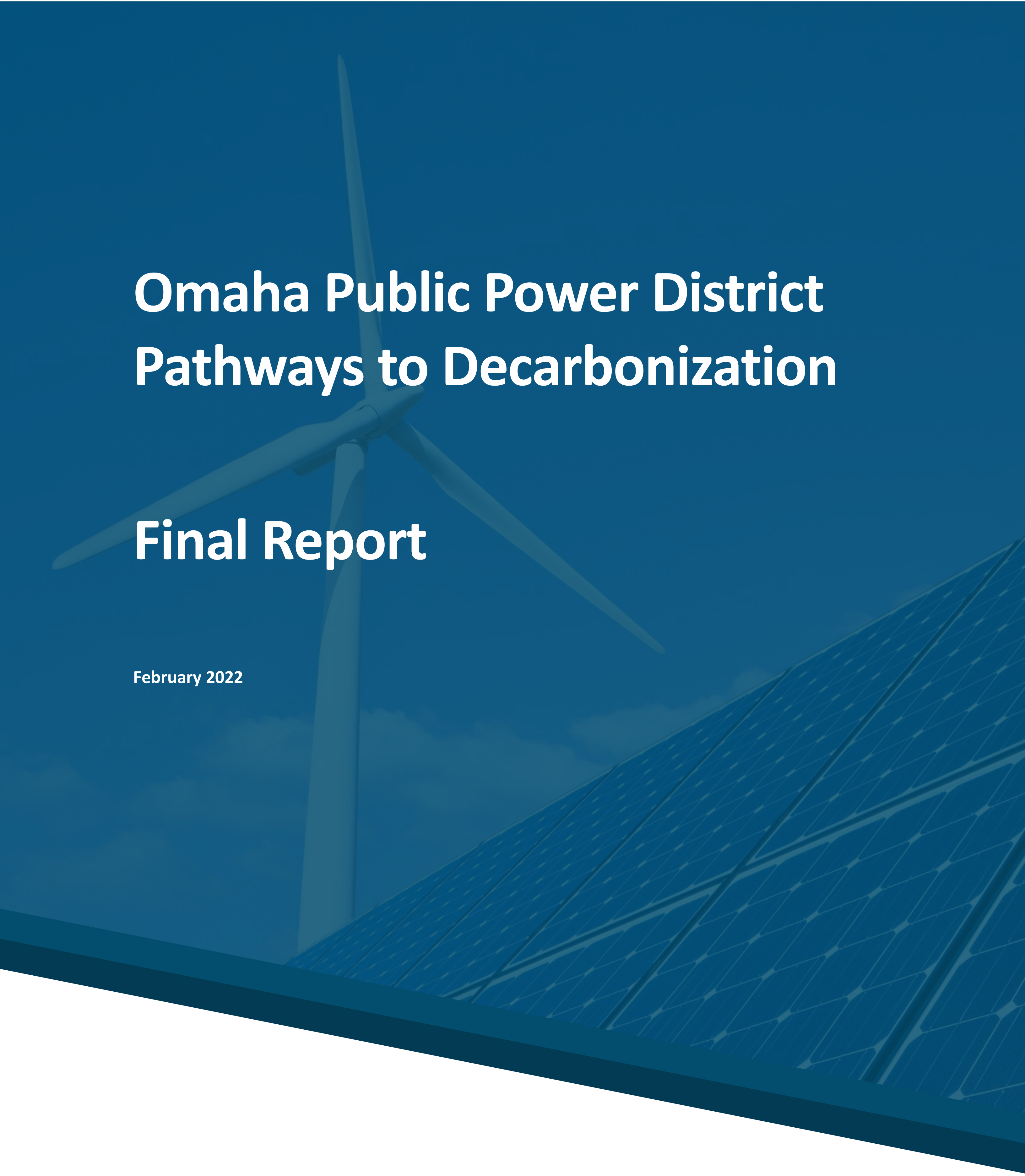

Omaha Public Power District Pathways to Decarbonization

Final Report

February 2022

Energy+Environmental Economics

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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.

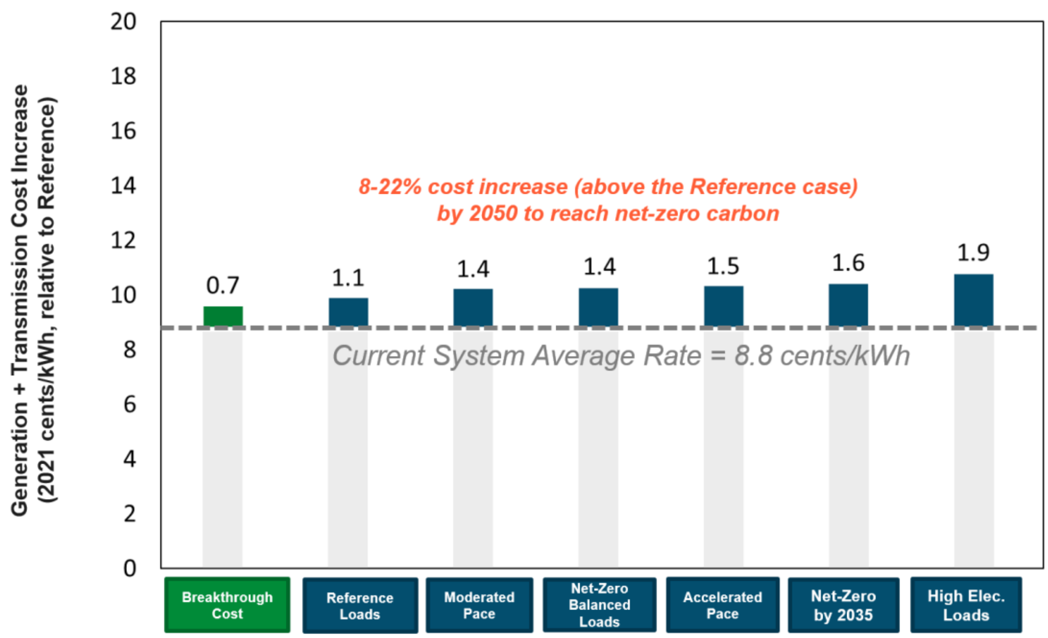
This report covers detailed documentation of E3's study approach, inputs, and results. This executive summary contains a summary of the following key study findings:

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

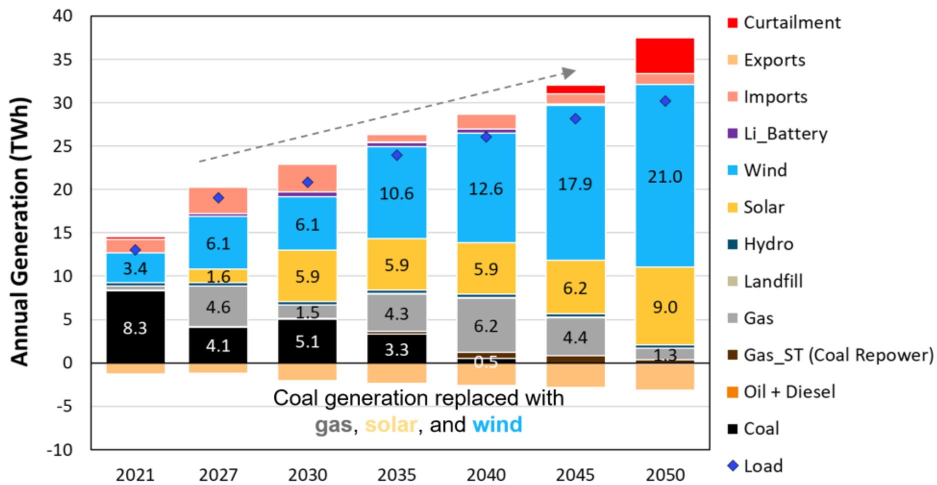
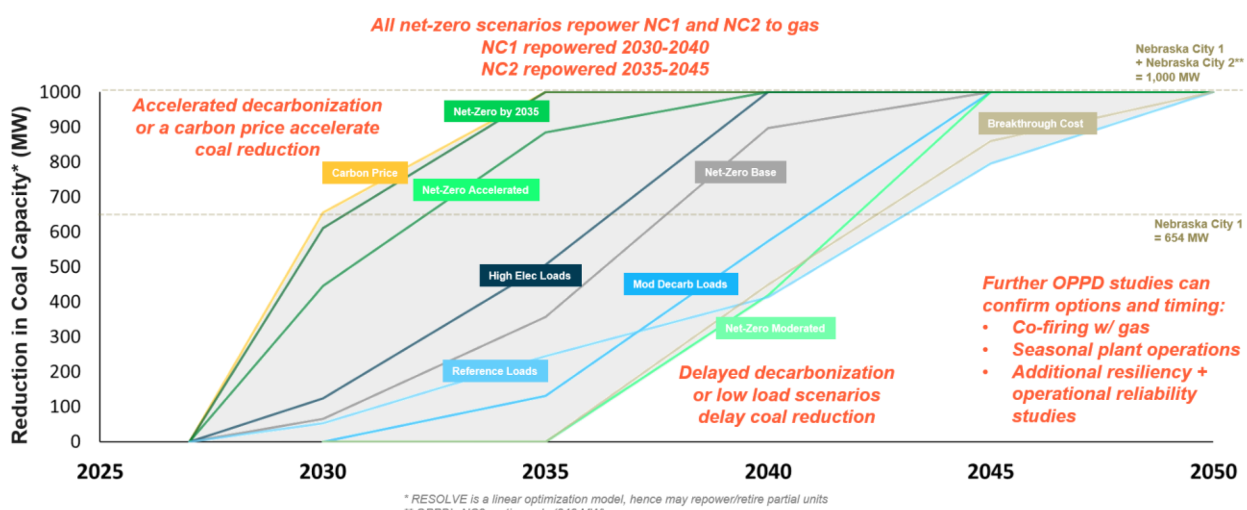


Figure 3 shows that all scenarios ultimately repower or retire all 1,000 MW of OPPD's remaining two coal-burning Nebraska City units by 2050. For Nebraska City 1, repowering occurs between 2030-2040; for Nebraska City 2, it occurs between 2035-2045.[2] All modeled scenarios repower the coal steam turbines 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



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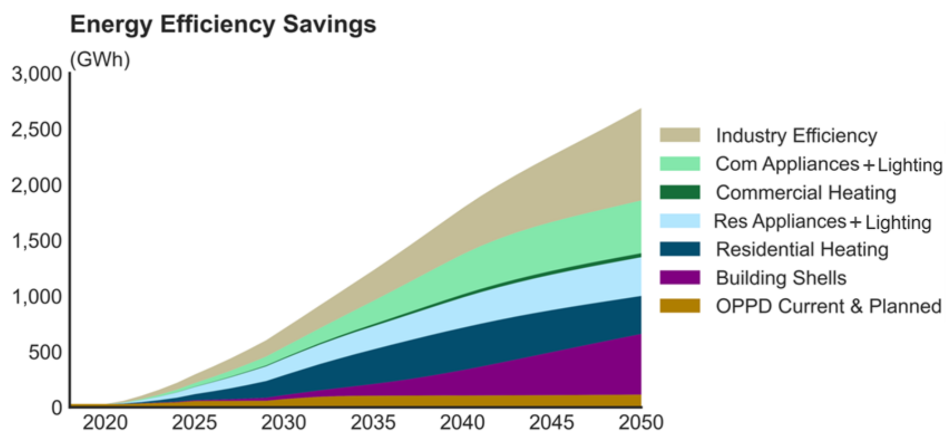
[2] Nebraska City Unit 2 stops coal operations by 2045 in all cases except for the Reference Loads and the Breakthrough Costs scenarios. In those two scenarios, coal operations fully cease in 2050.

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

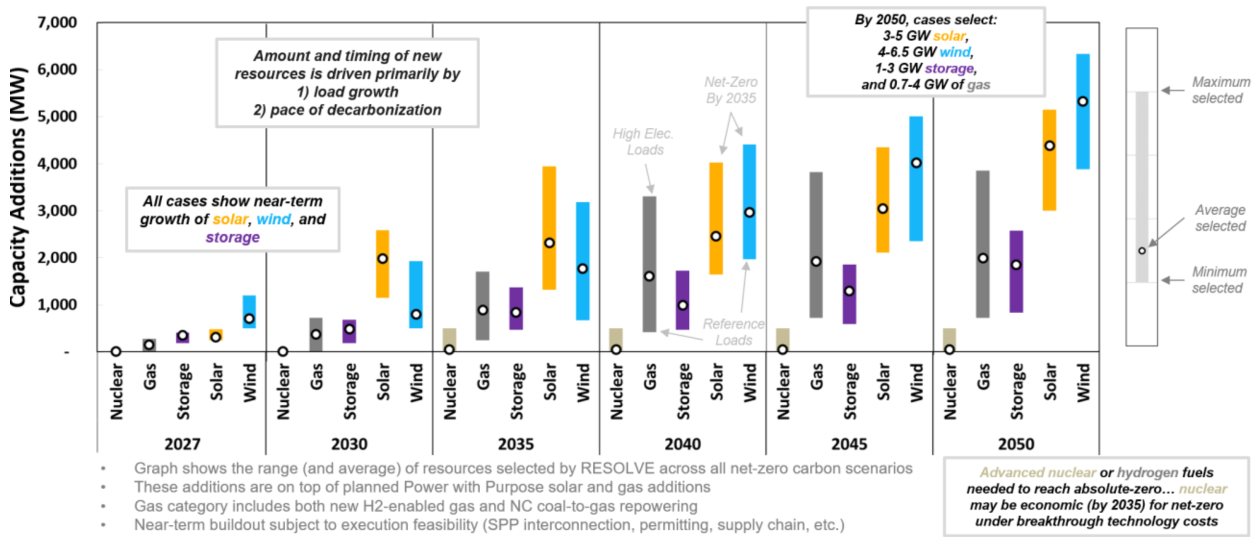
Energy efficiency is modeled in the multi-sector modeling scenarios, which expand efficiency adoption beyond current OPPD programs. Efficiency occurs at the economy-wide level, as primary energy uses when inefficient gasoline, diesel, and natural gas combustion is replaced with more efficient electric 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.

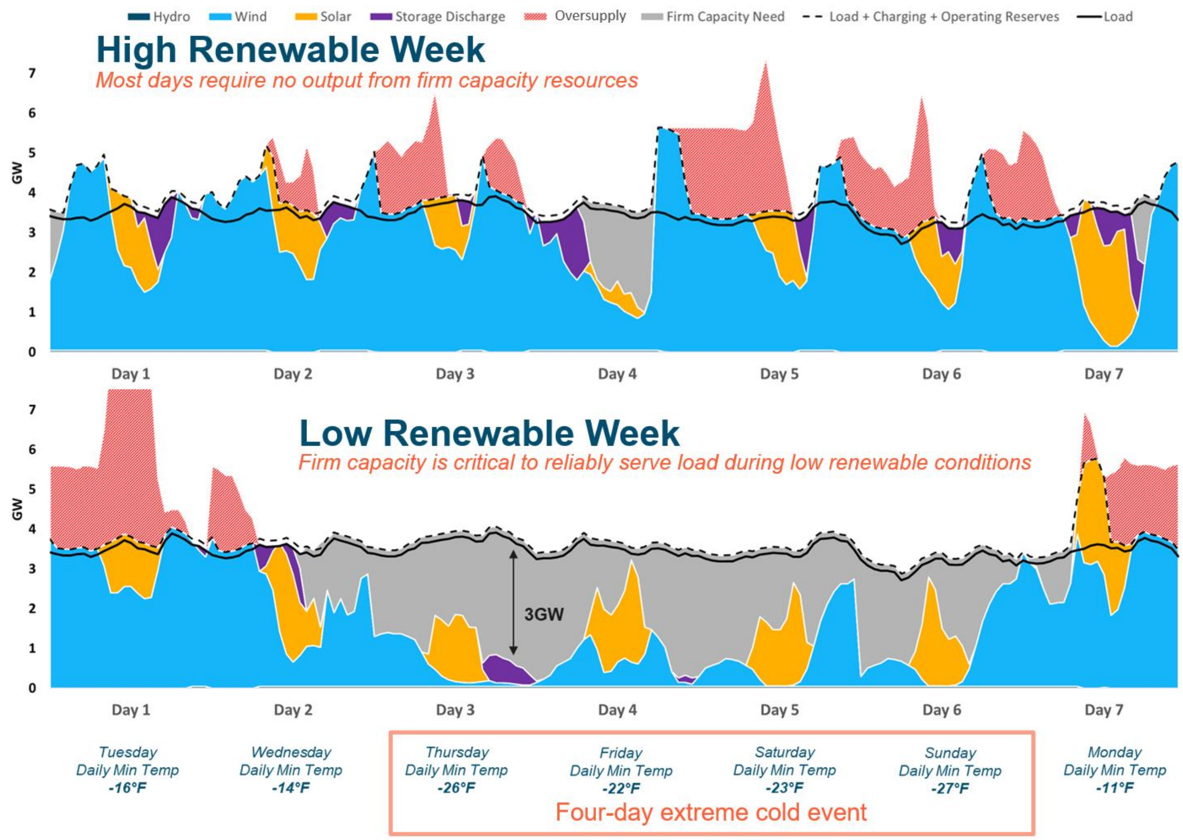
Figure 5. Incremental OPPD Low-Carbon Resources Selected to Reach Net zero Carbon



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.

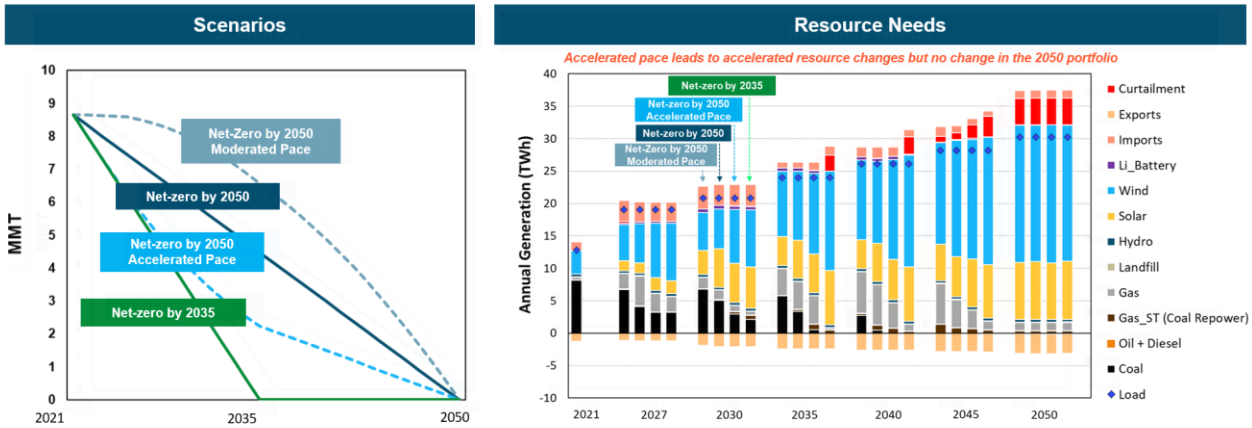
Figure 6. Firm Capacity Needs During a Low Renewable Extreme Winter Cold Event (2050 Net zero Carbon Base Scenario)



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

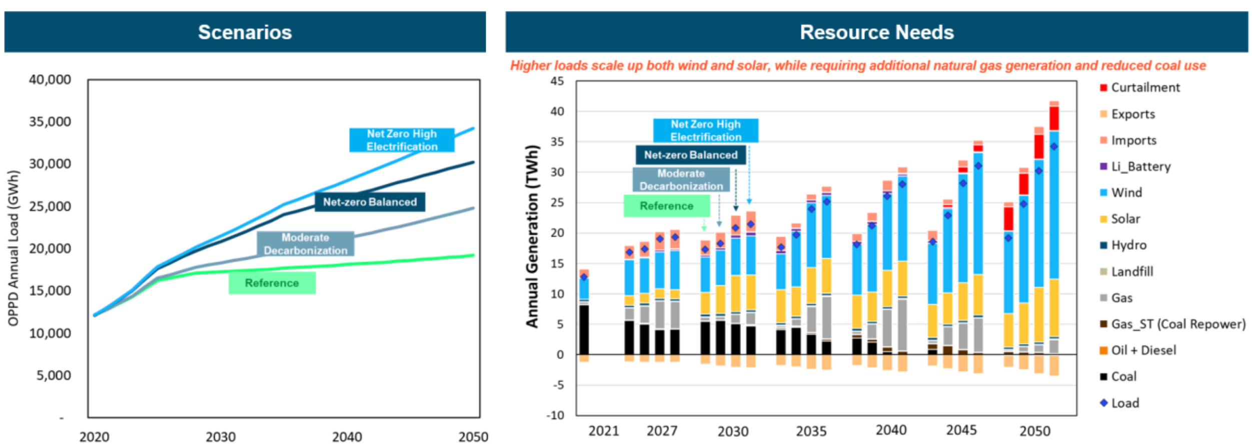
A core set of resource additions are common across a variety of scenarios, pointing to no regrets near-term investments in new solar, wind, and battery storage capacity, as well as fuel switching from coal to natural gas. The pace of decarbonization generally sets the speed of resource decisions. As 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.

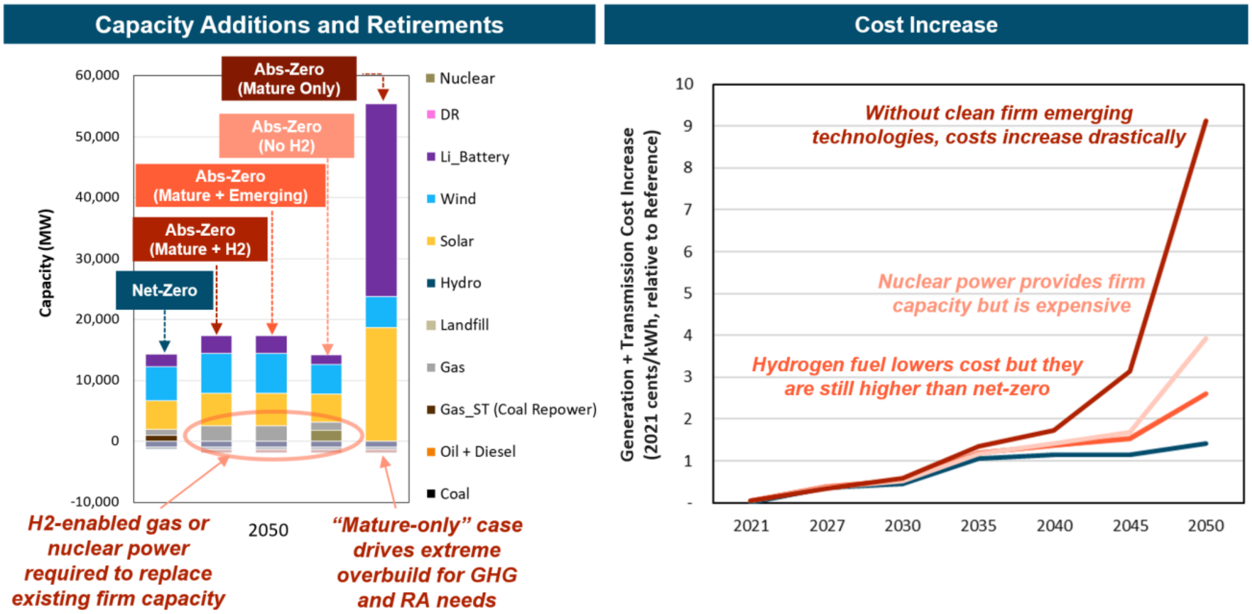
Figure 8. Load Growth Impacts the Level of Resource Changes



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.

