be sized for multiple days of fuel oil supply. It is anticipated that less than 1% of the energy generated by OPPD for each of the next five years will be produced with fuel oil.

5.2.2. Variable Energy Resources

In June 2007, OPPD established the Sustainable Energy & Environmental Stewardship Division. One of the primary objectives of the division was the incorporation of environmentally friendly generating resources into OPPD's generation portfolio. In January 2009, OPPD announced a voluntary plan to increase the utilization of renewable generation resources and to reduce overall energy demand. The plan included a goal to produce 10% of the energy provided to OPPD's retail customers with renewable generation resources by 2020. By 2014, OPPD met its 10% goal with the additions of the Broken Bow II and Prairie Breeze wind facilities.

Since 2014, OPPD has executed Power Purchase Agreements (PPAs) for the Grande Prairie and Sholes wind facilities. The Grande Prairie facility began commercial operation in December 2016, and the Sholes facility began commercial operation in November 2019, which added 560MW of aggregate nameplate capacity to OPPD's wind portfolio. In 2018, the Alternative Energy Program was formed as part of the newly formed Energy Production and Nuclear Decommissioning division, to help elevate and maintain focus on the integration of more renewable generation for OPPD.

In November 2019, OPPD entered into a 20-year Purchase Power Agreement (PPA) for the Sholes Wind Facility, located in Wayne County, Nebraska, approximately 100 miles North of Omaha. This facility has a 160MW nameplate capacity.

OPPD's first utility-scale solar facility, located near Fort Calhoun, Neb., reached commercial operation on January 1, 2020. This 5MW nameplate capacity solar farm supports OPPD's Community Solar Program.

In 2021, OPPD executed a PPA for the Platteview Solar facility for the creation of an 81MW facility near Yutan, Neb., for which 100% of the output will be sold to OPPD. The governing PPA has a 20-year term and is planned to be online in 2023.

As of June 30, 2021, OPPD had 1,060.3MW of renewable generation nameplate capacity, primarily through PPAs. In 2020, approximately 38.4% of retail energy sales came from renewable energy.

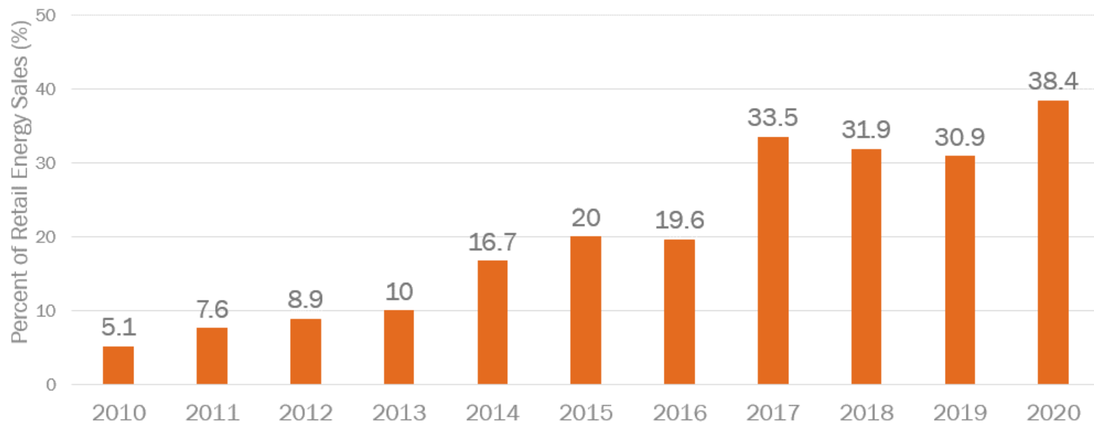


Figure 5-7 Percent of Renewable Energy Retail Energy Sales (%)

Wind - OPPD's total nameplate wind capacity was 971.65MW as of December 2021. All of the wind generation is provided through OPPD's participation in 20-year and 25-year PPAs for output from the wind projects listed in table 5-1. As of June 30, 2021, OPPD has the following commitment amounts for its power purchase agreements:

Table 5-6 OPPD's Nameplate Wind Capacity

Wind Farm	Location	Initial Contract Year	Total Size (MW)	District's Share (MW)	Final Year
Ainsworth	Ainsworth, NE	2005	59.4	10.0	2025
Elkhorn Ridge	Bloomfield, NE	2009	80.0	25.0	2029
Flat Water	Humboldt, NE	2010	60.0	60.0	2030
TPW Petersburg	Petersburg, NE	2011	40.5	40.5	2031
Crofton Bluffs	Crofton, NE	2012	42.0	13.7	2032
Broken Bow I	Broken Bow, NE	2012	80.0	18.0	2032
Broken Bow II	Broken Bow, NE	2014	73.1	43.9	2039
Prairie Breeze	Petersburg, NE	2014	200.6	200.6	2039
Grande Prairie	O'Neill, NE	2017	400.0	400.0	2037
Sholes	Sholes, NE	2019	160.0	160.0	2039

Ainsworth - OPPD purchases wind energy from a 10MW (16.8%) share of the 59.4MW Nebraska Public Power District (NPPD) wind energy facility near Ainsworth, Neb. This facility began commercial operation on September 15, 2005.

Elkhorn Ridge - OPPD began receiving wind energy from Elkhorn Ridge wind facility in March 2009, adding 25MW to OPPD's renewable portfolio. The total facility is sized at 80MW nameplate capacity and is near Bloomfield, Neb., in Knox County. NPPD subcontracts OPPD's share along with the other participants' shares. The facility began commercial operation on March 1, 2009, and is composed of 27, 3MW Vestas turbines.

Flat Water - The Flat Water Wind facility is a 60MW facility comprised of 40, 1.5MW GE turbines OPPD is the sole purchaser. Flat Water is located in OPPD's service territory in southwest Richardson County, Neb., near State Highway 105 and interconnects with OPPD's 161 kV transmission system. The facility reached commercial operation on December 21, 2010.

TPW Petersburg - The Petersburg Wind Facility began commercial operation on November 1, 2011. The facility, which has a nameplate capacity of 40.5MW, is located near Petersburg, Neb., and is composed of 27, 1.5MW GE turbines. OPPD is the sole purchaser of the energy from this wind facility.

Crofton Bluffs - The 22–turbine Crofton Bluffs Wind Facility, located southwest of Crofton, Neb., began commercial operation on November 1, 2012. Two turbines have a maximum capacity of 3.0MW, and 20 turbines have a maximum capacity of 1.8MW for a total nameplate capacity of 42MW. NPPD subcontracts OPPD's share along with the other participants' shares. The participants in the wind facility are NPPD (21MW); Omaha Public Power District (13.65MW); the Municipal Energy Agency of Nebraska (4MW); and Lincoln Electric System (3MW).

Broken Bow I - The 50–turbine Broken Bow I Wind Facility in Custer County began commercial operation on December 1, 2012. Each turbine has a maximum capacity of 1.6MW for a total of 80MW. NPPD subcontracts OPPD's share along with the other participants' shares. The participants in the wind facility are Nebraska Public Power District (51MW), Omaha Public Power District (18MW), Lincoln Electric System (10MW) and the City of Grand Island (1MW).

Broken Bow II - The 43–turbine Broken Bow II Wind Facility is located near Broken Bow, Neb. with the nameplate capacity of 75MW. NPPD subcontracts OPPD's share along with the other participant's shares. NPPD has committed to buy the total 75MW and will keep 30MW but sell 45MW to OPPD. OPPD purchases the remaining capacity of 43.9MW. Commercial operation began on October 1, 2014.

Prairie Breeze - The 118-turbine Prairie Breeze 1 Wind Facility is located near Elgin, Neb. The facility has a nameplate capacity of 200.6MW. OPPD is the sole purchaser of the energy from the Prairie Breeze 1 facility. Commercial operation began on May 1, 2014.

Grande Prairie - Grande Prairie Wind Facility is located near O'Neill, Neb., in Holt County. It consists of 200, 2MW turbines and has a nameplate capacity of 400MW. OPPD is the sole purchaser of the energy from this facility, which began commercial operation on December 1, 2016.

Sholes - The Sholes Wind Facility is a wind farm located in Wayne County, Nebraska, approximately 100 miles North of Omaha. This facility has a 160MW nameplate capacity, which is comprised of 60, 2.4MW primary turbines and 10, 1.7MW secondary turbines. OPPD is the sole purchaser of the energy, which began commercial operation on November 4, 2019.

Figure 5-8 Sholes Wind Facility

Solar - In early 2017, in response to growing interest in solar-powered generation from customer-owners, OPPD evaluated the incorporation of its first utility-grade solar facility into its portfolio as well as the exploration of a potential community solar project. Through a stakeholder process, OPPD developed the Community Solar program, which rolled out in April 2019. The program remains fully subscribed. To support the program, OPPD entered into its first utility-scale solar PPA in 2018.

Since the execution of the Fort Calhoun Community Solar PPA, the solar market continued to see trends favorable to adding additional solar due to cost reductions coupled with technological improvements. In November 2019, the OPPD Board approved a plan to implement 400 to 600MW of utility-scale solar generation as part of OPPD's Power with Purpose project. In early 2021, OPPD announced the first piece of this generation would be the 81MW Platteview Solar facility.

Fort Calhoun Community Solar - OPPD's first utility-scale solar facility, located near Fort Calhoun, Neb., began commercial operation on January 1, 2020. This 5MW nameplate capacity solar facility is made up of 17,680 Jinko 395-watt modules over a 34-acre footprint. OPPD purchases the entirety of the output from this facility on behalf of its customers.

Figure 5-4 Fort Calhoun Community Solar

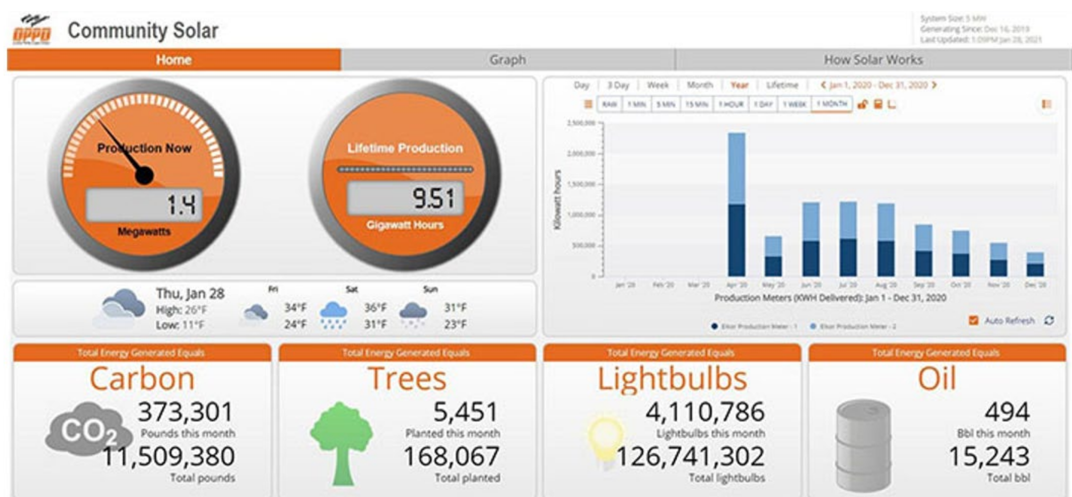


Figure 5-50 Fort Calhoun Community Solar Dashboard

For more information on the community solar project, click here Fort Calhoun Community Solar Dashboard.

Platteview Solar - OPPD executed a Power Purchase Agreement (PPA) with Platteview Solar, LLC for the creation of an 81MW solar facility near Yutan, Neb., for which 100% of the output will be sold to OPPD. The facility will be spread across approximately 500 acres with approximately 100 acres being planted with habitat. The facility will use modules on a single axis tracker, and has been designed to add potential energy storage in the future. The governing PPA has a term of 20 years and is anticipated to be commercial in 2023.

Figure 5-61 Platteview Solar render

Additional Solar - OPPD will continue to progress towards additional solar facilities with a target of 400-600 total solar for PWP, including Platteview Solar (81MW).

Hydro - OPPD has a contract with Western Area Power Administration (WAPA) to receive firm hydropower through 2050. The provided capacity is defined by maximums, in which WAPA provides a maximum of 17.2MW capacity from November through April (winter season) and a maximum of 47.8MW of capacity from May through October (summer season). WAPA, at its discretion upon giving OPPD notice of five years, can reduce capacity by up to 5% during the summer season.

Figure 5-72 Gavins Point Dam, hydroelectric facility (Photo credit US Army Corps of Engineer)

5.2.3. Energy Storage Resources

As energy storage technology is expected to decline in cost, have increased operational experience, and RTO policy matures, it becomes increasingly feasible at the utility-scale. Energy storage devices are one way to help balance fluctuations in electricity supply and demand and are becoming an important component to integrating more variable energy resources while maintaining a reliable and resilient grid. Energy storage devices come in numerous forms; popular options include pumped hydro, flow batteries and electrochemical batteries. The energy storage industry is constantly changing and OPPD is keeping a close eye on new developments and technologies. The Battery Research Innovation Guided by High-Potential Technologies (BRIGHT) project will allow OPPD to gain hands-on experience with an energy-storage device and will help promote more energy storage on OPPD's system in the future.

BRIGHT Battery Storage Project - In June 2020, OPPD received $600,000 in grant funding for a battery storage facility through the Nebraska Environmental Trust Air Quality category. OPPD's BRIGHT project will bring the first, utility-scale battery onto the system. In March 2021, the board of directors granted approval for competitive sourcing of the battery storage asset, and in July 2021, the Nebraska Power Review Board unanimously approved the application for this electric storage resource. This project will deploy an integrated lithium-ion Battery Energy Storage System (BESS), inverter, system management, and control system that provides 1MW of electric power and stores 2MWh of energy. This project will demonstrate how battery storage can reduce system load and associated costs during hours of peak demand. The system will be owned and operated by OPPD at a substation located in Cass County, Nebraska. OPPD awarded the Engineer, Procurement and Construction (EPC) contract for the battery asset with anticipated commercial operation in fall 2022.

Figure 5-83 Representative Project for BRIGHT (Photo credit BYD)

5.2.4. Demand-Side Programs

OPPD continuously invests in identifying and developing energy efficiency and demand response programs as an effective means of lowering customer costs and demands on OPPD's system.

In October of 2019, Applied Energy Group completed the DSM Potential Study Update and Program Assessment. This was an update to the 2014 study. Results of the update identified the achievable potential by the end of 2022 to be 181 MW of demand reduction through both energy-efficiency and demand-response programs and energy savings of 46,560 MWH. These projections were based on average three-year funding of $7.9M for the combined portfolio. By the end of 2020, actual results were 161.7 MW with a $6M spend. Through OPPD's decarbonization work stream a process has been developed to continuously evaluate products and programs to contribute to overall DSM goals. This process is also designed to align with findings from the DSM Potential Study Update and Program Assessment. As new program and products are developed, they fall into different areas of emphasis including Demand Response (DR) programs, such as interruptible rates and direct load control, as well as programs that promote high-efficiency equipment.

OPPD moved away from the Rate Impact Measure (RIM) for cost effectiveness and in 2020 began to utilize the Total Resource Cost (TRC) as its measure for DSM program feasibility. The TRC is defined as the program's ratio of lifetime benefits to the program's lifetime costs over its duration. TRC benefits include avoided supply and capacity costs.

The cumulative peak demand savings for the DSM programs planned through 2022 and extrapolated through 2024 is shown in the figure below. The peak demand savings in 2020 is 161.7 MW, reaching between 185MW and 198MW by the end of 2024.

Illustrative Potential Results[1]

— Expanded Program Portfolio
····· Extrapolated Portfolio
— Business as Usual

	Year 1	Year 2	Year 3
Total Budget[2]	$7,398,000	$8,058,000	$8,206,000
Energy Savings (GWh)[3]	35.18	42.07	46.56
Demand Savings (MW)	159	170	181
Emissions Reductions (Lifetime Tons CO2)[3]	350,649	416,724	459,393

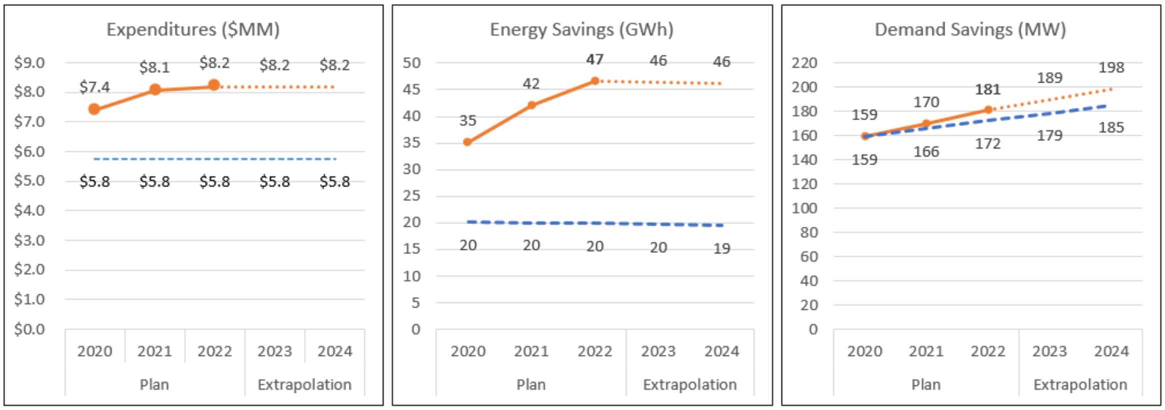


Figure 5-94 DSM Program Illustrative Potential Results

1 Scenarios assume all programs would be implemented January 1, 2020, but they remain to be prioritized for implementation

2 Total Budget includes customer incentives and other program administration costs

3 OPPD does not currently report Energy Savings or Emissions Reductions as part of the DSM portfolio

Energy Efficiency Programs

OPPD provides products and services aimed at improving energy efficiency and saving customers money. Programs are also available that are good for the environment. These programs are for both residential and commercial customers. OPPD wants to empower its customer to take control of their energy use.

Table 5-7 Energy Efficiency Programs

EE Program	Description	Start Year
Residential Efficient HVAC	Provides incentives for high-efficiency HVAC equipment and operational optimization	2015
Business Prescriptive	Provides customer incentives to implement energy-efficient measures that have predetermined electrical demand reduction values	2015
Business Custom	Provides incentives to qualifying projects based upon measures where electrical demand reductions are unique to their specific development	2015
Certified High-Performance Home	Provides incentive for customers to equip their homes with energy efficient features	2015
Residential Income Qualified	Provides home-management education and fully subsidized energy efficiency measures to income-qualified customers through existing local and regional agencies	2019

Demand-Response Programs

These programs are intended to shift electric use from peak periods, and provide an opportunity for consumers to play a role by reducing their usage during these times load during peak demand periods.

Cool Smart – This residential, direct load-control demand response program helps reduce OPPD's peak demand by up to 61.73 MW when demand is at its highest by implementing air conditioning (AC) curtailments.

Devices attached to the customer's AC unit will cycle on and off in 15 minute intervals to achieve this curtailment. The Cool Smart program consists of two groups with load shedding percentages of approximately 50% each. The two groups are always curtailed together to ensure there is 4 consecutive hours of curtailment. Each group can only be curtailed for a total of 3 hours and 15 minutes including ramp in and ramp out times of 15 minutes each. The groups have staggered starts and overlap for a period of 2 hours.

Smart Thermostat - This is a residential, direct load-control demand response program designed to reduce peak demand by up to 6MW through the use of smart, Wi-Fi enabled thermostats. This reduction is achieved after a precooling period of one hour in which the smart thermostat then adjusts the set temperature up an additional 1 to 3 degrees. Currently, the Smart Thermostat program includes Nest, Honeywell, Ecobee and Emerson thermostats.

Curtailable Program –Rate rider numbers 467 and 467H are curtailable load programs comprised of medium to large customers. Participants in these programs agree to reduce or turn off specific loads when notified by OPPD. When called, these programs are able to reduce OPPD's peak demand by up to 19.4MW.

Table 5-8 Demand Response Programs

DR Program	Description	Start Year
Cool Smart	Residential direct load control demand response program that reduces OPPD peak demand by up to 61.7 MW by implementing air conditioning curtailments	2012
Smart Thermostat	Resident direct load control demand response program that reduces peak demand by up to 6.0 MW with smart, Wi-Fi enabled thermostats	2018
467 & 467H	Curtailable load programs comprised of medium and large customers that agree to reduce or turn off specific loads when notified by OPPD resulting in a reduction of OPPD's peak demand by up to 19.4MW	

5.2.5. Transmission Resources

OPPD owns, operates and maintains a network of transmission lines that interconnect its generating stations and adjacent utilities to the various transmission and distribution substations serving the load of OPPD. In general, this network provides at least two alternate sources of supply to each load point on the system. A summary of the various transmission lines, as of December 31, 2021, making up this network are as follows:

Table 5-9 Transmission Lines Network

Voltage	Number of Circuit Miles
345 kV	423
161 kV	448
69 kV	470
Total	1,341

OPPD's transmission system is part of a larger network of transmission lines known as the Eastern Interconnection. OPPD's transmission facilities are physically interconnected to the transmission facilities of neighboring utilities. These connections are managed under interconnection agreements with each utility. OPPD can utilize these interconnections to provide for firm and participation power purchases and sales, short-term power and interchange of energy and transmission and ancillary services. The federal government, specifically the Federal Energy Regulatory Commission (FERC), has oversight and authority regarding the interchange of power over these networked transmission lines including wholesale market regulations, transmission service regulations and reliability standards

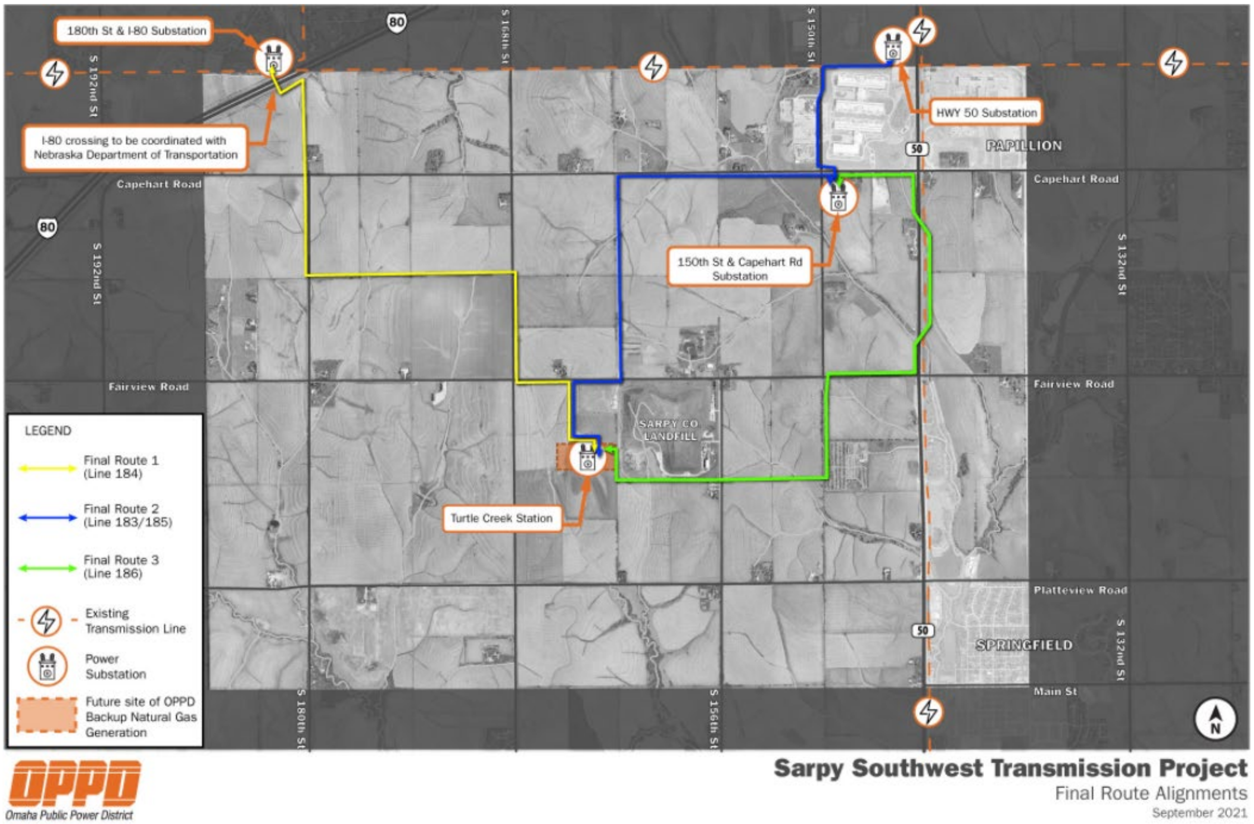


Figure 5-105 Sarpy Southwest Transmission Project

Being an owner and operator of these transmission facilities, OPPD is subject to oversight by FERC. FERC has designated an entity called the North American Electric Reliability Corporation (NERC) to ensure the reliability and protection of the networked transmission system in the United States. Regarding compliance to the NERC Reliability Standards, no potential violations or mitigation plans are currently being reviewed by OPPD's designated regional entity under NERC, the Midwest Reliability Organization (MRO). As mentioned earlier in this document, OPPD is a member of the Southwest Power Pool (SPP) Regional Transmission Organization (RTO), which is also subject to FERC and NERC oversight. SPP is designated by NERC as the regional Planning Coordinator (PC) and regional Reliability Coordinator (RC) that oversees regional transmission expansion planning and real-time reliability coordination for the SPP region. The SPP regional transmission expansion planning process includes the administration of the Generation Interconnection and transmission service processes. Since OPPD is a member of SPP, it is subject to SPP processes.

5.3. Load and Capability

The purpose of the load and capability position is to compare annual capacity obligations with the annual capability of OPPD's existing and planned resources.

5.3.1. SPP Planning Reserve Margin

The Planning Reserve Margin (PRM) describes the amount of resource capacity in excess of a system's peak demand used for planning purposes. PRM is commonly used to specify the amount of reserves necessary to be maintained for reliability purposes. The SPP Planning Reserve Margin is determined via a probabilistic Loss of Load Expectation (LOLE) Study, which analyzes the ability of the electric system to reliably serve customer electric demand across a variety of scenarios. The LOLE study is performed biennially. SPP studies the PRM such that the LOLE for the applicable planning year does not exceed one day in 10 years.

Attachment AA of the SPP Tariff defines the PRM to be 12% and that each utility maintain sufficient capacity to meet its load and planning reserve obligations. SPP is currently reviewing the need to increase the PRM to support reliability as the grid resource mix changes and as the frequency of extreme events increases.

5.3.2. Accredited Capacity

The SPP Planning Criteria contains the procedures for determining the annual and seasonal accredited net capacity of generators to be used towards meeting the resource adequacy requirement. Conventional generating unit and demand response program capacity ratings are established via a capability test. These tests must be conducted once every five years during the peak season.

Acknowledging the transition of SPP's system to a more variable and energy-limited resource fleet with aging thermal resources continuing to retire, SPP is reviewing the utilization of performance-based accreditation to accredit conventional generating facilities in the future. The objective of such a methodology would incentivize adequate maintenance for summer and winter seasons when resources are needed most and promote the procurement of dependable, reliable and effective resources. This method would utilize historical outages that have occurred for the conventional resources over a specific timeframe and an equation to calculate an individual resource's accredited capacity.

The accredited capacity of renewables is determined using the resource's historical output during the top 3% of peak load hours at a 60% confidence interval for each month. The seasonal or annual net capability is then determined by selecting the monthly megawatt values corresponding to the load serving entity's peak load month of the season of interest. Effective October 1, 2022, SPP will utilize Effective Load Carrying Capability (ELCC) methodology to determine the accredited capacity of wind, solar, and storage resources.

Using ELCC methods, a facility's accreditation is a fractional, probabilistic measure of the facility's nameplate rating that can be relied on to serve load. ELCC expresses the value that generation contributes to a system as penetration of the specific resource type increases. This is key as the amount of renewable resources in the SPP footprint increases. Overestimating the ability of such variable generation resources to help serve forecasted system peaks can result in lower levels of system reliability and increased risks of unserved load. Underestimating the ability of variable generation could lead to higher system costs.

Each year, SPP staff will conduct an ELCC study to determine the system's accredited capacity value for each resource tier. Wind and solar are each comprised of three tiers and stand-alone batteries contain two marginal tiers differentiated by battery duration. Once the system-wide accredited capacity value has been determined for each tier through the ELCC Study process specified in the SPP Business Practices, each individual wind, solar, or stand-alone battery resource will be assigned a percentage of the system-wide accredited capacity from its corresponding tier.

Tier 1 and 2 wind and solar resources will use the average production output from the top 3 percent load hours for each applicable season of the individual Load Responsible Entity (LRE). Individual resources of the applicable tier will then receive a proportional share of the total system-wide accredited capacity compared to the total historical average capacity value of all other wind and solar facilities in the applicable tier. Tier 3 resources on the other hand, will use average historical production output from the top 3 percent load hours for each applicable season of the SPP Balancing Authority Area's load.

5.3.3. Capacity Position Determination

The capacity position is developed first by determining the net peak load for each of the first 5 years in the planning horizon. The net peak demand is equal to the base peak forecast net of demand response programs and firm power purchases. Then, the annual accredited net capacity of generators is determined for the season utilizing SPP's accreditation methodology outlined in the section above and is summed with firm capacity contracts.

As mentioned in Section 4.2.2 of this document, OPPD is required to maintain sufficient capacity reserves to meet the resource adequacy requirement, which is equal to OPPD's season net peak demand plus its season net peak demand multiplied by the Planning Reserve Margin (PRM) of 12%. Finally, the capacity position is derived by adding the planning reserve margin and net peak demand and then subtracting this amount from the total capacity.

5.3.4. Capacity Positions Results

The table below breaks down the annual capacity balance and component line items for the period 2022 to 2026. OPPD is projected to be in a good position to meet its resource adequacy requirement in 2022 and beyond maintaining a reserve margin well over 12% over the five-year planning horizon. Most notably, the Power with Purpose gas assets

Turtle Creek and Standing Bear Lake coming online in 2023 will provide the necessary capacity to accommodate retiring North Omaha Units 1,2, and 3, as well as the slight reduction in output capacity at North Omaha 4 and 5 due to the gas conversion. Additionally, the currently contracted and projected solar assets coming online throughout the years 2024 to 2025 will support the capacity needs as demand continues to grow over the next 10 years.

With SPP's adoption of ELCC methodology to accredit renewable resources starting in 2023, OPPD's renewable portfolio could see minor gains in accredited capacity in the near-term but realize some losses over time as renewable penetration increases in the SPP territory. This is because ELCC captures the diminishing marginal contribution of variable energy resources to support reliability and is explained further in Appendix D.

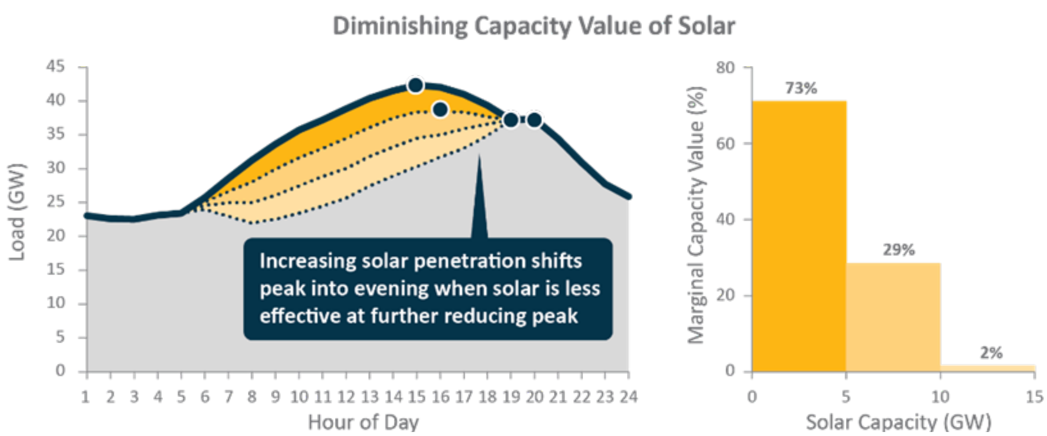


Figure 5-116 Diminishing Capacity Value of Solar example

Load and Capability Report – Summer Peak (All Values in MW)

The table below illustrates that OPPD will fully satisfy SPP's PRM obligation through the five-year IRP period.

Table 5-10 Load and Capability Report - Summer Peak (MW)

Load & Capability Report - Summer Peak(1)

All Values are Accredited MWs

Annual System Demand		**2022**	**2023**	**2024**	**2025**	**2026**
Base Peak Forecast		2632.8	2699.3	2777.3	2860.2	2930.4
Demand Response Programs		(96.5)	(101.5)	(105.1)	(109.3)	(113.5)
Firm Power Purchases		(79.7)	(79.7)	(79.7)	(79.7)	(79.7)
Net Peak Demand		2,456.6	2,518.1	2,592.5	2,671.2	2,737.2
Net Generating Capability						
Coal	NC1	650.3	650.3	650.3	650.3	650.3
	NC2	348.5	348.5	348.5	348.5	348.5
	North Omaha	333.9	333.9	-	-	-
Peaking Units	Sarpy County	315.7	315.7	315.7	315.7	315.7
	Jones Street	123.4	123.4	123.4	123.4	123.4
	Tecumseh	6.5	6.5	6.5	6.5	6.5
	Standing Bear	-	153.0	153.0	153.0	153.0
	Turtle Creek	-	-	444.0	444.0	444.0
	North Omaha	227.3	227.3	278.0	278.0	278.0
	Cass County	323.8	323.8	323.8	323.8	323.8
Landfill	ElkCity	6.0	6.0	6.0	6.0	6.0
Behind-The-Meter Thermal Generation(2)		29.6	29.6	29.6	29.6	29.6
Solar(3)	New Plants	-		55.7	188.0	402.8
Wind Participation Purchases(4)		245.7	147.8	138.6	129.9	127.9
Capacity Contracts		305.0	225.0	111.0	-	-
Total		2,915.7	2,890.8	2,984.1	2,996.7	3,209.4
Summary						
Total Capability		2,915.7	2,890.8	2,984.1	2,996.7	3,209.4
Net Peak Demand		(2,456.6)	(2,518.1)	(2,592.5)	(2,671.2)	(2,737.2)
Planning Reserve Margin		(294.8)	(302.2)	(311.1)	(320.5)	(328.5)
Position (MW)		164.3	70.6	80.5	5.0	143.8
Planning Reserve Margin		**18.7%**	**14.8%**	**15.1%**	**12.2%**	**17.3%**

(1) Using information consistent with 2022 SPP Resource Adequacy Submittal

(2) BTM Generation includes Curtailable 467L Load

(3) Timing for PwP Solar under development

(4) SPP Utilizes ELCC to accredit Wind, Solar, and Battery resources starting in 2023

6. Reliability and Resilience

Maintaining system reliability and resilience is a foundational requirement for OPPD and is a central topic of OPPD's 2021 IRP. This becomes increasingly important as the electric grid transitions to lower-carbon sources of energy, as customers increasingly rely on the electric grid for basic needs, and as weather becomes more volatile due to the impacts of climate change. OPPD's 2021 IRP incorporates a range of reliability and resilience topics, including high-level transmission considerations, resource adequacy and a resilience study that focuses on system performance under a range of extreme conditions.

6.1. Resource Adequacy

As a basic requirement, reliable operation of the bulk power system requires matching electric supply with electric demand on an instantaneous basis. Failure to maintain this balance can result in unexpected brownouts or blackouts of the bulk electric system, which can severely impact the health and safety of our communities. To ensure that this does not occur, utilities must plan to have sufficient resources under a wide variety of conditions, including diverse weather, load, fuel supply and generator outage conditions. This topic is called resource adequacy.

Resource adequacy is well established within the electric industry and is monitored and maintained at the regional level by SPP and at the federal level by NERC. These entities have established high-level guidelines and requirements for ensuring sufficient resources.

Traditionally, resource adequacy has focused on generator supply during peak load periods, as this is generally when the system is most stressed and requires the most generation capacity. Sufficient capacity during these periods ensures that, even if generators trip offline unexpectedly due to maintenance issues, utilities are able to continue serving all customer demand reliably.

However, integration of large amounts of variable energy resources (i.e. wind and solar) or energy limited resources (i.e. battery storage) create additional planning uncertainties for resource adequacy modeling. While wind and solar can produce during critical periods, their output is driven by weather conditions, which are outside of operational control. Battery storage may be able to shave system peak loads, but current technologies only provide limited duration. To account for these uncertainties, quantitative models are being adopted across the industry to more accurately value the resource adequacy contribution of these new resource types. This modeling is used to develop Effective Load Carrying Capability (ELCC) for specific resource types by simulating system Loss of Load Expectation (LOLE) under a wide range of conditions.

OPPD's 2021 IRP modeling uses industry-leading methods to simulate the resource adequacy contribution of different resource types over a long time horizon, taking into consideration OPPD's changing load profile and the saturation of renewables on the bulk electric system. This is an important planning consideration, as OPPD must plan for a reliable system throughout the planning horizon.

OPPD’s detailed resource adequacy analysis is an integrated and quantitative approach to address topics such as diversity, reliability and dispatchability, which are required as part of OPPD’s IRP submission to WAPA.

6.1.1. Loss of Load Expectation (LOLE)

Loss of Load Expectation is a study that evaluates the expected number of hours statistically in a given year that peak production cannot be met. This is an industry standard method of evaluation. The target LOLE in the model is 0.1 days a year (99.972%). This target allows the model to produce the needed PRM in the near and long-term planning horizon. The target PRM set by SPP is currently 12%, using the installed capacity (ICAP). The study used a unforced capacity (UCAP) based PRM and produced a PRM between 7% and 17% based upon the scenario to ensure that the LOLE targets were met. More detail on the LOLE study can be found in Appendix D.

6.1.2. Effective Load Carrying Capability (ELCC)

This method captures correlations between variable energy resources and load. Key outputs from this approach are the total capacity requirement (MW) in order to meet the 1-day-in-10-year standard. ELCC values are not static throughout long-term planning horizons. For each resource, ELCC depends on the penetration of the given resource as well as the quantity and type of other resources on the system. There are diminishing return impacts of variable and energy-limited resources, this is reflected by a decline in ELCC value at higher penetrations.

There is also a calculated diversity benefit when the combined capability of two resources may exceed the sum of the capability of the parts. More detail on development on ELCC values can be found in Appendix D.

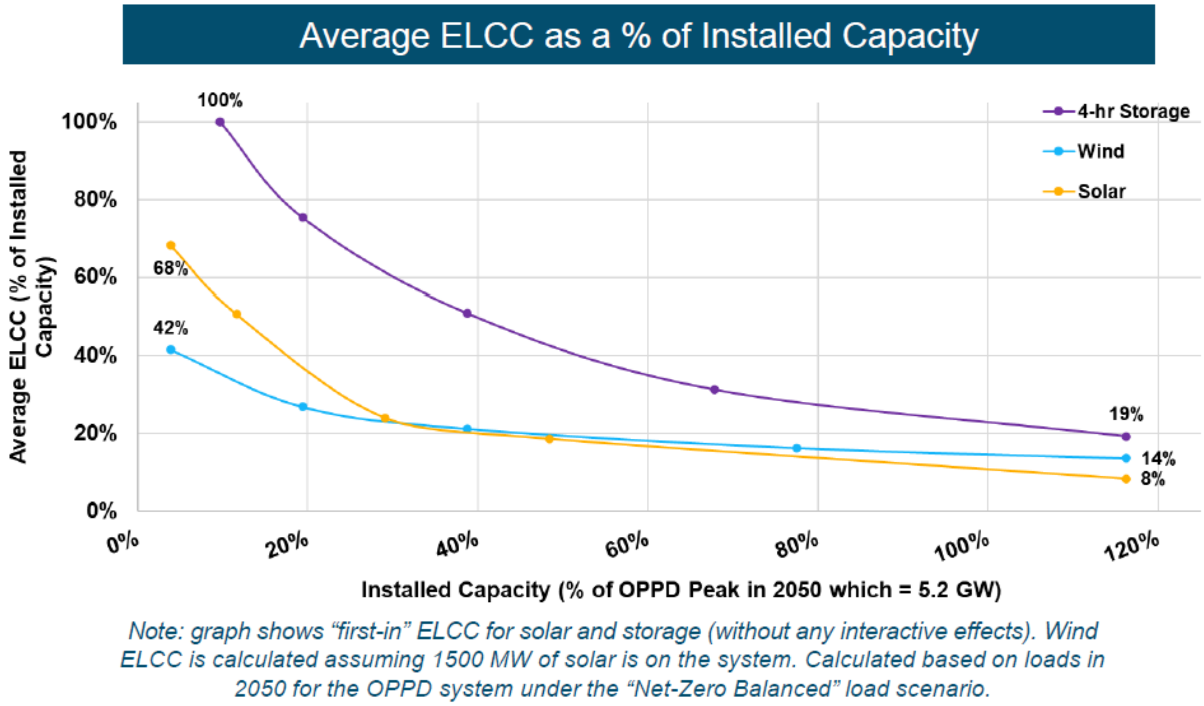


Figure 6-1 Average ELCC as a % of Installed Capacity

6.2. Resiliency Analysis

This risk test is for OPPD's net-zero carbon portfolio against four case studies. These case studies provide support behind how much firm generation is needed when and for how long.

6.2.1. Extended Low wind and solar output

Reliability metrics indicate critical periods that shift from summer afternoons to winter low wind and solar periods. Low wind and solar conditions are the primary drivers to reliability challenges.

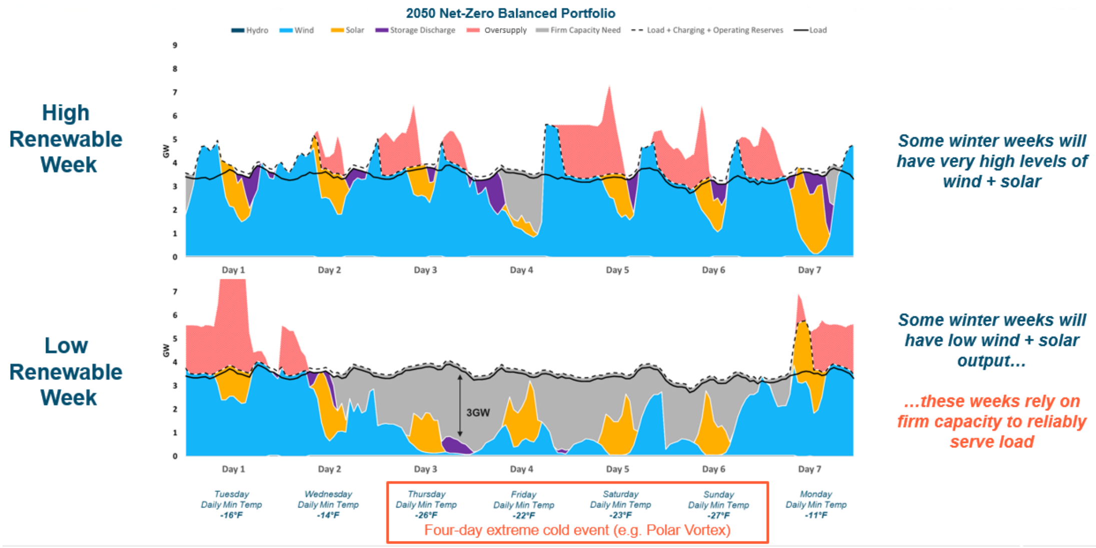


Figure 6-2 Low Renewable Week Resiliency Event

6.2.2. Extreme summer heat

Simulations for system conditions were conducted under an extreme heat event for both sufficient wind and solar output as well as low wind and solar output. Then, resiliency stress events were added to the simulated system. The resiliency stress events include climate impact assumptions and a five-degree-Fahrenheit temperature increase by mid-century.

6.2.3. Extreme winter cold

Simulations for system conditions were conducted under an extreme cold event for both sufficient wind and solar output as well as low wind and solar output. Then, resiliency stress events were added to the simulated system.

6.2.4. Extreme localized event

The resiliency challenge for all types of extreme events is the ability to withstand and/or recover from the events and return to normal operations. The impact of local events will depend on multiple factors: the widespread the nature of the event, OPPD's geographic diversity of resources, and networking of transmission facilities are key factors. Local events like tornados may be catastrophic to an OPPD generator, but OPPD reliability could be retained through geographic diversity, resource diversity, fuel security, local transmission investments, and if SPP generators can replace its output and transmission connections to SPP remain intact.

Figure 6-3 2019 Flood, Transmission Structures in water by the Elkhorn River, Nebraska

6.2.5. Resiliency Analysis Results

Resiliency case study results show that by 2050 reliability challenges will shift from peak demand to low renewable periods. In these low renewable periods, firm capacity is required to maintain reliability for extended renewable droughts. Additional information on the transmission system inputs can be found in section 7.5.

Extreme heat may also pose a threat to reliability during period of low wind and high loads. These events can be withstood, however, with sufficient firm capacity.

Extreme cold may threaten reliability through fuel availability challenges. This type of even may cause major customer outages if not mitigated. These impacts can be mitigated through steps such as winterizing fuel infrastructure, additional on-site backup fuel and wind turbine de-icing technologies.

The ability to withstand and recover from extremely localized events relies on OPPD's geographic diversity, resource diversity, fuel security, local transmission investments and interconnection to the broader regional SPP market to secure necessary essential reliability services. Steps to reduce the impact of these events include operational reliability studies on key asset contingencies, on system reliability investments and SPP reserve products to incent system flexibility.

Table 6-1 Resiliency Findings

Resiliency Scenario	Outcome
Extended Low Solar and Wind Output	• By 2050, reliability challenges shift from peak demand to low renewable periods • Firm capacity is required to maintain reliability during periods of extended low solar and wind output
Extreme Heat	• Extreme Heat may threaten reliability during periods of low wind and high loads • These events can be withstood with sufficient firm capacity

Extreme Cold	• Extreme cold may threaten reliability through fuel availability challenges • This can be mitigated via: winterizing fuel infrastructure, additional on-site backup fuel, and wind turbine de-icing technology
Extreme Localized Events	• Ability the withstand and recover from localized events depends on OPPD's geographic diversity, resource diversity, fuel security, local transmission investments, and the interconnection to the broader regional SPP market to secure necessary essential reliability services • Mitigation steps include: operational reliability studies on key asset contingencies, on-system reliability investments (e.g. synchronous condensers), solar facility design for high wind speeds, and SPP reserve products to incentivize system flexibility

6.3. Transmission Considerations for Resource Planning

Since the transmission system is comprised of a myriad of networked transmission lines of varying sizes and voltage levels, complex electric system modeling of resource changes is imperative in order to maintain a reliable and resilient system. Traditional transmission planning techniques employ a nodal, deterministic analysis evaluating set snapshots in time that represent book ends for the various seasonal variations in load and generation makeup. This is in stark contrast to traditional resource planning techniques that mainly focus on zonal, probabilistic, hourly or sub-hourly load and generation makeup. There is currently no software available commercially that fully and simultaneously includes both transmission planning and resource planning considerations. The integration and evaluation of resource planning decisions and the impacts to the transmission system have been traditionally evaluated using an iterative approach and not necessarily as part of a co-optimized integrated analysis. The desire to better integrate transmission planning with resource planning required an innovative approach to including more meaningful transmission system reliability and resiliency aspects.

7. Modeling Approach

In order to achieve its decarbonization goal, OPPD launched its Pathways to Decarbonization Strategic Initiative. This broad resource planning effort identifies potential pathways to achieve net-zero along with associated impacts to affordability and reliability. E3 worked side-by-side with OPPD throughout the modeling process. Together OPPD and E3 developed a robust and detailed study to understand pathways for decarbonization for OPPD and its service territory.

7.1. Approach Overview

The study incorporates key assumptions, market forecasts, multi-sectoral impacts, technology options and forecasts, resource adequacy, and resiliency analysis. The modeling approach takes place in three phases: Portfolio Development, Portfolio Validation and Portfolio Completion.

- The Portfolio Development phase consists of building resource pathways to meet OPPD's net-zero carbon goal, at least cost while maintaining resource adequacy.
- The Portfolio Validation phase validates the reliability and resiliency of the net-zero technology pathways with specific focused analysis.
- The Portfolio Completion Phase includes finalization of outputs for presentation and communication and a review across pathway outcomes.

There are several software solutions utilized in the development of the decarbonization pathways. PATHWAYS, a LEAP software, is an economy-wide representation of infrastructure, energy and emissions within a given geography. The Portfolio Development phase utilizes both RECAP and RESOLVE build optimized resource portfolio pathways to meet OPPD's net-zero carbon goal, while achieving least cost and maintaining resource adequacy. The Portfolio Validation Phase utilized PSSE, and TARA. This phase validate the reliability and resiliency of the net-zero technology pathways.

Table 7-1 Modeling Software Solutions

Tool	Brief Description
PATHWAYS	PATHWAYS is a model that allows users to define scenarios that achieve various energy and/or climate policies. PATHWAYS modeling includes stock rollover treatment of appliances, vehicles and building shells. It also includes modeling of low- and zero-carbon fuels, including hydrogen, synthetic fuels and biofuels, as substitutions for fossil fuels.
RECAP	This modeling software performs a loss-of-load probability analysis designed to evaluate the resource adequacy of electric power systems, including systems with high penetrations of renewable energy and other dispatch-limited resources such as hydropower, energy storage and demand response.
RESOLVE	An optimal capacity expansion model specifically designed to identify least-cost plans to meet reliability needs and achieve compliance with regulatory and policy requirements, such as GHG reductions.
PSS/E	PSS/E by Siemens PTI is a high-performance transmission planning and analysis software. This software is an industry standard used by transmission planning and operations engineers.
TARA	Transmission Adequacy & Reliability Assessment (TARA) by PowerGEM is a steady-state power flow software tool with modeling capabilities and analytical applications that extend beyond traditional power flow solution software.

The development of a robust set of assumptions for these tools is critical to the outcomes. Key assumptions include OPPD's current resource portfolio load forecasts, candidate technology forecasts, resource and fuel cost forecasts, transmission system capability and regional market dynamics. These elements play an impactful role in ensuring a reliable and resilient system for OPPD in a broad range of future market scenarios and are presented throughout OPPD's 2021 IRP and in E3's Pathways to Decarbonization study report.

7.2. Market Forecasts

OPPD's market outlook on fuel, power prices and general economic assumptions play an important role in simulating regional market dynamics and economic outcomes. Utilizing a rigorous analytical approach to forecasting these market elements ensures the highest quality results based on the best available information.

7.2.1. Fuel Forecasts

Fuel forecasts are a fundamental modeling input and were traditionally very significant component of total portfolio costs. While these forecasts remain important, they become less impactful to portfolio results for highly renewable energy portfolios that are less dependent on fuel consumption and therefore less sensitive to fuel- price volatility.

7.2.1.1. Coal Forecast

Coal costs are evaluated regularly for budgeting and modeling purposes. Coal forecasts are developed using two key methods. First, an aggregation of multiple, long-term proprietary vendor forecasts specific to delivered coal costs in Nebraska; and coal contracts OPPD already has committed to in the near-term.

OPPD's forecast does expect a modest recovery in coal prices over the next few years. Coal prices are expected to see continued downward pressure as a result of a protracted period of oversupply, lower natural gas prices and an aging coal generation fleet. Forecast details can be found in E3's Pathways to Decarbonization Results.

7.2.1.2. Natural Gas Forecast

Natural gas prices have historically influenced the market price of power in SPP more than any other fuel type. As a result, OPPD regularly calculates site-specific natural gas cost for budgeting and modeling purposes. The forecast for future natural gas prices is very important in the evaluation of resources in the 2021 IRP. The total cost of natural gas is comporised of a commodity price and a price for firm gas delivery. Weather, storage levels, consumer demand, production levels and production costs drive the price of natural gas. OPPD developed the natural gas price forecast used in the 2021 IRP using an aggregation of proprietary vendor forecasts and forward market prices.

According to EIA data, U.S. production of natural gas has grown 24.8% from 2016 to 2020. Robust production from shale gas is expected to continue the downward pressure on natural gas prices in the near-term. Natural gas prices are expected to increase in the long-term as a result of the growth of U.S. liquefied natural gas export capability and increasing demand from electric utilities. U.S. liquefied natural gas exports grew to record highs in the first half of 2021, and natural gas exports to Mexico established a new monthly record in June of 2021. Forecast details can be found in E3's Pathways to Decarbonization Results.

7.2.1.3. Fuel Oil Forecast

Fuel oil prices have not historically played an impactful role in the market price of power of SPP; this represents less than .01% of OPPD's energy supply. However, recent weather events, including Winter Storm Uri in February 2021, have increased OPPD's focus on the role of fuel oil to provide a critical energy hedge during times of low natural gas availability. The forecast is developed using an aggregation of proprietary vendor forecasts and forward market prices. Forecast details can be found in E3's Pathways to Decarbonization Results.

7.2.1.4. Renewable Gas Forecast

While OPPD's assets have varying levels of capability to use renewable gas, OPPD does not currently use renewable gases such as renewable natural gas and hydrogen as part of its fuel mix. Longer-term analysis was performed for the Pathways to Decarbonization: Energy Portfolio study. The analysis is composed of data from the E3 analysis for the base forecast and BloombergNef's (BNEF) 2020 Hydrogen Economy Outlook for the low-cost forecast. OPPD will continue to monitor resources and market conditions to determine the timing for additional use of the forecast and forwards for market prices. Forecast details can be found in E3's Pathways to Decarbonization Results.

7.2.2. Power Prices

Power prices for this study were developed within E3's RESOLVE tool and are reflective of hourly economic optimization of the regional electric system. By modeling hourly operations of the electricity system explicitly as part of its optimization, RESOLVE's investment plan is directly informed by the dynamics of system operations and the associated costs to serve load throughout the year. This is especially important for systems with large amounts of renewable generation, energy storage, hydroelectric generation, or other variable and limited duration resources, where representing hourly patterns and the associated flexibility challenges, as well as interactions among various resources, is crucial to identifying the correct combination of investments.

Natural gas prices and penetration of renewable generation are two of the most important determinants affecting long-term wholesale power prices.

According to the SPP Annual State of the Market Reports, in 2016 there was approximately 16,114MW of installed wind capacity, and 215MW of installed solar capacity in the SPP footprint. At the end of 2020, there was approximately 27,458MW of wind capacity, and 235MW of installed solar capacity. Future generation additions (and retirements) are implicit in the forward price curves. The pricing of this energy reflects the supply and demand balances in the entire Midwest region. These prices are based on the incremental fuel cost of the generating units, which perform the load-regulating duty during on-peak periods and are usually natural gas-fueled combustion turbines or combined cycle units.

7.2.3. General Economic Assumptions

Forecasting of economic assumptions such as economic growth, inflation and interest rates, as well as other economic variables, affect generation portfolio decisions. The major economic assumptions used in developing the forecasts for the 2021 IRP, which include generation cost estimates and the load forecast, include annual average inflation estimate of approximately 2%. At the time the analysis began, OPPD used an annual interest rate of 3% to secure long-term financing, during the study period, in alignment with the Federal Reserve Open Market Committee's long-term inflation goals and notwithstanding the most recent (November 2021) Personal Consumption Expenditure price index of 6.8%. OPPD will continue to monitor the changing cost of capital over time and incorporate updated, more detailed forecasts in any advanced impact studies. The discount rate, which is the marginal opportunity cost associated with capital secured and used to equate streams of revenue requirements to a present value equivalent (i.e., time value of money), was 5%.

7.3. Multi-Sector Modeling

Electrification plays a vital role in decarbonization across the broader economy. Multi-sector modeling forecasts electric demand will grow due to the electrification of end uses such as transportation and building energy use. The multi-sector modeling also informs the Pathways to Decarbonization: Community efforts by identifying the reduction potential of different focus areas. Multi-sector modeling provides a range of electricity demand to inform the portfolio optimization. This modeling will also facilitate discussions on what policies might be needed to support economy-wide decarbonization.

There are several key pillars of economy-wide decarbonization. These include energy efficiency and conservation, electrification, low-carbon electricity and low-carbon fuels. OPPD electric loads are forecasted to grow significantly across all economy-wide decarbonization scenarios. By 2050, OPPD’s annual electric load is 2.5 times larger than today due to a growing population, economy, electrification of transportation, buildings and industry in certain scenarios. Zero-carbon electricity becomes critical to decarbonize other economic sectors. Low-carbon fuels (biogas and hydrogen) also play a key role in areas that are difficult to decarbonize. OPPD has a key role to play in supporting the transition of the overall economy, but all sectors of the economy must undergo transformation.

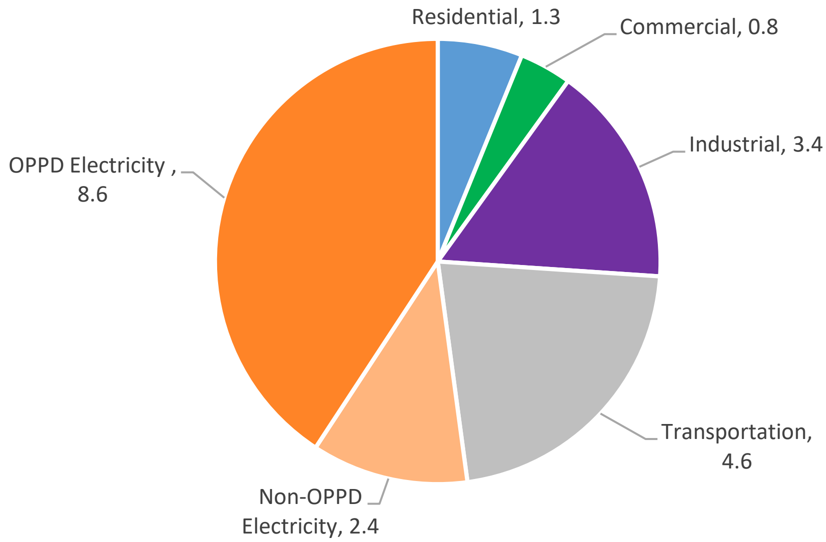


Figure 7-1 OPPD Service Territory GHG Emissions by sector in 2018 (MMT CO2e)

The model was benchmarked to 2018 for OPPD's service territory. Electric generation produces approximately 50% of economy-wide GHG emissions from energy use. The other half is split between non-electric energy use in transportation, as well as residential, commercial and industrial sectors. The multi-sector modeling scenarios examine a Reference scenario, which reflects current trends; a Moderate Decarbonization scenario, which reflects modest efforts of economy-wide decarbonization; and net-zero scenarios, which draw out a range of deep, economy-wide decarbonization futures. In all scenarios, OPPD's net-zero carbon goals are achieved and focused on the economy-wide decarbonization futures. These scenarios and their results can be found in Appendix D.

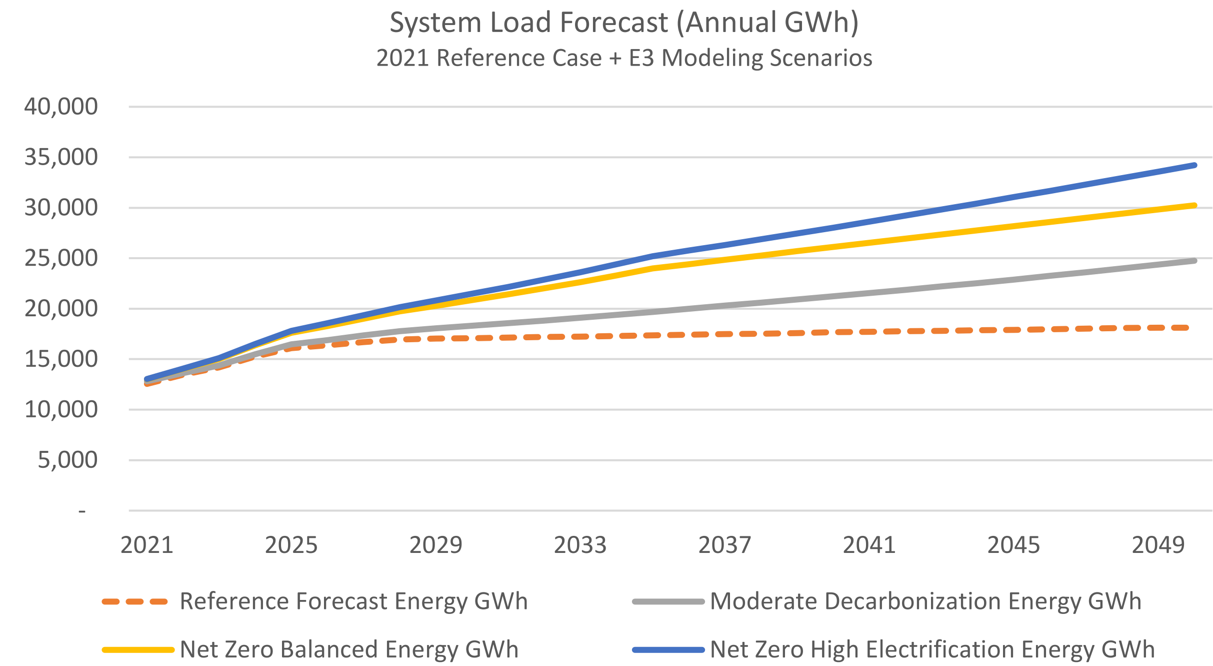


Figure 7-2 Multi-Sectoral Load Forecast

7.4. Technology Options and Forecasts

OPPD used the International Energy Administration (IEA) Technology Readiness Level (TRL) to prioritize and score technologies along a five-point spectrum from Mature, Emerging and Experimental.

Table 7-2 Technology Maturity Spectrum

	Technology Maturity Spectrum (1 – 2)	Technology Maturity Spectrum (3)	Technology Maturity Spectrum (4 – 5)
	Mature Technologies	**Emerging Technologies**	**Experimental Technologies**
Market Experience	Fully commercialized	Limited development	No development
Data: Costs	Available, documented near-term costs and established trajectories	Limited, possible near-term costs but speculative cost trajectories	Theoretical, no real-world cost data
Data: Potential	Available	Limited	Theoretical
Data: Operating Characteristics	Available	Limited	Theoretical
Examples	Solar, wind, battery storage, fossil gas CT/CCGT	Gas w/ CCS, small modular nuclear reactors, direct air capture, H2 combustion, power to gas seasonal storage	Advanced geothermal, new ultra long-duration storage technologies
Proposed Approach	**Model in all scenarios**	**Model in sensitivity scenarios**	**Do not model due to lack of data**
Impact	***Drives results + near-term decision making***	***Informs least-regrets planning, stranded asset risk***	***Informs R+D spending, pilot projects***

Based upon this evaluation of technologies OPPD identified technologies in each of these maturity levels and a feasibility screening to include geospatial considerations. The feasibility screening eliminated technologies such as hydro, pumped hydro storage and geothermal due to limited or no availability within the OPPD service territory. Selected candidate technologies to include in all the GHG Target scenarios were identified in the modeling process in accordance with technology availability and the additional sensitivities.

Table 7-3 GHG Target and Technology Availability

GHG Target	Technology Availability
Reference (no target)	• Mature + Hydrogen
Net-zero by 2050 Straight Line	• Mature Only • Mature + Hydrogen • Mature + Hydrogen + Emerging
Net-Zero by 2050 Accelerated Pace	• Mature Only • Mature + Hydrogen • Mature + Hydrogen + Emerging
Net-Zero by 2050 Moderate Pace	• Mature Only • Mature + Hydrogen • Mature + Hydrogen + Emerging
Absolute Zero by 2050	• Mature Only • Mature + Hydrogen • Mature + Hydrogen + Emerging
Near-Zero (80%, 80%, 95%)	• Mature Only • Mature + Hydrogen • Mature + Hydrogen + Emerging

The sensitivities are single variable changes from the base case assumptions. These include sensitivities such as multi-sector high-electrification, technology cost breakthrough reductions, carbon price and penalty for imported electricity with no export credit. The list of technology reviewed is shown in Appendix C.

7.4.1. Supply-Side Options

OPPD identified over 150 different technologies for inclusion in the study. These technologies have a varying level of technical feasibility and maturity. Data is limited for many technologies not yet at a commercial scale. OPPD also evaluated a range of options for existing assets to support the transition to the net-zero carbon goal. Existing Resources Conventional generating technologies such as natural gas combined cycle, natural gas combustion turbine, reciprocating engines, and existing unit fuel conversion were included as supply-side options in the study. Carbon capture and sequestration was not considered for the coal generation units. The costs are significantly higher than the alternatives, and coal produces significantly higher volumes of CO2 needing to be sequestered. A lack of geologic formations supporting sequestration near OPPD's service territory would require reliance on speculative future infrastructure. Carbon capture and sequestration will be considered for natural gas. This is due to different capture technology and because these units produce significantly lower volumes of CO2 than coal-generation units. Carbon capture and sequestration technologies and developments will continue to be monitored. The technology costs curves are discussed in Appendix D.

Utility-scale renewable energy will play a key role in OPPD's pathways to decarbonization. Solar and wind are included in the study. These resources are relatively low-cost compared to other forms of zero-emission technology. This region also has a high potential for generating those resources. Hydroelectric power was determined to be infeasible in this region due to geology and existing hydro facilities outside of OPPD's territory. Biomass was also determined to be infeasible, as well as geothermal due to geology.

Energy storage may play an important role in shifting wind and solar production on a daily basis. Shorter-duration energy storage presents key opportunities to shift energy within the day from lower-demand hours to higher-demand hours. It also allows for upward and downward regulation or load following reserves, and capacity value until energy becomes limited and peak extends beyond duration. Mid-duration energy storage has the same value streams as shorter-term energy storage but can provide capacity value for longer and may also allow for shifting energy across days. A key opportunity with long-duration storage is energy shifting between days/ weeks/ seasons. Long-duration storage will be addressed in this study modeling seasonal storage (power to gas to power); OPPD will continue to monitor other technologies for long-duration storage.

Low-carbon dispatchable resources will be needed to support grid reliability in extreme conditions. These are placed into three categories:

- **Conventional generating technologies** – Evaluated technologies such as natural gas combined cycle, natural gas combustion turbine, reciprocating engines, existing unit fuel conversion
- **Emerging Technologies** – Evaluated technologies such as Small Modular Reactors (SMRs), , natural gas with carbon capture and sequestration, hydrogen capable generation, and long-duration energy storage were evaluated.

  Hydrogen (H2) capable generation has key opportunities such as clean, firm zero-carbon capacity. Some key challenges with H2 are the high costs of fuel, electrolyzer technology maturity, and the H2 storage and transport infrastructure. The approach used for H2 for this study is to model H2 combustion in CTs (fuel via off-grid production). Presently, hydrogen can be used in stationary fuel cells, for power generation, to provide fuel for fuel cell vehicles, or stored as a compressed gas for later use. The interest in H2 is growing but current costs of the technology are high. A reduction in H2 technology cost and continued advancements may drive widespread usage of the technology in the future.

  Carbon Capture and Storage (CCS) has a key opportunity for clean, firm very low-carbon capacity (with greater than or equal to 90% capture rate). A key challenge with CCS is CO2 storage and transport infrastructure. The approach for CCS in this study is to model gas with CCS, not modeled with coal due to significantly higher costs.

- **Negative Emissions Technologies/ Offsets** – traditional offsets such as planting trees, direct air capture (DAC). A key opportunity with DAC is offset emissions by carbon dioxide removal from the air. A few key challenges with DAC are its technological maturity, CO2 storage and transport infrastructure. The approach for DAC in this study used as the model assumed approximately $200-250/ ton CO2 extracted.

Figure 7-3 Green Hydrogen Demonstration Project (Photo credit New York Power Authority)

7.4.2. Demand-Side Options

OPPD modeled a variety of demand-side options in the study:

- Continued review of future DSM opportunities through the Pathways to Decarbonization: Customer project and the Product Development and Marketing (PDM) team
- Distributed Energy Resources (DER)
- Energy efficiencies both explicitly defined by OPPD as well as future-building code and appliance efficiencies
- Demand response programs are modeled in this study as defined by OPPD
- Behind-the-meter solar, storage, flexible loads (emerging)

The OPPD portfolio optimization inputs include multiple types of energy efficiency improvements across the economy. These include OPPD's current and planned EE and

DR programs. There are additional energy efficiencies through appliances and building shell upgrades gleaned from the economy-wide analysis. Each case has the ability to select additional EE and/ or DR.

The magnitude of EE included is similar to the types of transformative energy-efficiency gains seen over the past few decades. This period includes advancements in technology, building codes, smart devices and more. Reaching net-zero carbon efficiently requires significant economy-wide gains, resulting in lower energy use despite economic and population growth.

OPPD's current identified and potential programs (194MW by 2024) only account for a small portion of the total energy efficiency included. These other areas of EE included in the overall study scope baseline are industry efficiency, commercial appliances, and lighting, commercial heating, residential appliances and lighting, residential heating and building shells. These EE resources make an impact by 2050 of over 2,500 GWh annually. Customers and communities play an essential role in enabling this level of future EE, DR and net-zero. Continued work through Pathways to Decarbonization: Customer, OPPD will engage with customers around how to enhance products and services offered so they can improve energy efficiency and reduce greenhouse gas emissions. The Pathways to Decarbonization: Customer pathway through phase one and two has reviewed and scored 228 concepts. The top 10 scoring product concepts (in no particular order) are:

Residential Programs:

- Energy Star Appliance Program
- Electric Yard Equipment Program
- LED Lighting & Controls Program
- Community Solar Expansion Program
- Weatherization Program
- Energy Efficient Smart Thermostat Program

Business Programs:

- Outdoor Lighting & Controls
- Food Service Equipment
- EV Fleet Adoption
- Business Community Solar

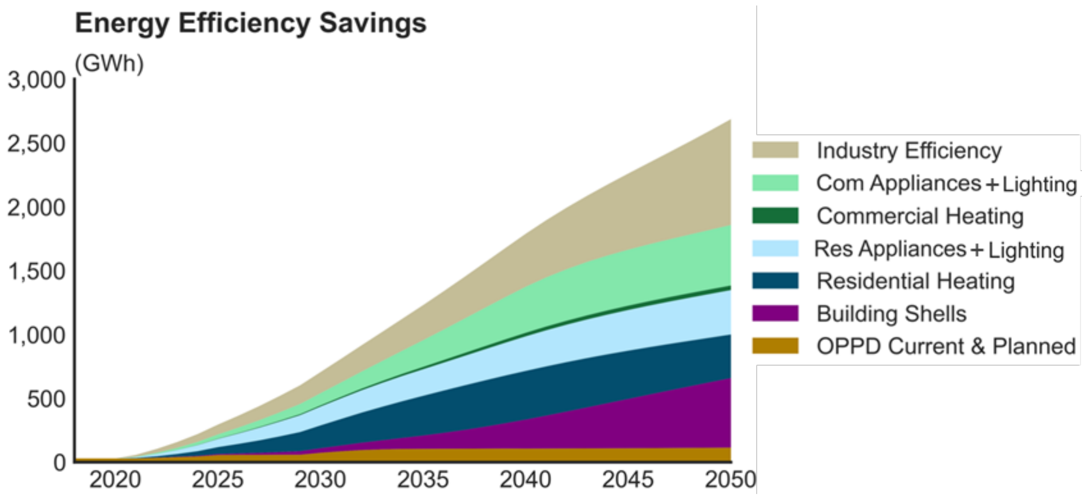


Figure 7-4 Energy Efficiency Savings (GWh)

Electrification promotes significant energy efficiency, especially in transportation and building primary energy consumption, but this electrification adds considerable electricity growth. Electric load growth is partially offset by significant, embedded energy efficiency gains, particularly through the adoption of energy-efficient appliances and building shell upgrades, which can account for an estimated 22% reduction in total electricity use.

7.5. Transmission System Reliability & Resiliency

OPPD developed a framework that integrates more in-depth transmission system characteristics with traditional resource planning. This advanced framework better informs which resource portfolios provide reliability and resiliency attributes under the aforementioned changing industry and environmental landscape. Those in-depth transmission system characteristics are:

- Simultaneous transmission import/export limits
- Transmission forced outage rates
- Transmission expansion costs and assumptions
- New resource interconnection assumptions
- New resource deliverability assumptions

7.5.1. Simultaneous Transmission Import/Export Limits

With transmission system operations in mind, two transmission planning screening methods were employed to identify significant thermal and voltage constraints on OPPD's transmission system. Leveraging existing SPP regional transmission planning models the screening methods were developed. The first method, First Contingency Incremental Transfer Capability (FCITC) was used to identify significant thermal constraints. These transmission constraints are represented by monitoring transmission elements (branch flows and transformer loadings) following credible single element (e.g. N-1) contingencies. The purpose of FCITC is to identify the maximum power that can be transferred from one area to another area across a networked transmission system before transmission elements become overloaded. A reliable transmission system as prescribed by federal regulations is one in which the networked transmission system has adequate capacity even during forced outage scenarios.

The second method, a Power-Voltage (PV) screen, was used to identify significant voltage constraints. These transmission constraints were identified by monitoring transmission buses following credible N-1 contingencies. The purpose of the PV screen is to identify instances where transmission network voltage declines due to insufficient voltage support. Simulated power transfers were used to stress OPPD's system until voltage declined to a minimum acceptable operating point. A transmission system that is reliable has sufficient voltage stability and is able to sustain adequate voltage at every bus of the transmission network even during forced outage scenarios.

The results of the two transmission planning screening methods identified that the most limiting conditions occurred during times of heavy power imports. This information is then used as transmission system modeling inputs into the resource planning model to place an import constraint on OPPD's system that is based on nodal transmission planning techniques. These limits are applied to imports and exports as zonal limits, limiting the OPPD zone's interaction with the surrounding zones.

7.5.2. Transmission System Forced Outages

In order for new resources to be counted towards resource adequacy, OPPD must be able to rely on them during times of transmission system disruption. Like resources, transmission system elements experience both planned and unplanned outages from time to time. Consideration of transmission outages may impact the ability of a resource that is counted on for capacity to deliver its capacity when needed. In order to account for some of this behavior in a zonal model, transmission forced outage rates were developed to proxy the behavior of a zonal tie line between OPPD and the surrounding zones. These forced outage rates were developed through an analysis of historic planned and unplanned 345kV transmission outages. Three years of OPPD historical data was utilized to create average availability, outage rate and average outage duration. Utilizing the information gained from the determination of import limits, the average depth of outage was derived as the difference between import limit during system intact and the import limit following transmission outage events.

7.5.3. Transmission Expansion Costs and Assumptions

Further engineering analysis was performed to develop transmission expansion options to alleviate the transmission constraints that were identified during the import limit analysis. Each transmission expansion option was assigned a cost that was based on transmission upgrade costs from recent SPP transmission expansion planning studies and OPPD's own experience.

Transmission constraint mitigation was studied as upgrades to existing transmission system elements or addition of new transmission system elements. The estimated cost of each mitigation was tallied and the benefit of each mitigation was measured as the amount of the constraints alleviated. The end result of this analysis was the derivation of a cost-per-megawatt to define conceptual transmission expansion that is then used in the resource planning model in two ways:

- To expand the import limit when the model determines it is economical to do so.
- As a hurdle to making new off-system resources deliverable to OPPD load as described below.

7.5.4. New Resource Interconnection

SPP and the other regions in the U.S. are undergoing a major shift in generation composition and technology. This shift is magnified by the substantial cumulative amount of new generation waiting in backlogged Generation Interconnection Queues throughout the country. This backlog in generation interconnection requests has drastically increased the complexity and potential transmission system upgrade costs associated with adding new generation. To ensure that an estimation of the large transmission expansion costs are included in the IRP, an interconnection and deliverability transmission upgrade methodology was developed. In order for resources to be counted toward resource adequacy, the following two assumptions were made:

- **Interconnection Costs**: Every resource requires transmission upgrades to interconnect to the transmission system.
- **Deliverability Costs**: Resources farther away from load have a higher risk of transmission upgrade cost exposure

Interconnection costs for new generation resources can vary widely based on different variables that include local transmission topology, geographic location, size of resource, etc. All new resources interconnecting to the transmission system require transmission system interconnection upgrades in order for them to inject power into the system. To represent these interconnection costs, the average cost per MW was calculated from results of the two most recent Southwest Power Pool (SPP) Generation Interconnection studies. The purpose of this calculation was to proxy the SPP Generation Interconnection process in the resource planning study to account for upgrades necessary for generator interconnection. Interconnection upgrades do not automatically make a resource deliverable to the OPPD system for purposes of gaining accredited capacity, but are required for every new resource added during the resource expansion step.

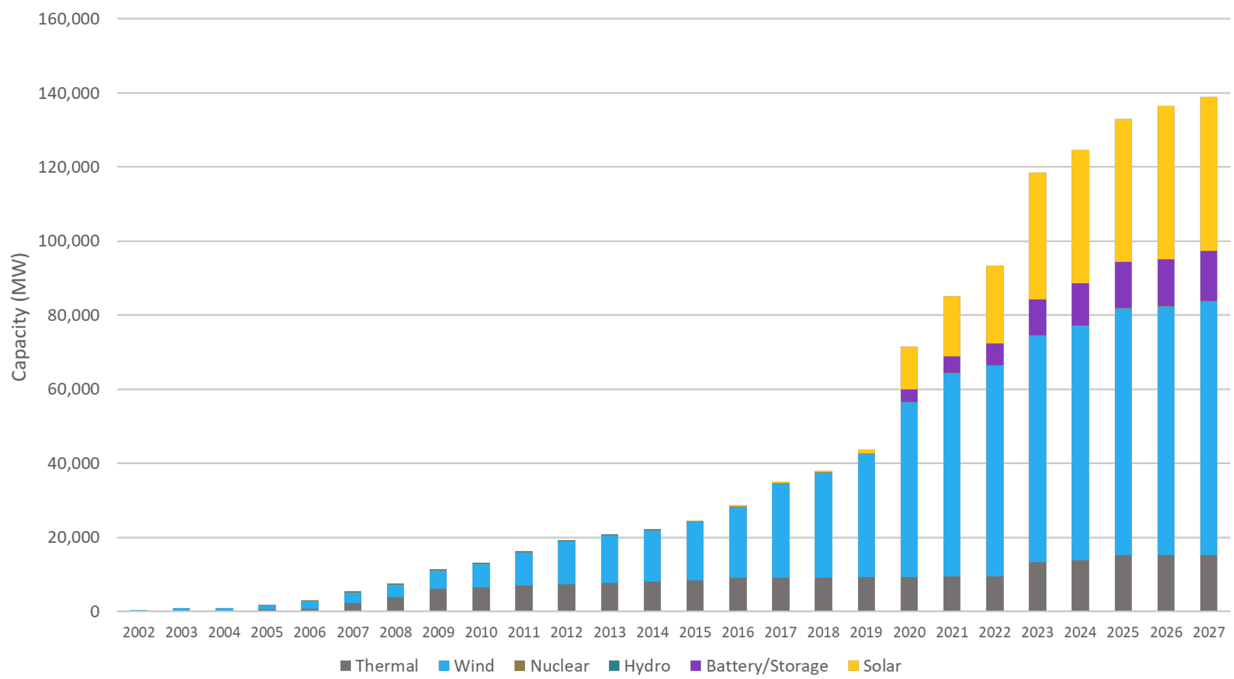


Figure 7-5 SPP Generation Interconnection Queue as of 1/14/2022

7.5.5. New Resource Deliverability

In order for an entity to accredit the capacity of a resource in SPP, the deliverability of a resource is assessed in an Aggregate Deliverability Study (AG Study). The study ultimately determines what transmission system upgrades are required for the resource to be deliverable to an entity's load. In general, the closer a resource is to the OPPD load, the lesser the risk exposure of large transmission network upgrades. To proxy for the AG study process, the Import Analysis, as described above, was used as the cost-per-MW basis for transmission upgrades needed outside of the OPPD area. Additional considerations were added to differentiate resources based on location. While the exact nature of transmission upgrades required for resource deliverability to OPPD's load cannot be known without exact knowledge of the resource size and interconnection location, in general, the farther a resource is from load, the more exposure it has to needing transmission system upgrades. Based on this, deliverability distance factors were developed. Resources located in the Nebraska resource zone were assigned a cost per MW equal to the transmission expansion cost per MW developed from the Import Analysis. For resources outside Nebraska, a multiplication factor was developed based on distance from OPPD. For consideration of resources located near OPPD but in SPP's neighboring region known as the Midwest Independent System Operator (MISO), an extra hurdle rate was developed in order to proxy delivering power from the MISO region into the SPP region and the OPPD area.

7.6. Resource Adequacy

Resource Adequacy is an established topic with industry-standard methods to ensure sufficient resources to meet electricity demands across a wide array of load and resource conditions. Operational reliability ensures that the grid has the capability and transmission connections to deliver power under a variety of operating conditions and events. ERS are fundamental attributes of resources required to support and operate the electric grid.

Insufficient resources can cause unexpected brownouts or blackouts of the bulk electric system. Modeling resource adequacy ensures there is sufficient reserve margin to account for:

- Forced outages of generators
- Higher-than-normal peak loads
- Unexpected weather conditions
- Normal operating reserves

This is typically done through a loss-of-load-probability study and is ubiquitous across the electric industry. The industry standard is to meet 1-day-in-10-year (or 99.972%). Variable energy resources and energy-limited resources provide different resource adequacy attributes than traditional firm and dispatchable generation. Planners need a new way to quantify the resource adequacy contribution of these resources that:

- Capture the declining marginal value of the resources as they serve a larger portion of load
- Capture the diversity benefits of combining resources to meet load

Diversity benefits capture the complimentary nature of resources, maximizing value to the system. Solar production reduces the summer peak, shifting to a narrower, shorter peak after solar hours. The resulting narrower peak is more easily satisfied by energy storage, increasing the capacity value of storage when combined with solar. Wind production is generally higher during the morning and evenings and has lower output during peak periods. Adding solar shifts the peak to evening hours when wind is more prevalent, thus increasing the capacity value of wind generation. However, there may still be periods when wind may not be available and firm resources are required.

In February 2021, the SPP region experienced Winter Storm Uri, affecting generation and causing insufficient generation to serve load. The event impacted all types of resources.

Renewable resources generally produced as expected during these conditions, but at lower than normal levels due to cloud cover and low wind speeds. These extended, low renewable periods challenge portfolios without firm dispatchable resources.

7.7. Resiliency Analysis

This analysis broadly ensures the system is prepared for, can withstand, and can recover from non-routine, high impact events. The focus on measurements and valuation is emerging topic with few established industry methods and metrics. Resiliency analysis is increasingly important as weather and non-traditional threats become more frequent. These events can be impacted by local systems, the types and frequency of catastrophic weather events and other factors. Resiliency is the ability of the system and its components to prepare, withstand, respond, adapt and quickly recover following a non-routine, high-impact disruption.

Resiliency analysis is generally focused on conditions outside the realm of existing reliability planning methods. Types of resiliency events that will be considered:

- OPPD loads under extreme weather events
- Fuel supply disruptions
- Low wind and solar output conditions

Resiliency of electricity portfolios assessed robustness to specific identified "resiliency events." The team identified potential resiliency events and the impact to electricity generation portfolio. To the extent that resiliency events impact the generation portfolio, the team considered options to improve the portfolio, including:

- Add resiliency infrastructure such as turbine blade winterization, levies
- Portfolio modifications such as modifications from wind to solar, distributed resources

7.8. Portfolio Optimization

Optimization identified a least-cost portfolio for each scenario while ensuring both reliability and environmental targets. All portfolios meet environmental/GHG targets for that scenario. All portfolios ensure that the system meets the resource adequacy requirements. Cost optimization developed a portfolio that minimizes costs.

The objective of the data-intensive modeling process is to produce optimal resource portfolios, subject to key modeling constraints. This minimizes the net-present value of electric system fixed and variable costs. This takes into consideration fixed costs of renewables, energy storage, energy efficiency, demand response, thermal and transmission assets. This also takes into account variable costs of operations and maintenance, startup costs, fuel costs and carbon.

Decisions from the optimization modeling are a review between resource investments or retirements and system operations.

Constraints within the process ensure that these areas are not violated. Constraints include reliability of the system, carbon reduction goals, hourly operations to ensure load and generation balance for every hour, subject to transmission limits, and resource limits so that the model does not build more resources than a given area can hold.

Key inputs into the portfolio optimization:

- Load forecast
- Market forecasts
- Existing resource options
- New resource options and constraints
- Fixed and variable costs for all technologies
- Transmission limits and expansion options

Key outputs from the portfolio optimization:

- Resource additions, retirements, or conversions
- System hourly dispatch
- System total resource costs
- System total emissions
- GHG abatement cost ($/ton)

8. Modeling Scenarios and Results

The modeling efforts create pathways in which OPPD can achieve decarbonization. The evaluation of modeling scenarios and sensitivities provides OPPD a better understanding of impacts of resource decisions in the near and long term in an effort to provide reliable, resilient and environmentally sensitive energy in a variety of potential futures. Additional modeling details are located with E3's Pathways to Decarbonization report.

8.1. Scenarios

The evaluation of scenarios explored various pathways to decarbonization and the impact of changes within the integrated marketplace. The results highlight new resource addition requirements for variable energy resources, energy storage and firm dispatchable resources.

8.1.1. SPP Capacity Expansion Scenarios

OPPD is directly impacted by changes within regional electric markets. Two scenarios are modeled for the future SPP regional resource mix: one assumes a reference scenario with business-as-usual conditions and the other considering GHG Mitigation where SPP as a region will achieve a 90% total GHG reduction by 2050. In both scenarios, near-term retirement dates of SPP resources are based on the latest SPP Integrated Transmission Planning Process assumptions.

Reference Case

The SPP Reference Case has no explicit GHG target. This creates a baseline for the SPP resource portfolio with only business-as-usual economics driving changes in the future selection, buildout and retirement of SPP resources.

Coal and natural gas steam turbines are retired based on existing current planned schedules and are largely replaced by new gas by 2035. There is increased solar and storage resources build out starting from 2035. There is not a notable change to the overall, installed wind resources capacity over the timeline.

GHG Mitigation Case

The SPP Mitigation Case has an explicit GHG target of 90% reduction by 2050. The scenario also includes a regional load increase of approximately 150 TWh due to regional electrification. This case creates an SPP resource portfolio with economics and an explicit GHG target driving the future selection, buildout and retirement of SPP resources.

SPP retirements occur in the mitigation scenario beyond the current planned retirements. There is also buildout of variable, energy storage and firm dispatchable resources to meet load requirements.

Coal and natural gas steam turbines that are retired based on schedules with additional retirements to achieve decarbonization targets. New firm dispatchable resources replace some of these assets. There is increased buildout of variable and storage resources to meet the increased energy demand.

8.1.2. OPPD Scenarios

These scenarios combine different assumptions that form different possible pathways to the future of OPPD's resource portfolio.

8.1.2.1. Reference Case

The OPPD Reference Case has no explicit GHG target. This is not consistent with OPPD policy but is utilized for comparing other scenarios for decarbonization impacts. This creates a baseline for the OPPD resource portfolio with only economics driving changes in the future of OPPD resources.

Without explicit GHG targets, emissions remain relatively, stable through 2050. The planned solar additions reduce emissions while load growth and expiration of wind PPAs increase emissions. In this scenario, some variable energy resources are selected based on economics as well as additional firm dispatchable resources. After 2027, the installed capacity of the overall portfolio remains relatively stable. Coal generation remains stable after North Omaha Units 4 & 5 are repowered from coal to natural gas.

8.1.2.2. Net-Zero Carbon by 2050

The OPPD net-zero carbon by 2050 case aligns with the board of directors' resolution. This creates a straight-line pathway to net-zero by 2050. This scenario load forecast includes major electrification of transportation, buildings and industry. The inclusion of the goal of net-zero by 2050 drives GHG-free resources.

OPPD's installed capacity increases substantially with the addition of large amounts of variable energy resources, over 12GW of solar, wind, storage and demand response will be added by 2050.

The annual energy needs increases almost 2.5 times in the scenario, as well. There is sustained electrification load growth and GHG reductions that drive new resource needs. Annual generation increases from under 15TWh to more than 35TWh in 2050. The generation demands of coal are replaced with gas, solar and wind.

Total capacity is largely renewable resources and energy storage. The annual energy is net-zero carbon. Firm capacity from fossil fuel and H2 enable gas resources to serve 60% of the resource adequacy needs. The installed capacity reaches about 16GW, with 12.5GW of variable energy and energy storage resources. Those variable energy and energy storage resources amount to only 2.3GW of resource adequacy capacity of the over 5.5GW required to meet an LOLE of 1-day-in-10-year standard.

8.1.2.3. Sensitivities

These are single variable changes to the base case assumptions. These changes test additional changes in the marketplace that would influence future portfolio decisions.

	Assumption	Base Case	Sensitivities
Framing Scenarios Assumptions	Pace of decarbonization	Net Zero 2050	Net Zero 2035, Absolute Zero 2050, Near Zero
	Technology availability	Mature + Hydrogen + Emerging	Mature Only, Mature + Hydrogen
Sensitivity Scenarios Assumptions	Multi-Sector electrification	Net-Zero "Balanced" scenario	High-Electrification, Moderate, Reference loads
	Technology costs	Baseline	Breakthrough reductions
	Carbon policy	No carbon price	Carbon price
	GHG import/export accounting	Penalty for imported electricity and credit for exported electricity	Penalty for imported electricity with no export credit

Figure 8-1 Sensitivity Scenarios Assumptions

Pace - These sensitives adjust the speed at which the scenario reaches the desired GHG reduction target. Four net trajectories were considered from a very aggressive net-zero by 2035 to moderated net-zero by 2050. The pace sensitivities have an impact on the timing of new resources and coal repowering.

The impact of the different paces is reflected in the increased build out of variable energy and energy storage resources installed capacity. Increasing the constraint around GHG emissions influences the speed of Nebraska City Station Units 1 & 2 repowering from coal to natural gas and retirements. The 2050 resource mixes in all paces are very similar in resource mix and volumes of resource types.

In the accelerated emissions reduction trajectories, OPPD sees a series of outcomes that include:

- Lower cumulative GHG emissions over time
- Increase in system cost over the time period
- Reduced optionality to take advantage of declining costs and emerging technologies
- Requires significantly more near-term infrastructure

Trajectories that are more aggressive increase system costs but reduce total cumulative emissions. The pace of the trajectories does not change the overall portfolios in 2050.

Absolute Zero by 2050 – Achieving absolute zero by 2050 was evaluated across a range of different technology availability scenarios, including mature only, H2-enabled gas and emerging technologies.

The results show that the more restrictive the technology assumption in the absolute zero scenario, the more challenging and more costly the solution, requiring either more expensive firm resources, or significant overbuild of variable energy resources coupled with energy storage.

In scenarios allowing H2 generation, this resource is selected in order to replace firm system capacity. When firm H2 is not availalble, SMRs are selected to fill this role while maintaining resource adequacy, although at a higher cost than H2-enabled firm generation.

The absolute-zero case with only mature technology does not allow for either H2-enabled in over 55GW of installed capacity. Extreme overbuild is required to satisfy resource adequacy needs.

The more variable energy and energy storage resources are required. In the absolute zero case with mature technology, the results lead to over 55GW of installed capacity. In most scenarios, H2-enabled gas (at a moderate cost increase) or nuclear power (at a high cost increase) is selected. The mature-only case drives extreme overbuilding for GHG and RA needs.

Load Sensitivities - These sensitivities affect the peak load and annual energy consumption through the 2050 time horizon based upon potential changes in consumers' energy needs. Four load trajectories were considered from the reference loads (with very little electrification) to high electrification. The high electrification scenario also requires about two times the planning reserve margin due to the peak winter heat challenge.

The load sensitivities result in increases in the demand of total annual GWh. The net-zero: balanced sensitivity has a load of about 28TWh and the net-zero: high electrification sensitivity has well over 30TWh. The planning reserve margin in the net-zero: high electrification sensitivity increases to 17%.

Installed capacity requirements increase with load sensitivities. The net-zero reference case has about 10GW by 2050 where the net-zero: high electrification sensitivity has just under 20GW of installed capacity. This increase in demand results in a scaled increase in variable energy, energy storage and firm dispatchable resources. The load scenario is a key driver of total resource needs and timing of coal repowering. All scenarios retain other existing firm capacity resources.

The high electrification sensitivity increases system costs due to the higher need for capacity and energy. There is additional H2-enabled gas capacity selected at significant cost but very low utilization. Additionally transmission and distribution capacity would be necessary, but gas infrastructure costs would be avoided. The load sensitivities show that the overall portfolios are similar, the scale of those resources increase or decrease based upon future load requirements.

Breakthrough Tech Costs - This sensitivity address the impact that breakthrough cost reductions on technology would have on the scenario. This assumes a decline in costs in clean energy resources (wind, solar, nuclear, etc.). Most of the inputs are based on NREL ATB low-cost scenario, though small modular nuclear reactors use aggressive industry-based cost assumptions.

Breakthrough technology cost sensitivity leads to the build out of nuclear as a resource. The reduced cost of nuclear, and its core as a firm dispatchable non-GHG emitting resource leads to a decreased buildout of some variable energy and energy storage resources, the total installed capacity need is decreased by around 15GW in 2050. This sensitivity also results in a decrease in total annual generation leading to reduced curtailments. Hydrogen fuel lowers costs but they are still higher than the net-zero case. Nuclear power provides firm capacity but is expensive.

High Flexible Loads - This sensitivity reviews the future impact of high, flexible customer loads and allowing demand to shift. The additional flexible loads are assumed available at a lower cost than bulk grid storage. Future OPPD studies will need to confirm the availability and cost.

The high flexible loads sensitivity results in the displacement of energy storage and reduces curtailment in 2050. The system capacity additions and retirements are similar in 2035. The system impacts reflect in the 2050 time horizon with a slight reduction in installed capacity build out. This reduced buildout of installed capacity leads to a decrease of about 1 cent/kWh in generation costs in 2050.

Carbon Price - This sensitivity reviews the impact of the Biden administration's interim Social Cost of Carbon. The cost of carbon increases from $0 per ton in 2021 to $63 per ton in 2030 and $87 per ton in 2050. Carbon price pushes fuel switching and early coal retirement by 2030-2035, but does not meaningfully change the 2050 portfolio.

The impact of this sensitivity with near-to-mid-term carbon price is greater than net-zero marginal abatement cost. This drives earlier coal repowering. The 2035 and 2050 portfolios are similar to the Net-Zero: Balanced scenario. Coal generation is repowered by 2035. The carbon price scenario achieves similar decarbonization objectives as other scenarios, but at significantly higher cost to OPPD.

Land Use Impact - This analysis reviews the scenarios and sensitivities to quantify the land use of each of the pathways. The review of land use includes both direct and indirect usage. Some examples of direct land use are wind turbine foundations and solar racking and PV panel areas. Solar energy has a larger direct land use impact compared to wind. Indirect land use is the total land footprint between wind turbines and between the rows of solar panels. Wind energy has a significantly larger indirect land use impact compared to solar. The net-zero scenario has a land use impact of less than 0.1% for solar and just over 1% for wind (direct and indirect) in Nebraska. The net-zero scenario has a land use impact of about 62 sq. miles of direct and 721 sq. miles of indirect land use for solar and wind. The city of Omaha is 145 sq. miles, the state of Nebraska is 77,358 sq. miles.

8.2. Scenario Resources Summary

Portfolio optimization produced a very similar future resource mix across all OPPD scenarios; however, these pathways change in scale based upon load and change in implementation timeline based on the pace of decarbonization. OPPD's 2050 resource mix is not significantly impacted by SPP GHG goals and trajectory. The resource mix added in the scenarios through 2030 is a mixture of solar, wind and energy storage resources. While the intensity of each resource varies between the scenarios, the addition of these resources occurs in all of them. The figure below shows the ranges of resources selected to be built in the scenarios and sensitivities.

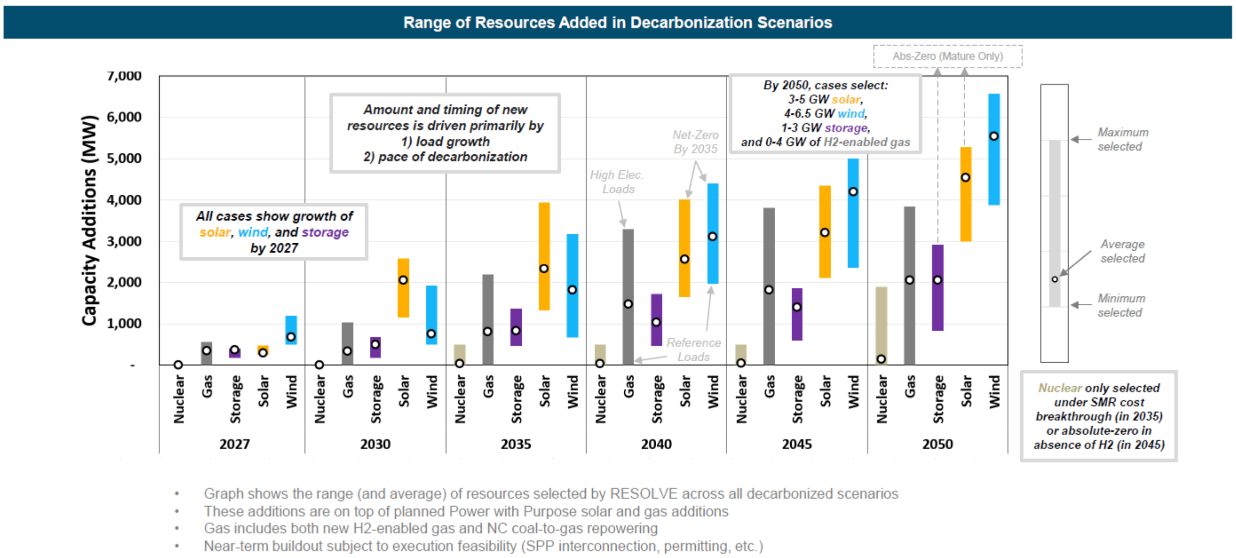


Figure 8-2 Range of Resources Added in Decarbonization Scenarios

OPPD's current fleet of existing and current planned firm dispatchable asset portfolio maintains commonalities within the scenarios. Nebraska City Station Units 1 and 2 continue to support reliability and resource adequacy in all scenarios in the near-term, although their utilization decreases significantly, with faster decarbonization leading to earlier conversion from coal to natural gas. Cessation of coal and repowering occur at varying times based on load and timelines. NOS Units 4 & 5 cease operations on coal by the end of 2023 and will be available on natural gas by the summer of 2024. The construction of PwP natural gas assets directly supports the decarbonization effort as the PwP study concluded as well as the decarbonization study. Turtle Creek Station and Standing Bear Lake Station play a vital role for resource adequacy throughout all scenarios.

8.3. Additional Sensitivity and Risk Analysis

Risk analysis was performed through scenario analysis and comparison of results. The identified near-term risks are through 2030, and are different from the long-term risks through 2050.

8.3.1. Near-term risk factors

- Carbon price
- Load uncertainty (load growth and load flexibility)
- Renewable integration creates new operational challenges
- Transmission interconnection costs

8.3.2. Long-Term risk factors

- Load uncertainty
- Net-zero crediting uncertainty
- Emerging technology uncertainty (modeled and do not become available/ not modeled and become available)
- Fuel prices are higher than anticipated

8.3.3. Risk Analysis Results

The risk analysis concluded that increased investment in wind, solar and battery storage is common across all pathways and is relatively low-risk, provided the scenarios that were evaluated and OPPD's targets. Minimum, "least regrets" additions of 1,100 MW of solar, 500 MW of wind and 150 MW of battery storage occur in all scenarios by 2030. These are incremental investments above OPPD's current Power with Purpose plans.

Firm, dispatchable capacity additions are also common across a range of key risk uncertainties, and are driven by total load growth. These resources are required to serve resource adequacy and contribute to reduced operational risks. These resources could utilize natural gas, biogas or green hydrogen as OPPD continues to reduce its portfolio emissions.

SMR nuclear technology becomes cost-effective for OPPD in two of the scenarios studied: the cost breakthrough scenario, and a scenario where hydrogen-ready natural gas technology is not available. SMRs should continue to be monitored as a potential technology for OPPD's portfolio especially if the costs reflect those used in the breakthrough scenario.

OPPD will need to continue a process of regular monitoring long-term uncertainties and adjust procurement plans over time.

8.4. Key Findings

The Pathways to Decarbonization: Energy Portfolio study has identified transformational work that needs to occur. The study surpasses all prior OPPD work to understand the directional changes required OPPD to achieve net-zero carbon by 2050, informing OPPD's leadership and board of directors to support future decision making.

OPPD identified several key findings in the study:

1. **OPPD can achieve net-zero while balancing affordability and reliability**
   Net-zero is achievable with projected generation and transmission cost impacts of approximately 8-22% over time by 2050 while maintaining resource adequacy levels.
2. **Cessation of coal generation and reduced use of fossil generation**
   Generation from fossil resources is reduced in all net-zero scenarios as low-carbon resources increasingly displace it. All scenarios ultimately repower or retire OPPD's coal generation by 2045 and maintain firm resources with minimum capacity factors.
3. **A mix of new low-carbon resources including renewable energy, energy storage and community-wide energy efficiency will be required**

Large quantities of low carbon resources are required to displace fossil generation and reduce emissions across OPPD's system.

4. **Firm, dispatchable generation is needed to maintain resource adequacy**

   Wind, solar, energy storage and demand-side resources support reliability but have limitations, especially during certain extreme weather events. Firm resources are required to support the system during these critical periods.

5. **Resources are consistent across a variety of pathways**

   A core set of resources are common across a variety of scenarios. Pace of decarbonization scenarios sets the speed of resource decisions. The solution scales proportionally with total load.

6. **Absolute-zero emissions scenarios are substantially higher cost and very dependent on future technology development**

   Achieving absolute-zero with current technology requires impractically high levels of new resources at significantly higher cost. This would require more than an additional 3.7 times the direct land use for wind/ solar resources, and have a cost impact of more than double the current average rate per kWh over the net-zero by 2050 scenario. However, emerging technologies such as hydrogen, long-duration storage and small modular reactors have the potential to make this more feasible.

7. **Accelerating decarbonization reduces cumulative emissions at a relatively low incremental cost, but poses implementation and integration challenges**

   Accelerating net-zero decarbonization pathways results in relatively low incremental cost, but requires integrating higher levels of resources in the near-term, which may pose supply chain, financial, grid interconnection and operational risks.

8. **The changing resource mix will pose new resiliency challenges that must be evaluated, understood and mitigated**

   Critical resource adequacy periods are expected to change from peak summer conditions to periods of extreme cold or extended periods of low renewable generation. Grid resiliency will depend on how utilities anticipate and prepare for these extreme events as the grid continues to evolve.

8.5 Further Areas of Investigation

The 2021 IRP reflects OPPD’s first comprehensive planning effort considering a complete transition to net-zero carbon. The study reflects findings resulting from a broad review of potential technologies and approaches. During the course of the study, OPPD identified further areas of investigation that will enhance findings and provide additional detail for specific plans.

Table 8-1 Future Areas of Investigation

Area of Investigation	Description
Energy Efficiency: Develop detailed plans for achieving modeled levels of energy efficiency	OPPD’s 2021 IRP portfolio optimization selected the demand-side portfolio options that the organization identified as outcomes of the 2018 AEG study and shows that additional programs and community participation are needed. The multi-sector modeling used a top-down modeling approach to incorporate further unspecified energy efficiency savings over the modeled 30-year time horizon. These estimates are reasonable based on historical technology advances, however, OPPD will need to conduct a future study to determine the most effective means to accomplish these savings through products and programs, advocacy for local energy codes, and/or rate design.
Load Flexibility: Identify future load flexibility opportunities	Load flexibility has significant potential in shaping energy consumption to better align with the output of variable energy resources, reducing the total need for energy storage resources and potentially mitigating some distribution system impacts. The 2021 IRP included assumptions for managed electric vehicle charging as well as a sensitivity including an additional 10% load flexibility. However, there are opportunities such as thermal storage or rate design that provide further opportunities. These specific opportunities would need to be explored with a more comprehensive and detailed study.
Rate Design: Consider impact of rate design on shifting load shape	Rate design is outside of the scope of the Pathways to Decarbonization study but may be an important tool to influence both energy efficiency and load flexibility. OPPD is planning for advanced metering infrastructure as part of its Grid Modernization strategic initiative. This capability will allow OPPD to consider more sophisticated, time based, rates in the future. OPPD will need to evaluate the system-wide benefits of alternative rate designs as part of its future rate planning work.
Distribution System Impacts: Evaluate potential distribution system impacts of electrification	Increasing customer electrification, particularly for transportation and building heating, may increase peak demand on distribution circuits, causing the need for widespread upgrades. Load flexibility and distributed resources may have the ability to mitigate the peak load impact but pose new operational considerations. Future detailed review of distribution system impacts, including potential mitigation by load flexibility and distributed resources should be further evaluated.

Distributed vs. Utility-Scale Resources: Evaluate role of distributed resources to meet resource need	OPPD evaluated both utility-scale and distributed resources as part of the resource optimization and found that the utility-scale resources provide a lower total resource cost for achieving decarbonization. However, distributed resources may provide additional benefits in certain applications that were not captured. These benefits include potential deferral of distribution upgrades, incentivized programs that increase customer adoption and specific opportunities with large customers. Deployment of distributed resources would partially offset the need for utility-scale resources and can be evaluated as part of the OPPD's strategy.
Hybrid Resources: Evaluate technical and financial opportunities of hybrid resources	OPPD evaluated individual resource types as part of its study. Hybrid resources combine two or more resource types at a single location and have the ability to reduce transmission interconnection costs, share some common infrastructure and utilize otherwise clipped energy. While including hybrid resources would change the overall composition of resources selected, there may be definite advantages to pursuing the identified resources, particularly wind, solar, energy storage, and firm resources as co-located or integrated hybrid resources.
Advanced Resource Adequacy Modeling: Pursue advances in resource adequacy modeling to identify key system risks	Resource Adequacy modeling is a key component of ensuring a reliable and resilient future energy mix. The Pathways to Decarbonization study incorporates industry-leading approaches, especially with regard to measuring the resource adequacy contribution of renewable resources. However, Resource Adequacy Modeling is a continually evolving topic and OPPD should continue to investigate ways to enhance this modeling through incorporation of more complex real world phenomena.
Energy Adequacy: Continue planning for system energy adequacy	Energy Adequacy refers to the ability of a system to reliably meet not only its peak capacity needs, but also its energy needs over an extended time period. This is an emerging topic within electric system planning and incorporates a review of the security and assurance of all energy sources, including resource weatherization, fuel storage and fuel delivery infrastructure. These investments are especially important as the system increasingly utilizes variable energy resources. While these topics were addressed in OPPD's reliability and resiliency analysis, they will need to be continually reviewed in future planning work.
Inter-Regional Transmission Expansion: Evaluate impacts of potential inter-regional transmission projects	Major investments in national transmission projects have the ability to unlock increased potential for renewable resources, allowing greater utilization of high-potential renewable resource locations. These investments face significant implementation challenges, spanning many jurisdictions and requiring huge financial investments. Due to this uncertainty, the 2021 IRP was not able to incorporate any specific inter-regional transmission plans. However, future studies should evaluate the impacts such projects would have on regional markets and OPPD's optimal portfolio mix.

9. The OPPD Plan

OPPD's Pathways to Decarbonization Study provides a direction for OPPD's future energy portfolio, including integration of new renewable resources, energy storage, demand side resources, the ultimate cessation of coal generation across the portfolio, and the continued role of firm dispatchable generation. The plan outlines near-term actions and next steps OPPD will undertake towards achieving this long-term direction.

The specific actions of the OPPD plan focus on the next five years in accordance with the IRP update frequency required by WAPA. However, the study provides insights on future resource decisions over a much longer time-period. In particular, the study identifies key opportunities across different scenarios and pathways for OPPD to achieve its net-zero goal.

The study results highlight a significant transition in how OPPD plans and operates its system. While the 2021 IRP includes a broad review of potential scenarios and pathways, the study also identified the need for advanced feasibility studies. These studies will provide additional resolution on topics such as the role of distributed vs. utility-scale resources, distribution and transmission impact studies and detailed infrastructure investments to ensure resilience. These advanced studies will be initiated in 2022 and will support future resource decisions by OPPD's Board of Directors and management.

9.1. OPPD Five-Year Action Plan

Over the next five-years, OPPD's resource needs are fully satisfied through the implementation of OPPD's Power with Purpose project, approved by OPPD's Board of Directors in November of 2019, and previously communicated to WAPA. This project is an important step in supporting emergent load growth and provides additional system capacity and on-peak energy. OPPD previously updated WAPA with these plans in its 2020 and 2021 annual IRP updates.

OPPD's Power with Purpose plans reduce reliance on coal generation while incorporating higher levels of new renewable resources, including 400MW to 600MW of utility-scale solar and up to 600MW of peaking natural gas capacity. OPPD is actively executing these plans and working to overcome numerous implementation challenges posed by the current market environment.

OPPD's near-term supply-side resource actions, including retirements, new facilities and repowering are provided in the following table.

Table 9-1 Five-Year Supply-Side Resource Actions

Resource	Nameplate Capacity	Technology	Fuel	Action	Year
BRIGHT	1 MW	Battery Energy Storage	Li-Ion	New Build	2022
Standing Bear Lake Station	150 MW	Reciprocating Internal Combustion Engines	Natural Gas, with Fuel Oil Backup	New Build	2023
Turtle Creek Station	450 MW	Combustion Turbine	Natural Gas, with Propane Backup	New Build	2023
Platteview Solar	81 MW	Photovoltaic Solar	Solar	New PPA	2023
Additional Power with Purpose Solar	up to 519 MW	Photovoltaic Solar	Solar	New Facilities	Ongoing Sourcing
North Omaha 1,2,3	241 MW	Steam Turbine	Gas	Retire	Fall 2023
North Omaha Station Units 4&5	278 MW	Steam Turbine	Coal	Repower to Natural Gas	Spring 2024
Ainsworth PPA	10 MW	Wind Turbine	Wind	PPA Expiration	2025

OPPD will also continue to develop demand-side programs as part of its integrated resource planning solution. Demand-side actions are identified in the following table:

Table 9-2 Five-Year Demand Side Action Plan

Program	Description	Action	Year
HVAC Tune up Rebate	Residential incentive to cover a portion of cost to have their HVAC system professionally tuned-up	New	2022
SMB Building Management Systems	Incentive for the installation of a business management system for small and medium business customers	New	2022
Solar Incentives	Residential incentives for the purchase and installation of solar panels	New	2022
Smart Thermostat Expansion	Expansion of eligible manufacturer’s smart thermostats units which can participate in OPPD’s current Smart Thermostat program	Expansion	2022

Energy Star Appliance Rebates	Residential customer adoption of Energy Star rated appliances through incentives, education, and marketing provided by OPPD	New	2023
Outdoor Commercial Lighting Rebates	Commercial incentive for installation or replacement of outdoor high efficiency lighting	New	2023
Residential Lighting/Controls	Residential incentive for the purchase of high efficiency lighting and lighting controls	New	2023
Smart Thermostat EE	Expansion of current OPPD Smart Thermostat program allowing customer to receive an incentive for the purchase of a smart thermostat without participation in Demand Response program	New	2024
Expanded Eco 24/7 Efforts	Expansion of the current Eco 24/7 offering both in terms expanding offering for smaller customers and available technologies offered as solutions	Expansion	2024
Heat Pump Water Heater Rebates	Residential incentive for the purchase and installation of a heat pump water heater	New	2025
Weatherization Residential Rebates	Residential rebates for the purchase and installation of home weatherization measures such as high efficiency windows and door, insulation, home sealing, etc.	New	2025
Commercial Food Service Rebates	Commercial customer incentives for purchase and installation of high efficiency commercial food service equipment	New	2026

9.2. Long-Term Portfolio Direction

The 2021 IRP outlines a significant transition in OPPD's energy portfolio over a 30-year time period. The study considered a wide range of emerging technologies under a variety of scenarios, yet all pathways ultimately lead to reduced utilization of fossil resources while incorporating larger quantities of energy efficiency, renewables and energy storage.

9.2.1 Integration of Renewable Energy Resources and Energy Storage

The Pathways results highlight a minimum incremental investment in 1,100MW of solar, 500MW of wind, and 150MW of energy storage resources by 2030 growing to 3,000MW of solar, 3,800 MW of wind, and 800MW of energy storage resources by 2050. These resources are considered "no regret" and are selected across all load and pace of decarbonization scenarios. While no new resources are needed above the Power with Purpose additions within the next 5 years, OPPD will need to consider these long-term needs as it develops future plans for sourcing and integrating new resources.

9.2.2 Cessation of Coal Generation and Role of Firm Resources

Cessation of coal generation, while preserving firm resources, is consistent across all pathways and is the most important element for OPPD to achieve its decarbonization goals. While OPPD plans to convert North Omaha Units 4 and 5 from coal to natural gas at the end of 2023, OPPD does not yet have specific plans in place for NCS Units 1 and 2.

The Pathways study indicates that repowering NCS units to natural gas is the most cost-effective option for reducing near-term emissions while maintaining firm-dispatchable capacity. Once converted, these units are expected operate at much lower capacity factors and generally during times of peak system needs. The lower greenhouse gas intenstity of natural gas, coupled with the significantly reduced run times will result in a drastic reduction in total GHG emissions for NCS.

OPPD has completed initial engineering studies to support assumptions for conversion and has found that both the conversion and additional fuel delivery infrastructure are technically and economically feasible. Additional detailed engineering studies are required to further define project scope and timeline for specific actions. These converted units will place significant demand on the natural gas system, and OPPD will need to further evaluate these demands in light of energy adequacy considerations and regional availability of natural gas.

Converted coal units have significantly less operational flexibility than combustion turbines and do not provide the continuous support of baseload units. Further detailed analyses are needed to ensure OPPD plans for and incorporates essential reliability services as a predecessor to its transition.

9.2.3 Role of Firm Resources

The recent events of Winter Storm Uri highlight the critical role of the electric system and underscore the need for continued focus on system reliability and resilience. OPPD worked extensively to include these aspects in the 2021 IRP. The analysis found that, despite significant investments in renewables and energy storage, firm dispatchable resources will play a central role in supporting the system, especially during extreme conditions. Although these resources are expected to generate less often, it is important that they receive adequate investment to ensure availability when they are needed most.

9.3. Implementation Challenges

The 2021 IRP outlines the need for large quantities of new resources to support continued progress toward decarbonization. These new resources enable greater economy-wide decarbonization and allow for the timely reduction in fossil fuel generation, achieving OPPD's net-zero goals.

Numerous external factors that exist at the global, national, regional and local levels have significant influence on OPPD's outcome. These challenges include but are not limited to:

- Geopolitics and global supply chain
- Federal energy policy
- FERC-regulated generator interconnection process
- Local planning and zoning regulations
- Customer preference

9.3.1. Geopolitics and Global Supply Chain

The Covid-19 pandemic exposed the vulnerabilities in the production strategies and supply chains of firms around the world. This major disruption in the global supply chain has led to increases in the cost of goods while constricting their ready availability. In the near-term, this creates challenges for OPPD to source materials in an expedient and cost-effective manner. However, the lessons learned from the supply disruption caused by Covid-19 will allow OPPD to reevaluate its sourcing strategies to reduce exposure to future supply chain disruptions.

In addition to global supply chain disruptions, the increasing interconnectedness of global markets may pose challenges to OPPD. In November 2021, the US experienced rapidly rising natural gas prices, largely a consequence of increased liquefied natural gas (LNG) exports to Europe. In the future, OPPD and other utilities across the US may become more exposed to the economics of supply and demand at a global level, which could disrupt planning efforts. However, OPPD's investment in dual-fuel generating resources and variable energy resources will help insulate the utility from this risk.

Beyond supply chain volatility, labor shortages and national demand for construction of new generation is challenging both the availability and timelines for EPC services. The ability to contract EPC firms is critical to OPPD's ability to build the requisite resources to reach net-zero.

9.3.2. Federal Energy Policy

At the federal level, dynamic energy policy is a significant factor influencing OPPD's path towards decarbonization. For instance, the continuation of production tax credits or the introduction of direct pay credits available to public entities from the federal government would decrease investment costs in renewables aiding in their development. Another potential influential federal policy is the implementation of a carbon price. Depending on the reliance of OPPD's generation portfolio on fossil fuels, a carbon price could meaningfully affect the speed of OPPD's transition towards net-zero. Contingent on how revenues from a carbon price are allocated, this could also increase OPPD's cost of generation.

9.3.3. New Generation Interconnection

At both the federal and regional levels, SPP's generator interconnection process, regulated by FERC, will pose challenges to OPPD's planning efforts. The risks associated with this process are twofold: the current backlog in the study process results in multi-year delays for interconnection to SPP's system delaying development, and the potential for study results to yield interconnection costs higher than anticipated. OPPD can positively influence these challenges by advocating at SPP and FERC to support interconnection reforms that will increase the efficiency of the process.

9.3.4. State and Local Policy

At the state level, the Nebraska Legislature will continue to adopt and foster energy policy discussions. Section, 4.3 covers issues and opportunities for implementation. In summary, the legislature maintains keen interest in ensuring resource adequacy for our state, along with reliability and affordability. State policy evolutions will certainly be an implication to OPPD's decarbonization efforts.

9.3.5. Local Planning & Zoning

Local planning and zoning activity is an important consideration for OPPD's ability to construct the resources and concomitant distribution and transmission system upgrades. Given the larger direct and indirect land use of renewables compared to conventional generating resources, securing land will be pivotal for OPPD to reach its net-zero carbon goal. OPPD has and will continue to collaborate with planning jurisdictions within its territory and the State to ensure positive implementation of regulations that align with a net-zero future.

Although OPPD is not subject to local planning and zoning regulations when engaged in the development of OPPD-owned generation resources, there is thoughtful consideration of the ramifications of local planning and zoning regulations on the impacted communities and counter-parties for wind and solar PPA contracts. Regulations for wind and solar are evolving within OPPD's service territory and across the state.

9.3.6. Customer Preference

Finally, customer acceptance and adoption of electrified or energy efficient technologies and towards the overall goal of decarbonization, can greatly influence OPPD's overall outcome. It will be pivotal that OPPD continues to engage with the community to ensure actions are taken to assist in decarbonization efforts of OPPD's portfolio and the broader community.

9.4. Next Steps

In addition to incorporating new resources as part of its Power with Purpose project, OPPD will launch Advanced Feasibility Studies starting in 2022. These advanced studies are the next step in enabling progress towards OPPD's net-zero goal and will incorporate further areas of investigation identified in the 2021 IRP. The studies will provide OPPD's leadership with important detailed information to support specific future resource decisions.

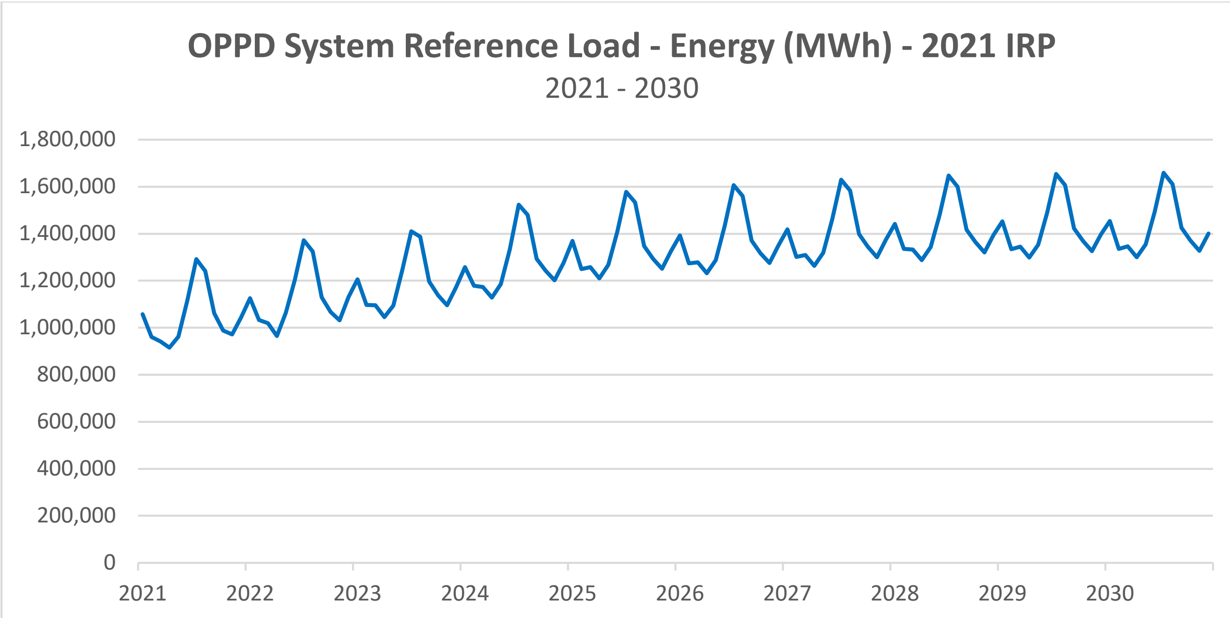
The advanced studies will be split into an Advanced Supply-Side Feasibility Study and an Advanced Demand-Side Feasibility Study.

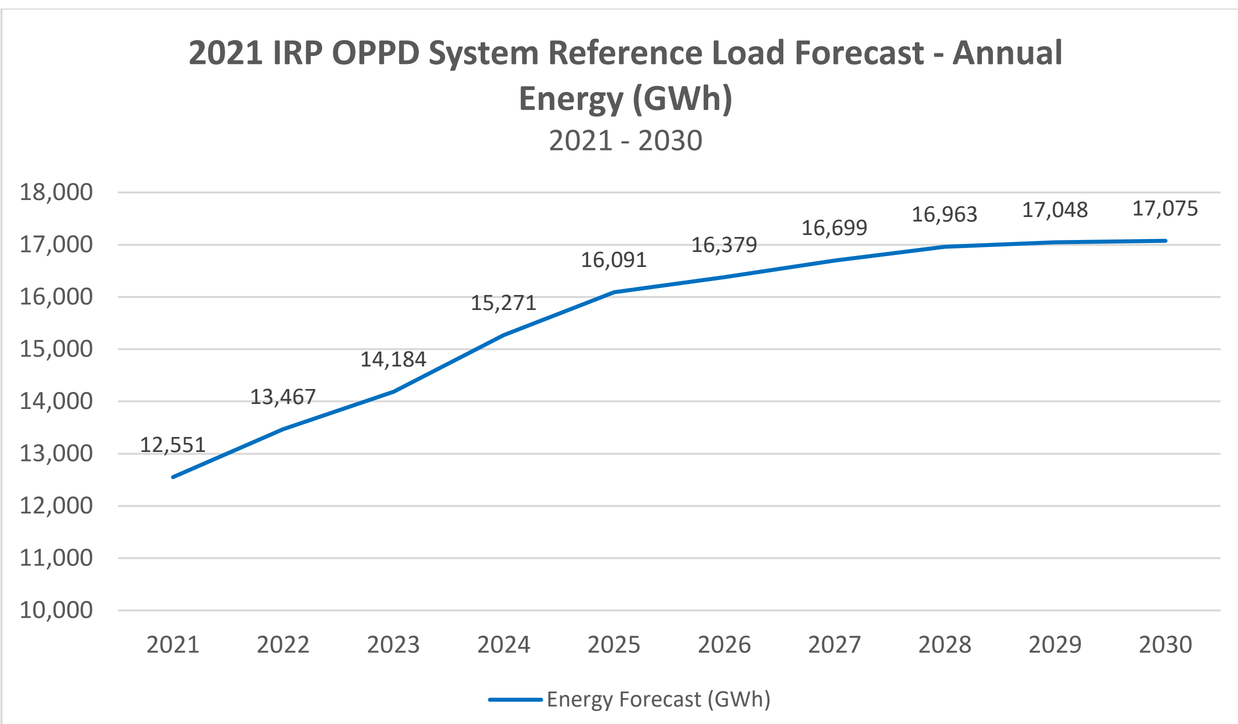
- The **Advanced Supply-Side Feasibility Study** will include detailed engineering studies of OPPD's existing resources, in particular the future transition of Nebraska City Station, opportunities associated with hybrid resources, and further development of advanced resource adequacy and energy adequacy monitoring among other topics.

- The **Advanced Demand-Side Feasibility Study** will include further evaluation of the technical, economic and feasible potential of demand side-technologies, impact of electrification on OPPD's distribution system, role of distributed vs. utility-scale resources, and the increasing role of load flexibility.

OPPD plans to fully scope both of these studies during 2022 and remains committed to both transparency and public engagement.

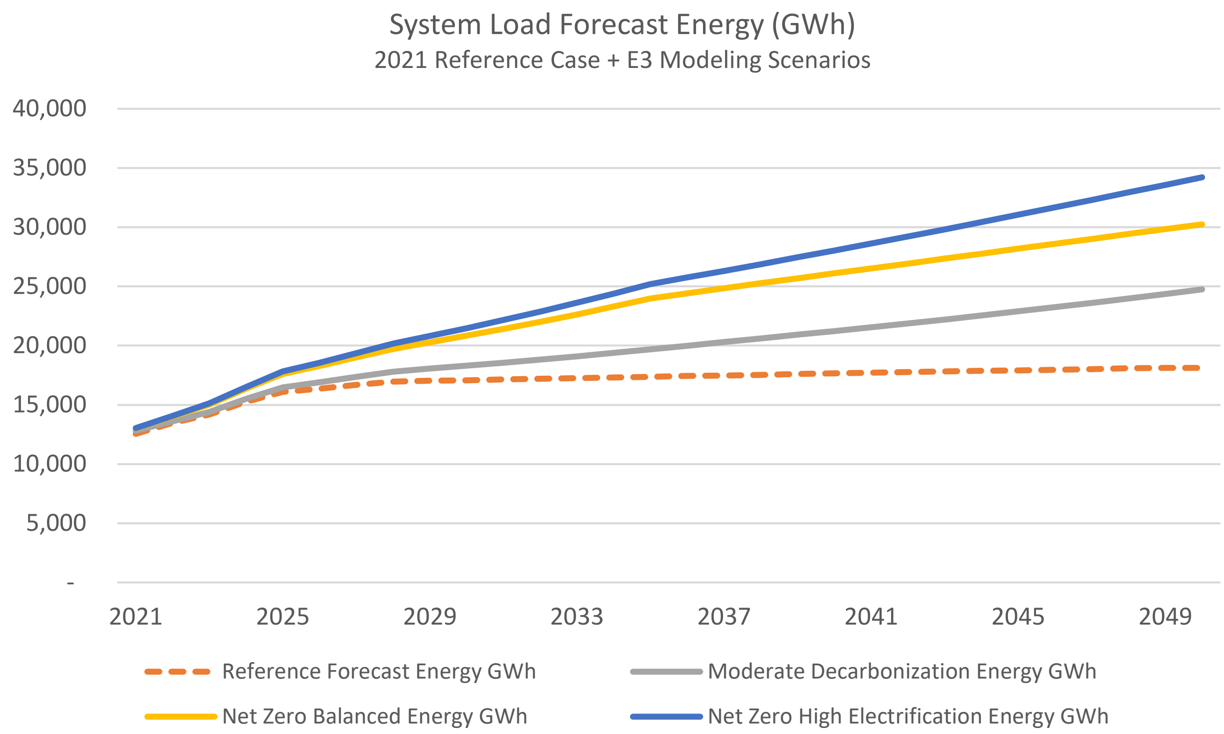
Appendix A – Reference Load Forecast

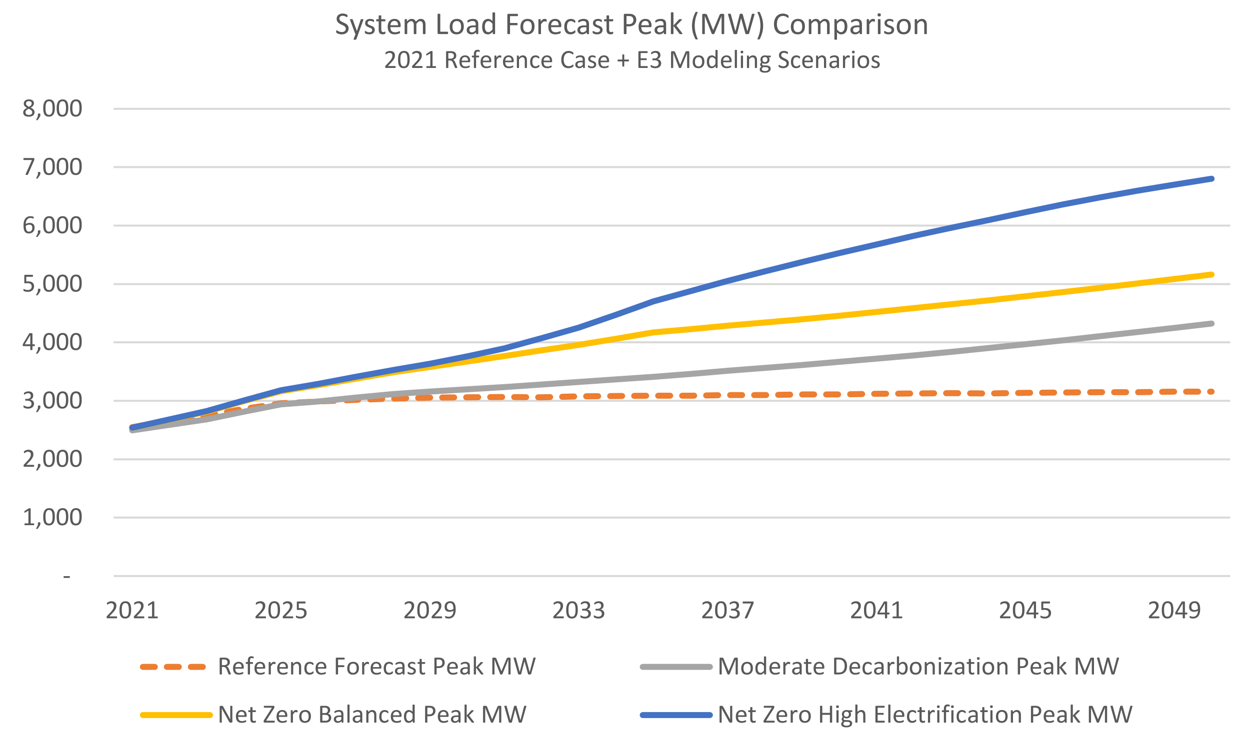




System Load Forecast

Reference Including E3 Modeling Scenarios





Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Reference Forecast Peak (MW)	2,549	2,663	2,748	2,863	2,958	2,988	3,019	3,039	3,055	3,058	3,064	3,061	3,074	3,081	3,086
Moderate Decarbonization Peak (MW)	2,494	2,588	2,682	2,815	2,937	2,991	3,054	3,115	3,159	3,199	3,238	3,280	3,322	3,365	3,413
Net-zero Balanced Peak (MW)	2,539	2,677	2,816	2,995	3,164	3,267	3,380	3,488	3,581	3,671	3,765	3,863	3,960	4,064	4,172
Net Zero High Electrification Peak (MW)	2,540	2,680	2,823	3,006	3,180	3,290	3,410	3,526	3,634	3,759	3,898	4,072	4,255	4,472	4,702

Year	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Reference Forecast Peak (MW)	3,085	3,098	3,101	3,107	3,107	3,119	3,125	3,130	3,125	3,139	3,143	3,149	3,147	3,157	3,157
Moderate Decarbonization Peak (MW)	3,462	3,512	3,563	3,615	3,667	3,721	3,777	3,840	3,906	3,969	4,036	4,104	4,175	4,247	4,323
Net-zero Balanced Peak (MW)	4,227	4,284	4,340	4,398	4,458	4,521	4,586	4,652	4,721	4,791	4,862	4,935	5,010	5,085	5,162
Net Zero High Electrification Peak (MW)	4,879	5,051	5,216	5,377	5,530	5,680	5,824	5,963	6,094	6,229	6,361	6,484	6,597	6,703	6,803

Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Reference Forecast Energy (GWh)	12,551	13,467	14,184	15,271	16,091	16,379	16,699	16,963	17,048	17,075	17,138	17,204	17,249	17,306	17,365
Moderate Decarbonization Energy (GWh)	12,817	13,609	14,383	15,488	16,482	16,893	17,358	17,786	18,055	18,307	18,556	18,817	19,094	19,384	19,688
Net-zero Balanced Energy (GWh)	13,012	14,024	15,022	16,367	17,613	18,283	19,018	19,727	20,288	20,836	21,410	22,011	22,640	23,299	23,981
Net Zero High Electrification Energy (GWh)	13,037	14,075	15,114	16,508	17,814	18,556	19,370	20,168	20,825	21,477	22,161	22,877	23,621	24,394	25,194

Year	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Reference Forecast Energy (GWh)	17,434	17,479	17,534	17,596	17,665	17,708	17,764	17,816	17,876	17,914	17,964	18,019	18,091	18,119	18,119
Moderate Decarbonization Energy (GWh)	19,994	20,302	20,610	20,922	21,230	21,547	21,870	22,204	22,544	22,892	23,249	23,613	23,984	24,362	24,751
Net-zero Balanced Energy (GWh)	24,415	24,841	25,268	25,689	26,102	26,518	26,936	27,352	27,773	28,188	28,604	29,017	29,427	29,830	30,239
Net Zero High Electrification Energy (GWh)	25,752	26,313	26,883	27,458	28,031	28,617	29,214	29,818	30,431	31,052	31,677	32,306	32,938	33,572	34,217

Load & Capability Report - Summer Peak(1)

All Values are Accredited MWs

Annual System Demand		**2022**	**2023**	**2024**	**2025**	**2026**
Base Peak Forecast		2632.8	2699.3	2777.3	2860.2	2930.4
Demand Response Programs		(96.5)	(101.5)	(105.1)	(109.3)	(113.5)
Firm Power Purchases (WAPA)		(79.7)	(79.7)	(79.7)	(79.7)	(79.7)
Net Peak Demand		2,456.6	2,518.1	2,592.5	2,671.2	2,737.2
Net Generating Capability						
Coal	NC1	650.3	650.3	650.3	650.3	650.3
	NC2	348.5	348.5	348.5	348.5	348.5
	NO4	117.7	117.7	-	-	-
	NO5	216.2	216.2	-	-	-
Peaking	SC1	55.4	55.4	55.4	55.4	55.4
	SC2	55.9	55.9	55.9	55.9	55.9
	SC3	107.8	107.8	107.8	107.8	107.8
	SC4	48.7	48.7	48.7	48.7	48.7
	SC5	47.9	47.9	47.9	47.9	47.9
	JS1	61.2	61.2	61.2	61.2	61.2
	JS2	62.2	62.2	62.2	62.2	62.2
	Tecumseh	6.5	6.5	6.5	6.5	6.5
	CC1	162.0	162.0	162.0	162.0	162.0
	CC2	161.8	161.8	161.8	161.8	161.8
	NO1	63.0	63.0	-	-	-
	NO2	71.8	71.8	-	-	-
	NO3	92.5	92.5	-	-	-
	Standing Bear	-	153.0	153.0	153.0	153.0
	Turtle Creek	-	-	444.0	444.0	444.0
	NO4	-	-	106.0	106.0	106.0
	NO5	-	-	172.0	172.0	172.0
Landfill	ElkCity	6.0	6.0	6.0	6.0	6.0
Behind-The-Meter Thermal Generation(2)		29.6	29.6	29.6	29.6	29.6
Solar(3)	New Plants	-	-	55.7	188.0	402.8
Wind Participation Purchases(4)		245.7	147.8	138.6	129.9	127.9
Capacity Contracts		305.0	225.0	111.0	-	-
Total		2,915.7	2,890.8	2,984.1	2,996.7	3,209.4
Summary						
Total Capability		2,915.7	2,890.8	2,984.1	2,996.7	3,209.4
Net Peak Demand		(2,456.6)	(2,518.1)	(2,592.5)	(2,671.2)	(2,737.2)
Planning Reserve Margin		(294.8)	(302.2)	(311.1)	(320.5)	(328.5)
Position (MW)		164.3	70.6	80.5	5.0	143.8
Planning Reserve Margin		**18.7%**	**14.8%**	**15.1%**	**12.2%**	**17.3%**

(1) Using information consistent with 2022 SPP Resource Adequacy Submittal

(2) BTM Generation includes Curtailable 467L Load

(3) Timing for PwP Solar under development

(4) SPP Utilizes ELCC to accredit Wind, Solar, and Battery resources starting in 2023

Load & Capability Report - Winter Peak[1]

All Values are Accredited MWs

Annual System Demand		22/23	23/24	24/25	25/26	26/27
Base Peak Forecast		1825.7	1871.3	1923.1	2024.0	2103.1
Firm Power Purchases (WAPA)		(37.7)	(37.7)	(37.7)	(37.7)	(37.7)
Net Peak Demand		1,788.0	1,833.6	1,885.4	1,986.3	2,065.4
Net Generating Capability						
Coal	NC1	650.3	650.3	650.3	650.3	650.3
	NC2	348.5	348.5	348.5	348.5	348.5
	NO4	101.8	-	-	-	-
	NO5	174.9	-	-	-	-
Peaking	SC1	55.4	55.4	55.4	55.4	55.4
	SC2	55.9	55.9	55.9	55.9	55.9
	SC3	107.8	107.8	107.8	107.8	107.8
	SC4	48.7	48.7	48.7	48.7	48.7
	SC5	47.9	47.9	47.9	47.9	47.9
	JS1	61.2	61.2	61.2	61.2	61.2
	JS2	62.2	62.2	62.2	62.2	62.2
	Tecumseh	6.5	6.5	6.5	6.5	6.5
	Standing Bear	-	153.0	153.0	153.0	153.0
	Turtle Creek	-	444.0	444.0	444.0	444.0
	CC1	-	-	-	-	-
	CC2	-	-	-	-	-
	NO1	-	-	-	-	-
	NO2	-	-	-	-	-
	NO3	-	-	-	-	-
	NO4	-	-	-	-	-
	NO5	-	-	-	-	-
Landfill	ElkCity	6.0	6.0	6.0	6.0	6.0
Behind-The-Meter Thermal Generation[2]		29.6	29.6	29.6	29.6	29.6
Solar[3]	New Plants	-	-	10.5	33.0	69.3
Wind Participation Purchases[4]		278.3	221.1	213.0	206.1	203.9
Capacity Contracts		275.0	225.0	111.0	-	-
Total		2,310.0	2,523.1	2,411.6	2,316.1	2,350.2
Summary						
Total Capability		2,310.0	2,523.1	2,411.6	2,316.1	2,350.2
Net Peak Demand		(1,788.0)	(1,833.6)	(1,885.4)	(1,986.3)	(2,065.4)
Planning Reserve Margin		(214.6)	(220.0)	(226.3)	(238.4)	(247.8)
Position (MW)		307.4	469.4	299.9	91.4	36.9
Planning Reserve Margin		**29.2%**	**37.6%**	**27.9%**	**16.6%**	**13.8%**

[1] Using information consistent with 2022 SPP Resource Adequacy Submittal

[2] BTM Generation includes Curtailable 467L Load

[3] Timing for PwP Solar under development

[4] SPP Utilizes ELCC to accredit Wind, Solar, and Battery resources starting in 2023

Appendix B – Outreach Materials

2021 INTEGRATED RESOURCE PLAN
EXECUTIVE SUMMARY

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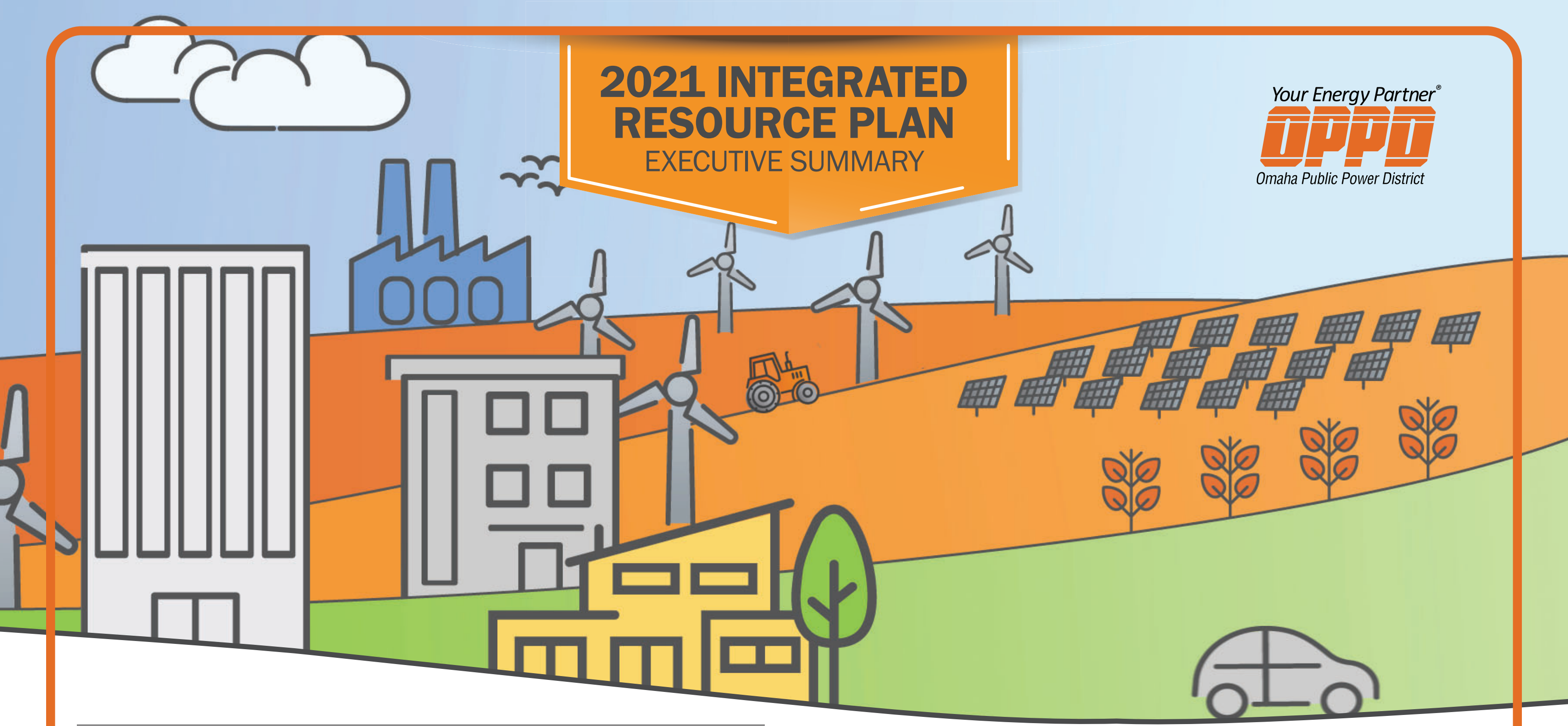

Our Journey

2017
OPPD begins ***Power with Purpose*** initiative to support near-term, growing service area demand.

November 2019
OPPD's board of directors approves net-zero carbon by 2050 goal and launches ***Pathways to Decarbonization***.

2020
OPPD hires E3, an energy consultant providing resource planning, to identify potential pathways to achieve it's net-zero goal while maintaining affordability and reliably.

2021
Pathways to Decarbonization Energy Portfolio Study workshops support concurrent **IRP development**

Jan./Feb. 2022
IRP Public Meeting, 30 day comment period and submittal to Western Area Power Administration

2022
OPPD begins **Advanced Supply and Demand-side Feasibility Studies** to inform future resource decisions that support decarbonization.

2023
Platteview Solar Project, generating 81MW, is scheduled to come online.

2023
New natural gas facilities at **Turtle Creek Station**, and **Standing Bear Lake Station** are scheduled to come online.

2030
Incrementally invest in additional solar, wind, and energy storage by 2030.

2045
Ultimately repower or retire OPPD's coal generation and maintain firm resources with minimum capacity by 2045.

2050
Grow renewable resources to meet net-zero carbon goal by 20510.

What is an Integrated Resource Plan (IRP)?

OPPD's **IRP** outlines a long-term perspective, while acting as a near-term road map to satisfy our ***Power with Purpose*** initiatives. It provides guidance on enhancing reliability and resiliency, reducing carbon emissions, and incorporating new, renewable resources to meet our energy objectives at the lowest cost. The IRP is also a tool to help evaluate the needs identified in our ***Pathways to Decarbonization***, to achieve our goal of net-zero carbon by 2050. It considers how to meet our customers' changing energy needs through thorough modeling that ensures reliability. The IRP is filed with the Western Area Power Administration (WAPA) every five years—and is due February 28, 2022.

OPPD's Five-Year Action Plan includes:

- Continue **reducing carbon emissions** without compromising reliability.
- **Cease coal operations** at North Omaha Station Units 4 and 5.
- Source 400–600MW of **new, utility-scale solar resources** through the ***Power with Purpose*** initiative.
  - **Platteview Solar**, Nebraska's first utility-scale solar installation that will generate 81MW, is scheduled to come online in 2023.
- Source up to 600MW of **new, modernized, backup natural gas facilities** and significantly reduce emissions through the Power with Purpose initiative.
  - **Turtle Creek Station** (two simple-cycle turbine units totaling 450MW), is scheduled to come online in 2023.
  - **Standing Bear Lake Station** (nine reciprocating internal combustion engine units totaling 150MW) is scheduled to come online in 2023.

2021 INTEGRATED RESOURCE PLAN

EXECUTIVE SUMMARY

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Over the next 5 years...

CO_2 Significantly **reduce emissions**

Cease coal operations at North Omaha Units 4 & 5

400–600MW **NEW Solar** resources

600MW **NEW Natural Gas** facilities

Support community-wide **electrification**

Energy efficient technology adoption

Begin **Advanced Feasibility Studies**

OPPD can achieve its **Net-Zero Carbon Goal by 2050** while maintaining **RELIABILITY** and **AFFORDABILITY**.

- Begin **Advanced Feasibility Studies** in 2022 to examine incremental supply and demand-side resource decisions that support decarbonization that will support future decisions.
- Support, educate and incentivize customer acceptance and adoption of **community-wide electrification** and **energy-efficient technologies**, to benefit decarbonization efforts.

OPPD's Net-Zero Carbon Goal by 2050 includes:

- Meeting minimal targets by adding **1,100MW of solar, 500MW of wind,** and **150MW of energy storage resources** by 2030.
- Growing renewable resources to **3,000MW of solar, 3,800MW of wind,** and **800MW of energy storage resources** by 2050.
- Investing in resources that ensure availability when needed to support system **reliability, resiliency** and **resource adequacy.**
- Ceasing all coal generation.

NET-ZERO CARBON PRODUCTION CO_2 NEUTRAL NET-ZERO CARBON PRODUCTION

Technology

Energy technologies are constantly changing and OPPD is keeping a close eye on those new developments. We understand that many assumptions made in the 2021 IRP will continue to evolve as regulations, technology and customer preferences change. OPPD is committed to being vigilant in efforts to make responsible financial choices and ensure that our choices reflect customer desires and the forward-looking view of our leadership and board of directors.

Energy Efficiency

OPPD's energy portfolio includes multiple types of **energy efficiency** (EE) improvements across the economy. Improvements will be gained through industry efficiency, commercial and residential appliances and lighting, commercial heating, new technology, building codes, smart devices and more. Reaching net-zero carbon efficiently will require significant economy-wide gains, resulting in lower energy use despite economic and population growth.

Customers and communities play an essential role in getting to net zero. OPPD's current and planned energy efficiency and demand response programs offer multiple incentives or rebates to commercial and residential customers for HVAC, lighting, smart thermostats, ENERGY STAR appliances, solar panels and more. We'll continue to engage with customers around how to enhance products and services offerings to help customers improve energy efficiency and reduce greenhouse gas emissions.

Next Steps

In addition to incorporating new resources as part of its ***Power with Purpose*** intitiative, OPPD will launch **Advanced Feasibility Studies** starting in 2022. These studies will cover both supply and demand-side. They are the next step towards OPPD's net-zero goal and will provide OPPD leadership with important information to support future resource decisions.

To learn more about the 2021 Integrated Resource Plan, visit *OPPDCommunityConnect.com/irp*

PATHWAYS TO DECARBONIZATION:

Energy Portfolio Workshop #2

OPPD, with support of Energy+ Environmental Economics (E3), is conducting a series of workshops to engage stakeholders in the Energy Portfolio decarbonization planning process. **Workshop #2** provided insight to the **multi-sectoral net-zero carbon modeling results** across all energy uses in OPPD's service territory. A recording of the workshop is available online.

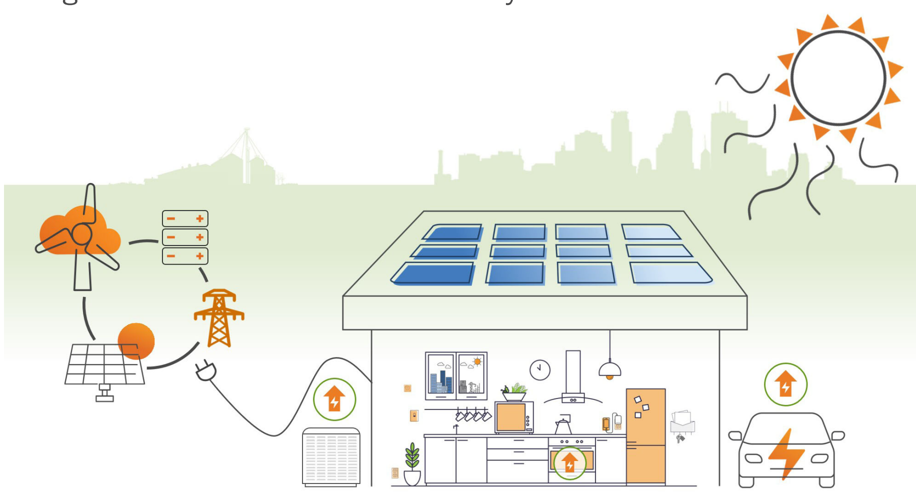
Workshops

- **Pathways Planning 101**
  April 7, 2021
  4–6 p.m.
- **Multi-Sector Modeling**
  April 28, 2021
  4–6 p.m.
- **Key Assumptions & Scenarios**
  May 12, 2021
  4–6 p.m.
- **Modeling Approach**
  May 26, 2021
  4–6 p.m.
- **Modeling Activities**
  Q2/Q3 2021
- **Initial Results**
  Q3/Q4 2021
- **Final Results**
  December 2021

Multi-Sector Modeling

1 Low-Carbon Electricity is Vital to Community Decarbonization

OPPD set the stage by emphasizing the fact that low-carbon electricity is critical to achieving community-scale decarbonization. To achieve deep carbon reduction, electrification of building and transportation systems must occur in parallel with a transition to low-carbon electricity. In combination, these strategies enable widescale transition away from fossil fuels.



2 All Sectors of the Economy Must Undergo Transformation

Electrification of building and transportation systems requires fundamental changes in infrastructure that make up the fabric of our communities. For example, achieving community-scale decarbonization will require development of convenient and effective electric vehicle (EV) charging infrastructure and retrofit of existing building stock to improve energy efficiency and electrify heating systems.

NET-ZERO CARBON PRODUCTION CO_2 NEUTRAL

Learn more at www.OPPDCommunityConnect.com

This site provides project updates, answers to FAQs, and videos of our workshop meetings.

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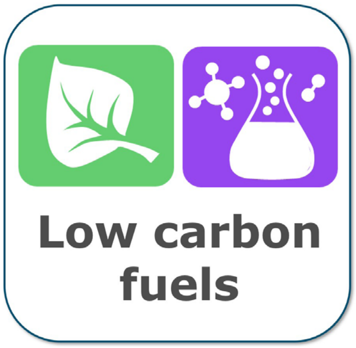
#2

PATHWAYS TO DECARBONIZATION: ENERGY PORTFOLIO WORKSHOP

Multi-Sector Modeling

3 The Role of Alternate, Low-Carbon Fuels should not be Overlooked



Even with transformative changes across electricity, building and transportation sectors, low-carbon fuels will play an important role for select end uses. For example, aviation and heavy-equipment may rely on fossil-fuels longer than passenger vehicles. Similarly, backup electric power sources will rely on storable fuels. In these cases, the availability of renewable diesel and natural gas or hydrogen fuel will be required to achieve decarbonization.

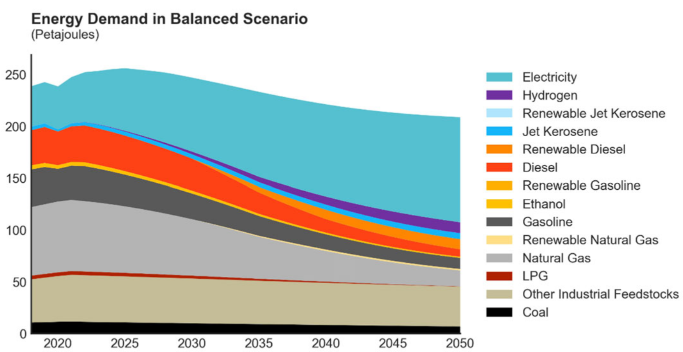
4 Multiple Pathways to Decarbonization, OPPD is Focused on a Balanced Scenario

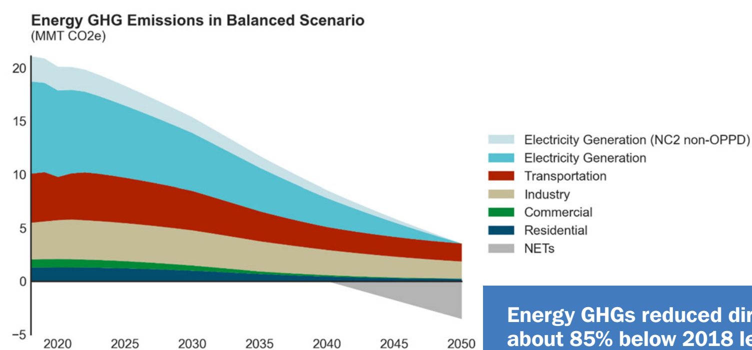
E3 shared multiple scenarios towards decarbonization, with different assumptions related to electrification and availability of renewable and lower-carbon fuels. Ultimately, OPPD's study will focus on the Balanced Scenario, deemed by E3 to be the most cost-effective, which assumes:

- high levels of light-duty vehicle electrification;
- moderate levels of medium-duty (MDVs) and heavy-duty vehicles (HDVs) electrification;
- electric heat pumps with gas backup for space heating;
- industry decarbonized through hydrogen, carbon capture and storage (CCS), and/or electrification; and
- about 15% of difficult to decarbonize industrial and transportation sector emissions offset by negative emissions technologies.

5 OPPD Must Manage Growth in Electricity Demand with Decarbonization, Reliability, and Resiliency

Modeling results from the Balanced Scenario revealed that annual electricity load will more than double. Furthermore, peak electricity demand will shift from summer to winter due to electrified heating, peak electricity demand will increase from approximately 2.5 gigawatts today to 5 gigawatts. With an increased reliance on electricity across sectors in a decarbonized future, OPPD's commitment to reliable and affordable power will be more important than ever.





Energy GHGs reduced directly about 85% below 2018 levels, and offset by Negative Emissions Technologies to reach net zero

NET-ZERO CARBON PRODUCTION CO_2 NEUTRAL NET-ZERO CARBON PRODUCTION

Learn more at www.OPPDCommunityConnect.com

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PATHWAYS TO DECARBONIZATION:

Energy Portfolio Workshop

#3

OPPD, with support of Energy+ Environmental Economics (E3), is conducting a series of workshops to engage stakeholders in the Energy Portfolio decarbonization planning process. **Workshop #3** built upon the multi-sector analysis to explore **key assumptions** that will inform the **net-zero carbon modeling**. A recording of the workshop is available online.

Schedule

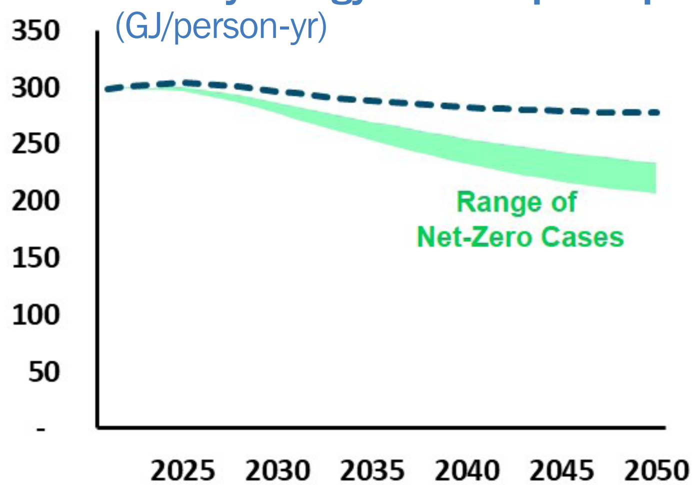
- **Pathways Planning 101**
  April 7, 2021
  4–6 p.m.
- **Multi-Sector Modeling**
  April 28, 2021
  4–6 p.m.
- **Key Assumptions & Scenarios**
  May 12, 2021
  4–6 p.m.
- **Modeling Approach**
  May 26, 2021
  4–6 p.m.
- **Modeling Activities**
  Q2/Q3 2021
- **Initial Results**
  Q3/Q4 2021
- **Final Results**
  December 2021

Key Assumptions & Scenarios

1 Energy Efficiency and Demand Response are Foundational to Net Zero Models

Energy that is never used is inherently low-carbon, that's why reducing electricity demand is a key assumption to achieving community-scale decarbonization. For energy efficiency, the model assumes widespread investment in efficient appliances, such as heat pumps, and electric vehicles, which are three to four times more efficient than conventional gasoline cars. For demand response, the model assumes implementation of existing programs and expansion of new programs and technologies.

Primary Energy Demand per Capita
(GJ/person-yr)



Total energy demand reduced up to 30%, amidst a growing population and economy, due to efficiency and electrification

Learn more at www.OPPDCommunityConnect.com
This site provides project updates, answers to FAQs, and videos of our workshop meetings.

NET-ZERO CARBON PRODUCTION CO_2 NEUTRAL

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PATHWAYS TO DECARBONIZATION: ENERGY PORTFOLIO WORKSHOP

#3 Key Assumptions & Scenarios

2 Existing Power Generation Assets will be Re-imagined in a Low Carbon Future

OPPD's existing power generation facilities will play an important role in our future. E3's analysis considers multiple options, including leave in place; fuel conversion; and retirement. Leave in place and fuel conversion takes advantage of existing infrastructure while transitioning to low-carbon alternatives, such as coal to natural gas or hydrogen, or natural gas to biofuel or hydrogen.

3 About 150 Technologies Considered, 18 will be Modeled as Viable Existing or Promising Emerging Options

OPPD put dozes of options on the table and used the International Energy Administration (IEA) Technology Readiness Level (TRL) to prioritize and score technologies along a maturity spectrum. Options include mature technologies, such as rooftop solar, behind-the-meter storage, and fuel conversion, as well as emerging technologies like flexible loads and hydrogen combustion turbines. E3's model will take into account technology and fuel cost projections, among other considerations.

4 Carbon Capture and Sequestration for Coal

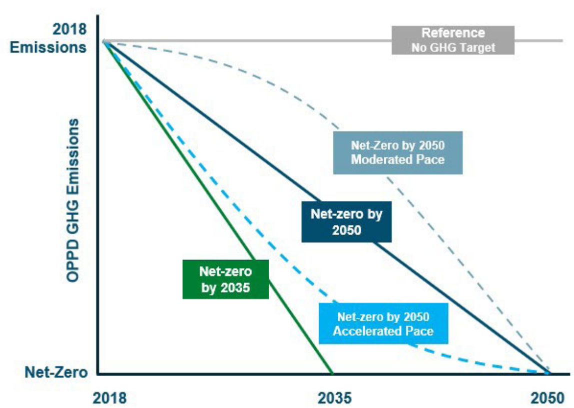
Carbon Capture and Sequestration is not considered a viable technology option for coal units based on the following technical and economic challenges:

- few geologic formations near OPPD's service territory that would allow for sequestration
- costs are significantly higher than other existing and emerging alternatives

Carbon Capture and Sequestration for natural gas will be included in the model due to using a different capture technology and lower carbon volumes.

5 Exploring the Many Pathways to Decarbonization

E3's scenario analysis not only include various mixes of technologies, such as mature only or mature + hydrogen, but also how fast decarbonization occurs. The analysis will examine three GHG reduction trajectories to net-zero by 2050: straight-line; accelerated; and moderated. The analysis will also examine a net-zero by 2035 scenario. A total of 19 unique combinations of technology and timing, referred to as "framing scenarios", will be explored in the decarbonization modeling.



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NET-ZERO CARBON PRODUCTION CO_2 NEUTRAL

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PATHWAYS TO DECARBONIZATION:

Energy Portfolio Workshop

#4

OPPD, with support of Energy+ Environmental Economics (E3), is conducting a series of workshops to engage stakeholders in the Energy Portfolio decarbonization planning process. **Workshop #4** narrowed in on the **technical modeling considerations** that will be used to develop the **pathways to decarbonization** based on results of the multi-sector modeling, key assumptions, and selected scenarios. A recording of the workshop is available online.

Schedule

- **Pathways Planning 101**
  April 7, 2021
  4–6 p.m.
- **Multi-Sector Modeling**
  April 28, 2021
  4–6 p.m.
- **Key Assumptions & Scenarios**
  May 12, 2021
  4–6 p.m.
- **Modeling Approach**
  May 26, 2021
  4–6 p.m.
- **Interim Modeling Update**
  August 4, 2021
- **Modeling Activities**
  Q2/Q3 2021
- **Initial Results**
  Q3/Q4 2021
- **Final Results**
  December 2021
- **Integrated Resource Plan**
  February 2022

Modeling Approach

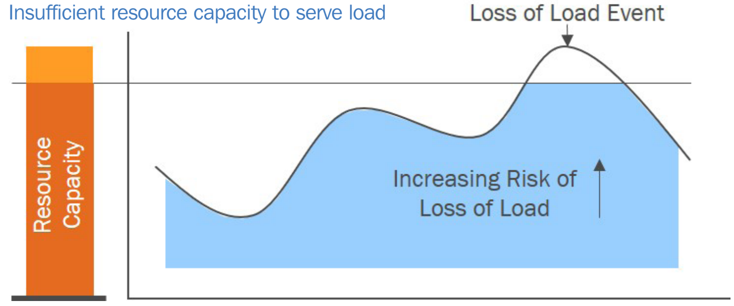
1 The grid is changing, but OPPD's commitment to delivering reliable electric service has not.

The changing energy mix is recognized by the North American Electric Reliability Corporation (NERC) as a top reliability risk. Specifically, Variable Energy Resources (VERs), including wind and solar, and Energy Limited Resources (ELRs), such as battery storage, are fundamentally different than conventional resources that are both firm and dispatchable. Our team is focused on identifying decarbonization pathways that maintain the reliability and resiliency that our customers depend upon.

2 Decarbonization pathways must meet our customers' electric demand.

E3's model is built upon a loss-of-load probability study that is widely used across the electric industry today. The purpose of this study is to ensure Resource Adequacy, meaning there are sufficient generation resources to meet electric demand and reserve margin. Assessing resource adequacy involves modeling the intermittent capacity of VERs and understanding the system benefits of combining technologies to meet demand. The goal of this analysis is to avoid scenarios where insufficient power generation resources cause unexpected brownouts or blackouts to the grid.

Loss of Load Example
Insufficient resource capacity to serve load



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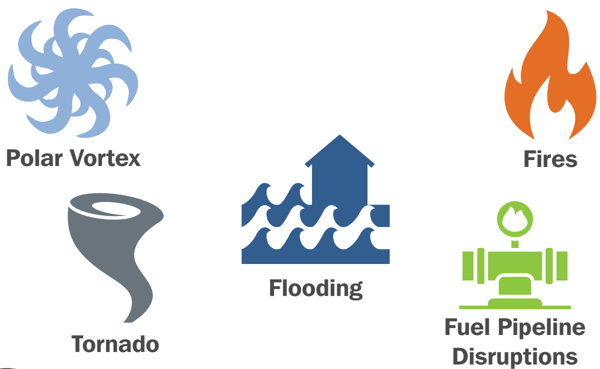
#4 PATHWAYS TO DECARBONIZATION: ENERGY PORTFOLIO WORKSHOP

Modeling Approach

3 Planning for a resilient energy system.

Resiliency refers to the ability of the electric grid to prepare, withstand, respond, adapt, and quickly recover following unexpected, high-impact disruption. E3 will consider portfolio modifications that enhance resiliency to manage select physical and operational risks. OPPD will continually assess resiliency in the future as specific decisions are made related to existing and new power generation and transmission assets.



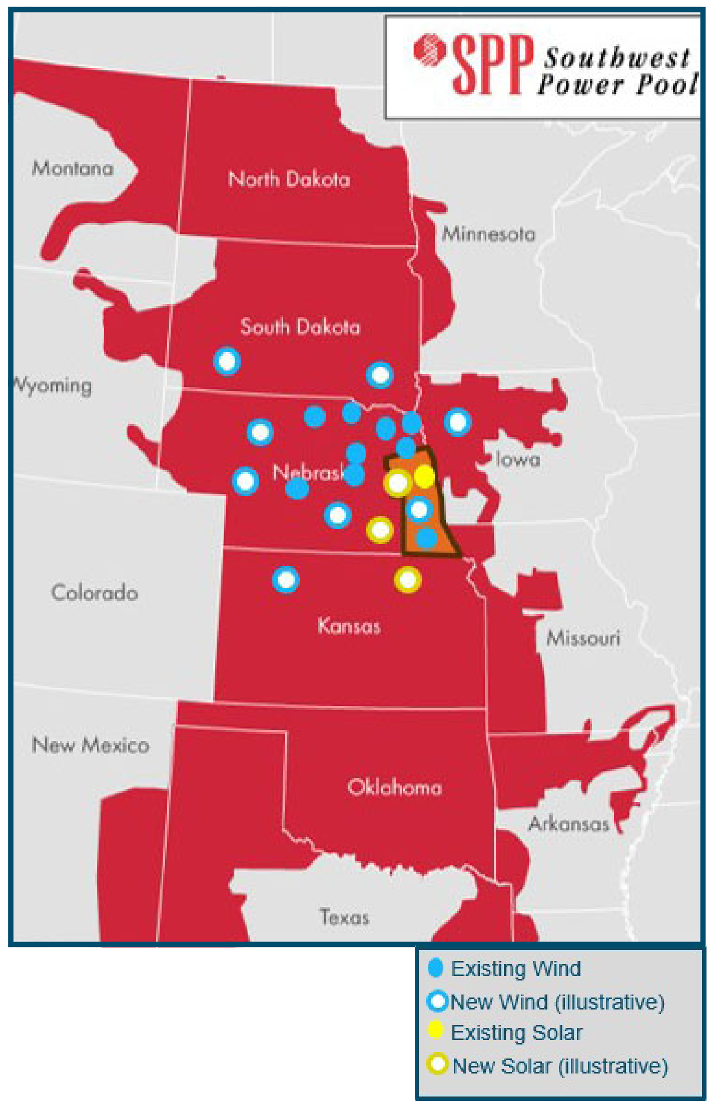
5 Portfolio optimization will identify least-cost pathways towards reliable, low-carbon electricity.

E3 will utilize a data intensive modeling process to optimize energy resource portfolios with the objective minimize costs while achieving decarbonization and reliability requirements. The model will consider inputs such as fuel conversion at OPPD's existing generation facilities, new resource options and potential, and transmission. The results will offer insight on commonalities of successful portfolios, operational considerations, reliability risks, and relative cost to reduce carbon emissions.

Environment	Reliability	Cost
All portfolios will meet environmental/GHG targets for that scenario	All portfolios will ensure system meets resource adequacy requirement	Optimization will develop a portfolio that minimizes cost
Required	Required	Minimize

4 OPPD is just one piece of the puzzle.

OPPD is one of many electric utilities across the Midwest and United States working towards net zero carbon reduction goals. The entire grid is transitioning and will affect how individual utilities interact in regional markets, such as the Southwest Power Pool. Therefore, E3's model will also consider OPPD's market imports and exports, transmission limits, and how these transactions affect carbon accounting.



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PATHWAYS TO DECARBONIZATION:

Energy Portfolio Workshop

#5

OPPD, with support from E3, is conducting a series of workshops to engage stakeholders in the Energy Portfolio decarbonization planning process. **Workshop #5** shared **initial modeling results for Energy Portfolio decarbonization pathways**. Findings provide preliminary insights to the least-cost power generation resource portfolio, taking into account resource adequacy, reliability, and achieving OPPD's net zero carbon goal. The recording is available online.

Schedule

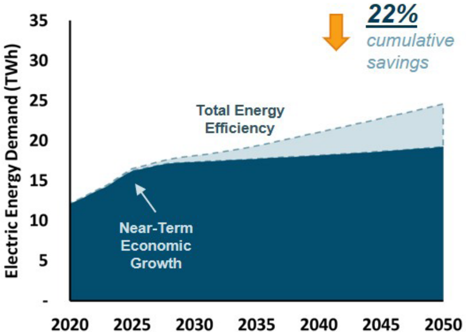
- **Pathways Planning 101**
  April 7, 2021 | 4–6 p.m.
- **Multi-Sector Modeling**
  April 28, 2021 | 4–6 p.m.
- **Key Assumptions & Scenarios**
  May 12, 2021 | 4–6 p.m.
- **Modeling Approach**
  May 26, 2021 | 4–6 p.m.
- **Interim Modeling Update**
  August 4, 2021
- **Modeling Activities**
  Q2/Q3 2021
- **Initial Results**
  October 27, 2021 | 4–6 p.m.
- **Final Results**
  December 9, 2021 | 4–6 p.m.
- **Integrated Resource Plan**
  February 2022

Initial Results

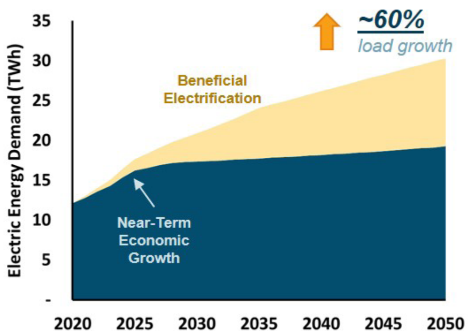
1 Continued advancement in energy efficiency

The model assumes a 22% cumulative improvement in energy efficiency between 2025 and 2050, which is similar to improvements realized over the past few decades. **OPPD, our customers, and the communities we serve will play an important role in achieving this ambitious level of energy efficiency.** At the same time, the model assumes that beneficial electrification in transportation and buildings will add about 60% load growth during this same time.

OPPD ELECTRIC LOAD FORECAST BEFORE BENEFICIAL ELECTRIFICATION



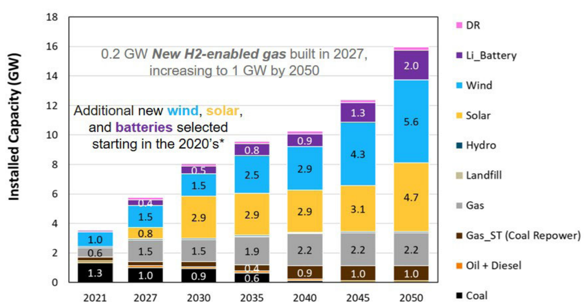
OPPD ELECTRIC LOAD FORECAST AFTER BENEFICIAL ELECTRIFICATION



2 12GW of solar, wind, storage and demand responses would potentially be added by 2050.

The optimal portfolio would require OPPD to steadily integrate unprecedented capacity of new renewable resources, while transitioning away from coal and reducing the energy generated by natural gas fueled assets. Some firm capacity is required to maintain resource adequacy due to anticipated saturation

(continued)



Repower of NC1 + NC2 coal units with gas between 2030 – 2045

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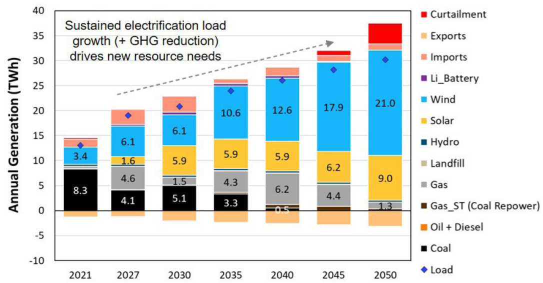
Initial Results

2

(continued)

of solar, wind, and battery storage across the Southwest Power Pool. While natural gas would continue to provide firm capacity critical to system reliability, the annual energy output of these resources is expected to incrementally decrease over time.



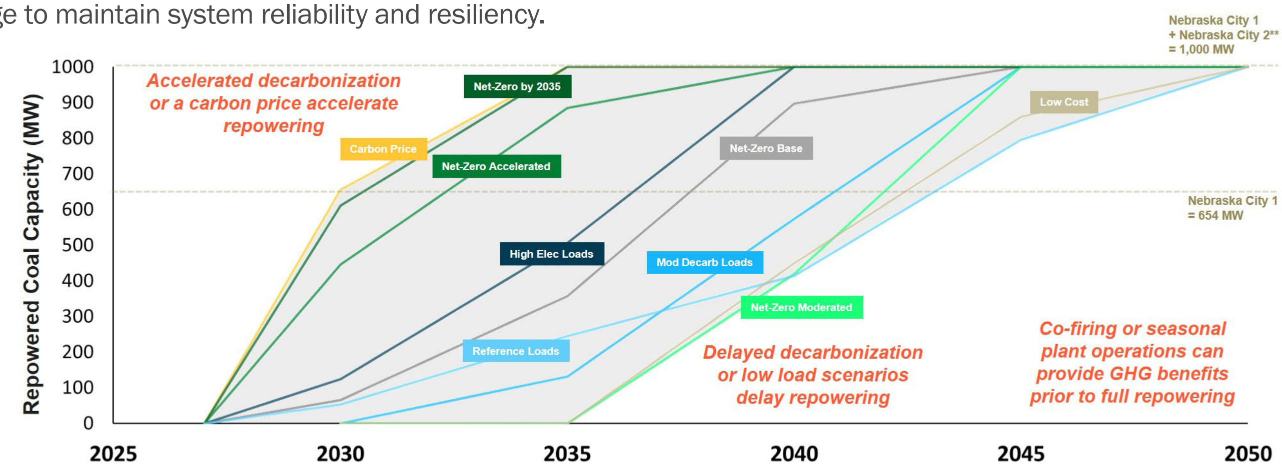
3 Generation costs for the optimal net-zero carbon scenario would increase by 1.4 cents/kWh.

Generation cost increases would result in rate increases but are comparatively low over the next decade, increasing just 5% by 2030, followed by an 8% increase between 2030 and 2040, and a 3% increase between 2040 and 2050. There may be opportunities for customers to offset rate increases with improvements in energy efficiency and cost savings associated with beneficial electrification. Modeled cost increases do not include all costs that may be required to support grid transformation.

4 Repowering coal fired power plants is part of the equation.

Repowering remaining coal-fired power plants to natural gas was selected by the model for all net-zero scenarios, although timing varies. Repowering Nebraska City Unit 1 would occur between 2030 and 2040, while Nebraska City Unit 2 would be refueled slightly later, between 2035 and 2045. When repurposed as natural gas units, they will serve as a valuable source of firm power, providing backup to intermittent renewable resources and battery storage to maintain system reliability and resiliency.

NEBRASKA CITY (NC) COAL REPOWERING ACROSS NEW-ZERO CARBON RESOLVE RUNS: All net-zero scenarios repower NC1 and NC2 to gas: NC1 repowered 2030–2040; NC2 repowered 2035–2045.



5 Maintaining system reliability and affordability remains a core value.

Even as OPPD plans to transition towards a net-zero carbon power generation portfolio, we remain steadfast in our commitment to maintaining system reliability and affordability. E3 included resource adequacy in the model, meaning how much installed capacity of each type of generation (gas, solar, wind) is needed to confidently generate necessary power. The optimal portfolio recommends the least cost scenario that puts OPPD on the path towards net-zero carbon, while reliably meeting anticipated energy demand at the lowest cost to our customers.

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PATHWAYS TO DECARBONIZATION:

Energy Portfolio Workshop

#6

OPPD, with support from E3, conducted a series of workshops to engage stakeholders in the Energy Portfolio decarbonization planning process. At **Workshop #6** we shared and discussed **final decarbonization pathway results and next steps**. Findings provide preliminary insights to the least-cost power generation resource portfolio, taking into account resource adequacy, reliability, and achieving OPPD's net zero carbon goal. The recording is available online.

Schedule

- **Pathways Planning 101**
  April 7, 2021 | 4–6 p.m.
- **Multi-Sector Modeling**
  April 28, 2021 | 4–6 p.m.
- **Key Assumptions & Scenarios**
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- **Integrated Resource Plan**
  February 2022

Final Results & Next Steps

1 Risk and resilience analyses of the final modeling results focused on identifying the optimal energy portfolio options to meet OPPD's net-zero carbon production goals by 2050.