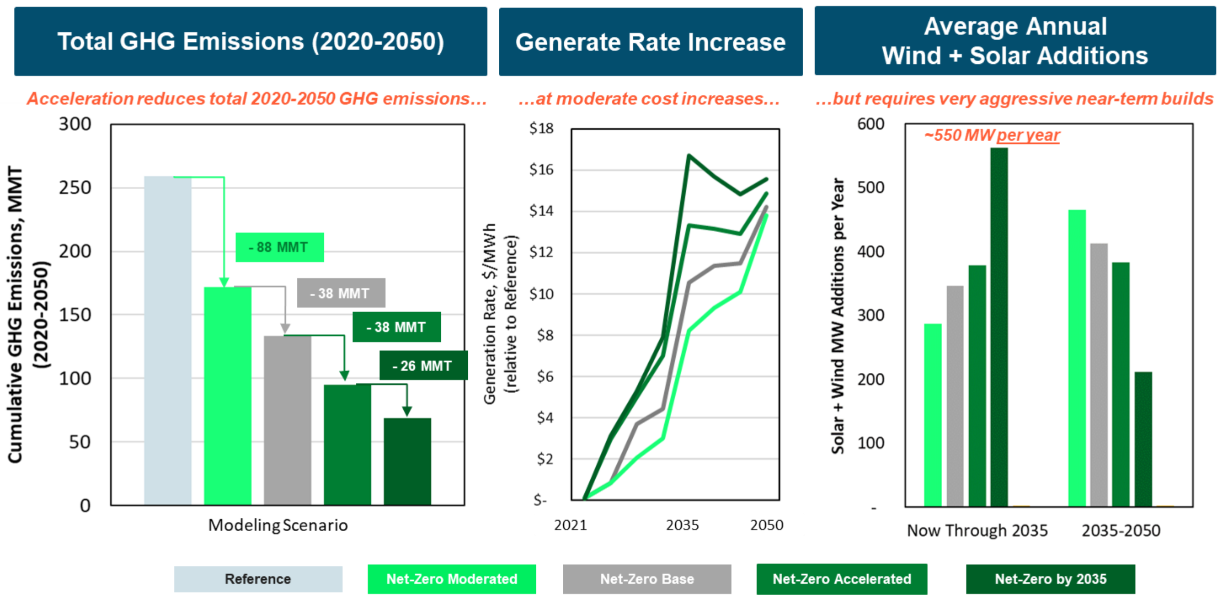
Figure 9. Net vs. Absolute Zero Scenario Resource Needs and Costs



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:

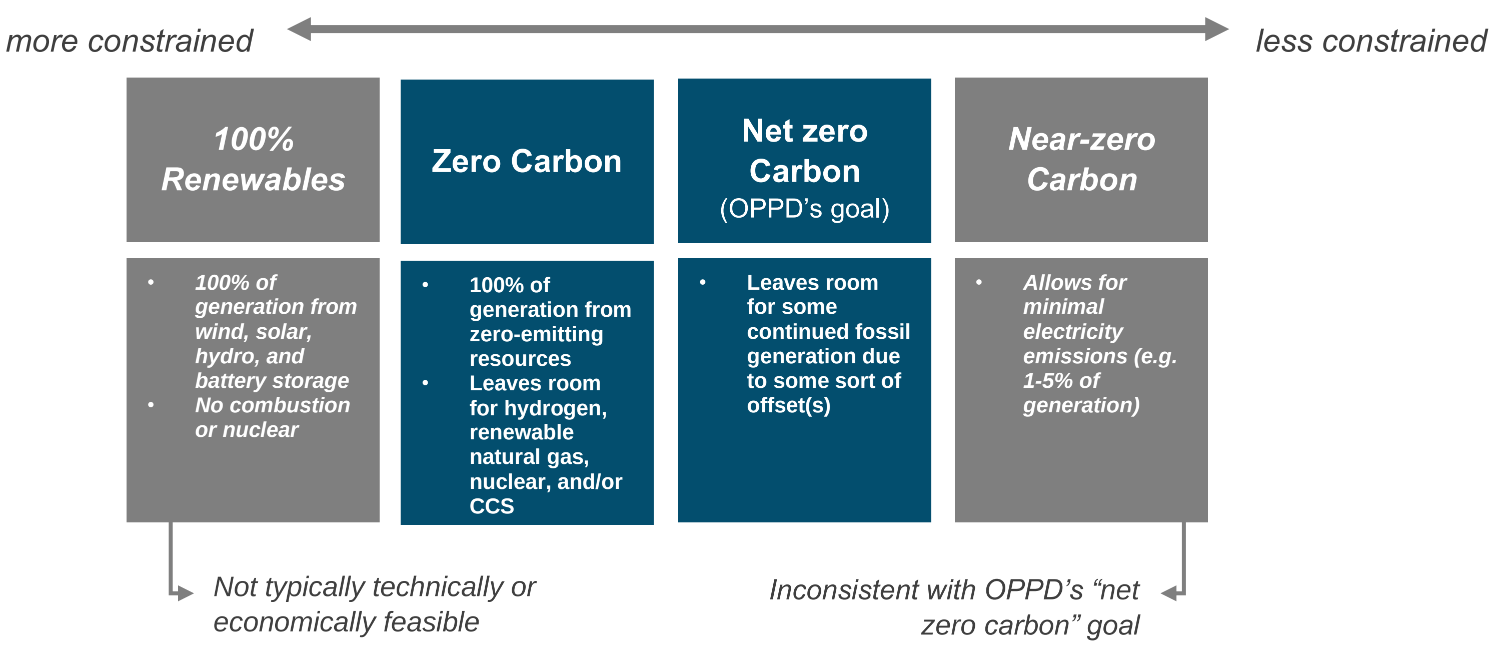
+ **Updated potential and cost-effectiveness studies of demand-side resources including energy efficiency, load flexibility, and distributed energy resources**
+ **Coordinated electric and gas utility planning on smart electrification pathways**
+ **Additional studies and activities to confirm coal retirement 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.

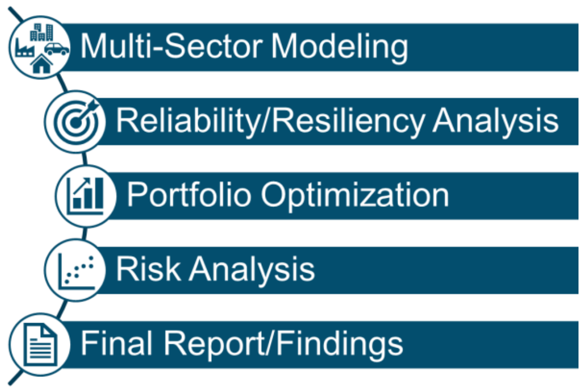
Figure 13. Net zero Carbon "Netting" Options Considered for this Study

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.



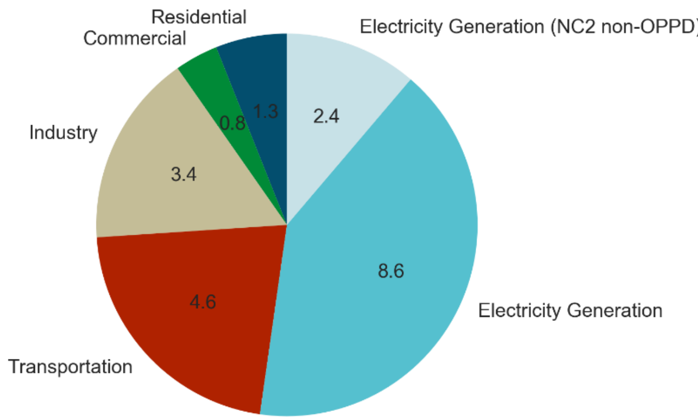
This section provides an overview of the modeling approach used in each of the key project steps.

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



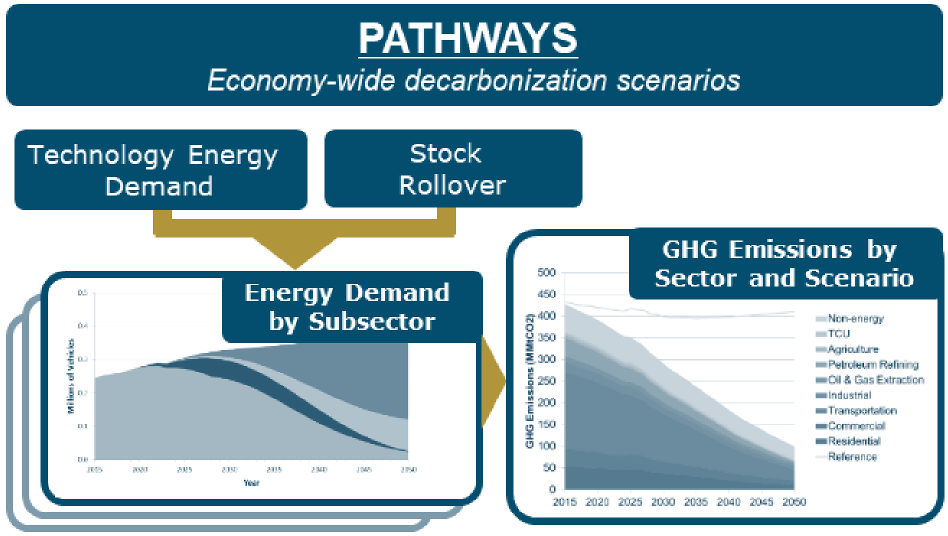
In addition to providing electric load forecast information for studying energy portfolios, E3 produced this multi-sector modeling so that it also may inform OPPD's community and customer programs within the broader Pathways to Decarbonization Program. The Community program is engaged with local community 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.

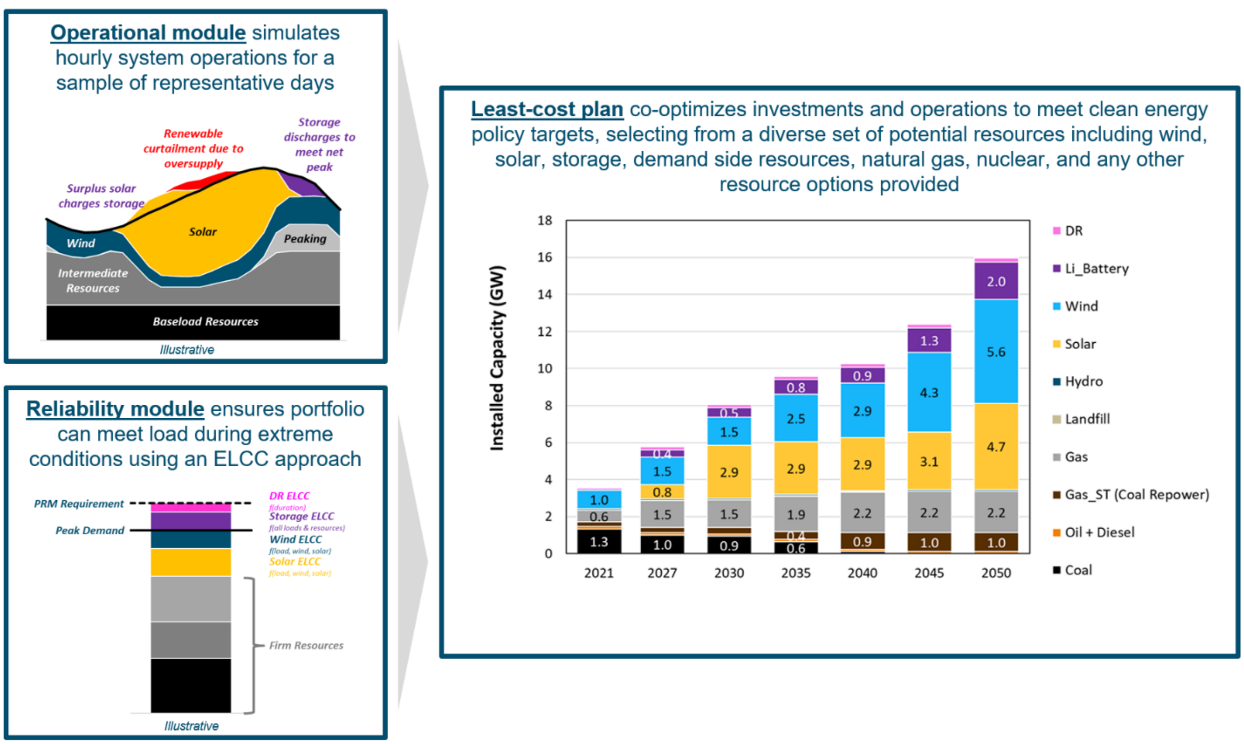
2.4 Portfolio Optimization

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.

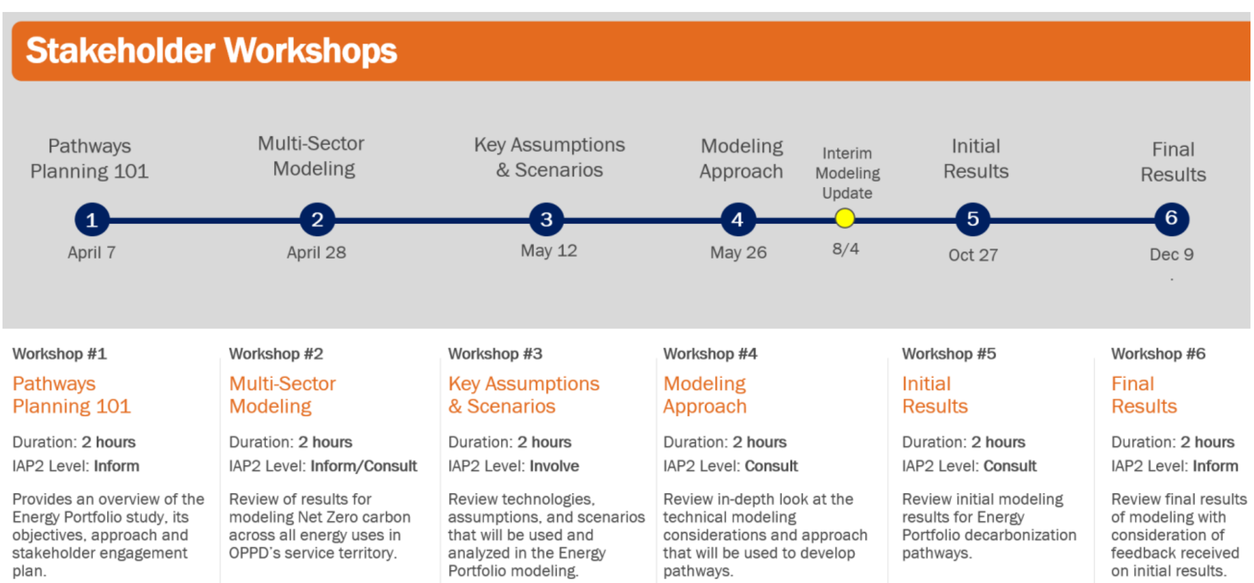
2.5 Risk Analysis

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

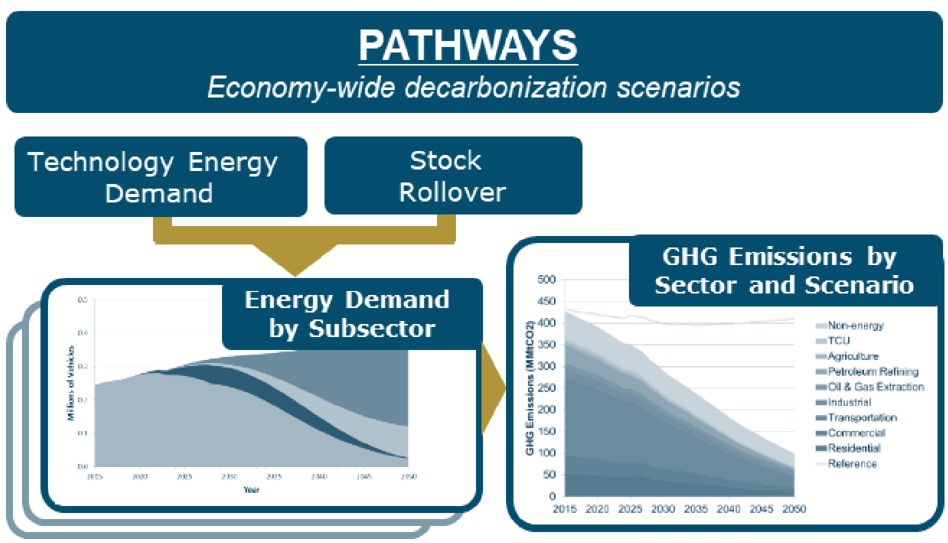
The multi-sectoral modeling leverages a suite of tools to develop scenarios for economy-wide energy demand. The primary model used in this analytical step is the PATHWAYS model, which is an economy-wide representation of infrastructure, energy, and emissions within a given geography. PATHWAYS is a model 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.

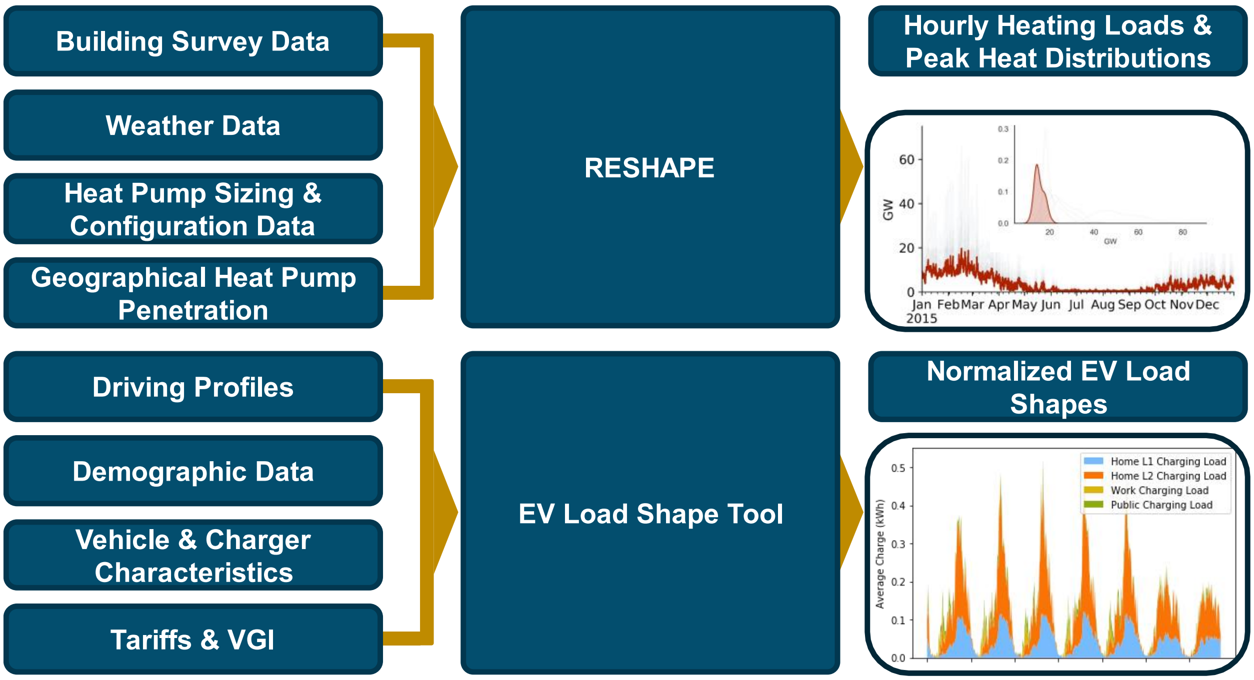
3.2 Models

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

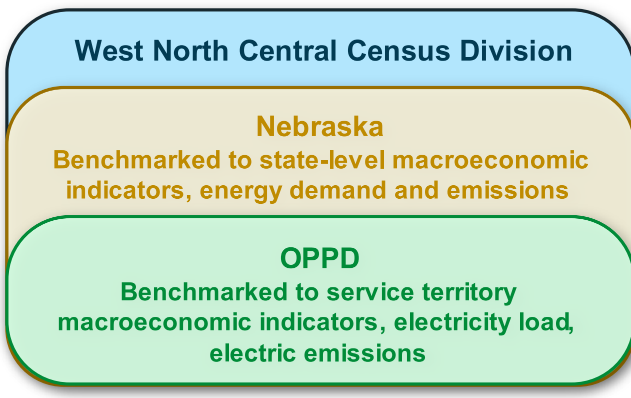
<table>
<tr><th>Measure Type</th><th>Measure</th><th>Moderate Decarbonization</th><th>Net Zero: High Fuels</th><th>Net Zero: Balanced</th><th>Net Zero: High Electrification</th></tr>
<tr><td rowspan="3">Efficiency</td><td>Efficient Appliances</td><td colspan="2">50% sales by 2040</td><td colspan="2">100% 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>

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

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

[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

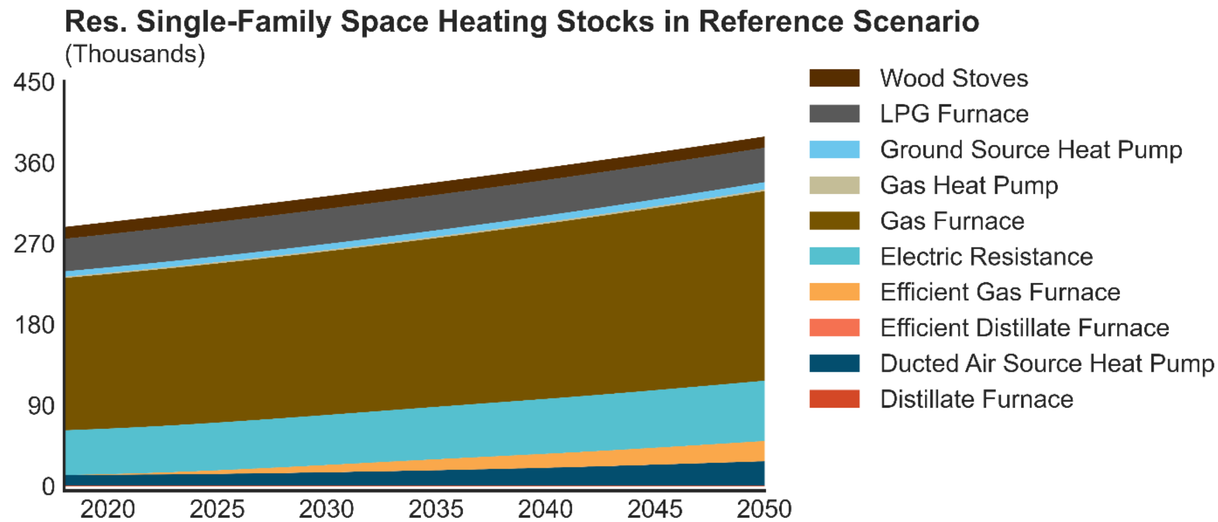


Figure 22 shows the evolution of residential single-family space heating stocks from 2018 to 2050. With the small amount of natural gas replacement with electrified space heating, there is a small growth of ducted air source heat pumps throughout the study period.