Traditional methods of energy planning risk consider variable or uncertain fuel prices as well as uncertainties surrounding environmental regulations, and the potential for taxes or fees on carbon emissions. Our risk analysis for this decarbonization study focused on technology evolution and investment risk to identify low-risk technology investments across the scenarios modeled.
For example:

- Solar, wind and battery storage are low-risk investments with robust build-out, even across the least optimal portfolio scenarios.
- Though firm capacity fueled by hydrogen, natural gas or biogas is not allowed in all the absolute-zero scenarios, it plays a critical role in optimal net-zero portfolio scenarios, therefore also making it low-risk among those options.
- Nuclear, which was not economic in the majority of our portfolio scenarios, carries more risk.

Additional analysis considered the potential risks associated with load growth uncertainties. There is less risk involved than with technology evolution, because OPPD has the ability to adapt, accelerate or moderate new asset implementation to meet load growth demands.

Following the risk analysis, we looked at generation portfolio scenarios and how they performed facing resiliency challenges, including extreme weather conditions caused by:

- Extended low wind and solar output
- Extreme summer heat
- Extreme winter cold or polar vortexes, and
- Extreme local weather events like flooding or tornadoes.

PATHWAYS TO DECARBONIZATION: ENERGY PORTFOLIO WORKSHOP

#6

Final Results & Next Steps

NET-ZERO CARBON PRODUCTION
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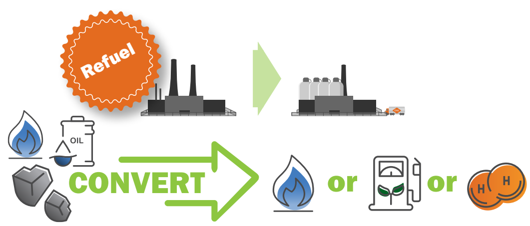
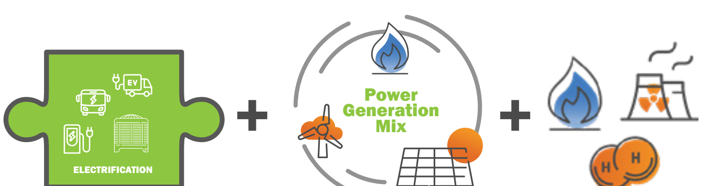
2 Our Pathways to Decarbonization team identified optimal portfolio scenarios to reach our Net-Zero Carbon Production Goal by 2050. Final analyses included these key findings:

1. OPPD can achieve Net-Zero carbon production while balancing affrodability and reliability. — Net-zero is achievable with projected generation and transmission cost impacts of approximately 10-20% over time by 2050 while maintaining historical resource adequacy levels.

2. Cease coal generation and reduce fossil generation. — Generation from fossil resources is reduced in all Net-Zero Scenarios as it is increasingly displaced by low-carbon resources. All scenarios ultimately re-power or retire OPPD's coal generation by 2050 and maintain firm resources with minimum capacity factors.

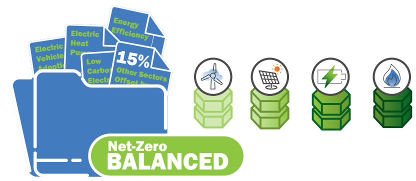


3. A mix of new, low-carbon resources including renewable energy, energy storage, and community-wide efficiency will be required. — Large quantities of low carbon resources are required to displace fossil generation and reduce emissions across OPPD's system. OPPD must plan for additional 'no regrets' resources if it is going to meet carbon reduction goals.

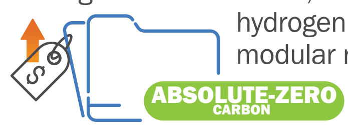


4. Firm generation is needed to maintain resource adequacy. — Wind, solar, energy storage, and demand-side resources support reliability but have limitations, especially during certain extreme weather events. Firm, dispatchable resources must be maintained to support the system during these critical periods.

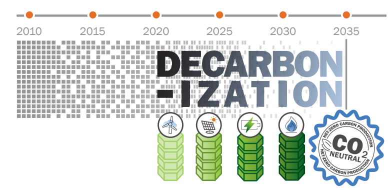
5. Resources are consistent across a variety of pathways. — A core set of resources are common across a variety of scenarios. Pace of Decarbonization scenarios accelerate or delay resources. The solution scales proportionally with total load.



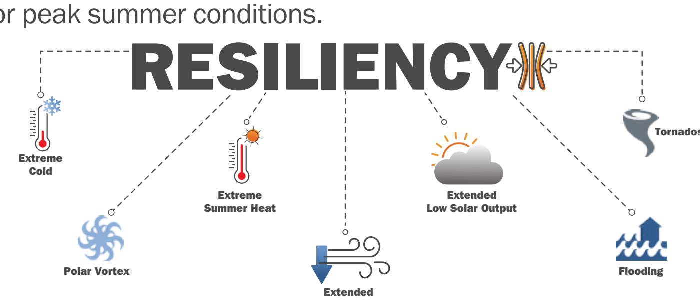
6. Absolute-Zero Scenarios are substantially more costly and are dependent on future technologies. — Achieving Absolute-Zero with current technology requires impractically high levels of new resources at significantly higher cost. However, emerging technologies such as hydrogen, long-duration storage, and small modular reactors have the potential to make this more feasible.



7. Accelerating decarbonization reduces emissions at a relatively low incremental cost, but poses implementation and integration challenges. — Accelerating Net-Zero Decarbonization Pathways results in relatively low incremental costs, but require integrating higher levels of resources in the near-term, which is challenged by supply chain and grid interconnection issues.



8. The changing resource mix will pose new resiliency challenges that must be evaluated, understood and mitigated — Critical resource adequacy periods are expected to change from peak summer conditions to periods of extreme cold or extended periods of low renewable generation. Utilities across the grid will need to anticipate and prepare for these extreme events differently than they have historically planned for peak summer conditions.



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Appendix C – Reviewed Technology List

- **Solar** - Perovskite Solar–Quantum Dot Solar–Tandem Solar–Organic Solar–Space Solar–Thin Film Solar–Crystalline Silicon Solar–Floating Solar–Commercial Partnership Solar–Community Solar–Concentrated Solar (CSP)
- **Wind** - Conventional wind generation–Aerial wind generation
- **Hydropower** - Utility-Scale-- Run-of-the-River Hydro–Micro-hydropower
- **Geothermal Power**
- **Energy Storage** - Li-ion Batteries (multiple chemistries)–Flow batteries–Liquid Air Energy Storage–Gravity energy storage–Liquid metal energy storage–Flywheels–Pumped hydro storage–Compressed Air Energy Storage–Cryogenic Energy Storage–Sensible heat storage (Water, Molten salts, Sand, Bricks/rocks)–Thermo-chemical storage–MGA Blocks (miscibility gap alloys)–Ice Storage
- **Energy Efficiency** - Efficient building design–Efficient appliances–Waste heat reclaim from waste water (SHARC Energy Systems) • Demand Side Management–Smart metering–Electric water heater control–Power factor enforcement–HVAC controlling–Cooling processes control/reduction–Thermal storage–Time of use control for appliances, i.e. dishwashers–Incentivize minimizing peak usage–Behavior programs–Demand response incentives–Lighting controls
- **Distributed Energy Resources (DER)** - Virtual Power Plant (Distributed Energy Resource Management System, DERMS)–Uncoordinated distributed energy resources (customer driven, randomly located, no OPPD operational control)–Targeted distributed energy resources–Aggregator – 3 rd. party controlling distributed generation groups and offering control as service to the Utility–Electric Vehicle as battery storage (V2G) or Vehicle to Grid integration (VGI)–Behind the meter energy storage–Behind the meter solar–Customer micro-grids
- **Hydrogen Generation, Storage, & Utilization** - Electrolyzer hydrogen generation–Synthetic methane production–Produce excess hydrogen when electric demand is low and utilize for generation later or sell and use as CO2 offset–Co-location to burn byproduct (i.e. carbon black)–Hydrogen fueled combustion turbine (simple or combined cycle)–Use in fuel cells–Blended with natural gas and utilized in generating assets–Hybrid fuel cell – gas turbine
- **Current Generation Retirements**
- **Current Generation Conversions** - Heat Rate Improvements–Convert NC1 to natural gas–Convert NC2 to natural gas–Co-firing NC1 with natural gas–Co-firing NC2 with natural gas–Blending or conversion to hydrogen for NC1–Blending or conversion to hydrogen for NC2–NC1 and NC2 seasonal unit cycling
- **Current Generation Conversions** - Blending or conversion to hydrogen SC1 and SC2–Blending or conversion to hydrogen SC3–Blending or conversion to hydrogen SC4 and SC5–

Blending or conversion to hydrogen CC1 and CC2–Blending or conversion to hydrogen JS1 and JS2–Blending or conversion to hydrogen Turtle Creek Station

- **New Fossil Assets** - Combined cycle combustion turbine–SCO2 (supercritical CO2) combustion turbine–Syngas fuel combustion turbine–High Firing Temperature (>3100 F) combustion turbine–Pressure gain combustion turbine–IGCC (Integrated coal gasification combined cycle) combustion turbine–Oxy-fuel cycle combustion turbine–Partial oxidation gas turbine (POGT)–Reciprocating internal combustion engines–Simple cycle combustion turbine • Nuclear–Advanced Small Modular Reactors (SMRs)–Fusion–Spent nuclear fuel recycling for use in SMRs–Light water reactor (i.e. AP1000)–Sodium cooled fast reactors–Very high temperature reactors–Molten salt reactors
- **Low Net Carbon Biofuels (for use in other technologies)** - Biomass–Algal–Biogas–Landfill Gas–Waste Gas–Ethanol–Liquid Biofuel (i.e. Biodiesel, Renewable diesel)
- **Carbon Capture** - Post-combustion capture with solvents–Post-combustion capture with sorbents–Post-combustion capture with membrane systems–Oxy-fuel cycle with post combustion capture–Carbon capture with geologic storage–Carbone capture with enhanced oil recovery usage–Carbon capture uptake via Algae or agricultural (i.e. produce biomass)–Carbon capture with conversion to fuels or chemicals–Carbon capture with mineralization into inorganic materials (i.e. carbonate cement)–Carbon capture via sewage treatment plant–Direct Air Carbon Capture

Appendix D – Decarbonization: Energy Portfolio Study

Omaha Public Power District Pathways to Decarbonization

Final Report

February 2022

Energy+Environmental Economics

Omaha Public Power District Pathways to Decarbonization

Final Report

February 2022

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Acronym and Abbreviation Definitions

Acronym	Definition
BTM	Behind the Meter
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CT	Combustion Turbine
DAC	Direct Air Capture
DR	Demand Response
DOE	Department of Energy
ELCC	Effective Load Carrying Capability
EPRI	Electric Power Research Institute
EE	Energy Efficiency
ELCC	Effective Load Carrying Capability
EV	Electric Vehicle
EVLST	E3's EV Load Shaping Tool
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
H2	Hydrogen
LOLE	Loss of Load Expectation
NATF	North American Transmission Forum
NERC	North American Electric Reliability Corporation
NIAC	National Infrastructure Advisory Council
NREL	National Renewable Energy Laboratory
NSRDB	National Solar Radiation Database
OPPD	Omaha Public Power District
PRM	Planning Reserve Margin
RECAP	E3's Renewable Energy Capacity Planning Model
RESOLVE	E3's Renewable Energy Solutions Model
SAM	System Advisor Model
SMR	Small Modular Reactor

SPP	Southwest Power Pool
ST	Steam Turbine
UCAP	Unforced Outage Rate
VGI	Vehicle to Grid Integration
WIND	Wind Integration National Database

Executive Summary

In 2019, the Omaha Public Power District (OPPD) announced an aspirational goal to reach net zero carbon emissions for its electricity system by 2050. OPPD created its “Pathways to Decarbonization” Program to explore key strategies to reach that goal and hired Energy and Environmental Economics (E3) as its technical consultant to perform a multi-stage analysis to inform decarbonization of OPPD’s energy portfolio. E3’s work is complementary to other ongoing OPPD efforts within the Pathways to Decarbonization program to support decarbonization at the community level, the customer level, and in OPPD’s internal operations. E3 developed multiple technology pathways to meet OPPD’s ambitious net zero carbon goal while simultaneously maintaining affordability, reliability, and resilience. The development of electric technology pathways was complemented by an economy-wide multi-sector modeling decarbonization study that contextualized the critical role of the electric system to support a decarbonized energy economy, including significant load growth from electrification.

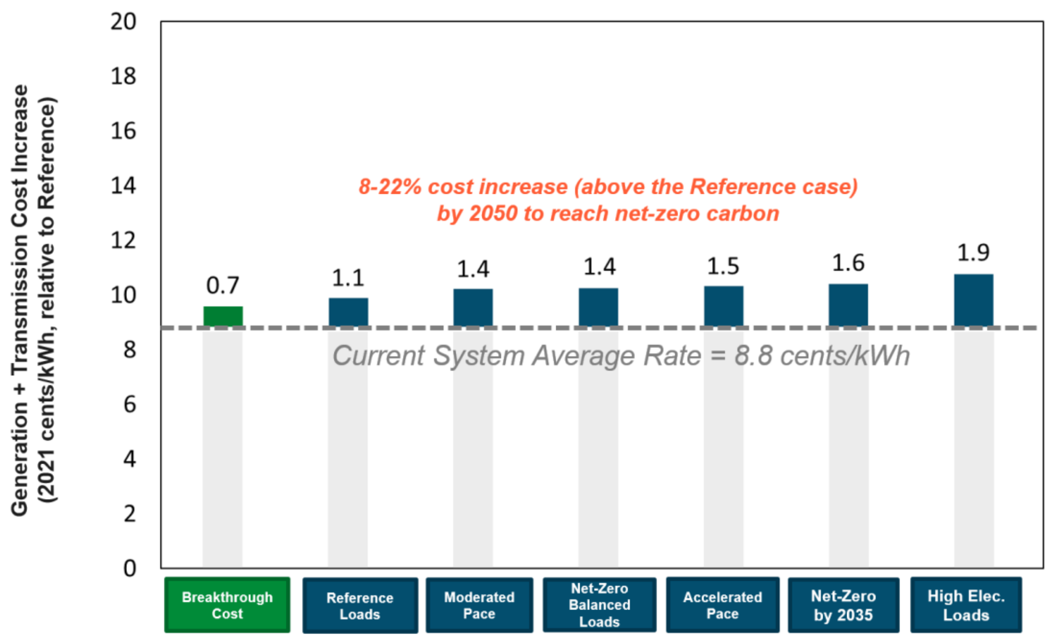
This report covers detailed documentation of E3’s study approach, inputs, and results. This executive summary contains a summary of the following key study findings:

1. OPPD can achieve net zero carbon while balancing affordability and reliability
2. All net zero pathways require a cessation of coal generation and reduced use of fossil generation
3. A mix of new low-carbon resources including renewable energy, energy storage, and community-wide energy efficiency will be required
4. Firm capacity resources are needed to maintain resource adequacy
5. Resource needs are broadly consistent across a variety of pathways
6. Scenarios that eliminate all carbon emitting generation are feasible, but are higher cost and dependent on future technology development
7. Accelerating decarbonization reduces cumulative emissions at a relatively low incremental cost, but poses implementation and integration challenges
8. The changing resource mix will pose new resiliency challenges that must be evaluated, understood, and mitigated

KEY FINDING 1: OPPD can achieve net zero carbon while balancing affordability and reliability

Net zero carbon electricity is achievable with incremental projected generation and transmission cost impacts of approximately 8-22% over time by 2050 while maintaining resource adequacy levels. These cost impacts are measured relative to a Reference OPPD system with reference loads and no carbon reduction target. The cost impacts do not reflect additional costs that may be required for the reference case. Reaching net zero carbon is possible with the use of mature, commercialized technologies such as energy efficiency, solar power, wind power, battery storage, and firm thermal generating capacity such as natural gas. While renewables, energy storage, and demand response contribute significantly to system reliability, firm resources are still needed to ensure resource adequacy. The flexibility of a "net zero" carbon target allows a small amount of carbon emitting natural gas generation to remain if netted against OPPD clean exports that reduce emissions in the broader Southwest Power Pool (SPP) marketplace or, if they become available and cost-effective, using negative emissions technologies like the direct air capture of carbon. Cost increases could be reduced or even eliminated under scenarios of aggressive federal carbon pricing or high fossil fuel prices. Cost impacts are summarized in Figure 1.

Figure 1. OPPD Modeled Cost Increases Across a Range of Net Zero Carbon Scenarios[1]



KEY FINDING 2: All net zero pathways require a cessation of coal generation and reduced use of fossil generation

Generation from fossil resources is reduced in all Net Zero scenarios as it is increasingly displaced by low-carbon resources, as shown in Figure 2. In the near-term, this requires a reduction in coal generation, an increase in natural gas generation, and a large increase in solar and wind power. In the net zero base case, coal generation is virtually eliminated as an energy source by 2040. This occurs earlier in scenario of accelerated decarbonization or a federal carbon price and later in scenarios of a moderated decarbonization pace or low load growth.

[1] Costs include generation cost impacts and transmission costs (transmission for new generation, i.e. interconnection, deliverability). Costs are directional in nature, are not representative of detailed financial modeling, and do not include all costs that may be required to support grid transformation. Full rate impact analysis should also include distribution + transmission cost impacts due to electrification, grid modernization, regional congestion, etc. A carbon tax (or change in fossil fuel prices) would decrease or eliminate the incremental costs of decarbonization relative to the reference scenario. Total customer cost impacts should also include holistic impact of higher electricity costs with gasoline and natural gas savings due to electrification. Note: average US electric rates in October 2021 were 11.32 cents/kWh, per EIA Electric Power Monthly: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.

Figure 2. OPPD Annual Generation in Net Zero Carbon Base Scenario

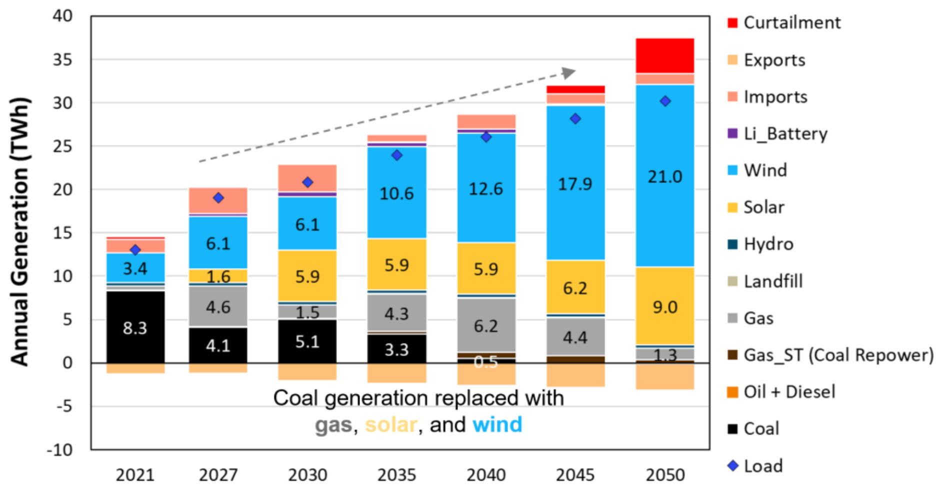
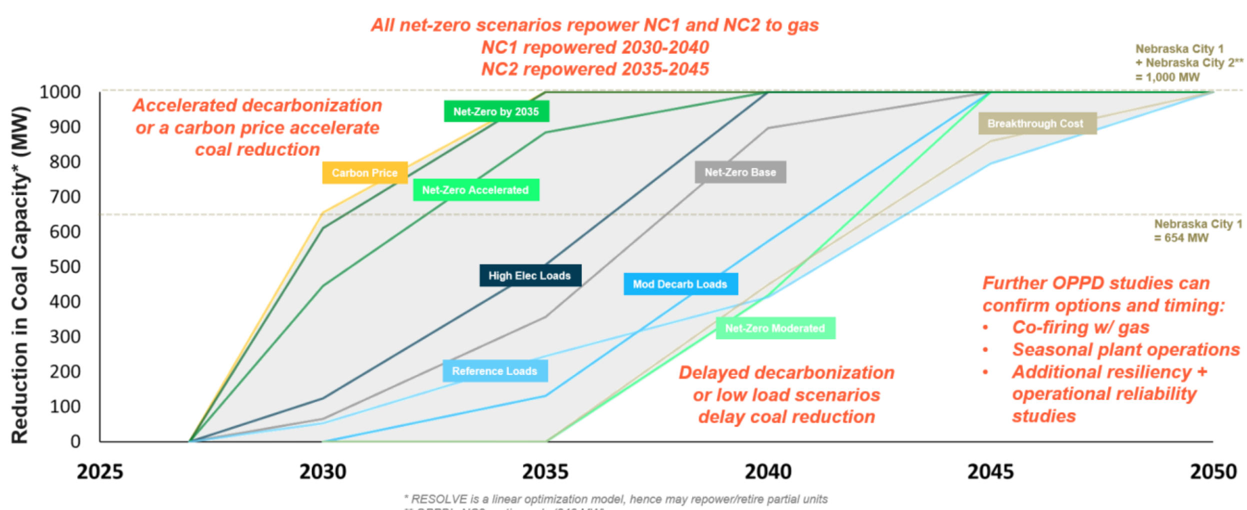


Figure 3 shows that all scenarios ultimately repower or retire all 1,000 MW of OPPD's remaining two coal-burning Nebraska City units by 2050. For Nebraska City 1, repowering occurs between 2030-2040; for Nebraska City 2, it occurs between 2035-2045.[2] All modeled scenarios repower the coal steam turbines to natural gas, serving as a low-cost source of flexible, low-emissions firm capacity. Though retirement or repowering to gas was modeled for this study, OPPD can explore other transition scenarios such as co-firing with natural gas or seasonal plant operations that operate coal capacity only during peak winter or summer demand periods.

Figure 3. Reduction in OPPD Coal Capacity in Net zero Carbon Scenarios

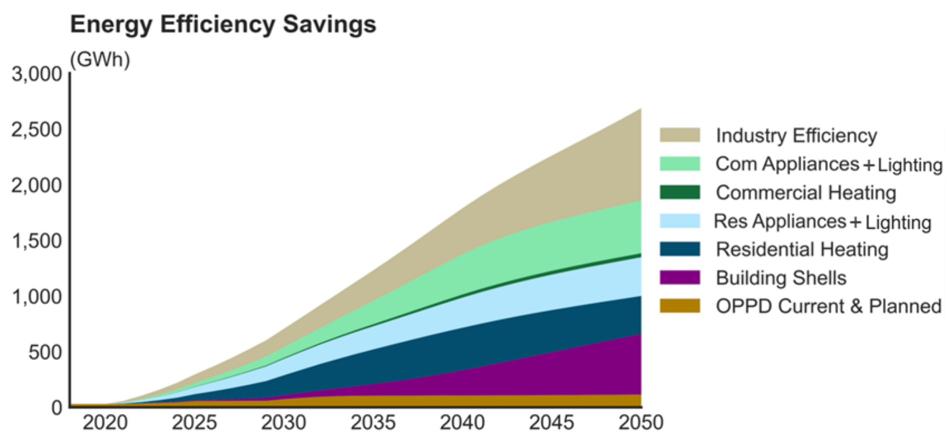


[2] Nebraska City Unit 2 stops coal operations by 2045 in all cases except for the Reference Loads and the Breakthrough Costs scenarios. In those two scenarios, coal operations fully cease in 2050.

KEY FINDING 3: A mix of new low-carbon resources including renewable energy, energy storage, and community-wide energy efficiency will be required

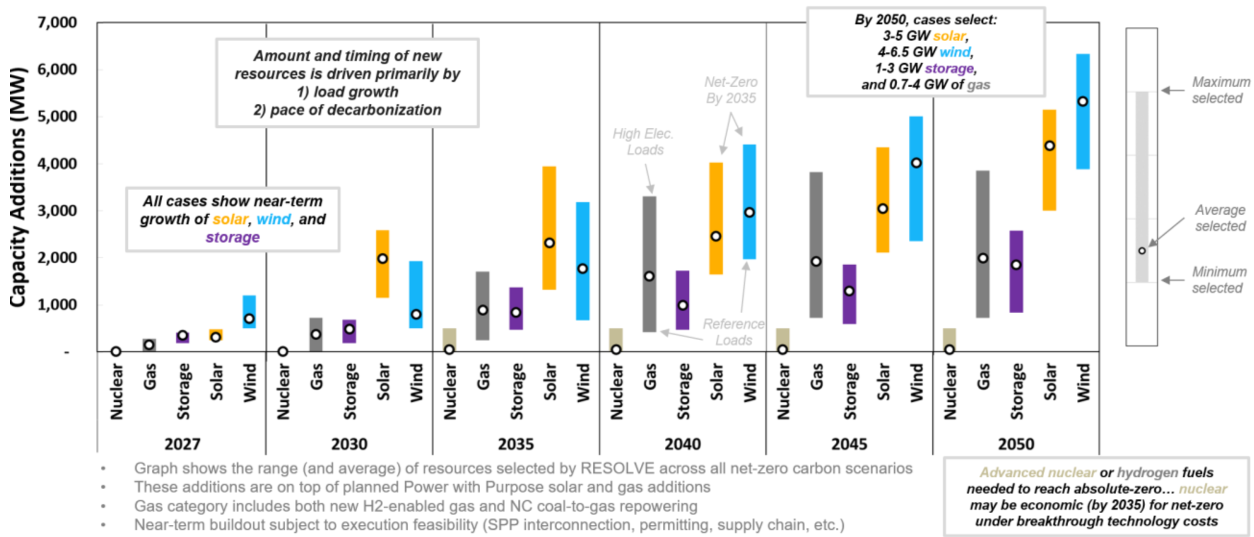
Energy efficiency is modeled in the multi-sector modeling scenarios, which expand efficiency adoption beyond current OPPD programs. Efficiency occurs at the economy-wide level, as primary energy uses when inefficient gasoline, diesel, and natural gas combustion is replaced with more efficient electric energy. Electric energy efficiency is assumed to increase via a range of customer investments in lighting, appliances, building shells, and industrial efficiency. Figure 4 shows the electric energy efficiency savings in the multi-sector modeling scenarios developed by E3, relative to the "Reference" level of EE savings that includes only OPPD's current and near-term planned EE programs. Further, more detailed implementation studies can be used to develop detailed data on EE potential and costs to inform the development of future OPPD EE programs or other sourcing mechanisms (building codes and appliance standards, etc.). Figure 4 shows energy efficiency by sector from the Net zero Balanced scenario.

Figure 4. Electric Energy Efficiency Savings in Net zero Balanced Load Scenario



Large quantities of low carbon generating resources and new battery storage are required to displace fossil generation, reduce emissions, and contribute to the reliability of OPPD's system. The low carbon generating units selected are primarily wind and solar power resources located within or near OPPD's service territory, where exists some of the highest quality wind resource potential in the region. Battery storage is selected to balance renewable energy and support reliability under growing loads. Planned natural gas resources help to offset coal generation in the near- to mid-term and new dual-fuel capable natural gas and hydrogen resources are also selected across all net zero scenarios (although they do not need to burn hydrogen fuel to reach net zero). New advanced nuclear resources, such as small modular reactors, are only selected under breakthrough cost scenarios or scenarios that disallow hydrogen technologies. When considered under a sensitivity scenario, additional flexible load resources were found to displace battery storage resources but were not capable of displacing firm capacity needs due to use limitations. Figure 5 summarizes the range of the major categories of new resources selected by E3's RESOLVE capacity expansion model for OPPD's system needs.

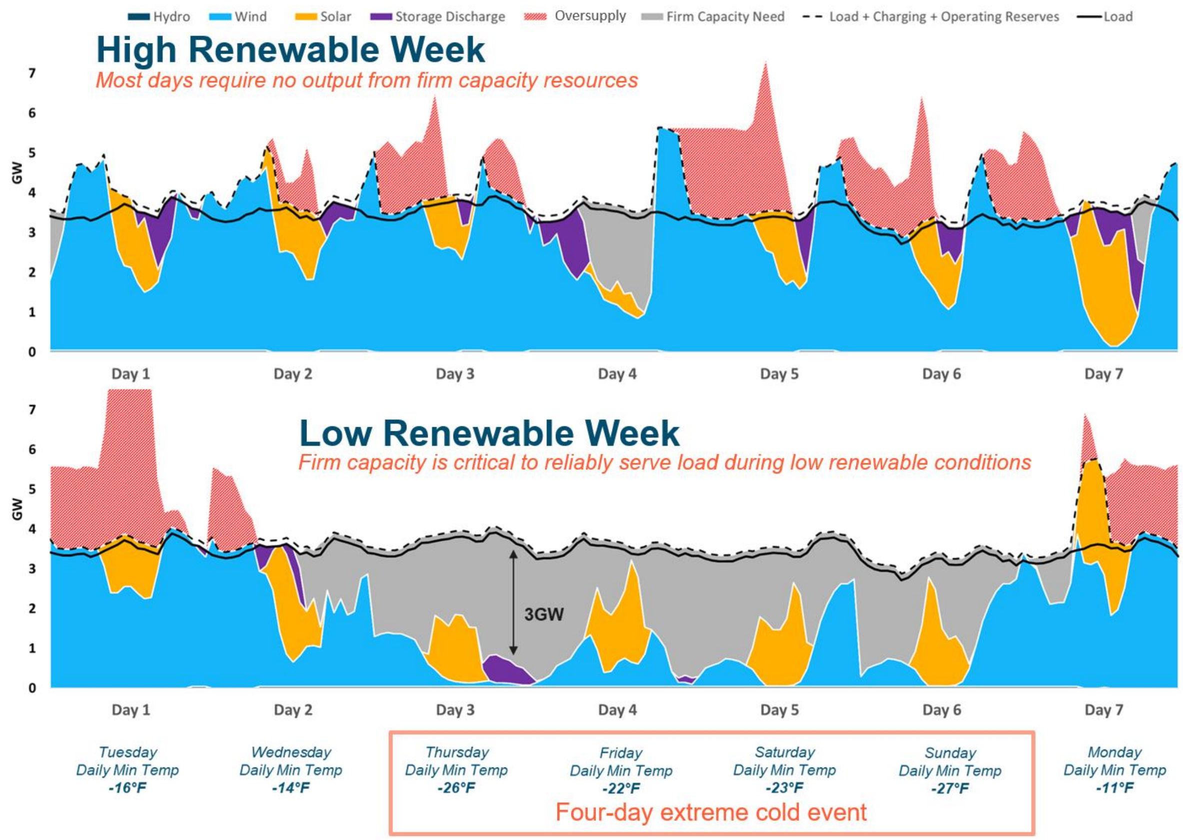
Figure 5. Incremental OPPD Low-Carbon Resources Selected to Reach Net zero Carbon



KEY FINDING 4: Firm capacity resources are needed to maintain resource adequacy

Growing levels of wind, solar, energy storage, and demand-side resources can provide support to OPPD's reliability needs under growing electrification loads. However, these resources are considered "non-firm", meaning they are weather dependent or have use-limitations, especially during certain extreme weather events. Based on probabilistic reliability simulation modeling performed in E3's RECAP model, firm capacity resources were found to be necessary to support the system during critical periods of high OPPD loads combined with multi-day low wind and solar conditions. Firm resources include both the retention of existing resources and/or construction of new firm capacity resources. These resources generally show very low capacity factors by 2050 and may barely operate during high renewable output conditions. However, as shown in the RECAP model outputs in Figure 6, their output is critical for system reliability during a low renewables week. Extended low renewable conditions become the primary reliability planning challenge by 2050 and were found to occur both in the winter (both low wind and solar) and summer (primarily low wind events). To avoid stranded asset risk, new firm resources are modeled as capable of burning either natural gas or hydrogen, should hydrogen become a necessary or cost-effective fuel option.

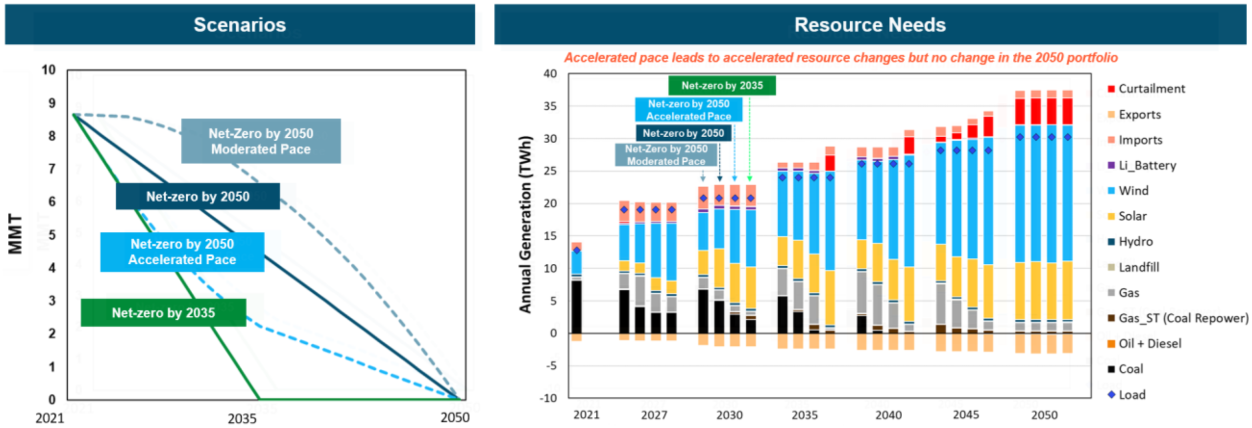
Figure 6. Firm Capacity Needs During a Low Renewable Extreme Winter Cold Event (2050 Net zero Carbon Base Scenario)



KEY FINDING 5: Resource needs are broadly consistent across a variety of pathways

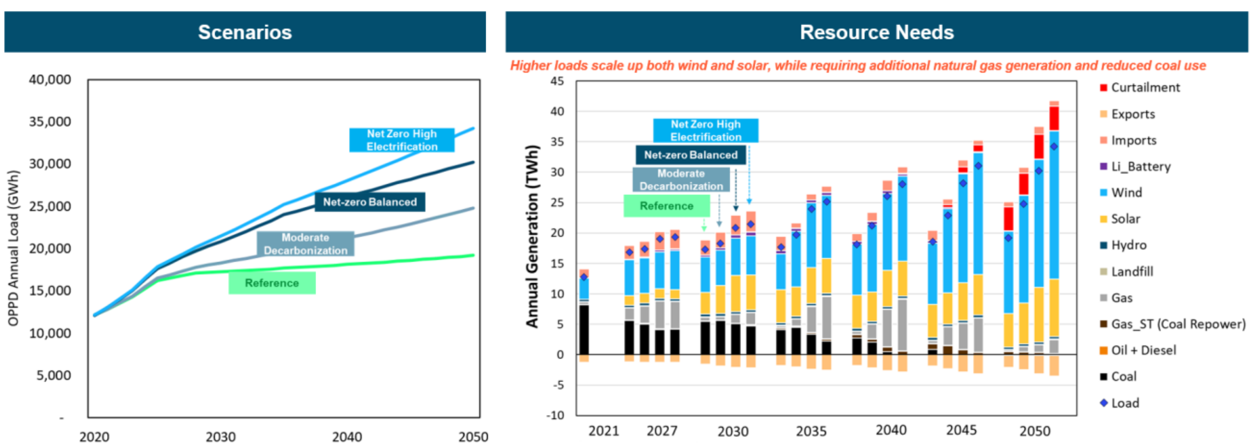
A core set of resource additions are common across a variety of scenarios, pointing to no regrets near-term investments in new solar, wind, and battery storage capacity, as well as fuel switching from coal to natural gas. The pace of decarbonization generally sets the speed of resource decisions. As shown in Figure 7, an accelerated pace leads to earlier investment in new wind and solar resources and quicker fuel switching from coal to natural gas. A moderated pace leads to later portfolio changes, but results in a nearly identical 2050 final portfolio.

Figure 7. Pace of Decarbonization Impacts the Timing of Resource Changes



As show in Figure 8, under scenarios of varying electrification load growth, the need for new resource additions scales proportionally with total load, while higher loads show less coal generation and more natural gas generation between 2035-2045. These conclusions indicate that, under the cost assumptions used in this study, the mix of key resources is generally consistent and their speed or level of additions is primarily dependent on the pace of decarbonization and future OPPD electric load growth.

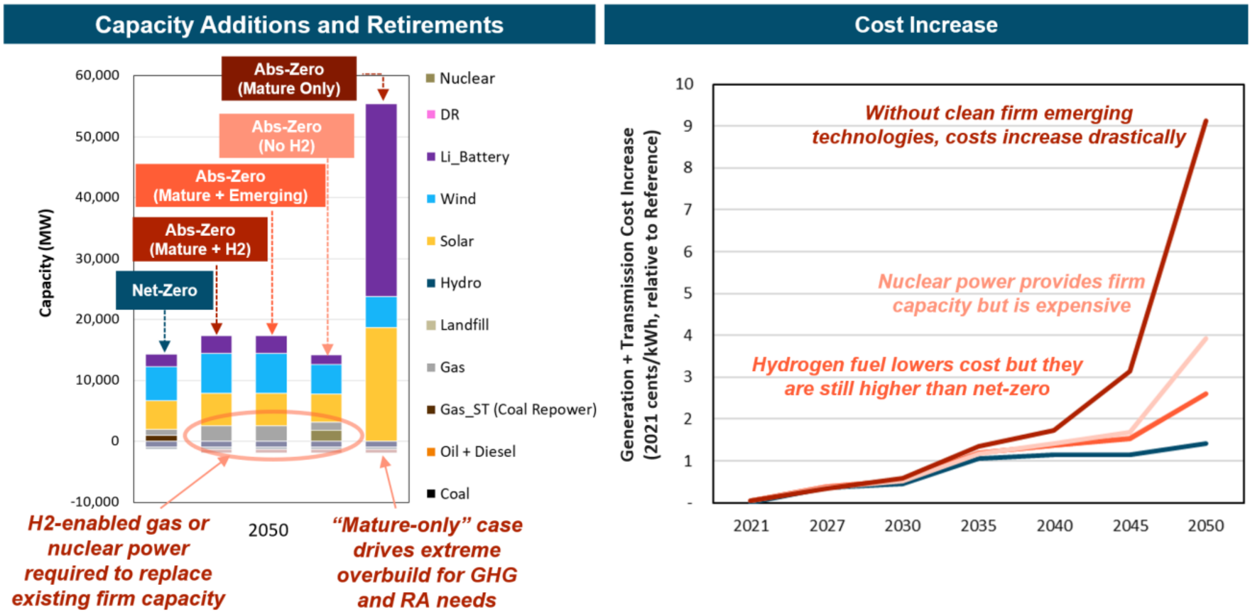
Figure 8. Load Growth Impacts the Level of Resource Changes



KEY FINDING 6: Scenarios that eliminate all carbon emitting generation are feasible, but are higher cost and depend on future technology development

In addition to scenarios of achieving net zero carbon, scenarios of achieving an elimination of all electric carbon emissions (achieving "absolute zero" carbon) were also studied. Achieving Absolute Zero carbon with today's mature technology requires significantly higher levels of new resources at an impractically high cost. Emerging technologies such as hydrogen, long-duration storage, or small modular reactors have the potential to make this more feasible at a significantly lower cost. As shown in Figure 9, relative to reaching net zero, reaching absolute zero requires replacing the firm capacity of OPPD's existing, fossil fuel based resources with either new hydrogen gas capacity (at a moderate cost increase), new advanced nuclear (at a high cost increase), or – if these emerging technologies are unavailable – extreme overbuild of solar and storage (at an extremely high cost). While hydrogen-capable gas turbines are selected in the net zero scenario, the utilization of hydrogen fuels was not found to be cost-effective unless an absolute zero carbon target must be met.

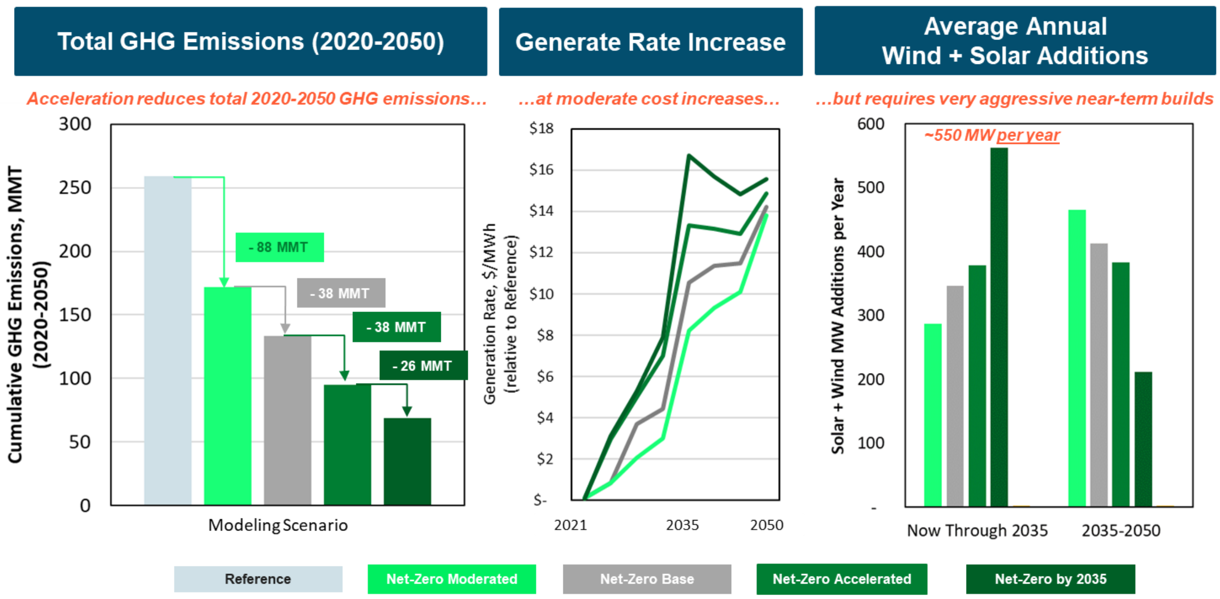
Figure 9. Net vs. Absolute Zero Scenario Resource Needs and Costs



KEY FINDING 7: Accelerating decarbonization reduces cumulative emissions at a relatively low incremental cost, but poses implementation and integration challenges

Accelerating Net Zero decarbonization pathways result in relatively low incremental cost, as shown in Figure 10. However, it also requires integrating higher levels of resources in the near-term, which may pose supply chain, financial, grid interconnection, and operational risks. To reach net zero by 2035, under the Net zero balanced load forecast assumptions, would require over 500 MW of solar and wind additions per year on average between now and 2035. Given near-term supply chain and interconnection challenges, those additions might need to be compressed into an even shorter timeframe, rendering them potentially infeasible. In addition to renewable additions, earlier fuel switching from coal to natural gas, dual gas + coal fuel usage, or seasonal coal operations can also provide near-term emissions reductions.

Figure 10. Emissions, Costs, and Average Annual Additions Across Different Paces of Decarbonization



KEY FINDING 8: The changing resource mix will pose new resiliency challenges that must be evaluated, understood, and mitigated

Critical resource adequacy periods are expected to change from peak summer conditions to periods of extreme cold or extended periods of low renewable generation. Grid resiliency will depend on how utilities anticipate and prepare for these extreme events as the grid continues to evolve. A resiliency framework was developed for this study that analyzed resiliency threats to OPPD's current and future electric system, and deterministic case studies were analyzed to consider discrete extreme events. The key resiliency threats considered in this study included climate change impacts, fuel supply disruptions, and unplanned extreme weather driven outages. Mitigation actions are proposed to ensure OPPD's ability to withstand and recover from these events. Ensuring the resiliency of both the electric power and fuel delivery systems will be critical to enable OPPD's transition to net zero carbon grid.

Conclusions and Recommendations

OPPD has an opportunity as an established regional decarbonization leader and as an electricity provider to engage its employees, its community, and its customers to support the transition to a carbon neutral economy in the region. Creating customer or community-based programs focused on carbon-reducing technology adoption – electric vehicles, energy efficiency, and building electrification – will help to speed along this transition. OPPD's electric portfolio will dramatically shift away from coal towards renewable energy, energy storage, demand flexibility, and low-carbon fuels. This transition can be done while balancing affordability and reliability so long as OPPD maintains or constructs sufficient resources to meet its resource adequacy needs.

While this study should provide confidence to OPPD about the key, near-term, no regrets actions necessary to set them on the road to net zero carbon electricity, further activities are recommended as OPPD embarks on its pathway to decarbonization:

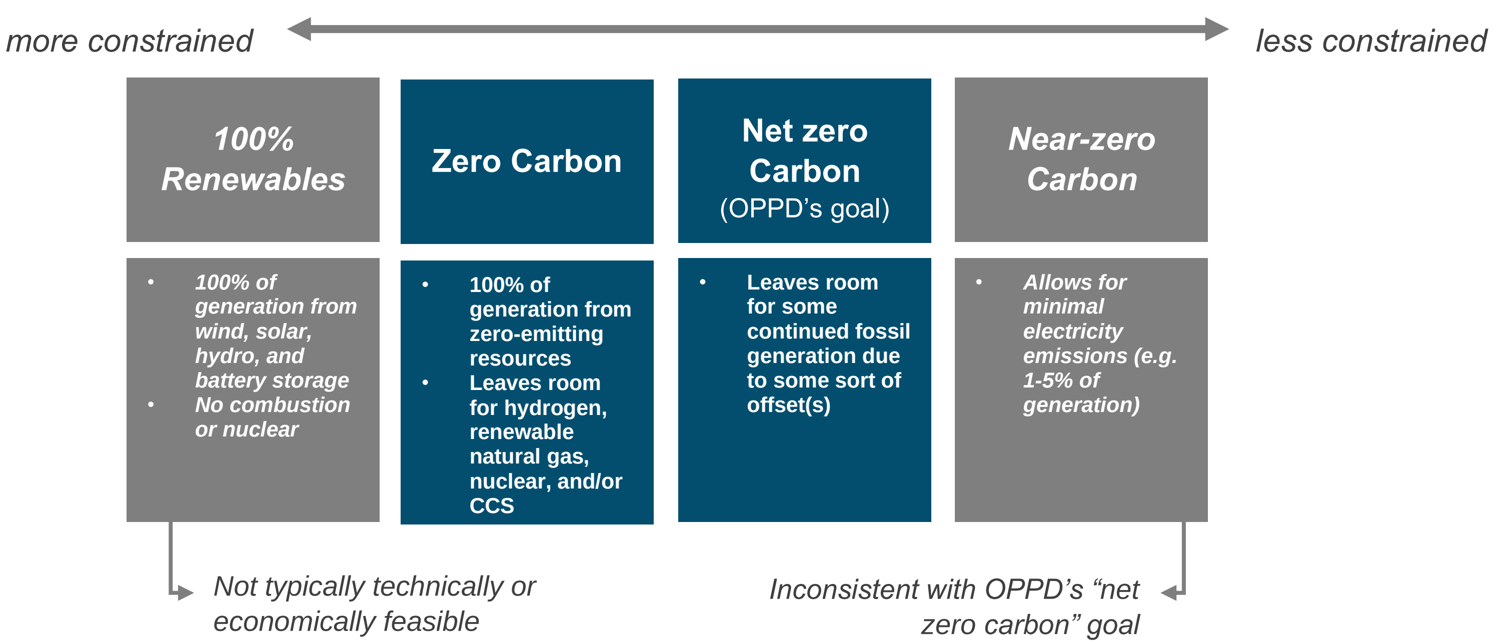
+ **Updated potential and cost-effectiveness studies of demand-side resources including energy efficiency, load flexibility, and distributed energy resources**
+ **Coordinated electric and gas utility planning on smart electrification pathways**
+ **Additional studies and activities to confirm coal retirement trajectory, including fuel assurance infrastructure, operational reliability, interim operational options, and NC2 contract negotiations**
+ **Continued participation in ongoing reliability and resiliency planning for the SPP market**
+ **Coordinated study of renewable energy siting, land use impacts, and transmission planning to facilitate integration of new wind and solar power**
+ **Continued monitoring of emerging long-duration storage and other zero-carbon generation technologies as well as the use of all-source procurement RFOs to facilitate least-cost procurement outcomes**

1 Background

In 2020, the Omaha Public Power District (OPPD) announced an aspirational goal to reach net zero carbon emissions for its electricity system by 2050. OPPD created its "Pathways to Decarbonization" Program to explore and implement key strategies to reach that goal. OPPD hired Energy and Environmental Economics (E3) as its technical consultant to perform a multi-stage analysis to inform decarbonization of OPPD's energy portfolio. This analysis includes the development of multiple technology pathways to meet OPPD's ambitious goal while simultaneously maintaining affordability, reliability, and resilience. E3's work is complementary to other ongoing OPPD efforts within the Pathways to Decarbonization program to support decarbonization at the community level, the customer level, and in OPPD's internal operations.

In the absence of sustained federal carbon targets for the electric sector, OPPD is one of a number of utilities that have set their own carbon reduction targets. These targets are based on a number of metrics, such as clean energy or renewable generation percentage targets or – as OPPD has chosen – reaching "net zero" carbon. Figure 11 shows four options for utility carbon targets and how each is defined. Zero-carbon (also referred to in this study as "*absolute*-zero carbon") means that all generation serving OPPD load in every hour must be from zero-emitting resources. Net zero carbon, OPPD's goal, allows for some level of carbon emitting generation to remain, as long as it is offset through a netting mechanism.

Figure 11. Options for Utility Carbon Target Setting



E3 surveyed the carbon targets of other electric utilities across the US. Most of these utility pledges are for "net zero" carbon and include a mix of netting approaches including various types of carbon offsets, negative emissions technologies, and inter-sector credits.

Figure 12. Net zero Carbon Goals of Other Electric Utilities[3]

Utility	Utility-Type	State	Notes
Portland General Electric	IOU	OR	Net zero by 2040 (“aspirational goal”)
Seattle City Light	Public Power	WA	Has been net-zero since 2005 (~90% hydro, uses **carbon offsets** for ~100-300k MTCO2e/yr)
Madison Gas & Electric	IOU	WI	Net zero by 2050, either by eliminating all emissions **or via carbon offsets** (planting trees, CCS, etc.)
Ameren	Holding Co.	MO	Net zero by 2050, retire all coal by 2042
PSE&G	IOU	NJ	Net zero by 2050, no plans to build or acquire any new fossil fuel generation
National Grid	Holding Co.	MA	Net zero by 2050, **balance between GHG emitted and GHGs removed from the atmosphere**
Lincoln Electric	Public Power	NE	Net zero by 2040
Alliant	IOU	WI	Net zero by 2050 “from the electricity we generate”, **allows carbon offsets**
Entergy	IOU	LA	Net zero by 2050, **allows carbon offsets**
Dominion	IOU	VA	Net zero by 2050, for both power and natural gas operations (CO2 and methane)
Duke Energy	IOU	NC	Net zero by 2050, 95% zero-carbon generation w/ 5% emitting gen + **carbon offsets**
DTE	IOU	MI	Net zero by 2050 for both electric and gas, including **renewable natural gas and carbon offsets**
Orlando Util. Commission	Public Power	FL	Net zero by 2050, proposes **inter-sector crediting for EVs**
Southern Company	Holding Co.	AL	Net zero by 2050, includes utilization of natural gas to enable the transition and **negative carbon solutions**
Consumers Energy	IOU	MI	Net zero by 2050, **allows carbon offsets** (methane capture, tree planting)
Puget Sound Energy	IOU	WA	Carbon neutral by 2030 (per WA’s CETA legislation) **allows offsets** for remaining emissions, before requiring 100% zero-carbon generation in 2045
SMUD	Public Power	CA	Carbon neutral by 2030, **previously considered inter-sector crediting** but exploring other options now

E3 and OPPD explored four net zero netting mechanisms for this study and included electricity exports and negative emissions technologies. The former was integrated into E3’s modeling and the latter was considered as a cost comparison point for the marginal abatement cost in E3’s modeling outputs. Electricity exports is consistent with the use of “load-based” GHG accounting, which matches GHG emissions to OPPD’s hourly energy position, crediting exports that reduce external emissions when OPPD’s portfolio is long on energy and penalizing imports that increase external emissions when OPPD’s portfolio is short on energy.

[3] Source: SEPA Utility Carbon Reduction Tracker and E3 research.

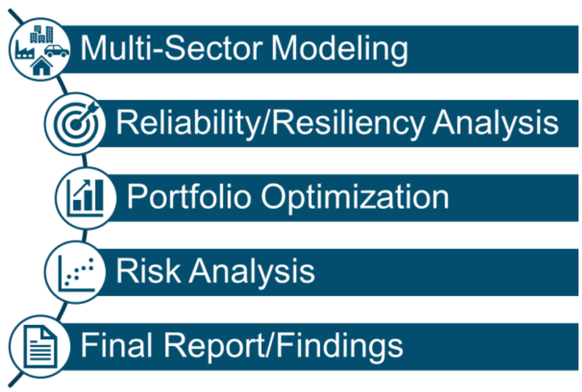
Figure 13. Net zero Carbon "Netting" Options Considered for this Study

Intersectoral Credit **Description**: claiming credit for emissions reductions achieved through electrifying other sectors. **Pros**: low to zero cost; supports utility action on electrification. **Cons**: incompatible with an economy-wide net zero target, which is needed to meet climate goals; challenging to confirm "incrementality" of utility actions.	*Not Included*
GHG Offsets **Description**: involves the purchase of traditional GHG offsets, which can include projects such as tree planting or carbon/methane capture. **Pros**: low cost. **Cons**: difficult to prove "additionality" of GHG offsets (would they have been pursued anyways?); not necessarily compatible with an economy-wide net zero target.	*Not Included*
Negative Emissions **Description**: offsetting remaining emissions through negative emissions technologies such as Direct Air Capture. **Pros**: compatible with an economy-wide net zero target; possibly lower cost than 100% zero-carbon electricity. **Cons**: high cost uncertainty due to lack of commercialized technologies.	*Included*
Electricity Exports **Description**: net-zero is defined on an annual basis, allowing emitting generation or imports to be offset by zero-emitting exports. **Pros**: low cost; encourages regional coordination. **Cons**: becomes more challenging to displace fossil generation as the system achieves higher percentages of decarbonization	*Included*

2 Project Approach

E3 and OPPD developed a comprehensive and detailed study plan to understand long-term decarbonization planning for both the OPPD economy and – in more detail – OPPD's electric system itself. Figure 14 provides an overview of the key project phases E3 conducted to complete the Pathways to Decarbonization: Energy Portfolio project.

Figure 14. Overview of the Pathways to Decarbonization: Energy Portfolio project.



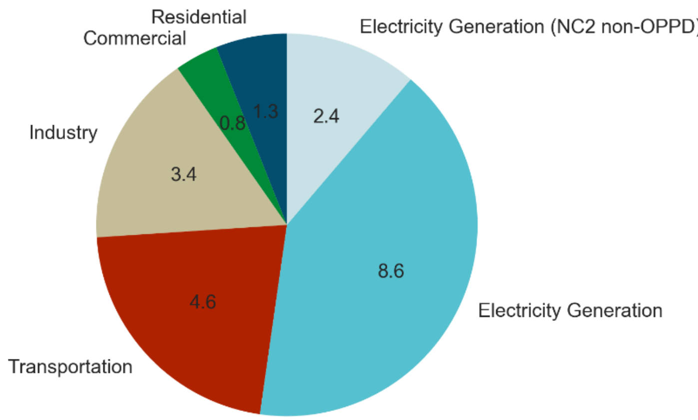
This section provides an overview of the modeling approach used in each of the key project steps.

2.1 Multi-sector Modeling

The first step in E3's analysis was multi-sector modeling, in which scenarios of economy-wide decarbonization were investigated. The primary purpose of this analysis is to develop scenarios of OPPD's electric loads, which may include additional electrification loads consistent with economy-wide decarbonization. This assumes that OPPD's electric system will not be decarbonizing in isolation, but instead will proceed along with additional policies and programs to support decarbonizing all economic sectors. Resulting electrification loads from the multi-sector modeling scenarios were fed into E3's electricity capacity expansion modeling to support electric generation planning scenarios.

To demonstrate the high-level opportunities for economy-wide decarbonization, Figure 15 shows all greenhouse gas (GHG) emissions from different economic sectors within the boundaries of OPPD's service territory. While Figure 15 shows that emissions from the electric sector comprise most of total emissions in 2018, it is clear all sectors of the economy are key in achieving deep decarbonization in the region. The multi-sector modeling focused on opportunities in the transportation, industrial, and buildings sectors, while the portfolio optimization task modeled the pathways to meet electric sector decarbonization.

Figure 15. Economy-wide Emissions in 2018 for the OPPD Service Territory



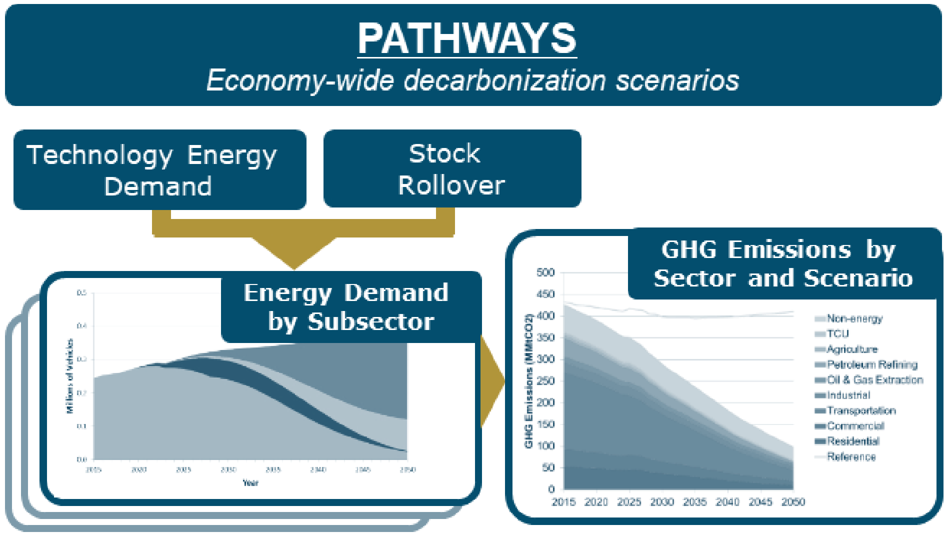
In addition to providing electric load forecast information for studying energy portfolios, E3 produced this multi-sector modeling so that it also may inform OPPD's community and customer programs within the broader Pathways to Decarbonization Program. The Community program is engaged with local community leaders and stakeholders to support decarbonization planning. The Customer program is exploring options for new customer programs, for which this study may provide indicative information about the types of customer choices and infrastructure changes consistent with decarbonization of the broader Omaha regional economy.

The multi-sectoral modeling leverages a suite of tools to develop scenarios for economy-wide energy demand. The primary model used is E3's PATHWAYS model, which is an economy-wide representation of infrastructure, energy, and emissions within a given geography. PATHWAYS is a model that allows users to define scenarios that achieve various energy and/or climate policies and includes the following features:

+ Stock rollover treatment of appliances, vehicles, and building shells;
+ Modeling of low- and zero-carbon fuels, including hydrogen, synthetic fuels, and biofuels, as substitutions for fossil fuels.

Such a representation allows users to connect long-term policy goals to realistic timelines of sectoral transformations, such as widespread increases in efficiency or adoption of electrified appliances and vehicles. As shown in Figure 16, E3's OPPD PATHWAYS model captured energy and emissions associated with each economic sector and was used to project future energy demand and GHG emissions under business-as-usual and mitigation scenario assumptions for the years 2018-2050.

Figure 16. Schematic of Key PATHWAYS Assumptions and Outputs



2.2 Input and Assumption Development

As a key preliminary step to the following modeling exercises, E3 and OPPD collaborated to develop a robust set of inputs, assumptions, and scenarios to be used in the reliability and resiliency analysis and the portfolio optimization stages of the project. This involved developing assumptions for OPPD load forecast scenarios, supply and demand-side resource options, scenarios of resource and fuel cost projections, technology operating characteristics, transmission topology and incremental transmission costs, and many other detailed assumptions. E3 worked with OPPD staff, as well as internal and external stakeholders, to review these assumptions and to develop a set of modeling scenarios for the portfolio optimization task that captures a broad range of market, technology, and policy futures under which to study OPPD resource needs.

The following key data points were developed.

+ **Load:** reference OPPD forecast + multiple additional scenarios based on economy-wide decarbonization multi-sector modeling
+ **Candidate Resources:** wind, solar, li-ion batteries, flow batteries, hydrogen-enabled gas turbines, gas with CCS, nuclear small modular reactors, seasonal energy storage, demand response, energy efficiency, distributed solar, distributed storage, coal-to-gas repower
+ **Resource quality and potential:** developed using primarily datasets from the National Renewable Energy Laboratory (NREL)
+ **Technology maturity:** four scenarios developed based on IEA technology readiness levels (TRLs) of emerging technologies
+ **Candidate Resource Costs:** Latest public estimates for resource costs based on NREL Annual Technology Baseline (ATB) 2020 and Lazard 6.0, with local adjustments

- **Fuel Prices:** Natural gas and coal price forecasts based on 2021 EIA AEO, hydrogen fuel prices based on E3 + BNEF research
- **Transmission:** OPPD to SPP zonal transmission limit modeled + interconnection and deliverability cost adders for candidate resources
- **Load Flexibility:** existing/planned/candidate demand response, managed EV charging in baseline + high flexible loads sensitivity

Scenarios developed consisted of three main variables:

- **Pace of decarbonization:** a range of paces from moderated to aggressive were studied, in addition to a net zero by 2035 case and multiple scenarios that reach "absolute-zero" instead of "net zero"
- **Technology availability:** four scenarios were considered for the availability of emerging technologies.
- **Additional sensitivity factors:** additional sensitivity variables were considered related to federal carbon pricing, load growth, SPP greenhouse gas policies, and technology costs.

2.3 Reliability and Resiliency

Reliability and resiliency analysis served as both an input into the portfolio optimization task and as a check on the portfolios resulting from that task. The portfolio optimization task includes a dispatch module that captures operating reserve needs and the need for electric loads and resources to be always in balance. E3 performed a more detailed reliability analysis for resource adequacy, which measures the ability for a power system to meet load and operating reserve requirements across a wide range of potential weather conditions subject to an acceptable failure rate. E3's Renewable Energy Capacity Planning Model (RECAP) was used to develop key inputs to the portfolio optimization, specifically the required total reliability need (expressed as a reserve margin above median peak load) and the effective capacity values for wind, solar, energy storage, and demand response (expressed in the form of "surfaces" or curves of effective load carrying capability values (ELCCs)). Resource adequacy of resource portfolios developed was then checked in RECAP against the 1-day-in-10-year loss of load expectation standard adopted by SPP. A detailed model description of RECAP is provided in the Reliability and Resiliency chapter of this report.

Resiliency is an emerging topic in power system planning, without the same defined methods and metrics as resource adequacy. E3 conducted a Resiliency Threat Analysis for OPPD's future net zero carbon power system and used this threat analysis to inform four targeted Resiliency Case Studies to further assess the resiliency of resource portfolios developed to extreme weather impacts beyond the those typically captured in traditional resource adequacy planning tools like RECAP.

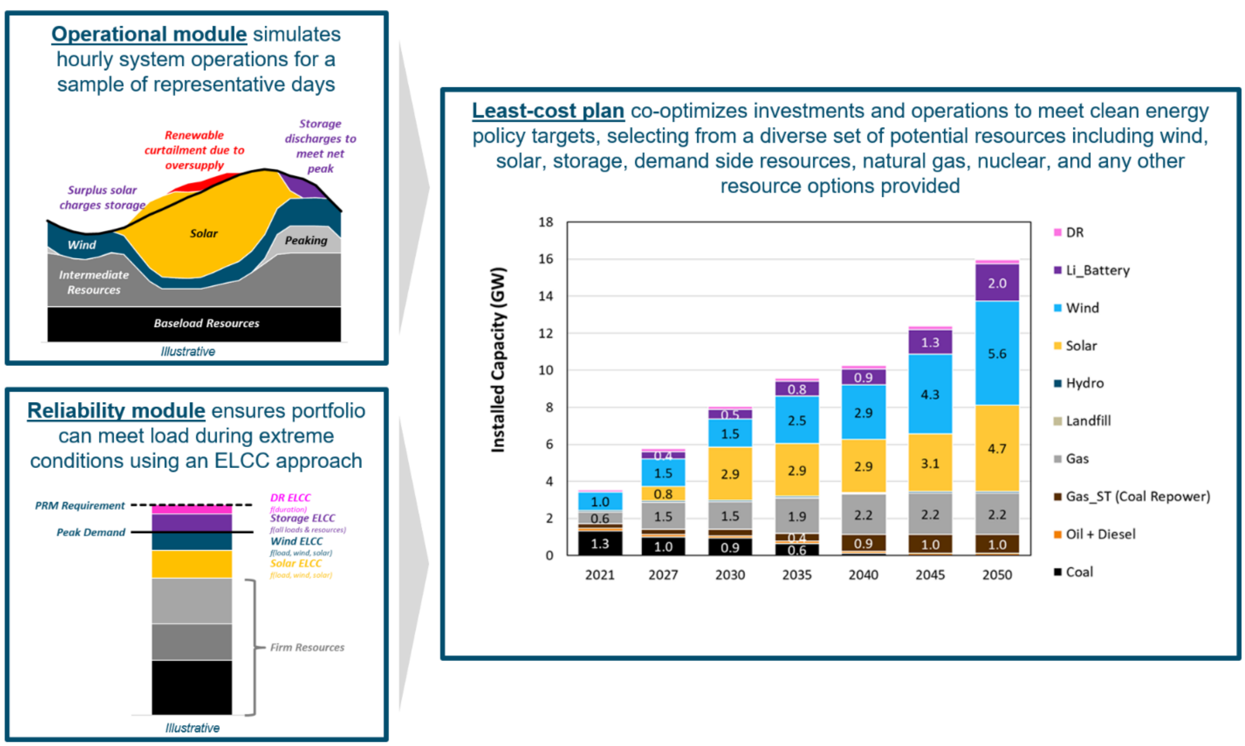
2.4 Portfolio Optimization

E3 used its Renewable Energy Solutions Model (RESOLVE) to perform a portfolio optimization of OPPD's electric generating resource needs between 2021 and 2050. This portfolio optimization had three primary drivers of system resource needs:

+ **Reliability:** all portfolios will ensure system meets resource adequacy requirement of 1-day-in-10-year loss of load expectation
+ **Greenhouse gas reduction:** all portfolios met environmental/GHG targets for that scenario, e.g. net zero carbon electricity
+ **Cost:** the model's optimization will develop a portfolio that minimizes costs

Figure 17 illustrates the use of RESOLVE's operational module, which tracks hourly system operations including cost and greenhouse gas emissions across a representative set of days, and RESOLVE's reliability module, that uses exogenously calculated input parameters to characterize system reliability of candidate portfolios using effective load carrying capability (ELCC).

Figure 17. Schematic Representation of the RESOLVE Model Functionality



RESOLVE develops least-cost portfolios using the inputs and assumptions described above, including loads, existing resources, new resource options, retirement or repowering resource options, resource costs, resource operating characteristics including resource adequacy contributions, a zonal transmission transfer topology, and new resource transmission costs. For this project, RESOLVE was also built to co-optimize the SPP resource mix alongside – and integrated with – the OPPD optimization. A more detailed model description of the OPPD RESOLVE model setup and portfolio optimization results is provided in the Inputs and Assumptions and Portfolio Optimization chapters of this report.

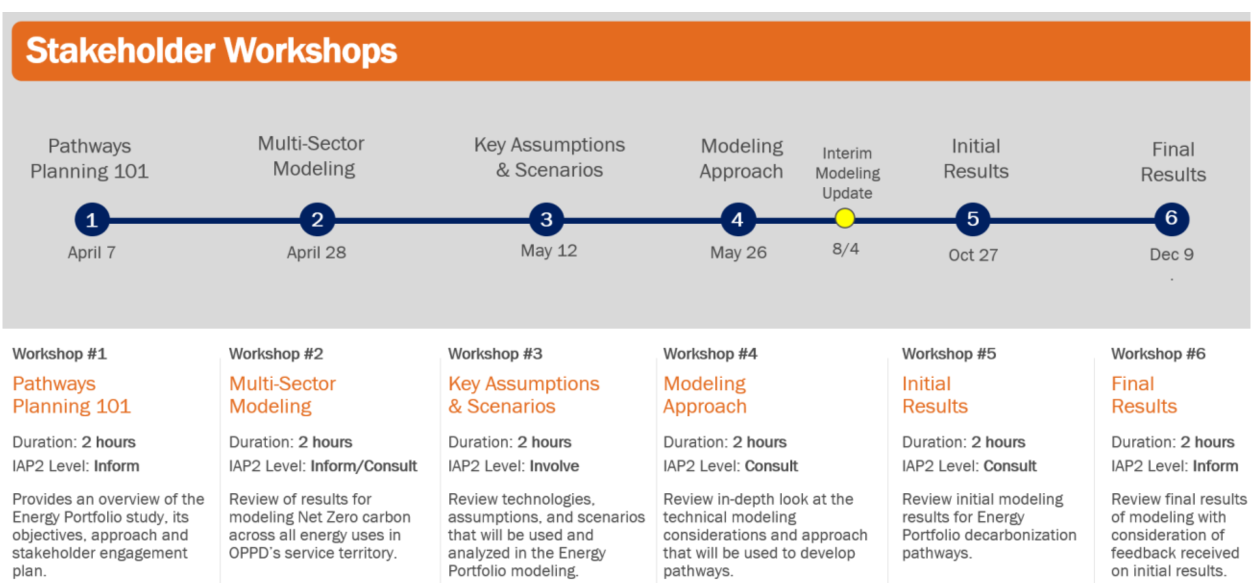
2.5 Risk Analysis

Traditional long-term planning risk analysis considers the impact of fuel price volatility and the potential for further environmental regulation. The risk analysis approach utilized in this project recognizes that both of these risks gradually, if not entirely, are reduced in a net zero carbon electric system. Because a net zero carbon system is so heavily dependent on capital intensive investments with minimal variable operating costs, the key risk is that OPPD may make investments in new resource that turn out not to be economically optimal or may become stranded (i.e. no longer able to operate economically and must be retired). E3 therefore focused the risk analysis on the range of sensitivity scenarios considered in the portfolio optimization task, to identify “no regrets” clean energy investments for OPPD, while recognizing under what scenarios additional resource of various types would become optimal.

2.6 Stakeholder Engagement

The Pathways to Decarbonization: Energy Portfolio project was conducted in a transparent manner through utilization of a nearly year-long stakeholder engagement process. This process included six public workshops and one interim modeling update, which were conducted virtually due to the ongoing COVID-19 pandemic. Stakeholders were given the opportunity to provide public comment during the workshops via written comments or through OPPD Community Connect after the workshop was completed. Stakeholder feedback was incorporated into the study design, modeling inputs, scenarios considered, and framing of the portfolio optimization results.

Figure 18. Overview of Public Stakeholder Workshops Conducted during this Study



3 Multi-Sector Modeling

3.1 Multi-sectoral Modeling Approach

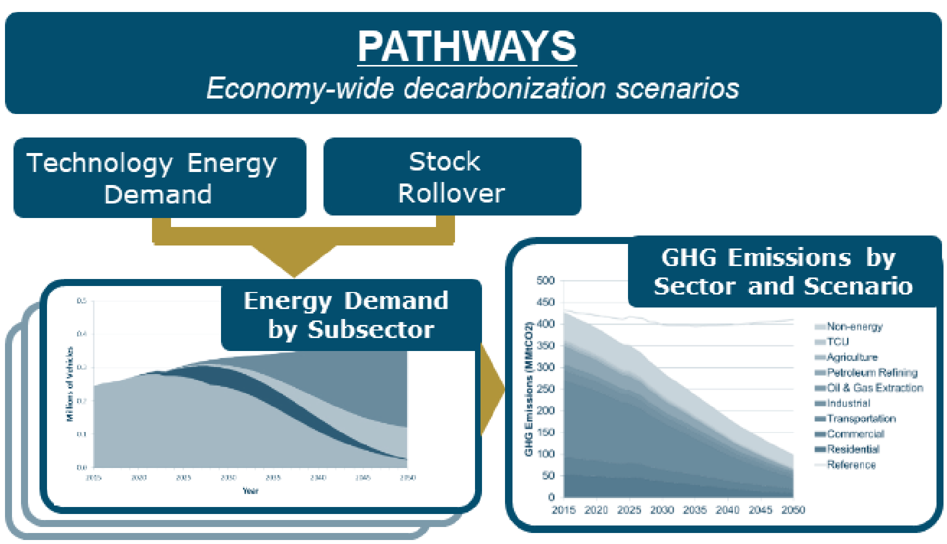
The multi-sectoral modeling leverages a suite of tools to develop scenarios for economy-wide energy demand. The primary model used in this analytical step is the PATHWAYS model, which is an economy-wide representation of infrastructure, energy, and emissions within a given geography. PATHWAYS is a model that allows users to define scenarios that achieve various energy and/or climate policies. PATHWAYS modeling includes the following features:

+ Stock rollover treatment of appliances, vehicles, and building shells;
+ Modeling of low- and zero-carbon fuels, including hydrogen, synthetic fuels, and biofuels, as substitutions for fossil fuels.

Such a representation allows users to connect long-term policy goals to realistic timelines of sectoral transformations, such as widespread increases in efficiency or adoption of electrified appliances and vehicles.

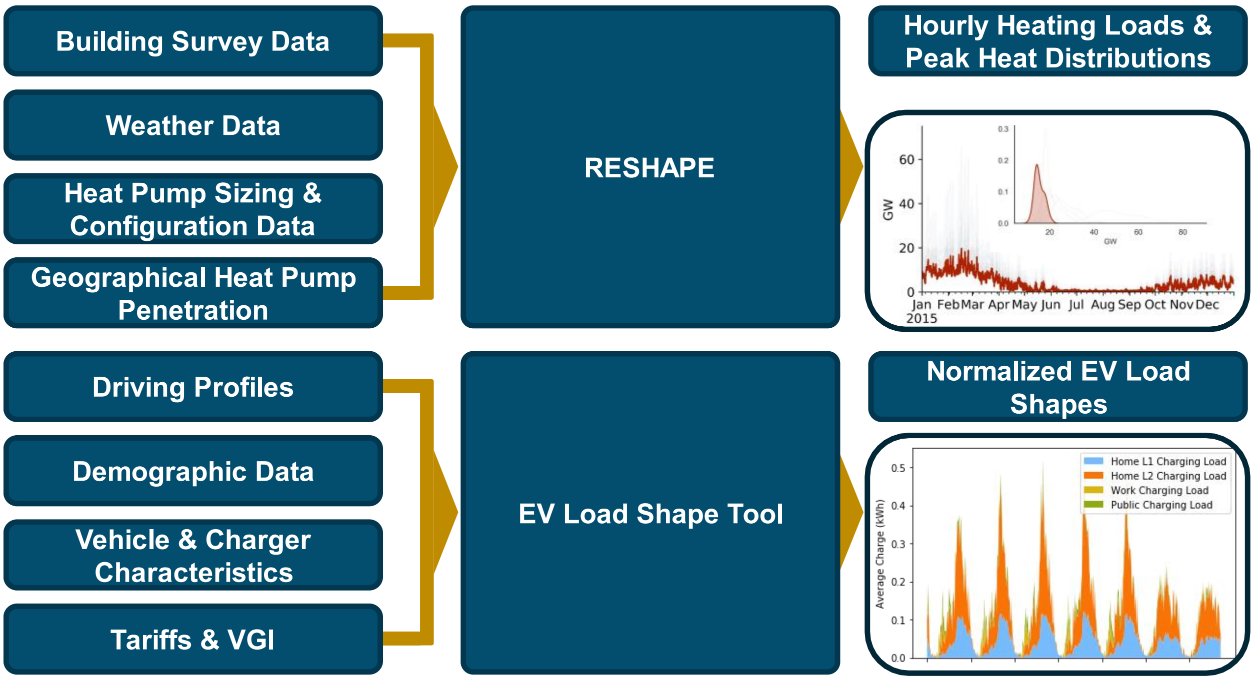
3.2 Models

Figure 19. Schematic of Key PATHWAYS Assumptions and Outputs



E3 built a detailed PATHWAYS model of the economy contained within OPPD's service territory using the Long-range Energy Alternatives Planning (LEAP) software. As shown in Figure 19, this model captured energy and emissions associated with each economic sector and was used to project future energy demand and GHG emissions under business-as-usual and mitigation assumptions. The years modeled in OPPD PATHWAYS were 2018-2050.

Figure 20. Building (RESHAPE) and Vehicle (EV Load Shape Tool) Model Descriptions



Several other E3 tools were used to complement OPPD PATHWAYS built in LEAP. Accurately determining the effects of certain electrification loads is challenging. In particular, the effect of electrifying space heating on load through the installation of heat pumps is highly dependent on geography, heat pump efficiency, and whether heat pumps are backed up by electric resistance heating or natural gas. In addition, vehicle electrification loads vary with driving patterns and average vehicle miles traveled (VMTs). E3 employed its RESHAPE model and the EV Load Shape Tool (EVLST) (see Figure 20) to comprehensively assess the impact of space heating and vehicle electrification, respectively, on electricity demand in the OPPD service territory. Some of the results of these models, such as the fraction of space heating demand met by the gas backup of dual fuel heat pumps, were used as key inputs to OPPD PATHWAYS. Others, such as heat pump and vehicle load shapes and peaks, were used to complement the long-term projections output from OPPD PATHWAYS.

3.3 Scenarios

E3 modeled five economy-wide scenarios, all of which assume that OPPD meets its net zero carbon target (for electric generation) by 2050. A high-level description of each scenario can be seen in Table 1. The Reference scenario assumes that the remainder of the economy outside of the electric sector continues a business-as-usual trajectory based on current trends. Decarbonization in the electric sector will decrease economy-wide emissions by approximately 50%.

The remainder of the scenarios are those that have some amount of decarbonization in other sectors. The Moderate Decarbonization scenario features low-cost, moderate GHG reductions elsewhere in the economy, leading to a 60% decrease in total GHG emissions. The final three scenarios, Net Zero: High Fuels, Net Zero: Balanced, and Net Zero: High Electrification, in Table 1 include full transition to a net zero carbon economy within OPPD's service territory. Similar scenarios to these three have featured in previous E3 multisector deep decarbonization studies.[4,5] Each of these scenarios has high levels of electrification and energy efficiency. The High Fuels scenario features the highest dependence on low- and zero-carbon fuels and negative emissions technologies (NETs) to achieve net zero emissions economy-wide. The High Electrification scenario most aggressively electrifies end uses and relies on significantly less zero-carbon fuel and fewer NETs. The Balanced scenario electrifies as many end uses that are presumed to be cost-effective and relies on zero-carbon fuel elsewhere, striking a middle ground between the High Fuels and High Electrification cases.

These scenarios have varying implications for both electricity and natural gas demand. They can result in a range of minimal changes to electricity demand and gas demand in the Reference scenario to very high electricity demand and low gas demand in the High Electrification scenario.

Table 1. High-level Descriptions and Outcomes of Scenarios Explored in this Report

Scenario	Description	Economy-Wide GHG Reduction	OPPD GHG Reduction	Electricity Demand	Natural Gas Demand
Reference	OPPD net zero Current trends in other sectors	**50%**	**Net zero**	**Medium**	**High**
Moderate Decarbonization	OPPD net zero Moderate GHG reductions elsewhere	**60%**	**Net zero**	**Medium-High**	**Medium**
Net Zero: High Fuels	Economy-wide net zero with high reliance on zero-carbon fuels	**Net zero**	**Net zero**	**Medium-High**	**Medium**
Net Zero: Balanced	Economy-wide net zero with reliance on cost-effective electrification and zero-carbon fuels elsewhere	**Net zero**	**Net zero**	**High**	**Low**
Net Zero: High Electrification	Economy-wide net zero with high electrification for transportation, buildings, and industry	**Net zero**	**Net zero**	**Very High**	**Low**

Table 2 details the specific assumptions associated with each scenario, broken out by measure type. The Moderate Decarbonization scenario has significant efficiency and electrification assumptions built in, while maintaining a similar level of biofuels as today. The High Fuels case more aggressively increases

[4] "Achieving Carbon Neutrality in California," Energy and Environmental Economics, 2020, https://ww2.arb.ca.gov/sites/default/files/2020-08/e3_cn_draft_report_aug2020.pdf.

[5] "Minnesota Decarbonization Scenarios," Energy and Environmental Economics, 2019, https://www.ethree.com/wp-content/uploads/2019/08/MN_PATHWAYS_Final-Report_2019-06-26.pdf.

efficiency in building shells, employs carbon capture and storage (CCS) in coal use in industry, and relies heavily on advanced biofuels and synthetic fuels to decarbonize any remaining fuel use relative to the Moderate Decarbonization scenario. The Balanced scenario more aggressively electrifies building space heating using heat pumps with a gas backup and increases vehicle electrification for all classes of vehicles, relative to the High Fuels case. Finally, the High Electrification case electrifies all non-electrified building end uses, including eliminating sales of any space heating appliances that use gas; increases efforts within industry to electrify end uses where possible; increases sales of electrified medium-duty vehicles (MDVs) and heavy-duty vehicles (HDVs) closer to 2050; and eliminates advanced biofuel and synthetic fuel use, except in end uses that are very hard to electrify.

Table 2. Detailed Multi-sector Modeling Scenario Assumptions

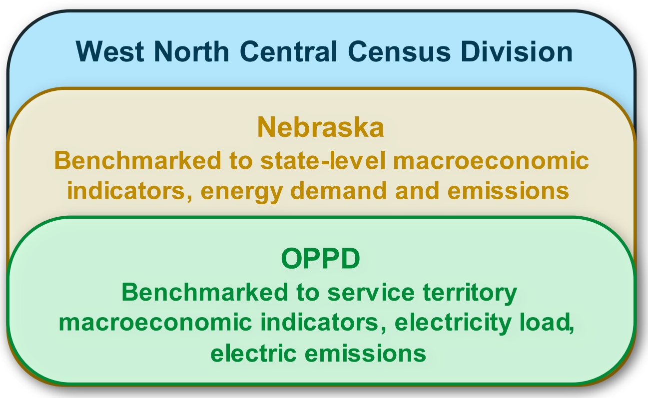
<table>
<tr><th>Measure Type</th><th>Measure</th><th>Moderate Decarbonization</th><th>Net Zero: High Fuels</th><th>Net Zero: Balanced</th><th>Net Zero: High Electrification</th></tr>
<tr><td rowspan="3">Efficiency</td><td>Efficient Appliances</td><td colspan="2">50% sales by 2040</td><td colspan="2">100% sales by 2040</td></tr>
<tr><td>Efficient Shells</td><td>50% sales by 2040</td><td colspan="3">100% sales by 2040</td></tr>
<tr><td>VMT</td><td colspan="4">Constant VMT per capita</td></tr>
<tr><td rowspan="6">Electrification</td><td>Building Electrification</td><td colspan="2">50% new construction all-electric by 2035
10% of space and water heating sales for existing buildings electrified by 2030</td><td>90% sales heat pumps with decarbonized gas backup by 2035; 10% ground source heat pumps</td><td>90% sales heat pumps with electric resistance backup by 2035; 10% ground source heat pumps</td></tr>
<tr><td>Industry Decarbonization</td><td>Medium amount of industry electrification</td><td colspan="2">Medium amount of industry electrification + CCS for coal use</td><td>High amount of industry electrification</td></tr>
<tr><td>Light-Duty Vehicles</td><td colspan="2">75% LDV ZEV sales by 2035</td><td colspan="2">100% LDV ZEV sales by 2035</td></tr>
<tr><td>Medium- and Heavy-Duty Vehicles</td><td colspan="2">25% MDV/HDV ZEV sales by 2035</td><td>50% MDV/HDV ZEV sales by 2035</td><td>50% MDV/HDV ZEV sales by 2035, with 100% sales by 2050</td></tr>
<tr><td>Buses</td><td colspan="2">50% electric bus sales by 2035</td><td colspan="2">100% electric bus sales by 2035</td></tr>
<tr><td>Off-Road</td><td colspan="2">No electrification</td><td colspan="2">50% of off-road diesel demand electrified</td></tr>
</table>

<table>
<tr><td rowspan="3">Electricity Generation and Fuels</td><td>Clean Electricity</td><td colspan="4">OPPD reaches net zero carbon by 2050</td></tr>
<tr><td>Low-Carbon Fuels</td><td>Hold constant at current ethanol/biodiesel blending</td><td>High reliance on advanced biofuels and synthetic fuels[6]</td><td>Moderate reliance on advanced biofuels and synthetic fuels</td><td>Advanced biofuels only used to displace remaining diesel and jet fuel demand</td></tr>
<tr><td>NETs</td><td>None</td><td colspan="3">DAC to offset remaining emissions</td></tr>
</table>

3.4 Inputs

3.4.1 First-Year Demand Benchmarking

Figure 21. Graphical Representation of PATHWAYS Model Downscaling



E3 used an iterative downscaling procedure to benchmark first-year (year 2018) energy use in the OPPD service territory, displayed in Figure 21. E3 employed its PATHWAYS model representation of the West North Central census division, downscaling to create a representation of Nebraska. This downscaling was benchmarked to the following data sources:

- Energy demand by fuel using the Energy Information Administration (EIA) State Energy Data System (SEDS);[7]
- VMTs and vehicle populations using the Federal Highway Administration (FHWA) Highway Statistics;[8]

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[6] Includes biofuels from purpose-grown crops and hydrogen-based synthetic fuels.

[7] "State Energy Data System," Energy Information Agency, n.d., https://www.eia.gov/state/seds/seds-data-complete.php?sid=US.

[8] "Highway Statistics 2018," Federal Highway Administration, n.d., https://www.fhwa.dot.gov/policyinformation/statistics/2018/.

- Population[9] and households[10] using the US Census Division American Community Survey (ACS);
- Electric generation emissions using EIA's State Electricity Profiles.[11]

This representation of Nebraska was further scaled down to the OPPD service territory by benchmarking to populations and households, electric load, and electric generation emissions using OPPD-provided data sets. OPPD's internal electric load forecast was used.

Table 3. Comparison of 2018 Annual Loads in OPPD Service Area and in PATHWAYS

Sector	OPPD 2018 (TWh)	PATHWAYS 2018 (TWh)	Difference (TWh)	Difference (%)
Residential	3.84	3.84	0	0%
Commercial	3.67	3.67	0	0%
Industry	3.24	3.25	-0.007	-0.23%
Total	*10.8*	*10.8*	*-0.007*	*-0.07%*

The results of the benchmarking process can be seen in Table 3. The downscaling procedure was able to replicate electric loads in 2018.

3.4.2 Key Drivers and Demographics

Growth in each sector is dependent on key drivers of activity. Table 4 describes those key drivers by sector. Additional detail is provided in the sections that follow.

Table 4. Key Drivers of Growth in the Reference Scenario for Each Sector

Sector	Key Driver	Compound Annual Growth Rate (%)	Data Source
Residential	Household Growth	0.93%	OPPD-Provided Data
Commercial	Square Footage Growth	1.29%	OPPD Load Growth Forecast
Industry	N/A	Varies	OPPD Load Growth Forecast
On-Road Transportation	Population	0.68%	OPPD-Provided Data
Off-Road Transportation	Energy Growth	Varies by Fuel	EIA AEO 2020 Growth Rates

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9 "2018 ACS 1-Year Estimates, Table ID DP05," U.S. Census Division, n.d., https://data.census.gov/cedsci/table?g=0400000US31&tid=ACSDP1Y2018.DP05&hidePreview=true.

10 "2018 ACS 1-Year Estimates, Table ID DP04," U.S. Census Division, n.d., https://data.census.gov/cedsci/table?g=0400000US31&tid=ACSDP1Y2018.DP04&hidePreview=true.

11 "State Electricity Profiles, Nebraska," Energy Information Agency, n.d., https://www.eia.gov/electricity/state/archive/2018/nebraska/.

3.4.3 Buildings Sector

3.4.3.1 Base Year

The OPPD PATHWAYS model includes a stock-rollover representation of 17 residential and 9 commercial building subsectors, including space and water heating, air conditioning, and cooking. As described above, sectoral electricity demand is benchmarked to OPPD-provided data sets, and all other energy demands are scaled down based on the ratio of OPPD electric demand to Nebraska electric demand. All residential and commercial subsectors are listed in Table 5.