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

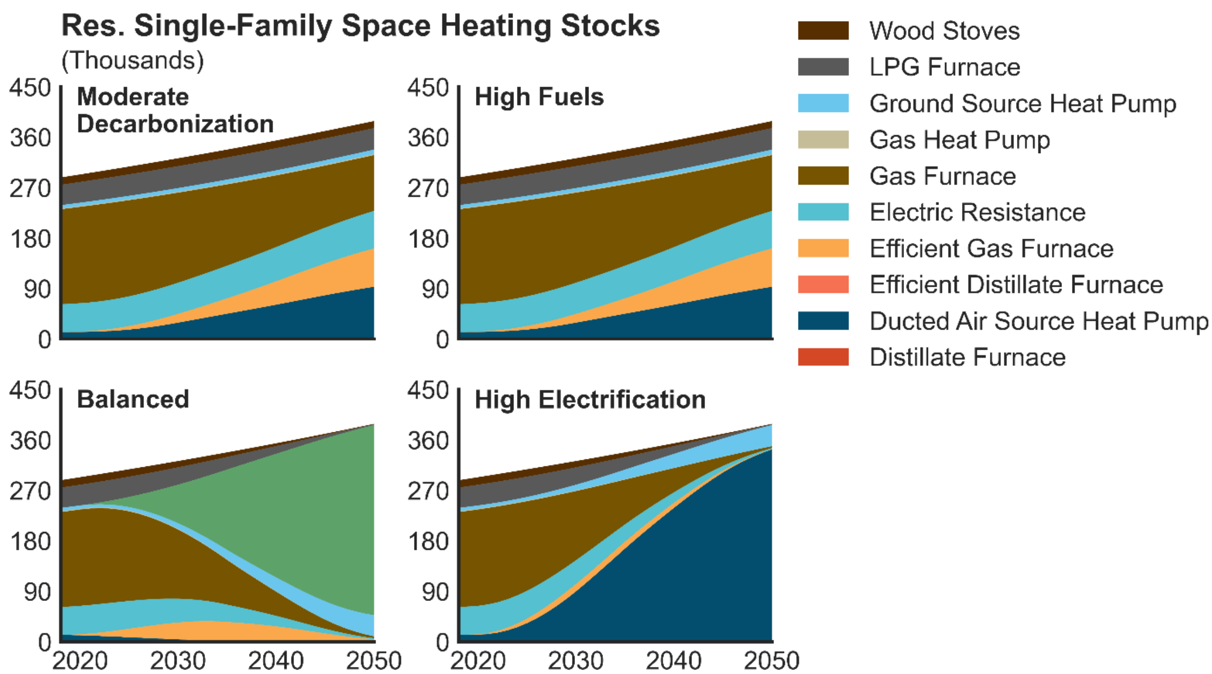


Figure 23 shows the evolution of residential single-family space heating stock for the mitigation scenarios. Despite high levels of sales of heat pumps by 2040 in the Moderate Decarbonization and High Fuels cases, only about a quarter of space heating stocks are electrified, showing that growth in stock 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

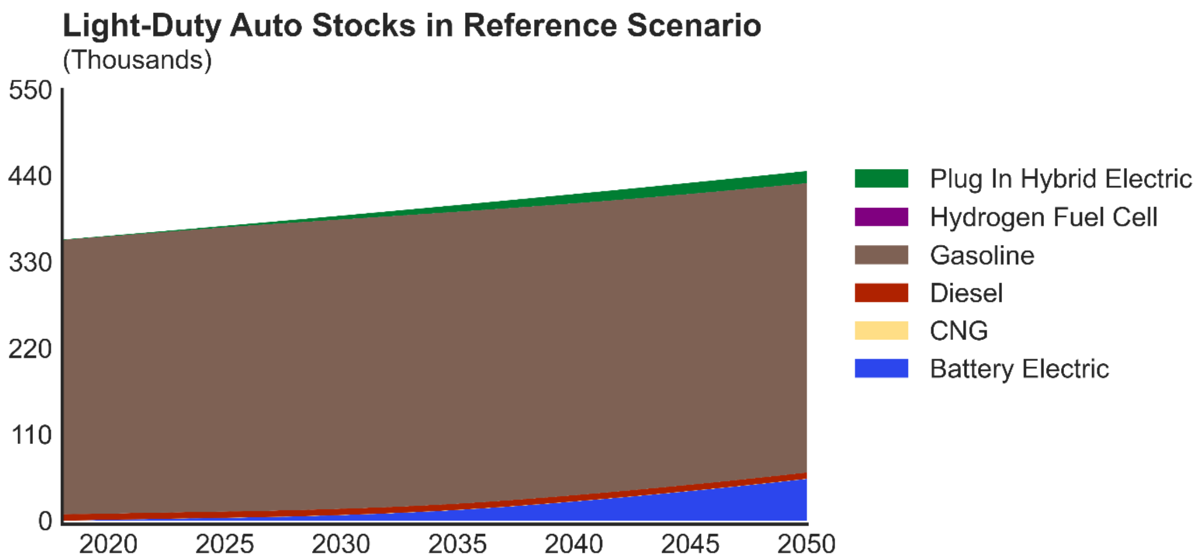


Figure 24 shows the evolution of LDA stocks. Based on the sales trajectories, gasoline internal combustion engine (ICE) vehicles will continue to dominate the LDA stock through 2050. Fossil fuel powered LDTs and medium-duty vehicles (MDVs) and heavy-duty vehicles (HDVs) will continue to similarly dominate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

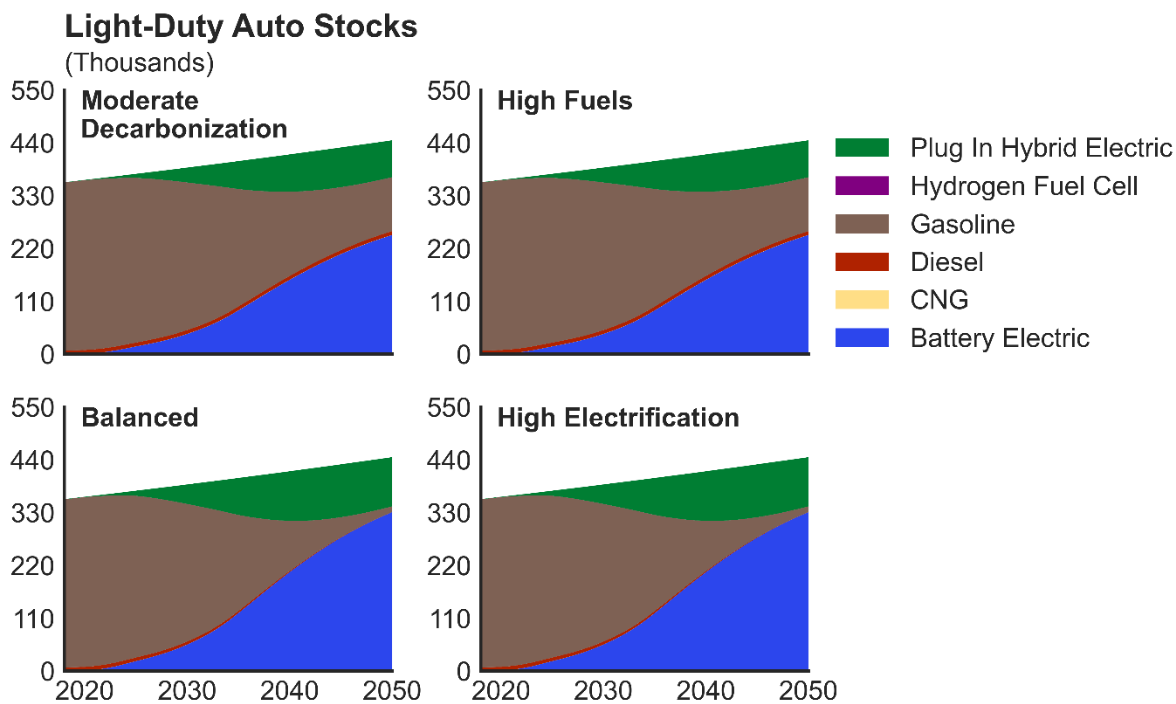
Table 10. Mitigation Scenario Transportation Electrification Assumptions

<table>
<tr><th>Transportation Measure Category</th><th>Moderate Decarbonization Scenario</th><th>Net Zero: High Fuels Scenario</th><th>Net Zero: Balanced Scenario</th><th>Net Zero: High Electrification Scenario</th></tr>
<tr><td>ZEV LDV sales share</td><td colspan="2">75% sales share by 2035</td><td colspan="2">100% sales share by 2035</td></tr>
<tr><td>ZEV MDV sales share</td><td colspan="2" rowspan="2">25% sales share by 2035</td><td rowspan="2">50% sales share by 2035</td><td rowspan="2">50% sales share by 2035, with 100% by 2050</td></tr>
<tr><td>ZEV HDV sales share</td></tr>
<tr><td>ZEV bus sales share</td><td colspan="2">50% sales share by 2035</td><td colspan="2">100% sales share by 2035</td></tr>
</table>

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

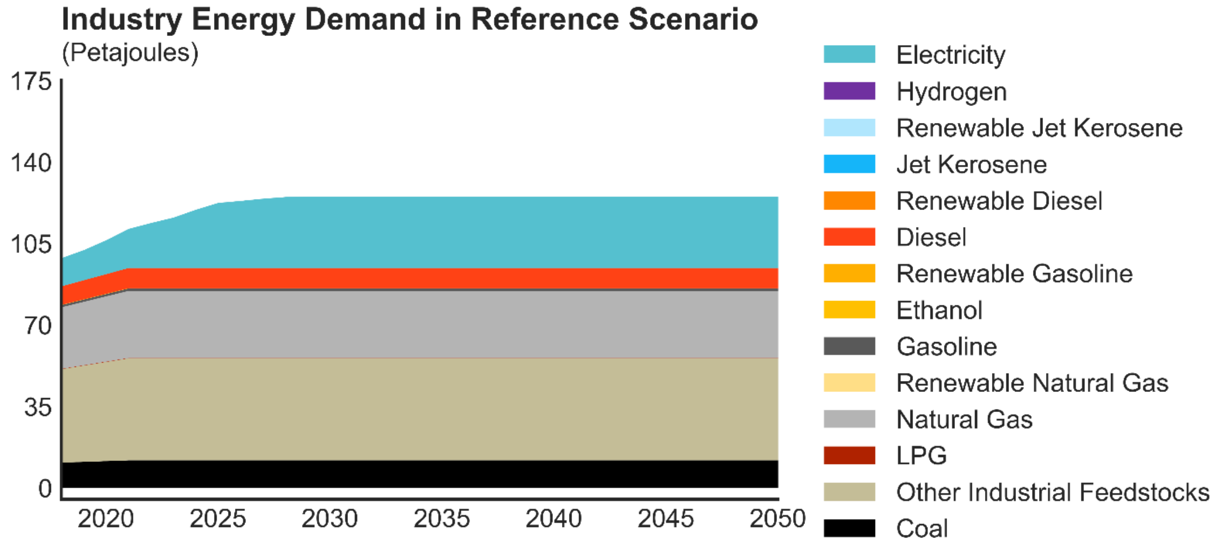


Figure 26 shows energy demand by fuel in industry. Demand grows for most fuels until the early 2020s, after which they are assumed to plateau. Electricity demand grows until about 2030 and plateaus thereafter. There is significant gaseous and liquid fuel demand that could be electrified or decarbonized,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

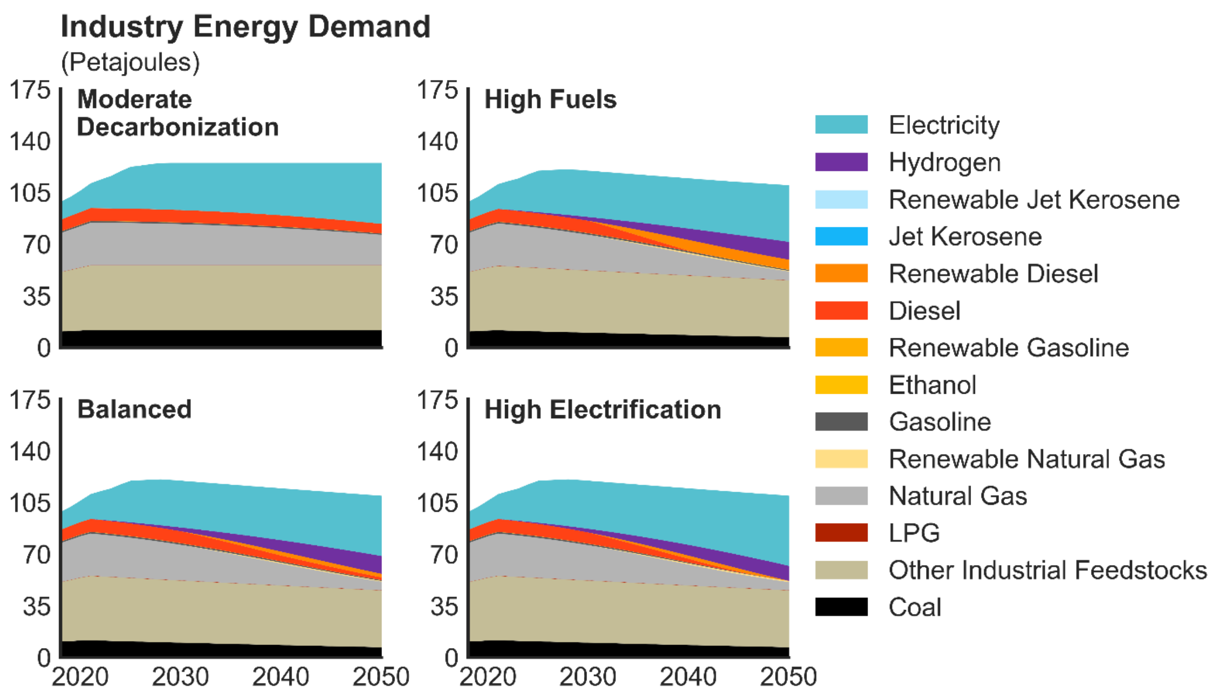
Table 13. Mitigation Scenario Industry Decarbonization Measures

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

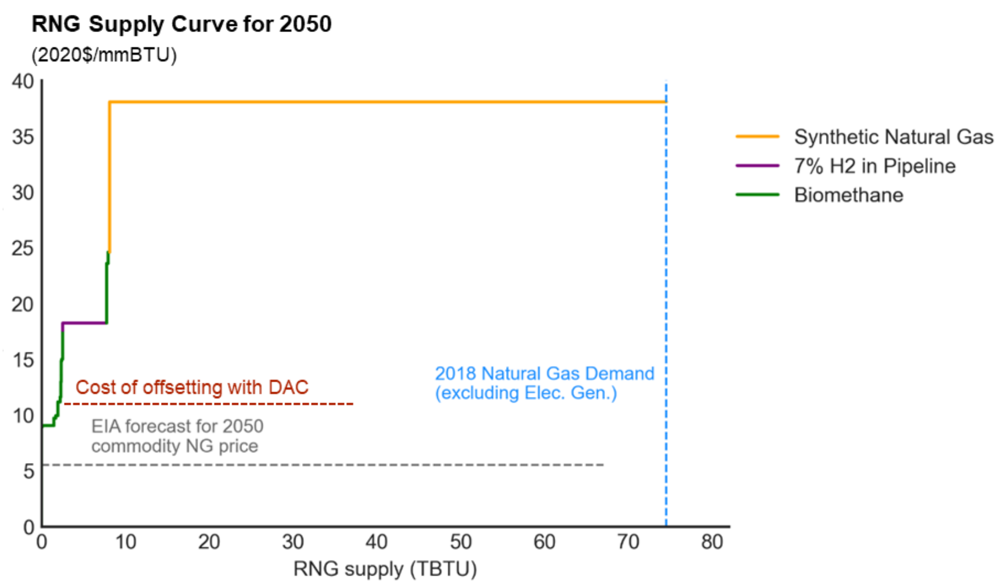
Nebraska already uses low-carbon fuels in the form of corn ethanol. The Reference scenario assumes that the current blending mixture of 10% ethanol with fossil gasoline persists through the study period.

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.

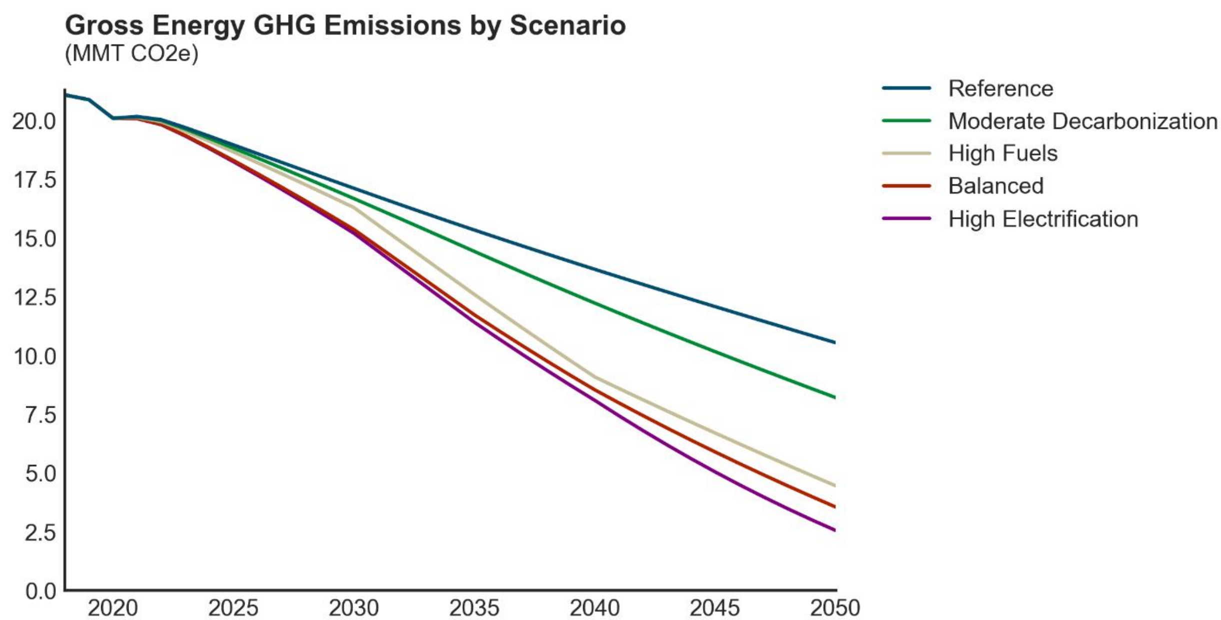
[13] "The Challenge of Retail Gas in California's Low-Carbon Future," Energy and Environmental Economics, University of California Irvine advanced Power and Energy Program, 2019, https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-F.pdf.

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

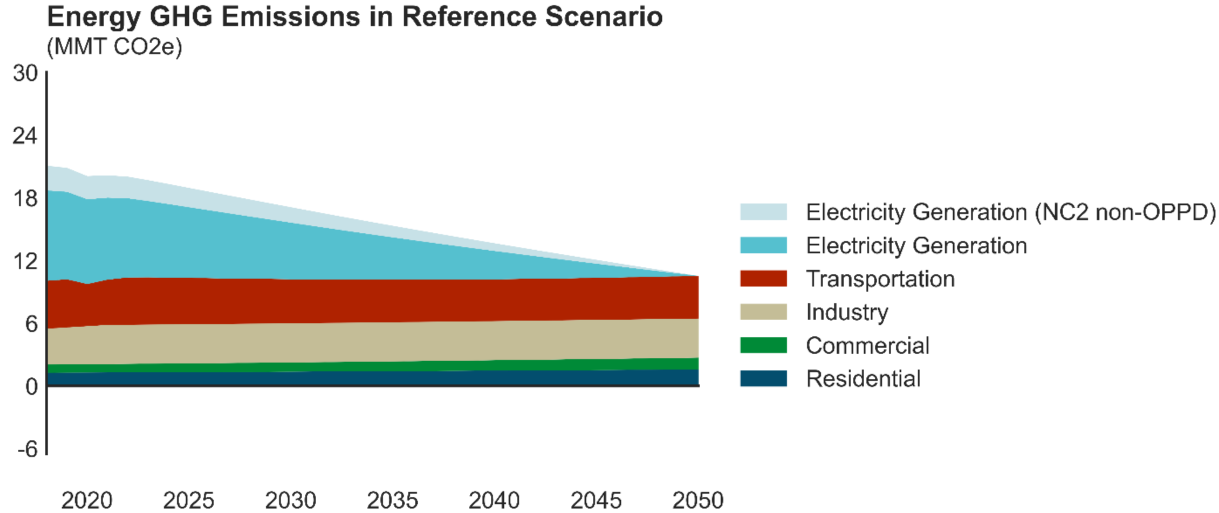
3.5.1 Economy-wide GHG Emissions

Figure 29. Economy-wide GHG Emissions by Scenario



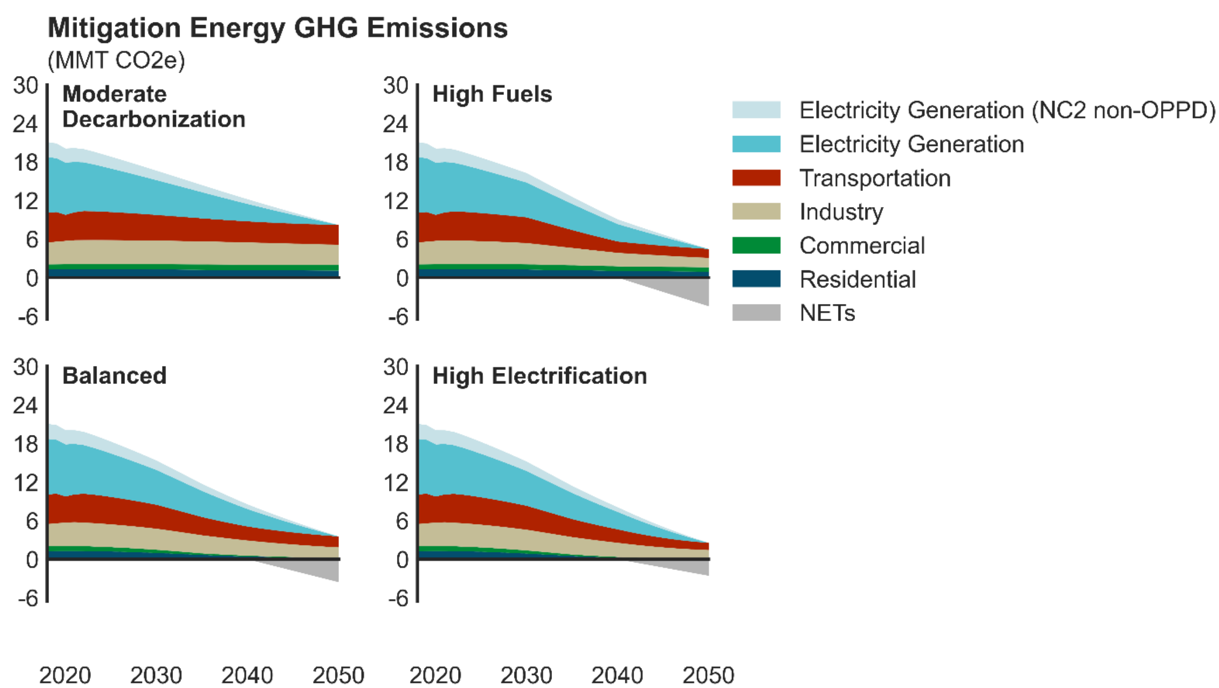
Economy-wide GHG emissions is a key output from each multi-sector modeling scenario. As shown in Figure 29, economy-wide GHG emissions decline by nearly 50% in the Reference scenario. As seen in Figure 30, this is due to OPPD reaching its own net zero GHG emissions target. However, because no other sectors 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.

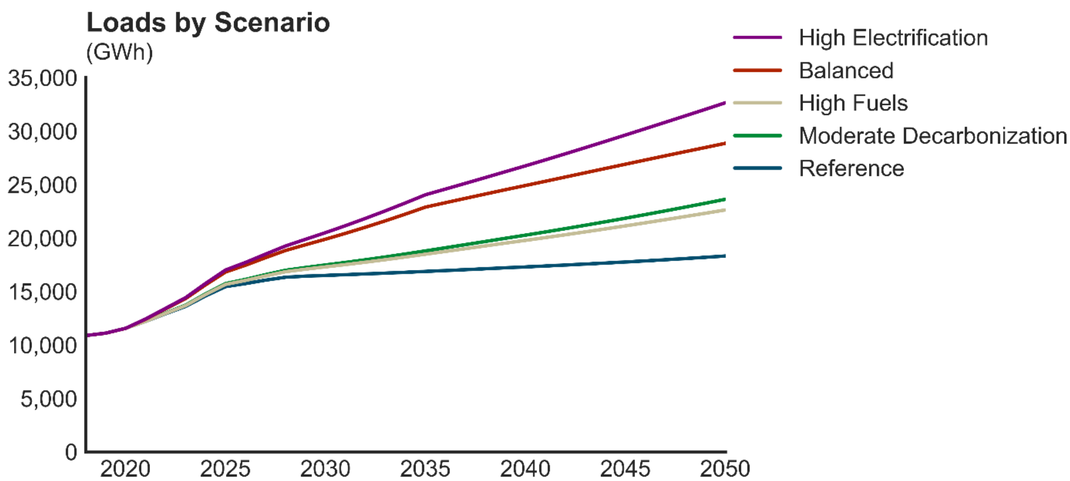
Figure 31. Mitigation Scenario GHG Emissions by Sector



3.5.2 Load Impacts

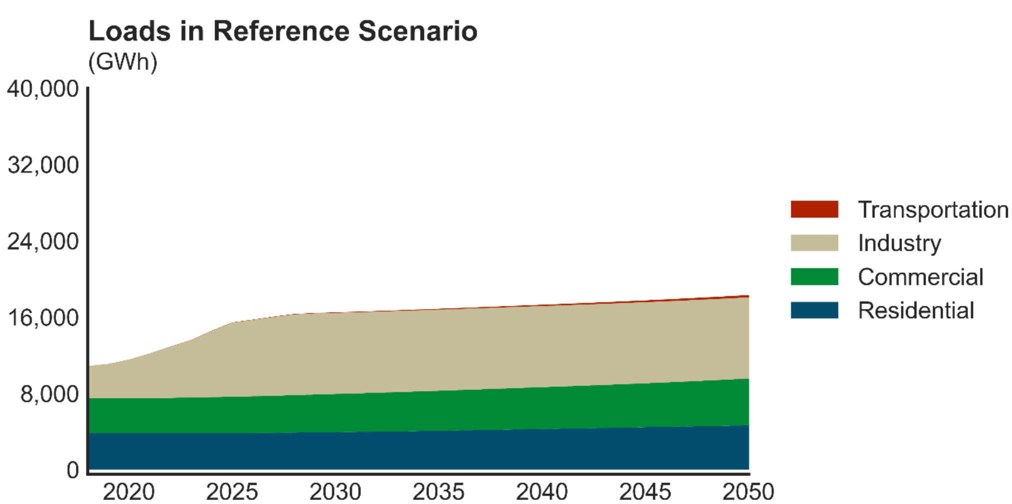
3.5.2.1 Electric Sector Load Growth

Figure 32. Electric Loads by Scenario



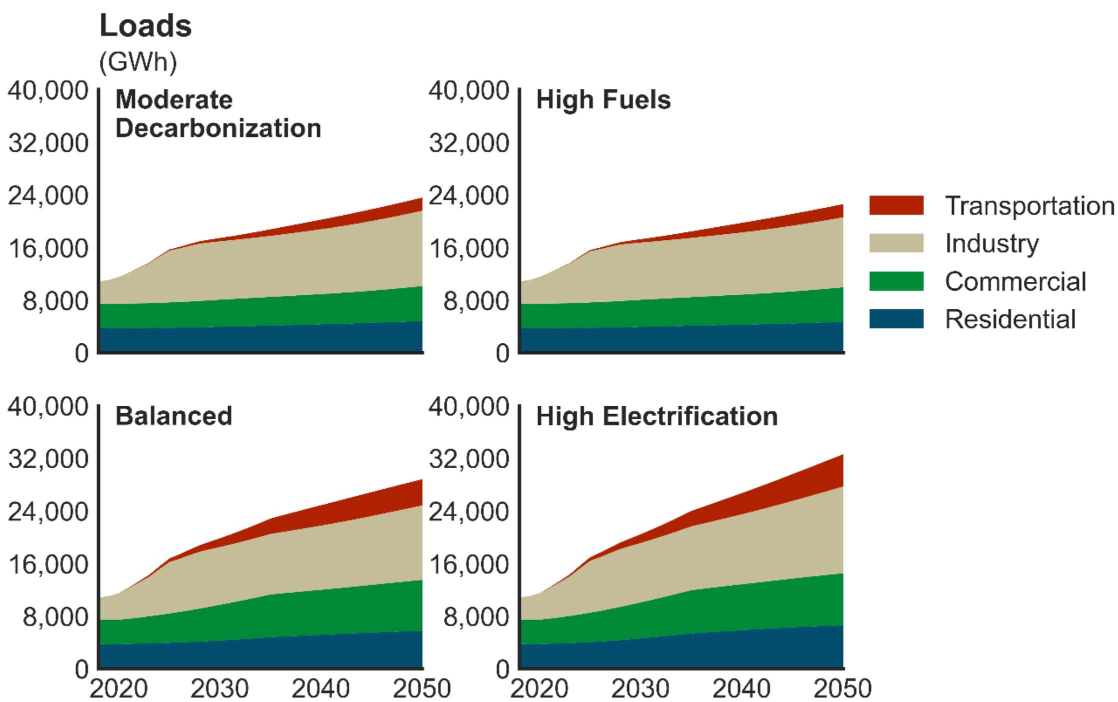
Economy-wide decarbonization has the potential for major impacts on future OPPD electric loads. As seen in Figure 32, load grows more quickly with tightening emissions targets and increasing levels of electrification. One notable exception is that the Moderate Decarbonization scenario has higher load 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



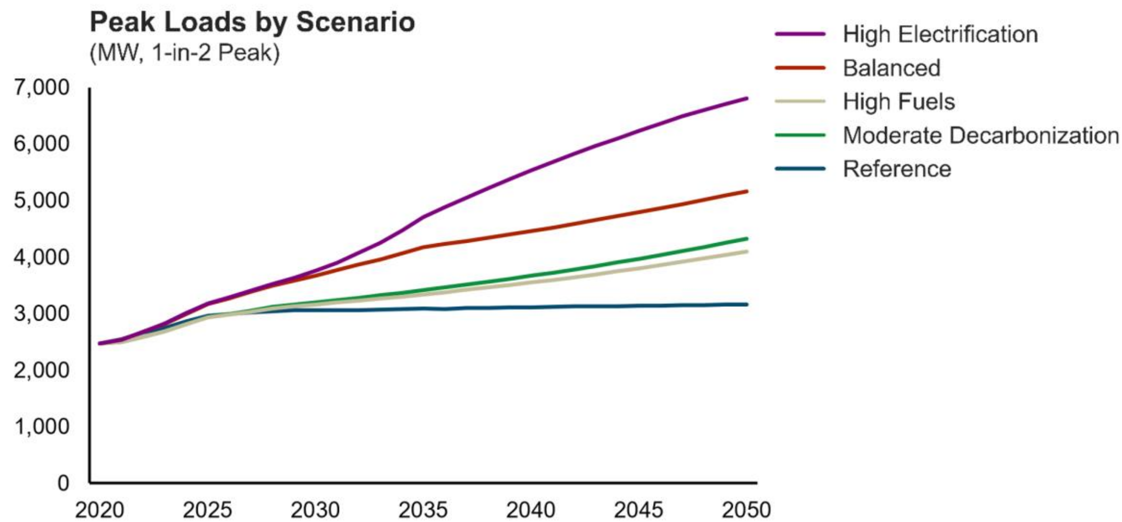
Load growth is influenced strongly by electrification of transportation, building, and industrial end uses, as seen in Figure 34. Consistent with the Reference scenario, load growth in the early 2020s is due to industry load growth. However, electrification plays a larger role in load growth beyond those 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)

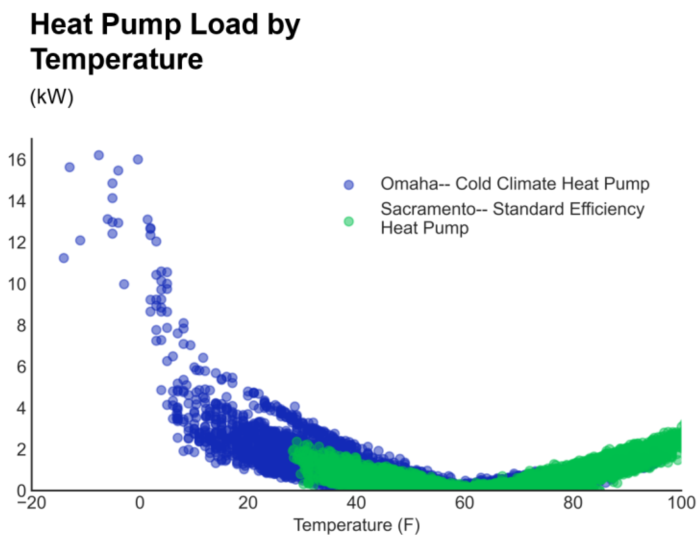
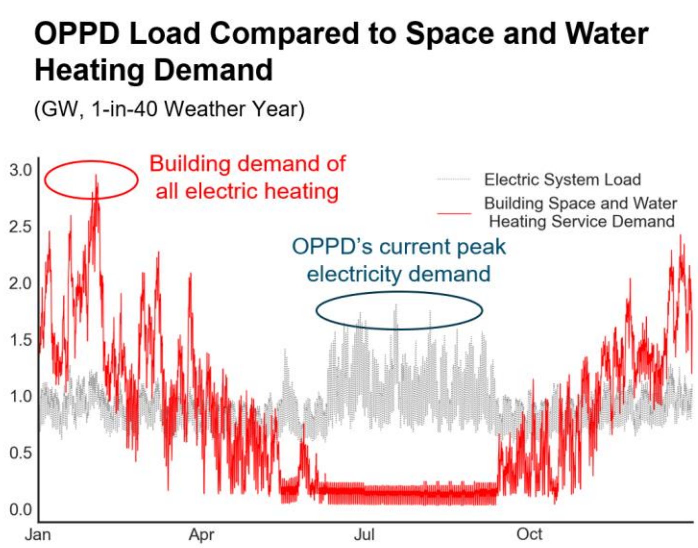


Figure 37 shows heat pump electricity demand during a 1-in-40 weather year, i.e. the coldest year of the last forty years. This shows the "peak heat" challenge, indicating that the peak building heating demand in under such conditions would be nearly double OPPD's current electric peak load. This may 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)

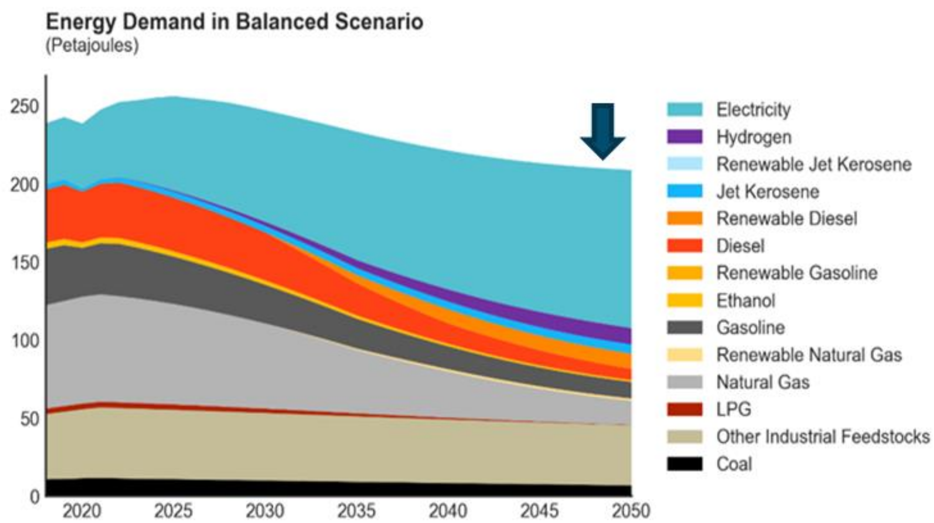


Figure 39. Electric Energy Efficiency Savings of Mitigation Scenarios

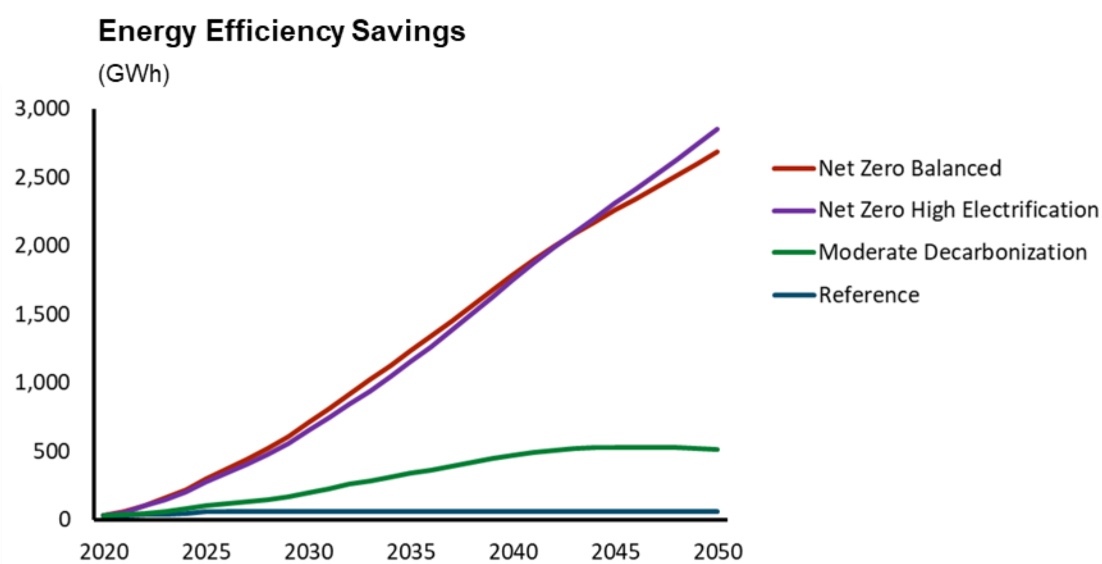
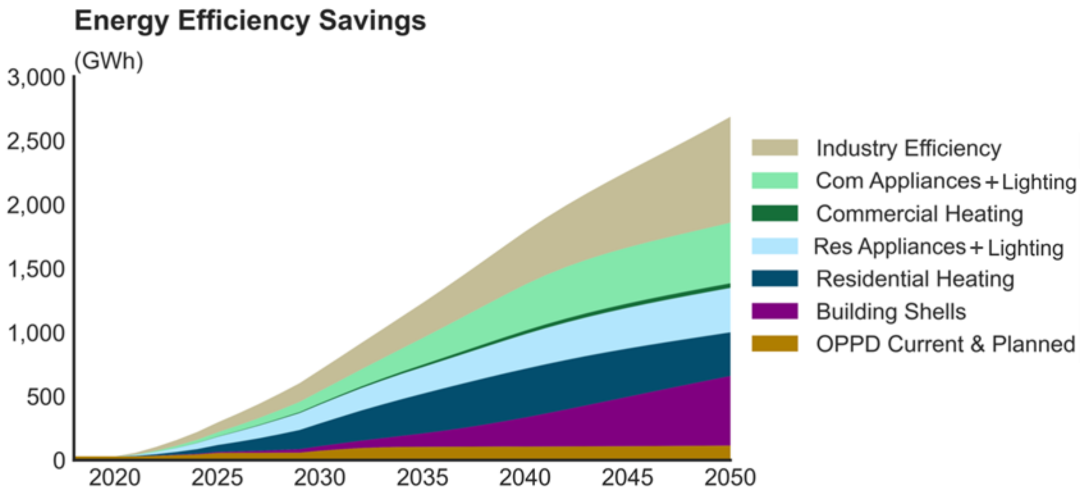
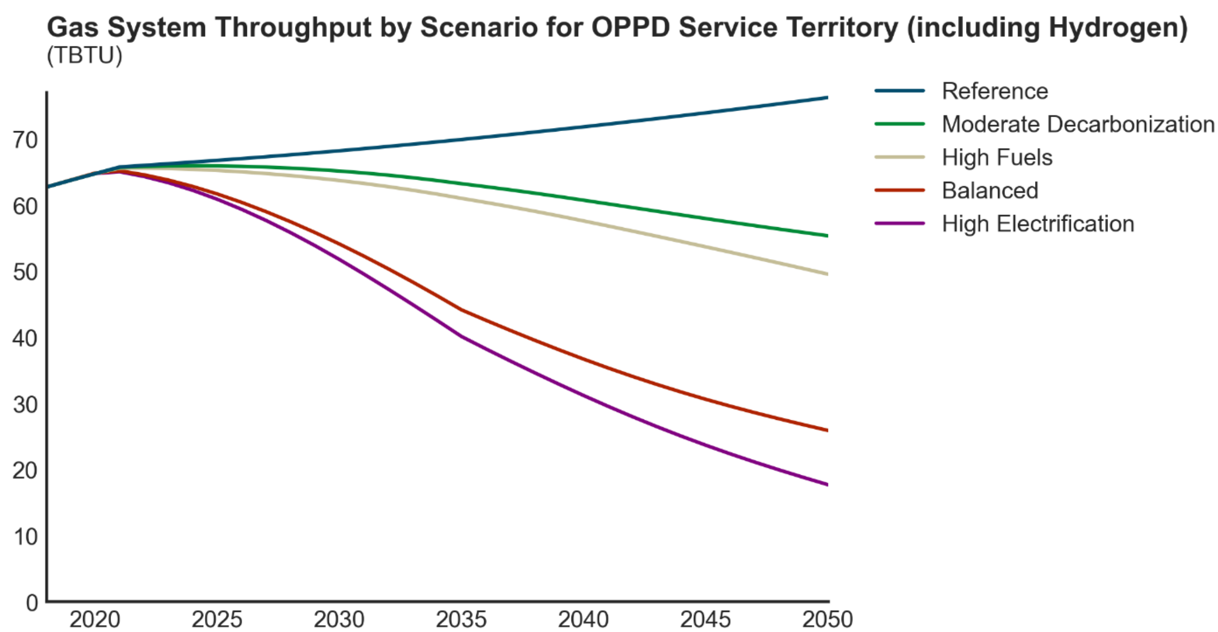


Figure 40. Electric Energy Efficiency Savings by End-Use (Net Zero Balanced Scenario)



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

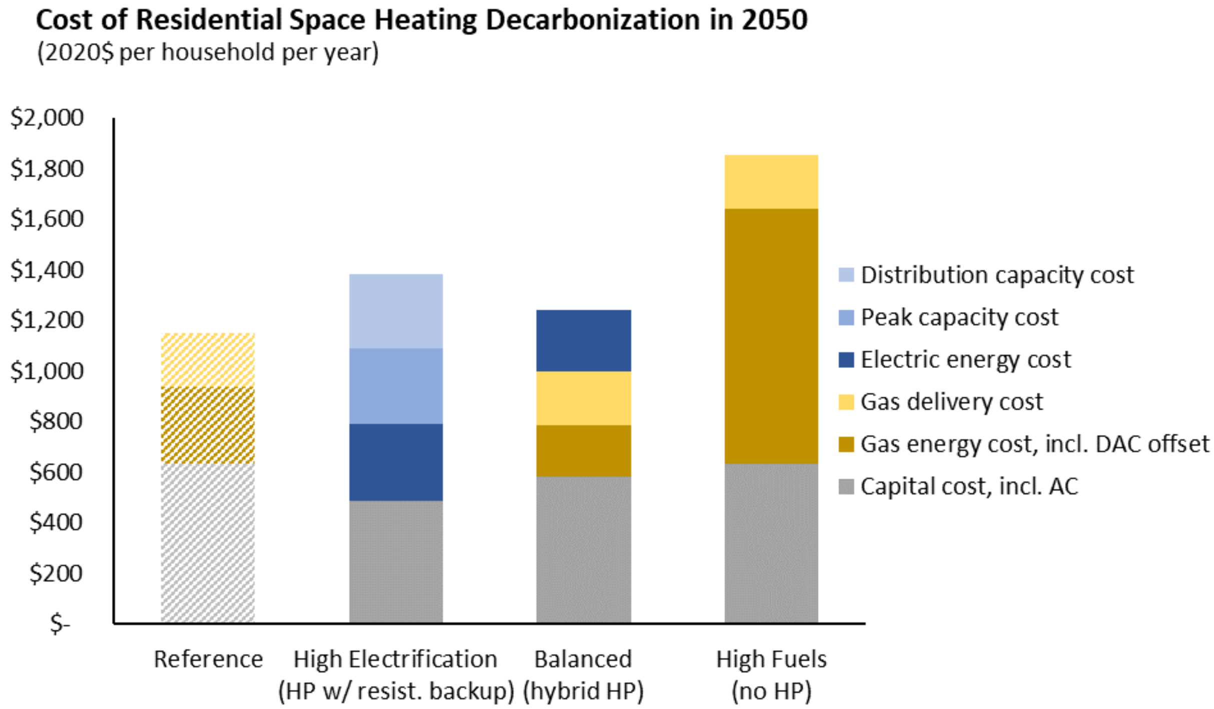
In this section, the sectoral measures leading to the GHG emissions reductions, peak and annual load growths, and gas throughput reductions are discussed.