Table 5. Representation of 2018 Building Energy Consumption by Subsector in OPPD

Sector	Subsector	Modeling Approach	Energy Use in 2018 (TBTU)	Percent of 2018 Energy Use (%)
Residential	Central Air Conditioning	Stock Rollover	1.06	1.6%
	Building Shell	Stock Rollover	0.00	0.0%
	Clothes Drying	Stock Rollover	0.73	1.1%
	Clothes Washing	Stock Rollover	0.06	0.1%
	Cooking	Stock Rollover	0.55	0.8%
	Dishwashing	Stock Rollover	0.27	0.4%
	Freezing	Stock Rollover	0.34	0.5%
	Reflector Lighting	Stock Rollover	0.21	0.3%
	Room Air Conditioning	Stock Rollover	0.09	0.1%
	General Service Lighting	Stock Rollover	0.91	1.4%
	Exterior Lighting	Stock Rollover	0.15	0.2%
	Linear Fluorescent Lighting	Stock Rollover	0.15	0.2%
	Single Family Space Heating	Stock Rollover	17.24	26.4%
	Multi-Family Space Heating	Stock Rollover	1.79	2.7%
	Refrigeration	Stock Rollover	1.00	1.5%
	Water Heating	Stock Rollover	6.85	10.5%
	Residential Other*	Total Energy by Fuel	6.54	10.0%

Commercial	Air Conditioning	Stock Rollover	1.13	1.7%
	Cooking	Stock Rollover	1.10	1.7%
	High Intensity Discharge Lighting	Stock Rollover	0.02	0.0%
	Linear Fluorescent Lighting	Stock Rollover	0.95	1.5%
	General Service Lighting	Stock Rollover	1.27	1.9%
	Refrigeration	Stock Rollover	1.69	2.6%
	Space Heating	Stock Rollover	6.72	10.3%
	Ventilation	Stock Rollover	1.82	2.8%
	Water Heating	Stock Rollover	0.87	1.3%
	Commercial Other*	Total Energy by Fuel	0.44	0.7%
Total			65.3	100%

*Residential Other includes furnace fans, plug loads (e.g. computers, phones, speakers, printers), secondary heating, fireplaces, and outdoor grills. Commercial Other includes plug loads, office equipment, fireplaces, and outdoor grills.

3.4.3.2 Reference Scenario

The reference measures represented in the buildings sector are efficiency and a small amount of space and water heating electrification. Efficiency takes the form of 10% of all building shell sales being efficient, happening at the end of the 40-year lifetime in existing buildings or at the time of construction of new buildings. Space and water heating electrification similarly occurs on “burn-out” of natural gas appliances. Sales of new electric space and water heaters to replace these appliances are 4% of all replacements. No other electrification or efficiency in buildings were assumed in the Reference case. Assumptions are shown in Table 6.

Table 6. Reference Scenario Building Efficiency and Electrification Assumptions

Building Measure Category	Reference Scenario Assumption
High efficiency building shells	10% of all building shell sales are efficient
Efficient appliance sales	None
Behavioral conservation	None
Building electrification	4% natural gas space and water heating appliance sales electrified by 2050
Other non-stock sectors	None

Figure 22. Reference Scenario Residential Space Heating Stocks

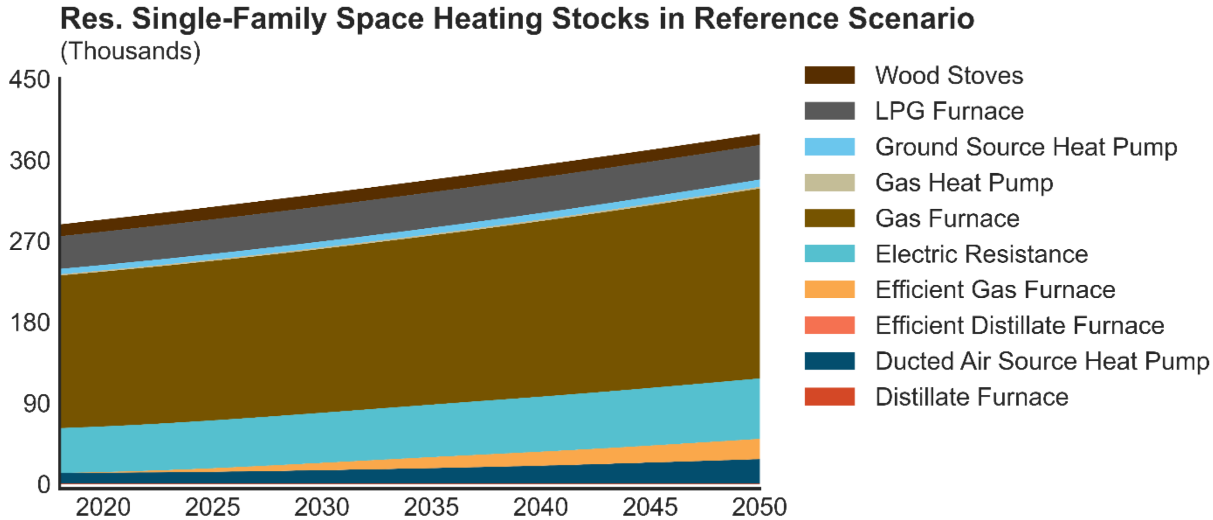


Figure 22 shows the evolution of residential single-family space heating stocks from 2018 to 2050. With the small amount of natural gas replacement with electrified space heating, there is a small growth of ducted air source heat pumps throughout the study period.

3.4.3.3 Mitigation Scenarios

The mitigation scenarios assume significant stock rollover to efficient appliances and building shells and to electrified appliances, where applicable. The Moderate Decarbonization scenario typically assumes 50% sales share of new efficient devices and shells, whereas the Net Zero scenarios (High Fuels, Balanced, and High Electrification) assume 100% sales share by 2040. The Moderate Decarbonization and High Fuels scenarios assume modest electrification, primarily in new construction and secondarily in space and water heating sales. Finally, the Balanced and High Electrification scenario aggressively electrifies appliance sales, with the Balanced scenario assuming heat pumps with gas backup as the primary tool of electrification in space heating and the High Electrification scenario assuming heat pumps with electric resistance backup as the primary electrification tool.

Table 7. Mitigation Scenario Building Efficiency and Electrification Assumptions

Building Measure Category	Moderate Decarbonization Scenario	Net Zero: High Fuels Scenario	Net Zero: Balanced Scenario	Net Zero: High Electrification Scenario
High efficiency building shells	50% sales of efficient building shells by 2040	100% sales of efficient building shells by 2040		
Efficient appliance sales	50% sales efficient appliances by 2040		100% sales efficient appliances by 2040	
Behavioral conservation	None			

Building electrification	50% new construction all-electric by 2030 10% of space and water heating sales for existing buildings electrified by 2030	90% sales heat pumps with decarbonized gas backup by 2035 10% ground source heat pumps	90% sales heat pumps with electric resistance backup by 2035 10% ground source heat pumps
Other non-stock sectors	50% new construction demand electrified by 2030	100% all demand electrified by 2035	

Figure 23. Mitigation Scenario Residential Single-family Space Heating Stocks

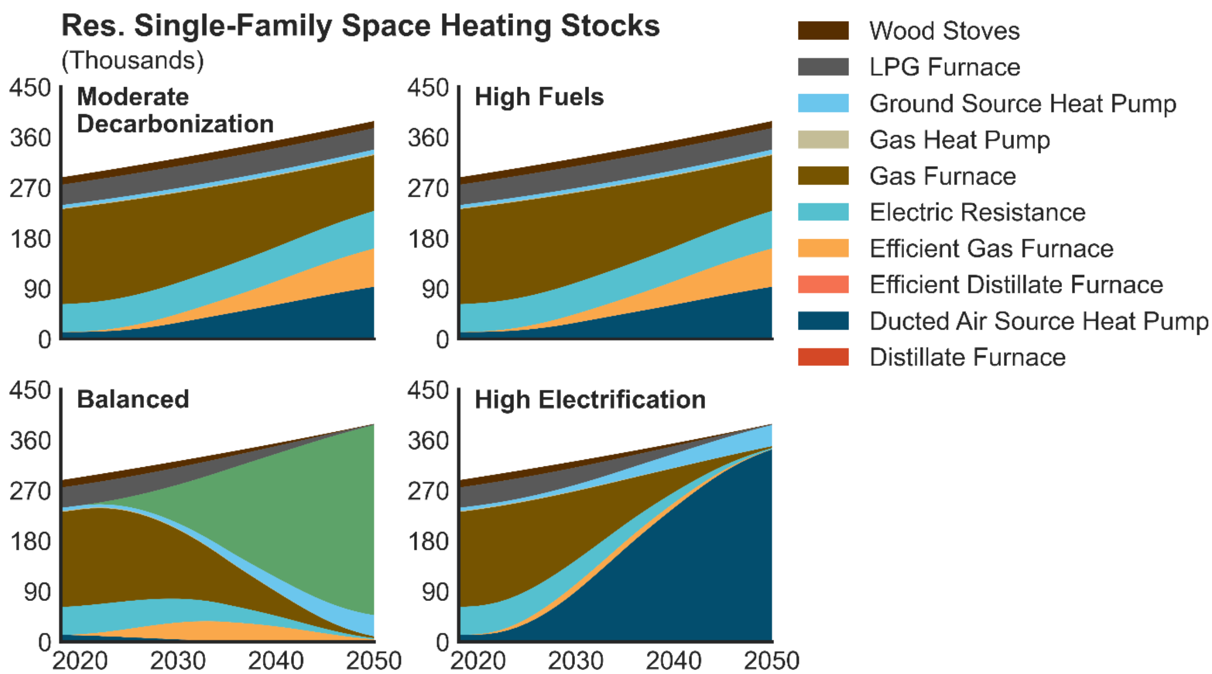


Figure 23 shows the evolution of residential single-family space heating stock for the mitigation scenarios. Despite high levels of sales of heat pumps by 2040 in the Moderate Decarbonization and High Fuels cases, only about a quarter of space heating stocks are electrified, showing that growth in stock shares lag that in sales shares due to the stock rollover assumptions within PATHWAYS. The Balanced and High Electrification scenarios show nearly full electrification of space heating stock by 2050.

3.4.4 Transportation Sector

3.4.4.1 Base Year

The OPPD PATHWAYS model includes a stock-rollover representation of five transportation subsectors, including light-duty autos (LDAs) and trucks (LDTs). All transportation subsectors are listed in Table 8.

Table 8. Representation of 2018 Transportation Energy Consumption by Subsector in OPPD

Sector	Subsector	Modeling Approach	Energy Use in 2018 (TBTU)	Percent of 2018 Energy Use (%)
Transportation	Aviation	Total Energy by Fuel	3.23	4.7%
	Light-Duty Autos	Stock Rollover	13.41	19.7%
	Light-Duty Trucks	Stock Rollover	13.56	19.9%
	Medium Duty Vehicles	Stock Rollover	6.69	9.8%
	Heavy Duty Vehicles	Stock Rollover	14.38	21.1%
	Buses	Stock Rollover	0.04	0.1%
	Transportation Other*	Total Energy by Fuel	16.84	24.7%
Total			68.1	100%

*Transportation Other includes demand for natural gas pipelines and off-road vehicles.

3.4.4.2 Reference Scenario

The reference measures represented in the transportation sector are electrification of the vehicle stock. Electrification of vehicles occurs at relatively low rates consistent with the AEO 2020 reference scenario sales trajectory, occurring on burnout of existing vehicles or the purchase of new vehicles. Assumptions are shown in Table 9.

Table 9. Reference Scenario Transportation Electrification Assumptions

Transportation Measure Category	Reference Scenario Assumption
ZEV LDV sales share	AEO 2020 reference scenario sales trajectory
ZEV MDV sales share	AEO 2020 reference scenario sales trajectory
ZEV HDV sales share	AEO 2020 reference scenario sales trajectory
ZEV bus sales share	AEO 2020 reference scenario sales trajectory
Transportation Other	AEO 2020 reference scenario growth rates by fuel

Figure 24. Reference Scenario Light-duty Auto Stock

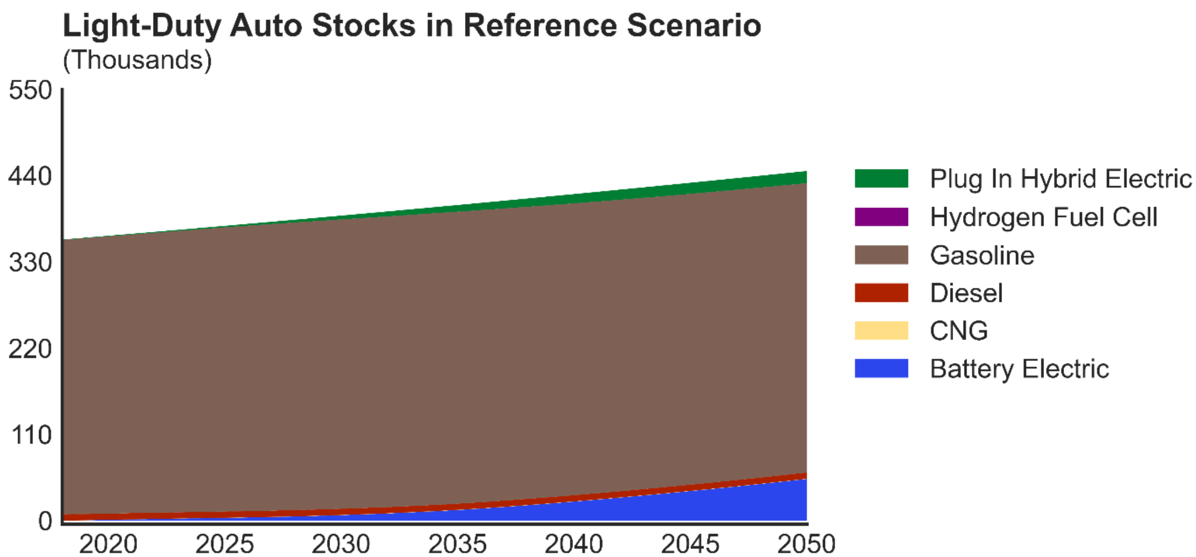


Figure 24 shows the evolution of LDA stocks. Based on the sales trajectories, gasoline internal combustion engine (ICE) vehicles will continue to dominate the LDA stock through 2050. Fossil fuel powered LDTs and medium-duty vehicles (MDVs) and heavy-duty vehicles (HDVs) will continue to similarly dominate through 2050, according to the EIA AEO 2020 sales trajectories.

3.4.4.3 Mitigation Scenarios

All mitigation scenarios assume varying levels of electrification across the transportation sector, which can be seen in Table 10. All mitigations assume at least 75% sales share of LDVs by 2035. Because MDVs and HDVs are more challenging to electrify, the Moderate Decarbonization and High Fuels scenarios assume 25% electric sales share of those transportation classes. This increases to 50% in the Balanced scenario. Buses are more aggressively electrified than MDVs and HDVs in the Moderate Decarbonization and High Fuels scenarios (at 50% sales share) and in the Balanced and High Electrification scenarios (at 100% sales share). Finally, only 50% of off-road diesel demand is electrified in the Balanced and High Electrification scenarios. Otherwise, it is assumed to follow the same trends in the Reference scenario.

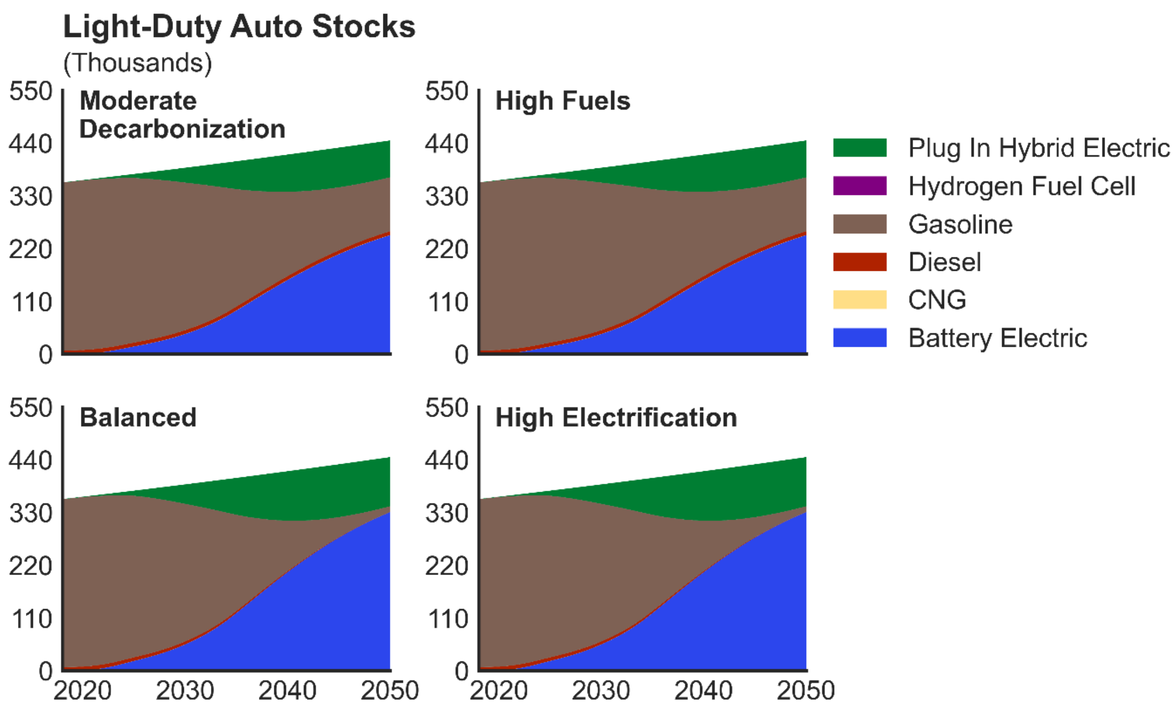
Table 10. Mitigation Scenario Transportation Electrification Assumptions

Transportation Measure Category	Moderate Decarbonization Scenario	Net Zero: High Fuels Scenario	Net Zero: Balanced Scenario	Net Zero: High Electrification Scenario
ZEV LDV sales share	75% sales share by 2035		100% sales share by 2035	
ZEV MDV sales share	25% sales share by 2035		50% sales share by 2035	50% sales share by 2035, with 100% by 2050
ZEV HDV sales share				
ZEV bus sales share	50% sales share by 2035		100% sales share by 2035	

Transportation Other	None	50% off-road diesel demand electrified

Figure 25 shows LDA stocks under mitigation scenario assumptions. These stand in contrast to the Reference scenario trajectory, in which electric vehicles were only a small minority of LDA stock. Electric vehicles become the majority of LDAs by 2050 in the Moderate Decarbonization and High Fuels cases, and gasoline ICE vehicles become a small minority of LDAs by 2050 in the Balanced and High Electrification cases.

Figure 25. Mitigation Scenario LDA Stocks



3.4.5 Industrial Sector

3.4.5.1 Base Year

The OPPD PATHWAYS model includes representation of 15 industrial subsectors. There are no stock rollover assumptions for any industrial subsectors.

Table 11. Representation of 2018 Industry Energy Consumption by Subsector in OPPD

Sector	Subsector	Modeling Approach	Energy Use in 2018 (TBTU)	Percent of 2018 Energy Use (%)
Industry	Agriculture	Total Energy by Fuel	5.94	6.4%
	Construction	Total Energy by Fuel	10.43	11.2%

	Mining and Upstream Oil and Gas	Total Energy by Fuel	9.21	9.9%
	Aluminum	Total Energy by Fuel	0.54	0.6%
	Cement and Lime	Total Energy by Fuel	4.56	4.9%
	Chemicals	Total Energy by Fuel	23.82	25.5%
	Food	Total Energy by Fuel	13.10	14.0%
	Glass	Total Energy by Fuel	0.59	0.6%
	Iron and Steel	Total Energy by Fuel	1.96	2.1%
	Metal-Based Durables	Total Energy by Fuel	4.00	4.3%
	Paper	Total Energy by Fuel	10.29	11.0%
	Plastics	Total Energy by Fuel	0.80	0.9%
	Refining	Total Energy by Fuel	0.00	0.0%
	Wood	Total Energy by Fuel	3.27	3.5%
	Other Manufacturing	Total Energy by Fuel	4.72	5.1%
Total			93.2	100%

3.4.5.2 Reference Scenario

The possible reference measures represented in the industrial sector are a mixture of efficiency, gaseous and liquid fuel electrification, and coal with CCS. No measures are chosen in the Reference scenario.

Table 12. Reference Scenario Industry Decarbonization Assumptions

Industry Measure Category	Reference Scenario Assumption
Manufacturing Efficiency	None
Natural Gas Electrification	None
Hydrogen Fuel Switching	None
Liquid Fuels Electrification	None
Coal CCS	None

Figure 26. Reference Scenario Industry Energy Demand

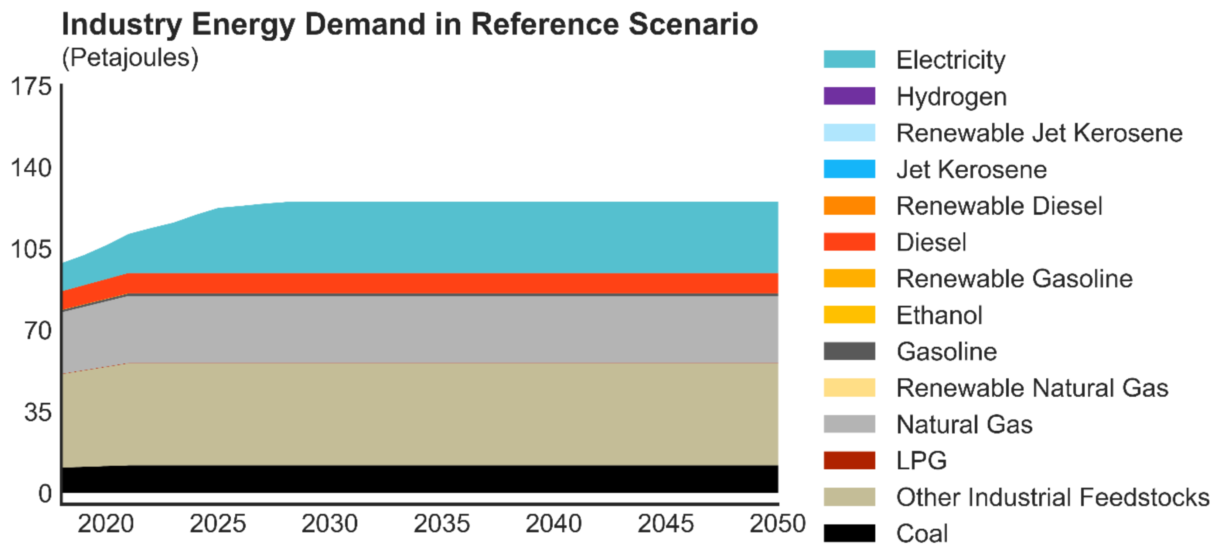


Figure 26 shows energy demand by fuel in industry. Demand grows for most fuels until the early 2020s, after which they are assumed to plateau. Electricity demand grows until about 2030 and plateaus thereafter. There is significant gaseous and liquid fuel demand that could be electrified or decarbonized, both of which are explored in the mitigation scenarios.

3.4.5.3 Mitigation Scenarios

The ease of decarbonizing industry demand varies, depending on the fuel, application, and the industrial subsector. The Net Zero scenarios assume 16% of manufacturing energy demand can be made more efficient by 2050. Low-temperature heat, including industrial space heating, can be electrified. The mitigation scenarios assume that 36.5% (Moderate Decarbonization, High Fuels, and Balanced scenarios) or 46.7% (High Electrification scenario) of natural gas demand, representing natural gas demand used for low temperature heat, can be electrified. Some process heating can be generated by hydrogen combustion, which is used to substitute for the remaining natural gas demand in the Net Zero scenarios. Some liquid fuels can be electrified, explored to varying degrees throughout the mitigation scenarios. Finally, coal, used in steel making, can be nearly fully decarbonized with CCS, which is assumed in the Net Zero scenarios. The assumptions for all mitigation scenarios regarding industry decarbonization can be seen in Table 13.

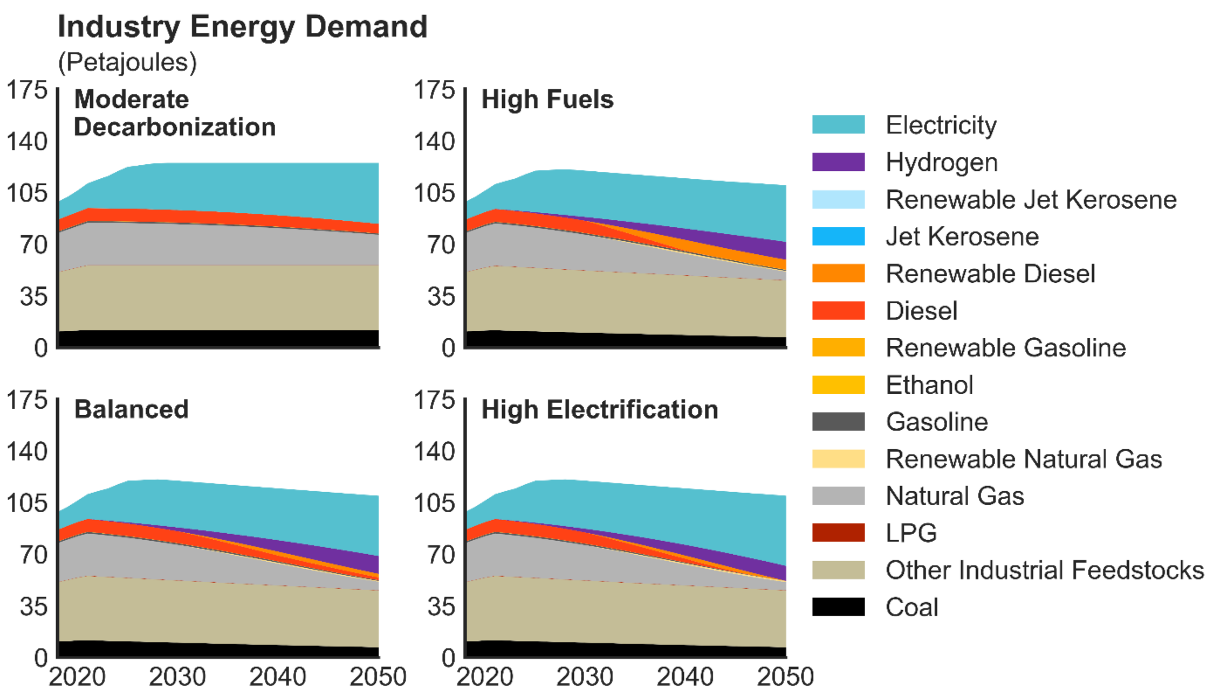
Table 13. Mitigation Scenario Industry Decarbonization Measures

Industry Measure Category	Moderate Decarbonization Scenario	Net Zero: High Fuels Scenario	Net Zero: Balanced Scenario	Net Zero: High Electrification Scenario
Manufacturing Efficiency	None	Demand reduced by 16% by 2050		
Natural Gas Electrification	36.5% natural gas demand electrified by 2050			47% by 2050

Hydrogen Fuel Switching	None	Remaining natural gas demand switched to H_2		
Liquid Fuels Electrification	25% liquid fuel demand electrified by 2050		50% by 2050	100% by 2050
Coal CCS	None	100% emissions mitigated by 2050		

The results of the various mitigation measures on industry energy demand can be seen in Figure 27. Because only fuel electrification occurs in the Moderate Decarbonization scenario, total energy demand does not decline. However, some gaseous and liquid consumption declines, substituted by electricity. In contrast, in the Net Zero scenarios, total demand declines after 2025, as efficiency measures in manufacturing significantly reduce demand. In addition, liquid and gaseous fuels are increasingly substituted for renewable or synthetic fuels, including hydrogen.

Figure 27. Mitigation Scenario Industry Energy Demand



3.4.6 Low-carbon Fuels

Complete use of liquid and gaseous fuels is unlikely to be eliminated in even the most deeply decarbonized futures. Strategic use of waste biomass, purpose-grown crops, and synthetic fuels will be needed to ensure net zero carbon emissions. Example biomass products include corn, soybeans, manure, switch grass, and agricultural waste. Example synthetic fuels include hydrogen produced using zero-carbon electricity (also known as green hydrogen) or synthetic natural gas produced by combining renewable hydrogen with CO_2 captured directly from the air or from biofuel production waste streams. These fuels are constrained by limited supply (in the case of biofuels) or limited commercialization and high cost (in the case of synthetic fuels).

Biomass feedstock potentials are derived from the 2016 DOE Billion Ton Study (BTS) Update, including sustainable yields of agricultural, forestry, and waste stream feedstocks.[12] Cost estimates for synthetic fuels are derived from those generated by E3 and UC Irvine.[13]

3.4.6.1 Reference Scenario

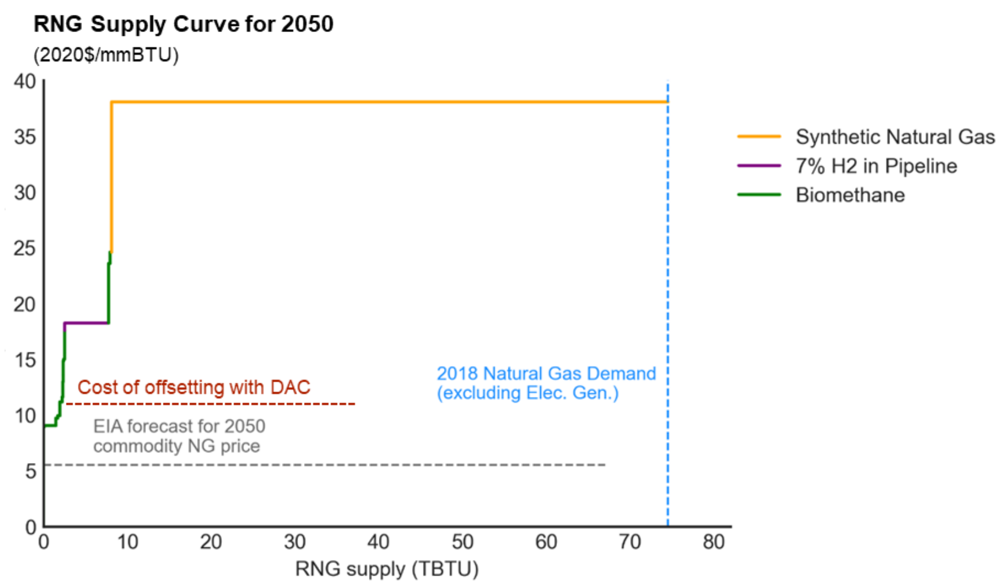
Nebraska already uses low-carbon fuels in the form of corn ethanol. The Reference scenario assumes that the current blending mixture of 10% ethanol with fossil gasoline persists through the study period.

3.4.6.2 Mitigation Scenarios

Like the Reference scenario, the Moderate Decarbonization scenario assumes constant blending of ethanol with gasoline.

The Net Zero scenarios use low-carbon fuels where possible. As discussed in prior sections, the High Fuels scenario electrifies fewer end uses, focusing on building and light-duty transportation electrification, and thus requires the most low-carbon fuels and negative emissions technologies. At the other extreme, the High Electrification scenario electrifies more end uses, including more natural gas demand in industry, and thus requires the least low-carbon fuel and negative emissions technologies out of all the Net Zero scenarios.

Figure 28. Renewable Natural Gas Supply Curve for 2050



Shown in Figure 28 is the renewable natural gas supply curve for OPPD in 2050. This highlights several key features of meeting fuel need with low-carbon fuels. First, low-cost biofuel supply is limited due to

[12] "2016 Billion-Ton Report," U.S. Department of Energy, 2016, https://www.energy.gov/sites/default/files/2016/12/f34/2016_billion_ton_report_12.2.16_0.pdf.

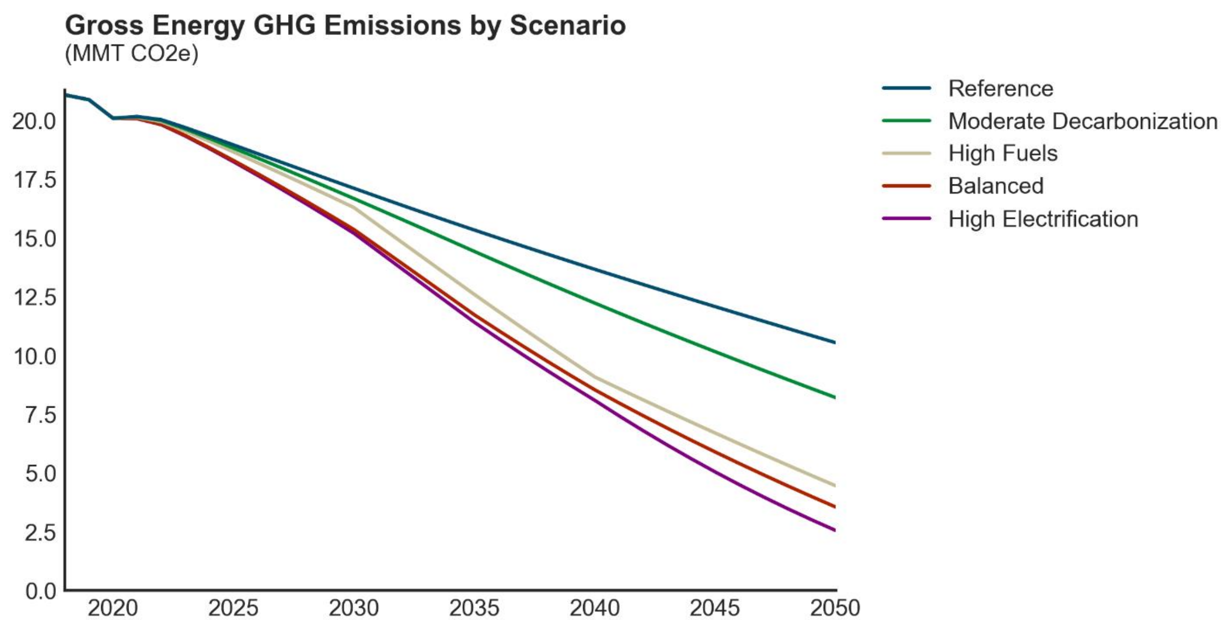
[13] "The Challenge of Retail Gas in California's Low-Carbon Future," Energy and Environmental Economics, University of California Irvine advanced Power and Energy Program, 2019, https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-F.pdf.

low supply of feedstock and competition between fuel end uses. Second, available hydrogen is constrained because it is assumed that hydrogen can only be blended with pipeline gas up to 7% by energy (except for certain industrial subsectors which are assumed to be able to be supplied by dedicated hydrogen pipelines). Third, because the cost of low-carbon fuels quickly escalates, this figure shows the need for NETs to offset remaining emissions from hard-to-electrify end uses (shown as the “cost of offsetting with DAC” or direct air capture and storage or use of carbon from the atmosphere). Finally, this curve highlights the importance of eliminating demand for fuel altogether, as total unabated fuel demand far exceeds cheaply available low-cost, low-carbon fuel availability.

3.5 Results

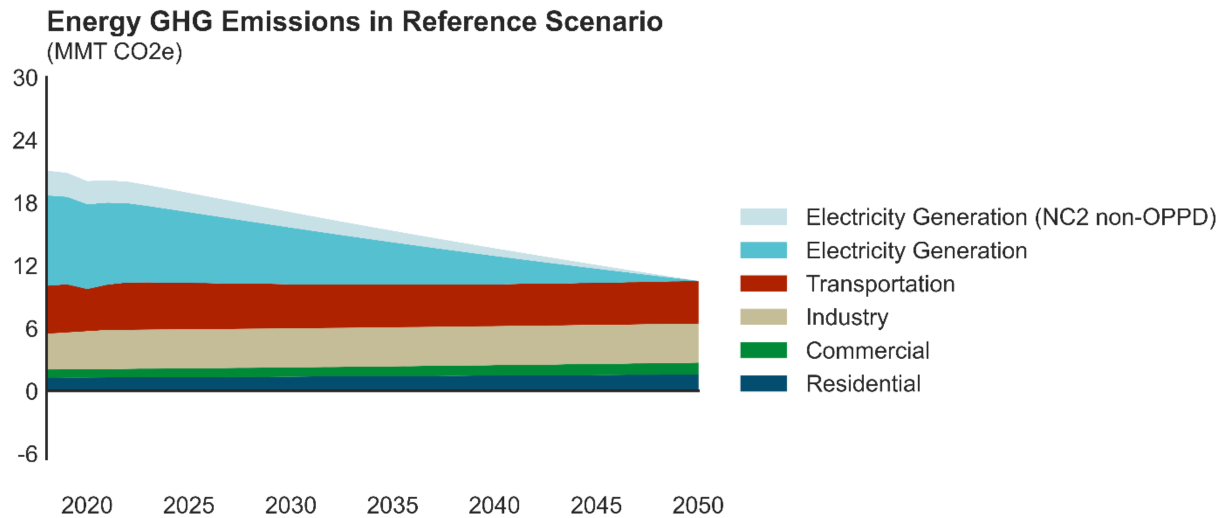
3.5.1 Economy-wide GHG Emissions

Figure 29. Economy-wide GHG Emissions by Scenario



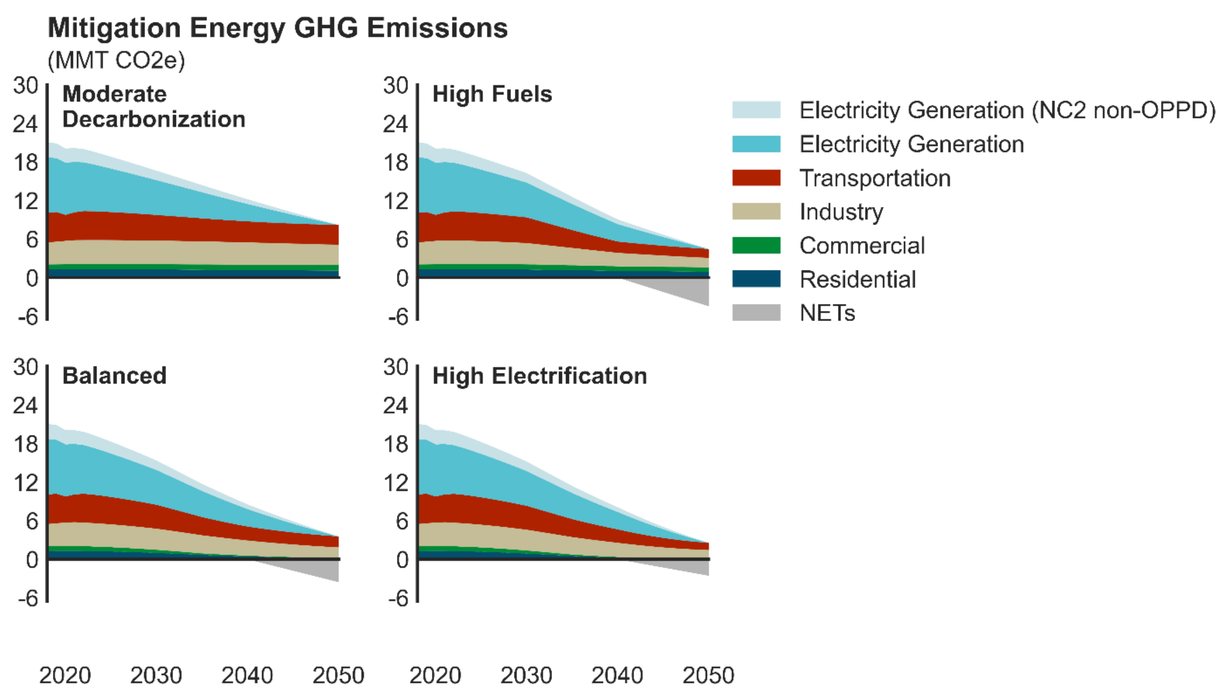
Economy-wide GHG emissions is a key output from each multi-sector modeling scenario. As shown in Figure 29, economy-wide GHG emissions decline by nearly 50% in the Reference scenario. As seen in Figure 30, this is due to OPPD reaching its own net zero GHG emissions target. However, because no other sectors have taken any measures, economy-wide emissions are still relatively high. (Note the Multi-Sector Modeling “Reference” scenario includes electric GHG reduction based on existing policies and should not be confused with the Portfolio Optimization “Reference” scenario does not include the electric GHG reduction target of net zero carbon by 2050.)

Figure 30. Reference Scenario GHG Emissions by Sector



As seen in Figure 31, layering in additional or more aggressive measures, such as high levels of building electrification, further reduces economy-wide gross emissions. The High Electrification scenario has about a quarter of the gross emissions of the Reference scenario. In addition, in the scenarios shown in Figure 31, NETs (such as direct air capture) are assumed to remove any remaining emissions from the non-electric sectors in 2040 and beyond.

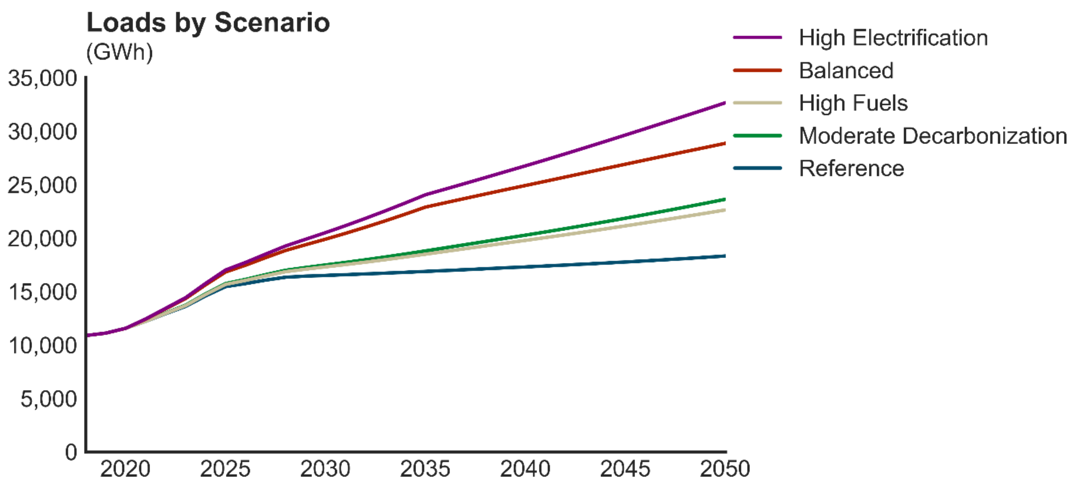
Figure 31. Mitigation Scenario GHG Emissions by Sector



3.5.2 Load Impacts

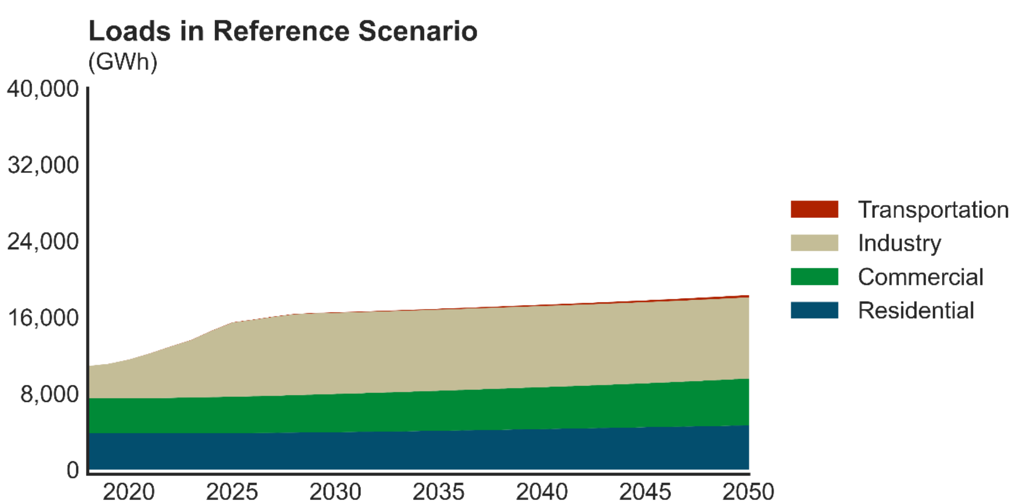
3.5.2.1 Electric Sector Load Growth

Figure 32. Electric Loads by Scenario



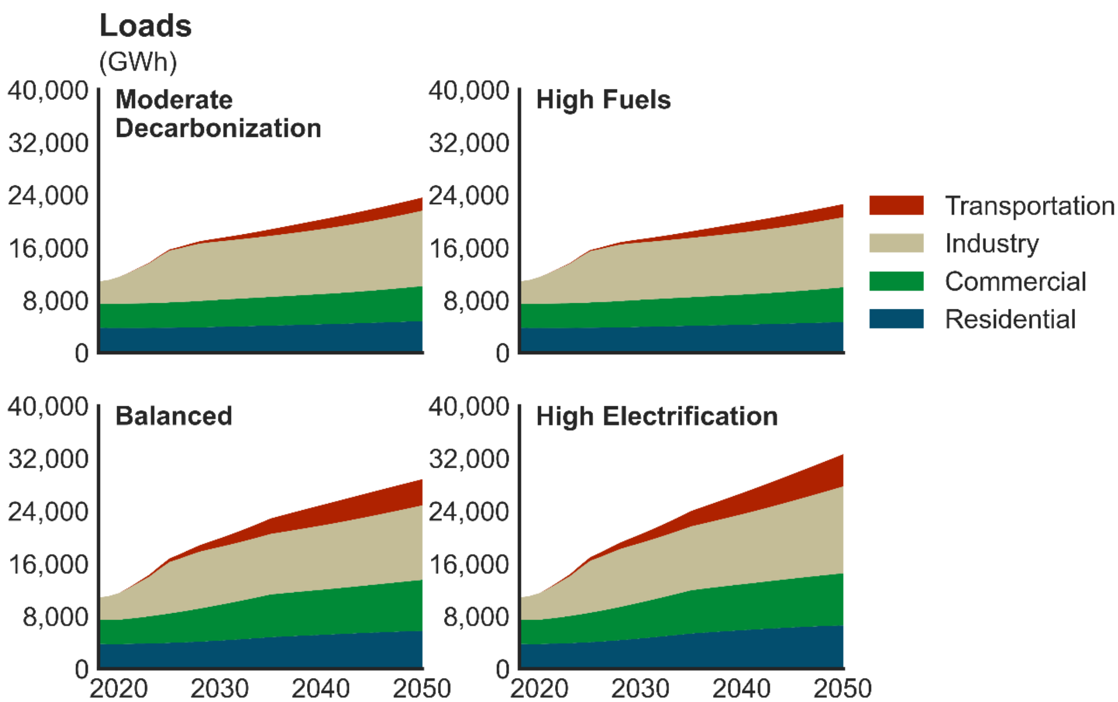
Economy-wide decarbonization has the potential for major impacts on future OPPD electric loads. As seen in Figure 32, load grows more quickly with tightening emissions targets and increasing levels of electrification. One notable exception is that the Moderate Decarbonization scenario has higher load growth than the High Fuels scenario. While these two scenarios share many of the same assumptions, the High Fuels scenario assumes increased efficiency in manufacturing and a higher proportion of efficient building shell sales. These two measures decrease electrification demand in the High Fuels scenario relative to the Moderate Decarbonization scenario.

Figure 33. Reference Scenario Electric Loads by Sector



The overall load grows primarily in the early 2020s due to industrial load growth, as seen in Figure 33, within the OPPD service territory. Thereafter, any net load growth is primarily driven by population and housing growth. A small portion of growth during this period is due to electrification, such as that assumed in transportation.

Figure 34. Mitigation Scenario Electric Loads by Sector



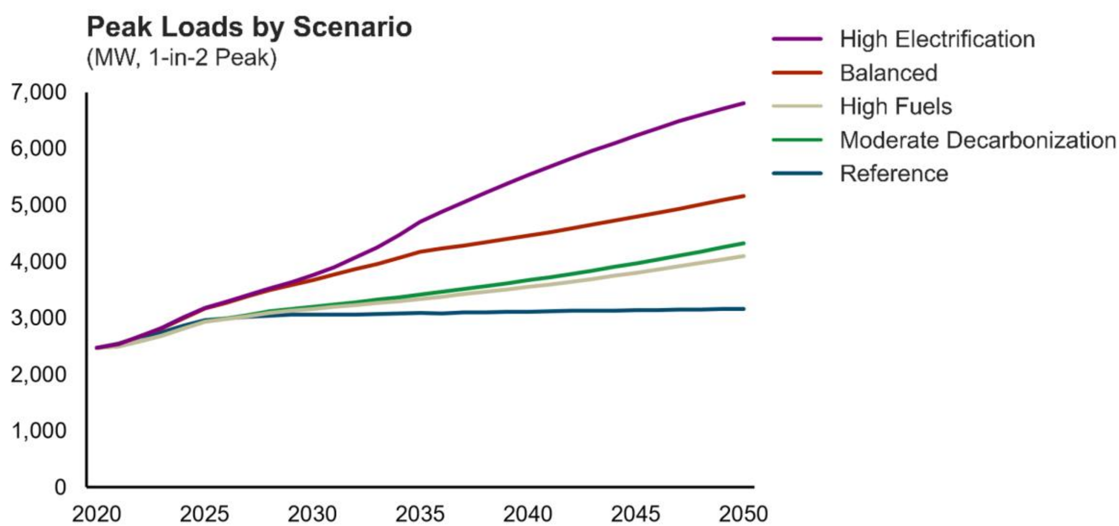
Load growth is influenced strongly by electrification of transportation, building, and industrial end uses, as seen in Figure 34. Consistent with the Reference scenario, load growth in the early 2020s is due to industry load growth. However, electrification plays a larger role in load growth beyond those years in the mitigation scenarios. In particular (see Table 14), transportation electrification contributes the largest incremental load in 2050 relative to electrification in other sectors for most of the mitigation scenarios. Industry electrification has the second highest contribution in most scenarios.

Table 14. Contributions by Sector to Incremental 2050 Load Growth Relative to Reference

Sector	Moderate Decarbonization	Net Zero: High Fuels	Net Zero: Balanced	Net Zero: High Electrification
Residential Buildings	3%	2%	12%	14%
Commercial Buildings	6%	10%	29%	21%
Industry	63%	38%	21%	31%
Transportation	28%	50%	38%	33%

3.5.2.2 Electric Sector Peak Impacts

Figure 35. Peak Loads by Scenario



Another component of load impacts relevant to OPPD are peak load impacts, which drive the total amount of capacity needed to be procured for electric reliability. The 1-in-2 (i.e. median) peak loads are shown in Figure 35. Like annual loads, peak loads tend to increase with tighter emissions targets and increasing electrification. Like annual loads, the sole exceptions to this rule are Moderate Decarbonization and High Fuels scenarios. As noted in the previous section, both scenarios have nearly identical electrification assumptions; however, the High Fuels scenario has additional industry and buildings efficiency assumptions, which thereby lower energy demand.

As expected, both transportation and building electrification play a larger role in incremental peak growth in the mitigation scenarios. These contributions are the largest in 2050. In fact, in the High Electrification case, aggressive building electrification forces the electric sector to transition from being summer peaking to winter peaking. This arises from the assumptions of high sales of heat pumps backed up by *electric resistance*. By merely substituting gas for electricity as the backup fuel for building space heating (as is the case in the Balanced scenario), the largest contributions to the winter peak are eliminated. From this perspective, retaining gas as a peaking resource for space heating will avoid high costs associated with building significant new transmission, distribution, and peaking generation assets for winter peaking hours.

This “peak heat” planning challenge can also be looked at across a range of weather conditions. E3’s RESHAPE model looks at 40 historical weather years to determine hourly space and water heating demand. Heat pumps drastically lose their efficiency in cold climates and this trend is exacerbated during the coldest years. Figure 36. Heat Pump Load by Temperature (Omaha, NE vs. Sacramento, CA) shows this trend, illustrating why heat pumps may be an ideal solution for Sacramento but struggle to efficiently provide heat during the extreme cold of Omaha winters.

Figure 36. Heat Pump Load by Temperature (Omaha, NE vs. Sacramento, CA)

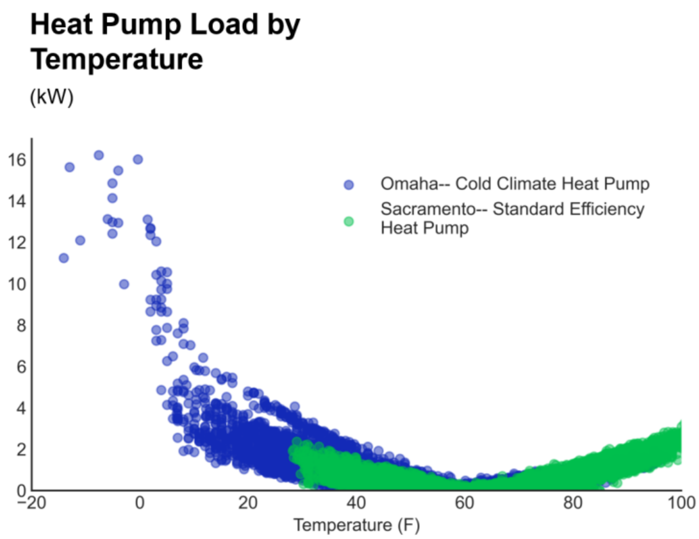
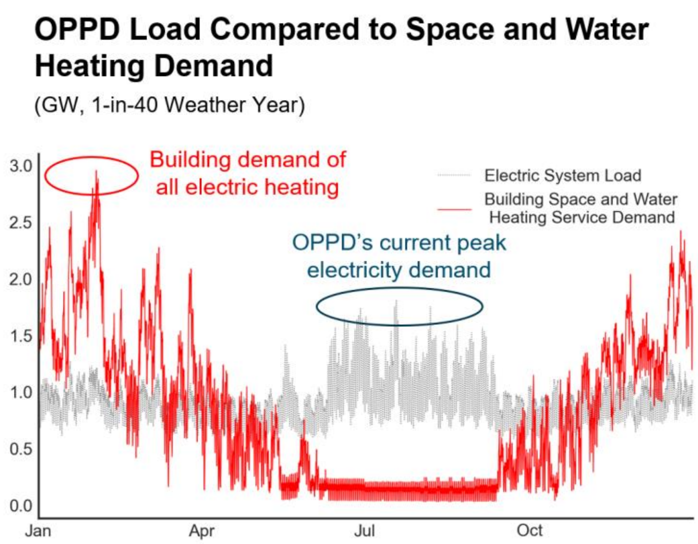


Figure 37 shows heat pump electricity demand during a 1-in-40 weather year, i.e. the coldest year of the last forty years. This shows the "peak heat" challenge, indicating that the peak building heating demand in under such conditions would be nearly double OPPD's current electric peak load. This may require building out electric generation, transmission, and distribution infrastructure to serve an 8 GW 1-in-40 winter peak in the Net Zero: High Electrification scenario (versus the 6.5 GW 1-in-2 winter peak).

Figure 37. OPPD Heat Pump Demand under 1-in-40 Weather Year Conditions



3.5.2.3 Energy Efficiency Savings

The multi-sector modeling includes two key energy efficiency results. First, as the economy transitions from combustion of fossil fuels in transportation, buildings, and industry to electricity for those electrified end uses, there are significant economy-wide gains in primary energy efficiency. This is illustrated in Figure 38. Second, the multi-sector modeling includes adoption of incremental energy efficiency technologies in the mitigation scenarios. Figure 39 shows the projected electric energy efficiency savings across the mitigation scenarios relative to the Reference scenario, which has only OPPD's current and near-term planned EE program savings. Figure 40 shows the breakdown of end uses whereby the net zero balanced electric energy efficiency savings are achieved.

Figure 38. Primary Energy Demand Across the Economy (Net Zero Balanced Scenario)

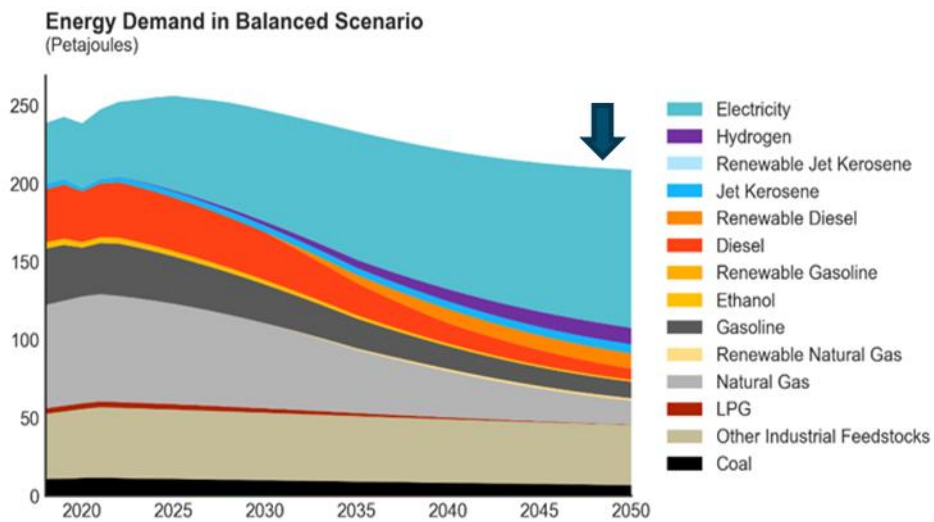


Figure 39. Electric Energy Efficiency Savings of Mitigation Scenarios

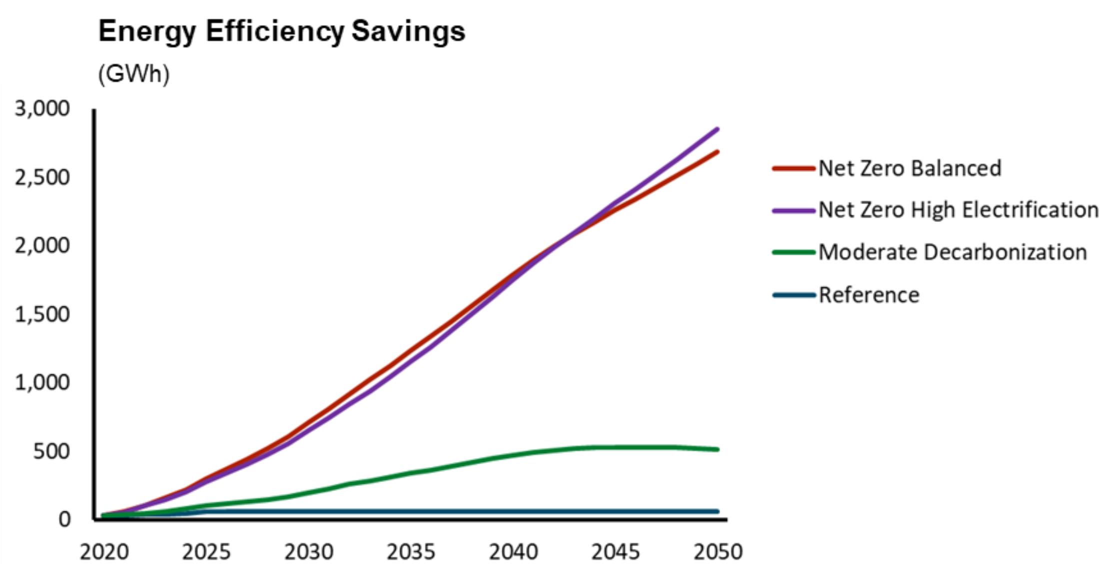
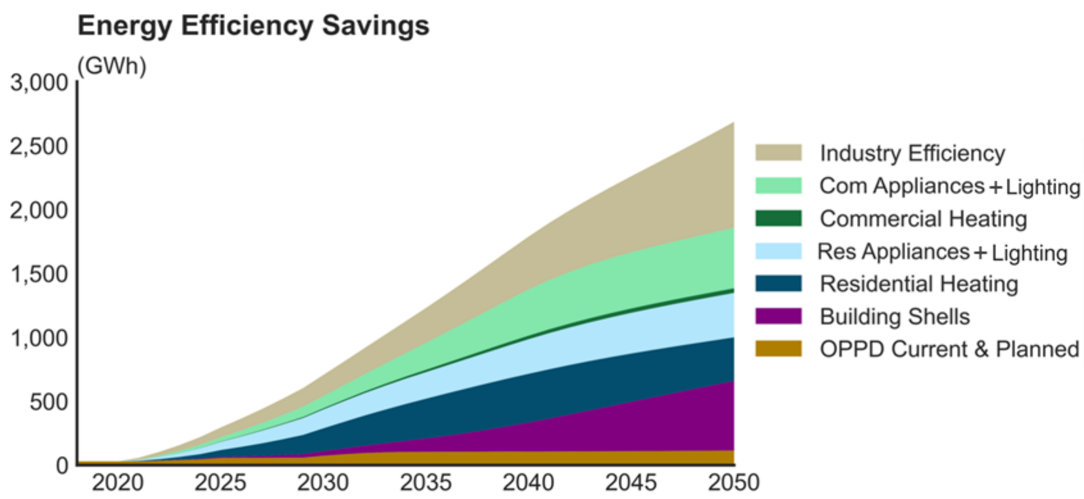
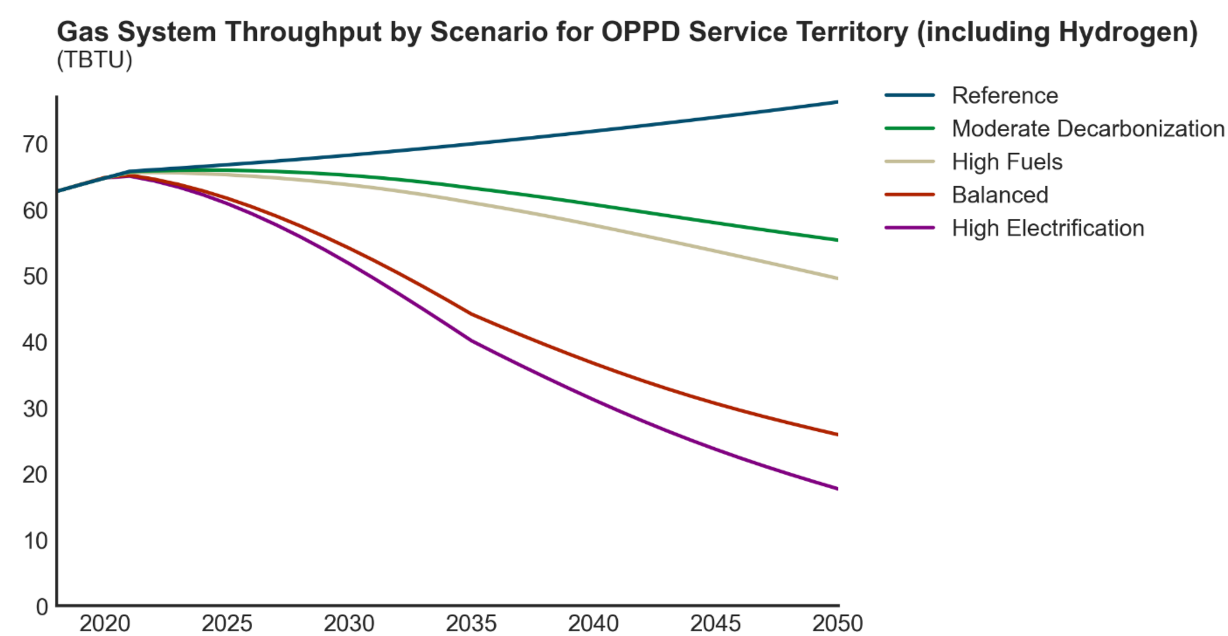


Figure 40. Electric Energy Efficiency Savings by End-Use (Net Zero Balanced Scenario)



3.5.2.4 Gas System Impacts

Figure 41. Gas Throughput by Scenario



Economy-wide decarbonization may require significant transformation of the natural gas system. As a result, it is important to evaluate the effect long-term decarbonization policies might have on the gas system. Figure 41 shows a comparison of gas throughput (which includes hydrogen)[14] in all scenarios. In only the Reference scenario does gas consumption increase over the study period. All mitigation scenarios have decreased gas throughput through the study period, owing to increased electrification of end uses that are currently dominated by gas and energy efficiency. Figure 41 also shows that the gas system will be necessary even in scenarios with the most aggressive levels of electrification, owing to the hard-to-decarbonize end uses (like high temperature industrial process heat) in the Balanced and High Electrification scenarios and to natural gas being used as a peaking fuel for space heating in the Balanced scenario.

In addition to the potential for throughput declines, the gas system must decarbonize much of the remaining fuel flowing through the pipeline. The use of low-carbon fuels is discussed in section 3.5.3.4 below.

3.5.3 Sectoral Findings

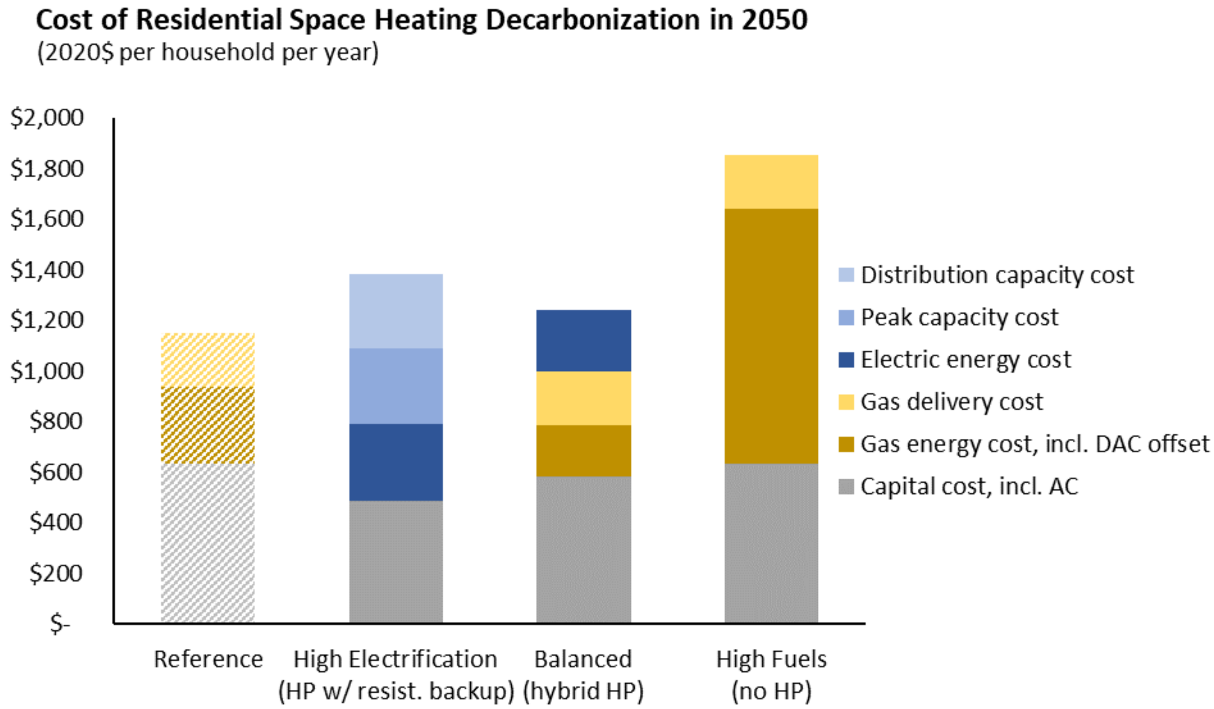
In this section, the sectoral measures leading to the GHG emissions reductions, peak and annual load growths, and gas throughput reductions are discussed.

3.5.3.1 Buildings

The primary methods of building decarbonization are space heating electrification, specifically replacing gas and less efficient electric resistance heaters with efficient heat pumps, and reliance on decarbonized fuels. As shown in Figure 23, the mitigation scenarios explored increasing levels of electrification and the kind of backup peaking fuel that was used in conjunction with the heat pump. In particular, the High Electrification and High Fuels scenarios represent bookends for building decarbonization that rely primarily on zero-carbon electricity and zero-carbon gaseous fuels, respectively. Each of these scenarios have implications for load that have been discussed in prior sections. The High Electrification case leads to very high peak loads in the winter from resistance heating, whereas the High Fuels case relies on expensive synthetic zero-carbon fuels.

[14] The High Fuels scenario includes significant displacement of natural gas for industrial customers with hydrogen. This minimizes gas throughput reduction but may require significant re-purposing or re-building of existing natural gas pipelines for to distribute gas/hydrogen blends assumed in this study.

Figure 42. Residential Space Heating Costs by Scenario and Contribution

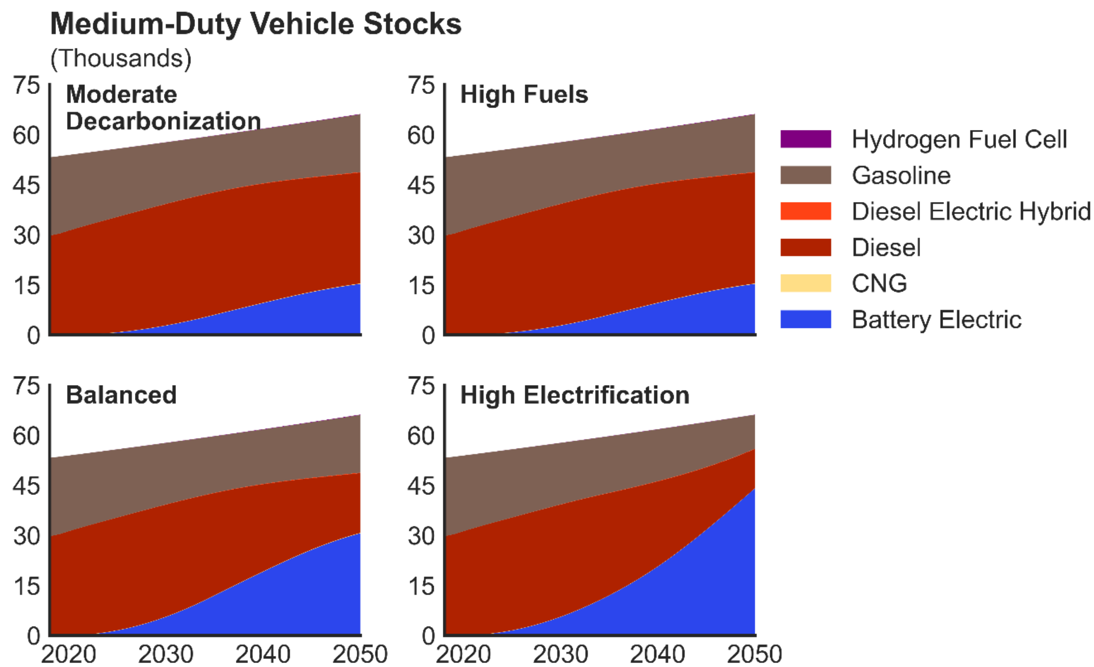


These bookends also have important cost implications, shown in Figure 42. The High Electrification case would require extensive distribution and peaking generation investments, thereby increasing the cost of electrification to each household. The High Fuels case relies on expensive synthetic gas, which increases fuel costs to each household. By electrifying through the pathway of heat pumps with decarbonized gas backup, the Balanced scenario avoids incremental distribution and peaking generation expenditures in the High Electrification scenario and most of the decarbonized gas fuel costs in the High Fuels scenario. This provides savings to a household relative to the High Electrification and High Fuels cases and only a moderate increase in costs relative to Reference.

3.5.3.2 Transportation

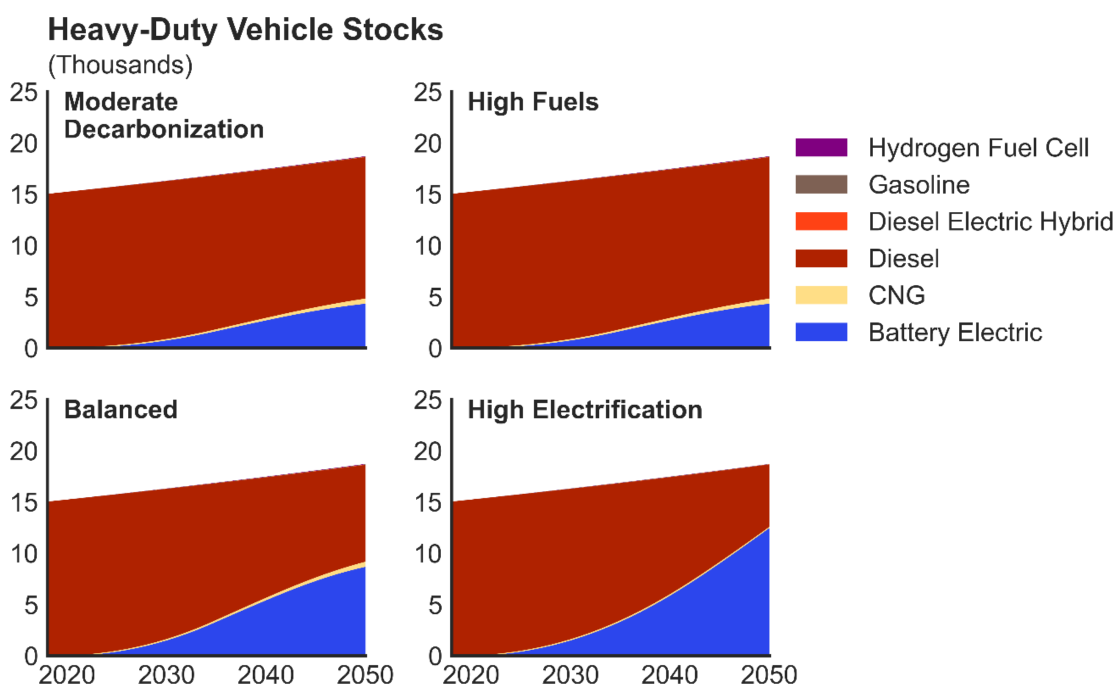
The primary methods of decarbonization in transportation explored in this report are electrification of the vehicle fleet and using decarbonized fuel for the remaining fuel-based vehicles. In the Net Zero scenarios, electrification occurs primarily in the LDV fleet (see Figure 25). Such a transformation is more challenging in MDVs and HDVs due to the weight of batteries needed for those vehicle classes. As such, much of the transportation electrification loads in Figure 32 and Figure 35 arise from LDV electrification.

Figure 43. Mitigation Scenario MDV Stocks



As shown in Figure 43 and Figure 44, MDV and HDV vehicle stocks are assumed to electrify more slowly than LDVs, leaving a large portion of their respective fleets dependent on diesel. Renewable diesel is needed to decarbonize these fleets throughout the study period.

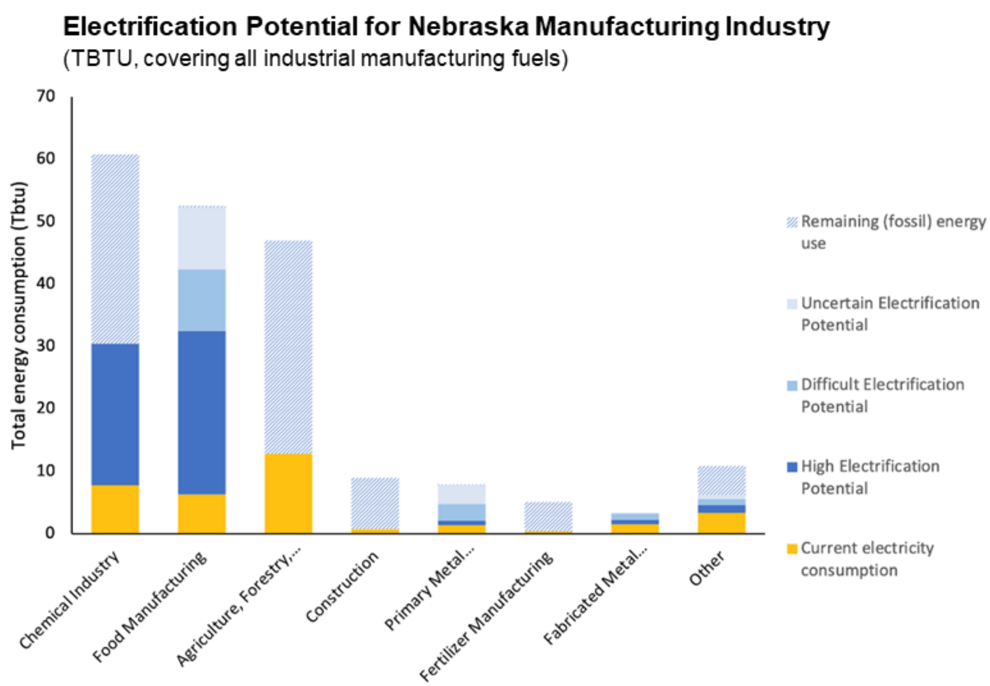
Figure 44. Mitigation Scenario HDV Stocks



3.5.3.3 Industry

Industry represents most of the remaining emissions in the Net Zero scenarios, largely due to the challenge of electrifying many energy-intensive industrial processes. As discussed earlier in the report, various elements of industry can be electrified, such as boilers and low-temperature heat. As shown in Figure 45, each subsector of Nebraska's manufacturing industrial subsectors greatly varies in its potential to easily electrify. As a result, hydrogen can be used to decarbonize some process heat, and CCS can be used to decarbonize process emissions where neither electrification or hydrogen can reasonably be deployed. Even with these measures, some processes cannot be reasonably decarbonized through any of the measures discussed above, leaving industry with most of the gross emissions in the Net Zero scenarios, that must be offset by negative emissions technologies.

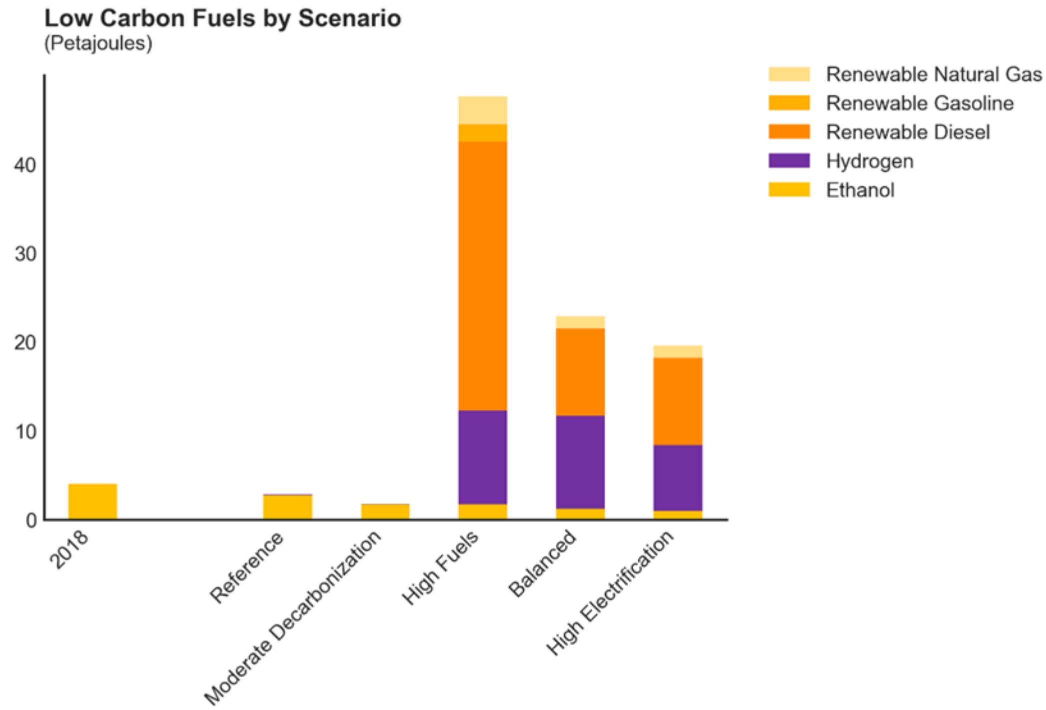
Figure 45. Estimated Electrification Potential of Nebraska's Manufacturing by Industrial Subsector



3.5.3.4 Low Carbon Fuels

As noted in prior sections, low-carbon fuels were used to decarbonize fuel demand. In all scenarios, ethanol was maintained at today's blending ratios of 10% with gasoline. In the Net Zero scenarios, low-carbon fuels were employed to decarbonize remaining fuel demand after electrification and efficiency measures were implemented. The results of these assumptions are shown in Figure 46. The Net Zero scenarios all have significantly increased low-carbon fuels supplied in comparison to the Reference and Moderate Decarbonization scenarios. In particular, the High Fuels scenario has the highest demand for low-carbon fuels. Most of this demand is in the form of renewable diesel. This demand is mitigated in both the Balanced and High Electrification scenarios by more aggressively electrifying the MDV and HDV fleets in the OPPD service territory.

Figure 46. Low Carbon Fuel Supplied by Scenario, Compared to Ethanol Supplied in 2018



3.5.3.5 Negative Emissions Technology (NET)

NETs were deployed in the Net Zero scenarios to deal with the remaining gross economy-wide emissions after all other decarbonization strategies were deployed. NETs are a class of technologies that can remove carbon dioxide directly from the atmosphere. There are several classes of NETs, described below:

- **Direct Air Capture (DAC)** removes carbon dioxide directly from the air and stores it underground. It can be powered either by natural gas with CCS or by renewables. High temperature heat need makes a fully renewable-powered process difficult. The estimated abatement cost via DAC is estimated to be \$170-370/tCO_2 in 2050.[15]
- **Bioenergy with Carbon Capture and Storage (BECCS)** converts biomass to energy and captures and stores resulting carbon dioxide emissions underground. This process leads to net negative lifecycle carbon dioxide emissions. The most promising pathway converts biomass to hydrogen. The estimated abatement cost via BECCS is estimated to be \$110-310/tCO_2 in 2050.[16]
- **Afforestation and reforestation**, while not technologies *per se*, are also means for carbon dioxide removal. These techniques involve planting and restoring forests. The estimated

[15] "Achieving Carbon Neutrality in California (Revised Report): 2045 Abatement Cost Estimate," Energy and Environmental Economics, 2020, https://ww2.arb.ca.gov/sites/default/files/2020-10/e3_cn_final_cost_data_supplement_oct2020.xlsx.
[16] Ibid.

abatement cost via afforestation and reforestation is ~$10/t$CO_2$ in 2050, although the potential to do so is likely limited due to land constraints.

It is important to note that the first two technologies (DAC and BECCS) are not yet commercialized, so their deployment potential remains uncertain. This uncertainty adds significant risk to any long-term decarbonization plan that relies too heavily on these technologies that have not yet been deployed at scale.[17]

3.5.3.6 Non-Energy Emissions

This analysis is focused on energy emissions, because decarbonization of the energy sector is what has the potential to impact OPPD. Additionally, a more rigorous and targeted analysis is needed to properly characterize non-energy emissions and related mitigation opportunities in Nebraska. However, reductions in non-energy emissions are still expected to play a role in economy-wide decarbonization. Key non-energy emissions that should be studied and addressed include:

+ **Refrigerant leakage** from air conditioners and refrigerators. A transition to low-GWP refrigerants and a focus on leakage prevention for large commercial customers can lead to significant reductions in this category.
+ **Methane leakage** from oil and gas extraction also presents a significant opportunity for non-energy emissions reductions. Methane is 25 more times potent than CO2 over a 100-year timespan. Leak detection and repair technology may be able to enable significant methane emission reduction.
+ **Agricultural emissions** from fertilizer application and other practices are another major category of non-energy emissions, with a significant opportunity for cost-effective abatement.

3.5.4 Costs

Cost is an important factor in evaluating the viability of a potential decarbonization plan. The categories used to determine costs include annualized measure costs, fuel costs, transmission and distribution costs, energy and capacity costs, and costs of NETs. Cost categories and sources are detailed in Table 15. It is important to note that NETs are assumed to be direct air capture in this cost analysis, and that electric sector costs are placeholders, as electricity costs will be updated after E3's portfolio optimization analysis.

Table 15. Cost Categories and Sources

Cost Category	Cost Sub-Category	Source
Fuel	Fossil Fuel	AEO 2020 Reference Case
	Biofuel	E3 Biofuels Module

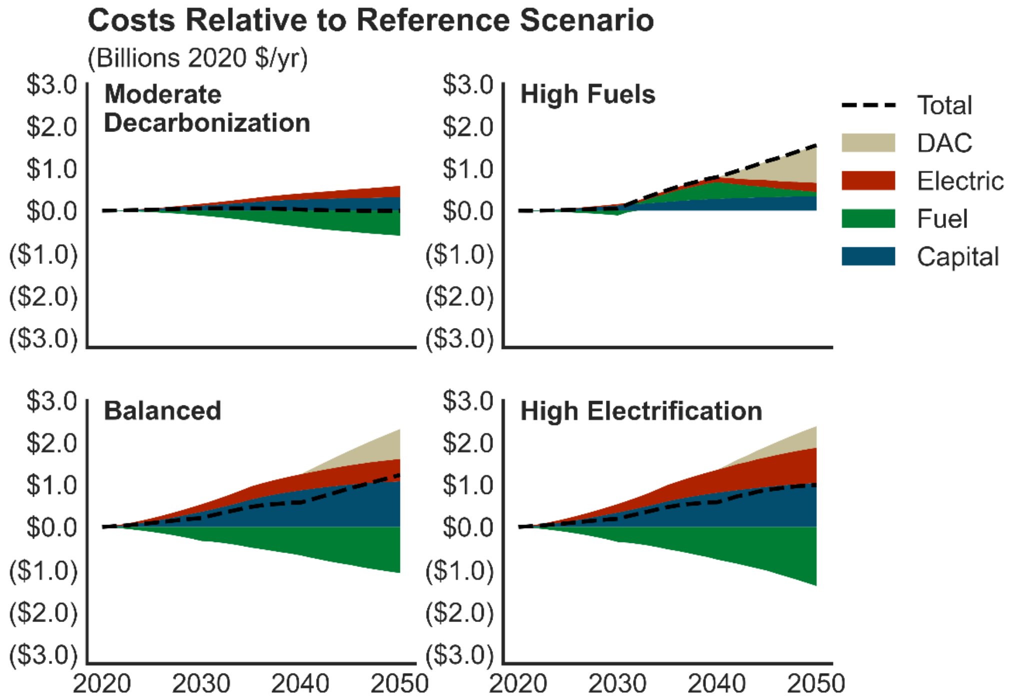
[17] "Achieving Carbon Neutrality in California," Energy and Environmental Economics, 2020, https://ww2.arb.ca.gov/sites/default/files/2020-08/e3_cn_draft_report_aug2020.pdf.

	Hydrogen	E3 Synthetic Fuel Calculator, assuming Nebraska wind for electricity source
Electric Sector	Transmission and Distribution	Placeholder; Will be updated in portfolio optimization task
	Energy	Placeholder; Will be updated in portfolio optimization task
	Peak Capacity	Placeholder; Will be updated in portfolio optimization task
End Use	Capital	Various sources[18,19]
NETs	DAC	E3 Literature Review[20]

The results of the cost analysis by mitigation scenario are shown in Figure 47. Note that the costs of these scenarios are reported *relative to the Reference scenario*. In most scenarios, reduced dependence on fuels result in cost savings that partially offset the increased capital, electric sector, and DAC expenditures relative to the Reference scenario. The sole exception is the High Fuels case, which relies most heavily on the most expensive tranches of decarbonized fuels. With the current cost assumptions, the Moderate Decarbonization scenario is approximately at cost parity with the Reference case. For the Net Zero cases, the total cost impacts are directionally aligned between the cases, at approximately $1 billion/yr (real 2020$) in incremental costs by 2050 (or ~2% of estimated Omaha GDP). Costs may be slightly lower for scenarios with higher levels of electrification, owing to increased energy efficiency of electrification (and resulting fuel savings) and decreased DAC need, which is offset by increasing capital and electric sector costs. However, the electric cost impacts and infrastructure planning challenges will be further explored via sensitivity analysis in E3's portfolio optimization phase of this project. While costs are quite uncertain for the next 30 years, the analysis shows that deep decarbonization using multiple strategies is possible at a manageable cost if technologies evolve as forecast in this analysis.

[18] "EIA NEMS Appendix A," Energy Information Agency, 2018, https://www.eia.gov/analysis/studies/buildings/equipcosts/pdf/appendix-a.pdf.
[19] "Update on electric vehicle costs in the United States through 2030," International Council on Clean Transportation, 2019, https://theicct.org/sites/default/files/publications/EV_cost_2020_2030_20190401.pdf.
[20] "Achieving Carbon Neutrality in California (Revised Report): 2045 Abatement Cost Estimate," Energy and Environmental Economics, 2020, https://ww2.arb.ca.gov/sites/default/files/2020-10/e3_cn_final_cost_data_supplement_oct2020.xlsx.