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

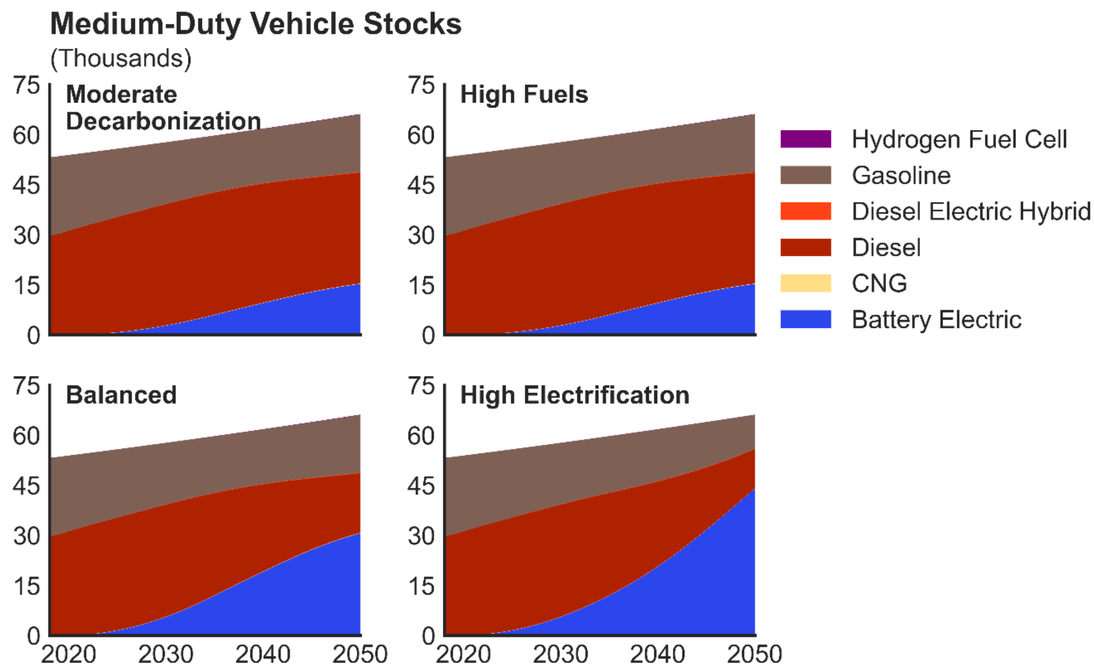


These bookends also have important cost implications, shown in Figure 42. The High Electrification case would require extensive distribution and peaking generation investments, thereby increasing the cost of electrification to each household. The High Fuels case relies on expensive synthetic gas, which 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

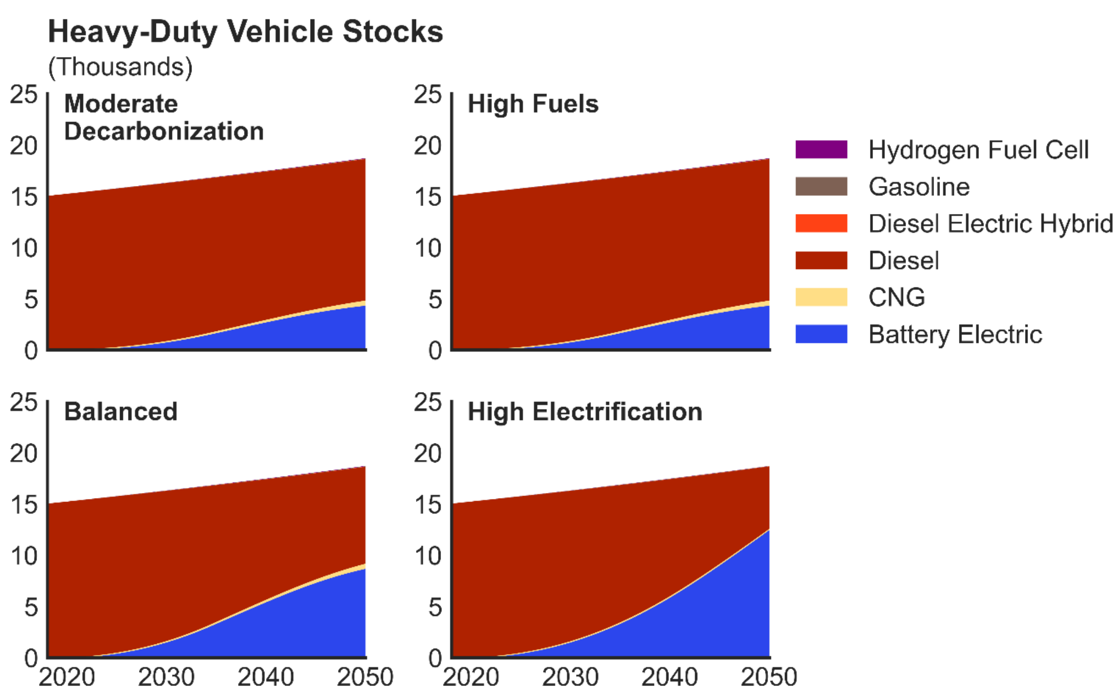
The primary methods of decarbonization in transportation explored in this report are electrification of the vehicle fleet and using decarbonized fuel for the remaining fuel-based vehicles. In the Net Zero scenarios, electrification occurs primarily in the LDV fleet (see Figure 25). Such a transformation 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.

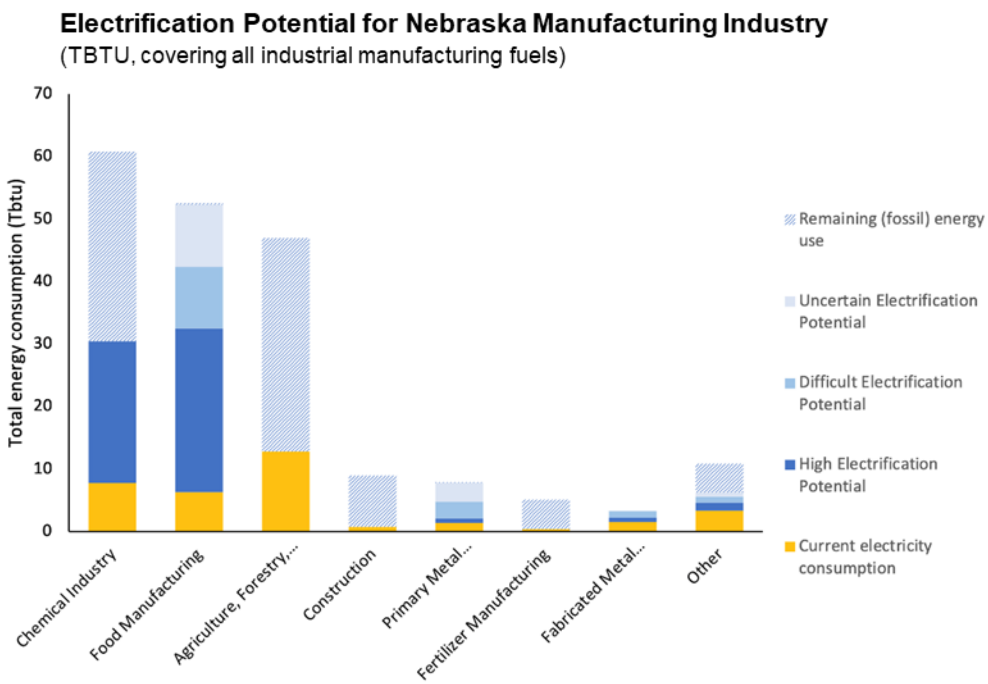
Figure 44. Mitigation Scenario HDV Stocks



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.

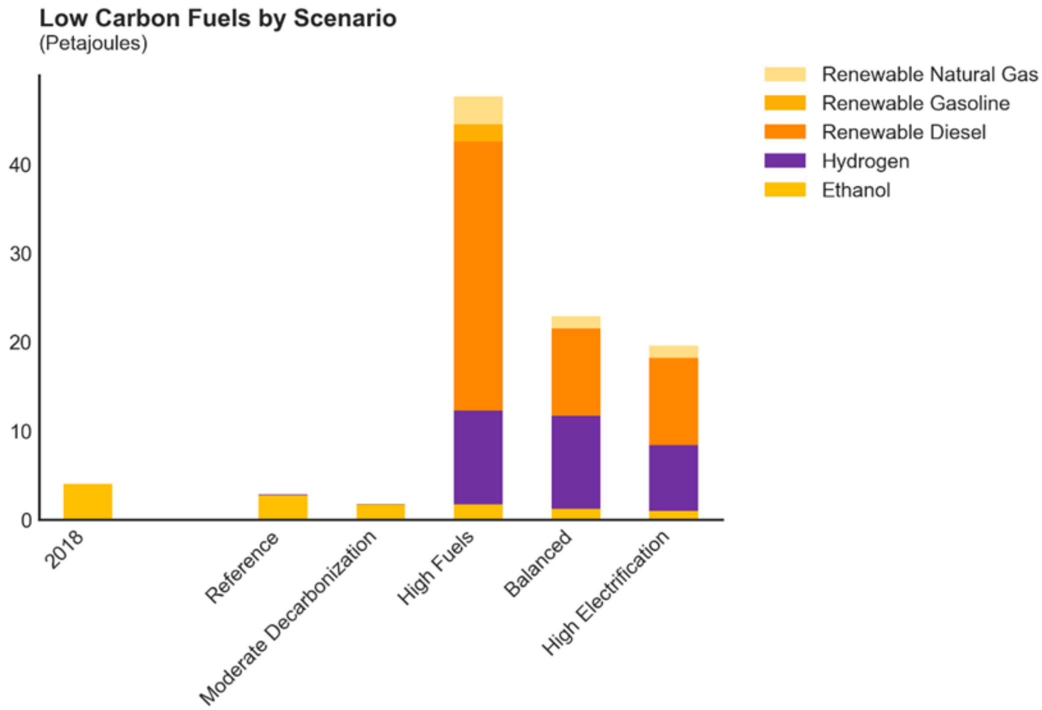
Figure 45. Estimated Electrification Potential of Nebraska's Manufacturing by Industrial Subsector



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

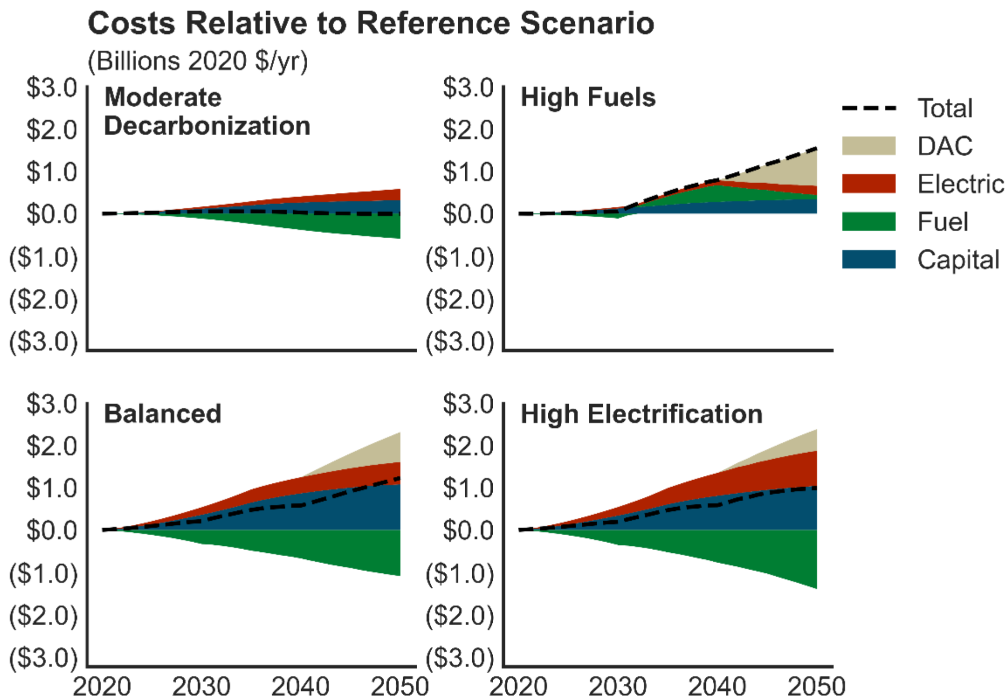
[17] "Achieving Carbon Neutrality in California," Energy and Environmental Economics, 2020, https://ww2.arb.ca.gov/sites/default/files/2020-08/e3_cn_draft_report_aug2020.pdf.

	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

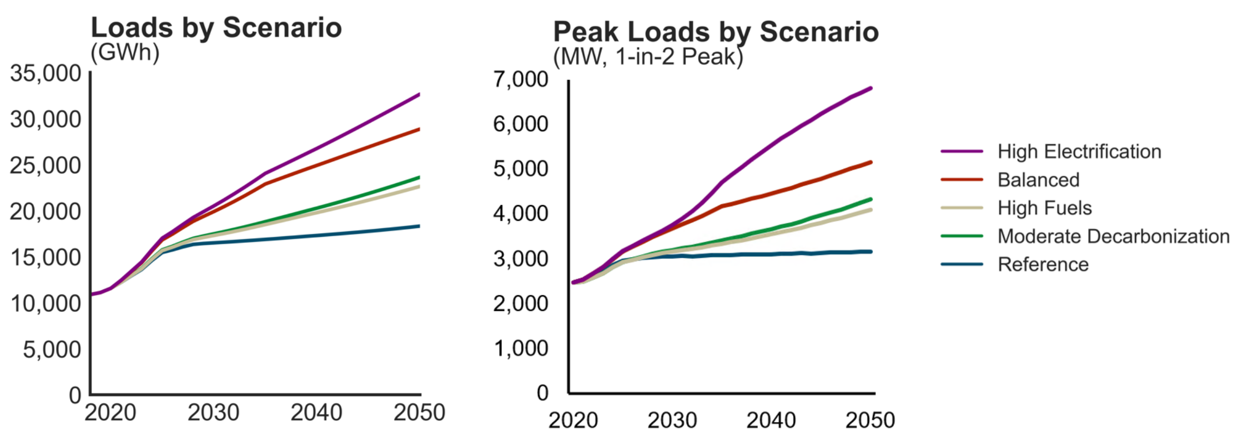
Multiple decarbonization scenarios of the Nebraskan energy economy within the OPPD service territory were investigated. Five scenarios were developed to reveal the potential impacts of economy-wide decarbonization on OPPD loads and to identify key opportunities for community engagement on decarbonization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

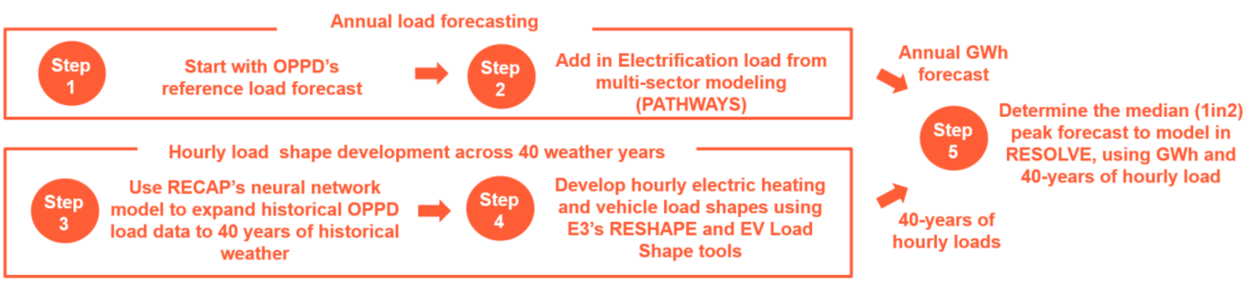
4 Inputs and Assumptions

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.

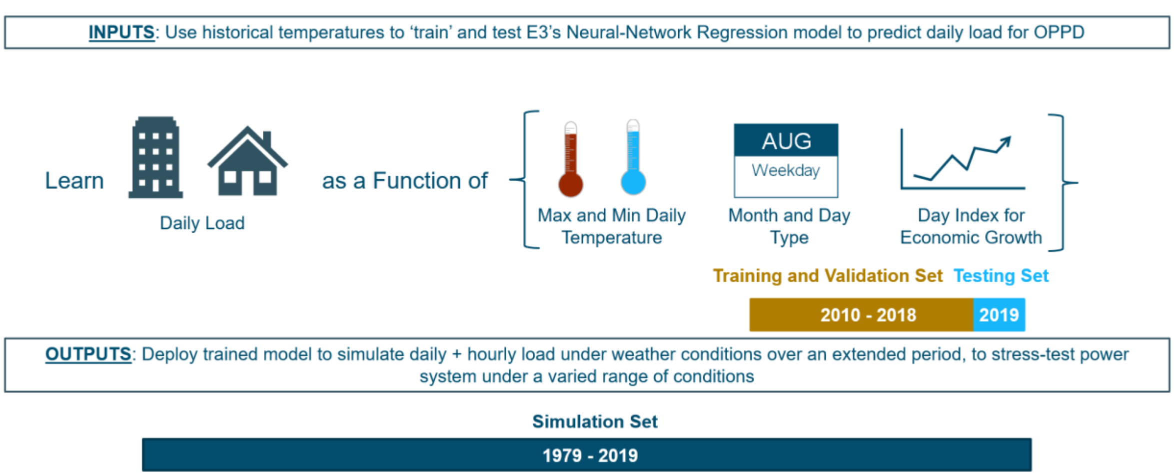
Figure 49. Overview of Load Forecast Development Process



4.1.2 OPPD Loads Across Historical Weather Years

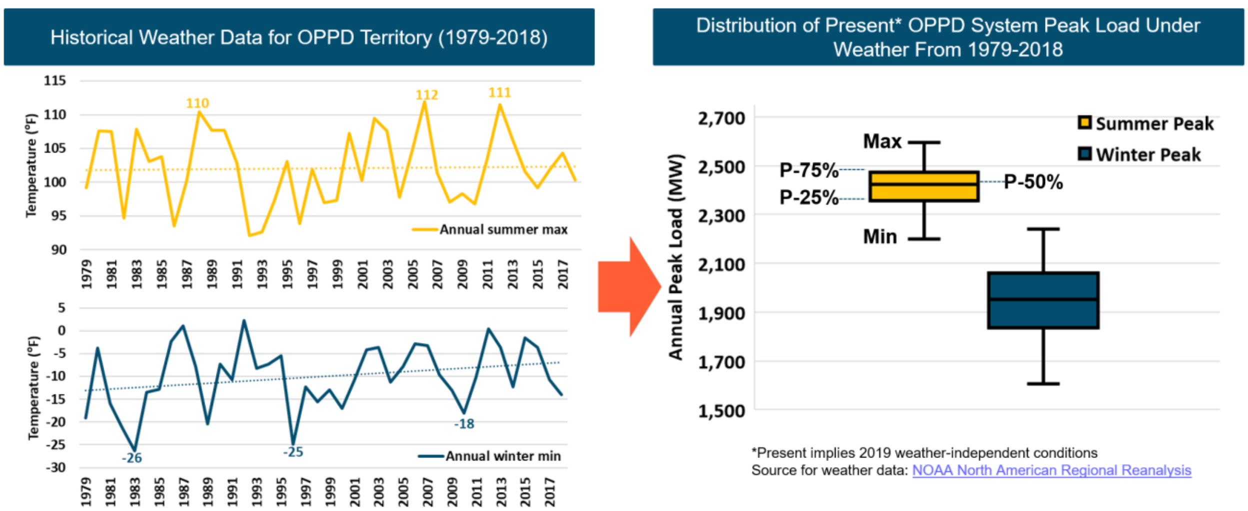
E3 modeled existing (under 2019 economic conditions) hourly load for OPPD across the weather years 1979 – 2019 using a neural network regression model. E3 used hourly load data from 2010-2019 to train and test the model. This analysis produced expected load profiles in OPPD under a variety of weather 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

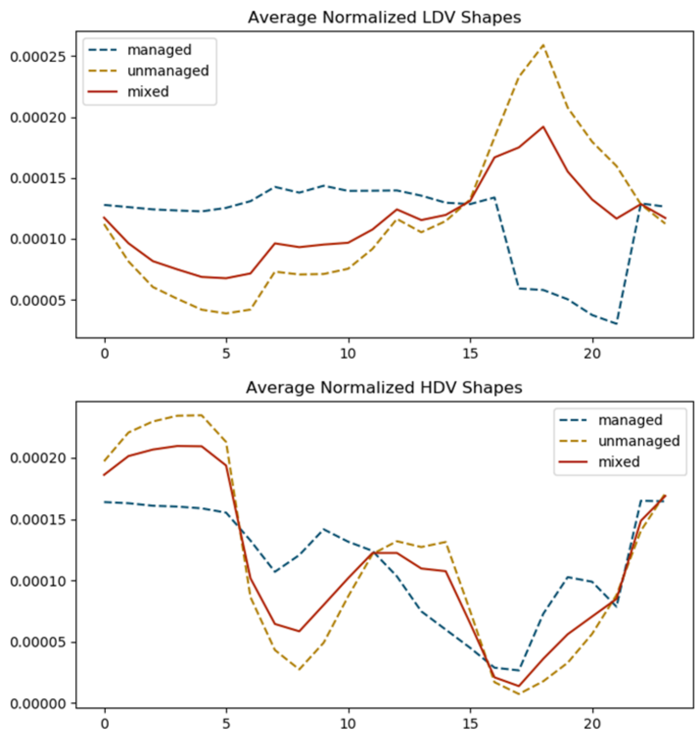


4.1.3 Electrification Load Shapes

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.

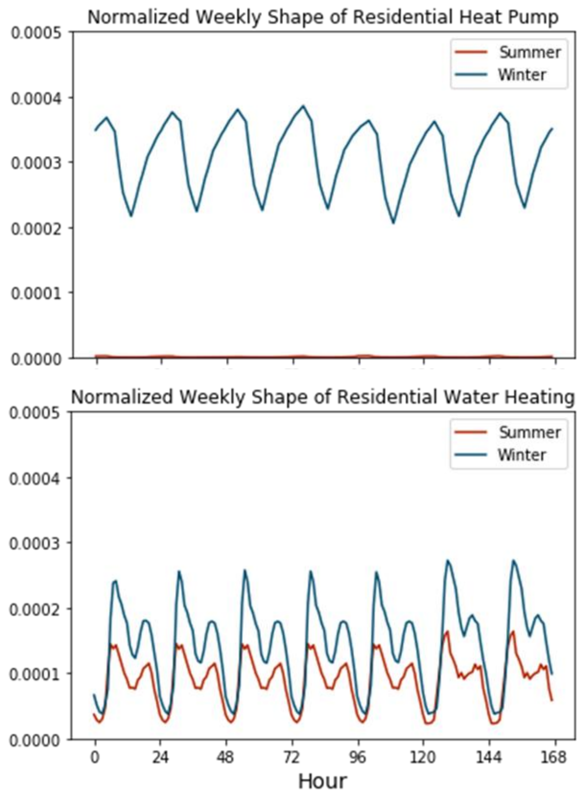
EV load shapes were developed for two different shapes for LDV and MDV/HDV vehicle types. "Unmanaged" charging shapes are driven purely by driver behavior and assume that customers charge based solely on their driving patterns. "Managed" charging shapes were modeled as price responsive to time of use 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.