Figure 47. Mitigation Scenario Costs by Category Relative to the Reference Scenario



3.6 Key Findings from Multi-Sector Modeling

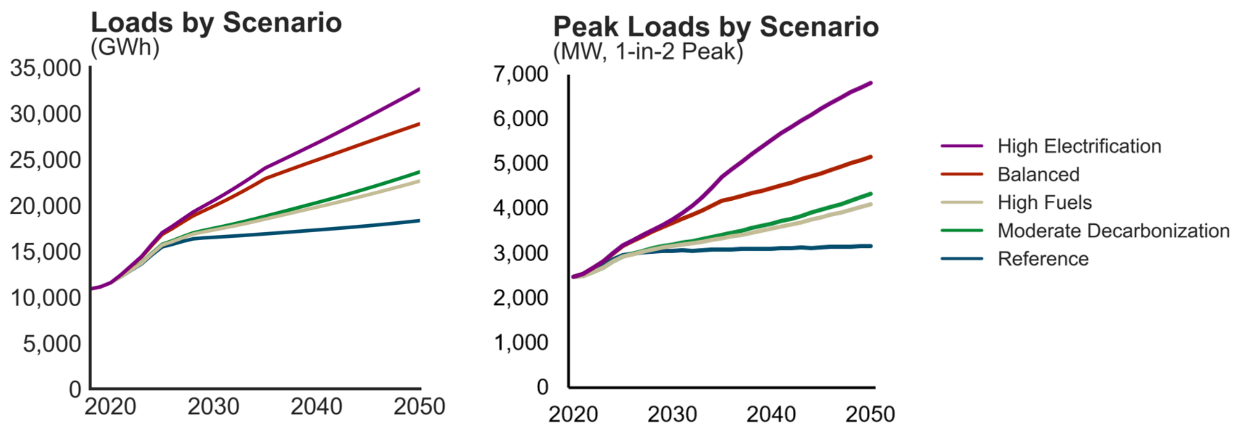
Multiple decarbonization scenarios of the Nebraskan energy economy within the OPPD service territory were investigated. Five scenarios were developed to reveal the potential impacts of economy-wide decarbonization on OPPD loads and to identify key opportunities for community engagement on decarbonization policies and future potential OPPD customer programs:

+ The **Reference** scenario represents a case in which OPPD "goes it alone", achieving net zero emissions on its own while the remainder of the economy follows current trends into the future.
+ The **Moderate Decarbonization** scenario features modest decarbonization strategies throughout the economy while OPPD achieves net zero carbon emissions by 2050.
+ The **Net Zero: High Fuels** scenario investigates full, economy-wide decarbonization with a high reliance on expensive biofuels and synthetic fuels (like hydrogen) and electrification only of relatively inexpensive end uses.
+ The **Net Zero: High Electrification** scenario aggressively electrifies most end uses, with remaining energy demand (arising from subsectors such as long-haul trucking and industrial high temperature heat) served primarily by decarbonized fuels.
+ The **Net Zero: Balanced** scenario borrows some aggressive electrification from the High Electrification scenario and increased reliance on renewable fuels from the High Fuels case, while addressing the "peak heat" electricity planning challenge with decarbonized gas backup for building space heating.
+ All net zero scenario rely on negative emissions technologies (such as direct air capture) to offset remaining emissions in the hardest to decarbonize sectors of the economy.

E3's analysis indicates that economy-wide decarbonization will have significant impacts on the electric system:

- All decarbonization scenarios include either moderate or high levels of transportation and building electrification that drive the need for OPPD to meet significantly increased annual and peak loads.
    - Fully electrifying building space heating in the High Electrification case leads to the highest load impacts and causes OPPD to switch from summer-peaking to winter-peaking, adding 3 GW of peak load relative to the Reference case in 2050.
- A significant portion of this peak load growth can be avoided by using decarbonized gas as a backup fuel in space heating applications, reducing the need for expensive peaking, transmission, and distribution upgrades in the electric sector. This requires maintaining the existing gas distribution system, instead of upgrading the electric system to replace it.

Figure 48. Electric Energy (GWh) and Peak Demand (MW) Load Impacts by Scenario



OPPD has an opportunity as an established regional decarbonization leader and as an electricity provider to engage the community and its customers to support the transition to a carbon neutral economy in the region. Creating customer programs focused on the carbon-reducing technologies described in this report – electric vehicles, energy efficiency, and building electrification – will help to speed along this transition. Additionally, new electric loads may offer flexibility to provide grid services, such as flexible electric vehicle charging or grid-responsive water heaters. Electric load growth may also support electric rate reduction through increased utilization of grid assets. However, this opportunity comes with its own responsibilities and challenges to overcome. Customers are likely to increasingly rely on OPPD's electric service for their transportation and heating needs. The follow sections of this report explore how to serve OPPD's growing electricity needs under a range of economy-wide decarbonization scenarios with net zero carbon electricity, while maintaining affordability, reliability, and resilience.

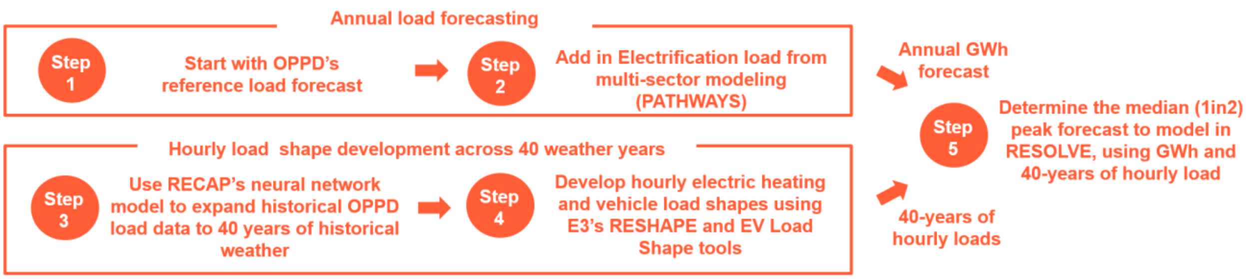
4 Inputs and Assumptions

4.1 Loads

4.1.1 Load Development Process

E3 started with OPPD's reference annual GWh and peak MW forecasts as well as historical hourly loads, including current and planned energy efficiency and demand response, then layered on load increases associated with transportation, building, and industrial electrification based on the multi-sector modeling scenarios developed. The process is illustrated in Figure 49.

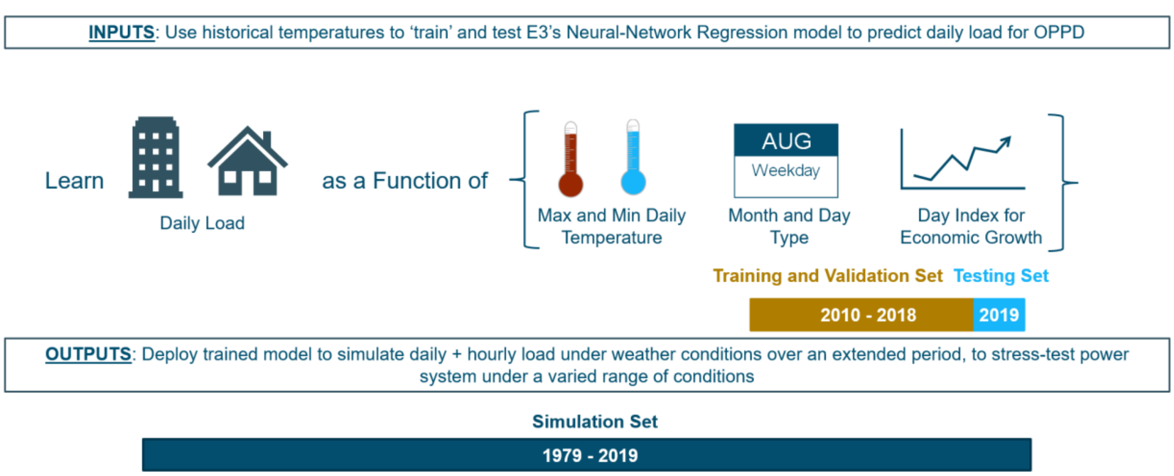
Figure 49. Overview of Load Forecast Development Process



4.1.2 OPPD Loads Across Historical Weather Years

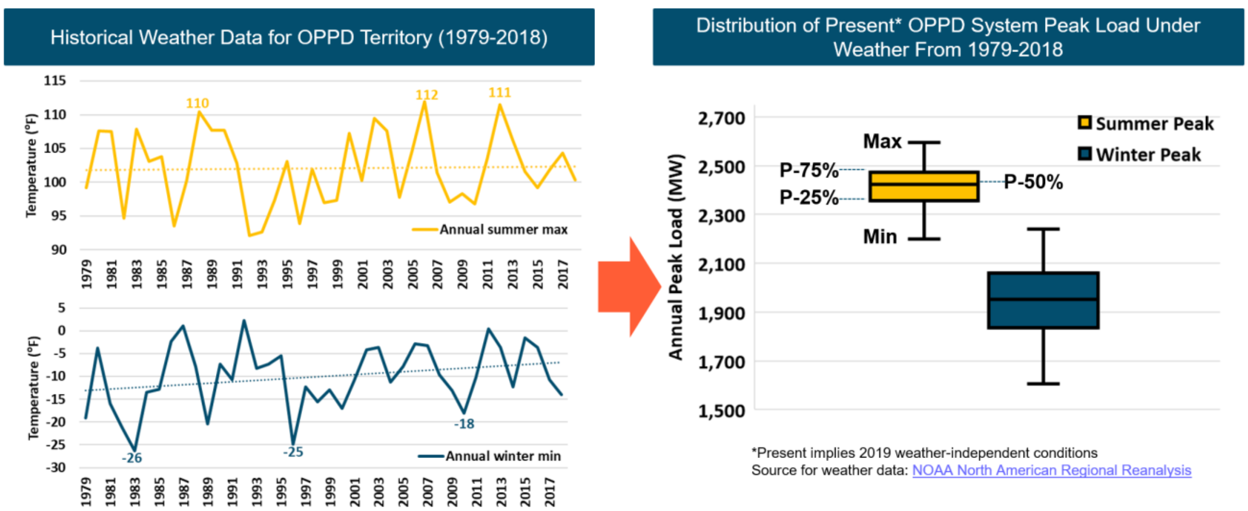
E3 modeled existing (under 2019 economic conditions) hourly load for OPPD across the weather years 1979 – 2019 using a neural network regression model. E3 used hourly load data from 2010-2019 to train and test the model. This analysis produced expected load profiles in OPPD under a variety of weather years in today's economic conditions. Later steps captured how load profiles might change in the future due to new load types such as electric vehicles or building space and water heating.

Figure 50. Schematic of Hourly Historical RECAP's Load Development Process



The temperature trends using historical weather stations in the OPPD region as well as the results of E3's neural network regression modeling are shown in Figure 51. Across the modeled weather years, the annual peak demand varied naturally due to the differences in weather patterns, particularly differences in the highest summer temperatures. Hotter weather years generally led to higher peaks. The RECAP model captured the distribution of peak load variability related to weather by simulating load across weather years from 1979 to 2019. OPPD system shows higher summer peak loads, but higher variance in the winter peak load. The system peak used in RESOLVE was the 1-in-2 median peak, meaning that the annual peak load will exceed this value every other year due to weather variability. A clear warming temperature trend was seen in the winter daily minimum temperature (although the recent 2021 polar vortex event likely altered that trend), but only a very minor warming trend was seen in the daily maximum temperatures.

Figure 51. Historical Weather Data Inputs and Distribution of 2019 Peak Load Outputs

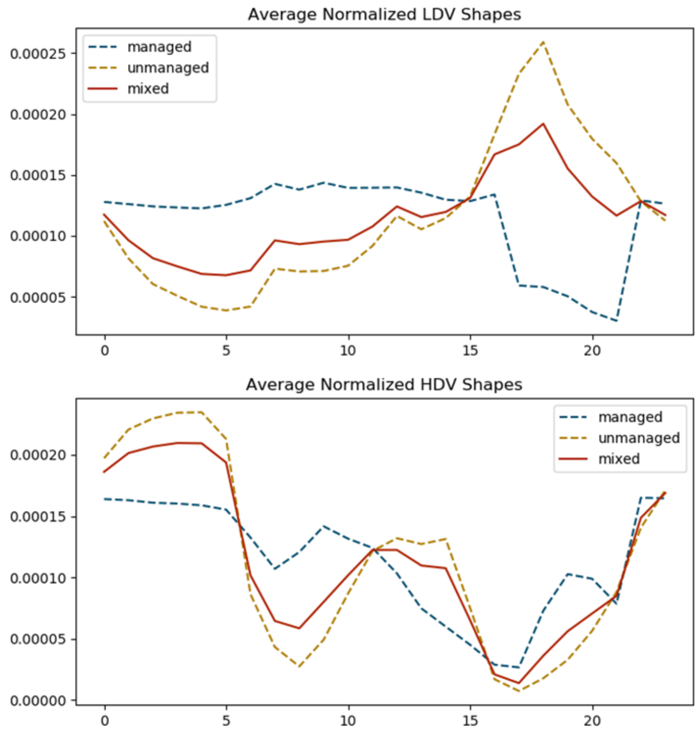


4.1.3 Electrification Load Shapes

To capture electrification load shapes, E3 developed electric vehicle load shapes using its EV Load Shaping Tool (EVLST) and building space and water heating load shapes using its RESHAPE model. These profiles were scaled to match annual load forecasts output by PATHWAYS and were combined while maintaining weather correlations.

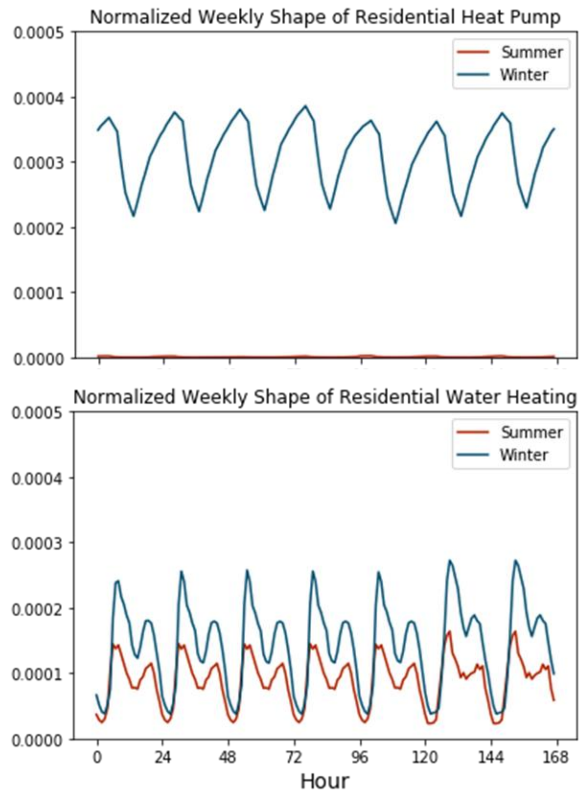
EV load shapes were developed for two different shapes for LDV and MDV/HDV vehicle types. "Unmanaged" charging shapes are driven purely by driver behavior and assume that customers charge based solely on their driving patterns. "Managed" charging shapes were modeled as price responsive to time of use electricity rates, which reduce EV charging during the late afternoon / early evening period of peak demand. As a base assumption, it was assumed that 1/3 of EVs followed the managed charging shape and 2/3 the unmanaged charging shape. Combined these are shown as the "mixed" line in Figure 52. Shapes were differentiated based on weekday and weekend charging patterns. E3 also explored a "high flexible loads" sensitivity scenario to consider higher amounts of price responsive loads.

Figure 52. Electric Vehicle Charging Shapes



Building electrification load shapes were developed using E3's RESHAPE tool. RESHAPE generates hourly system-level heat pump loads over 40 historical weather years that represent diversity in buildings, weather, and heat pump technology. These are produced for both space heating heat pumps and water heating heat pumps. Scenarios were differentiated between scenarios with electric heat pumps that have decarbonized gas backup for peak heat needs, such as the "Net zero Balanced" load forecast, and those that rely on electric resistance heating to supplement heat pump efficiency declines in extremely low temperatures, such as the "Net zero High Electrification" load forecast. Figure 53 shows the weekly shapes of electric space heating and water heating developed from RESHAPE, though the actual model outputs span 40 years of historical weather conditions to capture the peak heat need during extreme cold events.

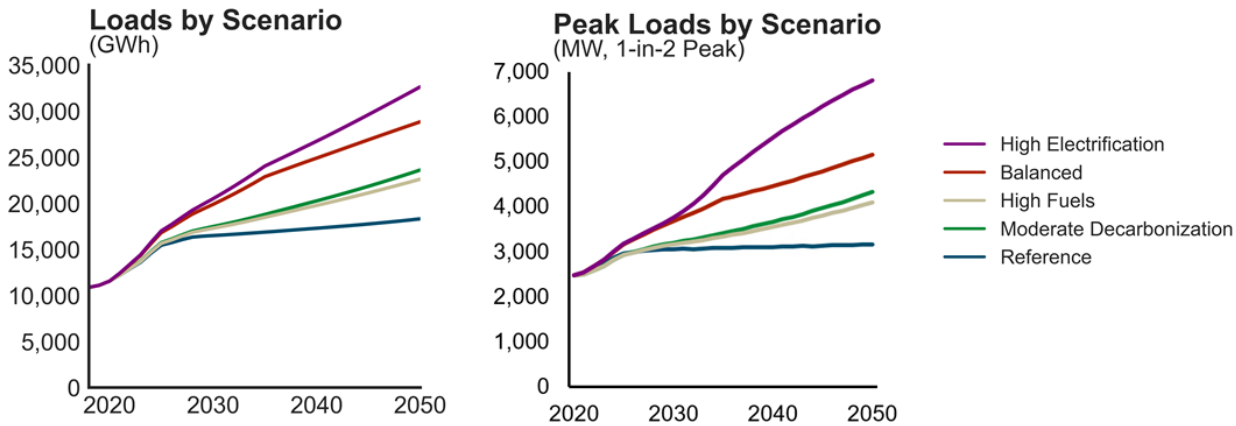
Figure 53. Sample Space Heating and Water Heating Heat Pump Loads from RESHAPE



4.1.4 Load Scenarios Used in Portfolio Optimization

The load forecast scenarios were used in RESOLVE to perform the portfolio optimization task that developed technology portfolio pathways for OPPD to reach net zero carbon emissions: Reference, Moderate Decarbonization, Balanced, and High Electrification. The annual GWh and median peak MW are shown in Figure 54. The “High Fuels” scenario on those graphs is the one multi-sector modeling scenario that was not modeled in RESOLVE, as the electric loads were generally captured well via the moderate decarbonization scenario that was analyzed. The energy efficiency and electrification assumptions in each scenario are captured in the Multi-Sector Modeling chapter of this report.

Figure 54. Annual GWh and Peak MW Load Scenarios

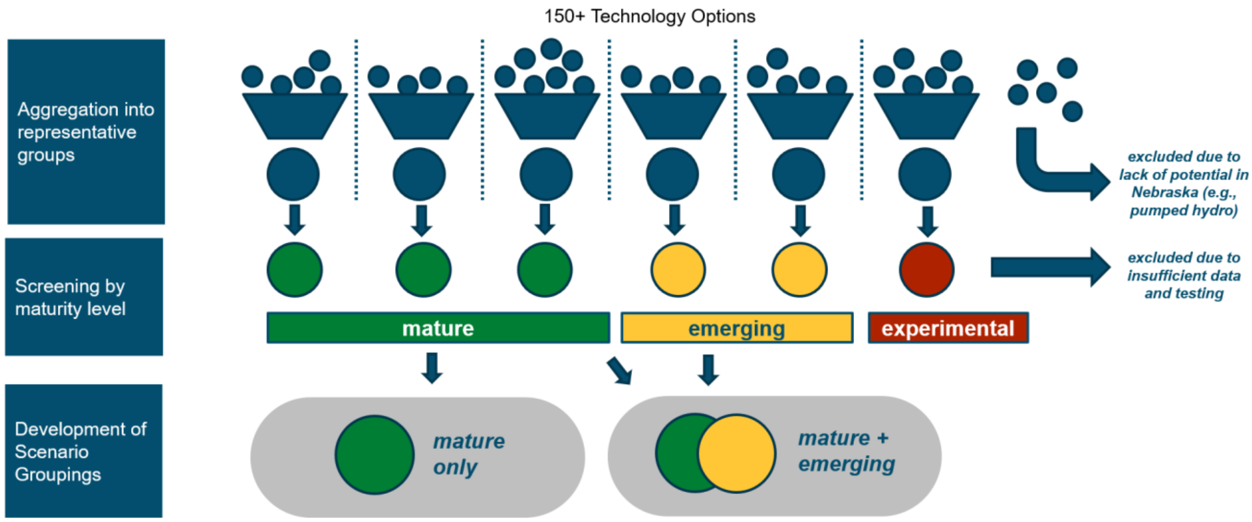


4.2 Technology Availability

4.2.1 Technology Screening Method

E3 and OPPD undertook an extensive exercise to determine the technologies to consider in the portfolio optimization in RESOLVE. As shown in Figure 55, the first step was to aggregate over 150 identified decarbonization technology options into representative groups. For instance, there are many different types of short-duration energy storage, such as various chemistries of battery storage, flywheels, thermal energy storage, etc. These were aggregated into a short-duration energy storage category, represented by lithium-ion batteries, the most prominent technology in the market today for which there exists robust data on current costs and near- and long-term cost trajectories. Another example is carbon capture and storage, for which many technology types exist (pre-combustion, post-combustion, etc.). Representative technologies were then screened for their feasibility, with technologies like geothermal and pumped hydro storage excluded, due to lack of local resource potential. Finally, remaining technologies were categorized into three technology maturity categories: mature, emerging, and experimental.

Figure 55. Schematic Diagram of Technology Screening Approach



To develop this approach, E3 relied on its Emerging Technology Planning Framework, as shown in Figure 56. This framework was developed for resource planners to enable an iterative process to incorporate the many types of important emerging technologies into long-term planning practices. A five-point spectrum was constructed for each technology considered using the International Energy Agency's Technology Readiness Level (TRL) rating. TRL ratings were developed by NASA to track technology development and are broadly applied across many different engineering applications today. Within this spectrum, three discrete categories were developed:

1. **Mature technologies** are those considered fully commercialized, with robust data available on their cost, potential, and operating characteristics. Examples include solar, wind, battery storage, and natural gas combustion turbines. Mature technologies should be modeled in all long-term planning scenarios and drive planning results and near-term resource additions.
2. **Emerging technologies** are those with limited installations and a general paucity of robust, third-party based data on cost, potential, and operating characteristics. This includes technologies such as gas with carbon capture and storage, small modular nuclear reactors, and direct air capture. Emerging technologies are important to capture in long-term planning to inform least-regrets planning and stranded asset risk, but should generally be modeled in sensitivity scenarios due to their uncertain commercialization timelines.
3. **Experimental technologies** are those with no real-world installations and no robust, third-party based data on cost, potential, and operating characteristics. This includes technologies such as advanced geothermal technologies, some ultra-long duration storage, and nuclear fusion. Because research into these technologies may create game changing innovations, they should be the focus on research and development (R+D) funding and small-scale pilot projects. They cannot be modeled in long-term planning studies due to a lack of data on their cost and characteristics.

Figure 56. E3's Emerging Technology Planning Framework

Technology Maturity Spectrum

1 2 3 4 5

	Mature Technologies	Emerging Technologies	Experimental Technologies
Market Experience	Fully commercialized	Limited development	No development
Data: Costs	Available, documented near-term costs and established trajectories	Limited, possible near-term costs but speculative cost trajectories	Theoretical, no real-world cost data
Data: Potential	Available	Limited	Theoretical
Data: Operating Characteristics	Available	Limited	Theoretical
Examples	Solar, wind, battery storage, fossil gas CT/CCGT	Gas w/ CCS, small modular nuclear reactors, direct air capture, H2 combustion, power to gas seasonal storage	Advanced geothermal, new ultra long-duration storage technologies
Proposed Approach	**Model in all scenarios**	**Model in sensitivity scenarios**	**Do not model due to lack of data**
Impact	***Drives results + near-term decision making***	***Informs least-regrets planning, stranded asset risk***	***Informs R+D spending, pilot projects***

The results of the technology screening analysis, including the feasibility screen and maturity level rankings are shown below in Table 16.

Table 16. Technology Screening Results

Category	Technology	Feasibility Screen	Maturity Level
Utility-scale Renewable Energy	Solar	Include	**Mature**
	Wind	Include	**Mature**
	Hydro	Exclude	*Infeasible*
	Biomass	Exclude	*Infeasible*
	Geothermal	Exclude	*Infeasible*
Distributed Energy Resources	Energy Efficiency	Include	**Mature**
	Demand Response	Include	**Mature**
	Rooftop Solar	Include	**Mature**
	Behind-the-Meter Storage	Include	**Mature**
	Flexible Loads	Include	**Emerging**
Conventional Generating Technologies	Natural Gas Combined Cycle	Include	**Mature**
	Natural Gas Combustion Turbine	Include	**Mature**
	Reciprocating Engines	Include	**Mature**

	Existing Unit Fuel Conversion	Include	**Mature**
Energy Storage	Li-Ion Battery Storage	Include	**Mature**
	Flow Battery Storage	Include	**Mature**
	Pumped Hydro Storage	Exclude	*Infeasible*
	Ultra-Long Duration Storage	Include	**Emerging**
Emerging Technologies	Advanced Nuclear	Include	**Emerging**
	Natural Gas with Carbon Capture & Sequestration	Include	**Emerging**
	Hydrogen Combustion Turbines	Include	**Emerging**
Negative Emissions Technologies / Offsets	Traditional Offsets (planting trees…)	Excluded since direct air capture is a more rigorous offset option	
	Direct Air Capture (DAC)	Include	**Emerging**

4.2.2 Technology Availability Scenarios

Based on the screening analysis and the emerging technology planning framework, three primary categories of technology availability were developed for this study, shown in Table 17. All scenarios allow all mature technologies. Emerging technology scenarios were split. One scenario allowed for hydrogen fuel usage in new dual-fuel natural gas and hydrogen combustion turbine or combined cycle power plants. Since hydrogen fuel usage is already a technology being procured by utilities seeking to decarbonize their electric systems[21], it was deemed to warrant a separate scenario. A third scenario enabled the additional emerging technologies of advanced small modular nuclear, natural gas with carbon capture and storage assuming a 90% post-combustion capture rate, and ultra-long duration seasonal storage. The latter was modeled as a power-to-gas-to-power type of seasonal arbitrage storage product that could chemically store electricity in the form of hydrogen or synthetic natural gas.

Table 17. Technology Availability Scenarios

	1. Mature Technologies	**2. Mature + Hydrogen**	**3. Mature + Emerging Technologies**
Mature Technologies	Solar Wind Li-ion battery storage Flow battery storage BTM solar BTM storage Coal retirements + conversions Gas plant additions	Solar Wind Li-ion battery storage Flow battery storage BTM solar BTM storage Coal retirements + conversions Gas plant additions	Solar Wind Li-ion battery storage Flow battery storage BTM solar BTM storage Coal retirements + conversions Gas plant additions

[21] https://www.publicpower.org/periodical/article/ladwp-embarks-hydrogen-generation-project

Zero-carbon Fuels	n/a	H2 fuel (in existing or new plants)	H2 fuel (in existing or new plants)
Emerging Technologies	n/a	n/a	Advanced Nuclear Gas w/ carbon capture and storage Ultra-long duration energy storage

A fourth scenario ("mature + emerging, no hydrogen") was also considered that was consistent with the "mature + emerging technologies" scenario but excluded hydrogen fuels. This was done to determine what emerging technology may be needed if hydrogen fuels do not reach the level of cost reduction and/or technology maturity assumed, and therefore other emerging technologies may be needed as a backstop for clean firm capacity needs (e.g. in the absolute-zero carbon scenario).

***Defining "Green" Hydrogen**: hydrogen as referenced in this report is assumed to be "green" hydrogen, i.e. hydrogen produced via electrolysis using renewable energy as an input. Other types of hydrogen exist such as natural gas steam methane reformation (blue or grey hydrogen) or hydrogen generated by nuclear power (pink hydrogen).* [22]

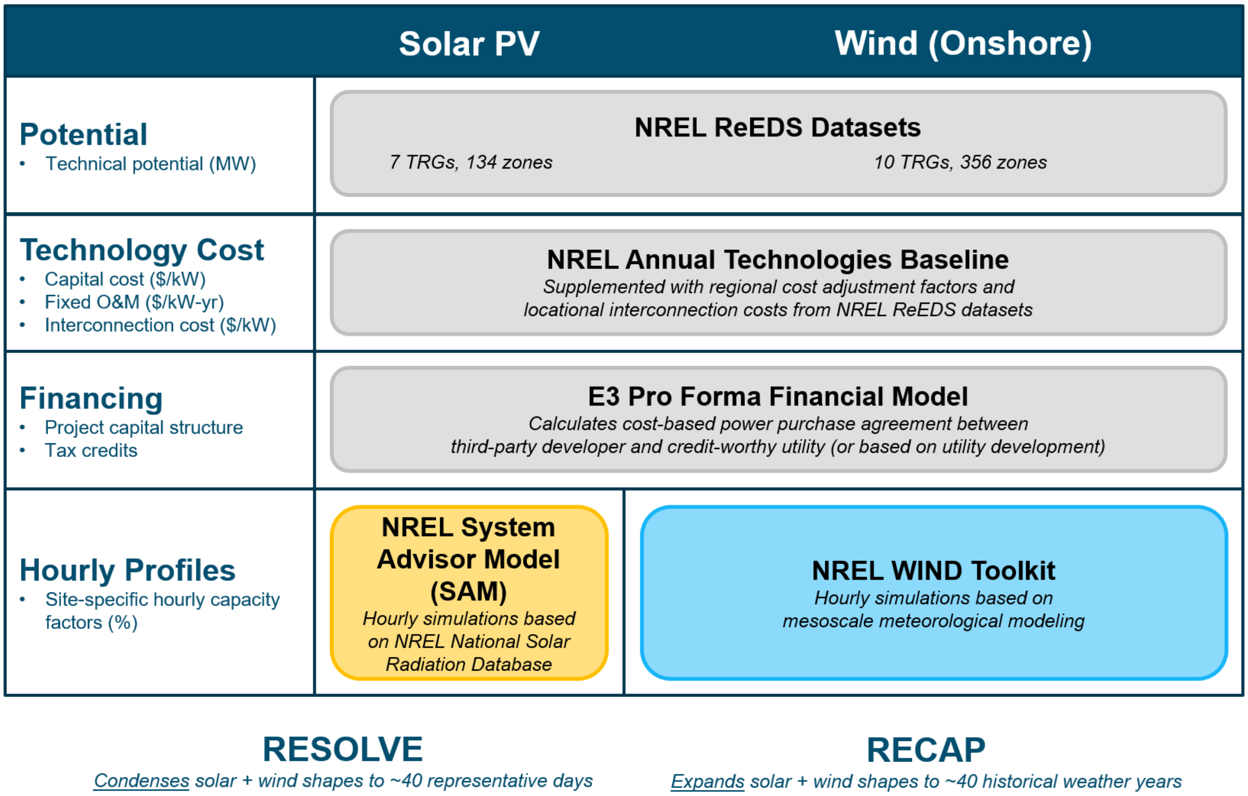
4.3 Resource Potential, Cost, and Characteristics

4.3.1 Solar and Wind Resources

Solar power and wind power are mature zero-carbon generating technologies. Their recent dramatic cost declines have opened the door for low-cost decarbonization across the world, particularly in places of high resource quality. Nebraska has some of the best wind power available in the United States and a decent solar power resource as well. Figure 57. Overview of Solar and Wind Power Input Development shows an overview of the process to develop solar and wind power inputs into the portfolio optimization task. Potential was taken from the National Renewable Energy Laboratory's ReEDS model dataset, which features detailed resource potential for 134 solar zones and 356 wind zones across the US. Technology costs were developed from the 2020 NREL Annual Technology Baseline (ATB) while the levelized costs were developed using E3's pro forma financial model, assuming POU financing per OPPD ownership. Hourly profiles for solar and wind also came from NREL datasets: the System Advisor Model (SAM) for solar and the WIND Toolkit for wind. Renewable shapes were condensed to ~40 representative days for RESOLVE's optimization, while RECAP's simulation was based on expanding NREL data to the 40 years of historical weather conditions modeled.

[22] For a full list of hydrogen production vehicles see here: https://www.nationalgrid.com/stories/energy-explained/hydrogen-colour-spectrum

Figure 57. Overview of Solar and Wind Power Input Development



4.3.1.1 Solar and Wind Shapes

Hourly onshore wind and solar profiles were simulated at different sites (shown in Figure 58 and Figure 59) across Nebraska and surrounding states. Wind speed and solar radiation data was obtained from the NREL Wind Integration National Database (WIND) Toolkit and the NREL National Solar Radiation Database (NSRDB), respectively. They were then transformed into hourly production profiles using the NREL System Advisor Model (SAM) and aggregated to produce regional profiles. Hourly wind speed data was available from 2007-2012 and hourly solar insolation data was available from 1998-2018. Only the coincident period was used to accurately capture correlations.

Figure 58. Wind Sites used to Produce Hourly Generation Profiles

(Darker colors represent higher capacity factors)

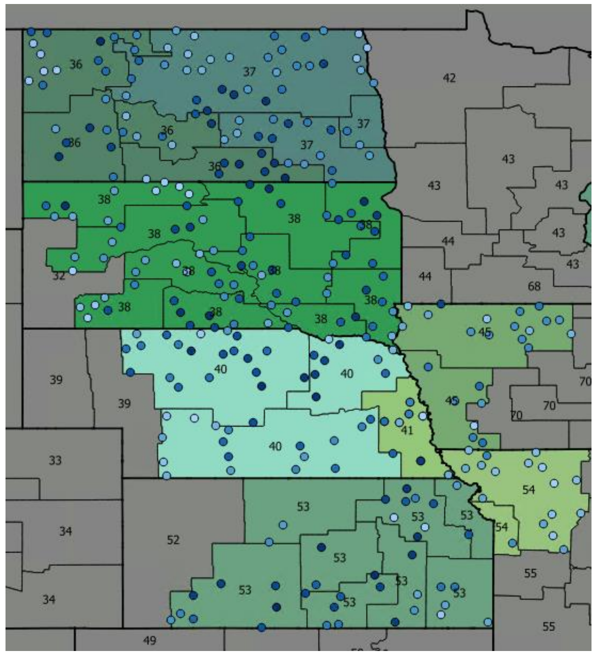


Figure 59. Solar Sites used to Produce Hourly Generation Profiles

(Darker colors represent higher capacity factors)

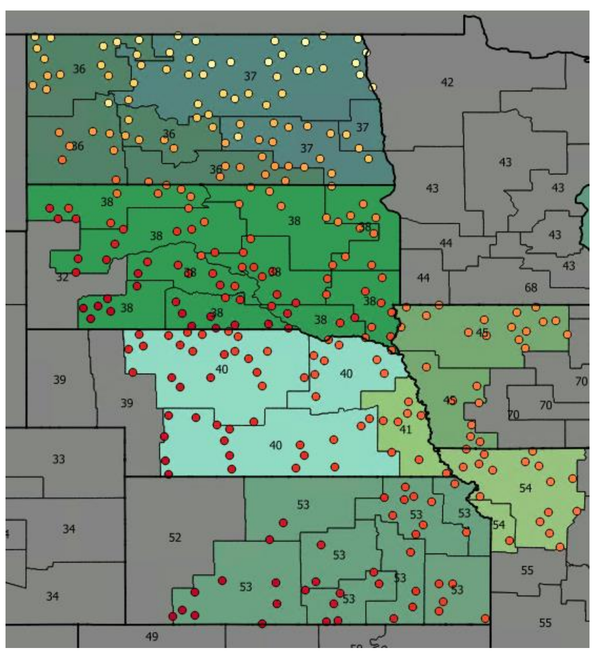
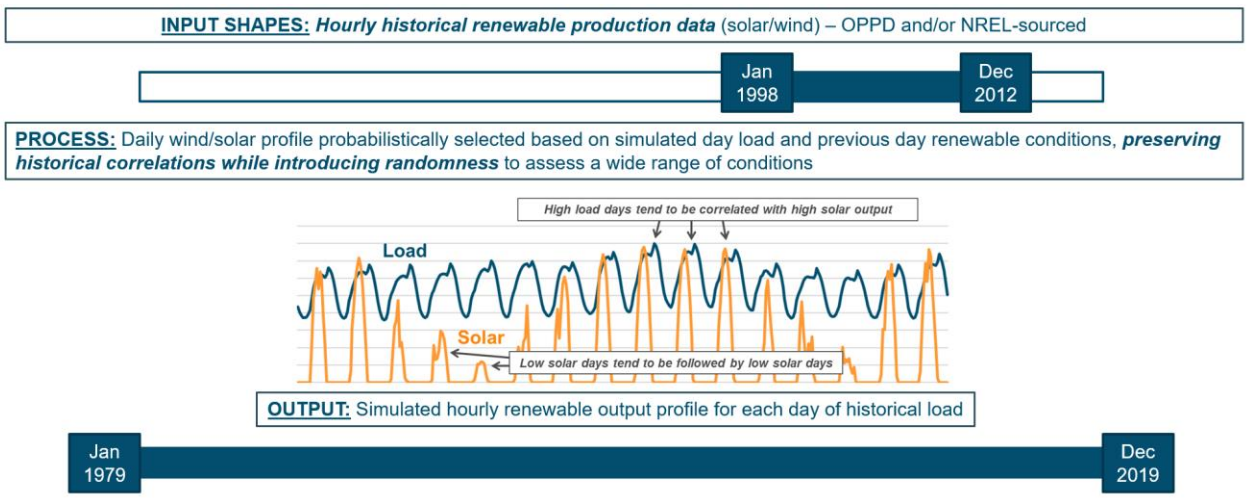


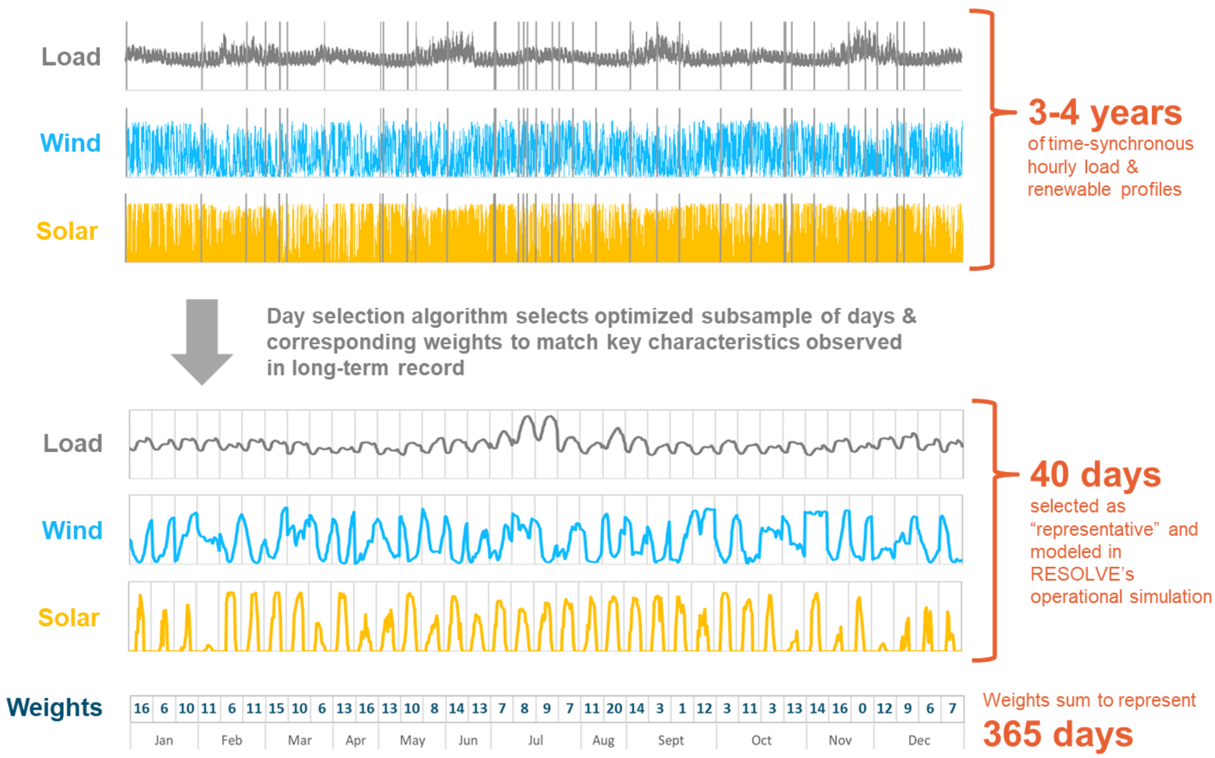
Figure 60 shows a schematic of the method used by RECAP to expand the NREL historical weather data to simulate solar and wind conditions across 40 historical weather years. This method involves a probabilistic algorithm that selects the daily wind or solar profile using the simulated day's load and the previous day's renewable energy output conditions. This preserves historical correlations while introducing some randomness into the monte simulations.

Figure 60. RECAP Methodology to Expand Solar and Wind Data to Historical Weather Conditions



In RESOLVE, a representative set of 40 days were selected to reduce computational time while capturing a representative range of system conditions (Figure 61). The sampled days were generated with a reasonable distribution by season and day type based on input datasets of OPPD historical load and simulated renewable profiles based on historical weather data. Various potential net load shapes were developed to capture load, wind, and solar correlations to derive the representative historical days.

Figure 61. RESOLVE Methodology to Sample Days to Capture Historic and Future System Conditions



4.3.1.2 Existing and Planned Solar and Wind Resources

OPPD's existing fleet of wind and solar resources were modeled, using the data shown in Table 18. This also includes OPPD's planned additions of solar for its Power with Purpose program, shown as those resources coming online in 2022-2025. Existing solar and wind projects were made eligible for re-contracting after their contract expiration rates, with no incremental transmission costs at the modeled cost for new build technologies based on the NREL ATB forecast.

Table 18. Existing and Planned OPPD Wind and Solar Resources

Technology	Station Name	Installed Capacity (MW)	Total by Technology (MW)	Online Date	Contract Expiration Date	Capacity Factor
	Wind - Ainsworth	10		1/1/2012	12/31/2025	30%
	Wind - Sholes	160		10/1/2019	9/30/2039	47%
	Wind - Elkhorn Ridge	25		1/1/2012	4/1/2029	34%
	Wind - Flat Water	60		1/1/2012	12/20/2030	40%
Wind	Wind - Petersburg	41	973	1/1/2012	11/1/2031	45%
	Wind - Crofton Bluffs	14		10/1/2012	11/1/2032	44%
	Wind - Broken Bow 1	18		12/31/2012	12/1/2032	42%
	Wind - Broken Bow 2	44		10/1/2014	10/1/2039	49%
	Wind - Prairie Breeze	201		5/1/2014	5/1/2039	44%

	Wind - Grande Prairie	401		9/1/2016	12/1/2036	42%
Solar	Community Solar	5	505	8/12/2019	12/31/2038	18%
	PV Solar (Power With Purpose)[23]	419		1/1/2023	12/31/2045	24%
	PV Platteview	81		5/1/2023	5/1/2043	24%

4.3.1.3 New Solar and Wind Resource Potential

New solar and wind resources were modeled across various resource zones, aligning with the neighboring states to Nebraska; Nebraska itself was bifurcated into the OPPD service territory and the non-OPPD portion of the state. Resource potential was discounted because NREL Technical Potential from the ReEDS model is significantly larger than what OPPD system would need to meet carbon goals and may not represent the achievable potential accounting for land use constraints. Haircut of resource potential was applied via land screening assumptions that only allow 1% of farmland for solar development and 5% of forest and farmland allowed for wind development.

Table 19. Wind and Solar Resource Potentials and Capacity Factors

Resource Zone	Wind Capacity Factor	Raw Wind Potential GW	Discounted Wind Potential GW	Solar Capacity Factor	Raw Solar Potential GW	Discounted Solar Potential GW
OPPD	50%	38	10	24%	404	23
NE (non-OPPD)	47%	187	20	26%	2,139	47
KS	48%	251	13	26%	2,902	75
IA	50%	133	8	23%	1,372	17
MO	49%	86	9	23%	966	16
SD	51%	148	12	23%	1,684	69
ND	51%	182	11	22%	2,405	63

4.3.2 Energy Storage Resources

Three types of energy storage resource were modeled:

1. **Lithium-ion battery storage**: the predominant energy storage technology in the market today, generally suited to short- to medium-duration applications due to relatively higher $/kWh battery module costs.
2. **Flow battery storage**: generally longer duration energy storage but with a cost premium to lithium-ion technologies

[23] Since the Power With Purpose solar assets are currently unbuilt (including Platteview), capacity factors were estimated by E3 using historical NREL solar shape data.

3. **Ultra-long duration seasonal storage**: representing a power-to-gas-to-power type of seasonal arbitrage storage product that could chemically storage electricity in the form of hydrogen or synthetic natural gas.[24]

Table 20. Energy Storage Operating Characteristics

Resource	Roundtrip Efficiency	Duration
Lithium-ion Battery Storage	85%	4
Flow Battery Storage	85%	12
Ultra-long Duration Seasonal Storage	25%[25]	730

Lithium-ion battery reliability contributions were modeled on an ELCC surface, together with solar penetration (to capture the solar + storage diversity benefit). Flow batteries and ultra-long duration seasonal storage were both assumed to provide 100% ELCC.

4.3.3 Other Resource Types

4.3.3.1 Thermal Resources

OPPD's existing thermal resources shown in Table 21 below.

Table 21. Existing and Planned OPPD Thermal Resources

Technology	OPPD Units Included	Nameplate Capacity (MW)	Total by Technology (MW)	Retirement date
Coal	Nebraska City (1)	652	1,743	Unplanned
	Nebraska City (2)	738 / 2 = 369[26]		Unplanned
	North Omaha (4) - (5)	354		12/31/2023 (gas conversion)
Gas	Cass County (CT-1) & (CT-2)	345	1,848	Unplanned
	Sarpy County (1) - (2)	111		Unplanned
	Sarpy County (3)	106		Unplanned

[24] The hydrogen fuel resource modeled is a similar type of resource since the fuel production pathway is the same (green hydrogen via electrolysis). However, the hydrogen fuel modeled was modeled via off-grid fuel production, so the loads associated with electrolyzers to create the hydrogen fuel were not modeled in RESOLVE. The hydrogen fuel resource benefits from the fact that it can utilize existing or future dual-fuel power plants that can initially utilize natural gas and then transition to hydrogen fuel if/when hydrogen becomes a cost-effective decarbonization resource based on the scenario modeled. The ultra-long duration seasonal storage resource was modeled with endogenous loads that must be served by additional resources added to OPPD's portfolio.

[25] The roundtrip efficiency here represents the combined efficiency of electrolysis and the combustion of H2 in CT to generate electricity.

[26] Nebraska City was split for the purposes of the OPPD Portfolio Optimization, since half of the unit is contracted to non-OPPD load serving entities. Both units were modeled in RESOLVE to capture physical power flow constraints, but only the half of NC2 in OPPD's portfolio was modeled to serve OPPD's load and contribute to OPPD's greenhouse gas emissions.

	Sarpy County (4) - (5)	118		Unplanned
	North Omaha Gas (4) - (5)	278		Unplanned[27]
	North Omaha (1) - (3)	291		12/31/2023
	Standing Bear (1) - (7)	125		Unplanned
	Turtle Creek (1) - (2)	475		Unplanned
Landfill Gas	Elk City Station (1) - (8)	6	6	N/A
Fuel Oil	Jones Street (1) - (2)	130	130	Unplanned
Diesel	Tecumseh	7	7	Unplanned
	Leased G	40	40	Unplanned

New natural gas combustion turbines and combined cycle plants were modeled. To address any potential stranded asset risk, these units were all modeled as dual-fuel natural gas and hydrogen capable plants. The extra cost of making these plants hydrogen capable was added to the NREL 2020 ATB costs for new natural gas power plants, based on the estimate used in PNM's 2020 Integrated Resource Plan of ~$150/kW.[28]

Also modeled was the capability to convert the existing Nebraska City coal steam turbine units from coal to natural gas. The cost data for this conversion was provided by OPPD and included the costs of unit equipment upgrades for natural gas combustion, new firm natural gas pipeline costs, and on-site backup fuel tanks for resiliency.

Thermal Resource Outage Rates

Thermal resources were modeled in terms of their unforced capacity (UCAP) values, which was the percentage of nameplate capacity available after a unit's forced outage rate was taken into account. This accounts for OPPD's participation in SPP, whereby resource diversity allows thermal units' unforced capacity to count for their effective reliable capacity contributions. In contrast, if actual outages were modeled in a RECAP model using only OPPD's loads and resources, then large thermal units would show lower effective reliable capacity contributions due to their outages causing loss of load events. Table 22 shows the range of forced outage rates for various generator types in OPPD's portfolio.

[27] North Omaha units 4+5 were modeled assuming a 15-year life post conversion from coal to gas. However, this was a modeling assumption adopted for this study and does not reflect any current long-term plans by OPPD for this asset.

[28] https://www.pnmforwardtogether.com/assets/uploads/PNM-2020-2040-IRP-REPORT-corrected-Nov-4-2021.pdf

Table 22. Generator Outage Characteristics

Generator Type	Forced Outage Rate
Gas Combustion Turbine	1.2% - 7%
Gas Steam Turbine	3% - 4%
Gas Reciprocating Engine	5%
Oil Combustion Turbine	3.5%
Diesel Combustion Turbine	2.5%
Coal Steam Turbine	5% - 12%
Landfill Gas Internal Combustion	2.5%

4.3.3.2 Other Resources

Advanced Nuclear (Small Modular Reactors)

The candidate nuclear resource was assumed to be a small modular nuclear reactor that has significant flexibility, including short minimum up and down times (1 to 3 hours) and a relatively fast ramping capability.

Carbon Capture and Storage (CCS)

Gas with Carbon Capture and Storage (CCS) was modeled as a candidate resource for RESOLVE to select, with emissions based on a 90% CO2 capture rate.

Hydro

Hydro energy is provided by Western Area Power Administration (WAPA) to OPPD. Hydro is a resource that is limited by weather (rainfall) but can still be dispatched for energy and reliability within max hourly output and a monthly hydro budget, based on data provided by OPPD.

BTM Solar and Storage

Candidate behind-the-meter (BTM) solar and storage resources were also modeled and set with unlimited potential for RESOLVE to select, with a relatively higher costs than front-of-the-meter (FTM) counterparts based on the NREL ATB. Without any emission target, OPPD forecasts BTM solar adoption to grow from 2 MW in 2020 to 28 MW in 2050, an input included in all scenarios.

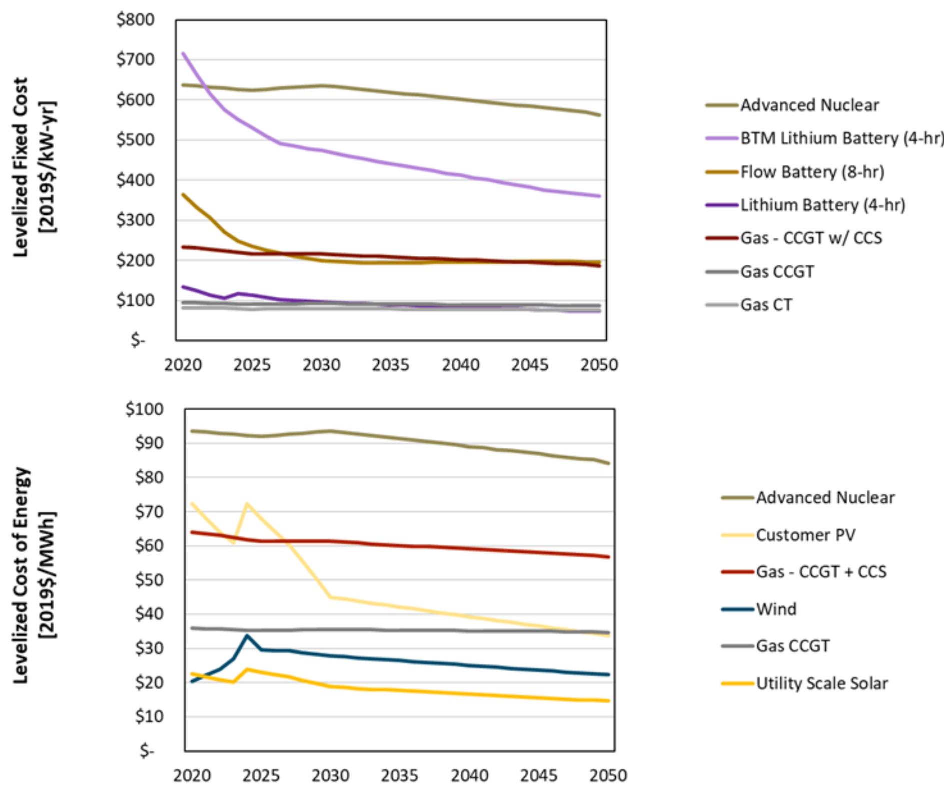
Demand Response

Demand response is dispatched as the resource of last resort since demand response programs often have a limitation on the number of times they can be called upon. For this study, demand response was modeled based on OPPD's programs, ranging from 3 to 15 calls per year, with each call lasting from 3 to 10 hours depending on the program. E3 used DR data provided by OPPD to model 121 MW of existing and 100 MW of planned DR and 80 MW of new candidate DR that RESOLVE could select.

4.3.4 Resource Costs and Fuel Prices

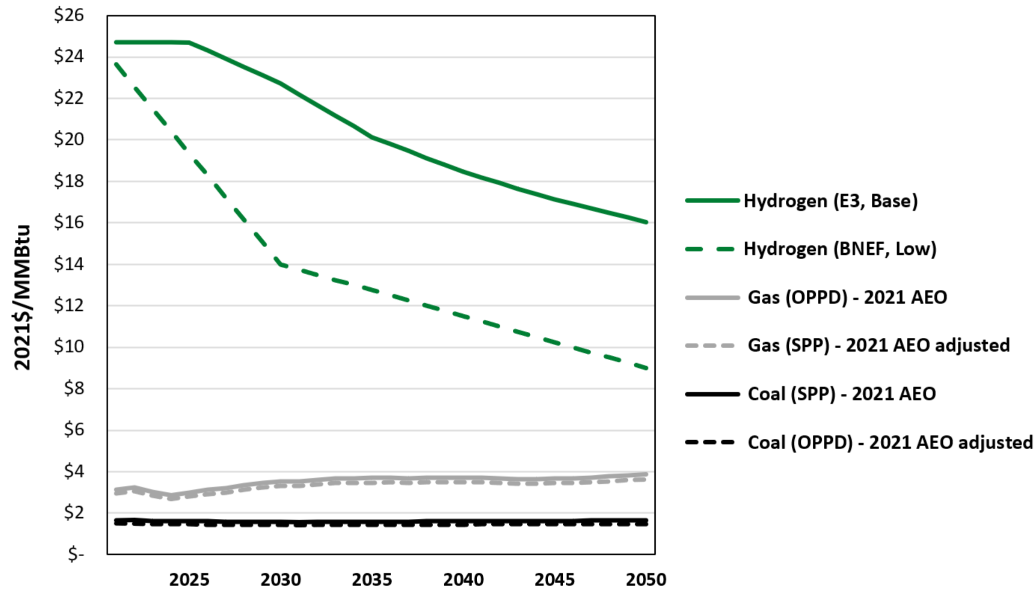
Candidate resource costs were developed based on the NREL 2020 ATB public data source. The levelized fixed costs (for primarily capacity resources) or the levelized cost of energy (for primarily energy resources) is shown below in Figure 62. Candidate Resource Costs.

Figure 62. Candidate Resource Costs



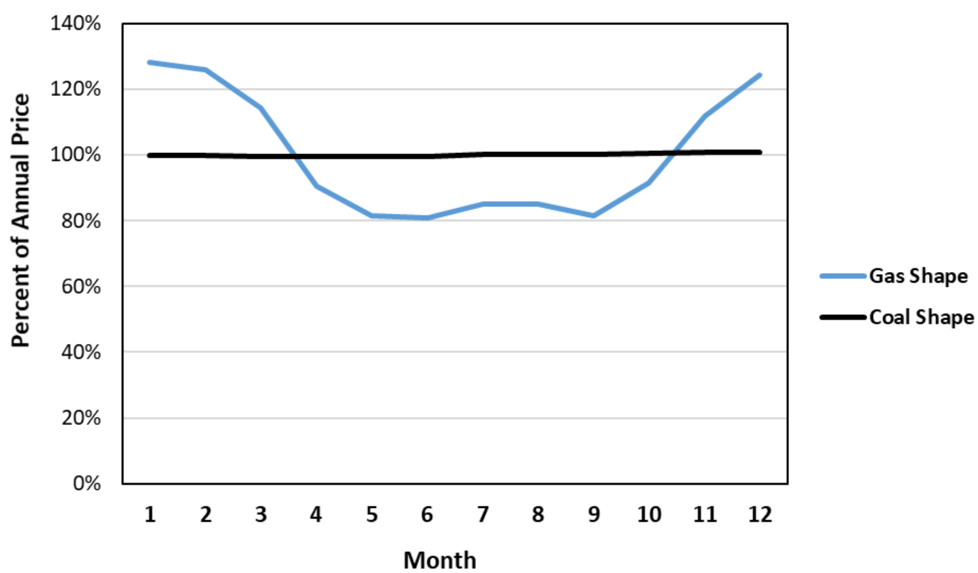
Fuel prices were developed from a combination of data sources. The US Energy Information Administration (EIA) 2021 Annual Energy Outlook (AEO) was utilized for a public forecast of natural gas and coal prices. These were differentiated between SPP and OPPD based on the EIA region that most closely matched the fuel source region for each zone, per OPPD guidance. Hydrogen fuel prices were developed by E3 for the base price forecast and a "breakthrough" low cost forecast was developed using the Bloomberg New Energy Finance 2020 Hydrogen Economy Outlook.

Figure 63. Annual Fuel Price Forecasts



Gas prices were shaped based on higher winter heating demand for natural gas, as shown in Figure 64.

Figure 64. Monthly Variation in Fuel Price



4.4 Additional Inputs

4.4.1 Transmission

Transmission inputs were a key aspect of the model set up for the RESOLVE portfolio optimization.

The key transmission constraint captured in RESOLVE and RECAP is the zonal transfer limit between the OPPD system and the broader SPP market. While this interface is composed of multiple transmission lines, for the purpose of the zonal level modeling performed in RESOLVE and RECAP, these lines were condensed into a single zonal transfer constraint, based on OPPD transmission expert's guidance. While RESOLVE had the opportunity to upgrade this zonal limit at a cost of $12,800/MW-yr, it did not find it cost-effective to do so in any of the cases simulated for this study. This fact, however, does not suggest that there are no other scenarios of resource additions and/or load growth whereby upgrading the OPPD to SPP transfer limit may be cost-effective.

The existing transmission characteristics were calculated by OPPD using First Contingency Incremental Transfer Capability (FCITC) and Voltage Stability (PV) analyses performed on SPP regional transmission planning models. They are supported by 3 recent years of data records for OPPD's 345 kV transmission lines' operations and forced outages. Any additional transmission lines modeled to bring new renewable power into the system were subject to the equivalent Forced Outage Rates (FOR) and Mean Times to Repair (MTTR) as those determined for existing lines. The magnitude of forced outage was modeled as 67% of the new line capacity. Forced outages adhering to these assumptions was randomly simulated in RECAP to check and ensure resource portfolios resulting from this study are reliable.

In addition to the zonal transfer limit, the other key treatment of transmission was the transmission costs associated with new candidate resource options. Interconnection costs were paid by all resources interconnecting at new resource sites and were modeled as $202,000/MW based on analysis by OPPD of recent SPP interconnection costs. For new OPPD contracted resources interconnecting to SPP instead of OPPD's system, a transmission deliverability cost adder was developed to estimate the additional cost required to make these resources deliverable to the OPPD system. This cost increased the further the resource additions were from the Omaha region. Transmission costs are summarized in Table 23.

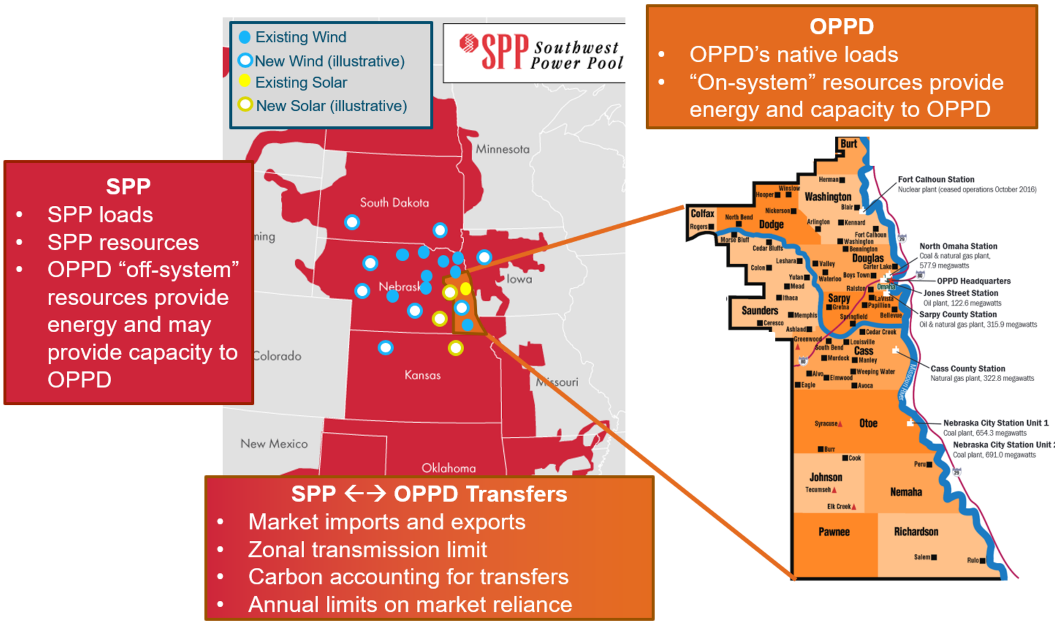
Table 23. Transmission Cost Assumptions for New Resources

Resource Zone	Interconnection Cost ($/MW)	Transmission Deliverability Cost ($/MW)	MISO to SPP, firm ($/MW-yr)	MISO to SPP, non-firm ($/MWh)
OPPD	$202,000	$0		
NE (non-OPPD)	$202,000	$233,000		
KS	$202,000	$314,834		
IA	$202,000	$201,176	$51,913	Hourly on-peak: $10.78 Hourly off-peak: $5.12
MO	$202,000	$463,727		
SD	$202,000	$394,395		
ND	$202,000	$704,683		

4.4.2 Model Topology

The RESOLVE model topology was set up to enable an accurate representation of the zonal transfer limit between the two zones modeled: OPPD and SPP. It also was set up to capture the load-based accounting framework, whereby energy delivered to SPP, either through "exports" of excess generation from OPPD's physical system or from delivery of OPPD contracted resources within the SPP market, is counted as a GHG credit against imported power or on-system emissions. A schematic of the OPPD and SPP model topology, capturing the key treatment of loads, resources, transmission, and carbon accounting is shown in Figure 65.

Figure 65. Overview of SPP and OPPD Zonal Interactions

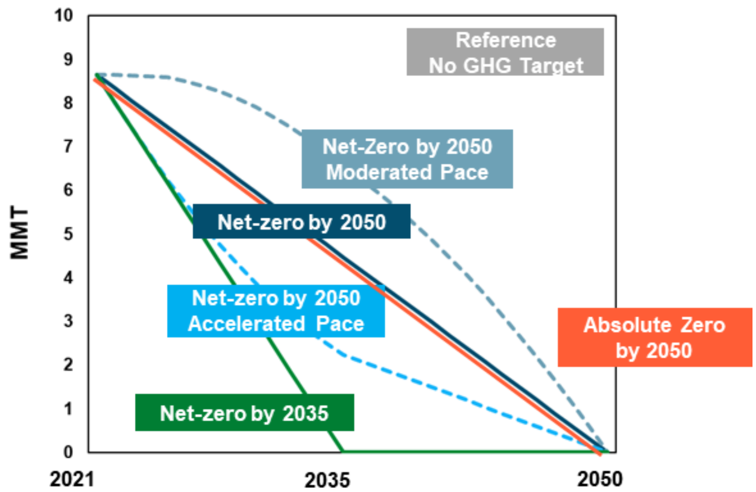


An annual limit on market transfer between the OPPD and SPP region was set based on OPPD guidance. This constraint was set at 30% maximum imports and 10% maximum annual exports, both set relative to OPPD's annual load.

4.4.3 GHG Trajectories

Based on feedback from OPPD staff and stakeholders, the following trajectories of OPPD GHG reduction were modeled in the OPPD portfolio optimization. A reference case had no GHG target modeled, whereby emissions were a model output based solely on economics; this trajectory was used for the Reference scenario. The "straight-line" net zero by 2050 scenario was the base assumption used for most of the decarbonized scenarios considered. However, moderated and accelerated paces by 2050 were also modeled, as was a net zero by 2035 scenario. The "absolute-zero" carbon scenarios modeled all followed the straight-line net zero by 2050 trajectory. The starting point for OPPD's emissions of 8.6 MMT in 2021 was based on analysis of recent trends in OPPD emissions between 2017-2019, landing on the year 2018 as a baseline starting point from which to measure carbon reductions. This value was based on OPPD's 2018 scope 1+2+3 emissions minus half the emissions from Nebraska City 2, since half of that unit is contracted to other load serving entities.

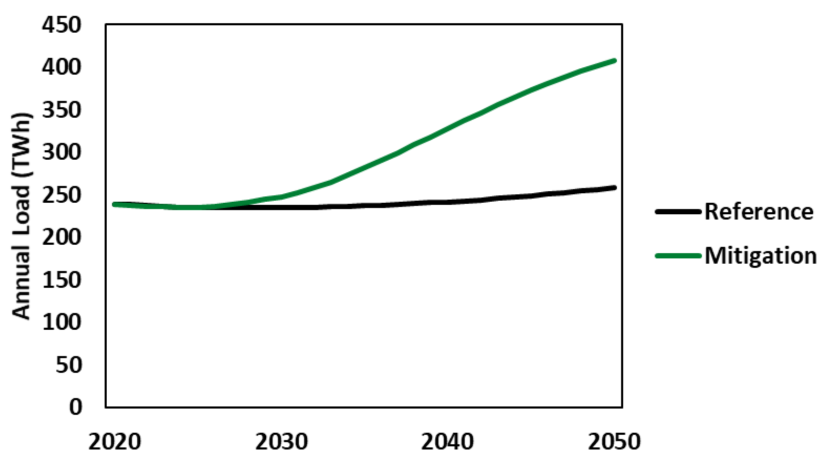
Figure 66. Greenhouse Gas Reduction Trajectories



4.5 SPP Portfolios

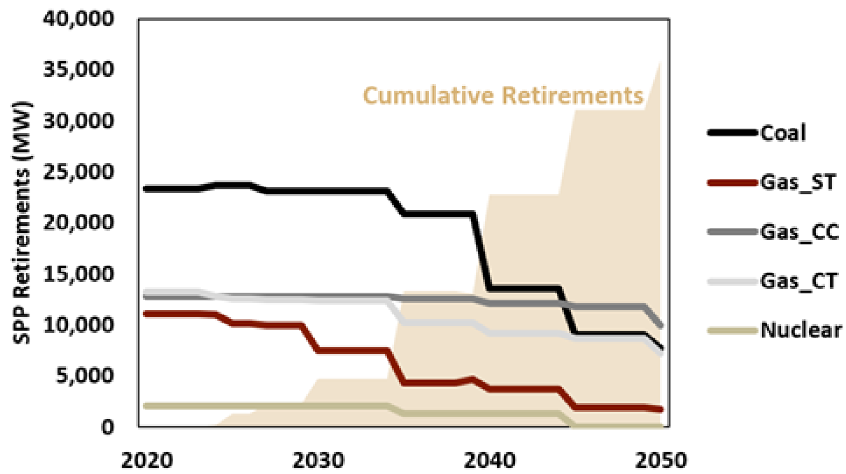
As a member of the broader SPP market, OPPD was co-optimized with SPP in RESOLVE to capture regional interactions. Two scenarios were developed to reflect different SPP future scenarios. The Reference scenario is the "business as usual" scenario where SPP load remains relatively flat and SPP does not pursue any emission reduction goal. The Mitigation scenario is a more aggressive decarbonization future where SPP sees high load growth due to electrification and achieves 90% carbon emission reduction by 2050. Figure 67 shows the annual load in SPP and Figure 68 lays out the retirement schedule assumed in SPP for both the Reference and Mitigation scenarios. The retirement schedule is based on the latest SPP Integrated Transmission Planning Process assumptions[29].

Figure 67. SPP Load Assumptions



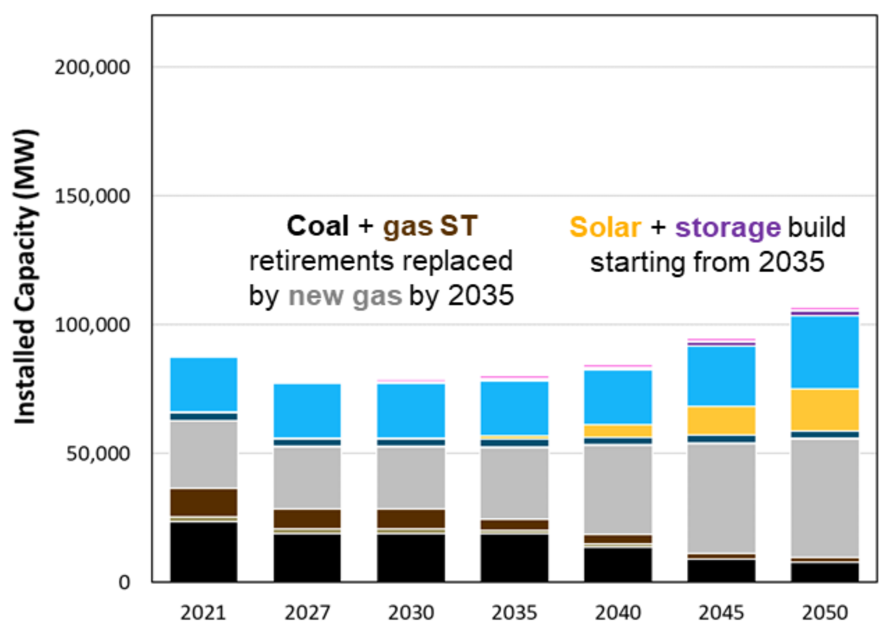
[29] https://www.spp.org/engineering/transmission-planning/integrated-transmission-planning/

Figure 68. SPP Resource Retirement Schedule



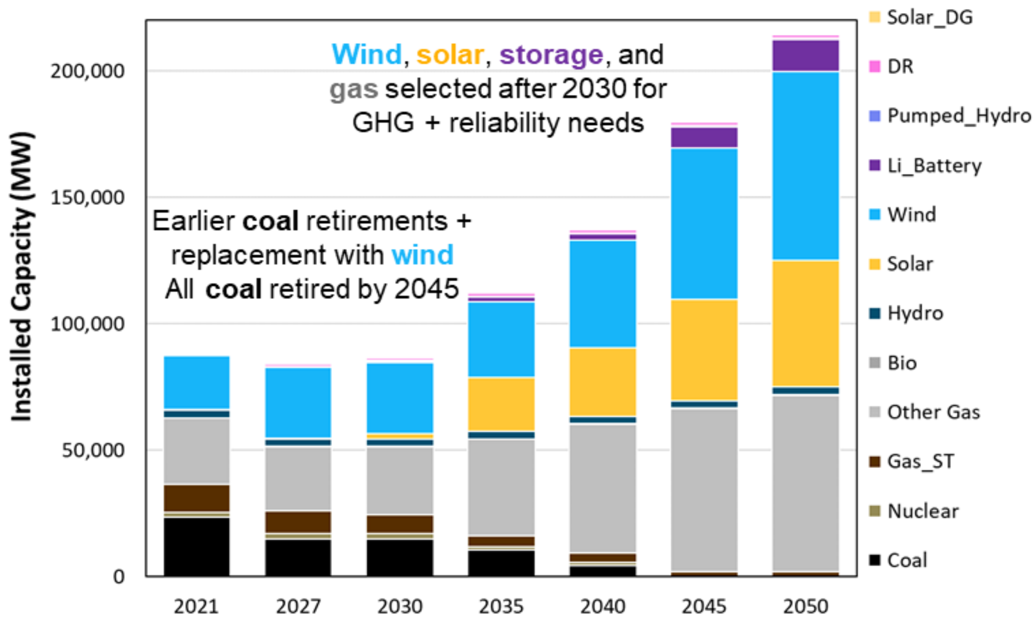
In the Reference scenario, without any emission target and with minimal load growth, SPP is modeled in RESOLVE to build new gas to replace existing coal and older gas retirements for energy and capacity needs. Solar and storage is added starting around 2035 (Figure 69).

Figure 69. SPP Capacity Expansion Results under Reference Scenario



In the Mitigation scenario, with a target of 90% GHG reduction by 2050 and high electrification load growth, SPP will need to retire all the existing coal assets by 2045 and build a large amount of new gas, solar, wind, and energy storage for reliability and GHG reduction needs (Figure 70). Compared to the Reference scenario, the total capacity needs in SPP are almost double in the Mitigation scenario.

Figure 70. SPP Capacity Expansion Results under Mitigation Scenario



The results above do not include the capacity of resources installed in OPPD. In RESOLVE, SPP Reference load was only used in the OPPD Reference scenario and the sensitivity of OPPD meeting net zero under an SPP Resource Portfolio. The SPP Mitigation load was used in co-optimization with all other OPPD Net Zero and Absolute Zero scenarios.

5 Reliability and Resiliency

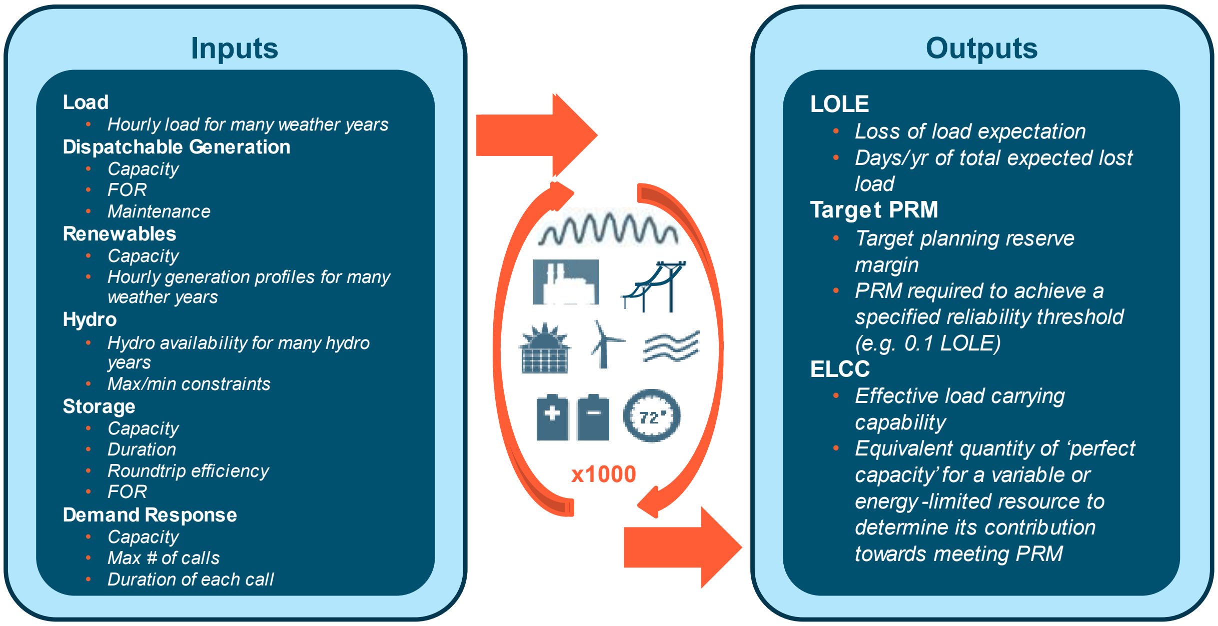
5.1 Reliability Modeling Approach

5.1.1 Model

This study assessed resource adequacy of the OPPD system using E3's Renewable Energy Capacity Planning (RECAP) model. RECAP is a loss-of-load-probability model developed by E3 that has been used extensively to test the resource adequacy of electric systems across the North American continent, including California, Hawaii, Canada, the Pacific Northwest, the Upper Midwest, New England, Texas, and Florida. RECAP was developed by E3 specifically to evaluate the reliability of electricity systems operating under high penetrations of renewable energy and energy storage, which present unique methodological challenges that are not present in the historical reliability planning paradigm.

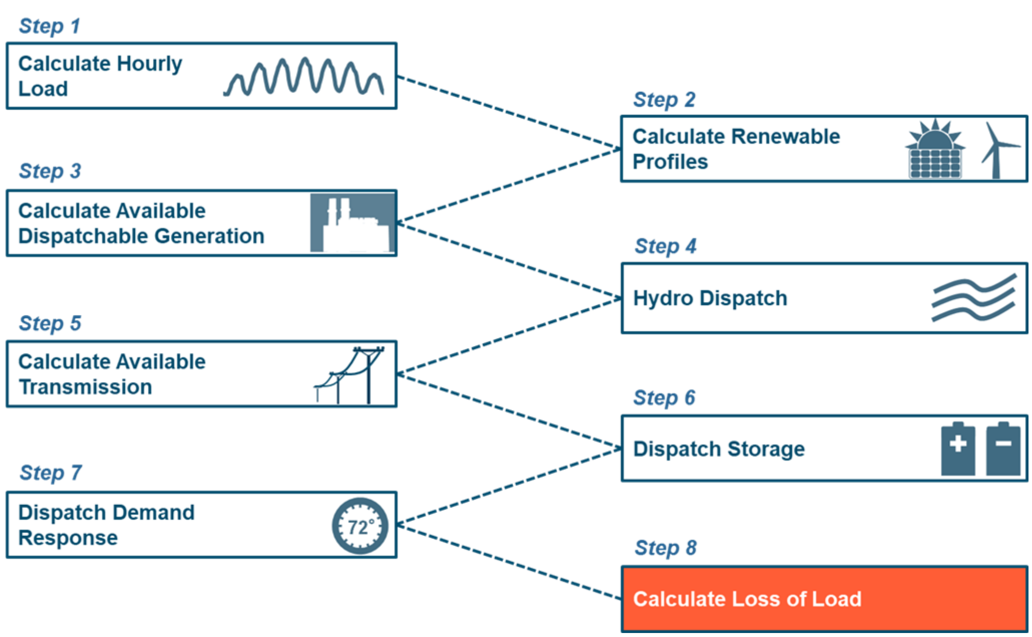
RECAP calculates several metrics related to reliability including loss of load expectation (LOLE), the target planning reserve margin (PRM) required to achieve the target LOLE, and the effective load carrying capability (ELCC) that quantifies the contribution of non-firm resources such as renewable energy and energy storage toward the PRM requirement. RECAP calculates these metrics by simulating electricity system resource availability with a specific set of generating resources (storage and demand-side resources included) and loads under a wide variety of weather-years and renewable generation-years. By simulating the system thousands of times through Monte Carlo analysis with different combinations of these factors, RECAP provides a statistically significant estimation of LOLE. An electricity system with a LOLE that meets or exceeds the 1-day-in-10-year standard is deemed reliable for the purposes of this analysis, using the same reliability standard adopted by SPP. An overview of the RECAP model is shown in Figure 71.

Figure 71. RECAP Model Overview



Several aspects of RECAP are designed specifically to characterize systems operating under high penetrations of renewable energy and storage. Correlations within the model capture linkage between load, weather, and renewable generation conditions. Time-sequential simulation tracks the state of charge for energy-limited dispatchable resources such as hydro, energy storage, and call constraints for demand response. An overview of the RECAP modeling process is shown below in Figure 72.

Figure 72. RECAP Model Simulation Steps



RECAP is used in several capacities throughout the analysis. ***First, it is used to generate the PRM necessary to meet the 0.1 days/yr LOLE target reliability standard***. Second, it is ***used to generate the ELCC values that quantify how non-firm resources such as wind, solar, and energy storage can contribute to the PRM***. Both the PRM and the ELCCs will be inputs for the capacity expansion modelling with RESOLVE. ***Finally, RECAP was used to calibrate the cost-optimal resource portfolio output from RESOLVE to ensure 0.1 days/yr reliability was achieved for the resource portfolios developed***.

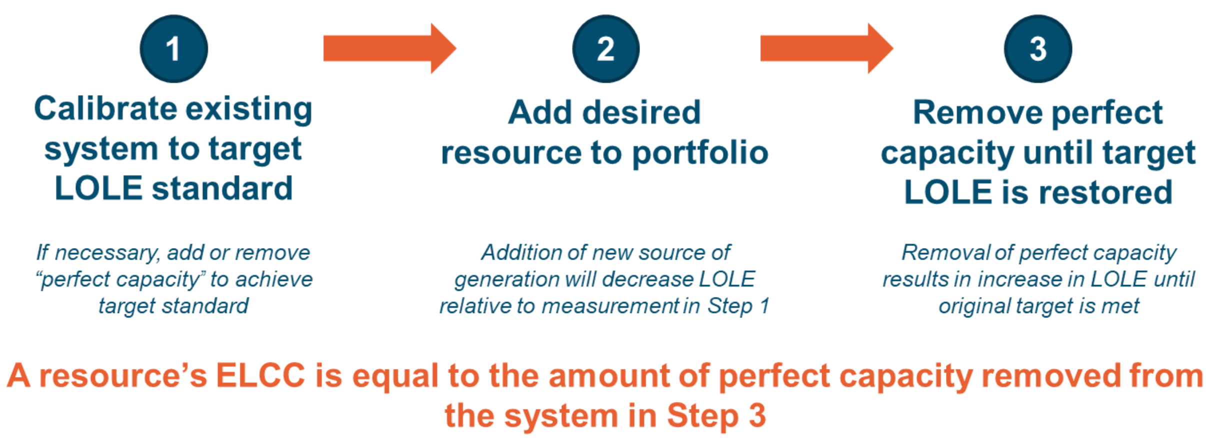
ELCC is the quantity of "perfect capacity" that could be replaced or avoided with renewables or storage while providing equivalent system reliability. A value of 50% means that the addition of 100 MW of a variable resource could displace the need for 50 MW of firm capacity without compromising reliability.

ELCC is calculated via the following steps:

1. Calibrate the base system LOLE to 0.1 days/yr LOLE
2. Add renewable or storage resource(s) to the system and re-calculate LOLE
   + Due to the new resource(s), available generation in each hour is now greater than or equal to the base system which improves reliability (i.e. decreases LOLE)
3. Remove perfect capacity from the system until reliability returns to 0.1 days/year LOLE
   + Removing perfect capacity to the system reduces reliability (i.e. increases LOLE)

This process is illustrated in Figure 73.

Figure 73. Overview of Modeling Steps to Calculate Resource ELCC



5.1.2 Scenarios

E3 modeled four different load scenarios from the multi-sectoral analysis to calculate the target planning reserve margin for OPPD's system. Table 24 includes the high-level descriptions of each scenario. More details can be found in the Multi-Sectoral Modeling Results report.

Table 24. High-Level Descriptions of Scenarios

Scenario	Description	Economy-Wide GHG Reduction	OPPD GHG Reduction	Electricity Demand	Natural Gas Demand
Reference	OPPD net zero Current trends in other sectors	**50%**	**Net zero**	**Medium**	**High**
Moderate Decarbonization	OPPD net zero Moderate GHG reductions elsewhere	**60%**	**Net zero**	**Medium-High**	**Medium**
Net Zero: Balanced	Economy-wide net zero with reliance on cost-effective electrification and zero-carbon fuels elsewhere	**Net zero**	**Net zero**	**High**	**Low**
Net Zero: High Electrification	Economy-wide net zero with high electrification for transportation, buildings, and industry	**Net zero**	**Net zero**	**Very High**	**Low**

5.1.3 Capturing the Benefits of SPP Market Participation

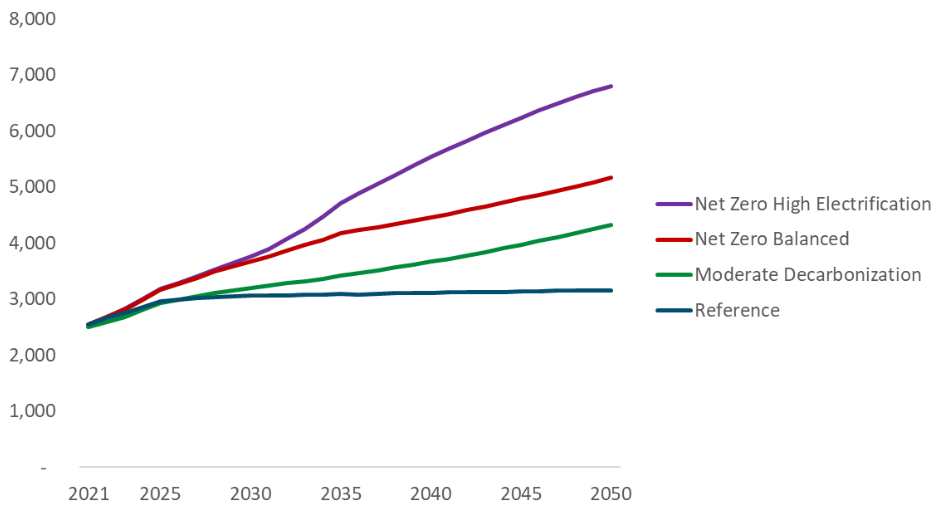
OPPD participates in the SPP regional market. Participants in the SPP market obtain load and resource diversity benefits from being a part of a geographically diverse market. For example, the peak loads of SPP entities can occur at different times due to differences in locations and load profiles. Excess generation capacity in one zone can be used to serve loads in another zone during peak hours instead of building new generation capacity in that zone. Moreover, the diverse resources in SPP's footprint can better respond to emergency events such as a loss of a generator than a single entity alone, whereby a single generator outage may cause loss of load. In this study, OPPD's thermal resources were modeled at their UCAP ratings without randomly simulated outages, assuming the SPP market would have enough resource diversity across its footprint such that shortfalls caused by OPPD resource outages can be filled from other SPP generators. These assumptions lead to lower reliability resource needs for OPPD's system compared to if the benefits of SPP were not captured in this analysis.

5.2 Reliability Modeling Results

5.2.1 Peak Load Forecasts across Scenarios

Figure 74 shows the annual peak loads calculated from the RECAP model. The most aggressive scenario, Net Zero High Electrification, has a system peak that is more than twice that of the Reference case.

Figure 74. Peak Loads by Scenario (Median 1-in-2 Peak MW)



5.2.2 Planning Reserve Margin

A loss of load probability model like RECAP can be used to calculate the total effective capacity (i.e. perfect capacity equivalent MW) needed to achieve a given reliability standard. This total reliability need can then be expressed as the "planning reserve margin", a heuristic that measures the reliability need as a reserve margin above the median system peak. SPP currently uses an installed capacity (ICAP) based PRM, which is higher because generator outages are accounted for in the reserve margin. E3 used an unforced capacity (UCAP) based PRM in this study, which allows for a lower reserve margin by accounting for generator outages in the resource accounting, rather than the reserve margin.

Table 25 shows the calculated PRMs to ensure a 1-day-in-10-year reliability standard, or 0.1 LOLE, for the four load scenarios in 2050. The Reference, Moderate Decarbonization, and Net Zero Balanced scenarios have a similar PRM of around 7%. This requirement roughly translates to an ICAP-based PRM in the 10% to 12% range, similar to SPP's current requirement for OPPD. The Net Zero High Electrification scenario has the highest PRM of 17%. Significant electrification of weather-related end-uses can lead to the load during the worst heatwaves and cold-spells to be much larger than the median peak. As discussed in the Multi-Sectoral Modeling Results report, fully electrifying building space heating in the Net Zero High Electrification scenario leads to the highest load impacts and causes OPPD to switch from summer-peaking to winter-peaking. The PRM required to meet the 0.1 LOLE target varies as the level of electrification increases over time. Table 26 shows the PRM in 2030, 2040, and 2050 for this scenario.

Table 25. Planning Reserve Margin Requirement in 2050

Metric	Units	Reference	Moderate Decarbonization	Net Zero: Balanced	Net Zero: High Electrification
Expected System Median Peak	MW	3,157	4,323	5,162	6,803
UCAP Planning Reserve Margin	%	7%			17%

Table 26. Planning Reserve Margin Requirement for Net Zero: High Electrification

Metric	Units	2030	2040	2050
Expected System Median Peak	MW	3,759	5,530	6,803
UCAP Planning Reserve Margin	%	7%	16%	17%

5.2.3 Effective Load Carrying Capability (ELCC)

Figure 75 shows the ELCC provided by solar, wind, and storage in the Net Zero Balanced scenario. It also highlights the diminishing ELCC with increasing penetration of these resources. The diminishing returns for renewable resources are due to saturation of production during high load hours and the shift of net peak to hours with little to no renewable production. For battery storage, the diminishing value is due to peak-clipping. The net peak that remains after a tranche of storage is dispatched, is longer in duration (see Figure 76). This limits the incremental value that the next tranche of storage can bring. Solar availability is generally larger than wind during OPPD's peak load hours, resulting in a higher ELCC for the former at low penetrations.