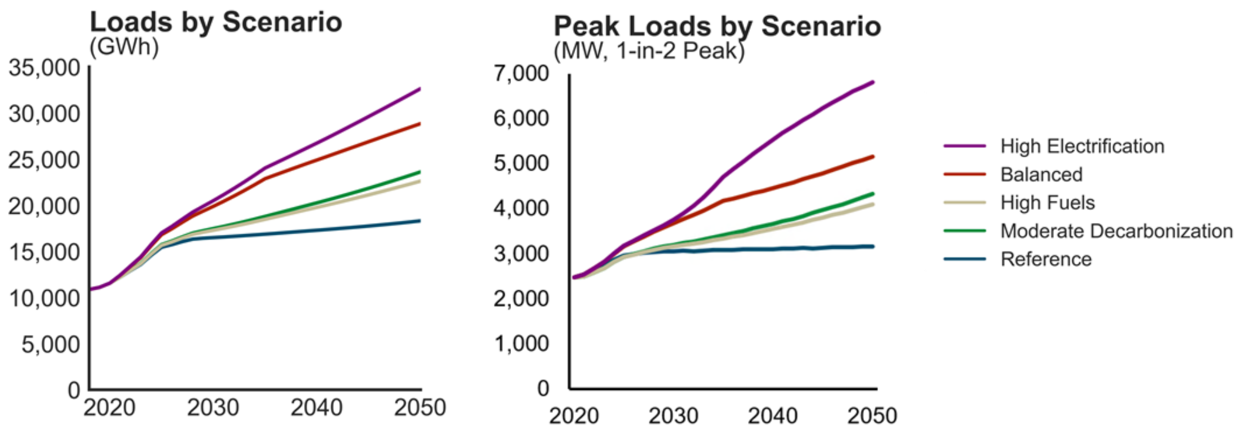
Figure 53. Sample Space Heating and Water Heating Heat Pump Loads from RESHAPE



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

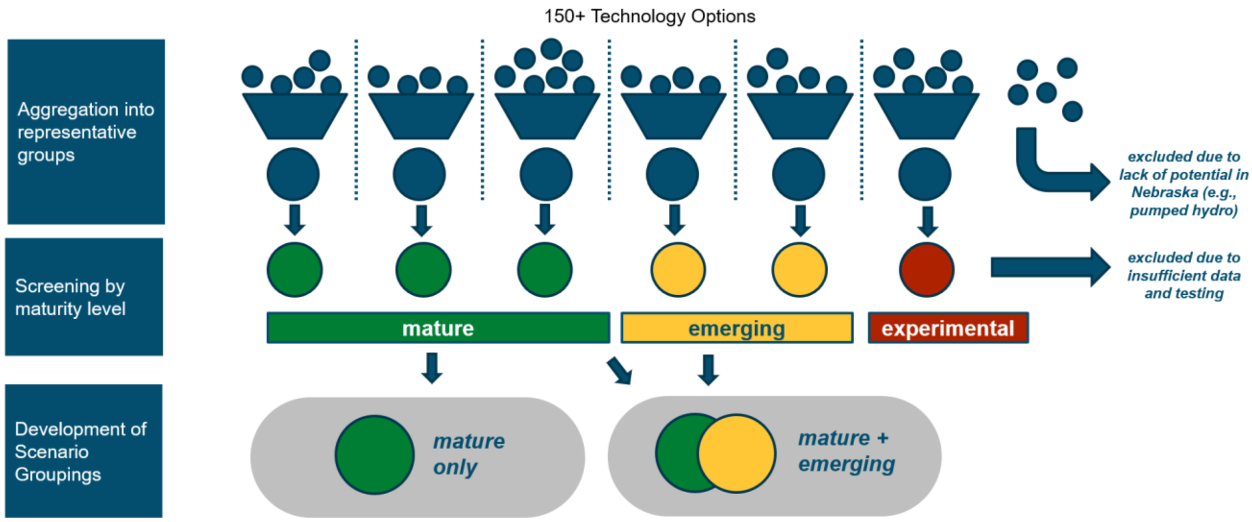


4.2 Technology Availability

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]

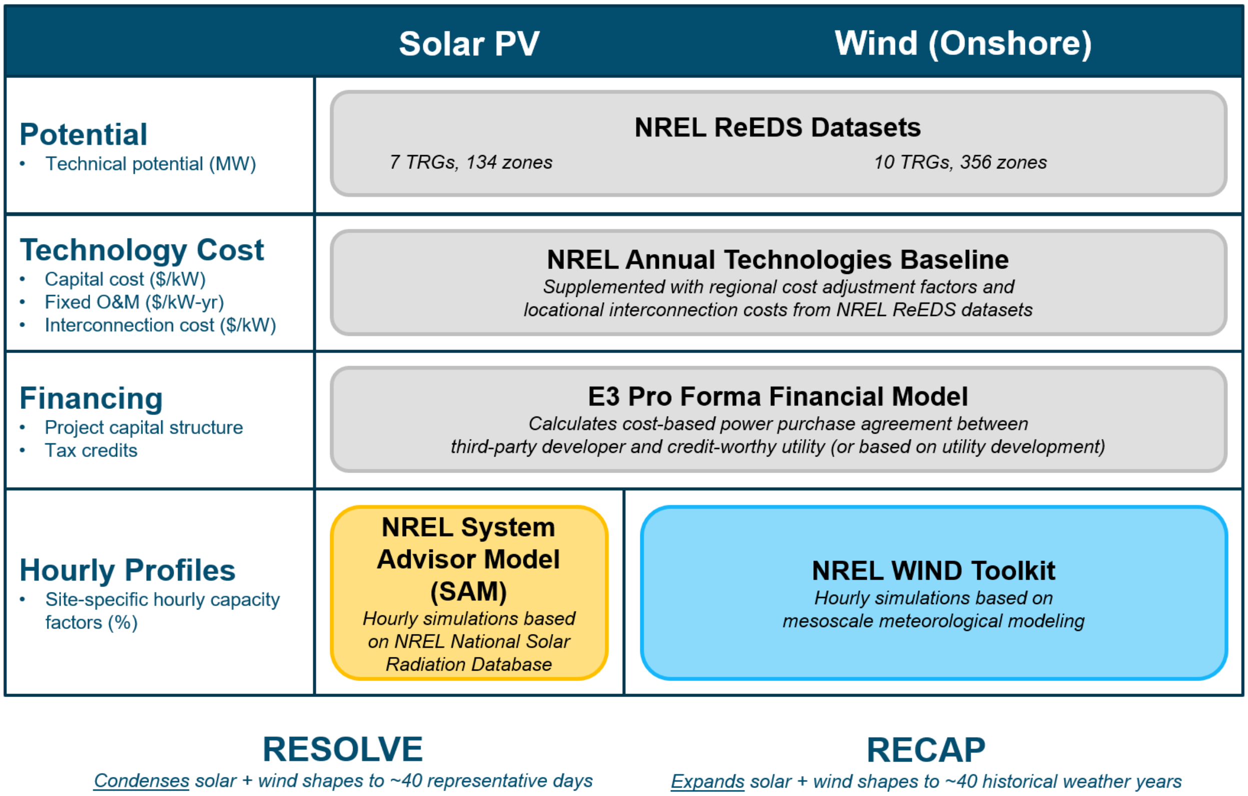
4.3 Resource Potential, Cost, and Characteristics

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)

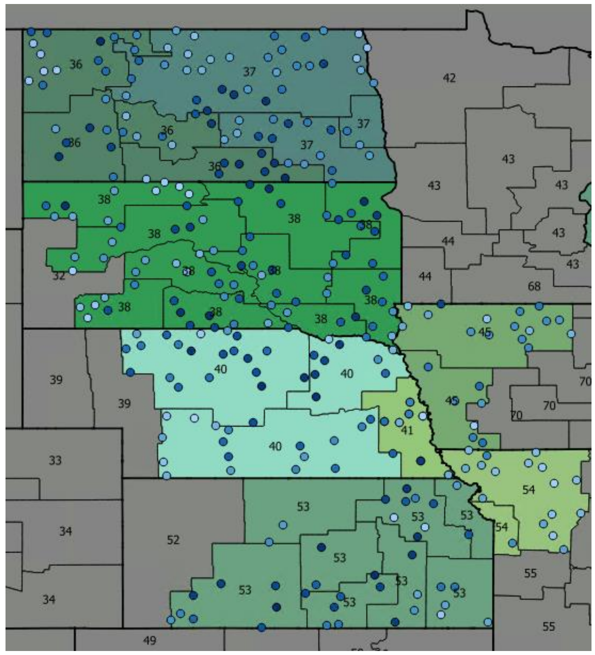


Figure 59. Solar Sites used to Produce Hourly Generation Profiles

(Darker colors represent higher capacity factors)

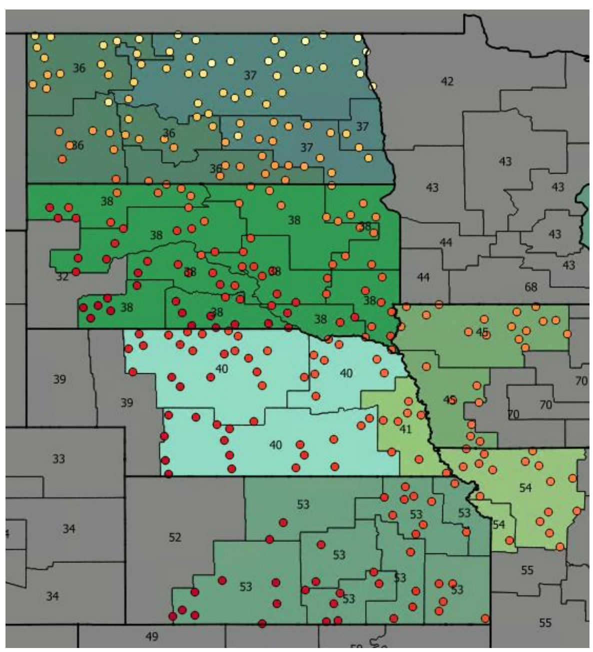
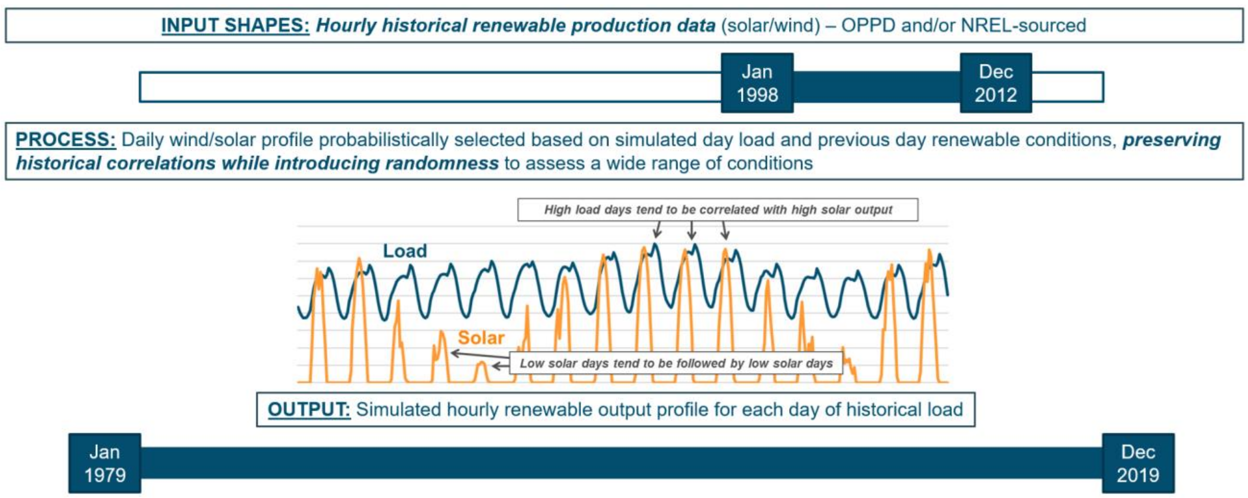


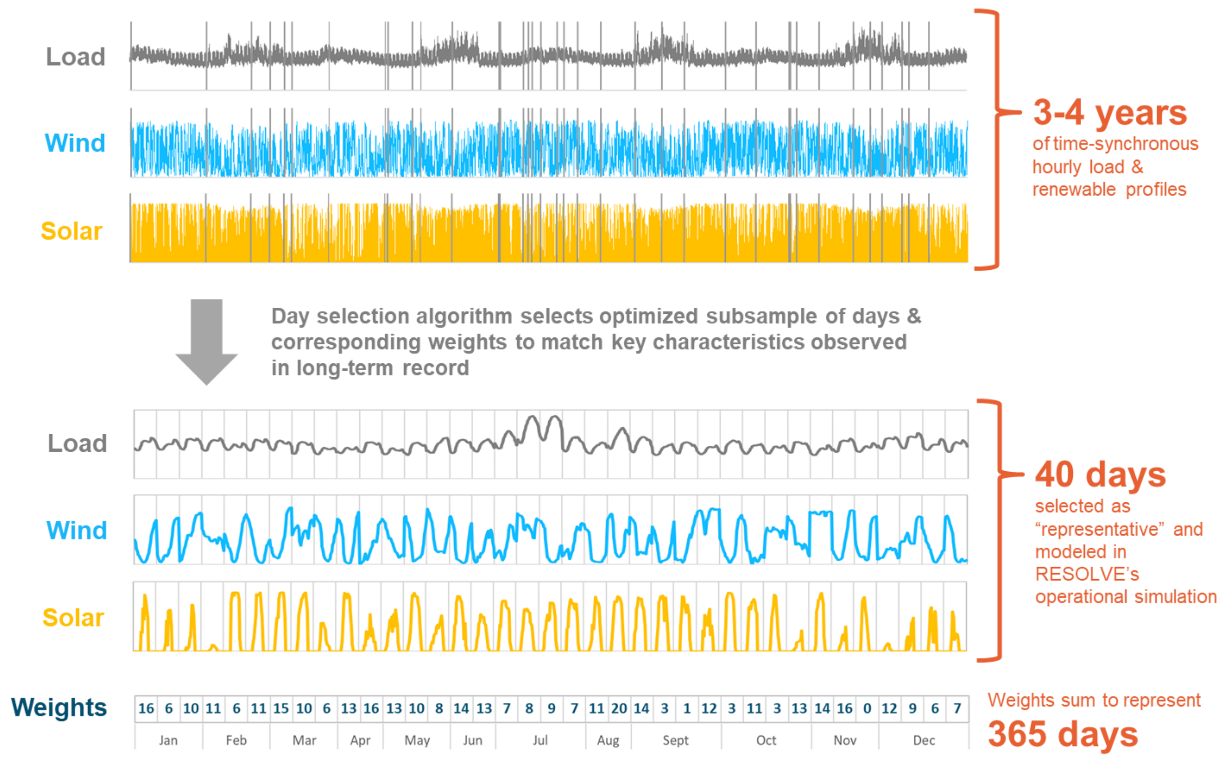
Figure 60 shows a schematic of the method used by RECAP to expand the NREL historical weather data to simulate solar and wind conditions across 40 historical weather years. This method involves a probabilistic algorithm that selects the daily wind or solar profile using the simulated day's load and the 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.

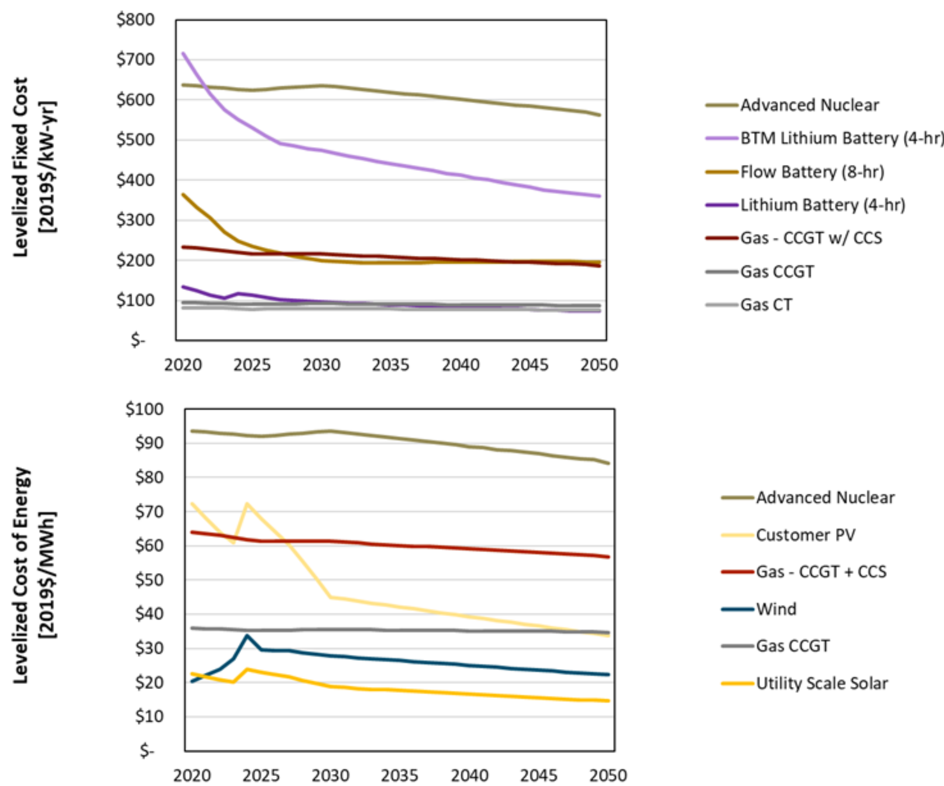
Demand Response

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

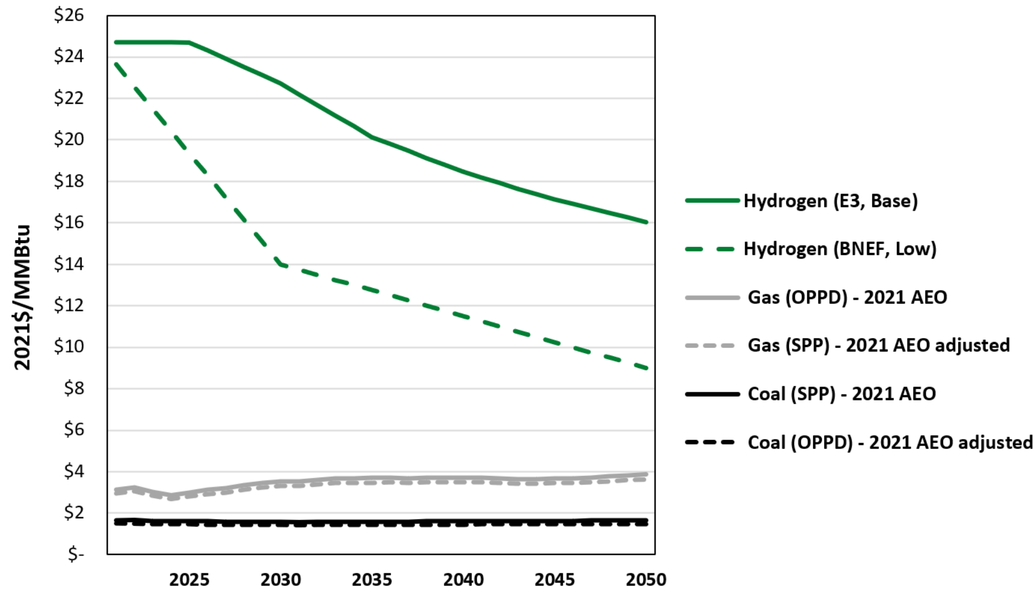
Candidate resource costs were developed based on the NREL 2020 ATB public data source. The levelized fixed costs (for primarily capacity resources) or the levelized cost of energy (for primarily energy resources) is shown below in Figure 62. Candidate Resource Costs.

Figure 62. Candidate Resource Costs



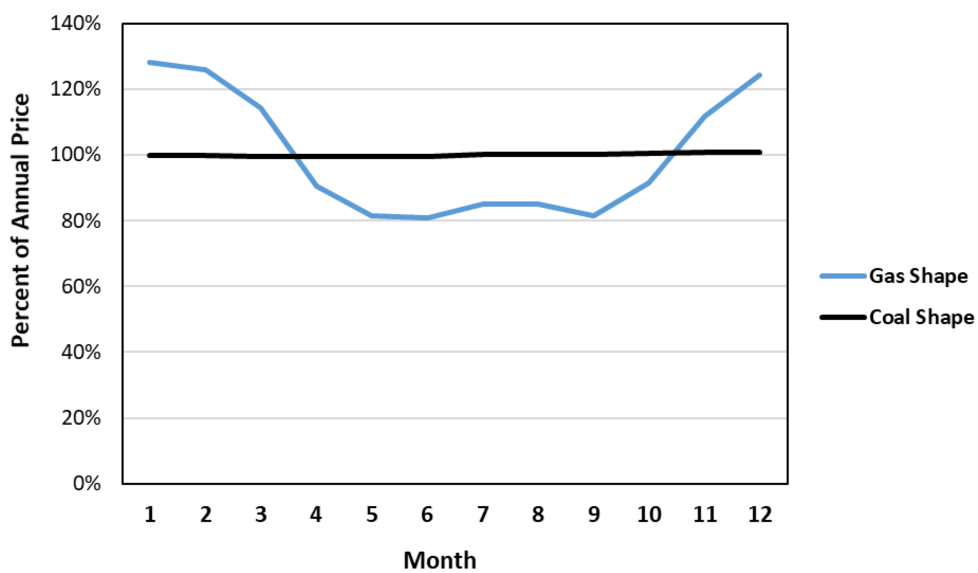
Fuel prices were developed from a combination of data sources. The US Energy Information Administration (EIA) 2021 Annual Energy Outlook (AEO) was utilized for a public forecast of natural gas and coal prices. These were differentiated between SPP and OPPD based on the EIA region that most closely matched 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.

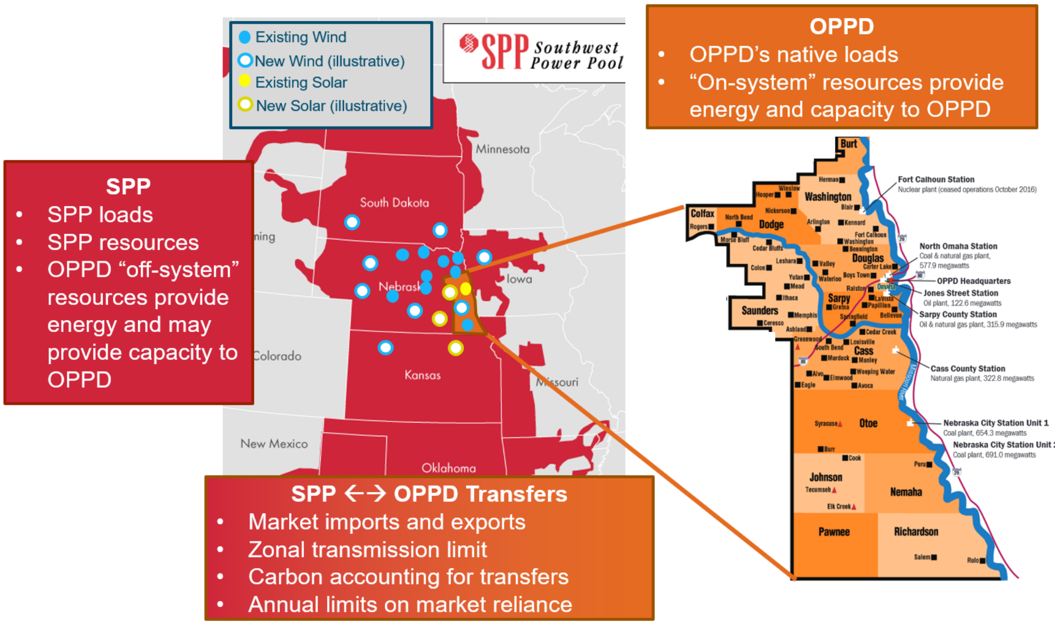
Table 23. Transmission Cost Assumptions for New Resources

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

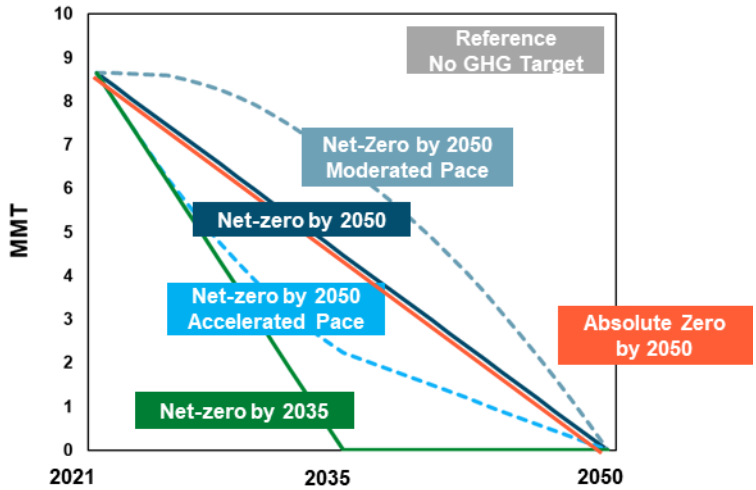


An annual limit on market transfer between the OPPD and SPP region was set based on OPPD guidance. This constraint was set at 30% maximum imports and 10% maximum annual exports, both set relative to OPPD's annual load.