Figure 75. Average ELCC of Solar, Wind, and Storage Resources

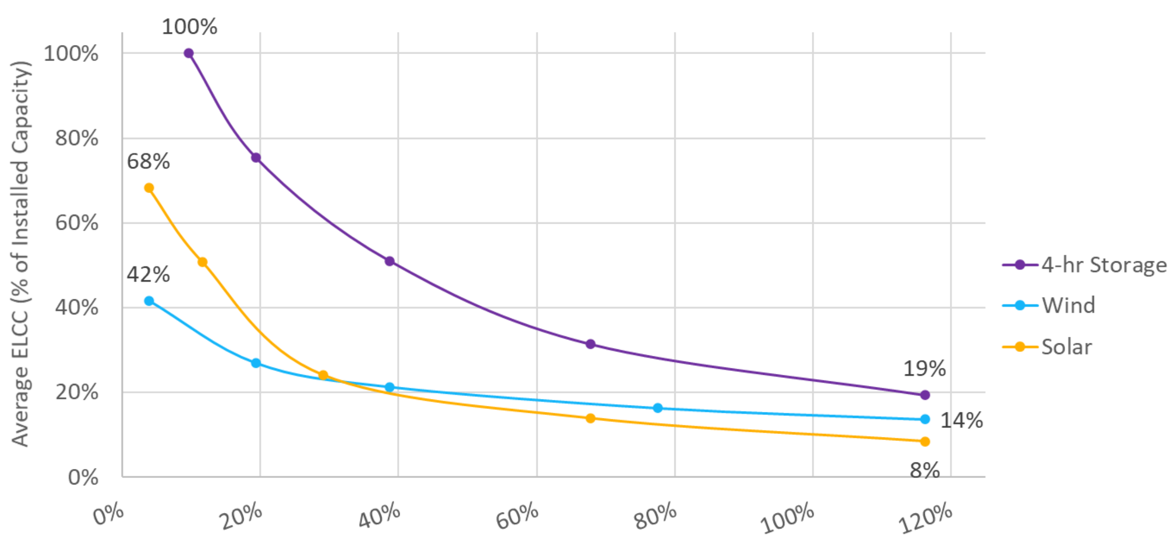
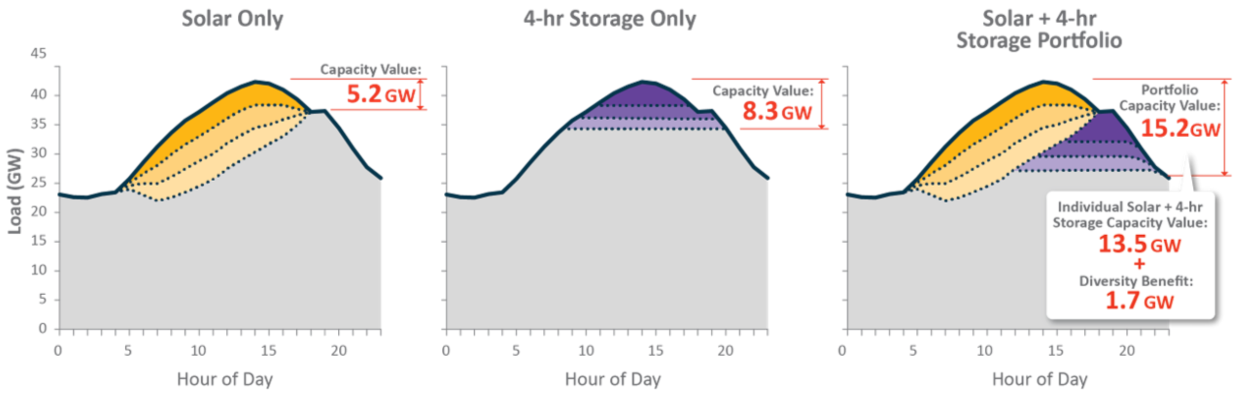


Figure 76. Illustrative Solar and Storage ELCC



While resources with similar operating characteristics yield diminishing returns, combining resources with complementary characteristics can yield a total ELCC that is greater than the sum of its parts. This effect has commonly been described as a "diversity benefit" in jurisdictions that have explored ELCC implementation. Solar and storage typically produce such an effect (see Figure 76). This is because solar acts to "sharpen" the shape of the net peak demand, reducing the length of the period during which storage must discharge to reduce the peak, in addition to providing a source of energy for charging. Table 27 shows the total ELCC provided by solar and storage resources and Table 28 shows the diversity benefit. Total ELCC = ELCC of solar alone + ELCC of storage alone + diversity benefit.

In this study, E3 accounted for this diversity benefit by developing a solar-storage ELCC surface and included this surface in the resource portfolio optimization analysis. Figure 77 illustrates the ELCC surface for solar and storage conceptually, where the x-axis and y-axis correspond to solar and storage capacity and the z-axis corresponds to the total ELCC in MW. E3 used the ELCC for various penetration levels of solar and storage capacity to trace out the surface. Because the two resources are being added together to the system in the portfolio optimization analysis, the ELCC captures any diversity benefits.

In addition to the ELCCs of renewable and storage resources, E3 also calculated the ELCC of demand response programs. The RECAP model dispatches demand response if there is insufficient energy storage to meet load and reserve requirements. Demand response is the resource of last resort since demand response programs often have a limitation on the number of times they can be called upon over a set period of time. For this study, demand response was modeled using a maximum of 3 to 15 calls per year, with each call lasting for a maximum of 3 to 10 hours, depending on the specific OPPD program. The resulting ELCC of demand response programs was 85%.

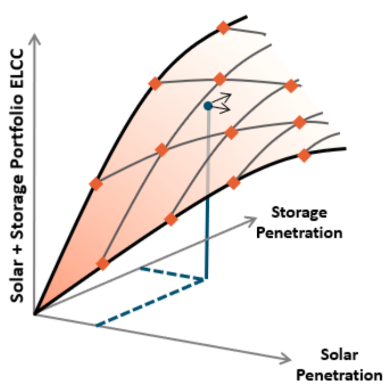
Table 27. Solar and Storage Total ELCC[30]

ELCC (MW)		Solar Installed Capacity (MW)							
		0	**1,500**	**2,500**	**3,500**	**4,500**	**6,000**	**7,500**	**10,000**
4-hr Storage Installed Capacity (MW)	**0**		344	348	351	353	354	356	357
	500	488	841	846	847	850	852	852	852
	1,000	732	1,303	1,344	1,346	1,352	1,353	1,354	1,355
	2,000	1020	1,535	1,735	1,819	1,858	1,894	1,927	1,968
	3,500	1093	1,610	1,846	1,907	1,942	1,995	2,036	2,097
	6,000	1156	1,676	1,904	1,976	2,027	2,093	2,150	2,229
	10,000	1236	1,747	1,947	2,029	2,102	2,186	2,257	2,365

Table 28. Solar and Storage Diversity Benefits

Diversity Benefits (MW)		Solar Installed Capacity (MW)							
		0	**1,500**	**2,500**	**3,500**	**4,500**	**6,000**	**7,500**	**10,000**
4-hr Storage Installed Capacity (MW)	**0**								
	500		9	10	8	9	10	9	8
	1,000		227	264	263	267	268	266	267
	2,000		171	367	448	485	521	551	592
	3,500		172	405	462	497	548	587	647
	6,000		176	401	469	518	583	638	716
	10,000		167	363	442	513	596	666	772

Figure 77. Illustrative Solar and Storage Surface



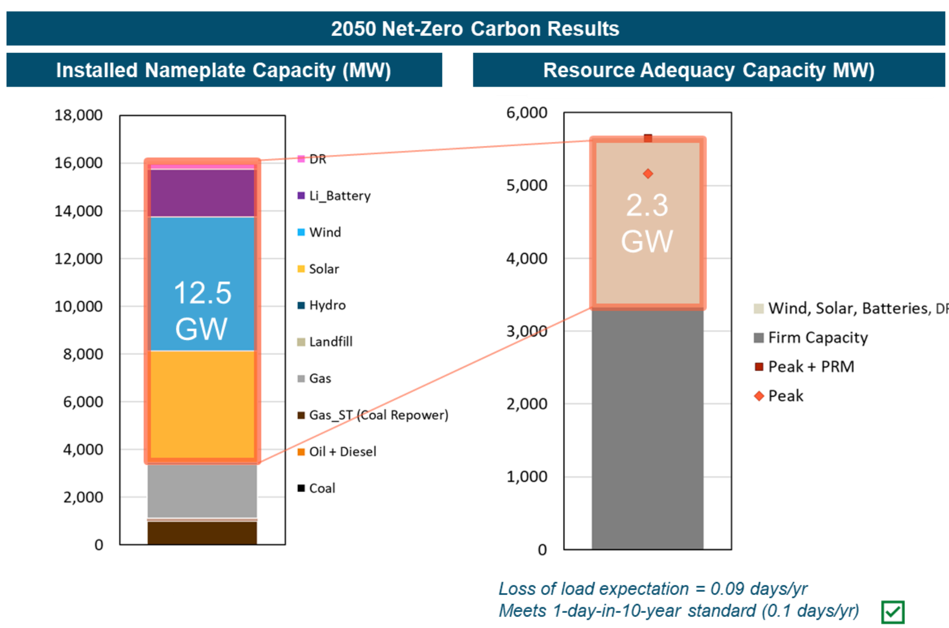
[30] Values only include the interactions between solar and storage resources. The actual values used in the resource portfolio optimization analysis include interactions with other resources, such as hydro, wind, and demand response.

5.2.4 Net Zero Carbon Base Scenario Reliability Results

The RESOLVE capacity expansion model used the reliability need (PRM) and ELCC results above, as well as other inputs, to develop the optimal resource mix for OPPD[31]. The reliability of the Net Zero Carbon Base portfolio developed by RESOLVE was checked using the RECAP model to ensure it met the 1-day-in-10-year loss of load expectation standard when assessed against RECAP's probabilistic simulation over 40 weather years. A calibration between the two models was performed using preliminary 2030 and 2050 RESOLVE portfolios. It was found that updates were needed for RESOLVE to add additional resources to meet <0.1 days/yr LOLE. During this calibration, E3 updated the ELCC input formulas into RESOLVE and modeled a slightly increased PRM by 2050.

After completing these calibration activities, the results show that the final net zero carbon base scenario portfolio from RESOLVE can reliably serve OPPD's needs and meet the 1-day-in-10-year reliability standard (0.1 days/yr) set by SPP. The 12.5 GW of renewables built by 2050 can contribute around 2.3 GW of resource adequacy capacity, however additional resource adequacy capacity was needed to meet the 2050 peak of 5.2 GW, plus a PRM. RESOLVE's least-cost solution to meet the total RA capacity need included maintaining existing firm capacity and adding new firm capacity resources to meet the rest of the resource adequacy needs due to the saturation of solar, wind and battery storage resources (see Figure 78).

Figure 78. Resource Adequacy Capacity in the Net Zero Carbon Base Scenario (2050)

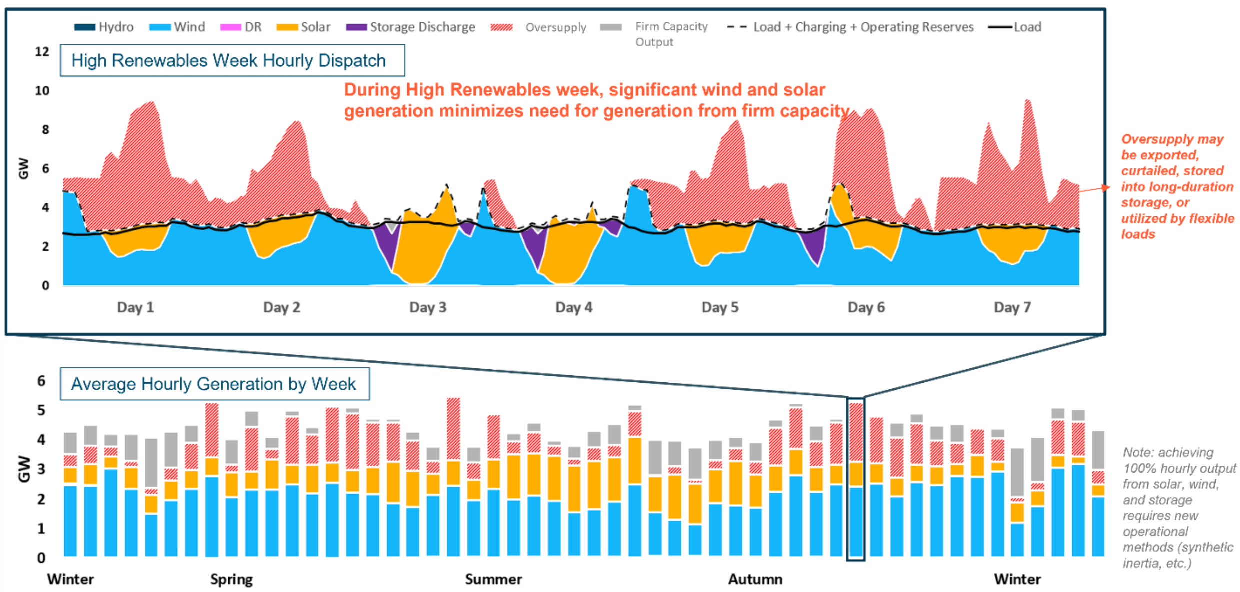


The Net Zero Carbon Base Scenario portfolio contains a significant amount of renewable capacity, selected by the model to achieve the net zero carbon emissions reduction target. In many weeks of the year when solar and wind are producing at average or above average output, the generation from these

[31] For detailed information on the RESOLVE model and the Net Zero Carbon Base Scenario assumptions, please refer to the Portfolio Optimization section of the report.

resources, in conjunction with energy storage on the system, is sufficient to meet most, if not all, of OPPD's energy needs. A typical week with sufficient renewable energy is shown in Figure 79. Though renewables and storage are non-firm resources, during these conditions OPPD's system can operate many days with solely those resources. However, during weeks with prolonged low renewable output, it becomes necessary to dispatch firm capacity resources as shown in Figure 80. In this example, all firm capacity retained or added by RESOLVE (~3GW) is needed to maintain reliability during the "dunkelflaute"[32] conditions where solar and wind production is low.

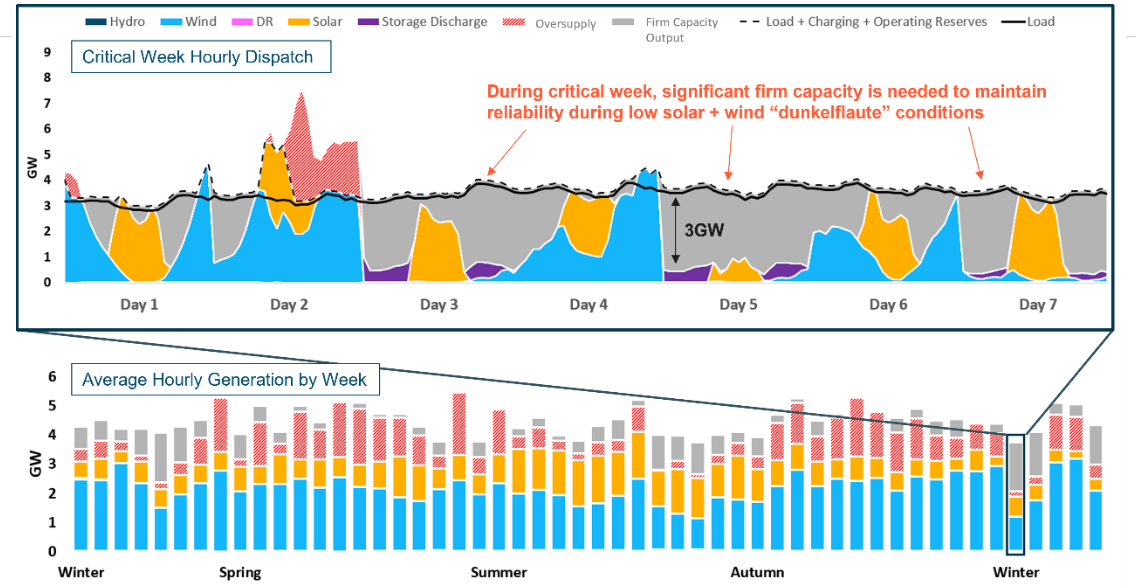
Figure 79. Resource Availability Dispatch over a High Renewable Week in 2050 in the Net Zero Carbon Base Scenario[33]



[32] Dunkelflaute is a German word meaning "dark doldrums", describing an extended period of low wind and solar output. These are also referred to "renewable droughts".

[33] The figure reflects one specific realization among several RECAP simulations of the year 2050 under different weather conditions and resource availability.

Figure 80. Resource Availability over a Critical Renewable Week in 2050 in the Net Zero Carbon Base Scenario[33]



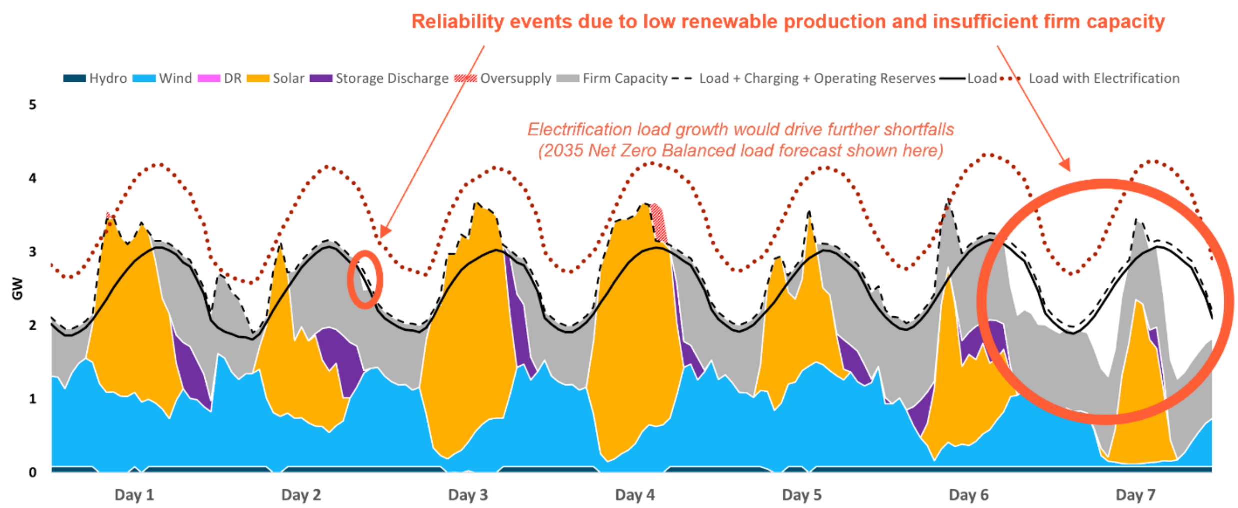
In addition to the Net Zero Carbon Base portfolio, E3 also modeled – at the recommendation of OPPD stakeholders – the reliability of another sensitivity scenario, the "No New Firm Capacity" sensitivity. This 2035 case assumed full coal retirement, no new firm resource additions (including Power with Purpose assets), no electrification load growth, and additional energy efficiency. The comparison of the two cases' reliability results is shown in Table 29. The sensitivity case does not meet the 1-day-in-10-year or 0.1 days per year target and, without any firm capacity additions, is much less reliable than the Net Zero Carbon Base portfolio. Figure 81 shows an example of the reliability challenges that the sensitivity portfolio faces during a summer week, when lack of firm capacity leads to major energy shortfalls with three days of lost load. The energy shortfall would be further increased if electrification load growth was included. Thus, firm resources will still play an important role in ensuring reliability as OPPD transitions to net zero, even as their utilization decreases as renewable energy makes an increasing share of OPPD's annual generation.

Table 29. Net Zero Carbon Base Scenario and No New Firm Sensitivity Scenario Reliability Results

Reliability Metrics	Net Zero Carbon Base Scenario (2030)	Net Zero Carbon Base Scenario (2050)	No New Firm Capacity Sensitivity Case (2035)
Loss of load expectation (days/year)	0.07 *(meets 0.1 target)*	0.09 *(meets 0.1 target)*	65 *(exceeds 0.1 target)*
Loss of load hours (hours)	0.11	0.26	365
Expected unserved energy (MWh/year)	10	74	144,000

Perfect capacity shortfall vs. 1-day-in-10-year loss of load expectation (MW)	-28	-10	670

***Figure 81. Illustrative Dispatch over a Summer Week in 2035 in the No New Firm Capacity Sensitivity Scenario*[33]**



5.3 Resiliency

In addition to reliability analysis, this study considers the resiliency of the OPPD system during disruptive events. Grid resiliency is becoming an increasingly important topic in the industry as extreme events are becoming more frequent and more impactful in a changing climate. The following sections describe the overall approach that was used to incorporate resiliency into this analysis, the definition of resiliency, a resiliency threat analysis for OPPD, and resiliency cases studies on OPPD's 2050 net zero carbon system.

5.3.1 Overall Approach to Incorporating Resiliency

The resiliency analysis included the following steps:

+ **Literature Review**: E3 reviewed literature on resiliency definitions, resiliency planning frameworks, and related current industry practices.
+ **Threat Analysis**: E3 created a matrix that considered a wide array of resiliency threats and their frequency, impact, and mitigation solutions.
+ **Case Studies**: E3 and OPPD developed case studies to examine specific threats identified in the threat analysis and assessed resiliency investments to mitigate those threats.

5.3.2 Resiliency Definition + Literature Review

Resiliency is a system attribute of increasing importance without a single, uniform definition. After reviewing the definitions proposed by many organizations in the industry (see Table 30), E3 supports OPPD's definition:

> ***Resiliency is the ability of the system and its components to prepare, withstand, respond, adapt, and quickly recover following a non-routine, high-impact disruption.***

Table 30. Resiliency Definitions

Organization	Resiliency Definition
Federal Energy Regulatory Commission (FERC) **National Infrastructure Advisory Council (NIAC)**	The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event.[34]
National Association of Regulatory Utility Commissioners (NARUC)	Robustness and recovery characteristics of utility infrastructure and operations, which avoid or minimize interruptions of service during an extraordinary and hazardous event.[35]
Department of Energy (DOE)	The ability of a power system and its components to withstand and adapt to disruptions and rapidly recover from them.[36]
Electric Power Research Institute (EPRI) **North American Transmission Forum (NATF)**	The ability of the system and its components (that is, both the equipment and human components) to minimize damage and improve recovery from nonroutine disruptions, including high-impact, low-frequency (HILF) events, in a reasonable amount of time.[37]
Grid Modernization Laboratory Consortium	The ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions, including the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents.[38]

[34] "Docket Nos. RM18-1-000 and AD18-7-000," Federal Energy Regulatory Commission, 2018, https://cms.ferc.gov/sites/default/files/2020-05/20180108161614-RM18-1-000_3.pdf

[35] "Resilience in Regulated Utilities," The National Association of Regulatory Utility Commissioners, 2013, https://pubs.naruc.org/pub/536f07e4-2354-d714-5153-7a80198a436d#:~:text=Resilience%20%2Fri%CB%88zily%C9%99ns%2F%20noun%2C%20regulatory,an%20extraordinary%20and%20hazardous%20event.

[36] "Resilience Framework Methods, and Metrics for the Electricity Sector," IEEE Power & Energy Society, 2020, https://www.naesco.org/data/industryreports/DOE-IEEE_Resilience%20Paper_10-30-2020%20for%20publication.pdf

[37] "Transmission and Distribution Resiliency: What's Going on, and What is EPRI Doing to Help," Electric Power Research Institute, 2019, https://www.epri.com/research/products/3002015363

[38] "Grid Modernization: Metrics Analysis (GMLC1.1) – Resilience," Pacific Northwest National Laboratory, 2020, https://gmlc.doe.gov/sites/default/files/resources/GMLC1.1_Vol3_Resilience.pdf

Figure 82 illustrates system performance before, during, and after a disruptive event. A resilient system should have the resources and procedures to withstand a disruptive event and quickly restore the system to its targeted performance.

Figure 82. System Performance Before, During, and After a Disruptive Event

Disruptive events in the resiliency context are generally non-routine and high-impact extreme events, also known as high-impact, low-frequency events (or HILFEs). In a changing climate, extreme weather events are more frequent and impactful.[39] They are also rising in duration and geographic scope.[39] Traditional planning analysis typically uses historical weather data and investigates system operations under normal conditions. However, this approach is likely to underestimate the impacts of today's and tomorrow's extreme events.[39] Some utilities have started to incorporate long-term climate forecasts in their planning processes. For example, Consolidated Edison has looked at climate projections in its service area and expects its electric system's summer peak to increase by 700 MW to 900 MW due to temperature increase by 2050.[40] In addition to changes in electricity demand, extreme events can lead to physical damages and operational disruptions to specific assets, reduced generation efficiency and capacity, reduced transmission transfer capability, reduced fuel supply, etc. Analyzing and planning for these potential disruptions can help increase grid resilience.

It is also important to note that disruptive events can impact not only one but multiple components on the system at the same time. Current resource adequacy planning often assumes outages are independent and uncorrelated.[39] Deterministic transmission reliability analyses consider only a discrete set of contingencies that may not align with extreme events. Past assumptions may no longer be appropriate as more weather-dependent renewable resources come online and as extreme events rise in duration and geographic scope.[39] Furthermore, extreme events may not only impact assets within the

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[39] "Exploring the Impacts of Extreme Events, Natural Gas Fuel and Other Contingencies on Resource Adequacy," Electric Power Research Institute, 2021, https://www.epri.com/research/products/000000003002019300

[40] "Climate Change Resilience and Adaptation: Summary of 2020 Activities," Consolidated Edison Company of New York, 2021, https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/climate-change-resiliency-plan/climate-change-resilience-adaptation-2020.pdf

electric system, but also related infrastructure, such as natural gas, telecom, water, etc., that have interdependencies with the electric system.[36] For example, during the February 2021 Polar Vortex event in Texas, thermal and renewable resources, as well as natural gas supply were all impacted by the cold weather, causing significant electricity supply shortfalls and rolling blackouts. Water infrastructure was damaged by extended electricity outages, exacerbating social harm.

These types of correlated outages during "common mode events" should be considered when planning for a resilient grid. One approach to evaluate system's robustness against these events is to model specific worse-case scenarios. For example, NREL explored ways to integrate resiliency consideration into its Probabilistic Resource Adequacy Suite model by simulating a multiday fuel supply disruption that forced gas units offline in a system.[41] The analysis quantified the unserved energy in that system under different storage capacity to evaluate the impacts of adding storage resources to ride through that extreme event.[41] The Climate Change Impact Study for the New York Independent System Operator modeled several climate disruption scenarios that increased demand and/or impacted resources and transmission lines' availability.[42] It identified vulnerabilities of renewable-heavy systems to certain climate disruptions.[42] Modeling these worst-case scenarios can be an important tool to help utilities understand system vulnerabilities.

Another aspect to consider while evaluating the impacts of resiliency threats and system vulnerability is the economic consequence of unserved loads and damages to assets. It helps quantify the value of resiliency improvements and guide investments. The average estimates of the cost of unserved energy range from $2,000/MWh to $20,000/MWh in the Unites States, although the actual cost can vary significantly by the end use, consumer type, time period, etc.[41] Using average values might not lead to an accurate valuation of resiliency improvements. Furthermore, the traditional static value of lost load might no longer be adequate in resiliency planning as extreme events can cause long-duration power interruptions.[41] Understanding the time-dependence of the value of lost load becomes important, as lost load during life-threatening extreme weather may have a much higher cost.[41] Capturing the true cost of disruptions will allow utilities to determine cost-effective resiliency measures.

Different resiliency investments exist for different components of the electric system. For example, electricity supply resiliency strategies include hardening generators to reduce outages, assuring fuel security, adding backup fuel for redundancy, and increasing local supply such as distributed energy resources and microgrids.[43] To improve the resiliency of transmission and distribution infrastructure, measures include hardening poles and wires, adding network redundancies, and increasing local resource supply closer to customer load pockets.[43] In terms of communications resiliency, improvement opportunities include enhancing cyber security and creating reliable network architecture and

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[41] "Adapting Existing Energy Planning, Simulation, and Operational Models for Resilience Analysis," National Renewable Energy Laboratory, 2020, https://www.nrel.gov/docs/fy20osti/74241.pdf

[42] "Climate Change Impact Phase II: An Assessment of Climate Change Impacts on Power System Reliability in New York State," Analysis Group, 2020, https://www.nyiso.com/documents/20142/15125528/02%20Climate%20Change%20Impact%20and%20Resilience%20Study%20Phase%202.pdf/89647ae3-6005-70f5-03c0-d4ed33623ce4

[43] "Power System Supply Resilience: The Need for Definitions and Metrics in Decision-Making," Electric Power Research Institute, 2020, https://www.epri.com/research/programs/0TIZ12/results/3002014963

communications.[43] Resiliency strategies should target towards specific risks and vulnerabilities that a system encounters, which will vary across energy systems.

In summary, planning for a resilient system involves the following steps:

+ **Threat Assessment**: understand the exposure of assets to resiliency threats, their vulnerabilities, and the consequences of asset failure.
+ **Resiliency Plan**: identify and assess resiliency measures and prioritize investments that mitigate the most critical vulnerabilities.
+ **Periodic Updates**: monitor progress and re-assess vulnerabilities and resiliency measures based on new information.

Resiliency planning can complement existing utility risk management strategies, adapting asset planning to better consider extreme weather events.

5.3.3 Reliability vs. Resiliency

Resiliency is one aspect of the broader scope of reliability planning performed by utilities and grid operators. Reliability also encompasses both operational reliability assessments and resource adequacy assessments. Operational reliability assessments are typically deterministic studies using detailed production simulation modeling to assess operational feasibility and costs, ramping needs, and flexibility, or using power flow modeling to assess steady state and dynamic thermal, voltage, and frequency requirements. Resource adequacy assessments, as described earlier in this section, are probabilistic resource availability simulations across a broad range (typically decades) or expected weather conditions.

Resource adequacy modeling is the established framework for ensuring resource sufficiency across a broad range of weather conditions, using probabilities and correlations of weather, load, generator and transmission outages, and renewable output. However, this framework is only effective when the probabilities of certain events are well known. Resource adequacy modeling can be improved to better capture correlations with extreme weather conditions, such as generator de-rates or common mode outages. However, certain extreme conditions are better studied under scenario analysis, as a complement to resource adequacy modeling when the frequency and impact of those extreme conditions are not well understood. For instance, the fuel supply disruption of February 2021 must be studied as a key resiliency threat, but it is unclear whether those events will occur every 5 years, every 10 years, or every 30 years. In part, it will depend on not just resource adequacy investments made (e.g. a higher PRM leading to more resource additions) but on resiliency investments outside the electric system (e.g. hardening of natural gas fuel delivery infrastructure.

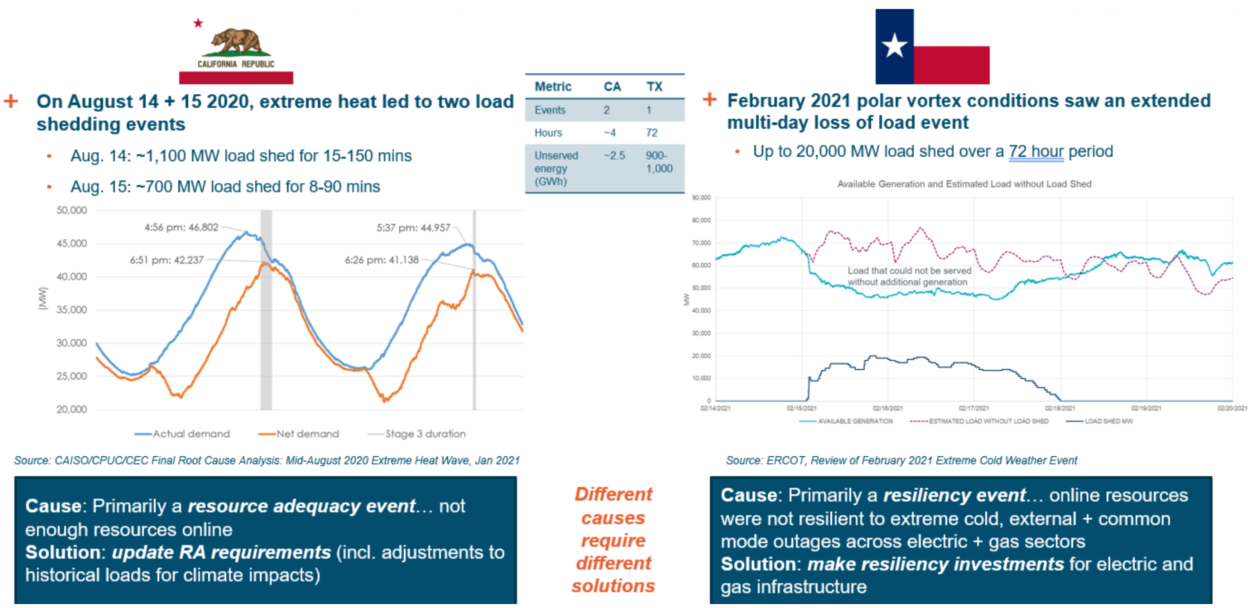
Table 31. Events Captured in Resource Adequacy (LOLP) Modeling vs. Resiliency Planning

Events captured in LOLP modeling	Events that COULD POTENTIALLY BE captured in LOLP modeling	Resiliency events not appropriately captured in LOLP modeling
Extreme load/renewable events based on **historical conditions**	Extreme load/renewable events based on **future weather incl. climate impacts**	Specific **worse case scenarios**

Randomly simulated outages	Correlated outages	**External or common mode events** beyond electricity (e.g. gas fuel supply during a polar vortex, natural disasters, etc.)
The frequency, magnitude, and duration of **expected loss of load events**		The **ability to withstand and recovery from the loss of load events** modeled

Not all events are clearly a "resource adequacy" event versus a "resiliency event". However, past events can be analyzed based on their primary causes and the necessary solutions. Figure 83 compares recent outage events in California and Texas. The California event stemmed primarily from a lack of resource adequacy resources during very hot weather conditions, requiring updates to the state's resource adequacy planning approach. The Texas event saw a common mode failure across both electric and gas delivery systems, requiring more targeted resiliency investments.

Figure 83. Comparison of Recent California and Texas Outage Events



5.3.4 Resiliency Threat Analysis

Resiliency threats can broadly be categorized into three categories: (1) natural threats such as extreme heat and cold weather events, (2) technological threats such as equipment failures, (3) human-caused threats such as cyberattacks. E3 developed a matrix that considered these resiliency threats and their frequency, impact, and solutions for the OPPD system (see Table 32).

Table 32. Resiliency Threat Matrix

Type of Threat	Specific Threats	Frequency	Impact	Solutions
Unplanned outages	• Unanticipated equipment mechanical failure (transmission or generation)	Mid	High	• Gather and incorporate known failure rate data in planning models ($) • Asset specific recovery planning (varied $)
	• Natural disasters (floods, tornados, etc.)	Low	High	• OPPD input needed on key risks and solutions for various assets ($-to-$$$)
Extreme winter weather	• Polar vortex driven winter load	Low	High	• Incorporate historical polar vortex conditions into LOLP simulations and build capacity as needed ($)
	• External or common mode events (multiple generator outages or combined gas/electric system failures)	Low	Very High	• On-site fuel storage ($$) • Plant (+ fuel supply) winterization ($$)
	• Wind turbine icing	Low	Mid	• Invest in de-icing technology for new wind farms ($)
	• Solar snow cover losses	Mid	Mid	• Build tracking instead of fixed tilt PV (none-to-$)
Extreme summer weather	• Extreme heat load impacts (incl. climate impacts)	High	High	• Incorporate historical extreme heat conditions into LOLP modeling and build capacity as needed ($$) • Incorporate climate impacts ($, but data challenges)
	• Thermal plant de-rates or heat-related outages	Mid	Low	• Generator hardening investments ($$)
Energy sufficiency	• Multi-day "dunkelflaute" low wind and/or solar events	Low	High	• Firm capacity provision in net-zero pathways ($$$)
Impacts of electrification	• Electric reliability threats to mobility and winter heating/safety	Mid	High	• Gaseous fuel backup for heat pumps ($$) • Increased winter reserve margins ($$) • New utility/RTO programs for flexible EVs / VGI (varied $)
Cybersecurity Risk	• Critical systems taken offline by nefarious actor	N/A (out of scope)	High	• N/A (out of scope)

5.3.5 Resiliency Case Studies

Based on the threat analysis, E3 examined case studies on the net zero carbon system for the following key resiliency threats:

+ Extended low wind and solar output
+ Extreme summer heat
+ Extreme winter cold (polar vortex)
+ Extreme localized events (tornadoes, floods)

These case studies included a mix of quantitative and qualitative analysis and focused on a single portfolio, the 2050 Net Zero Carbon Base portfolio identified in the Portfolio Optimization workstream. Figure 78 shows the resource mix of the portfolio. This portfolio meets the 1-day-10-year (i.e. 0.1 LOLE) reliability standard in RECAP simulations based on historical weather. The resiliency case studies, except for the extended low wind and solar output case study, built upon RECAP simulations and traditional resource adequacy modeling approaches, and examined a broader range of extreme weather impacts by introducing additional resiliency stresses. Many scenarios analyzed in this section are not intended to represent typical system operations, but operations under unusual circumstances. The goal of these case studies is to inform where the 2050 system may become challenged under extreme conditions, if the system can be operated reliably during those conditions, and – if not – what resiliency investments are required to minimize customer impacts.

5.3.5.1 Extended Low Wind and Solar Output

The nature of reliability challenges in deeply decarbonized systems are significantly different from current challenges. Variable and energy-limited resources provide resource adequacy attributes that are different than that from traditional firm and dispatchable generation. Because most existing generation capacity is dispatchable, the biggest reliability challenge is the peak load event when there is the greatest probability that loads will exceed available generation. Presently for OPPD, this typically occurs on hot summer afternoons (see Figure 84). With more solar resources coming online in the short term under the Net Zero Carbon Base Scenario, the period with the biggest reliability challenge shifts to early evening in 2030 (see Figure 85). By 2050, the OPPD system achieves net zero with a significant amount of generation being variable or energy-limited. The summer reliability challenge gets pushed further into the nights when there is high load and low wind outputs (see Figure 86). More importantly, the biggest reliability challenge shifts to extended periods where renewable generation is very low. These prolonged periods of low renewable output are most likely to occur during cold winter periods in November through January. When renewable energy production is low for only a short period of time, existing energy storage technologies can help provide sufficient energy. However, when renewable production is low across multiple days, limited-duration energy storage is likely to be insufficient to provide all the required energy. Under the Net Zero Carbon Base Scenario, increased electric heating loads also add stress to the system operation during those prolonged periods of low renewable production; this stress would be much worse in the "High Electrification" case that relies on inefficient electric resistance backup to heat pumps during extreme cold conditions.

Figure 87 further demonstrates that low wind and solar conditions, instead of load variability, are the primary drivers to reliability challenges. Figure 87 uses "box-and-whisker" plots to show the range of OPPD's weekly load and firm energy needs of the Net Zero Carbon Base portfolio in 2050 across all RECAP simulations, which include 10 Monte Carlo draws of 40 weather years. The box extends from the first quartile to the third quartile values of the data, with a line at the median. The whiskers extend from the edges of the box to show the range of the data. Outliers are plotted as separate dots. The weekly load data at the top of the figure shows generally small inter-annual variance, with higher ranges in the summer. However, the weekly firm energy need data at the bottom of the figure shows high inter-annual variance, ranging from 0% to 75% of weekly load, with higher ranges and extreme outliers in the winter. These outliers occur during extended periods of low renewable output, and they drive reliability challenges and firm capacity needs. In addition to illustrating the periods when OPPD needs to dispatch a lot firm resources, Figure 87 also shows that in almost all weeks of the year, there are some simulated weather years with enough solar and wind energy to avoid the need for any firm generation (i.e. the bottom whiskers, representing the minimum value, of the firm energy need plot reach zero).

The Net Zero Carbon Base portfolio can withstand nearly all low renewable events simulated in the RECAP model and meets the reliability target using firm capacity operating on-demand for multiple hours and even multiple days, assuming this firm capacity has fuel security. Section 5.3.5.2 and 5.3.5.3 have examples of system performance under extended low wind and solar output during more extreme weather events simulated in RECAP.

Figure 84. Loss-of-Load Probability Distribution by Month-Hour for the Net Zero Carbon Base Scenario in 2021

Figure 85. Loss-of-Load Probability Distribution by Month-Hour for the Net Zero Carbon Base Scenario in 2030

Figure 86. Loss-of-Load Probability Distribution by Month-Hour for the Net Zero Carbon Base Scenario in 2050

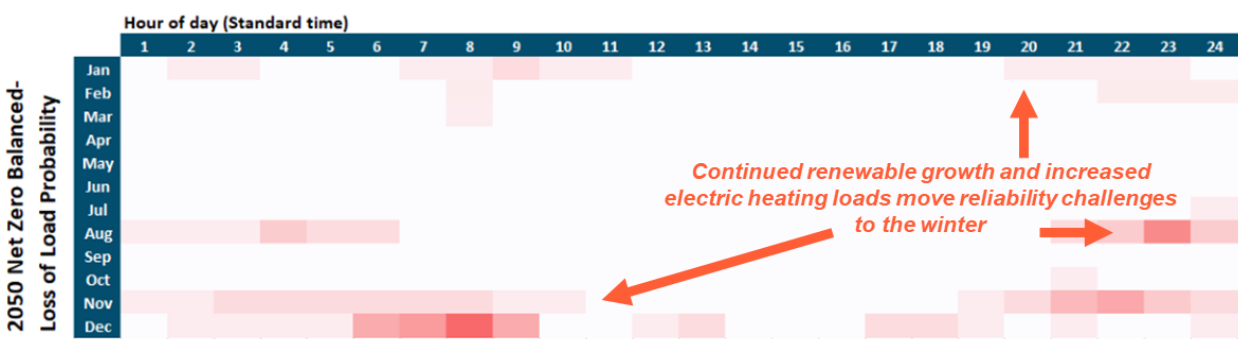
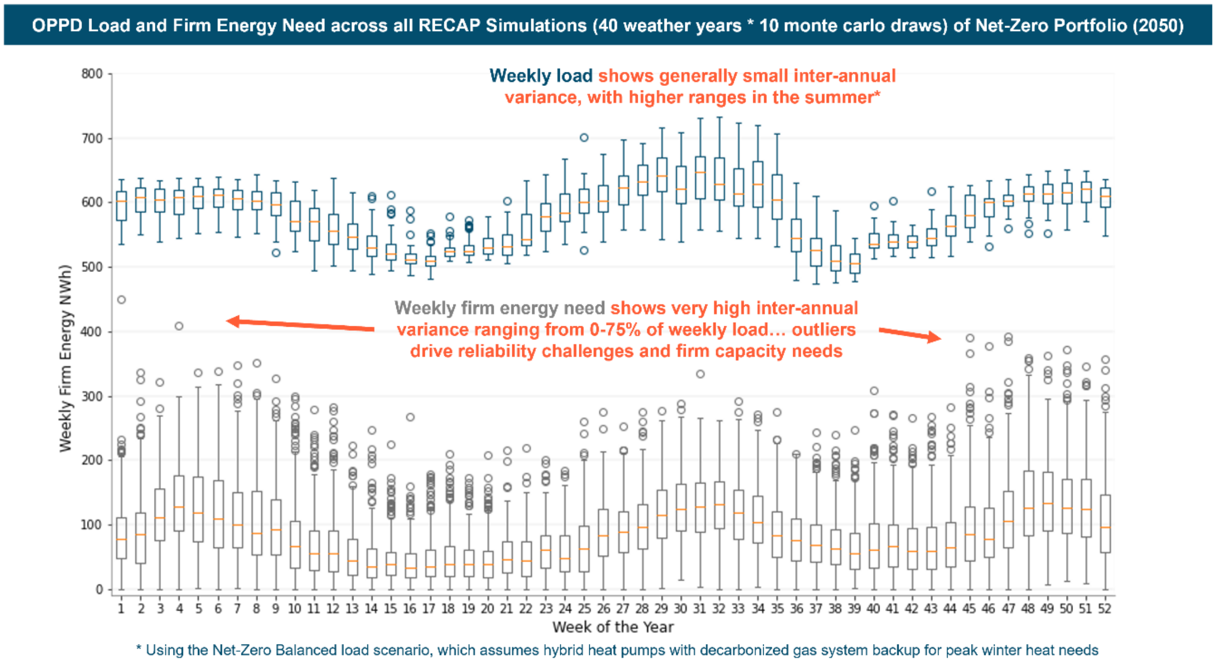


Figure 87. OPPD's Load and Firm Energy Needs for the Net Zero Carbon Base Scenario in 2050



5.3.5.2 Extreme Summer Heat

The extreme summer heat case study focused on a historical weather condition where there was a four-day period with daily maximum temperatures around 110°F. E3 examined how the 2050 Net Zero Carbon Base Scenario performed under three different scenarios: a week with high renewable generation, a week with low renewable generation, and a week with low renewable generation and additional resiliency stresses. The amount of renewable generation available in these scenarios came from RECAP simulations that consider historical correlations between load, weather, and renewable generation conditions. These scenarios reflect a few specific realizations among many RECAP simulations of the year 2050 under different weather conditions and resource availability. As seen in Figure 88, with high wind and solar outputs, there was a small need for firm resources to serve load. However, with low renewable output (which typically indicates low wind conditions as solar production is generally high during summer months), there was a higher dependency on firm resources to serve load, especially during nighttime (see Figure 89). Several days needed all of the firm resources (~3GW) in the portfolio to be online.

Figure 88. Illustrative Dispatch over a High Renewable Summer Week in 2050 (Net Zero Carbon Base Scenario) [33]

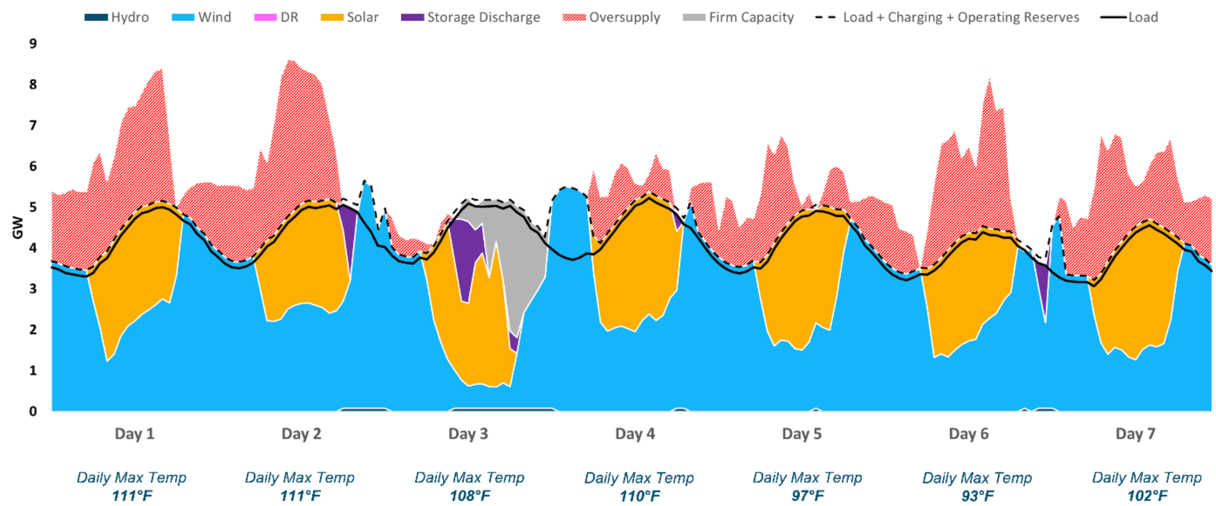
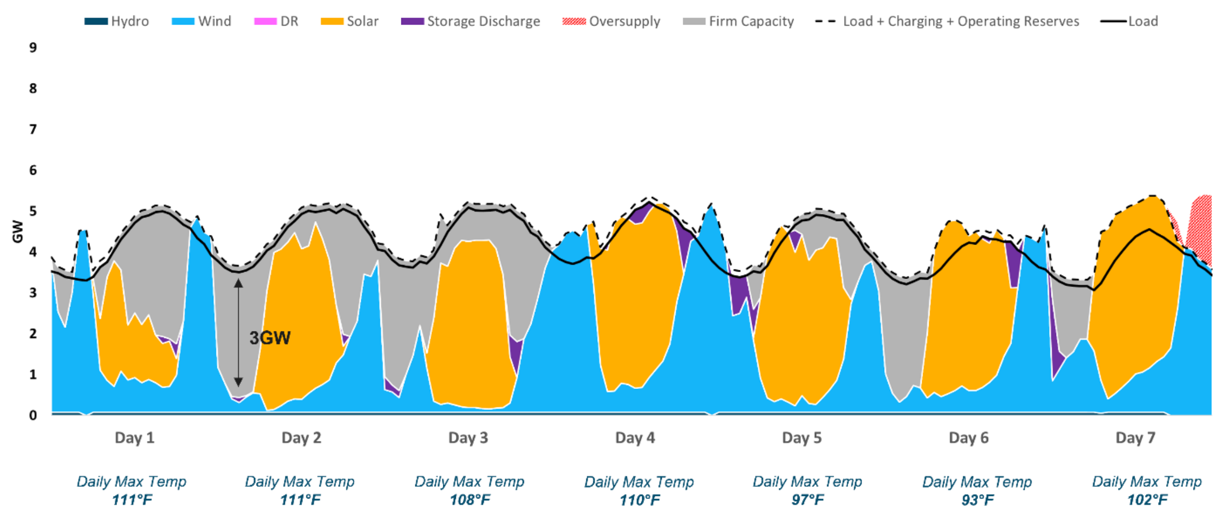


Figure 89. Illustrative Dispatch over a Low Renewable Summer Week in 2050 (Net Zero Carbon Base Scenario) [33]

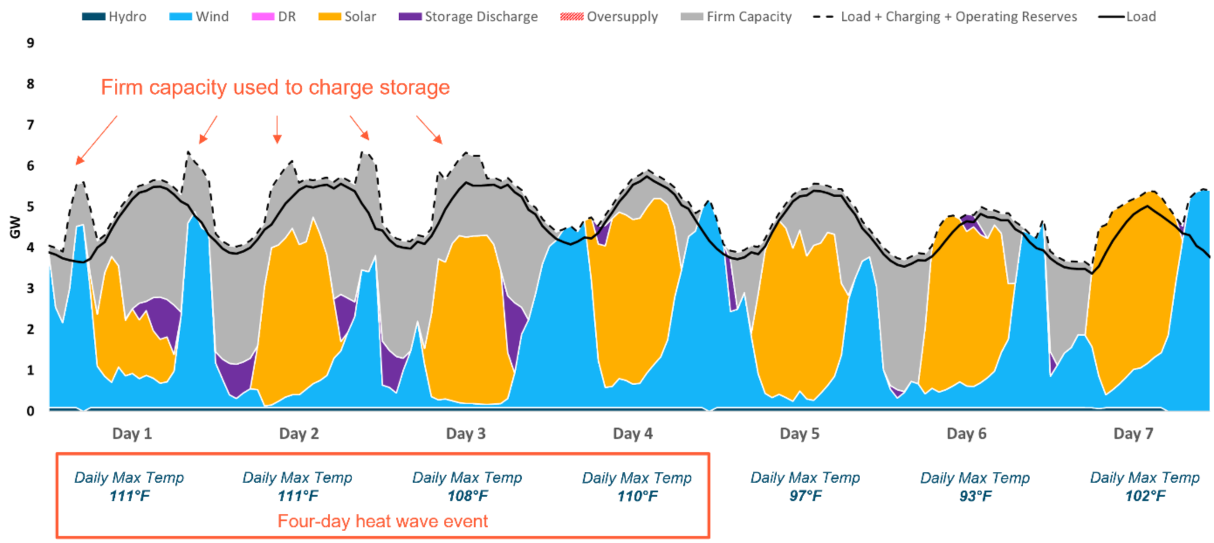


In addition to the availability of renewable output during this extreme heat event, resiliency stresses such as higher customer loads due to climate change, lower firm capacity availability, and lower energy storage availability were also considered in this case study (see Table 33). As seen in Figure 90, which builds on the low renewable condition in Figure 89 by adding the resiliency stresses, the increased load and decreased resource availability did not trigger a reliability event, but the OPPD system had to dispatch firm resources more to meet the additional load and charge energy storage to avoid loss-of-load events during critical periods with low wind output.

Table 33. Extreme Summer Heat Event Resiliency Stress Parameters

Parameter	Assumption	Source
Load	**10% increase** under 5°F temperature increase by Mid-Century	Based on U.S. Climate Resilience Toolkit Climate Explorer and E3 working assumption
Firm capacity	**11% de-rate** due to extreme heat	OPPD
Energy storage	**5% outage rate**	California Energy Storage Association

Figure 90. Illustrative Dispatch over a Low Renewable Summer Week with Resiliency Stress in 2050 (Net Zero Carbon Base Scenario)



5.3.5.3 Extreme Winter Cold (Polar Vortex)

The extreme winter cold case study focused on a historical weather condition where there was a four-day period with daily minimum temperatures around -25°F, a polar vortex-type condition. Like the extreme heat event above, E3 examined how the 2050 Net Zero Carbon Base portfolio performed under three different scenarios given the weather condition: a week with high renewable generation, a week with low renewable generation, and a week with low renewable generation and additional resiliency stresses. During the week with high renewable output, renewables and energy storage were able to serve nearly all OPPD's load (see Figure 91). However, when the system experienced prolonged periods of low renewable output, it relied on significantly more firm resources to meet customer demand (see Figure 92). Firm resources were needed at large quantities during multiple days to avoid load shedding conditions.

Figure 91. Illustrative Dispatch over a High Renewable Winter Week in 2050 (Net Zero Carbon Base Scenario) [33]

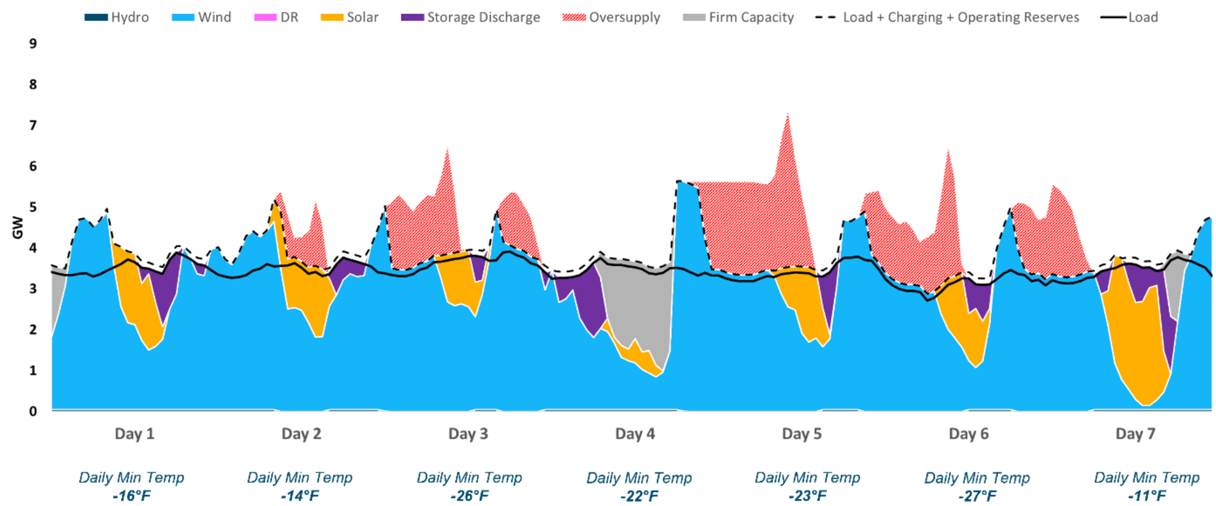
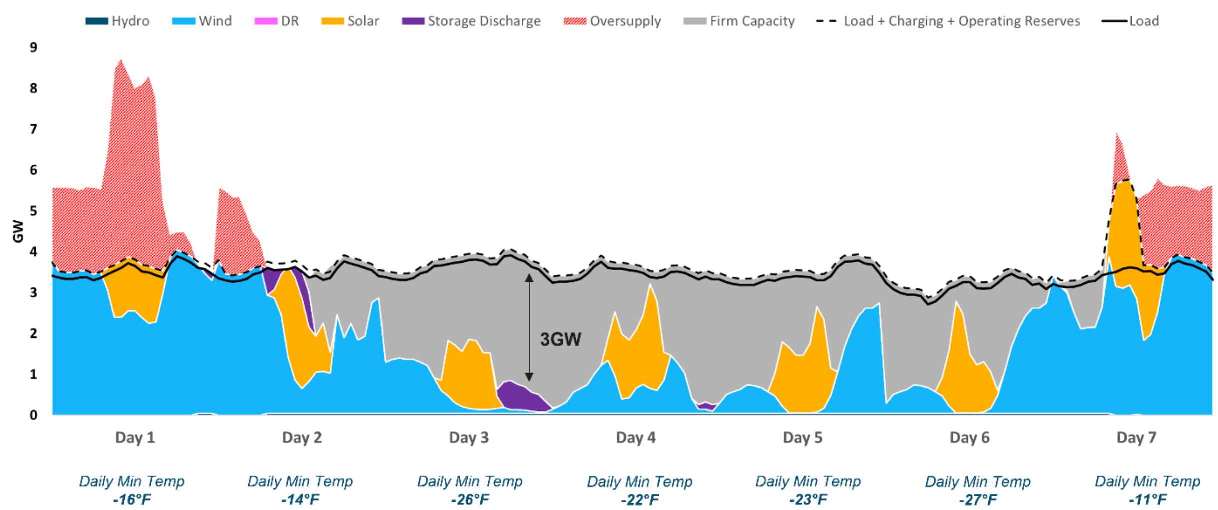


Figure 92. Illustrative Dispatch over a Low Renewable Winter Week in 2050 (Net Zero Carbon Base Scenario) [33]



In addition to the availability of renewable output, resiliency stresses were added, based on the significant resource outages experienced during the February 2021 winter storm (see Table 34). Based on SPP's data during the winter storm, it was assumed that OPPD's firm resources would have 40% - 50% outages due to disruptions on fuel supply and start up failures during this extreme cold week. OPPD's assets with on-site fuel tanks could operate for two to three days before experiencing outages. It was also assumed that 43% of wind generation would be unavailable due to turbine icing and energy storage would have a 5% outage.

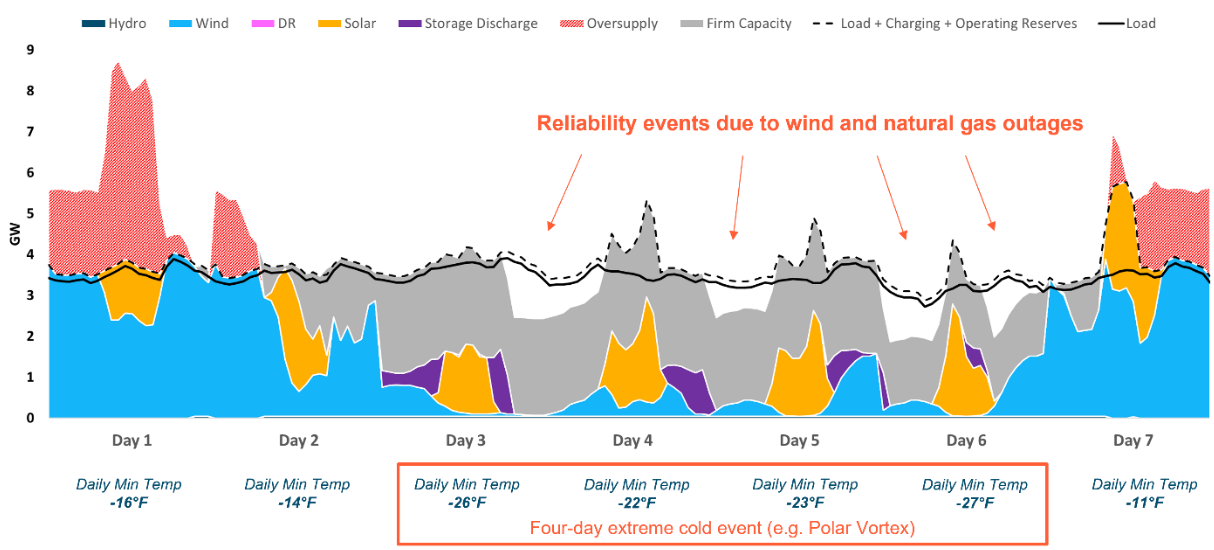
As seen in Figure 93, which builds on the low renewable condition by adding the resiliency stresses, the significant reduction in resource availability, especially in firm resources given that the wind generation was already low, triggered reliability events. These events mostly occurred during nighttime where there was low renewable output, depleted energy storage, and limited firm resources. The duration of these events ranged from 8 to 14 hours, with a maximum hourly loss of load of 1,400 MW and an average of 700 MW.[44] Demand response resources can sometimes be a tool to help mitigate energy shortfall but practical limitations on magnitude and duration of response limit their contributions. For example, it would be unrealistic to expect many customers to reduce electricity use for heating on multiple consecutive nights of during extreme cold week. OPPD's demand response programs were included in RECAP simulations, but they were called up to their maximum limits during other times of the year and thus were not included in this week.

To avoid these reliability events, mitigations include winterizing the fuel delivery infrastructure (e.g. well heads, fuel storage, delivery pipelines, etc.), adding more on-site backup fuel to ensure continued operation if fuel supply is disrupted, and investing in wind turbine de-icing technologies. On-site backup fuel could be biodiesel if a zero-emissions fuel is desired.

Table 34. Extreme Winter Cold Event Resiliency Stress Parameters

Parameter	Assumption	Source
Fuel availability	Start up failures + fuel supply disruption **reduce firm capacity ~40-50%** Units with on-site fuel tanks can operate for 2-3 days	SPP Feb. 2021 Polar Vortex conditions
Wind	**43% unavailable** due to turbine icing	SPP Feb. 2021 Polar Vortex conditions
Energy storage	**5% outage rate**	California Energy Storage Association

Figure 93. Illustrative Dispatch over a Low Renewable Winter Week with Resiliency Stress in 2050 (Net Zero Carbon Base Scenario)



44 Not including operation reserve shortfalls.

5.3.5.4 Extreme Localized Events (Tornadoes, Floods)

Table 35 lists the type of the extreme localized events considered in this study and their potential impacts, recovery, and mitigation strategies. These events may be catastrophic to OPPD's generators, but other regions that are connected to OPPD might have excess resources to supplement the lost generator. Therefore, OPPD's ability to withstand and recover from local events depends on the remaining available local capability and remaining interconnection to the surrounding transmission network.

Mitigation strategies to avoid devastating impacts from localized events include developing operational reliability studies on key asset contingencies, making on-system reliability investments (e.g. synchronous condensers), and coordinating with other SPP market participants on system flexibility products.

Table 35. Impact, Recovery, and Mitigation of Extreme Local Events

Event	Event Impact	Post-Event Impact	Recovery	Mitigation
Major Fuel Supply Disruption	Reduction in firm generating capabilities during dangerous cold weather events	Depends on SPP regional impact, likely major reliability challenges	Switch to on-site backup fuel, such as (bio)diesel	Fuel production /delivery and plant "winterization" Sufficient on-site backup fuel or ability to re-fuel
Natural disaster (tornado, floods)	Long-term generator outage/destruction OPPD<>SPP transmission ties outage/destruction	Likely major but will depend on connection to SPP and whether transmission reliability can be retained with less interconnection	Short-term: transmission operational actions Mid- to Long-term: asset rebuild	Invest in transmission reliability based on contingency planning studies (networked grid, local synchronous condensers, etc.)
Major renewable forecast error	Day-ahead or hours-ahead wind/solar mis-forecast creates energy shortfall	Major if OPPD generators can't start up in time (e.g. steam turbines), but limited if they can (CTs or reciprocating engines) Limited if SPP generators and transmission can supplement OPPD shortfall	Turn on and ramp up OPPD or SPP firm capacity as fast as possible	Invest in better forecasting capabilities Ensure sufficient SPP market products (either reserves or RT market flexibility)

5.4 Conclusions from Reliability and Resiliency Analysis

As the OPPD system transitions to achieve net zero in 2050, the reliability challenges shift from the traditional peak load events in the winter to extended periods of low renewable generation which occurs primarily in winter. The Net Zero Carbon Base Scenario identified in the Portfolio Optimization workstream meets the target reliability standard of 1-day-10-year (i.e. 0.1 LOLE) under robust loss of load probability testing in RECAP. While renewable and energy storage resources are the main sources of energy in 2050, firm capacity resources play an important role in maintaining system reliability during challenging times such as prolonged low renewable periods and extreme weather events. During critical weeks, firm resources may be required in significant quantities and over multi-day period. The firm resources in the Net Zero Carbon Base Scenario are sufficient to withstand many of the critical conditions analyzed in this study, including the resiliency case studies. Extreme cold weather may threaten system reliability through fuel availability challenges and may lead cause customer outages if those challenges are not mitigated. This is a resiliency threat today and will continue to be a resiliency threat in future business-as-usual scenarios as well as future net zero carbon scenarios that rely on fuel-based resources for reliability. Investing in winterizing fuel infrastructure, securing on-site backup fuel, and adding wind turbine de-icing technologies can help increase the resilience of OPPD’s system.

6 Portfolio Optimization

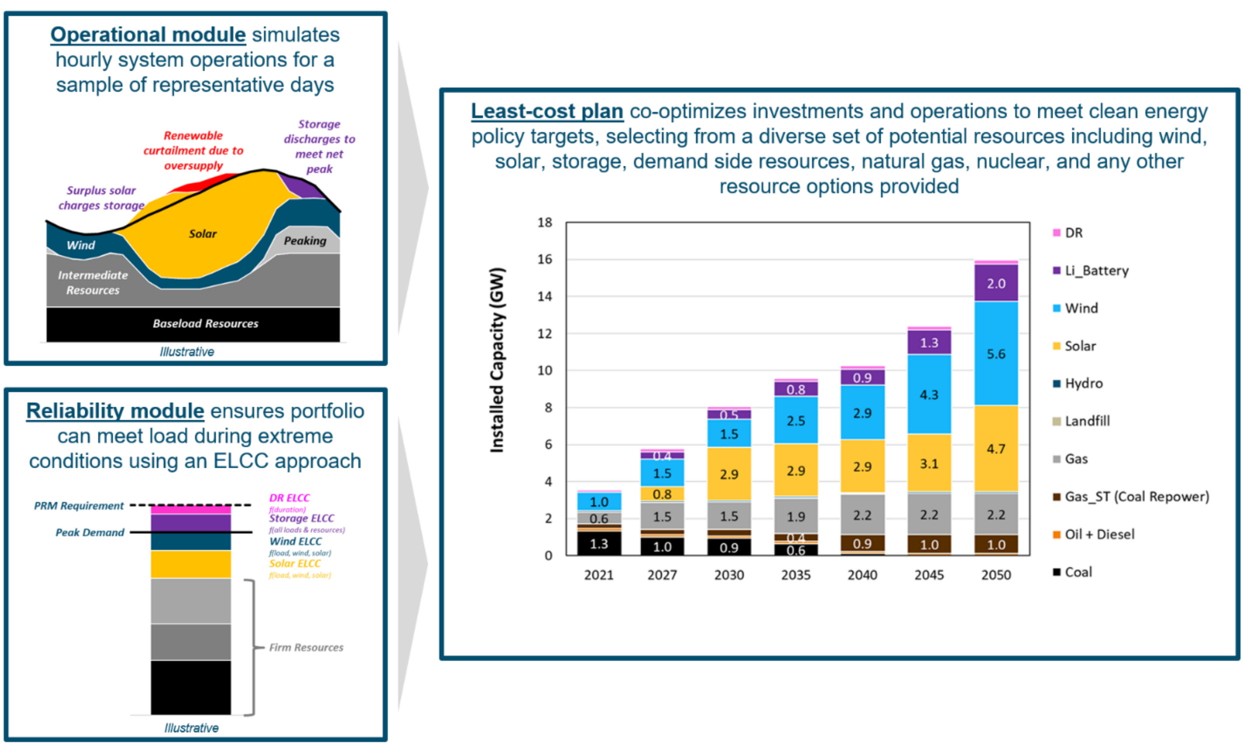
6.1 Modeling Approach

E3 used its Renewable Energy Solutions Model (RESOLVE) to perform a portfolio optimization of OPPD's electric generating resource needs between 2021 and 2050. This portfolio optimization had three primary drivers of system resource needs:

- **Reliability**: all portfolios will ensure system meets resource adequacy requirement of 1-day-in-10-year loss of load expectation
- **Greenhouse gas reduction**: all portfolios met environmental/GHG targets for that scenario, e.g. net zero carbon electricity
- **Cost**: the model's optimization will develop a portfolio that minimizes costs

Figure 94 illustrates the use of RESOLVE's operational module, which tracks hourly system operations includes cost and greenhouse gas emissions across a representative set of days, and RESOLVE's reliability module, that uses exogenously calculated input parameters to characterize system reliability of candidate portfolios using effective load carrying capability (ELCC).

Figure 94. Schematic Representation of the RESOLVE Model Functionality



RESOLVE develops least-cost portfolios using the inputs and assumptions described in a previous chapter of this report, including loads, existing resources, new resource options, retirement or repowering resource options, resource costs, resource operating characteristics including resource adequacy contributions, a zonal transmission transfer topology, and new resource transmission costs. For this project, RESOLVE was also built to co-optimize the SPP resource mix alongside – and integrated with – the OPPD optimization.

A more detailed description of the OPPD RESOLVE model inputs and topology are provided in the Inputs and Assumptions chapter of this report. A more detailed model description of the OPPD RESOLVE model is provided in an Appendix to this report.

6.2 Scenarios

E3 modeled framing scenarios and sensitivity scenarios from the portfolio optimization analysis. The framing scenarios consider various paces of decarbonization under multiple technology availability scenarios. The sensitivity scenarios consider additional scenarios for load, cost, technology and policy. Table 36 includes the high-level descriptions of each scenario.

Table 36. High-Level Descriptions of Scenarios

Scenario Category	Scenario Name	OPPD GHG Reduction	OPPD Load	Technology Availability
Pace of Decarbonization	Reference	None	Reference	Mature + H2 enabled gas[45]
	Net Zero Carbon Base	Net Zero	Net Zero Balanced	
	Net Zero by 2035			
	Net Zero Accelerated Pace			
	Net Zero Moderated Pace			
Technology Availability	Absolute Zero Mature Only	Absolute Zero	Net Zero Balanced	Only mature (solar, wind, gas, li-ion, flow batteries, etc.)
	Absolute Zero Mature + H2 enabled gas			Mature + H2 enabled gas
	Absolute Zero Mature + Emerging			Mature + H2 enabled gas + Advanced nuclear, gas w/ carbon capture and storage, ultra-long

[45] H2 enabled gas refers to new dual fuel natural gas and hydrogen combustion based power plants.

				duration seasonal storage
	Absolute Zero Mature + Emerging + No H2			Mature + Advanced nuclear, gas w/ carbon capture and storage, ultra-long duration seasonal storage
Multi-Sector Electrification Loads	Net Zero Reference Loads	Net Zero	Reference	Mature + H2 enabled gas
	Net Zero Moderate Decarbonization		Moderate Decarbonization	
	Net Zero High Electrification		High Electrification	
Sensitivities	Net Zero Breakthrough Technology Costs	Net Zero	Net Zero Balanced	Mature + H2 enabled gas
	Net Zero High Flexible Loads			
	Net Zero Carbon Base Price			
	Net Zero SPP Resource Portfolio (SPP Reference Load)			

6.3 Portfolio Optimization Modeling Results

This section highlights the results of the RESOLVE modeling scenarios and sensitivities to answer the questions around OPPD's strategy to achieve net zero carbon by 2050. The OPPD RESOLVE model was co-optimized with capacity expansion in SPP to better capture the regional dynamics. These results are organized in the following order to answer the questions of:

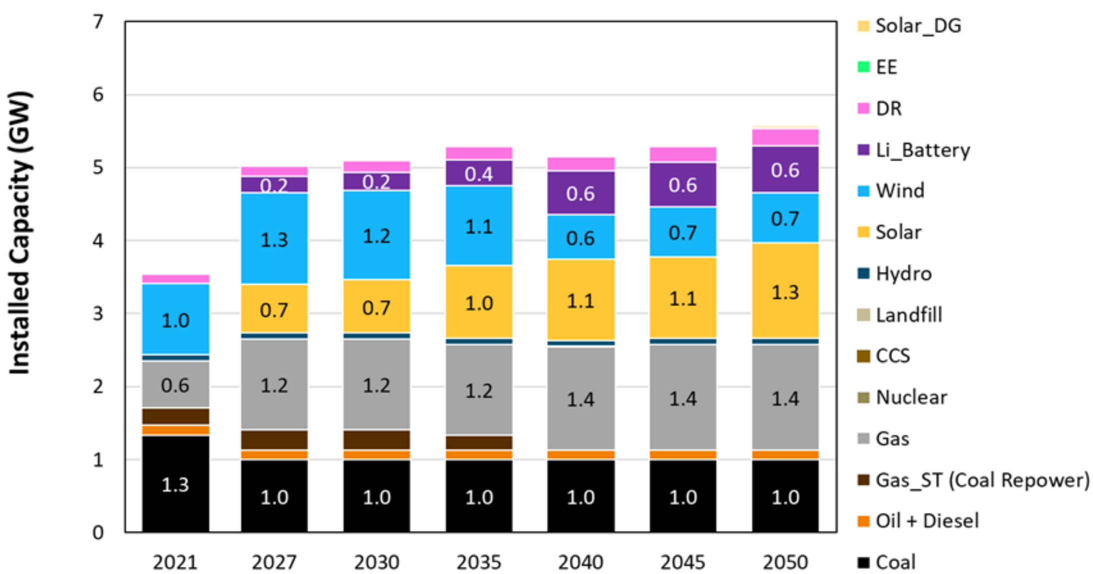
+ How will OPPD's resource portfolio change without any emission target?
+ What resources does OPPD need to build to achieve net zero carbon?
+ How will the pace of decarbonization impact portfolio needs?
+ How will load trajectories impact portfolio needs?
+ How will OPPD's portfolio change if OPPD needs to achieve absolute zero carbon instead of net zero carbon? How will technology availability impact the optimal portfolio?
+ How will breakthrough technology costs impact portfolio needs?
+ How will flexible load availability impact portfolio needs?
+ How will carbon prices impact portfolio needs?
+ How will OPPD's net zero carbon portfolio be impacted if SPP does not pursue decarbonization policies?

6.3.1 OPPD Reference Scenario

The Reference scenario is a "Business as Usual" scenario, assuming OPPD will experience limited load growth with no emission target (though renewable energy and storage may be economically selected to meet energy or capacity needs). Though not consistent with OPPD's current policy to achieve net zero carbon by 2050, this scenario serves as a counterfactual cost comparison point for decarbonized scenarios.

In the Reference scenario, OPPD load will grow slightly in the near-term with industrial load growth but experience slow growth going forward (see Inputs and Assumptions chapter of this report). The near-term capacity additions are primarily driven by planned Power with Purpose solar and gas additions and near-term industrial load growth, followed by a moderate growth of new wind, solar, and batteries between 2027 to 2050 (Figure 95). The planned North Omaha coal conversion will retire by 2040 and be displaced with 0.2 GW of new gas. Without an emission target, no additional coal retirements were selected by the model.

Figure 95. OPPD Installed Capacity (GW) under Reference Scenario



Without a GHG target, coal will continue to stably provide around half of the energy needs all the way to 2050 (Figure 96). Therefore, the emission level at OPPD will also remain relatively stable to 2050 (Figure 97). Starting from 2040, imports increase as load grows and wind PPAs expire.

Figure 96. OPPD Annual Generation (TWh) under Reference Scenario

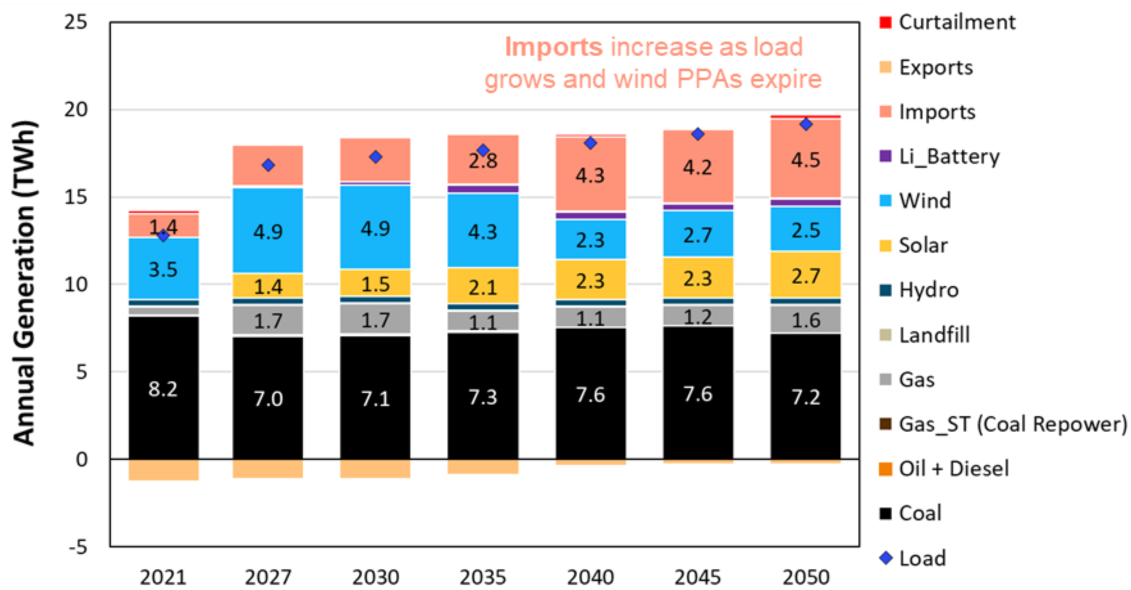
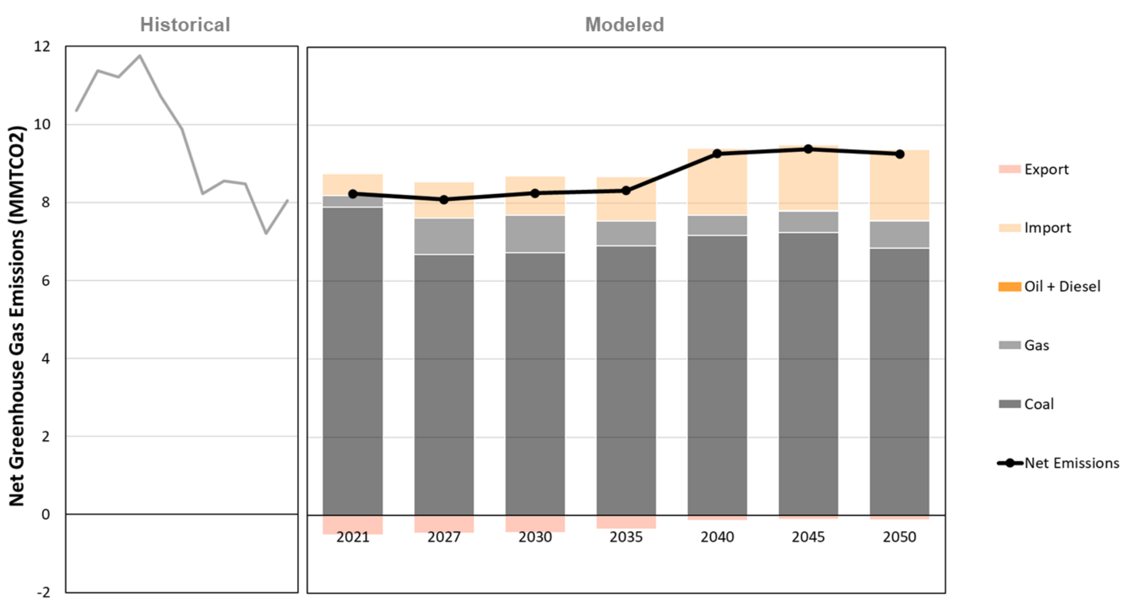


Figure 97. OPPD Annual GHG Emission (MMT) under Reference Scenario



6.3.2 OPPD Net Zero Carbon Base Scenario

The Net Zero Carbon Base scenario is the core case to answer the question of how OPPD resource portfolio will change with a net zero GHG target by 2050. To reflect economy-wide decarbonization, the underlying load forecast of this scenario, "Net Zero Balanced", includes major electrification of transportation, buildings and industry. Table 37 presents the detailed assumptions of the Net Zero Carbon Base scenario.

Table 37. Base Scenario Definition

Assumption	Base Case
Pace of Decarbonization	Net Zero 2050
Technology Availability	Mature + Hydrogen + Emerging
Multi-Sector electrification	Net zero "Balanced" scenario
Technology costs	Baseline
Carbon pricing	No carbon price
SPP Resource Mix	Near-zero carbon in SPP
GHG import/export accounting	Penalty for imported electricity and credit for exported electricity
Flexible Loads	Moderate

With electrification load growth and a net zero carbon constraint, by 2050 OPPD needs to build more than 12GW of solar, wind, storage, and demand response (DR) to achieve net zero carbon and around 1 GW of new H2-enabled gas to provide firm capacity by 2050 (Figure 98). The existing Nebraska City 1 and Nebraska City 2 coal units were selected to be repowered to gas starting from 2030 and fully converted to gas in 2045[46]. These converted gas units were retained by the model through 2050.

In terms of energy, coal will be gradually replaced with gas, solar, and wind (Figure 99). Since the Net Zero Carbon Base scenario allows OPPD to export renewables to neighboring utilities to offset its internal emission, OPPD will shift from being a net importer to a net exporter to maximize emission credits to achieve net zero emission in 2050. Figure 100 illustrates that OPPD can achieve net zero by 2050 via renewable exports to offset internal and import emissions. The annual export is set to not exceed 10% of OPPD's annual load.

[46] RESOLVE is a linear optimization model that will make partial conversion decisions.

Figure 98. OPPD Installed Capacity (GW) under Net Zero Carbon Base Scenario

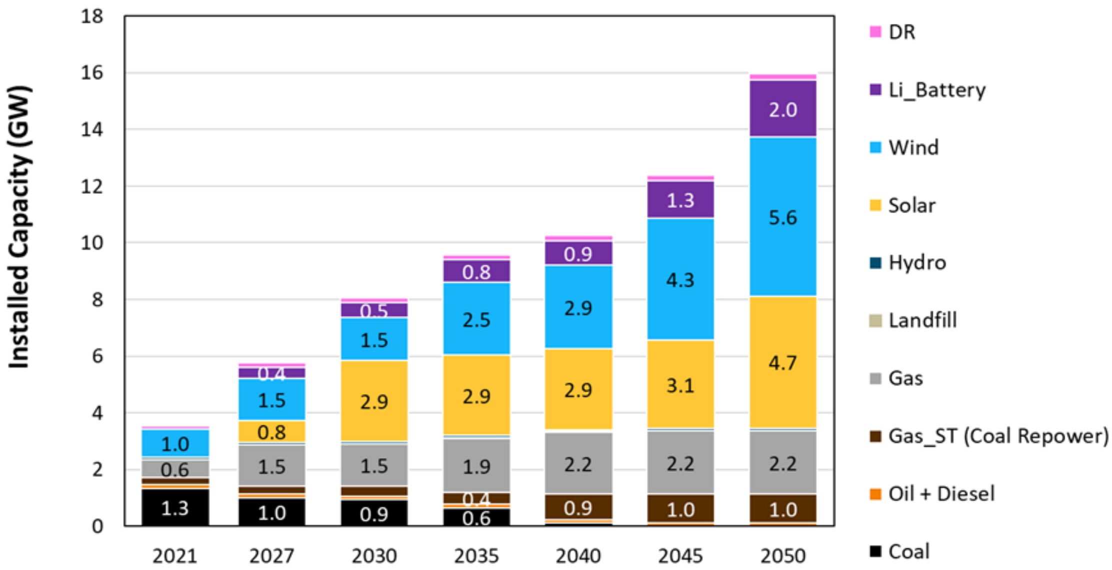


Figure 99. OPPD Annual Generation (TWh) under Net Zero Carbon Base Scenario

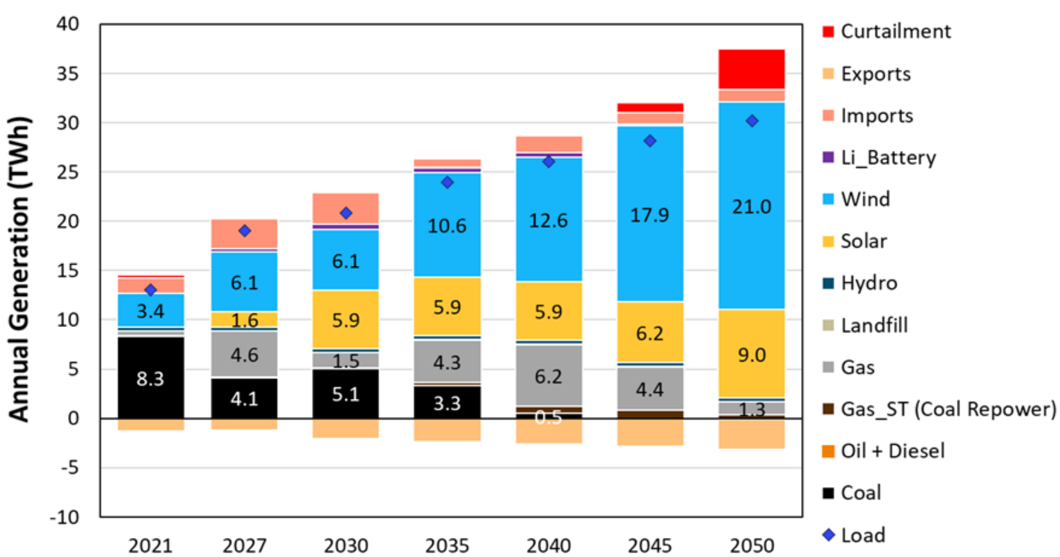
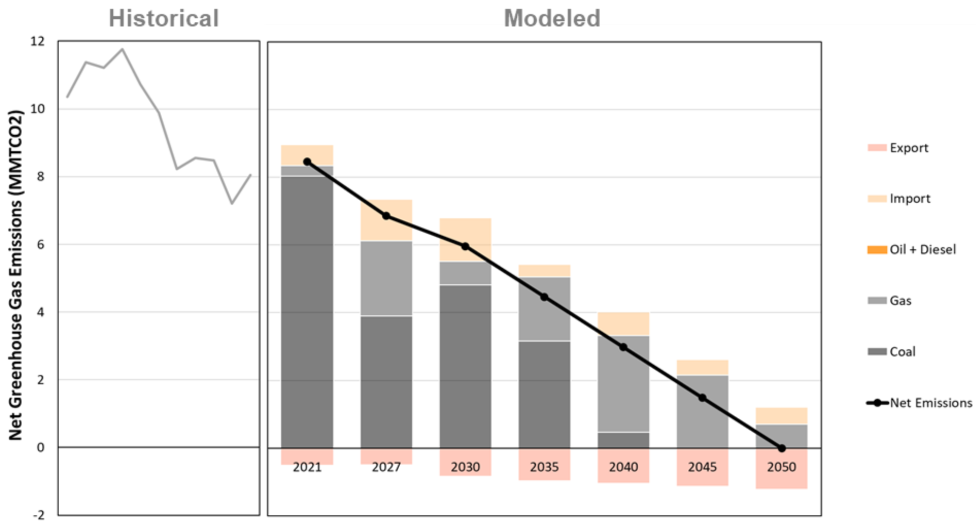


Figure 100. OPPD Annual GHG Emission (MMT) under Net Zero Carbon Base Scenario



The analysis found that the Net Zero Carbon Base Scenario will lead to approximately 1.4 cents/kWh increase in generation (and transmission for new generation) costs relative to the Reference scenario in 2050[47]. That is a 16% increase relative to OPPD's current system average rate of 8.8 cents/kWh. As the emission target gets more stringent, the marginal cost of carbon abatement increases to $72/ton in 2050 (Table 38).

Table 38. Cost Metrics of the Net Zero Carbon Base Scenario

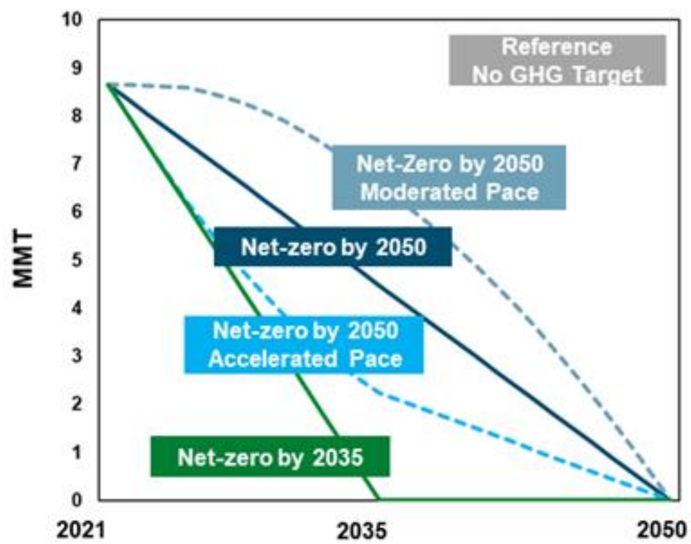
	2021	2030	2040	2050
Generation Cost Impact (2021 cent/kWh, increase from Reference)	+0	+0.4	+1.1	+1.4
(% increase vs. current system avg. rate)	(+0%)	(+5%)	(+13%)	(+16%)
Marginal Carbon Abatement Cost (2021 $/ton CO2)	-	$24	$29	$72

[47] It is noted that the generation costs here only include modeled generation costs, not other potential rate drivers such as transmission and distribution investment, grid modernization, energy efficiency or electrification programs and etc.

6.3.3 Pace of Decarbonization Sensitivities

The Net Zero Carbon Base Scenario assumes a straight-line pathway to net zero by 2050. However, OPPD does has the flexibility to accelerate or moderate the decarbonization pace. This section includes three additional decarbonization pace sensitivities modeled in RESOLVE: Net Zero by 2035, Net Zero by 2050 with an Accelerated Pace, and Net Zero by 2050 with a Moderated Pace (Figure 101). The Net Zero by 2035 is the most aggressive trajectory, shortening the decarbonization timeline to the next 15 years.

Figure 101. OPPD Decarbonization Trajectories



The accelerated pace scenarios switch coal to gas and build renewables faster than the Net Zero Carbon Base scenario, though all the decarbonization pace scenarios end with the same 2050 portfolio (Figure 102). The early build of renewables reduces OPPD's optionality to take advantage of declining costs and emerging technologies, resulting in slightly higher system costs, especially in the Net Zero by 2035 scenario (Figure 104). Accelerated decarbonization also requires significantly more near-term infrastructure to be built, which might pose implementation challenges of getting permits and interconnection for new resources in the near term. Despite the near-term challenges, accelerated scenarios benefit from lower cumulative total GHG emissions by 2050.

Figure 102. OPPD Installed Capacity (GW) of Pace of Decarbonization Sensitivities

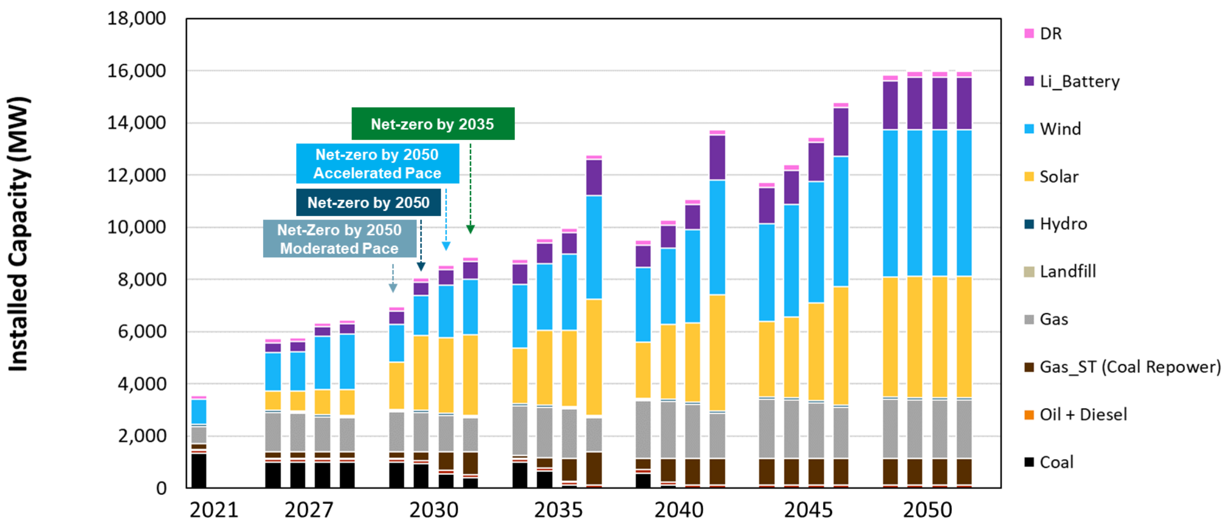


Figure 103. OPPD Annual Generation (GWh) of Pace of Decarbonization Sensitivities

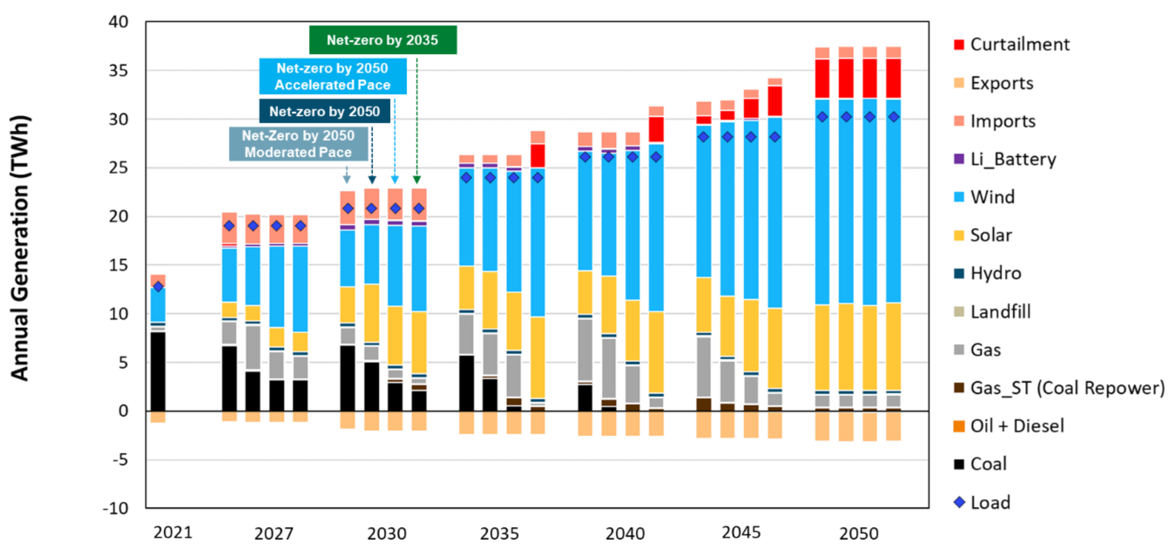
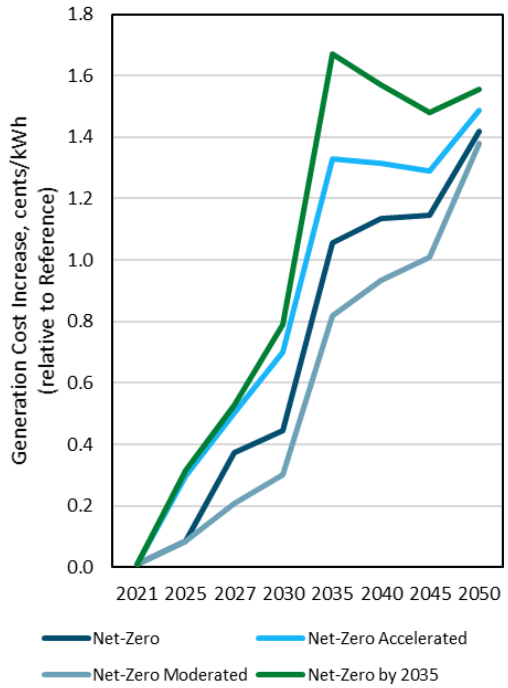


Figure 104. Generation Costs (cents/kWh) relative to Reference for Pace of Decarbonization Sensitivities



6.3.4 Load Forecast Sensitivities

The four load trajectories developed in the Multi-Sector Modeling Chapter of this report were modeled in RESOLVE to identify resource needs under different future load scenarios from Reference loads to High Electrification loads (Figure 105). Due to the challenge to meet peak winter heating demand, the High Electrification load requires a planning reserve margin (PRM) of 17%, almost two times higher than the 7% to 9% required in the Reference, Moderate Decarbonization and Net Zero Balanced loads. Therefore, OPPD will need to build out more new firm capacity and resources with faster load growth, though the portfolio mix will be similar across load scenarios (Figure 106). Higher loads also increase costs by driving additional new firm capacity needs (Figure 108).

Figure 105. Load by Scenarios from the Multi-Sector Modeling

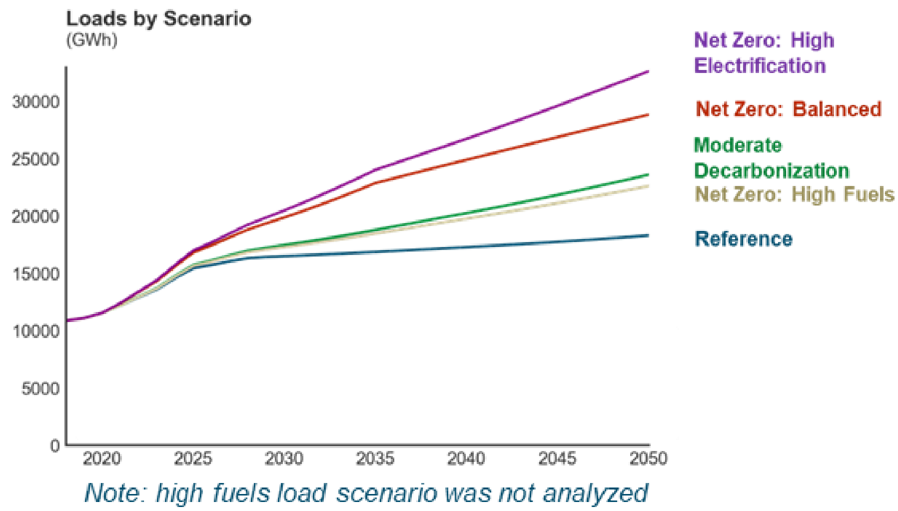


Figure 106. OPPD Installed Capacity (GW) of Load Sensitivities

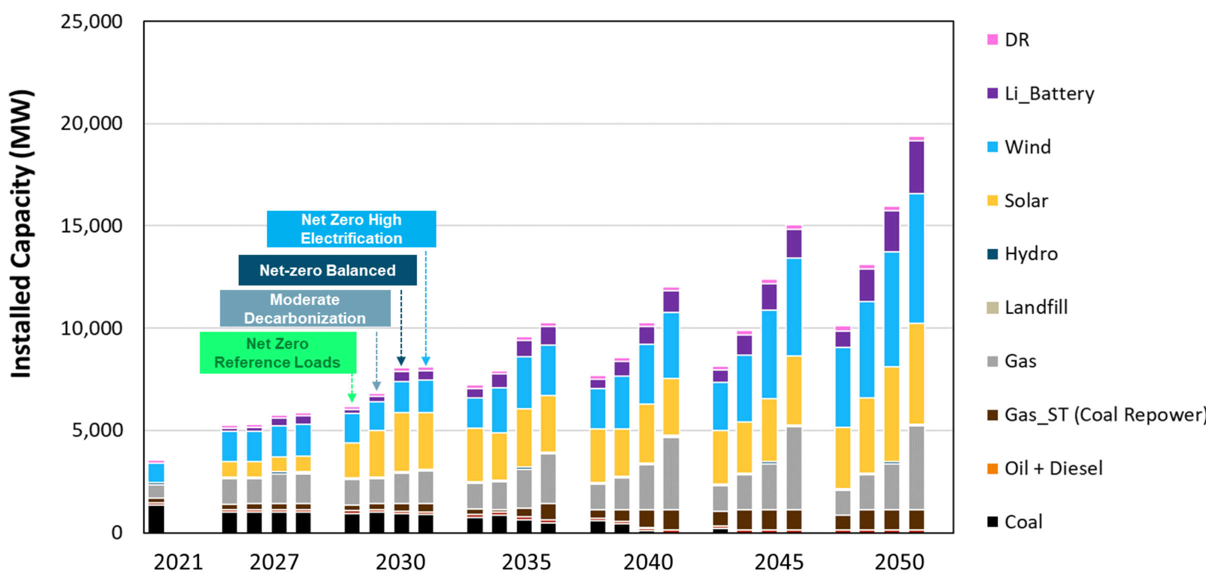


Figure 107. OPPD Annual Generation (GWh) of Load Sensitivities

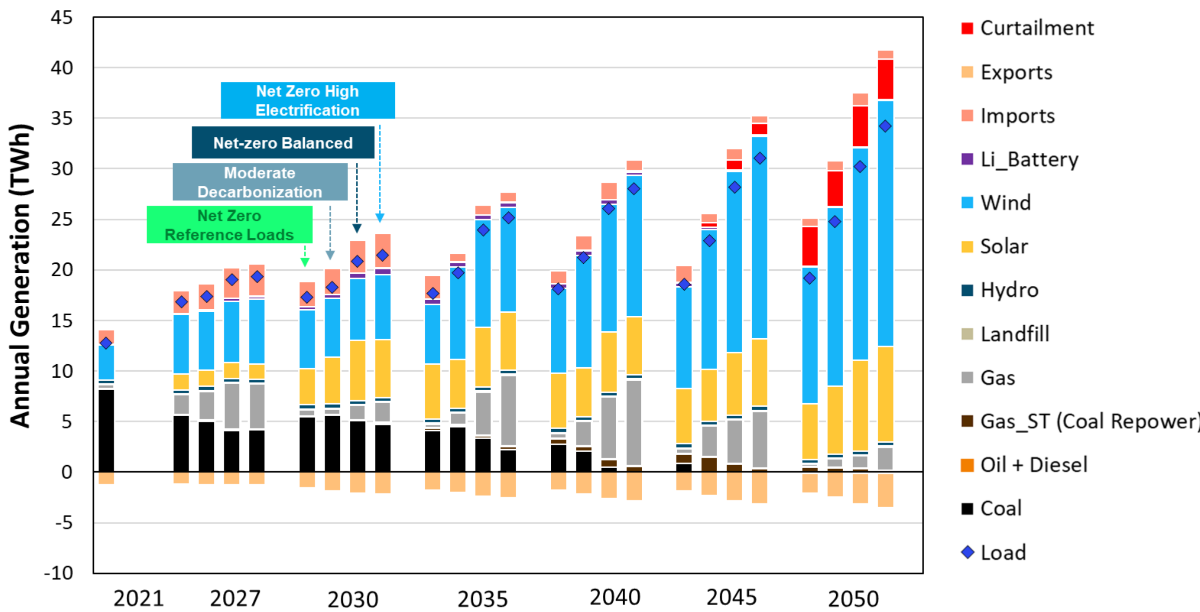
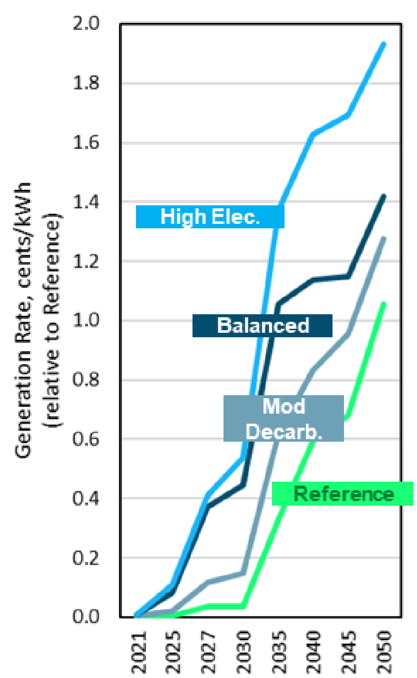


Figure 108. Generation Costs (cents/kWh) relative to Reference for Load Sensitivities



6.3.5 *Absolute-Zero + Technology Availability Sensitivities*

As mentioned in Inputs and Assumptions Chapter of this report, the net zero GHG accounting allows on system or import emissions balanced by off-system reductions (exports). In another words, it allows OPPD to offset its internal emissions by exporting renewables to SPP when SPP is burning fossil fuels, subjected to OPPD's annual export limit. Nevertheless, if the whole SPP system transitions to a net zero system, there will be no emissions for OPPD to offset in SPP via exports, which means that OPPD will need to achieve absolute zero emissions in its own territory with no on-system or import emissions allowed by 2050. (OPPD may also pursue negative emissions technologies such as direct air capture, which will be more cost-effective if absolute zero GHG mitigation costs are higher than ~$170-310/ton CO2, the expected future cost of direct air capture.)

Absolute zero target is more challenging to achieve as it requires retiring all emitting OPPD resources and was found to require emerging technologies to help meet target in a cost-effective manner. Technology sensitivities only impact results in the absolute zero scenarios, not the net zero scenarios.[48] Four technology sensitivities are modeled for the absolute zero scenarios (Table 39).

Table 39. Modeled Technology Sensitivities

Scenario	Technologies Available
Mature Only	Only mature (solar, wind, gas, li-ion, flow batteries, etc.)
Mature + H2	+ Hydrogen enabled gas
Mature + Emerging	+ Advanced nuclear, gas w/ carbon capture and storage, ultra-long duration seasonal storage
Mature + Emerging, No H2	- Hydrogen enabled gas

The capacity additions of absolute zero scenarios do not differ the most from the net zero scenarios until after 2040, with most pronounced differences in 2050. Compared to the Net Zero Carbon Base Scenario, absolute zero scenarios generally require additional resources for capacity and GHG needs (Figure 109). The scenarios (Absolute Zero Mature + H2, Absolute Zero Mature + Emerging) that assume hydrogen availability build H2-enabled gas to replace existing non-H2-enabled firm capacity that needs to be retired by 2050. When hydrogen is not available, for example in the Absolute Zero No H2 scenario, around 2GW of nuclear is built to replace existing firm capacity, and nuclear is heavily relied on to provide more than 20% of energy generation (Figure 110). The Absolute Zero Mature Only scenario drives extreme and impractical overbuild of solar and storage for GHG and Resource Adequacy (RA) needs. This scenario pushes the total installed capacity to around 60 GW, four times larger than what is required in the net zero scenarios.

[48] When allowed, dual fuel "H2 enabled gas" was selected in nearly all net zero carbon scenarios, but hydrogen fuel combustion was not utilized in these units on the RESOLVE representative days modeled. Enabling hydrogen combustion, even if not utilized to reach net zero, would make these new assets resilient to future policy changes that may push OPPD to an absolute zero requirement, since they have the option of burning natural gas fuel or zero-carbon biogas or hydrogen fuels.

Figure 109. OPPD Capacity Additions and Retirements (GW) of Absolute Zero Sensitivities in 2050

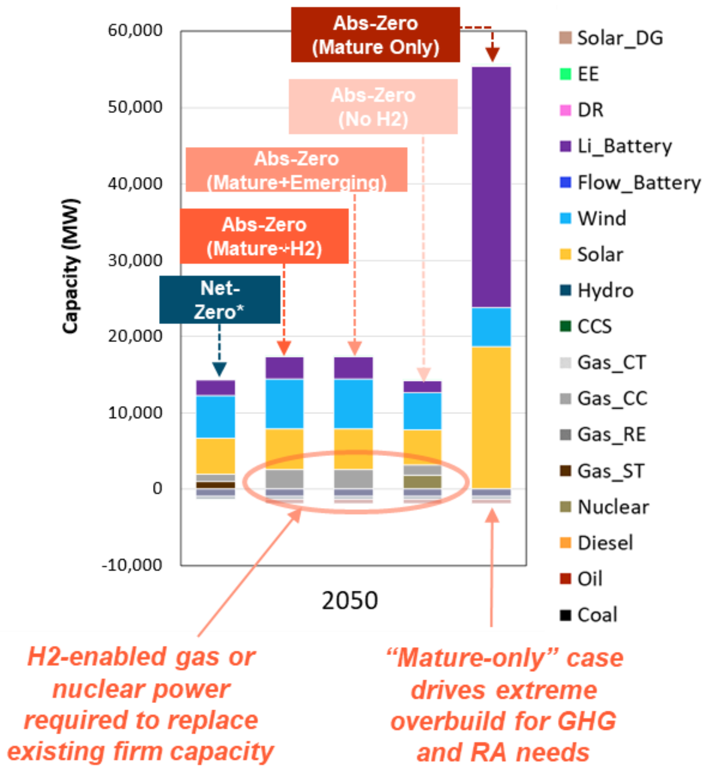
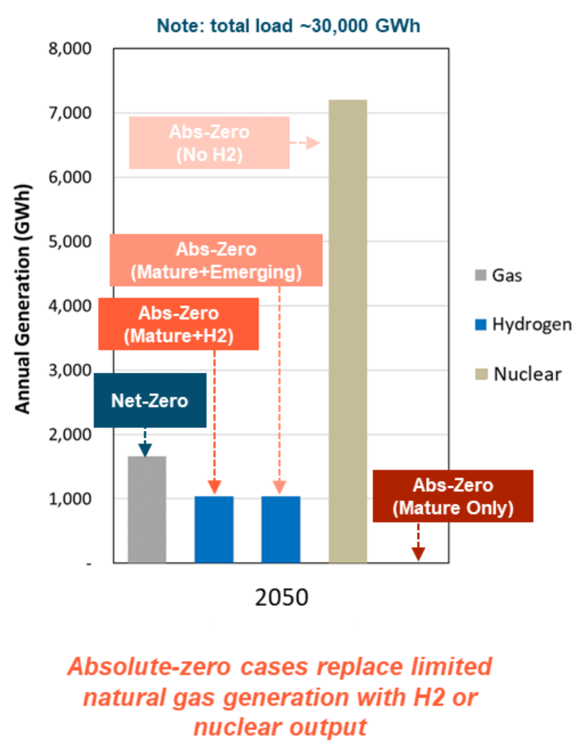


Figure 110. OPPD Firm Generation (GWh) of Absolute Zero Sensitivities in 2050



Given the additional resources required, absolute zero scenarios have higher cost impacts for OPPD by not allowing netting of on-system emissions with off-system emission offsets (Figure 111). The costs of the Absolute Zero Mature Only scenario increase drastically due to the overbuild of solar and storage and will have a large impact on OPPD customer bills. The generation costs increase about 9 cents/kWh and total system costs increase about $16,000 M relative to the Reference scenario (Figure 112). This scenario indicates that achieving absolute zero target requires emerging technologies to be viable and it is important for OPPD to monitor technology evolution and SPP decarbonization efforts when OPPD develops its decarbonization strategies.

Figure 111. Generation Costs (cents/kWh) relative to Reference for Absolute Zero Sensitivities

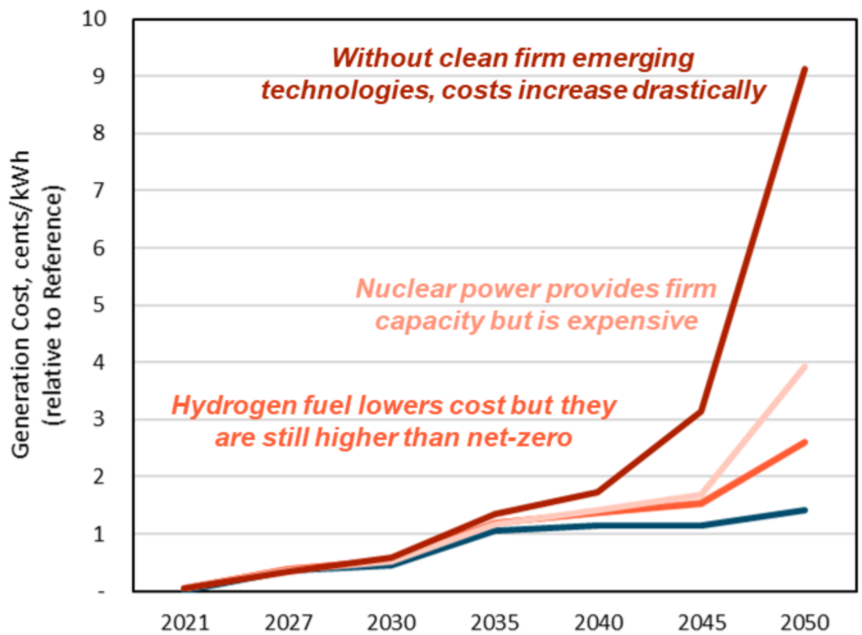
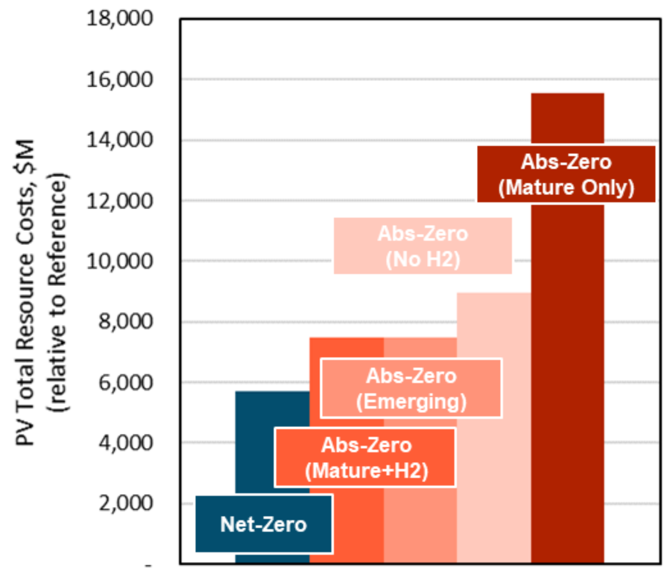


Figure 112. Total System Cost in Present Value ($M) relative to Reference for Absolute Zero Sensitivities



One key question arises with the significant renewable build is the impact of land use across scenarios. By accounting for both the direct[49] and indirect[50] land uses, absolute zero scenarios require more land use compared to the net zero scenarios except in the case where nuclear addition is allowed (Figure 113). The Absolute Zero Mature Only scenario requires substantially more land use due to very large solar additions. That being said, the land use impact of renewables in OPPD is small relative to the total land use available. For the net zero scenarios, the direct and indirect impact of solar is less than 0.1% of total land use and the direct and indirect impact of wind is just over 1% of total land use. Absolute zero scenarios will have higher, but still minimal, land use impact.

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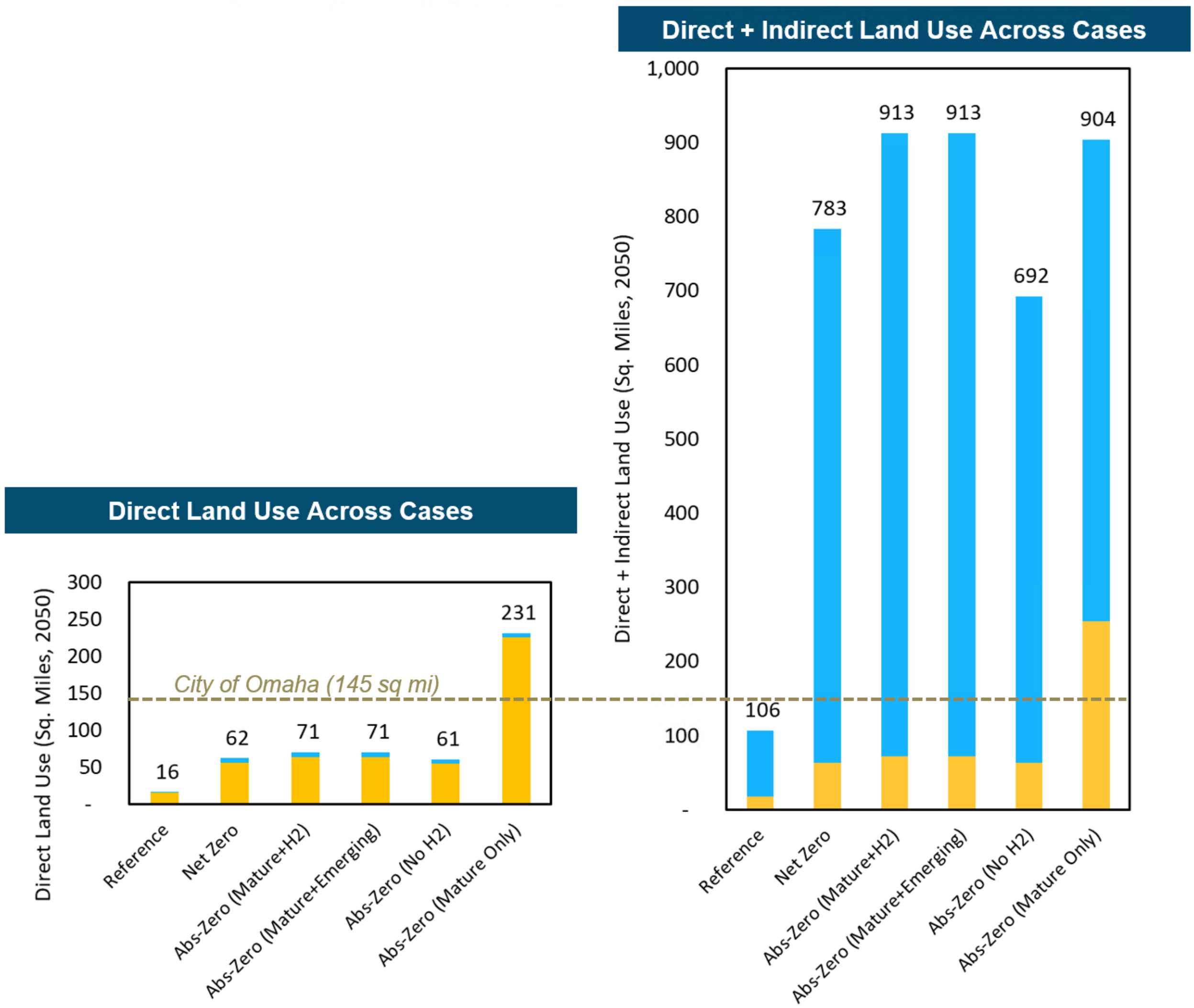
[49] Direct land use: Wind turbine foundations and solar racking and PV panel area. Solar energy has a larger direct land use impact compared to wind

[50] Indirect land use: Total land footprint between wind turbines and between the rows of solar panels. Wind energy has a significantly larger indirect land use impact compared to solar

Figure 113. Direct and Indirect Land Use Across Scenarios



6.3.6 Breakthrough Technology Costs Sensitivity

Breakthrough technology development can drive cost reductions faster than expected and a sensitivity scenario was developed to examine how lower technology costs will impact OPPD's future portfolio. This analysis assumes a decline in the costs of clean energy resources (wind, solar, storage, nuclear, etc.) using the inputs from NREL ATB Low-Cost Scenario and aggressive industry-based cost assumptions for small modular nuclear reactors.

With aggressive decline in technology costs, especially the costs of nuclear, RESOLVE selects 500 MW of nuclear in 2050 to displace 2,000 MW of H2-enabled gas, solar, wind and storage build in the Net Zero Carbon Base scenario (Figure 114). Small modular nuclear reactors with flexible ramping capability replaces gas and coal to provide firm capacity and meet RA needs. The significant cost decline assumed cuts the incremental generation cost increase (relative to the Reference scenario) almost by half (Figure

116). The total resource costs in present value are only $4,000 M higher than the Reference Scenario, $1,700M less compared to the Net Zero Carbon Base Scenario ($5,700 M relative to Reference).

Figure 114.OPPD Installed Capacity (GW) of Breakthrough Costs Sensitivity

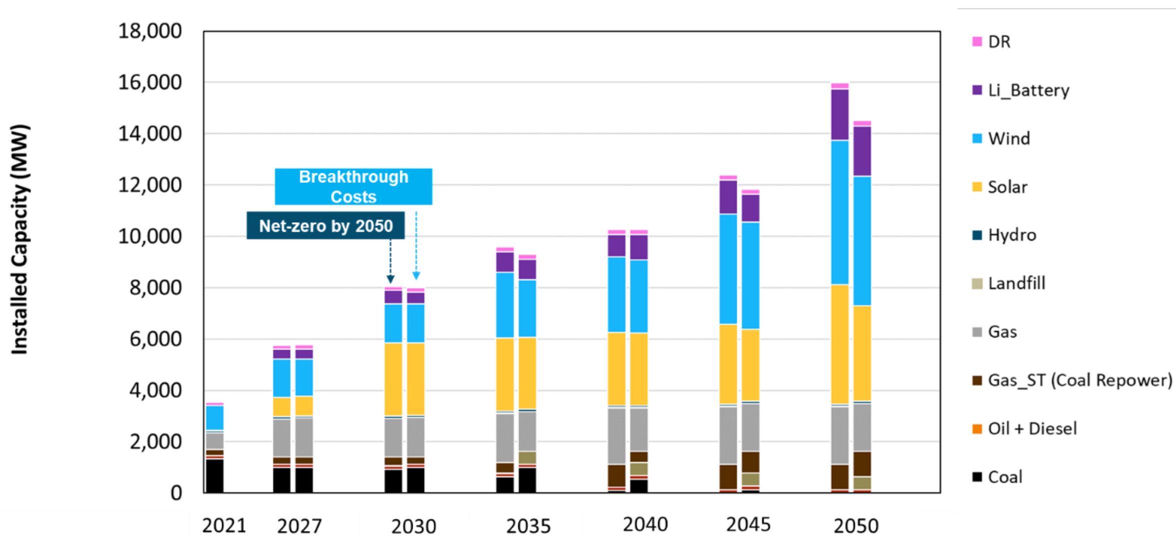


Figure 115. OPPD Annual Generation (GWh) of Breakthrough Costs Sensitivity

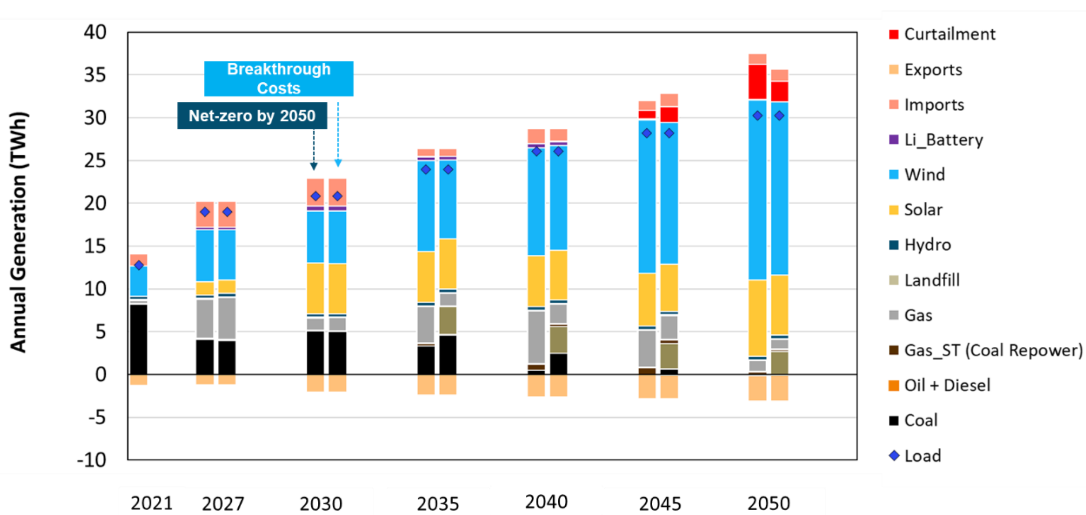
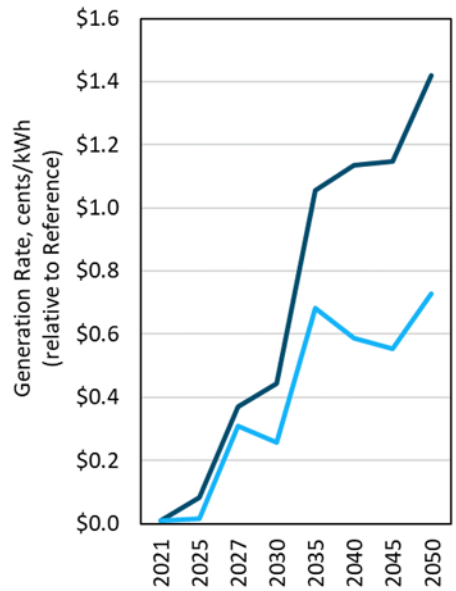


Figure 116. Generation Costs (cents/kWh) relative to Reference for Breakthrough Costs Sensitivity



6.3.7 High Flexible Loads Sensitivity

Supply-side investments may be replaced with cheaper flexible loads on the demand side. Additional flexible loads are assumed in the High Flexible Loads scenario to be available at a lower cost than bulk grid storage for RESOLVE to select. The potential of flexible loads is set to be 10% of the OPPD peak with 2-hour duration to shift load. The costs of flexible loads are calculated based on the LBNL DR Potential Study (Citation[51]) around $15/kW-yr or around $7.5 kWh-yr. These are estimates based on studies outside of OPPD due to a lack of data and future OPPD potential studies need to confirm the actual available supply and cost of flexible loads in OPPD.

With similar characteristics as energy storage, around 500 MW of flexible loads are selected in RESOLVE by 2050 to displace energy storage; however, due to use limitations, flexible loads cannot displace firm capacity needs (Figure 117). The present value of total resource costs under the High Flexible Loads scenario is around $5,380 M relative to the Reference scenario, which is around $340 M lower than the Net Zero Carbon Base scenario ($5,720 M relative to Reference). The availability of relatively cheaper flexible loads slightly reduces generation costs (Figure 119). Flexible loads show promise as an emerging resource and follow on studies should validate their potential and cost to implement within OPPD's footprint.

[51] Download Phase 3 DR Potential Study | Building Technology and Urban Systems Division (lbl.gov)

Figure 117. OPPD Installed Capacity (GW) of High Flexible Loads Sensitivity

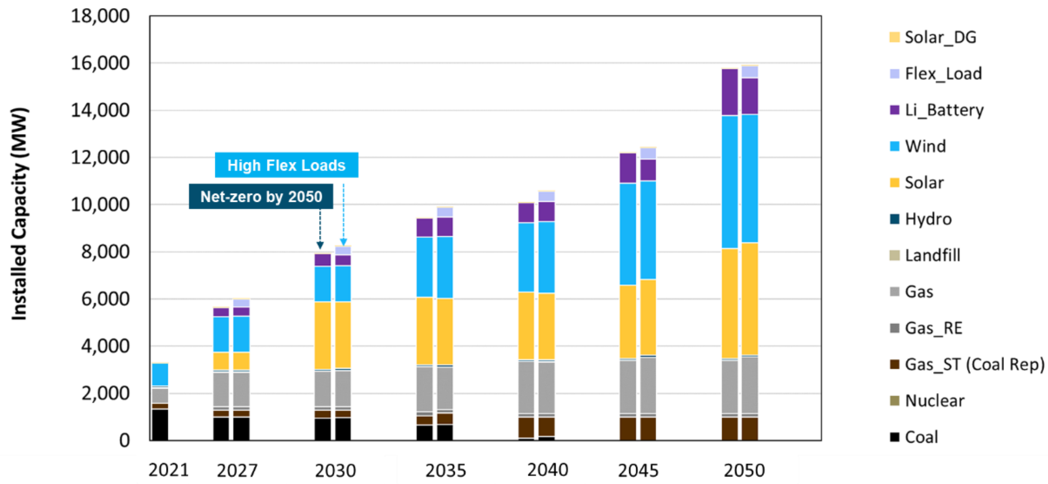


Figure 118. OPPD Annual Generation (GWh) of High Flexible Loads Sensitivity

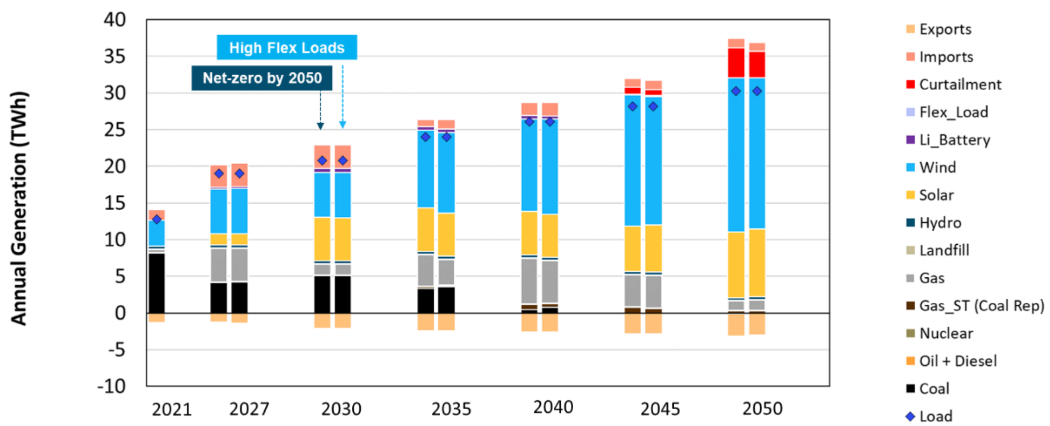
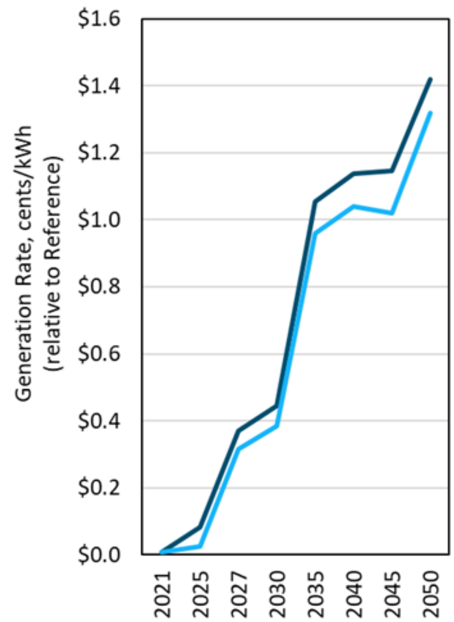


Figure 119. Generation Costs (cents/kWh) relative to Reference for High Flexible Loads Sensitivity



6.3.8 Carbon Price Sensitivity

One of the federal policy risks that OPPD faces is the enactment of carbon price. If imposed, carbon price will have a meaningful impact on OPPD's near-term portfolio as OPPD is still heavily dependent on fossil fuel generation but will have a relatively small impact in the long term as OPPD transitions away from carbon intensive fuels. This analysis is based on Biden White House interim Social Cost of Carbon that ramps from $0/ton in 2021 to $63/ton in 2030 to $87/ton in 2050 ("3% average" scenario).[52] The results show that carbon price accelerates GHG reduction with earlier coal repowering and selects to build more wind than solar in the near term to meet energy needs as coal and gas generation is significantly reduced (Figure 120). The carbon price scenario eliminates coal generation by 2035, rather than by 2045 in the Net Zero Carbon Base Scenario (Figure 121). A carbon price will increase generation cost and total resource costs significantly (Figure 122), though cumulative carbon emissions will be reduced. Ultimately, cost impacts will be determined by the use of carbon revenues; for instance, in California carbon price revenues are recycled to electric customers via a biannual rebate. While the graphs below show cost increases relative to a Reference scenario without a carbon price, a decarbonized scenario is lower cost than a reference scenario with a carbon price, assuming no portfolio changes from OPPD's current generation mix. In fact, additional federal or state policies, such as those that would create an industry-wide carbon price, would be a key launching point for other regional utilities to decarbonize their portfolios along with OPPD. A carbon price would ensure that regional electric emissions trend down consistent with the trajectories needed to address climate change mitigation.

[52] Technical Support Document: Social Cost of Carbon, Methane, (whitehouse.gov)

Figure 120. OPPD Installed Capacity (GW) of Carbon Price Sensitivity

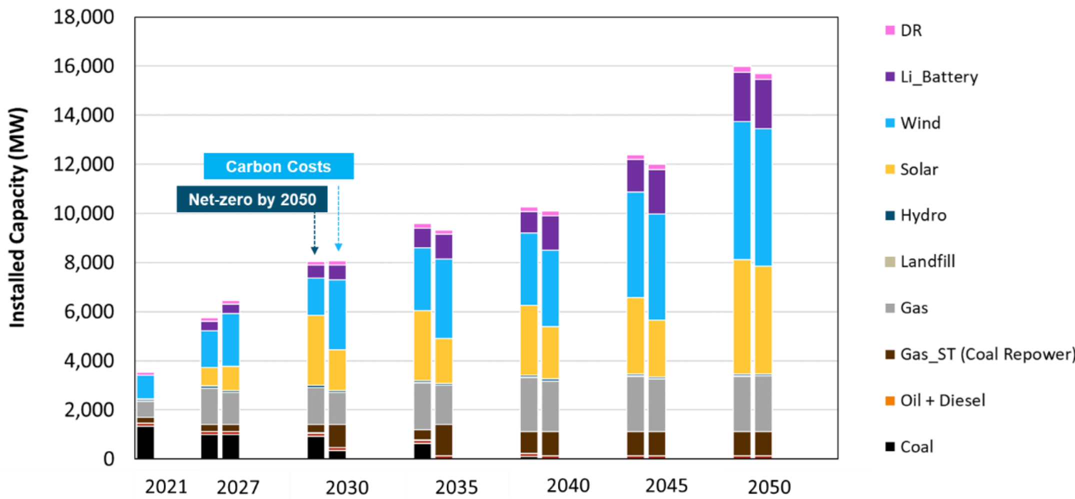


Figure 121. OPPD Annual Generation (GWh) of Carbon Price Sensitivity

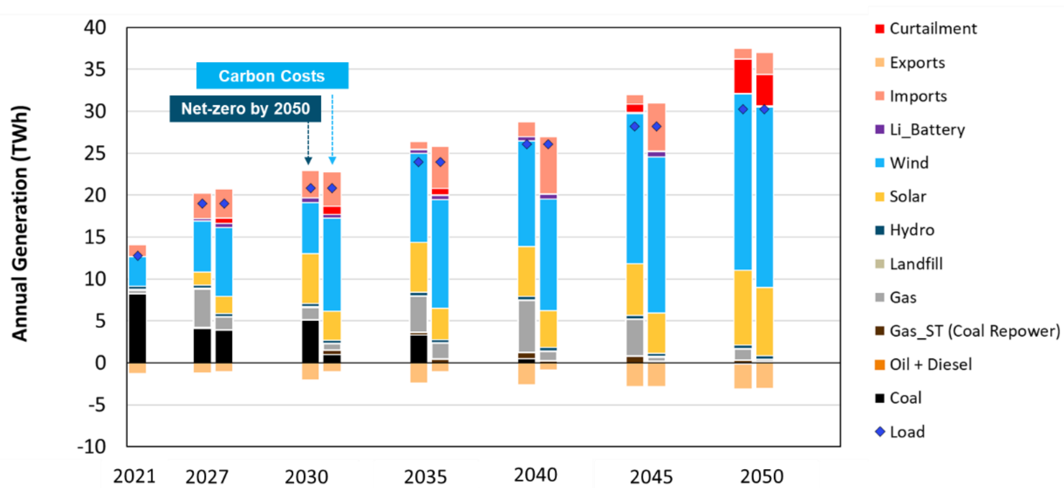


Figure 122. Generation Costs (cents/kWh) relative to Reference for Carbon Price Sensitivity

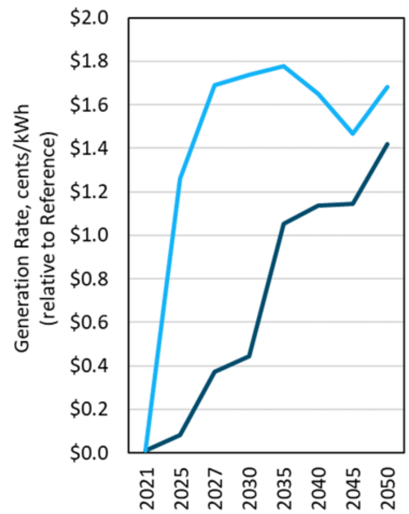
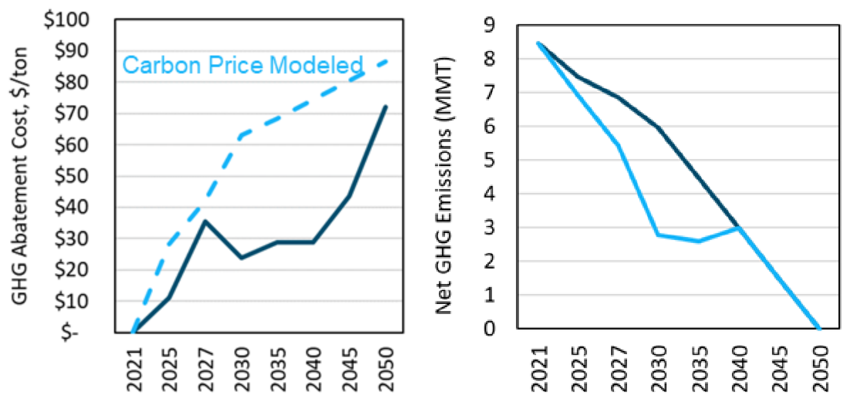


Figure 123. Carbon Cost and Emissions of Carbon Price Sensitivity



6.3.9 SPP Resource Portfolio Sensitivity

The SPP Resource Portfolio sensitivity assumes SPP's Reference loads (no electrification growth) with no emissions target while OPPD aims to achieve Net Zero with the Net Zero Balanced load forecast. This scenario examines the impact of low load growth and no emission target in SPP on the OPPD portfolio. Figure 124 shows that SPP resource portfolio has a limited impact on the total installed capacity of OPPD's portfolio since OPPD is built to be reasonably self-sufficient and less influenced by SPP market changes. SPP resource mix also has a minimal impact on OPPD's generation costs and total resource costs (Figure 126). While E3 did not adjust ELCCs for this scenario, if SPP-wide ELCCs were higher due to limited renewable growth in SPP then OPPD might be able to rely less on additional firm capacity (compared to the results shown below) but would be more dependent on transmission import capacity.

Figure 124. OPPD Installed Capacity (GW) of SPP Resource Portfolio Sensitivity

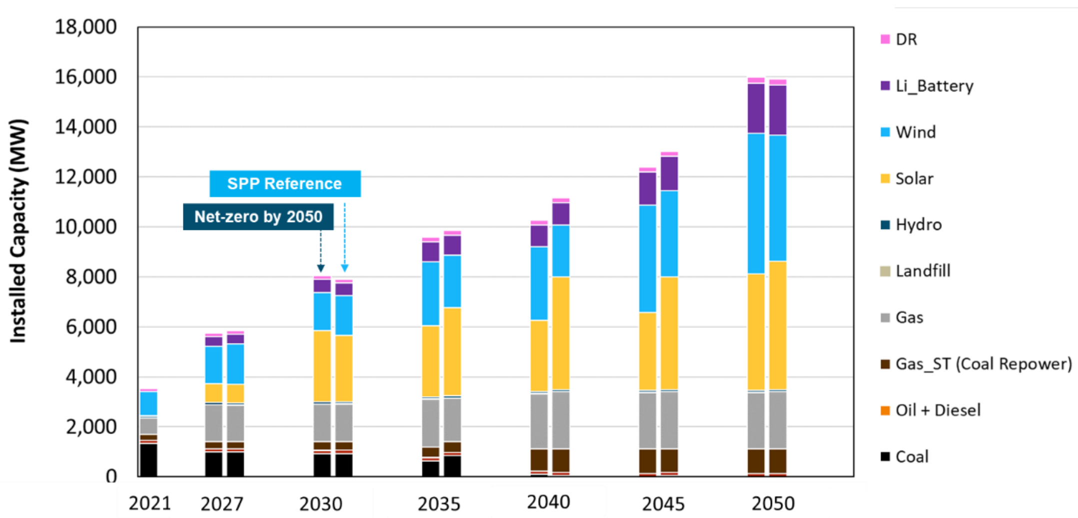


Figure 125. OPPD Annual Generation (GWh) of SPP Resource Portfolio Sensitivity

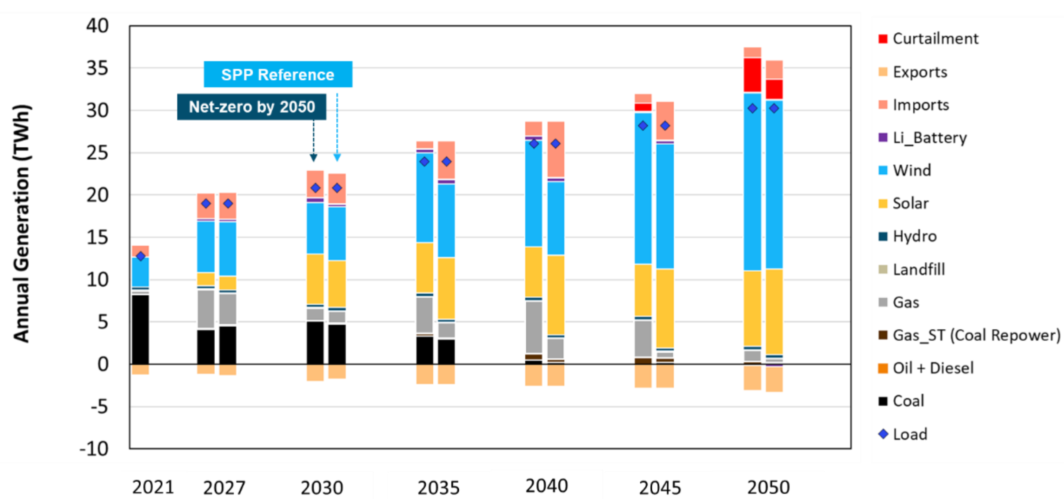
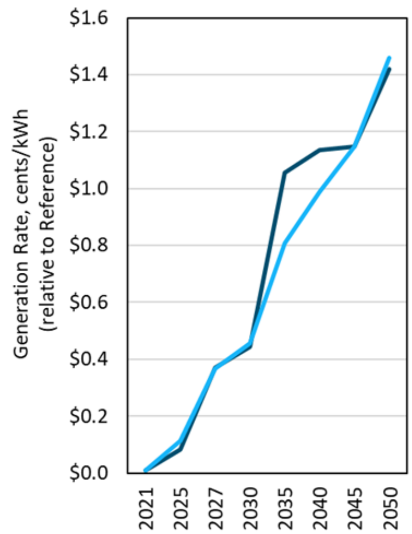


Figure 126. Generation Costs (cents/kWh) relative to Reference for SPP Resource Portfolio Sensitivity



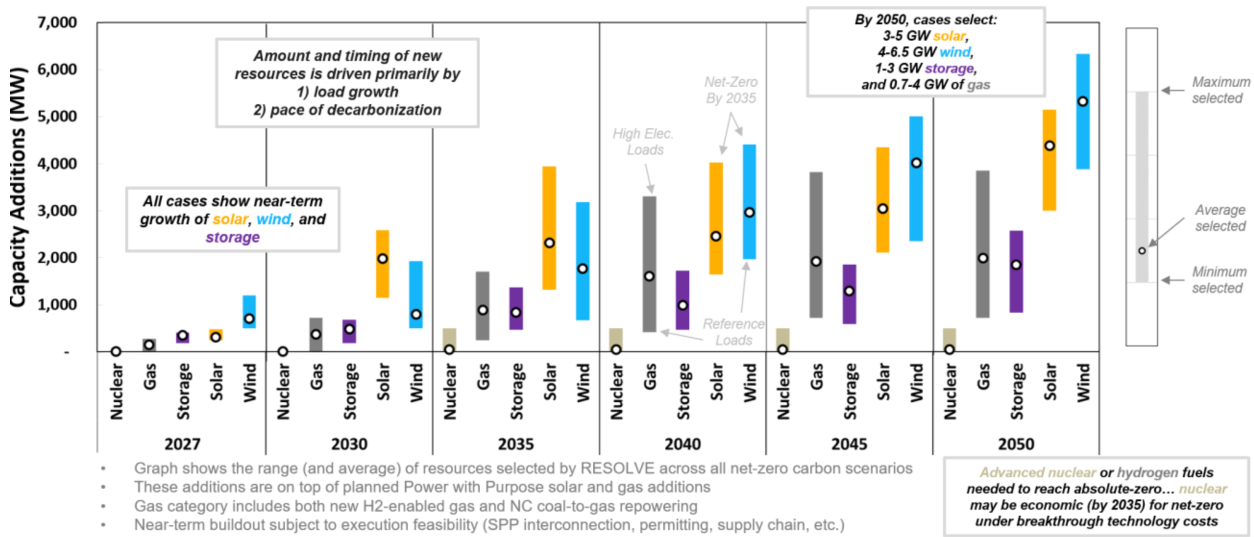
6.4 Summary of Key Results Across Scenarios

6.4.1 New Resource Needs

Across all the net zero carbon scenarios, RESOLVE selects to build new solar, wind, and battery storage as well as new hydrogen-enabled gas plants, though the exact amount of resource build varies by scenario. All cases show that there is a near-term need for incremental solar, wind, and storage additions by 2030, beyond planned additions. By 2050, RESOLVE selects to build 3-5 GW of solar, 4-6.5 GW of wind, 1-3 GW of storage and 0.7-4 GW of gas (including new H2-enabled gas and Nebraska City coal-to-gas repowering) in OPPD (Figure 127).[53] The amount and timing of new resources is driven primarily by load growth and the pace of decarbonization. Higher load growth results in larger resource needs, and faster decarbonization drives earlier resource build.

[53] These values are incremental to planned Power with Purpose solar and gas additions.

Figure 127. Range of Resources Added in Net Zero Scenarios



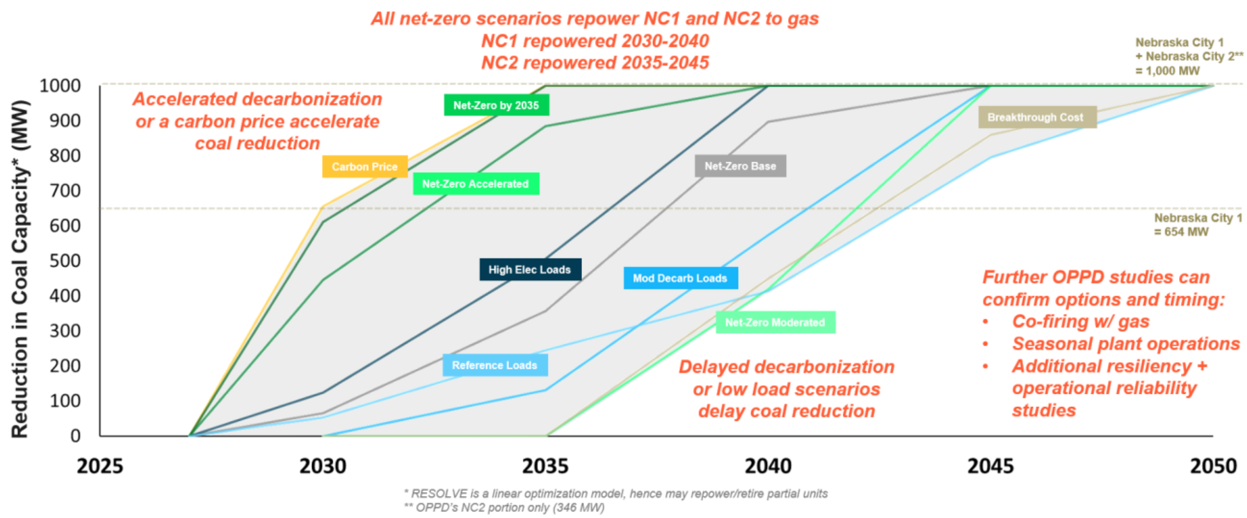
6.4.2 Coal Repowering

As shown in Figure 128, all net zero carbon scenarios modeled in RESOLVE show a need to repower Nebraska City Unit 1 and Unit 2 from coal to gas, though the exact timing of the repowering varies by scenario. One key question concerning OPPD decarbonization is when and how to retire the existing two Nebraska City coal units as OPPD transitions to net zero. The analysis shows that the retirement timeline of Nebraska City Unit 1 is around 2030-2040, around 5 years earlier than the 2035-2045 timeline of Nebraska City Unit 2.[54] Unit 2 started operation in 2009 and is a newer and more efficient generator with more advanced pollution controls. However, the exact dates require further studies of the financial and reliability impact of retiring these units. In all net zero carbon scenarios, the retirement of coal usage is coincident with a repowering of the Nebraska City units to natural gas, providing a low-cost form of firm capacity.

The scenarios that push the faster repowering of coal are the scenarios that accelerate decarbonization or have higher load growth (e.g., Carbon Price Scenario, Net Zero by 2035 Scenario, Net Zero Accelerated Scenario and High Electrification Scenario). In these scenarios, coal needs to be repowered faster to follow the more aggressive trajectories of decarbonization. For the scenarios that take a slower path to decarbonization or have lower load growth, repowering will be delayed, but all scenarios show that coal will need to be repowered by 2050 to achieve the net zero carbon target. In the near term, these coal units can also be operated seasonally or co-fired with gas to provide GHG emissions reduction before their repowering.

[54] Nebraska City Unit 2 stops coal operations by 2045 in all cases except for the Reference Loads and the Breakthrough Costs scenarios. In those two scenarios, coal operations fully cease in 2050.

Figure 128. Nebraska City (NC) Coal Capacity Reduction Across Net Zero Carbon Scenarios



6.4.3 GHG Emission Impacts

Achieving OPPD's Net Zero Carbon by 2050 goal significantly reduces greenhouse emissions relative to the Reference Scenario, while accelerated decarbonization pathways result in even lower cumulative GHG emissions from today to 2050. As shown in Figure 129, all the Net Zero scenarios achieve zero net carbon emissions by 2050 with the accelerated decarbonization and carbon price scenarios reducing emissions at a faster pace. The Reference scenario has high emissions because it included no emissions target and its emissions increase with load growth and contract expirations. Figure 130 shows the total cumulative GHG emissions over the 30 years from 2020-2050.

Figure 129. GHG Emissions Across Net Zero Scenarios, Benchmarked to the Reference Scenario

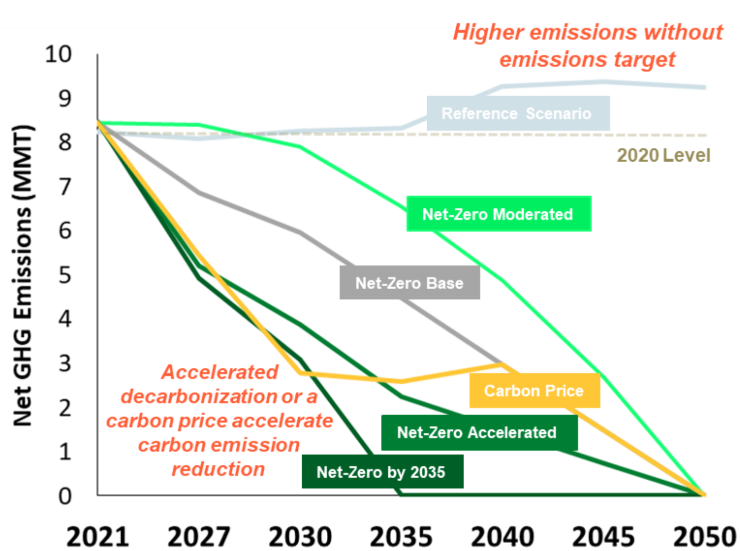
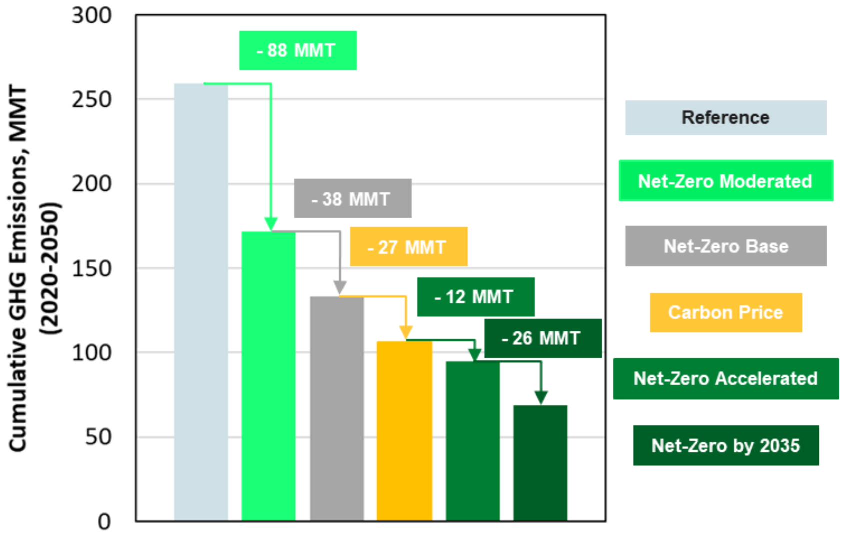


Figure 130. Total GHG Emissions from 2020 to 2050



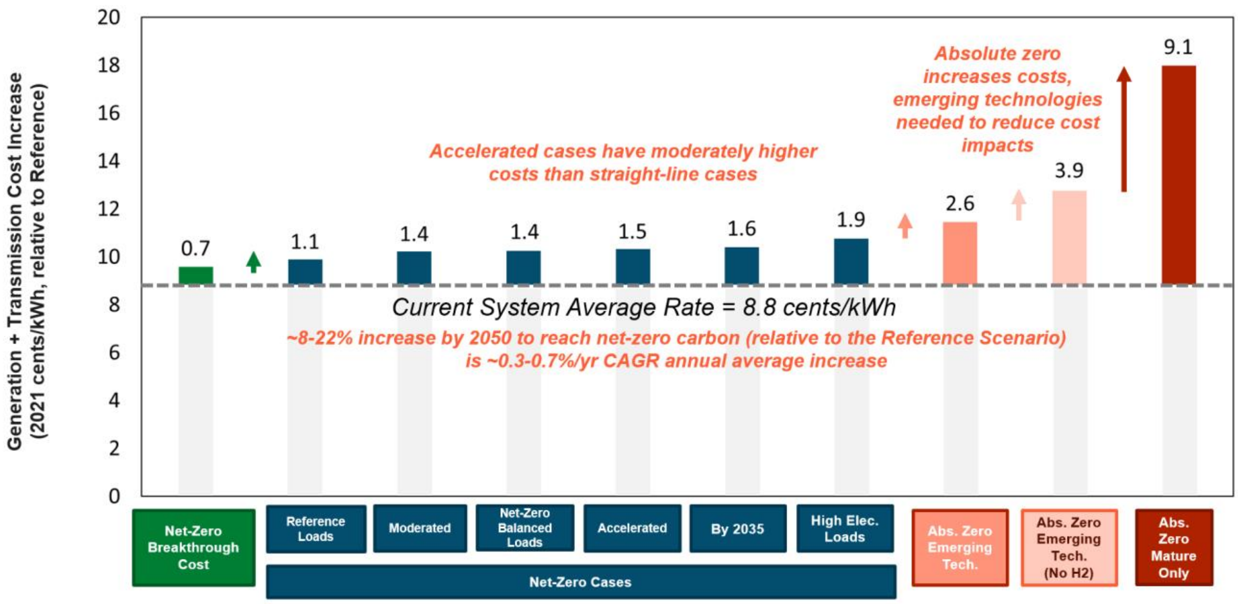
6.4.4 Costs Impacts

The analysis finds that OPPD can achieve its net zero carbon emissions goal while still ensuring affordable electricity to customers. Across all the net zero cases studied, the incremental cost of achieving net zero carbon is approximately 1.1 – 1.9 cents/kWh by 2050, which is a 12-22% increase compared to the current 8.8 cents/kWh OPPD system average rate (Figure 131). Averaged over time, customers are expected to only see a small annual increase of approximately 0.3-0.6% per year in rates attributable to OPPD's net zero carbon goal. These costs impacts are measured on a real dollar basis relative to the Reference case generation (and new transmission for generation) costs. This means they do not include the rate increasing impact of annual inflation and they did not include a comprehensive analysis of all utility revenue requirement components (such as distribution and transmission costs due to electrification, grid modernization, regional congestion, etc.).

If significant breakthrough reductions in clean energy costs materialize, the cost impact will be even smaller at an increase of 0.7 cents/kWh in 2050. On the contrary, achieving absolute zero carbon will be higher cost to OPPD. Achieving absolute zero carbon will result in higher costs increase ranging from 2.6 – 9.1 cents/kWh in 2050. The Absolute Zero Mature Only scenario shows that the costs of eliminating carbon emissions in OPPD will be significantly higher with only mature technologies like solar, wind and short-duration battery storage, while the availability of new emerging technologies such as hydrogen or advanced nuclear can reduce the costs of achieving absolute zero carbon.

It is worth mentioning that the accelerated decarbonization scenarios are only 0.1 or 0.2 cents/kWh more expensive than the Net Zero Carbon Base scenario by 2050 (Figure 130). This cost increase comes earlier but acceleration also results in higher cumulative GHG emissions reductions by 2050.

Figure 131. Costs Impacts of Decarbonization (Relative to the Reference Scenario)[55]



55 Costs include generation cost impacts and transmission costs (transmission for new generation, i.e. interconnection, deliverability). Costs are directional in nature, are not representative of detailed financial modeling, and do not include all costs that may be required to support grid transformation. Full rate impact analysis should also include distribution + transmission cost impacts due to electrification, grid modernization, regional congestion, etc. A carbon tax (or change in fossil fuel prices) would decrease or eliminate the incremental costs of decarbonization relative to the reference scenario. Total customer cost impacts should also include holistic impact of higher electricity costs with gasoline and natural gas savings due to electrification.

7 Portfolio Risk Analysis

7.1 Risk Analysis Approach

A decarbonized electricity system presents a very different risk profile than a traditional electricity system. The costs of a decarbonized electricity system are predominantly fixed costs from long-term asset investments or PPAs rather than limited fixed costs and high variable fuel costs commonly faced by the traditional carbon-emitting electricity system. Therefore, the more relevant risks for a decarbonized electricity system are more related to technology evolution and stranded costs rather than fuel prices or environmental regulations like carbon prices or taxes. As OPPD shifts towards a decarbonized electricity system, the key risk questions that OPPD needs to answer are:

+ What risks would cause a change to the optimal pathways to decarbonization portfolios selected?
+ What investments can OPPD make in the near-term that can be considered “no regrets”?
+ What risk mitigation strategies should OPPD consider?

A portfolio risk analysis was conducted for OPPD by unpacking and comparing the capacity additions under different scenarios and sensitivities modeled to identify risks by each technology in the near term (2030) and long term (2050). It examines both the key risk uncertainties that are generally out of OPPD’s control as well as load uncertainties that are more adaptable by OPPD since they will manifest over time. The portfolio risks analysis focuses on the financial risk that the portfolio diverges from the least-cost outcome. The Reliability and Resiliency Chapter of this report focuses on system reliability and resiliency risks.

7.2 Risk Analysis Results

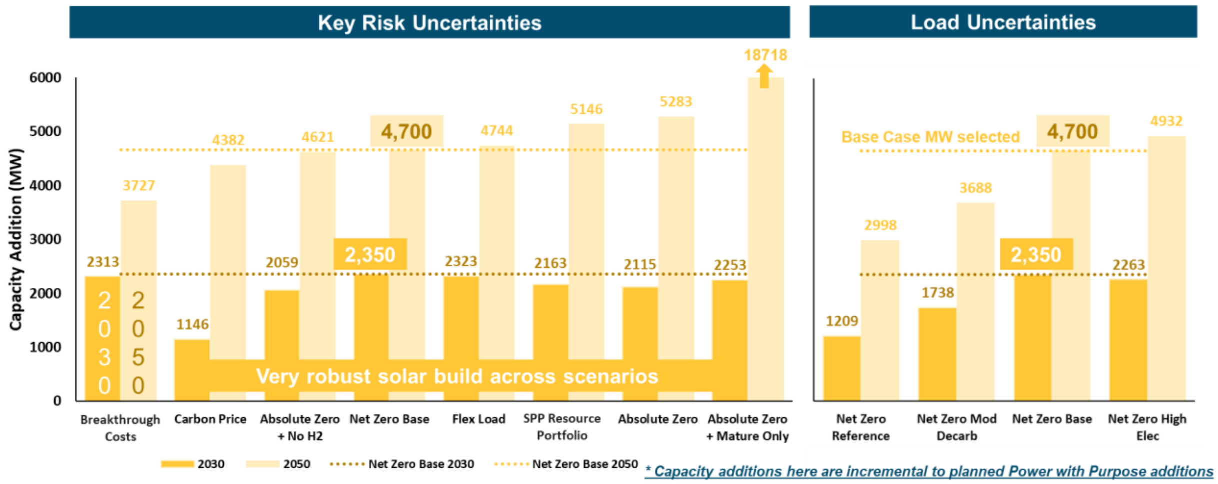
7.2.1 *Solar Risk Analysis*

Figure 132 shows that across all scenarios, there is a robust amount of solar that needs to be built in OPPD on top of the planned solar in Power with Purpose to achieve net zero. Therefore, it is low risk to build significant quantities of solar. The system needs at least around 1,150 MW of solar build in 2030 and 3,000 MW in 2050, and the Net Zero Carbon Base scenario builds around 2,350 MW of solar in 2030 and 4,700 MW in 2050.

In the near term, only the Carbon Price scenario and low load growth scenarios build less solar than the Net Zero Carbon Base scenario. The reason behind the reduced investment of solar in the Carbon Price scenario is because the presence of carbon prices pushes earlier conversion of the existing Nebraska City coal units to gas and reduces gas consumption. Therefore, the system needs to build additional renewables to supply energy and selects to build more wind to serve the system at night when solar is not shining. After adding together solar and wind, most net zero carbon scenarios show similar quantities of renewable build to meet GHG and reliability needs.

In the long term, there are more uncertainties on solar build, primarily driven by load growth and technology costs, but OPPD can adapt to these risks by monitoring load growth and technology cost evolution. Only the Absolute Zero Mature Only scenario shows substantially high solar addition, however that scenario is uneconomic for OPPD to pursue.

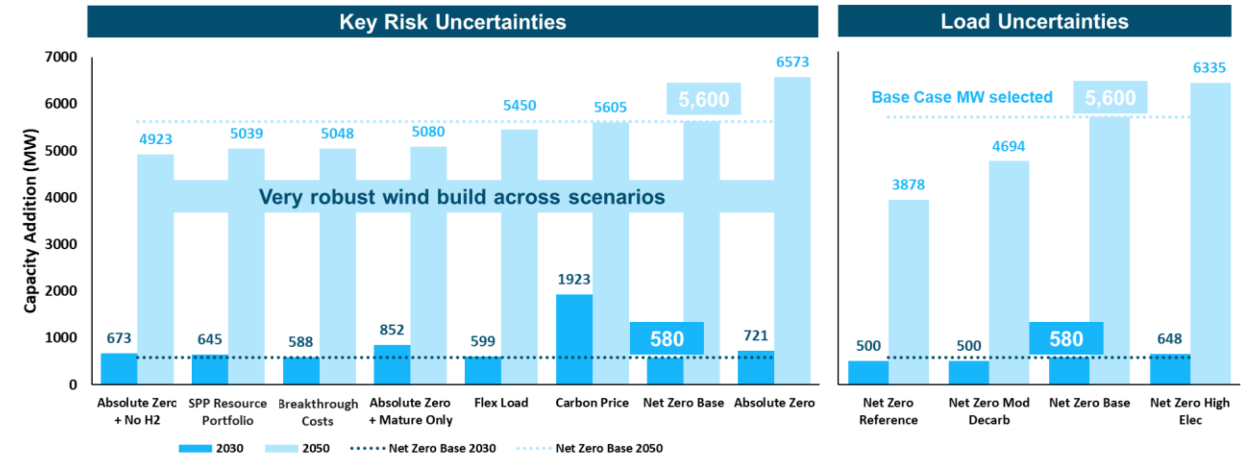
Figure 132. Solar Capacity Addition Uncertainties by Scenarios



7.2.2 Wind Risk Analysis

Like solar, across all scenarios, a large quantity of wind is selected in all scenarios. Therefore, it is low risk for OPPD to pursue additional wind power (Figure 133). The Net Zero Carbon Base scenario selects around 580 MW of wind in 2030 and 5,600 MW of wind in 2050. The quantity of wind selected is relatively consistent across most scenarios around 500-800 MW of wind in the near term except for the Carbon Price scenario (explained in Solar Risk Analysis above). In the long term, the highest uncertainty for wind comes from load uncertainties but OPPD can adapt by increasing or decreasing the pace of additions over time as load evolves.

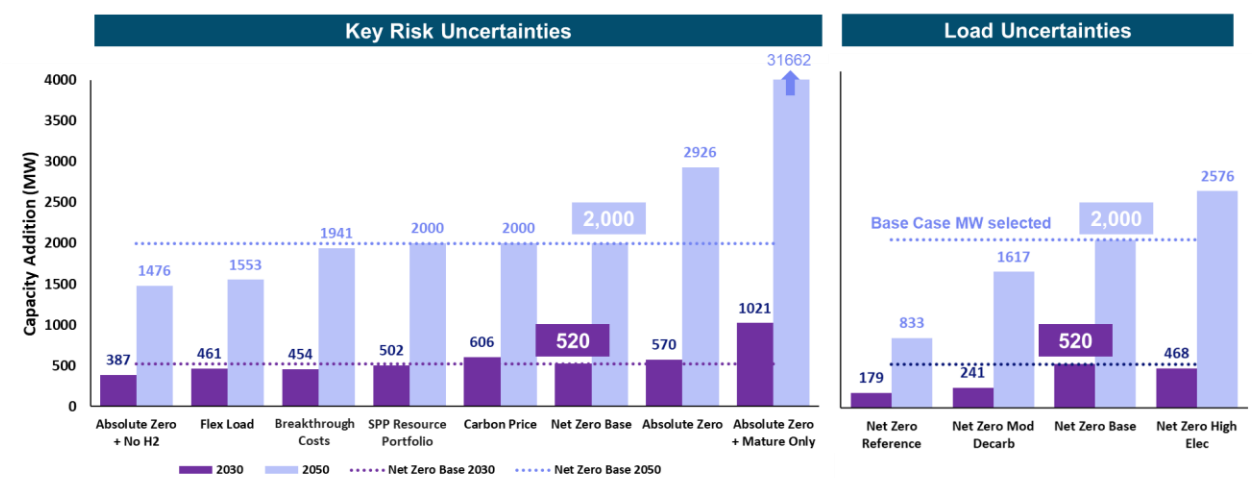
Figure 133. Wind Capacity Addition Uncertainties by Scenarios



7.2.3 Energy Storage Risk Analysis

Like solar and wind, all scenarios select a robust amount of energy storage, thus signifying a low risk to building energy storage. In the near term, around 200 – 600 MW of storage is selected, except for the Absolute Zero Mature Only scenario where higher storage build is needed due to no new gas or emerging clean firm resources being allowed (Figure 134). The Absolute Zero Mature Only scenario also requires a substantial and infeasibly expensive amount of storage build coupled with the very high solar build in the long term.

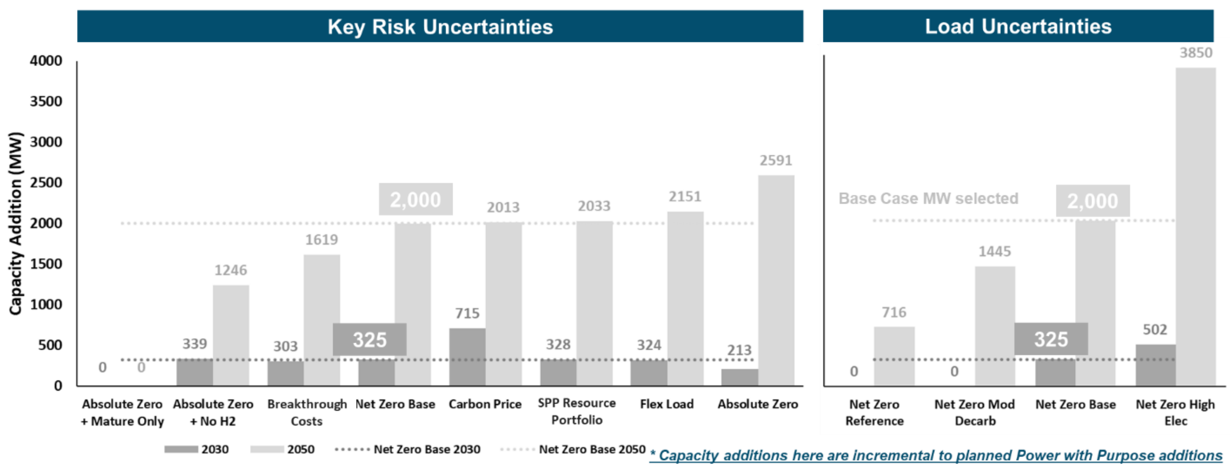
Figure 134. Energy Storage Capacity Addition Uncertainties by Scenarios



7.2.4 New Firm Capacity Risk Analysis

The new firm capacity additions risk analysis focused on the addition of new power plants that can utilize either natural gas and/or multi-fuel enabled plants that can burn natural gas, biogas, or green hydrogen. Figure 135 shows that all scenarios need to build new firm capacity except when it is explicitly excluded as an option in the Absolute Zero Mature Only scenario. The analysis proves that firm capacity addition incremental to Power with Purpose additions is an optimal component of a net zero carbon portfolio, particularly in scenarios with electrification load increases. As described earlier in the report, firm capacity resources are necessary to maintain resource adequacy, even if their average annual operations remain low. Any emissions from natural gas generation in 2050 would be offset by renewable exports in the net zero carbon scenarios and the option of combusting hydrogen or biogas can minimize the risk of stranding investments if OPPD pursues an absolute zero carbon target. The Net Zero Carbon Base Scenario selects to build around 325 MW of new or repowered gas plants in 2030 and 2,000 MW in 2050. High electrification load scenario will demand almost double the new firm capacity in the long term to meet the peak heating challenge in winter relying solely on the electric system, but OPPD has time to adapt and plan for it as load evolves.

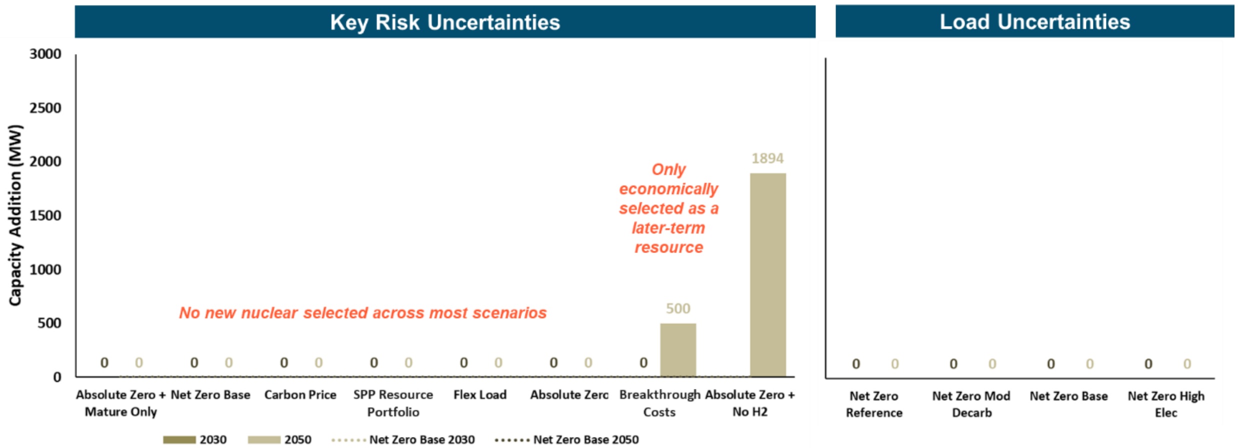
Figure 135. New Firm Capacity Addition Uncertainties by Scenarios



7.2.5 Nuclear Risk Analysis

Nuclear is an available option in most scenarios in the long term but is only economic 1) when there is an aggressively low cost assumed for the Small Modular Reactors or 2) when hydrogen generation is unavailable in the absolute zero scenario (Figure 136). Therefore, it is high risk for OPPD to pursue nuclear unless real-world project costs align with the low-cost scenario, though OPPD can re-assess advanced nuclear cost-effectiveness in the long term as the technology evolves.

Figure 136. Nuclear Capacity Addition Uncertainties by Scenarios



7.3 Risk Mitigation Strategies

To mitigate the risks, OPPD can develop risk mitigation strategies in the short term and long term. Table 40 summarizes the mitigation strategies in response to each risk factors identified in RESOLVE sensitivities (highlighted in blue) and addressed in the Reliability and Resiliency Chapter of this report (highlighted in green). For the other risks that are not covered by this report (highlighted in beige), it is proposed to OPPD to address them in future studies.

Table 40. Risk Mitigation Strategies

Time	Risk Factors	Mitigation Strategies
Short Term	**Carbon pricing** is implemented by the federal government	• Monitor federal climate policy development + continue modeling carbon price sensitivity scenarios • Advocate for returning carbon revenues to electric customers to avoid high electric rate increases
	If **investments in new resources are unable to be recovered** before those investments exit the market (e.g. new gas plants are built but cannot operate due to earlier / more stringent carbon regulations)	• Ensure new firm capacity investments allow zero-carbon fuel (biogas, hydrogen, etc.) blending
	Load growth, load flexibility is more or less than anticipated	• Continue studying sensitivity scenarios with a range of load forecasts • Develop flexible load pricing/programs and incorporate into future resource planning
	Solar and wind resources face large scale outages during extreme weather (e.g., polar vortex)	• Require new renewables to use best in class winterization resiliency investments, such as wind turbine de-icing and solar snow cover mitigation (e.g., use of tracking vs. fixed tilt panels)

		• Ensure sufficient firm capacity resources to provide backup generation during low solar and wind events
	Renewable integration creates new operational challenges (e.g. increasing operating reserves to address forecast error, need to grid forming inverters for synthetic inertia, etc.)	• Support long-term deep decarbonization scenarios in SPP's Integrated Transmission Planning process to identify required transmission + operational reliability investments • Ensure new solar, wind, and energy storage can provide operating reserves and other essential reliability services (economic dispatchability, frequency regulation, synthetic inertia, reactive power + voltage support, etc.)
	Transmission interconnection costs are higher than anticipated (or cause development delays)	• Support proactive regional planning to identify least-regrets transmission upgrades to support high-quality, low-impact solar and wind development areas • Advocate at SPP and FERC to support interconnection process reforms
Long Term	**SPP regional market dynamics or climate policies change**, changing the market value (energy, RA capacity, etc.) of OPPD's resources	• Monitor and participate in long-term SPP regional studies and near-term RA accreditation rulemaking • Assess OPPD RA capacity position using the latest available SPP ELCCs (and, as needed, develop forecast(s) of near- to mid-term SPP ELCCs) • Utilize long-term, fundamentals-based energy and A/S price forecasts
	Technologies modeled do not become unavailable or are more costly than assumed (e.g., hydrogen, advanced nuclear, etc.)	• Continue studying sensitivity scenarios of emerging technologies based on best available cost projections
	Technologies not modeled become available and cost-effective (e.g., ultra long-duration batteries, 100% capture CCS, low-cost biofuels, etc.)	• As dependable data becomes available, incorporate new emerging technologies into resource planning • Ensure all-source competitive resource solicitations open to and able to effectively value all resource options
	Fuel prices are higher than anticipated (coal, natural gas, hydrogen, etc.)	• Adapt resource strategy as prices change (e.g., if fuel switching to gas and gas fuel fundamentals shift, adopt more solar and wind) • Refine hedging strategies to limit price exposure consistent with utility risk management strategies

7.4 Risk Analysis Conclusions

The risk analysis concludes that investing in significant quantities of wind, solar, and battery storage is a robust and low-risk action for OPPD to achieve net zero targets. By 2030, RESOLVE selects a *minimum* of 1,100 MW of solar, 500 MW of wind and 150 MW of battery storage that are incremental to the planned Power with Purpose solar. These investments are no regrets. Investments made over the minimum should be considered low regret since it helps OPPD move forward 2035-2050 capacity additions and provides additional GHG savings. However, building at the minimum amount may not be a least-regret strategy because it under-procures resources under many scenarios and may delay OPPD's progress to achieve net zero carbon.