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.

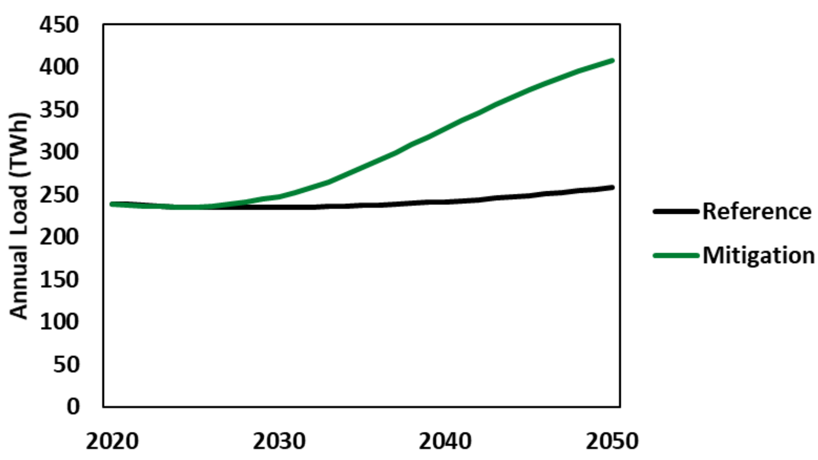
Figure 66. Greenhouse Gas Reduction Trajectories



4.5 SPP Portfolios

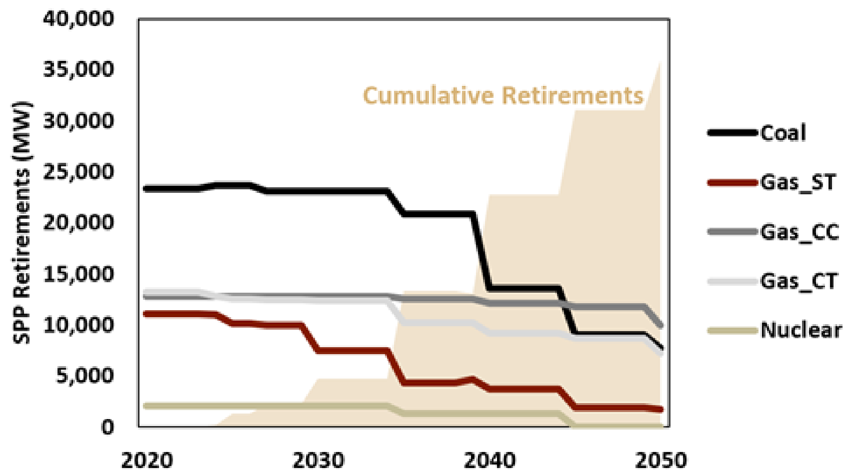
As a member of the broader SPP market, OPPD was co-optimized with SPP in RESOLVE to capture regional interactions. Two scenarios were developed to reflect different SPP future scenarios. The Reference scenario is the "business as usual" scenario where SPP load remains relatively flat and SPP does not 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



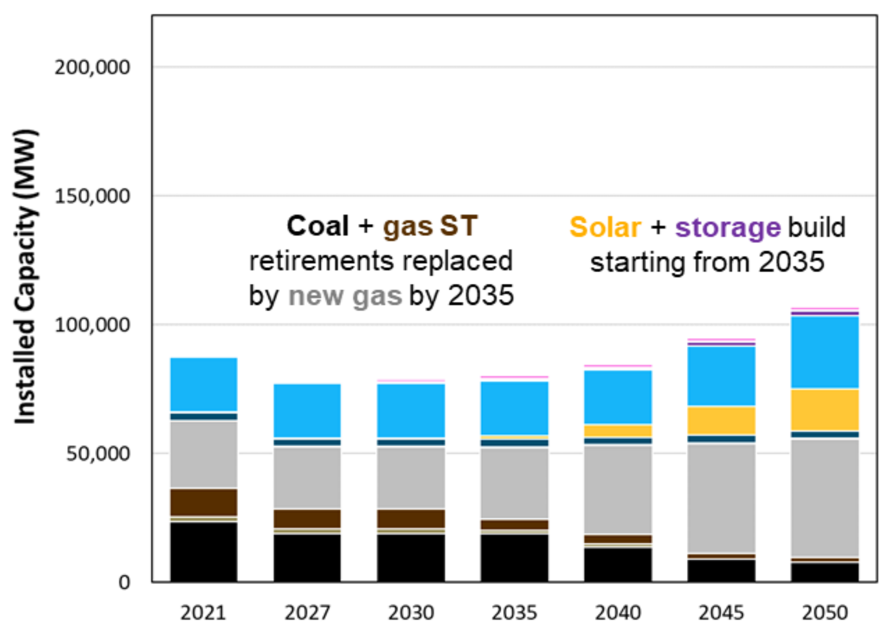
[29] https://www.spp.org/engineering/transmission-planning/integrated-transmission-planning/

Figure 68. SPP Resource Retirement Schedule



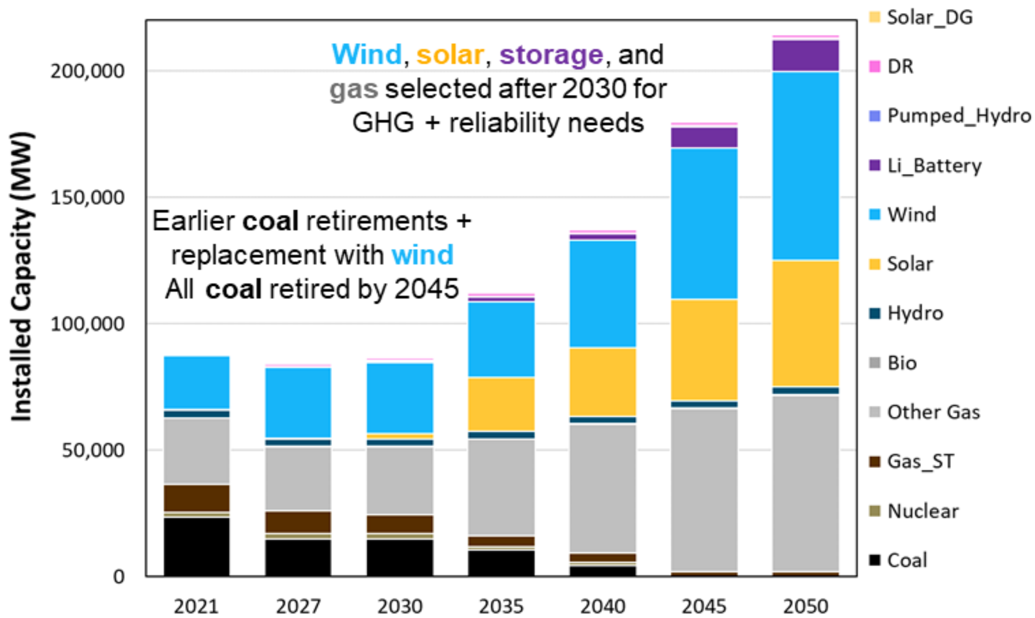
In the Reference scenario, without any emission target and with minimal load growth, SPP is modeled in RESOLVE to build new gas to replace existing coal and older gas retirements for energy and capacity needs. Solar and storage is added starting around 2035 (Figure 69).

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

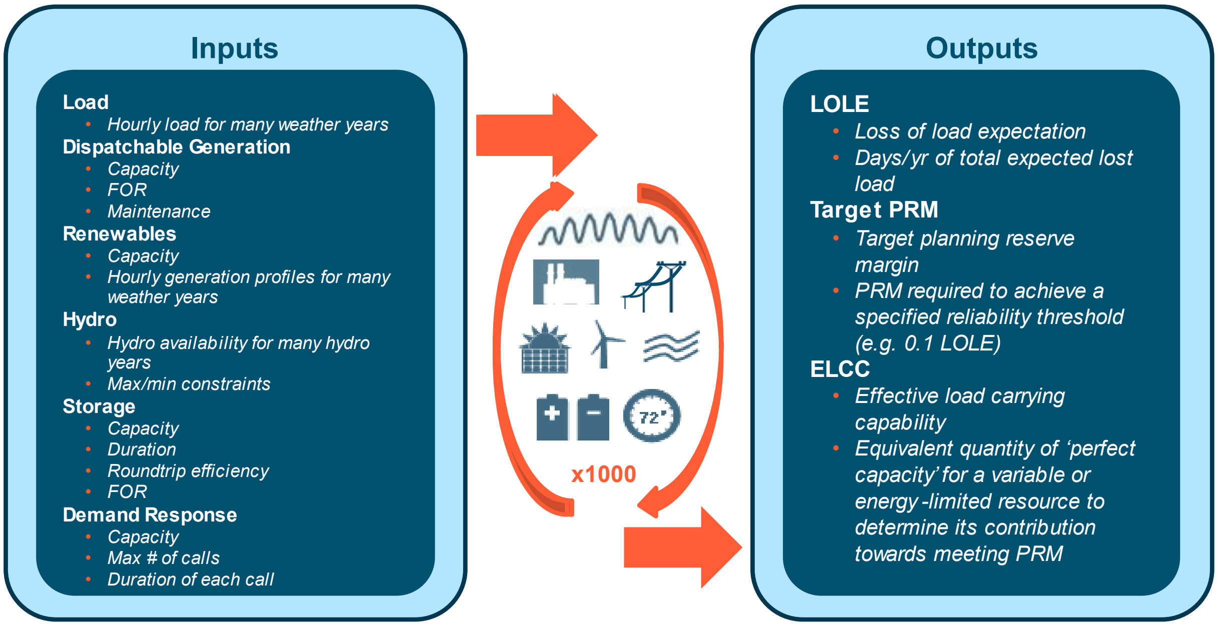
5.1 Reliability Modeling Approach

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.

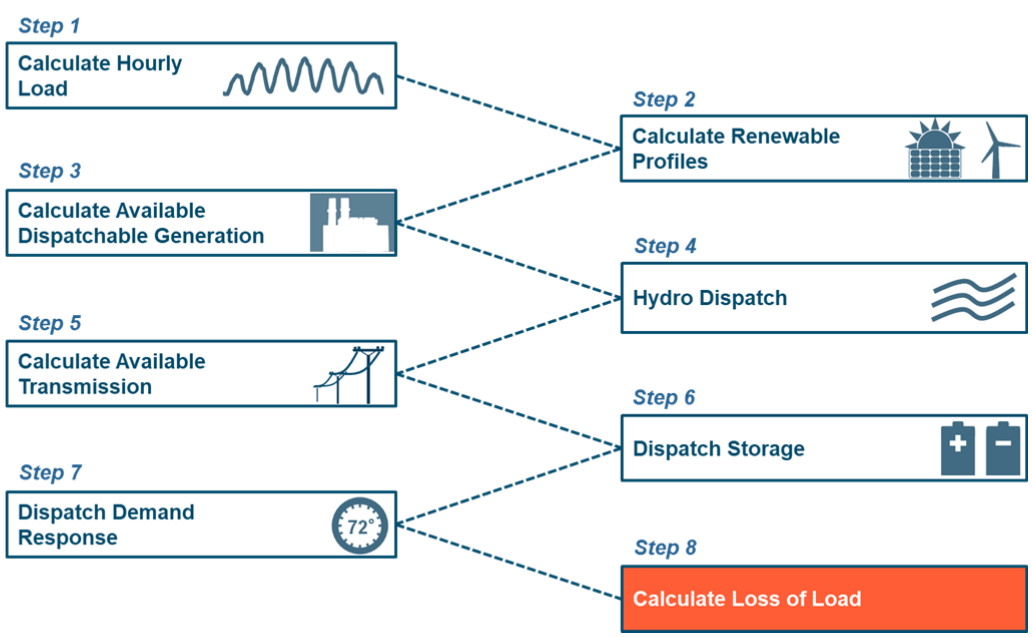
RECAP calculates several metrics related to reliability including loss of load expectation (LOLE), the target planning reserve margin (PRM) required to achieve the target LOLE, and the effective load carrying capability (ELCC) that quantifies the contribution of non-firm resources such as renewable energy 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***.

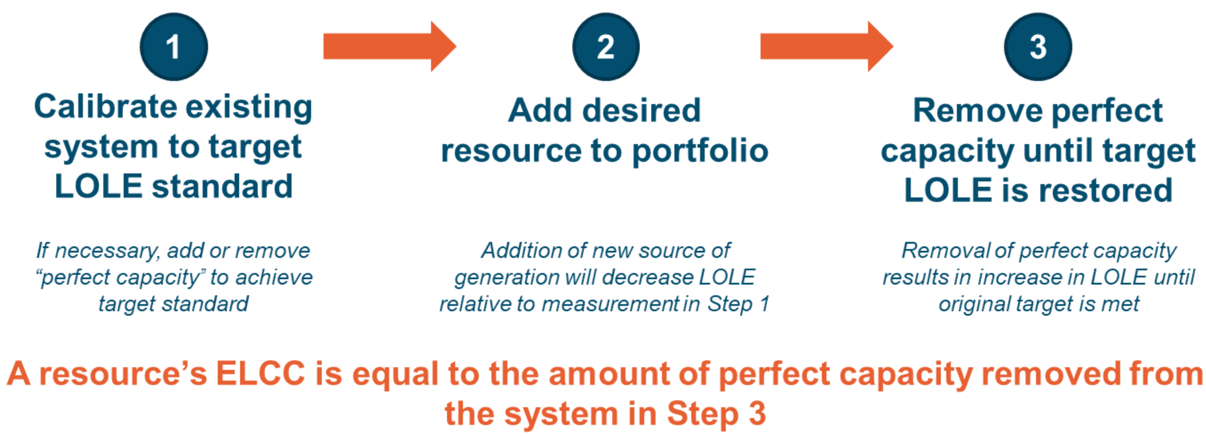
ELCC is the quantity of "perfect capacity" that could be replaced or avoided with renewables or storage while providing equivalent system reliability. A value of 50% means that the addition of 100 MW of a variable resource could displace the need for 50 MW of firm capacity without compromising reliability.

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

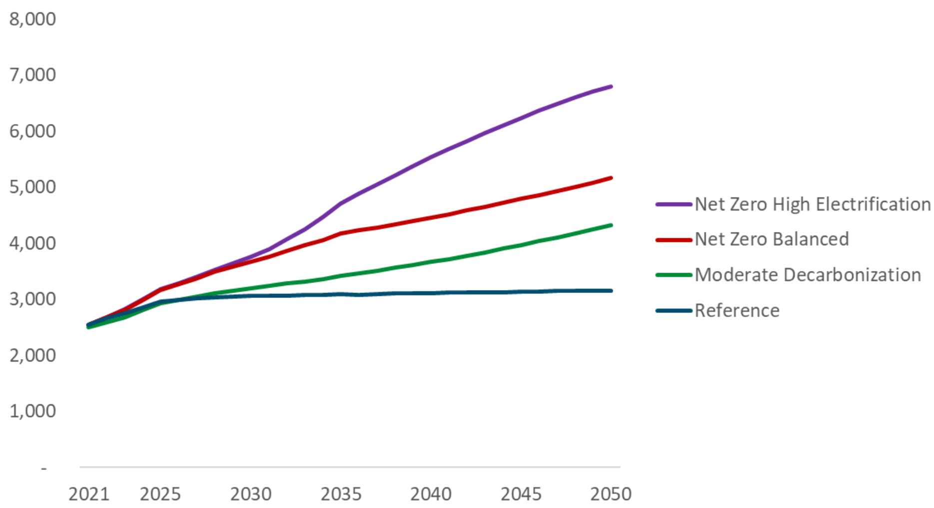
OPPD participates in the SPP regional market. Participants in the SPP market obtain load and resource diversity benefits from being a part of a geographically diverse market. For example, the peak loads of SPP entities can occur at different times due to differences in locations and load profiles. Excess 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

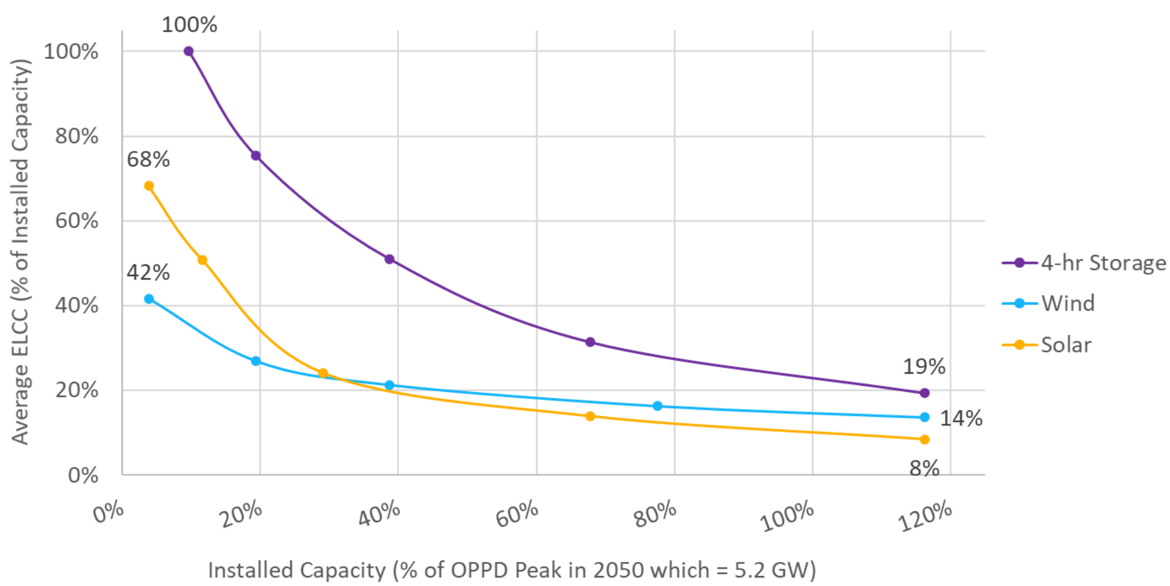
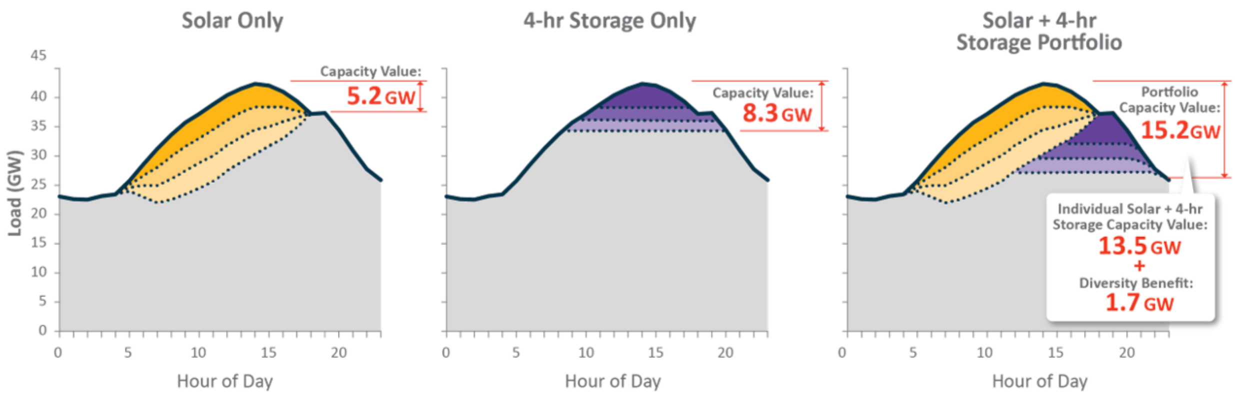


Figure 76. Illustrative Solar and Storage ELCC



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%.

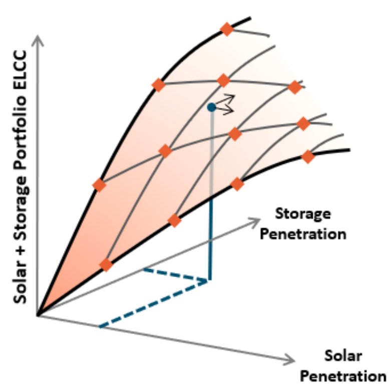
Table 27. Solar and Storage Total ELCC[30]

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



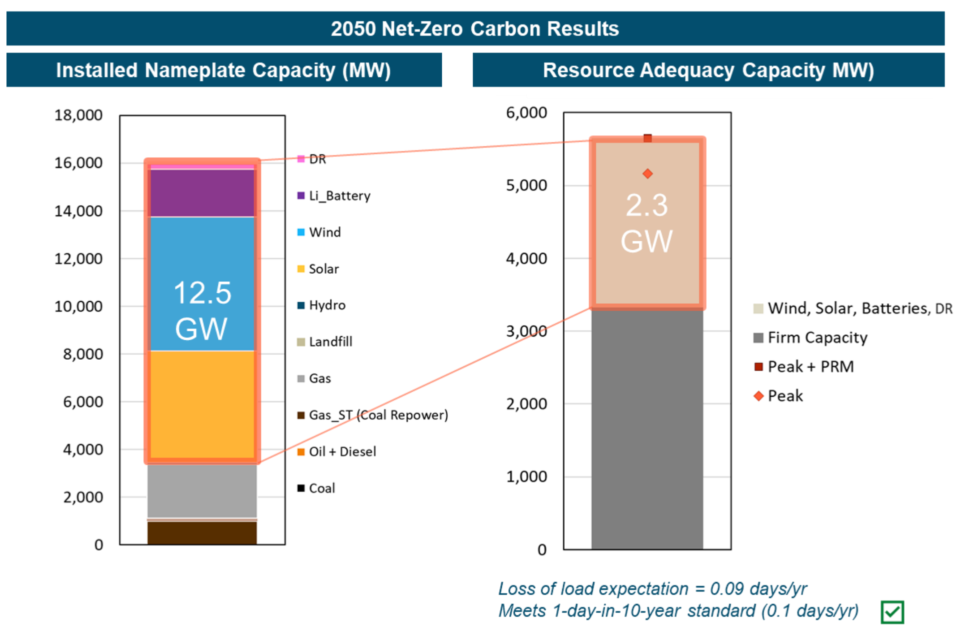
[30] Values only include the interactions between solar and storage resources. The actual values used in the resource portfolio optimization analysis include interactions with other resources, such as hydro, wind, and demand response.