New firm capacity additions (that can utilize natural gas, biogas, or green hydrogen) are consistent with and an optimal component of a net zero portfolio. Across a range of key risk uncertainties, new firm capacity additions are selected to ensure system reliability.

Nuclear is only a cost-effective resource if costs drop dramatically or OPPD cannot develop hydrogen-ready natural gas generation. As nuclear technology development evolves, OPPD can reassess the economics and feasibility of nuclear in future decarbonization studies.

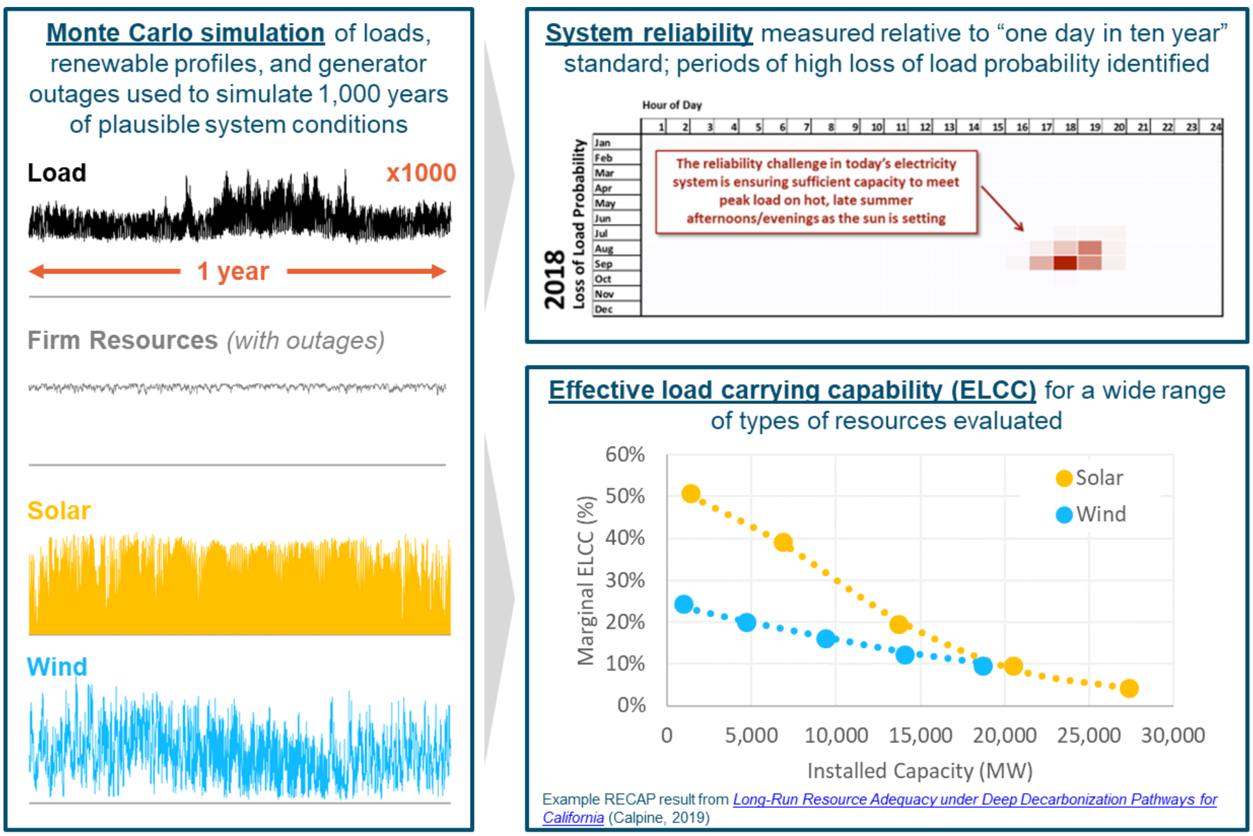
The focus of this decarbonization study is to inform OPPD's procurement decisions in the next decade and ensure near-term procurement decisions are consistent with OPPD's long-term goal in 2050. As technology matures and load grows, **OPPD should continue to monitor long-term uncertainties and risks and adjust its procurement plans over time**.

Appendices

A. RECAP Model Methodology

RECAP is a time-sequential Monte Carlo based model that evaluates hourly resource availability over thousands of simulated years. RECAP has been used by a number of utilities and state commissions across North America.[56]

Figure 137. Overview of the RECAP Loss-of-load-probability Model



RECAP was initially developed for the California Independent System Operator (CAISO) in 2011 to facilitate studies of renewable integration and has since been adapted for use in many jurisdictions across North America, as shown in Figure 138. Recently, RECAP has been applied in a California-wide context for the study *Long-Run Resource Adequacy Under Deep Decarbonization Pathways for California*, as well as recently in the *California Independent System Operator's Energy Storage and Distributed Energy Resources*

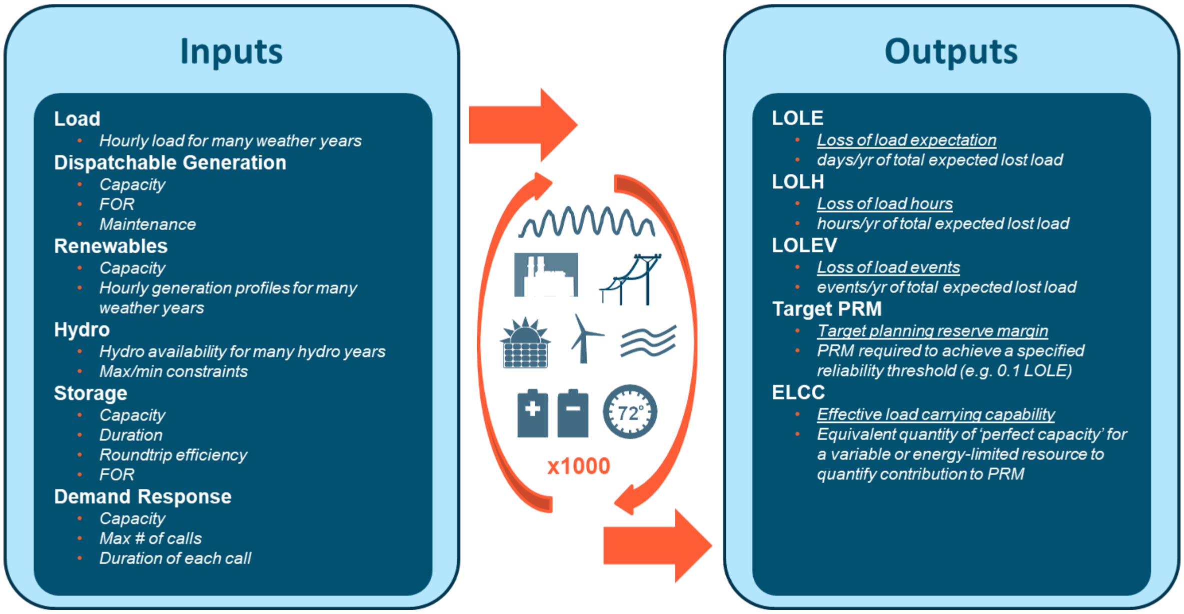
[56] California PUC, Portland General Electric, Sacramento Municipal Utilities District, Los Angeles Department of Water and Power, El Paso Electric, Xcel Minnesota, WECC, Florida Power and Light, New York State Research and Development Authority, New England ISO, Nova Scotia Power, and more.

[4 stakeholder process](#) to evaluate the capacity contribution of “shed” demand response programs in California.

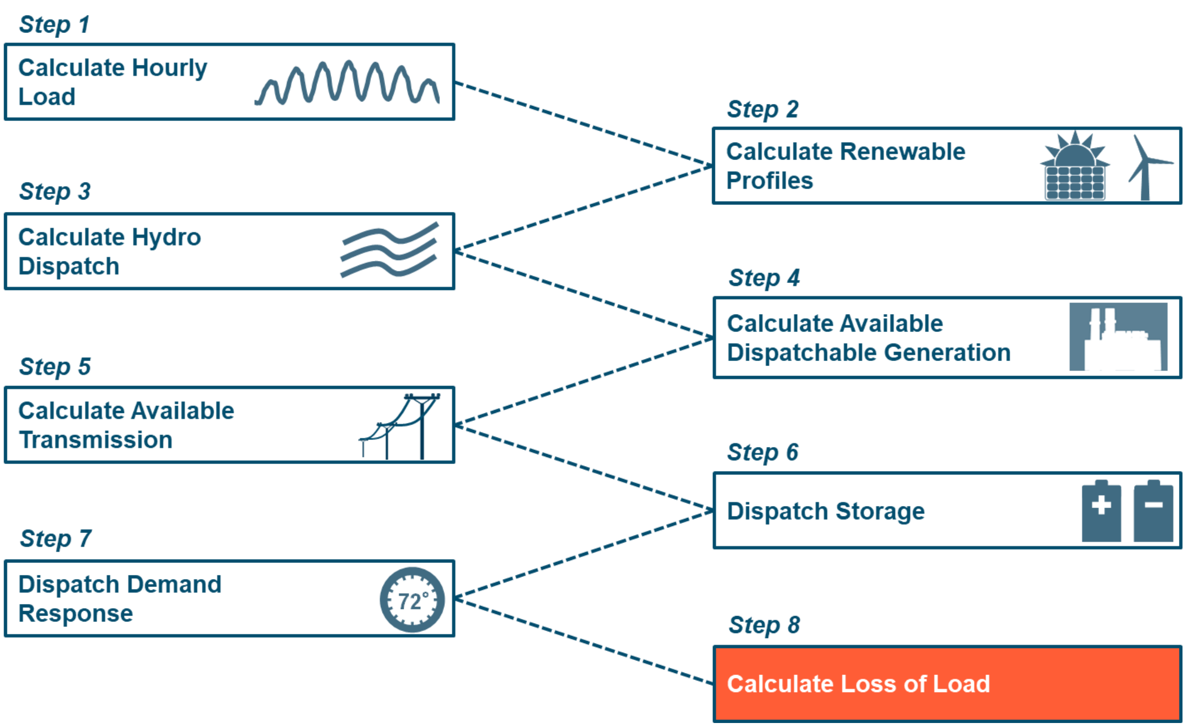
Figure 138. Map of E3 RECAP Projects

RECAP was developed specifically to address the needs of a changing electricity sector by incorporating the unique characteristics of dispatch-limited resources such as wind, solar, hydro, batteries, and demand response into the traditional reliability framework. RECAP calculates a variety of reliability-specific metrics useful to utilities in planning including loss of load expectation (LOLE) or loss of load hours (LOLH), the target planning reserve margin (PRM) required to meet a specified loss of load expectation target, and effective load carrying capability (ELCC) that quantifies the contribution of dispatch-limited resources toward the PRM requirements of the system.

RECAP calculates these metrics through by simulating the electric system with a specific set of generating resources and loads under a wide variety of weather years, renewable generation years, and stochastic forced outages of electric generation resources and imports on transmission. Correlations enforced within the model capture linkage among load, weather, and renewable generation conditions. Time-sequential simulation tracks the state of charge and energy availability for dispatch-limited resources such as hydro, energy storage, and demand response. By simulating the system thousands of times with different combinations of these factors, RECAP provides robust, stochastic estimation of LOLE, target PRM, and other reliability statistics shown in the figure below.

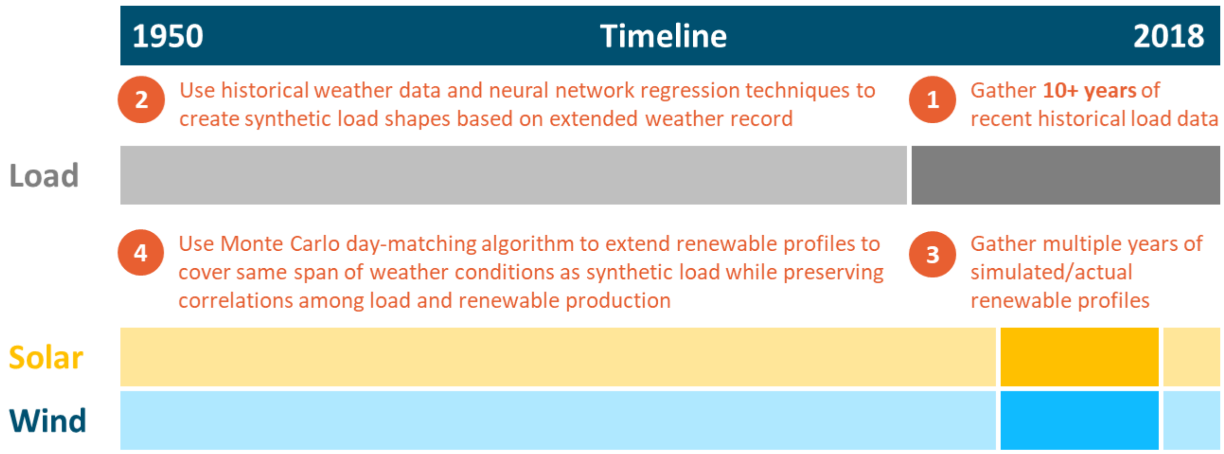


A broad overview of the time-sequential methodology of the model is shown in the diagram below.



Capturing a wide range of potential load, wind, and solar conditions while preserving the underlying relationships between them is crucial to performing a robust loss-of-load-probability analysis. Raw data covering a sufficient range of conditions is often unavailable, and so RECAP has a process for extending profiles to cover a large range of years as demonstrated in the figure below.

Figure 139. Methods Used to Extend Load and Renewable Data Sets to Cover Long-term Weather Record



Effective Load Carrying Capability

E3 will use RECAP to calculate effective load carrying capability (ELCC) values for variable and energy-limited resources as inputs into the portfolio optimization analysis. ELCC measures the ability of non-firm resources such as wind, solar, storage, hydro, and demand response to contribute to the PRM while still maintaining an equivalent level of system reliability. Equivalently, ELCC is the quantity of "perfect capacity" that could be replaced or avoided with renewables or storage while providing equivalent system reliability. A value of 50% means that the addition of 100 MW of a variable resource could displace the need for 50 MW of firm capacity without compromising reliability.

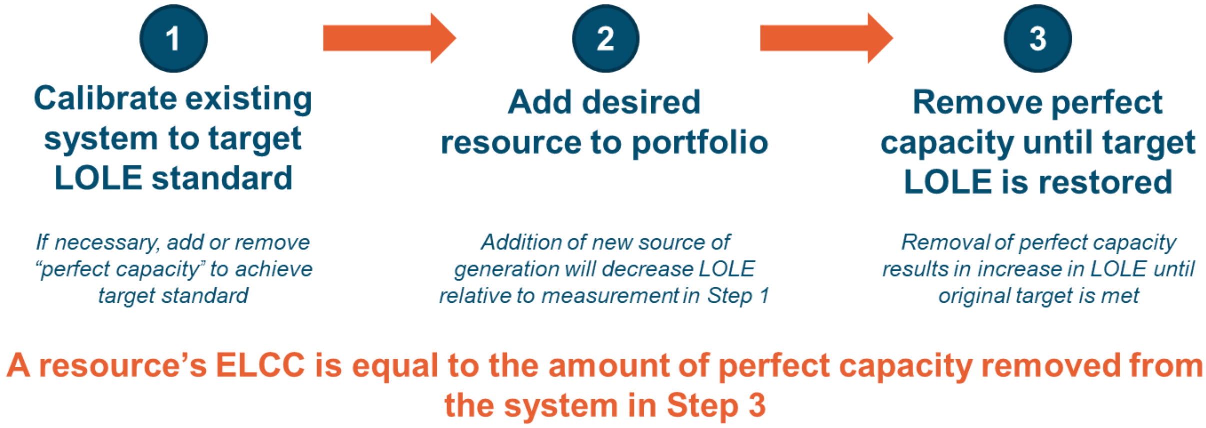
This metric was first introduced in the 1960's as a method of estimating the effect of a change in a conventional unit's capacity or forced outage rate but it has been adapted for evaluating the capacity contribution of variable resources such as wind, solar, and non-dispatchable hydro. ELCC is the most rigorous and accurate measure of a resource's contribution to reliability, but it is also one of the most complex, requiring significant data and computer modeling horsepower.

ELCC is calculated via the following procedures, assuming that the utility uses an LOLE reliability standard:

1. **Calculate base system LOLE**
2. **Add variable resource(s) to the system and re-calculate LOLE**
    - **Due to the new variable resource(s), available generation in each hour is now greater than or equal to the base system which improves reliability (i.e. decreases LOLE)**
3. **Add flat load (or remove perfect generation) to the system until reliability returns to base system LOLE**
    - **Adding flat load (i.e. the same quantity of load in each hour) to the system reduces reliability (i.e. increases LOLE)**

This process is illustrated in the figure below.

Figure 140. Overview of Methodological Steps to Calculate a Resource's ELCC

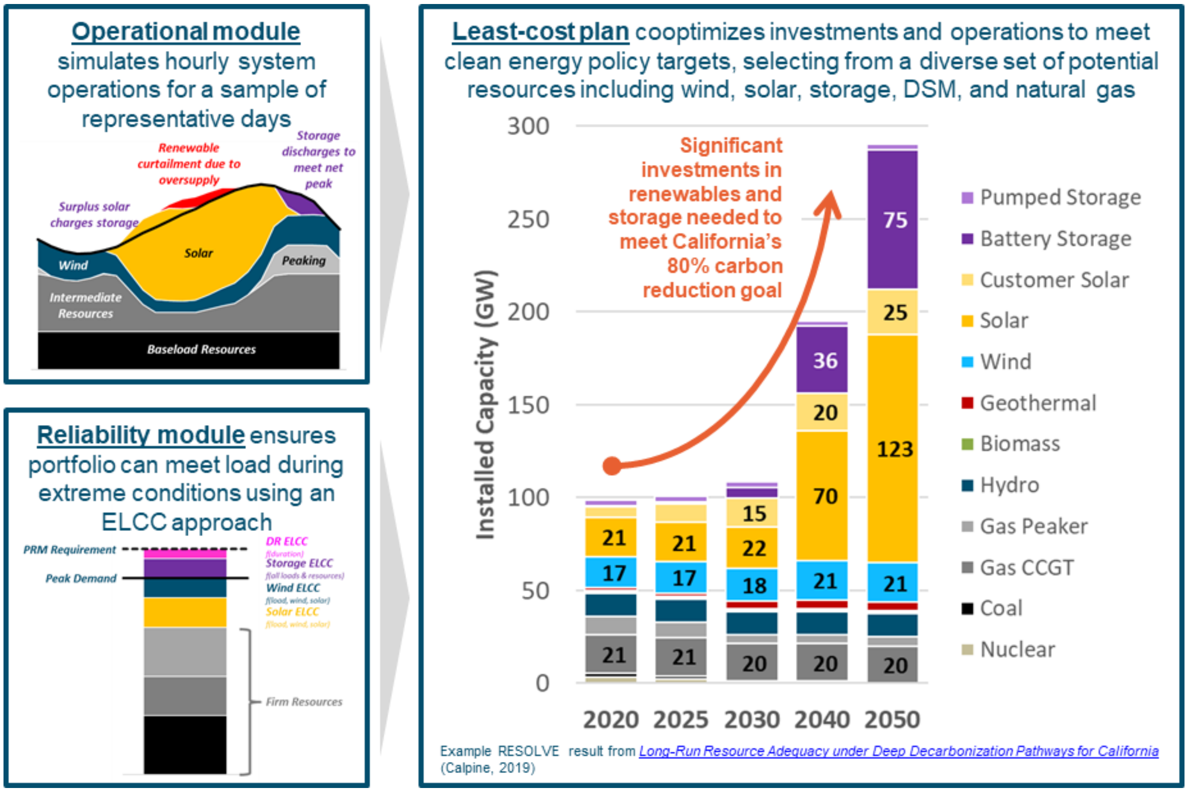


B. RESOLVE Model Methodology

RESOLVE is an optimal capacity expansion model specifically designed to identify least-cost plans to meet reliability needs and achieve compliance with regulatory and policy requirements, such as GHG reductions. It is a linear optimization model that balances the fixed cost of new investments, the variable costs of system operations, and the costs of maintaining existing assets to identify a least-cost portfolio of resources to meet needs across a long time horizon in a single stage as shown below.

RESOLVE has been designed by E3 for specific application to electricity systems seeking to integrate high penetrations of variable renewable energy and will provide a robust set of analytics to inform decision-making. RESOLVE has been used to study high renewable scenarios in numerous jurisdictions including California, New York, Hawaii, Minnesota, and the Pacific Northwest.

Figure 141. Illustration of Key Components of RESOLVE's Long-term Portfolio Optimization

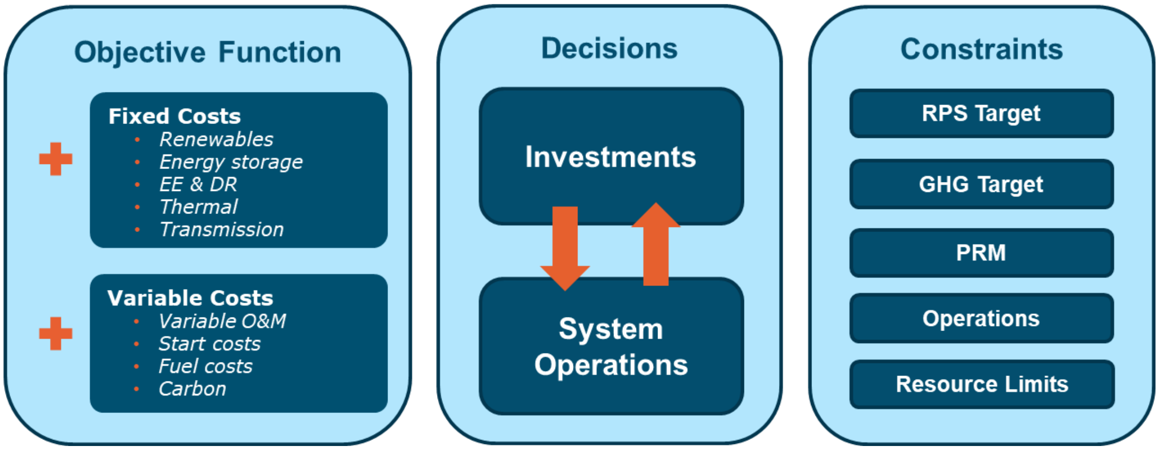


RESOLVE co-optimizes investment and dispatch over a multi-year horizon for a study area. RESOLVE solves for the optimal investments in energy efficiency and renewable resources as well as complementary resources such as new gas plants, gas plant retrofits, demand response, and various energy storage technologies. The portfolio is optimized subject to:

+ A Renewables Portfolio Standard (RPS) target
+ A cap on greenhouse gas emissions
+ Carbon pricing
+ A prohibition or restriction on new fossil investments.

Because investment decisions are optimized simultaneously with operational decisions, RESOLVE endogenizes flexibility value by trading off the cost of curtailed renewable energy—which might require additional investment in solar or wind to meet RPS and/or GHG constraints—against the cost of investments in flexible resources such as flexible gas generation or energy storage.

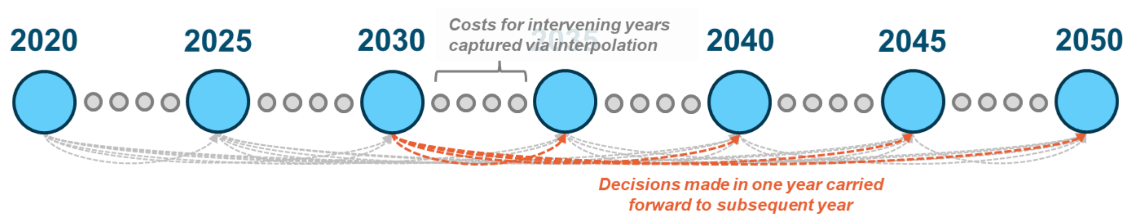
Figure 142. Summary of Key Components of RESOLVE



RESOLVE's objective function minimizes the net present value of cost across a long time horizon, providing a portfolio that is optimized to balance near-term and long-term goals.

As shown in Figure 143, RESOLVE simulates investment decisions and operations for a subset of snapshot years and interpolates costs for intervening periods; the choice of which years to model explicitly varies depending on the study's needs and the relevant milestones of interest. The optimization minimizes the net present value across the entire horizon within a single stage. Additional "weight" is applied to the last year of analysis to account for end effects.

Figure 143. Illustration of Method Used to Model Select Years Within a Long Time Horizon and Interpolate Between Select Years



RESOLVE's options for new resource investments include a diverse range of commercial and emerging technologies.

RESOLVE's selection of new generation investments considers a broad array of options, each of which may contribute in a unique way to the system operations, reliability needs, and policy targets of the system. Table 41 shows the usual options for new investments that are included in RESOLVE studies.

Table 41. Examples of New Generation Technologies Modeled as Options in RESOLVE

Resource Type	Examples of Available Options
Natural Gas Generation	+ Simple cycle combustion turbines (CTs) + Combined cycle gas turbines (CCGTs)

	+ Reciprocating engines + CCGTs with carbon capture & sequestration
Renewable Generation	+ Biomass + Geothermal + Hydro upgrades + Solar PV + Wind (onshore & offshore)
Energy Storage	+ Lithium-ion batteries (1+ hour duration) + Pumped storage (12+ hour duration) + Other long duration storage technologies
Customer Technologies	+ Energy efficiency + Demand response + Flexible loads
Additional Resource Options	+ Small modular nuclear reactors + Hydrogen or other carbon-free synthetic or bio-based fuels (can be used as a drop-in fuel in traditional CCGT/CT, fuel cells, or other technologies)
Options reported in italics are considered emerging technologies and are not included in all studies	

Each technology is broadly defined by three characteristics:

+ **Cost:** all fixed (capital, interconnection, fixed O&M, financing, taxes) and operating costs (fuel, carbon, variable O&M) needed to construct and operate the resource;
+ **Performance:** the resource's operating characteristics, including operating constraints, hourly profiles, capacity contributions; and
+ **Potential:** technical or other limits on developable potential.

The level of detail used to characterize each resource varies based on the nature of the resource and data availability, for instance:

+ For **renewable resources**, E3 typically develops detailed geospatial supply curves for renewable resources like wind and solar that draw upon a variety of NREL databases and reflect regional and local differences in cost, performance, and potential;
+ **Energy efficiency** and **demand response** are typically developed based on studies specific to the area of interest—often studies sponsored by utilities or regulators to example demand-side resource potential;
+ New **gas resources** are typically defined by generic costs and operating characteristics.

RESOLVE simulates system operations on an hourly basis to determine the cost to serve load throughout the year.

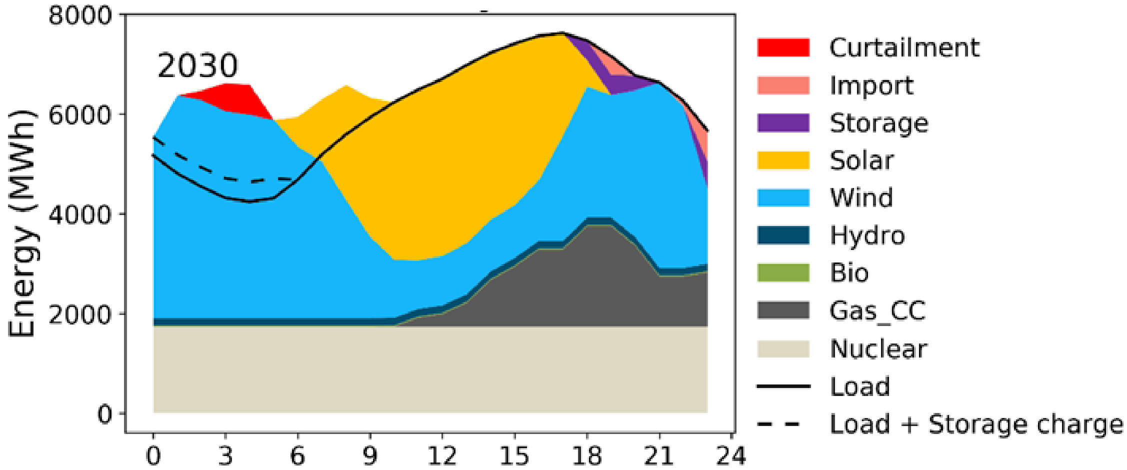
By modeling hourly operations of the electricity system explicitly as part of its optimization, RESOLVE's investment plan is directly informed by the dynamics of system operations and the associated costs to serve load throughout the year. This is especially important for systems with large amounts of renewable generation, energy storage, hydroelectric generation, or other variable/use-limited resources, where representing hourly patterns and the associated flexibility challenges, as well as interactions among various resources, is crucial to identifying the correct combination of investments.

RESOLVE endogenizes the traditional logic of production simulation modeling with some simplifications to conform with RESOLVE's linear structure. The key components of RESOLVE's operational simulation include:

+ **Hourly load shapes** that vary by year, allowing for the incorporation of future changes to load shape with increased levels of efficiency, transportation electrification, and building electrification;
+ **Hourly operating reserve requirements** that reflect a system's need to hold contingency, flexibility, and regulation reserves in order to balance load on a subhourly basis and respond in the event of unexpected contingencies;
+ A representation of the **unit commitment and dispatch of thermal generation** resources that includes key constraints and characteristics that would affect their operations, including linearized heat rate curves, minimum stable operating levels, ramp rates, minimum up and down time;
+ **Dispatch of hydroelectric resources** on a daily basis based on assumed daily energy budgets and minimum/maximum generation levels, which vary by season;
+ **Hourly profiles for renewable resources** that reflect their diurnal and seasonal production patterns, along with the ability to curtail output from renewable facilities when the available production exceeds the system's ability to use it;
+ **Dispatch of energy storage** resources subject to limitations on charging/discharging capability, duration, and round-trip losses;
+ **Capability to shift load** among different periods of the day to capture potential future opportunities from advanced demand response, flexible electric vehicle charging, or hydrogen electrolysis.

RESOLVE simulates operations for a subset of "sample days" selected to match a broad range of conditions (see below), modeling each day as independent from the others. An example of a RESOLVE operating day is show in Figure 144.

Figure 144. An Example of RESOLVE's Operational Simulation for a Single Day

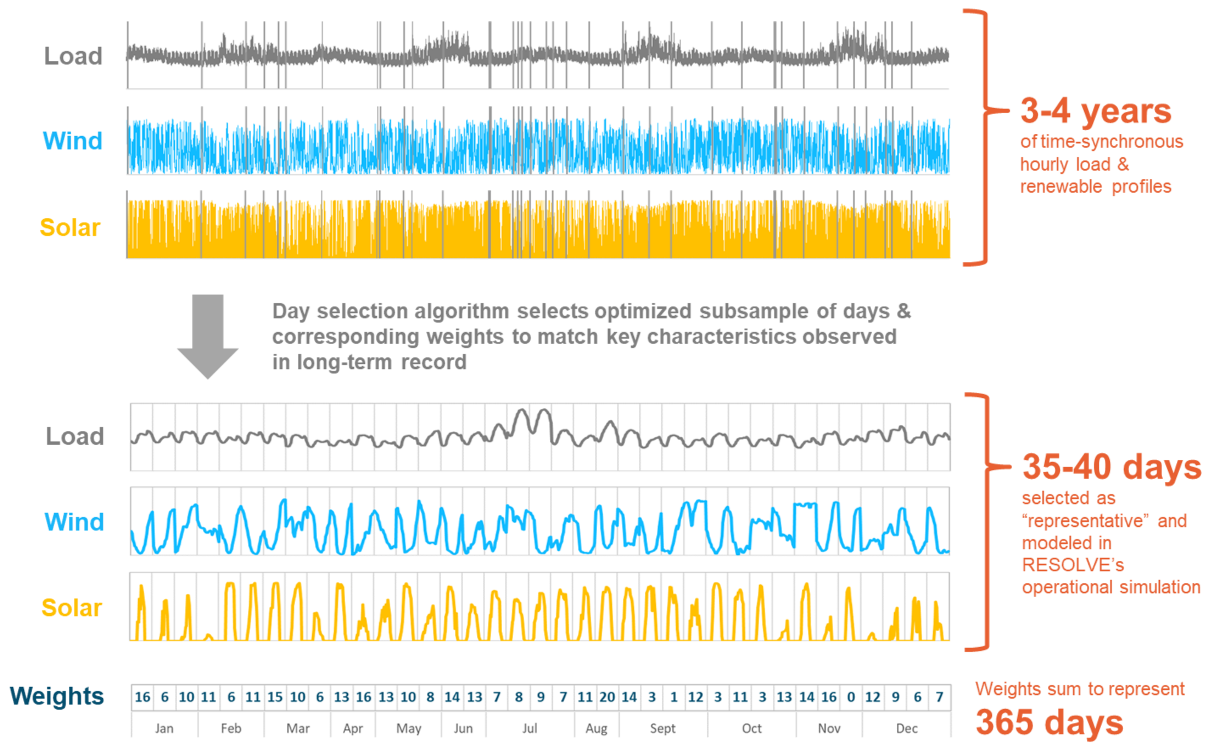


RESOLVE's sample of operating days is selected to match the full distribution of conditions that a system would experience based on multiple years of historical data.

In capacity expansion models that represent hourly system operations, simulating hourly operations across all 8760 hours of the year is typically computationally prohibitive. Other models choose various approaches to simplify the representation of a year, including (1) collapsing the year into time slices representing different seasons and time of day; (2) using a single representative day for each season or month; or (3) using a representative week for each day or month; or (4) various combinations of the approaches listed above.

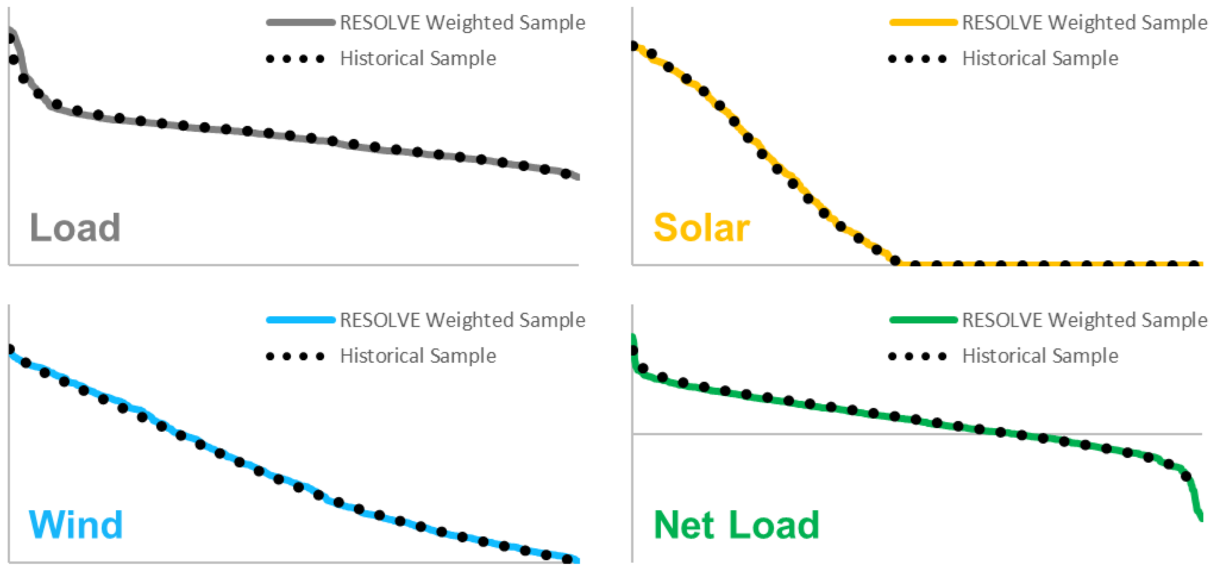
In contrast, RESOLVE uses an optimization algorithm to select a sample of approximately 40 days whose characteristics are broadly representative of the conditions that a system would encounter over the course of multiple years. The day-sampling optimization results in representative days where the correlation between the yearly actuals and sampled subset is accurately represented. At the same time, days of the year with extended solar and wind outages can be represented to reflect the variability and uncertainty inherent to renewable sources such as solar and wind. This process is illustrated in Figure 145: using a library of hourly profiles that spans multiple years of historical conditions, the day sampling algorithm will select individual days and associated "weights" (so that the weighted subsample reflects a 365-day year) to construct a synthetic year's worth of conditions.

Figure 145. Illustration of Down-sampling Process Used to Select Smart Sample of Days Modeled in RESOLVE



Together, the weighted days capture the distributions of key variables of interest in studying highly renewable electricity systems. Figure 146 shows an example comparison between duration curves using actual historical data and those constructed from a corresponding RESOLVE sample of days for hourly load, solar, wind, and net load conditions on an electricity system; in all four instances, the range of conditions captured within RESOLVE aligns very closely with the range of conditions expected over a longer time period.

Figure 146. Comparison of Conditions Captured in RESOLVE Days with Actual Historical Duration Curves

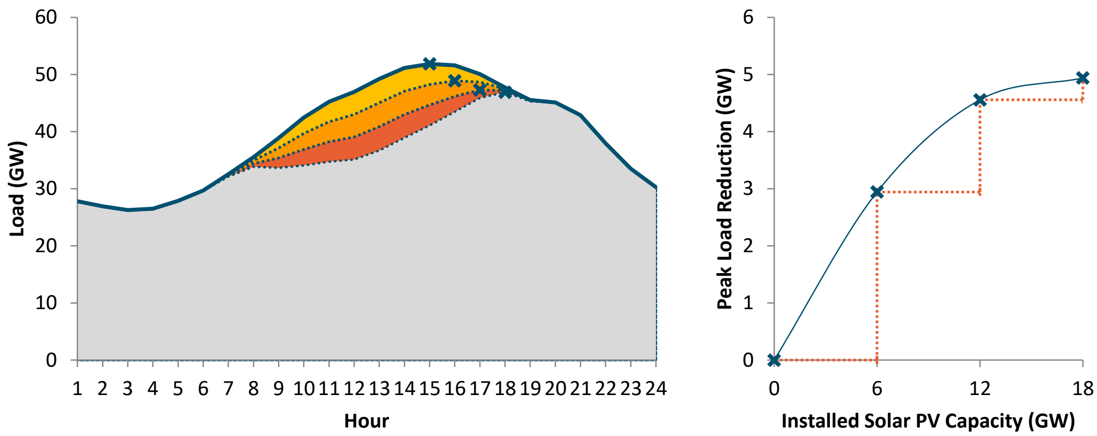


RESOLVE designs each portfolio to meet a system's resource adequacy needs, capturing the declining value of renewables and storage using "effective load carrying capability" (ELCC).

Simulating the ability of an electricity system to meet load across a sample of 40 days (or even the 365 days of a single year) is insufficient to ensure that the portfolio is reliable to the stringent standards typically required by utilities, often one day of lost load in ten years. To circumvent this challenge, RESOLVE incorporates an additional constraint that requires the portfolio in each year to meet a minimum planning reserve margin (PRM) requirement. In each year, the portfolio must have sufficient capacity to meet or exceed the PRM requirement, which may be chosen based on (1) regulatory requirements or utility conventions, or (2) detailed loss-of-load-probability modeling to identify a requirement consistent with the one day in ten year standard.

While PRM requirements have been used throughout the industry to ensure reliability for decades, the increasing prevalence of "non-firm" resources—resources like wind, solar, and energy storage, whose ability to produce power at a sustained level of output for extended periods—has created a challenge for traditional PRM accounting. The nature of this challenge is twofold: (1) the capacity contributions of non-firm resources generally less than their full rated capacity; and (2) the capacity contribution of non-firm resources will change as a function of penetration and the other resources on the system. These phenomena are intuitively illustrated in Figure 147, which shows how an increasing level of solar generation will tend to push the "net peak" into the evening—a period when solar does not produce—thereby lowering the incremental capacity value provided by the next solar resource.

Figure 147. Illustration of the Declining Capacity Contribution of Solar with Increasing Penetration



To account for this challenge, RESOLVE relies on inputs of technology-specific specification of "effective load carrying capability" (ELCC), a statistically robust measure of a resource's contribution to reliability. ELCC in RESOLVE is specified not as a single point, but is expressed as a series of "curves" that capture how the capacity contribution of resources changes with increasing penetration; RESOLVE uses this information to adjust the capacity contribution of wind, solar, and storage over time to capture the saturation effects at scale. At high penetrations of renewables, the declining ELCCs of these resources will tend to lead to a high premium on resources that can provide capacity to meet the PRM requirement—even if it is dispatched infrequently.

RESOLVE produces a wide range of useful and actionable outputs, including an optimal investment plan and a variety of other metrics.

RESOLVE's outputs include a variety of useful metrics, each provided for each year within the time horizon modeled. An inventory of the most commonly reported metrics is summarized in Table 42.

Table 42. Inventory of Key Outputs Provided by RESOLVE

Metric	Units
Optimized capacity additions & retirements	MW
Annual energy mix	GWh
Effective RPS achieved	% of retail sales
Capacity factors by unit/technology	%
Greenhouse gas emissions	MMTCO2e
Renewable curtailment	GWh

Total annual production cost	$/yr
Fixed costs of new resources	$/yr
Ongoing fixed costs of existing resources	$/yr
Average retail rate	c/kWh
Hourly energy prices	$/MWh
Marginal capacity cost	$/kW-yr
Marginal greenhouse gas abatement cost	$/ton

C. Detailed Portfolio Optimization Results

Active Scenario Name	Reference

Generation Summary

Total capacity (MW)	Unit	2021	2027	2030	2035	2040	2045	2050
Coal	MW	1,336	1,000	1,000	1,000	1,000	1,000	1,000
Oil	MW	123	123	123	123	123	123	123
Diesel	MW	7	7	7	7	7	7	7
Nuclear	MW	-	-	-	-	-	-	-
Gas_ST	MW	242	278	278	203	-	-	-
Gas_RE	MW	-	150	150	150	150	150	150
Gas_CC	MW	-	-	-	-	174	204	204
Gas_CT	MW	640	1,090	1,090	1,090	1,090	1,090	1,090
CCS	MW	-	-	-	-	-	-	-
Landfill	MW	6	6	6	6	6	6	6
Hydro	MW	80	80	80	80	80	80	80
Solar	MW	5	663	729	996	1,114	1,114	1,304
Wind	MW	973	1,256	1,231	1,099	609	693	693
Flow_Battery	MW	-	-	-	-	-	-	-
Li_Battery	MW	-	223	245	354	602	608	647
H2	MW	-	-	-	-	-	-	-
DR	MW	128	149	160	178	195	213	231
EE	MW	-	0	4	10	11	11	12
Solar_DG	MW	3	6	7	11	17	22	28
Flex_Load	MW	-	-	-	-	-	-	-

Total generation (GWh)	Unit	2021	2027	2030	2035	2040	2045	2050
Energy Efficiency	GWh	31	57	57	57	57	57	57
Coal	GWh	8,178	7,035	7,082	7,278	7,552	7,628	7,207
Oil	GWh	1	1	2	2	4	11	16
Diesel	GWh	0	0	0	0	0	1	1
Nuclear	GWh	-	-	-	-	-	-	-
Gas_ST	GWh	46	86	89	52	-	-	-
Gas_RE	GWh	-	103	124	86	60	78	79
Gas_CC	GWh	-	-	-	-	648	514	888
Gas_CT	GWh	462	1,571	1,609	1,043	428	580	591
CCS	GWh	-	-	-	-	-	-	-
Landfill	GWh	53	53	53	53	53	53	53
Hydro	GWh	391	387	374	364	371	380	373
Solar	GWh	10	1,375	1,511	2,066	2,310	2,310	2,705
Wind	GWh	3,536	4,914	4,855	4,252	2,311	2,668	2,530
Flow_Battery	GWh	-	-	-	-	-	-	-
Li_Battery	GWh	-	81	148	499	409	394	448
H2	GWh	-	-	-	-	-	-	-
DR	GWh	-	-	-	-	-	-	-
Solar_DG	GWh	4	9	12	18	26	35	44
Flex_Load	GWh	-	-	-	-	-	-	-
Curtailment	GWh	155	38	22	135	137	80	218
Imports	GWh	**1,381**	**2,339**	**2,524**	**2,848**	**4,292**	**4,228**	**4,547**
Exports	GWh	**(1,271)**	**(1,138)**	**(1,104)**	**(892)**	**(350)**	**(284)**	**(298)**
Load	GWh	**12,792**	**16,816**	**17,278**	**17,669**	**18,113**	**18,595**	**19,184**

Active Scenario Name	Net Zero Emerging/Net Zero Mature + H2

Generation Summary

Total capacity (MW)	Unit	2021	2027	2030	2035	2040	2045	2050
Coal	MW	1,336	1,000	934	644	104	-	-
Oil	MW	123	123	123	123	123	123	123
Diesel	MW	7	7	7	7	7	7	7
Nuclear	MW	-	-	-	-	-	-	-
Gas_ST	MW	242	278	344	407	896	1,000	1,000
Gas_RE	MW	-	150	150	150	150	150	150
Gas_CC	MW	-	232	259	684	954	1,001	1,001
Gas_CT	MW	640	1,090	1,090	1,090	1,090	1,090	1,090
CCS	MW	-	-	-	-	-	-	-
Landfill	MW	6	6	6	6	6	6	6
Hydro	MW	80	80	80	80	80	80	80
Solar	MW	5	755	2,860	2,860	2,860	3,109	4,663
Wind	MW	973	1,507	1,517	2,543	2,937	4,311	5,626
Flow_Battery	MW	-	-	-	-	-	-	-
Li_Battery	MW	-	387	522	808	864	1,308	2,000
H2	MW	-	-	-	-	-	-	-
DR	MW	128	149	160	178	195	213	231
EE	MW	-	0	4	10	11	11	12
Solar_DG	MW	3	6	7	11	17	22	28
Flex_Load	MW	-	-	-	-	-	-	-

Total generation (GWh)	Unit	2021	2027	2030	2035	2040	2045	2050
Energy Efficiency	GWh	58	440	707	1,231	1,790	2,261	2,687
Coal	GWh	8,306	4,129	5,075	3,326	488	-	-
Oil	GWh	1	-	1	8	5	2	0
Diesel	GWh	0	-	-	0	0	0	-
Nuclear	GWh	-	-	-	-	-	-	-
Gas_ST	GWh	56	75	86	309	755	825	352
Gas_RE	GWh	-	502	63	52	69	70	50
Gas_CC	GWh	-	1,591	969	3,866	5,735	4,003	1,125
Gas_CT	GWh	477	2,535	452	404	429	301	131
CCS	GWh	-	-	-	-	-	-	-
Landfill	GWh	53	53	53	53	53	53	53
Hydro	GWh	381	382	391	403	396	385	380
Solar	GWh	10	1,566	5,931	5,931	5,931	6,175	8,961
Wind	GWh	3,425	6,056	6,110	10,601	12,607	17,903	21,023
Flow_Battery	GWh	-	-	-	-	-	-	-
Li_Battery	GWh	-	286	558	486	472	93	(120)
H2	GWh	-	-	-	-	-	-	-
DR	GWh	-	-	-	-	-	4	4
Solar_DG	GWh	4	9	12	18	26	35	44
Flex_Load	GWh	-	-	-	-	-	-	-
Curtailment	GWh	266	-	-	-	-	1,015	4,108
Imports	GWh	**1,546**	**3,050**	**3,215**	**920**	**1,742**	**1,156**	**1,255**
Exports	GWh	**(1,250)**	**(1,217)**	**(2,084)**	**(2,398)**	**(2,610)**	**(2,819)**	**(3,024)**
Load	GWh	**13,011**	**19,017**	**20,833**	**23,979**	**26,098**	**28,186**	**30,236**

Active Scenario Name	Net Zero Moderated Pace

Generation Summary

Total capacity (MW)	Unit	2021	2027	2030	2035	2040	2045	2050
Coal	MW	1,336	1,000	1,000	1,000	581	-	-
Oil	MW	123	123	123	123	123	123	123
Diesel	MW	7	7	7	7	7	7	7
Nuclear	MW	-	-	-	-	-	-	-
Gas_ST	MW	242	278	278	112	418	1,000	1,000
Gas_RE	MW	-	150	150	150	150	150	150
Gas_CC	MW	-	238	289	661	992	1,042	1,042
Gas_CT	MW	640	1,090	1,090	1,090	1,090	1,090	1,090
CCS	MW	-	-	-	-	-	-	-
Landfill	MW	6	6	6	6	6	6	6
Hydro	MW	80	80	80	80	80	80	80
Solar	MW	5	755	1,803	2,142	2,142	2,880	4,604
Wind	MW	973	1,463	1,438	2,429	2,872	3,751	5,637
Flow_Battery	MW	-	-	-	-	-	-	-
Li_Battery	MW	-	387	523	808	864	1,390	1,869
H2	MW	-	-	-	-	-	-	-
DR	MW	128	149	160	178	195	213	231
EE	MW	-	0	4	10	11	11	12
Solar_DG	MW	3	6	7	11	17	22	28
Flex_Load	MW	-	-	-	-	-	-	-

Total generation (GWh)	Unit	2021	2027	2030	2035	2040	2045	2050
Energy Efficiency	GWh	58	440	707	1,231	1,790	2,261	2,687
Coal	GWh	8,306	6,713	6,750	5,734	2,706	-	-
Oil	GWh	1	2	1	10	6	4	0
Diesel	GWh	0	-	0	0	0	0	-
Nuclear	GWh	-	-	-	-	-	-	-
Gas_ST	GWh	56	101	64	10	323	1,360	349
Gas_RE	GWh	-	108	86	53	66	69	52
Gas_CC	GWh	-	916	1,101	3,726	5,969	5,786	1,129
Gas_CT	GWh	477	1,358	600	441	430	449	127
CCS	GWh	-	-	-	-	-	-	-
Landfill	GWh	53	53	53	53	53	53	53
Hydro	GWh	382	356	395	408	404	390	383
Solar	GWh	10	1,566	3,738	4,443	4,443	5,633	8,831
Wind	GWh	3,425	5,569	5,787	10,101	12,322	15,646	21,125
Flow_Battery	GWh	-	-	-	-	-	-	-
Li_Battery	GWh	-	201	575	496	453	46	(99)
H2	GWh	-	-	-	-	-	-	-
DR	GWh	-	-	-	-	-	0	4
Solar_DG	GWh	4	9	12	18	26	35	44
Flex_Load	GWh	-	-	-	-	-	-	-
Curtailment	GWh	266	293	-	-	-	879	4,063
Imports	GWh	**1,549**	**3,211**	**3,520**	**884**	**1,508**	**1,533**	**1,261**
Exports	GWh	**(1,253)**	**(1,145)**	**(1,847)**	**(2,398)**	**(2,610)**	**(2,819)**	**(3,024)**
Load	GWh	**13,011**	**19,017**	**20,833**	**23,979**	**26,098**	**28,186**	**30,236**

Active Scenario Name	Net Zero Accelerated Pace

Generation Summary

Total capacity (MW)	Unit	2021	2027	2030	2035	2040	2045	2050
Coal	MW	1,336	1,000	554	116	-	-	-
Oil	MW	123	123	123	123	123	123	123
Diesel	MW	7	7	7	7	7	7	7
Nuclear	MW	-	-	-	-	-	-	-
Gas_ST	MW	242	278	724	884	1,000	1,000	1,000
Gas_RE	MW	-	150	150	150	150	150	150
Gas_CC	MW	-	75	134	680	847	892	1,001
Gas_CT	MW	640	1,090	1,090	1,090	1,090	1,090	1,090
CCS	MW	-	-	-	-	-	-	-
Landfill	MW	6	6	6	6	6	6	6
Hydro	MW	80	80	80	80	80	80	80
Solar	MW	5	977	2,903	2,903	3,028	3,761	4,661
Wind	MW	973	2,024	2,015	2,947	3,569	4,649	5,629
Flow_Battery	MW	-	-	-	-	-	-	-
Li_Battery	MW	-	387	600	808	965	1,492	2,000
H2	MW	-	-	-	-	-	-	-
DR	MW	128	149	160	178	195	213	231
EE	MW	-	0	4	10	11	11	12
Solar_DG	MW	3	6	7	11	17	22	28
Flex_Load	MW	-	-	-	-	-	-	-

Total generation (GWh)	Unit	2021	2027	2030	2035	2040	2045	2050
Energy Efficiency	GWh	58	440	707	1,231	1,790	2,261	2,687
Coal	GWh	8,306	3,215	2,943	543	-	-	-
Oil	GWh	1	-	1	5	3	1	0
Diesel	GWh	0	-	-	0	-	-	-
Nuclear	GWh	-	-	-	-	-	-	-
Gas_ST	GWh	56	57	386	810	755	689	356
Gas_RE	GWh	-	374	60	54	63	69	50
Gas_CC	GWh	-	488	493	3,966	3,532	2,555	1,136
Gas_CT	GWh	477	2,000	405	384	325	257	132
CCS	GWh	-	-	-	-	-	-	-
Landfill	GWh	53	53	53	53	53	53	53
Hydro	GWh	374	387	389	406	403	386	379
Solar	GWh	10	2,025	6,020	6,020	6,276	7,440	8,732
Wind	GWh	3,402	8,320	8,303	12,379	15,383	18,429	21,261
Flow_Battery	GWh	-	-	-	-	-	-	-
Li_Battery	GWh	-	304	532	471	436	167	(130)
H2	GWh	-	-	-	-	-	-	-
DR	GWh	-	-	-	-	1	5	4
Solar_DG	GWh	4	9	12	18	26	35	44
Flex_Load	GWh	-	-	-	-	-	-	-
Curtailment	GWh	289	-	-	-	6	2,061	4,109
Imports	GWh	**1,545**	**2,961**	**3,320**	**1,270**	**1,451**	**921**	**1,241**
Exports	GWh	**(1,217)**	**(1,176)**	**(2,084)**	**(2,398)**	**(2,610)**	**(2,819)**	**(3,024)**
Load	GWh	**13,011**	**19,017**	**20,833**	**23,979**	**26,098**	**28,186**	**30,236**

Active Scenario Name	Net Zero 2035

Generation Summary

Total capacity (MW)	Unit	2021	2027	2030	2035	2040	2045	2050
Coal	MW	1,336	1,000	389	-	-	-	-
Oil	MW	123	123	123	123	123	123	123
Diesel	MW	7	7	7	7	7	7	7
Nuclear	MW	-	-	-	-	-	-	-
Gas_ST	MW	242	278	889	1,278	1,000	1,000	1,000
Gas_RE	MW	-	150	150	150	150	150	150
Gas_CC	MW	-	62	64	64	488	728	1,001
Gas_CT	MW	640	1,090	1,090	1,090	1,090	1,090	1,090
CCS	MW	-	-	-	-	-	-	-
Landfill	MW	6	6	6	6	6	6	6
Hydro	MW	80	80	80	80	80	80	80
Solar	MW	5	977	3,093	4,442	4,466	4,539	4,661
Wind	MW	973	2,141	2,126	3,985	4,406	5,006	5,629
Flow_Battery	MW	-	-	-	-	-	-	-
Li_Battery	MW	-	387	679	1,366	1,722	1,856	2,000
H2	MW	-	-	-	-	-	-	-
DR	MW	128	149	160	178	195	213	231
EE	MW	-	0	4	10	11	11	12
Solar_DG	MW	3	6	7	11	17	22	28
Flex_Load	MW	-	-	-	-	-	-	-

Total generation (GWh)	Unit	2021	2027	2030	2035	2040	2045	2050
Energy Efficiency	GWh	58	440	707	1,231	1,790	2,261	2,687
Coal	GWh	8,306	3,187	2,140	-	-	-	-
Oil	GWh	1	-	1	-	-	0	0
Diesel	GWh	0	-	-	-	-	-	-
Nuclear	GWh	-	-	-	-	-	-	-
Gas_ST	GWh	56	58	596	497	285	473	360
Gas_RE	GWh	-	316	57	36	42	64	50
Gas_CC	GWh	-	389	246	189	968	1,220	1,143
Gas_CT	GWh	477	1,676	337	114	111	109	129
CCS	GWh	-	-	-	-	-	-	-
Landfill	GWh	53	53	53	53	53	53	53
Hydro	GWh	383	389	382	383	380	380	377
Solar	GWh	10	2,025	6,414	8,390	8,373	8,290	9,011
Wind	GWh	3,376	8,833	8,795	15,307	17,263	19,643	20,962
Flow_Battery	GWh	-	-	-	-	-	-	-
Li_Battery	GWh	-	309	503	(6)	87	(91)	(107)
H2	GWh	-	-	-	-	-	-	-
DR	GWh	-	-	-	5	4	6	4
Solar_DG	GWh	4	9	12	18	26	35	44
Flex_Load	GWh	-	-	-	-	-	-	-
Curtailment	GWh	315	-	-	2,455	2,688	3,180	4,129
Imports	GWh	**1,595**	**2,950**	**3,382**	**1,392**	**1,117**	**824**	**1,233**
Exports	GWh	**(1,251)**	**(1,177)**	**(2,084)**	**(2,398)**	**(2,610)**	**(2,819)**	**(3,024)**
Load	GWh	**13,011**	**19,017**	**20,833**	**23,979**	**26,098**	**28,186**	**30,236**

Active Scenario Name	Absolute Zero Mature Only

Generation Summary

Total capacity (MW)	Unit	2021	2027	2030	2035	2040	2045	2050
Coal	MW	1,336	1,000	1,000	1,000	1,000	569	-
Oil	MW	123	123	123	123	123	123	-
Diesel	MW	7	7	7	7	7	7	-
Nuclear	MW	-	-	-	-	-	-	-
Gas_ST	MW	242	278	278	278	278	278	-
Gas_RE	MW	-	150	150	150	150	150	-
Gas_CC	MW	-	-	-	-	-	-	-
Gas_CT	MW	640	1,090	1,090	1,090	1,090	1,090	-
CCS	MW	-	-	-	-	-	-	-
Landfill	MW	6	6	6	6	6	6	-
Hydro	MW	80	80	80	80	80	80	80
Solar	MW	5	977	2,758	4,872	5,439	8,351	18,718
Wind	MW	973	1,780	1,790	2,703	3,721	4,863	5,080
Flow_Battery	MW	-	-	-	-	-	-	-
Li_Battery	MW	-	575	1,021	2,287	3,194	7,829	31,662
H2	MW	-	-	-	-	-	-	-
DR	MW	128	149	160	178	195	213	315
EE	MW	-	0	4	10	11	11	12
Solar_DG	MW	3	6	7	11	17	22	28
Flex_Load	MW	-	-	-	-	-	-	-

Total generation (GWh)	Unit	2021	2027	2030	2035	2040	2045	2050
Energy Efficiency	GWh	58	440	707	1,231	1,790	2,261	2,687
Coal	GWh	8,006	5,384	4,818	4,021	2,490	1,297	-
Oil	GWh	1	-	0	2	-	-	-
Diesel	GWh	-	-	-	-	-	-	-
Nuclear	GWh	-	-	-	-	-	-	-
Gas_ST	GWh	83	49	-	-	-	-	-
Gas_RE	GWh	-	165	36	35	23	7	-
Gas_CC	GWh	-	-	-	-	-	-	-
Gas_CT	GWh	740	1,537	232	266	28	-	-
CCS	GWh	-	-	-	-	-	-	-
Landfill	GWh	53	53	53	53	53	52	-
Hydro	GWh	405	362	371	383	364	362	350
Solar	GWh	10	2,025	5,710	9,464	10,944	14,934	21,991
Wind	GWh	3,662	7,226	7,132	10,665	13,703	15,077	12,783
Flow_Battery	GWh	-	-	-	-	-	-	-
Li_Battery	GWh	-	301	410	15	(397)	(1,326)	(1,919)
H2	GWh	-	-	-	-	-	-	-
DR	GWh	-	-	-	-	-	6	10
Solar_DG	GWh	4	9	12	18	26	35	44
Flex_Load	GWh	-	-	-	-	-	-	-
Curtailment	GWh	29	28	186	1,181	2,151	7,126	26,659
Imports	GWh	**1,119**	**2,062**	**3,053**	**1,242**	**1,473**	**562**	**-**
Exports	GWh	**(1,073)**	**(156)**	**(992)**	**(2,184)**	**(2,610)**	**(2,819)**	**(3,024)**
Load	GWh	**13,011**	**19,017**	**20,833**	**23,979**	**26,098**	**28,186**	**30,236**

Active Scenario Name	Absolute Zero Emerging/ Absolute Zero Mature + H2

Generation Summary

Total capacity (MW)	Unit	2021	2027	2030	2035	2040	2045	2050
Coal	MW	1,336	1,000	1,000	1,000	654	-	-
Oil	MW	123	123	123	123	123	123	-
Diesel	MW	7	7	7	7	7	7	-
Nuclear	MW	-	-	-	-	-	-	-
Gas_ST	MW	242	278	278	278	278	278	-
Gas_RE	MW	-	150	150	150	150	150	150
Gas_CC	MW	-	213	213	420	772	1,556	2,591
Gas_CT	MW	640	1,090	1,090	1,090	1,090	1,090	450
CCS	MW	-	-	-	-	-	-	-
Landfill	MW	6	6	6	6	6	6	-
Hydro	MW	80	80	80	80	80	80	80
Solar	MW	5	755	2,620	2,818	3,524	4,120	5,283
Wind	MW	973	1,649	1,659	2,882	3,808	4,746	6,573
Flow_Battery	MW	-	-	-	-	-	-	-
Li_Battery	MW	-	387	570	808	1,350	1,722	2,926
H2	MW	-	-	-	-	-	-	-
DR	MW	128	149	160	178	195	213	231
EE	MW	-	0	4	10	11	11	12
Solar_DG	MW	3	6	7	11	17	22	28
Flex_Load	MW	-	-	-	-	-	-	-

Total generation (GWh)	Unit	2021	2027	2030	2035	2040	2045	2050
Energy Efficiency	GWh	58	440	707	1,231	1,790	2,261	2,687
Coal	GWh	8,006	4,654	4,492	3,175	1,646	-	-
Oil	GWh	1	-	1	1	1	1	-
Diesel	GWh	-	-	-	-	-	-	-
Nuclear	GWh	-	-	-	-	-	-	-
Gas_ST	GWh	83	60	4	7	0	6	-
Gas_RE	GWh	-	338	45	82	50	63	2
Gas_CC	GWh	-	1,338	766	1,869	2,065	2,704	1,036
Gas_CT	GWh	740	1,777	310	406	227	228	-
CCS	GWh	-	-	-	-	-	-	-
Landfill	GWh	53	53	53	53	53	53	-
Hydro	GWh	394	372	373	396	384	387	366
Solar	GWh	10	1,566	5,406	5,391	6,759	7,523	9,479
Wind	GWh	3,633	6,669	6,560	11,571	15,207	18,609	23,098
Flow_Battery	GWh	-	-	-	-	-	-	-
Li_Battery	GWh	-	294	468	287	119	(1)	(773)
H2	GWh	-	-	-	-	-	-	-
DR	GWh	-	-	-	2	5	4	7
Solar_DG	GWh	4	9	12	18	26	35	44
Flex_Load	GWh	-	-	-	-	-	-	-
Curtailment	GWh	58	12	201	975	1,778	2,969	6,561
Imports	GWh	**1,119**	**2,016**	**2,970**	**1,216**	**1,106**	**717**	**-**
Exports	GWh	**(1,032)**	**(130)**	**(627)**	**(494)**	**(1,549)**	**(2,142)**	**(3,024)**
Load	GWh	**13,011**	**19,017**	**20,833**	**23,979**	**26,098**	**28,186**	**30,236**

Active Scenario Name	Absolute Zero No H2

Generation Summary

Total capacity (MW)	Unit	2021	2027	2030	2035	2040	2045	2050
Coal	MW	1,336	1,000	1,000	948	380	183	-
Oil	MW	123	123	123	123	123	123	-
Diesel	MW	7	7	7	7	7	7	-
Nuclear	MW	-	-	-	-	-	275	1,894
Gas_ST	MW	242	278	278	278	278	278	-
Gas_RE	MW	-	150	150	150	150	150	150
Gas_CC	MW	-	215	339	500	1,226	1,246	1,246
Gas_CT	MW	640	1,090	1,090	1,090	1,090	1,090	450
CCS	MW	-	-	-	-	-	-	-
Landfill	MW	6	6	6	6	6	6	-
Hydro	MW	80	80	80	80	80	80	80
Solar	MW	5	755	2,564	2,956	3,399	3,764	4,621
Wind	MW	973	1,636	1,611	2,627	3,193	4,196	4,923
Flow_Battery	MW	-	-	-	-	-	-	-
Li_Battery	MW	-	387	387	808	1,021	1,476	1,476
H2	MW	-	-	-	-	-	-	-
DR	MW	128	149	160	178	195	213	231
EE	MW	-	0	4	10	11	11	12
Solar_DG	MW	3	6	7	11	17	22	28
Flex_Load	MW	-	-	-	-	-	-	-

Total generation (GWh)	Unit	2021	2027	2030	2035	2040	2045	2050
Energy Efficiency	GWh	58	440	707	1,231	1,790	2,261	2,687
Coal	GWh	8,006	4,578	4,226	2,879	948	422	-
Oil	GWh	1	-	1	1	0	-	-
Diesel	GWh	-	-	-	-	-	-	-
Nuclear	GWh	-	-	-	-	-	1,803	7,201
Gas_ST	GWh	83	60	3	7	-	-	-
Gas_RE	GWh	-	366	56	51	55	57	-
Gas_CC	GWh	-	1,403	1,210	2,275	3,950	2,016	-
Gas_CT	GWh	740	1,816	357	331	288	169	-
CCS	GWh	-	-	-	-	-	-	-
Landfill	GWh	53	53	53	53	53	53	-
Hydro	GWh	395	373	383	400	392	374	352
Solar	GWh	10	1,566	5,294	5,823	6,828	7,674	9,052
Wind	GWh	3,652	6,618	6,393	10,597	12,716	15,520	17,050
Flow_Battery	GWh	-	-	-	-	-	-	-
Li_Battery	GWh	-	299	451	376	380	696	(446)
H2	GWh	-	-	-	-	-	-	-
DR	GWh	-	-	-	2	2	6	7
Solar_DG	GWh	4	9	12	18	26	35	44
Flex_Load	GWh	-	-	-	-	-	-	-
Curtailment	GWh	39	3	176	681	929	2,254	3,742
Imports	GWh	**1,119**	**2,028**	**3,128**	**1,631**	**894**	**459**	**-**
Exports	GWh	**(1,053)**	**(152)**	**(734)**	**(465)**	**(434)**	**(1,098)**	**(3,024)**
Load	GWh	**13,011**	**19,017**	**20,833**	**23,979**	**26,098**	**28,186**	**30,236**

Active Scenario Name	Net Zero Reference Load

Generation Summary

Total capacity (MW)	Unit	2021	2027	2030	2035	2040	2045	2050
Coal	MW	1,336	1,000	948	755	587	204	-
Oil	MW	123	123	123	123	123	123	123
Diesel	MW	7	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-
Gas_ST	MW	242	278	278	277	413	716	716
Gas_RE	MW	-	150	150	150	150	150	150
Gas_CC	MW	-	-	-	-	-	-	-
Gas_CT	MW	640	1,090	1,090	1,090	1,090	1,090	1,090
CCS	MW	-	-	-	-	-	-	-
Landfill	MW	6	6	6	6	6	6	6
Hydro	MW	80	80	80	80	80	80	80
Solar	MW	5	753	1,714	2,629	2,629	2,629	2,998
Wind	MW	973	1,463	1,438	1,473	1,967	2,353	3,878
Flow_Battery	MW	-	-	-	-	-	-	-
Li_Battery	MW	-	179	179	465	465	590	833
H2	MW	-	-	-	-	-	-	-
DR	MW	128	149	160	178	195	213	231
EE	MW	-	0	4	10	10	10	12
Solar_DG	MW	3	6	7	11	17	22	28
Flex_Load	MW	-	-	-	-	-	-	-

Total generation (GWh)	Unit	2021	2027	2030	2035	2040	2045	2050
Energy Efficiency	GWh	31	57	57	57	57	57	57
Coal	GWh	8,178	5,606	5,493	4,119	2,781	869	-
Oil	GWh	1	0	1	2	7	2	1
Diesel	GWh	0	-	-	-	-	-	-
Nuclear	GWh	-	-	-	-	-	-	-
Gas_ST	GWh	46	87	55	245	505	923	517
Gas_RE	GWh	-	232	73	42	73	75	100
Gas_CC	GWh	-	-	-	-	-	-	-
Gas_CT	GWh	462	1,744	585	372	495	478	191
CCS	GWh	-	-	-	-	-	-	-
Landfill	GWh	53	53	53	53	53	53	53
Hydro	GWh	382	434	436	408	422	416	385
Solar	GWh	10	1,561	3,555	5,452	5,452	5,452	5,510
Wind	GWh	3,431	5,862	5,787	5,900	8,347	10,039	13,541
Flow_Battery	GWh	-	-	-	-	-	-	-
Li_Battery	GWh	-	123	316	524	463	405	(148)
H2	GWh	-	-	-	-	-	-	-
DR	GWh	-	-	-	-	-	-	7
Solar_DG	GWh	4	9	12	18	26	35	44
Flex_Load	GWh	-	-	-	-	-	-	-
Curtailment	GWh	260	-	-	-	0	1	3,908
Imports	GWh	**1,494**	**2,263**	**2,481**	**2,300**	**1,300**	**1,708**	**901**
Exports	GWh	**(1,270)**	**(1,158)**	**(1,568)**	**(1,767)**	**(1,811)**	**(1,860)**	**(1,919)**
Load	GWh	**12,792**	**16,816**	**17,278**	**17,669**	**18,113**	**18,595**	**19,184**

Active Scenario Name	Net Zero Mod Decarb

Generation Summary

Total capacity (MW)	Unit	2021	2027	2030	2035	2040	2045	2050
Coal	MW	1,336	1,000	1,000	869	426	-	-
Oil	MW	123	123	123	123	123	123	123
Diesel	MW	7	7	7	7	7	7	7
Nuclear	MW	-	-	-	-	-	-	-
Gas_ST	MW	242	278	278	131	574	1,000	1,000
Gas_RE	MW	-	150	150	150	150	150	150
Gas_CC	MW	-	-	-	124	314	445	445
Gas_CT	MW	640	1,090	1,090	1,090	1,090	1,090	1,090
CCS	MW	-	-	-	-	-	-	-
Landfill	MW	6	6	6	6	6	6	6
Hydro	MW	80	80	80	80	80	80	80
Solar	MW	5	755	2,243	2,303	2,303	2,494	3,688
Wind	MW	973	1,463	1,438	2,214	2,596	3,300	4,694
Flow_Battery	MW	-	-	-	-	-	-	-
Li_Battery	MW	-	197	241	661	710	984	1,617
H2	MW	-	-	-	-	-	-	-
DR	MW	128	149	160	178	195	213	231
EE	MW	-	0	4	10	11	11	12
Solar_DG	MW	3	6	7	11	17	22	28
Flex_Load	MW	-	-	-	-	-	-	-

Total generation (GWh)	Unit	2021	2027	2030	2035	2040	2045	2050
Energy Efficiency	GWh	35	131	197	337	471	528	516
Coal	GWh	8,192	5,057	5,609	4,515	2,067	-	-
Oil	GWh	1	0	1	9	6	4	0
Diesel	GWh	0	-	-	0	0	0	-
Nuclear	GWh	-	-	-	-	-	-	-
Gas_ST	GWh	47	91	57	127	518	1,533	469
Gas_RE	GWh	-	452	71	59	73	95	67
Gas_CC	GWh	-	-	-	693	1,891	2,459	678
Gas_CT	GWh	463	2,411	506	456	483	504	147
CCS	GWh	-	-	-	-	-	-	-
Landfill	GWh	53	53	53	53	53	53	53
Hydro	GWh	366	447	431	418	410	389	380
Solar	GWh	10	1,566	4,651	4,775	4,775	5,125	6,665
Wind	GWh	3,296	5,862	5,787	9,155	11,109	13,819	17,755
Flow_Battery	GWh	-	-	-	-	-	-	-
Li_Battery	GWh	-	141	415	506	504	214	7
H2	GWh	-	-	-	-	-	-	-
DR	GWh	-	-	-	-	-	3	7
Solar_DG	GWh	4	9	12	18	26	35	44
Flex_Load	GWh	-	-	-	-	-	-	-
Curtailment	GWh	395	-	-	-	-	431	3,556
Imports	GWh	**1,582**	**2,532**	**2,544**	**872**	**1,437**	**947**	**951**
Exports	GWh	**(1,200)**	**(1,266)**	**(1,831)**	**(1,969)**	**(2,123)**	**(2,289)**	**(2,475)**
Load	GWh	**12,815**	**17,356**	**18,307**	**19,687**	**21,228**	**22,890**	**24,749**

Active Scenario Name	Net Zero High Elec

Generation Summary

Total capacity (MW)	Unit	2021	2027	2030	2035	2040	2045	2050
Coal	MW	1,336	1,000	877	495	-	-	-
Oil	MW	123	123	123	123	123	123	123
Diesel	MW	7	7	7	7	7	7	7
Nuclear	MW	-	-	-	-	-	-	-
Gas_ST	MW	242	278	401	783	1,000	1,000	1,000
Gas_RE	MW	-	150	150	150	150	150	150
Gas_CC	MW	-	239	379	1,192	2,300	2,816	2,850
Gas_CT	MW	640	1,090	1,090	1,090	1,090	1,090	1,090
CCS	MW	-	-	-	-	-	-	-
Landfill	MW	6	6	6	6	6	6	6
Hydro	MW	80	80	80	80	80	80	80
Solar	MW	5	755	2,768	2,768	2,768	3,365	4,932
Wind	MW	973	1,576	1,586	2,483	3,246	4,796	6,335
Flow_Battery	MW	-	-	-	-	-	-	-
Li_Battery	MW	-	400	468	911	1,071	1,410	2,576
H2	MW	-	-	-	-	-	-	-
DR	MW	128	149	160	178	195	213	231
EE	MW	-	0	4	10	11	11	12
Solar_DG	MW	3	41	42	46	52	57	63
Flex_Load	MW	-	-	-	-	-	-	-

Total generation (GWh)	Unit	2021	2027	2030	2035	2040	2045	2050
Energy Efficiency	GWh	55	405	649	1,152	1,753	2,311	2,855
Coal	GWh	8,319	4,163	4,754	2,249	-	-	-
Oil	GWh	1	0	2	6	3	1	0
Diesel	GWh	0	-	-	0	-	-	-
Nuclear	GWh	-	-	-	-	-	-	-
Gas_ST	GWh	56	75	142	304	589	396	185
Gas_RE	GWh	-	469	65	46	59	48	28
Gas_CC	GWh	-	1,591	1,519	6,724	8,201	5,436	2,252
Gas_CT	GWh	481	2,426	459	293	318	182	60
CCS	GWh	-	-	-	-	-	-	-
Landfill	GWh	53	53	53	53	53	53	53
Hydro	GWh	381	380	396	396	393	391	384
Solar	GWh	10	1,566	5,740	5,740	5,740	6,672	9,441
Wind	GWh	3,420	6,359	6,413	10,336	13,968	20,015	24,348
Flow_Battery	GWh	-	-	-	-	-	-	-
Li_Battery	GWh	-	287	569	467	368	108	(107)
H2	GWh	-	-	-	-	-	-	-
DR	GWh	-	-	-	-	-	2	4
Solar_DG	GWh	4	64	66	72	81	89	99
Flex_Load	GWh	-	-	-	-	-	-	-
Curtailment	GWh	271	-	-	-	-	1,069	3,977
Imports	GWh	**1,550**	**3,152**	**3,444**	**1,022**	**1,057**	**761**	**888**
Exports	GWh	**(1,240)**	**(1,218)**	**(2,148)**	**(2,519)**	**(2,803)**	**(3,105)**	**(3,422)**
Load	GWh	**13,036**	**19,369**	**21,475**	**25,191**	**28,027**	**31,048**	**34,214**

Active Scenario Name	Net Zero SPP Reference

Generation Summary

Total capacity (MW)	Unit	2021	2027	2030	2035	2040	2045	2050
Coal	MW	1,336	1,000	938	853	47	47	-
Oil	MW	123	123	123	123	123	123	123
Diesel	MW	7	7	7	7	7	7	7
Nuclear	MW	-	-	-	-	-	-	-
Gas_ST	MW	242	278	340	424	953	953	1,000
Gas_RE	MW	-	150	150	150	150	150	150
Gas_CC	MW	-	219	265	504	1,034	1,034	1,034
Gas_CT	MW	640	1,090	1,090	1,090	1,090	1,090	1,090
CCS	MW	-	-	-	-	-	-	-
Landfill	MW	6	6	6	6	6	6	6
Hydro	MW	80	80	80	80	80	80	80
Solar	MW	5	755	2,668	3,517	4,520	4,520	5,146
Wind	MW	973	1,608	1,583	2,108	2,057	3,436	5,039
Flow_Battery	MW	-	-	-	-	-	-	-
Li_Battery	MW	-	387	502	808	901	1,370	2,000
H2	MW	-	-	-	-	-	-	-
DR	MW	128	149	160	178	195	213	231
EE	MW	-	0	4	10	11	11	12
Solar_DG	MW	3	6	7	11	17	22	28
Flex_Load	MW	-	-	-	-	-	-	-

Total generation (GWh)	Unit	2021	2027	2030	2035	2040	2045	2050
Energy Efficiency	GWh	58	440	707	1,231	1,790	2,261	2,687
Coal	GWh	8,305	4,530	4,734	2,966	180	200	-
Oil	GWh	1	-	-	1	1	2	-
Diesel	GWh	0	-	-	0	-	-	-
Nuclear	GWh	-	-	-	-	-	-	-
Gas_ST	GWh	56	70	105	86	431	560	200
Gas_RE	GWh	-	357	67	33	49	59	34
Gas_CC	GWh	-	1,438	847	1,582	2,158	333	367
Gas_CT	GWh	478	1,976	503	236	233	318	74
CCS	GWh	-	-	-	-	-	-	-
Landfill	GWh	53	53	53	53	53	53	53
Hydro	GWh	380	380	380	377	384	400	375
Solar	GWh	10	1,566	5,533	7,294	9,372	9,339	10,138
Wind	GWh	3,357	6,499	6,425	8,692	8,727	14,791	19,977
Flow_Battery	GWh	-	-	-	-	-	-	-
Li_Battery	GWh	-	283	274	500	450	350	(277)
H2	GWh	-	-	-	-	-	-	-
DR	GWh	-	-	-	-	-	-	2
Solar_DG	GWh	4	9	12	18	26	35	44
Flex_Load	GWh	-	-	-	-	-	-	-
Curtailment	GWh	334	-	-	-	13	45	2,398
Imports	GWh	**1,606**	**3,171**	**3,666**	**4,538**	**6,644**	**4,566**	**2,271**
Exports	GWh	**(1,240)**	**(1,314)**	**(1,765)**	**(2,398)**	**(2,610)**	**(2,819)**	**(3,024)**
Load	GWh	**13,011**	**19,017**	**20,833**	**23,979**	**26,098**	**28,186**	**30,236**

Active Scenario Name	Net Zero Breakthrough Costs

Generation Summary

Total capacity (MW)	Unit	2021	2027	2030	2035	2040	2045	2050
Coal	MW	1,336	1,000	1,000	1,000	551	141	-
Oil	MW	123	123	123	123	123	123	123
Diesel	MW	7	7	7	7	7	7	7
Nuclear	MW	-	-	-	500	500	500	500
Gas_ST	MW	242	278	278	-	449	859	1,000
Gas_RE	MW	-	150	150	150	150	150	150
Gas_CC	MW	-	277	303	303	453	616	619
Gas_CT	MW	640	1,090	1,090	1,090	1,090	1,090	1,090
CCS	MW	-	-	-	-	-	-	-
Landfill	MW	6	6	6	6	6	6	6
Hydro	MW	80	80	80	80	80	80	80
Solar	MW	5	755	2,818	2,818	2,818	2,818	3,727
Wind	MW	973	1,463	1,526	2,230	2,857	4,166	5,048
Flow_Battery	MW	-	-	-	-	-	-	-
Li_Battery	MW	-	387	454	808	981	1,077	1,941
H2	MW	-	-	-	-	-	-	-
DR	MW	128	149	160	178	195	213	231
EE	MW	-	-	4	10	11	11	12
Solar_DG	MW	3	6	7	11	17	22	28
Flex_Load	MW	-	-	-	-	-	-	-

Total generation (GWh)	Unit	2021	2027	2030	2035	2040	2045	2050
Energy Efficiency	GWh	58	440	707	1,231	1,790	2,261	2,687
Coal	GWh	8,306	3,976	5,012	4,634	2,457	649	-
Oil	GWh	1	-	1	6	4	4	2
Diesel	GWh	0	-	-	0	-	0	-
Nuclear	GWh	-	-	-	3,300	3,150	2,986	2,652
Gas_ST	GWh	56	69	32	-	274	419	288
Gas_RE	GWh	-	518	63	43	54	36	21
Gas_CC	GWh	-	1,905	1,128	1,265	1,936	2,632	1,075
Gas_CT	GWh	477	2,568	422	284	341	203	100
CCS	GWh	-	-	-	-	-	-	-
Landfill	GWh	53	53	53	53	53	53	53
Hydro	GWh	377	382	391	407	406	384	382
Solar	GWh	10	1,566	5,843	5,843	5,843	5,513	7,059
Wind	GWh	3,641	5,862	6,149	9,229	12,257	16,540	20,203
Flow_Battery	GWh	-	-	-	-	-	-	-
Li_Battery	GWh	-	286	552	418	437	(48)	(66)
H2	GWh	-	-	-	-	-	-	-
DR	GWh	-	-	-	-	-	-	-
Solar_DG	GWh	4	9	12	18	26	35	44
Flex_Load	GWh	-	-	-	-	-	-	-
Curtailment	GWh	50	-	-	-	-	1,798	2,350
Imports	GWh	**1,321**	**3,035**	**3,260**	**877**	**1,471**	**1,600**	**1,446**
Exports	GWh	**(1,236)**	**(1,211)**	**(2,084)**	**(2,398)**	**(2,610)**	**(2,819)**	**(3,024)**
Load	GWh	**13,011**	**19,017**	**20,833**	**23,979**	**26,098**	**28,186**	**30,236**

Active Scenario Name	Net Zero Carbon Prices

Generation Summary

Total capacity (MW)	Unit	2021	2027	2030	2035	2040	2045	2050
Coal	MW	1,336	1,000	346	-	-	-	-
Oil	MW	123	123	123	123	123	123	123
Diesel	MW	7	7	7	7	7	7	7
Nuclear	MW	-	-	-	-	-	-	-
Gas_ST	MW	242	278	932	1,278	1,000	1,000	1,000
Gas_RE	MW	-	150	150	150	150	150	150
Gas_CC	MW	-	61	61	343	803	895	1,013
Gas_CT	MW	640	1,090	1,090	1,090	1,090	1,090	1,090
CCS	MW	-	-	-	-	-	-	-
Landfill	MW	6	6	6	6	6	6	6
Hydro	MW	80	80	80	80	80	80	80
Solar	MW	5	977	1,651	1,823	2,142	2,298	4,382
Wind	MW	973	2,155	2,861	3,254	3,094	4,318	5,605
Flow_Battery	MW	-	-	-	-	-	-	-
Li_Battery	MW	-	387	606	995	1,411	1,827	2,000
H2	MW	-	-	-	-	-	-	-
DR	MW	128	149	160	178	195	213	231
EE	MW	-	0	4	10	11	11	12
Solar_DG	MW	3	6	7	11	17	22	28
Flex_Load	MW	-	-	-	-	-	-	-

Total generation (GWh)	Unit	2021	2027	2030	2035	2040	2045	2050
Energy Efficiency	GWh	58	440	707	1,231	1,790	2,261	2,687
Coal	GWh	8,306	3,910	1,004	-	-	-	-
Oil	GWh	1	-	-	-	-	-	-
Diesel	GWh	0	-	-	-	-	-	-
Nuclear	GWh	-	-	-	-	-	-	-
Gas_ST	GWh	56	49	488	436	276	193	73
Gas_RE	GWh	-	162	78	43	29	29	16
Gas_CC	GWh	-	428	317	1,639	929	354	275
Gas_CT	GWh	477	926	422	230	161	121	34
CCS	GWh	-	-	-	-	-	-	-
Landfill	GWh	53	53	53	53	53	53	52
Hydro	GWh	385	365	360	358	375	400	389
Solar	GWh	10	2,025	3,400	3,762	4,437	4,765	8,135
Wind	GWh	3,418	8,222	11,115	12,959	13,293	18,674	21,553
Flow_Battery	GWh	-	-	-	-	-	-	-
Li_Battery	GWh	-	458	471	498	563	623	94
H2	GWh	-	-	-	-	-	-	-
DR	GWh	-	2	5	5	6	6	7
Solar_DG	GWh	4	9	12	18	26	35	44
Flex_Load	GWh	-	-	-	-	-	-	-
Curtailment	GWh	273	674	925	786	10	-	3,733
Imports	GWh	**1,563**	**3,443**	**4,168**	**5,073**	**6,797**	**5,753**	**2,587**
Exports	GWh	**(1,263)**	**(1,037)**	**(1,059)**	**(1,097)**	**(848)**	**(2,819)**	**(3,024)**
Load	GWh	**13,011**	**19,017**	**20,833**	**23,979**	**26,098**	**28,186**	**30,236**

Active Scenario Name	Net Zero Flex Load

Generation Summary

Total capacity (MW)	Unit	2021	2027	2030	2035	2040	2045	2050
Coal	MW	1,336	1,000	973	687	163	-	-
Oil	MW	123	123	123	123	123	123	123
Diesel	MW	7	7	7	7	7	7	7
Nuclear	MW	-	-	-	-	-	-	-
Gas_ST	MW	242	278	305	476	837	1,000	1,000
Gas_RE	MW	-	150	150	150	150	150	150
Gas_CC	MW	-	230	296	559	947	1,133	1,151
Gas_CT	MW	640	1,090	1,090	1,090	1,090	1,090	1,090
CCS	MW	-	-	-	-	-	-	-
Landfill	MW	6	6	6	6	6	6	6
Hydro	MW	80	80	80	80	80	80	80
Solar	MW	5	755	2,828	2,828	2,828	3,226	4,744
Wind	MW	973	1,527	1,537	2,632	3,017	4,162	5,450
Flow_Battery	MW	-	-	-	-	-	-	-
Li_Battery	MW	-	387	461	808	864	928	1,553
H2	MW	-	-	-	-	-	-	-
DR	MW	128	149	160	178	195	213	231
EE	MW	-	0	4	10	11	11	12
Solar_DG	MW	3	6	7	11	17	22	28
Flex_Load	MW	-	338	367	417	446	479	516

Total generation (GWh)	Unit	2021	2027	2030	2035	2040	2045	2050
Energy Efficiency	GWh	58	440	707	1,231	1,790	2,261	2,687
Coal	GWh	8,306	4,235	5,126	3,601	757	-	-
Oil	GWh	1	-	1	7	4	1	0
Diesel	GWh	0	-	-	-	-	-	-
Nuclear	GWh	-	-	-	-	-	-	-
Gas_ST	GWh	56	46	33	205	544	636	332
Gas_RE	GWh	-	520	52	46	60	63	48
Gas_CC	GWh	-	1,600	1,095	3,129	5,424	4,149	1,255
Gas_CT	GWh	477	2,438	338	310	338	263	138
CCS	GWh	-	-	-	-	-	-	-
Landfill	GWh	53	53	53	53	53	53	53
Hydro	GWh	385	382	403	420	414	402	393
Solar	GWh	10	1,566	5,864	5,864	5,864	6,468	9,266
Wind	GWh	3,412	6,143	6,197	10,992	12,961	17,431	20,567
Flow_Battery	GWh	-	-	-	-	-	-	-
Li_Battery	GWh	-	277	553	494	455	190	9
H2	GWh	-	-	-	-	-	-	-
DR	GWh	-	-	-	-	-	-	5
Solar_DG	GWh	4	9	12	18	26	35	44
Flex_Load	GWh	-	0	(0)	0	(0)	0	0
Curtailment	GWh	279	-	-	-	-	780	3,656
Imports	GWh	**1,560**	**3,157**	**3,190**	**1,238**	**1,809**	**1,315**	**1,148**
Exports	GWh	**(1,254)**	**(1,408)**	**(2,084)**	**(2,398)**	**(2,610)**	**(2,819)**	**(3,024)**
Load	GWh	**13,011**	**19,017**	**20,833**	**23,979**	**26,098**	**28,186**	**30,236**