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)

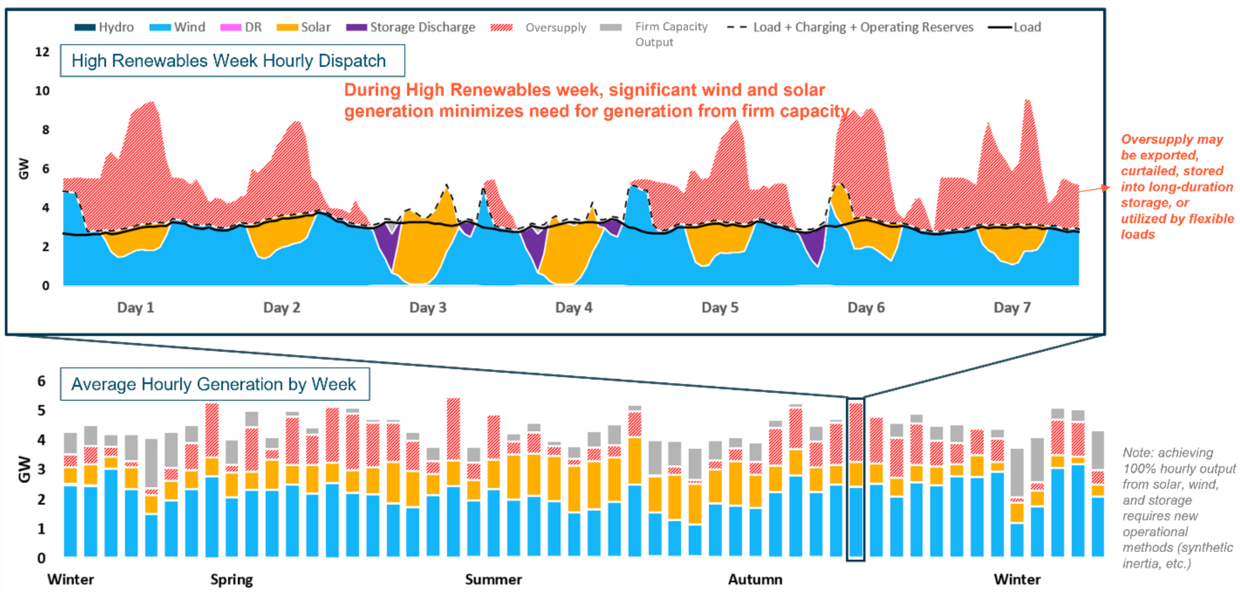


The Net Zero Carbon Base Scenario portfolio contains a significant amount of renewable capacity, selected by the model to achieve the net zero carbon emissions reduction target. In many weeks of the year when solar and wind are producing at average or above average output, the generation from these

[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.

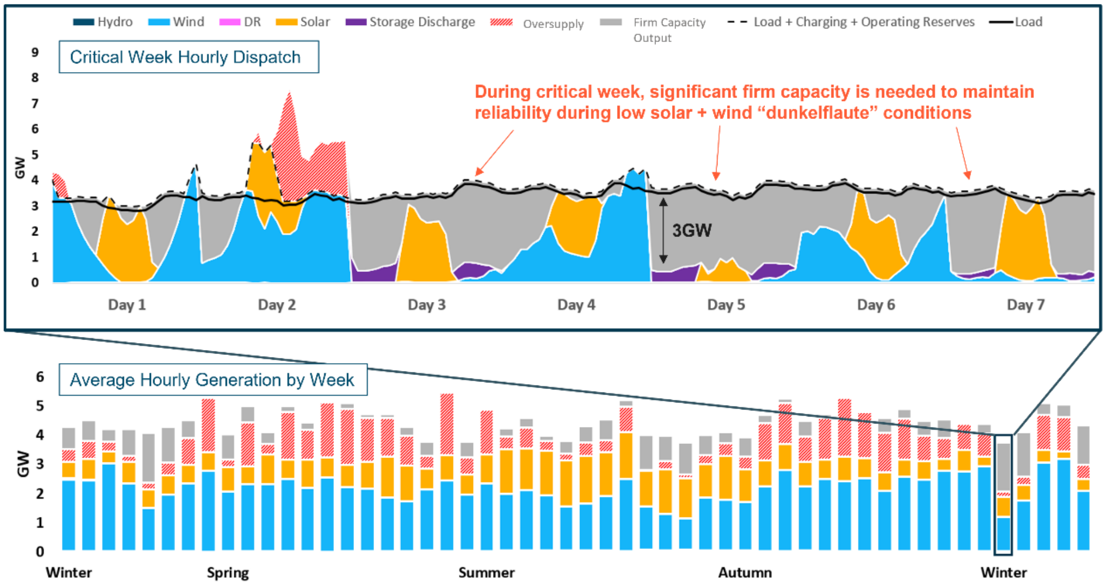
Figure 79. Resource Availability Dispatch over a High Renewable Week in 2050 in the Net Zero Carbon Base Scenario[33]



[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]



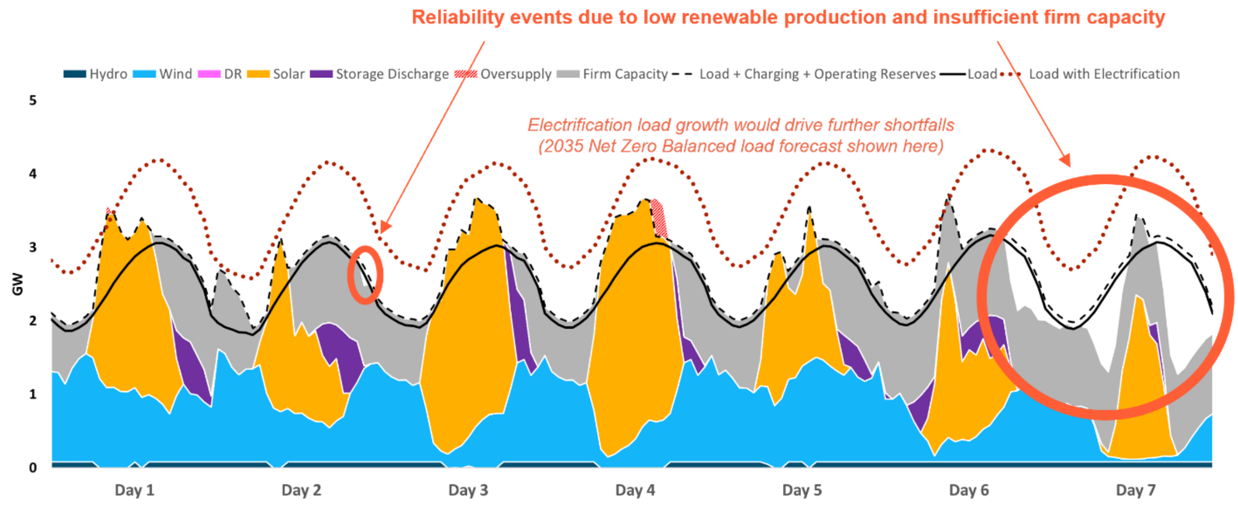
In addition to the Net Zero Carbon Base portfolio, E3 also modeled – at the recommendation of OPPD stakeholders – the reliability of another sensitivity scenario, the "No New Firm Capacity" sensitivity. This 2035 case assumed full coal retirement, no new firm resource additions (including Power with 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]

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[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.

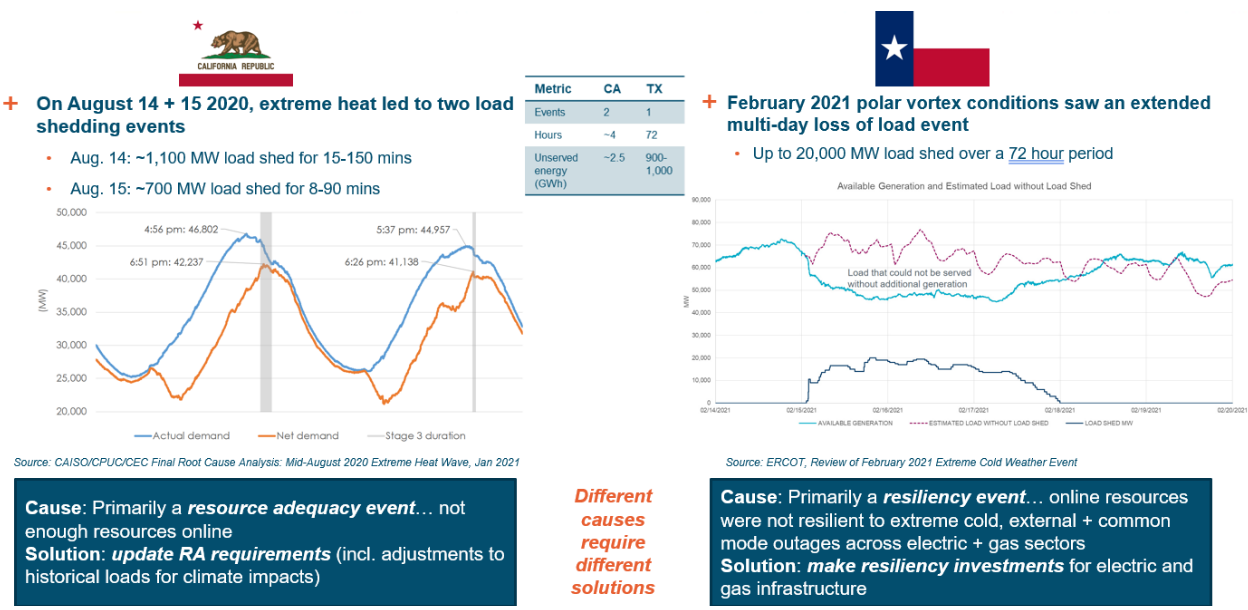
Table 31. Events Captured in Resource Adequacy (LOLP) Modeling vs. Resiliency Planning

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

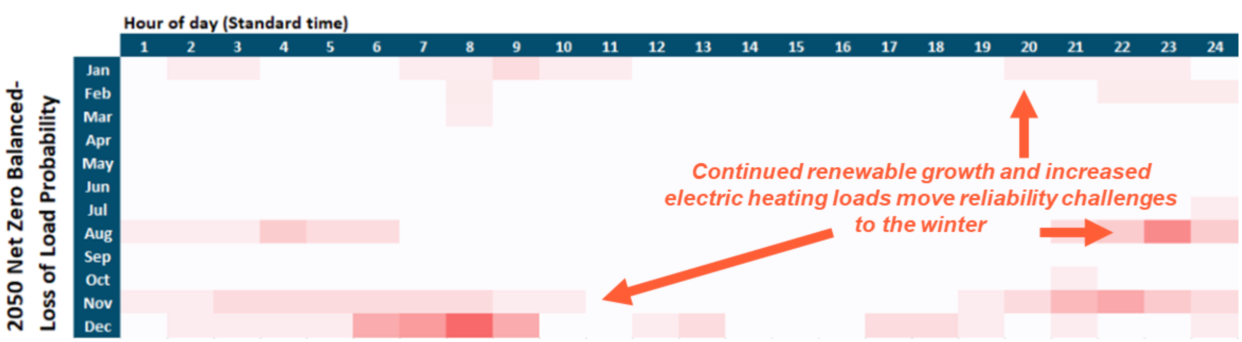
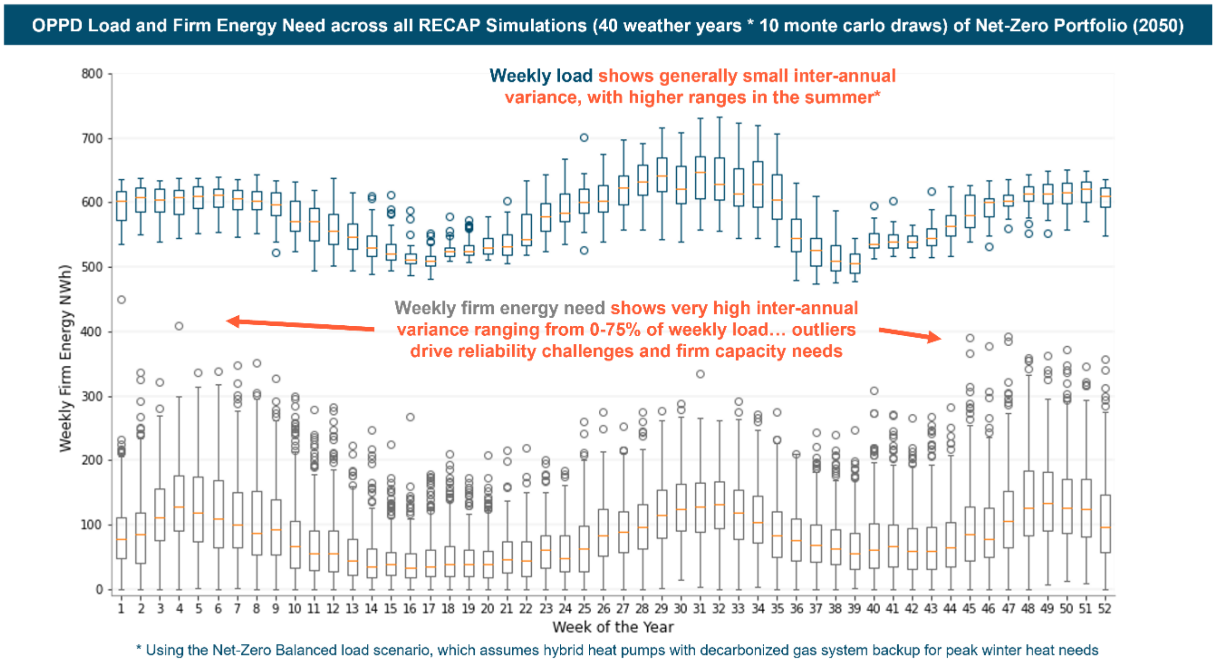


Figure 87. OPPD's Load and Firm Energy Needs for the Net Zero Carbon Base Scenario in 2050



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]

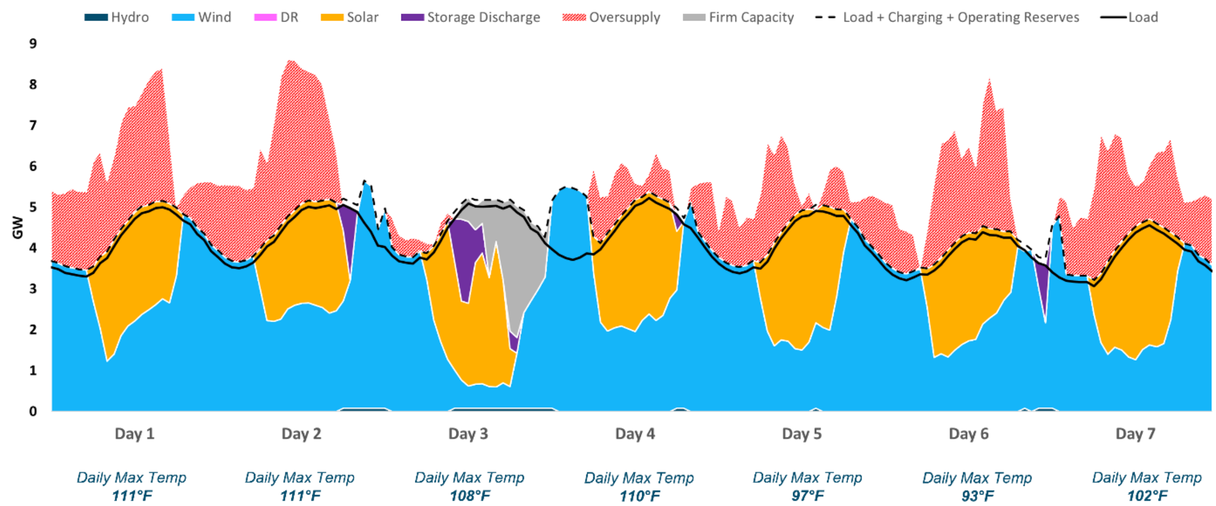
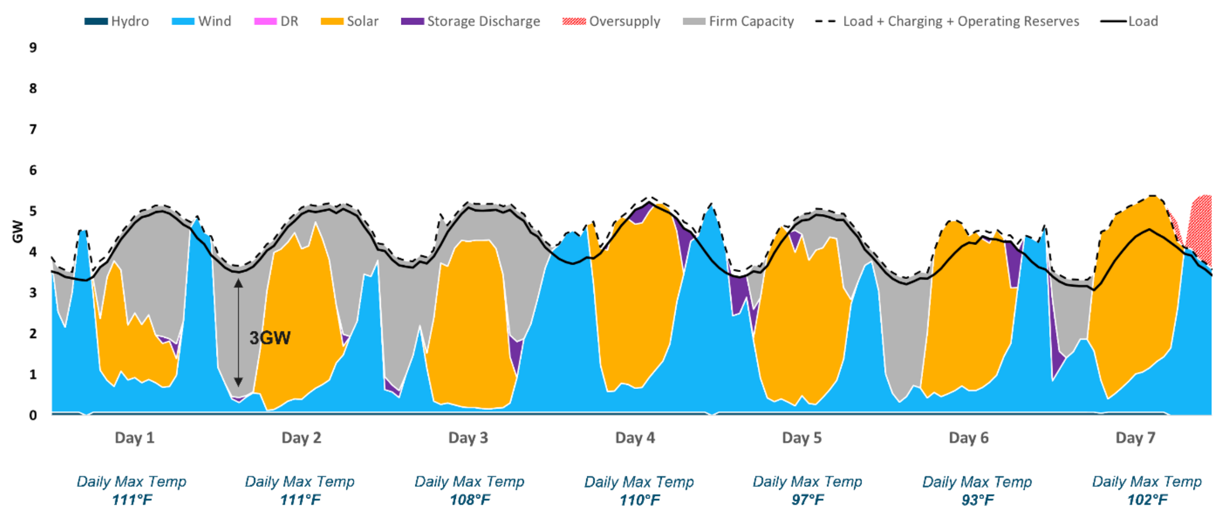


Figure 89. Illustrative Dispatch over a Low Renewable Summer Week in 2050 (Net Zero Carbon Base Scenario) [33]

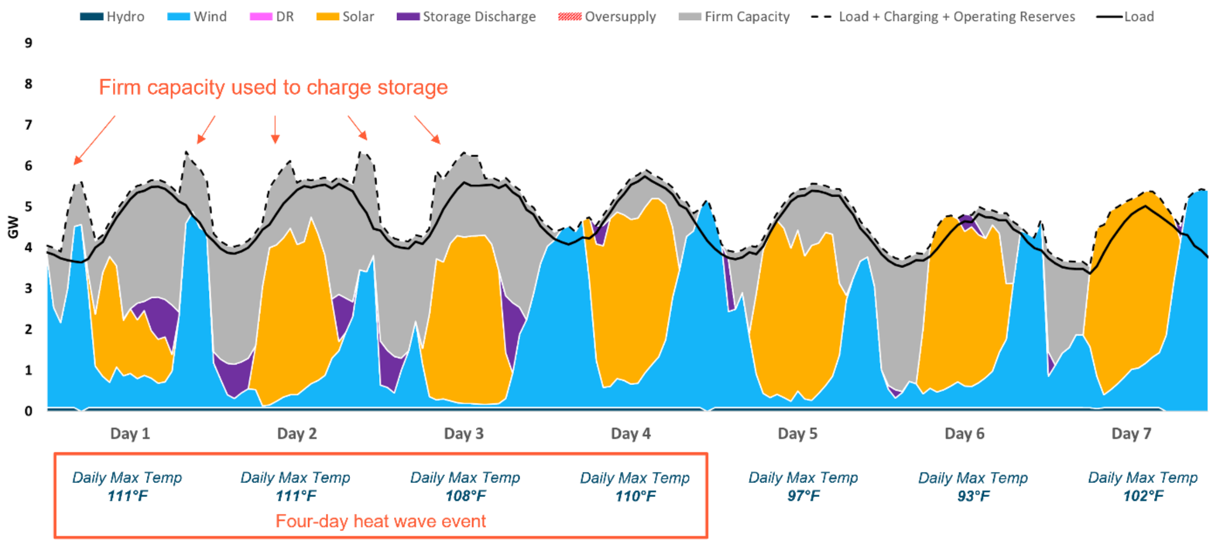


In addition to the availability of renewable output during this extreme heat event, resiliency stresses such as higher customer loads due to climate change, lower firm capacity availability, and lower energy storage availability were also considered in this case study (see Table 33). As seen in Figure 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]

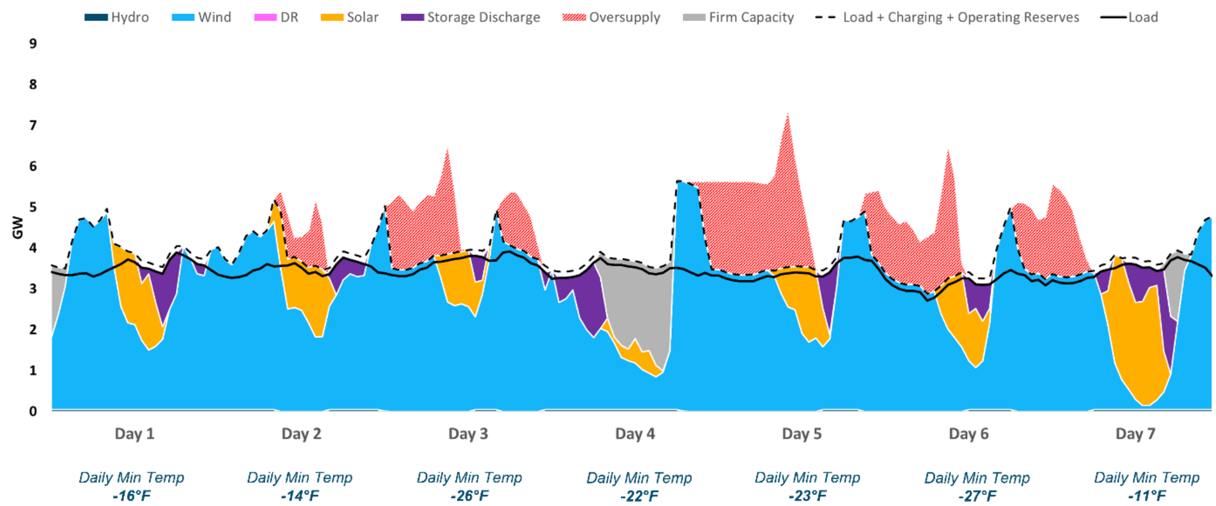
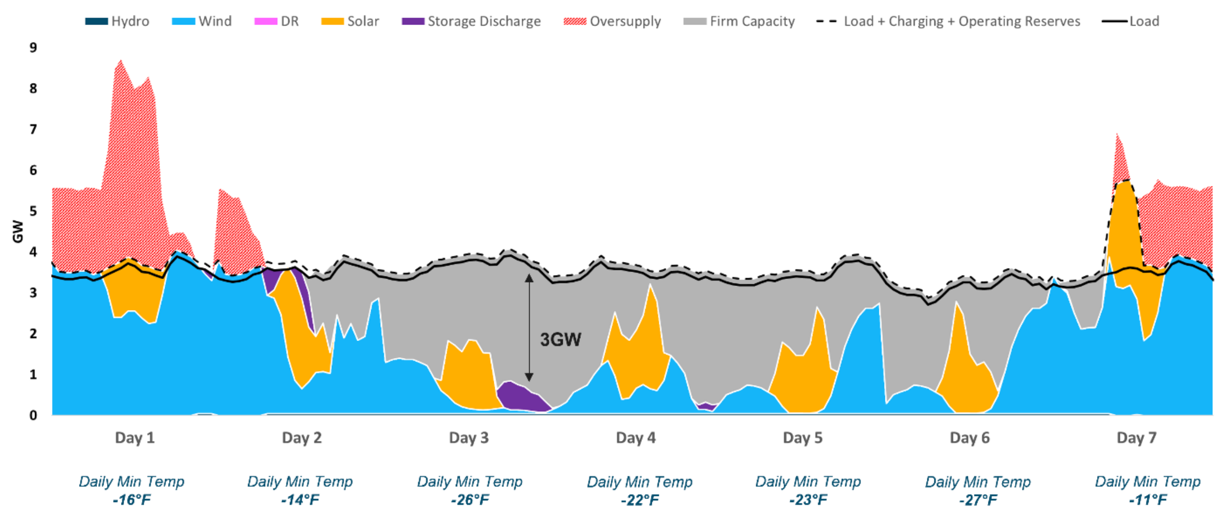


Figure 92. Illustrative Dispatch over a Low Renewable Winter Week in 2050 (Net Zero Carbon Base Scenario) [33]



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.

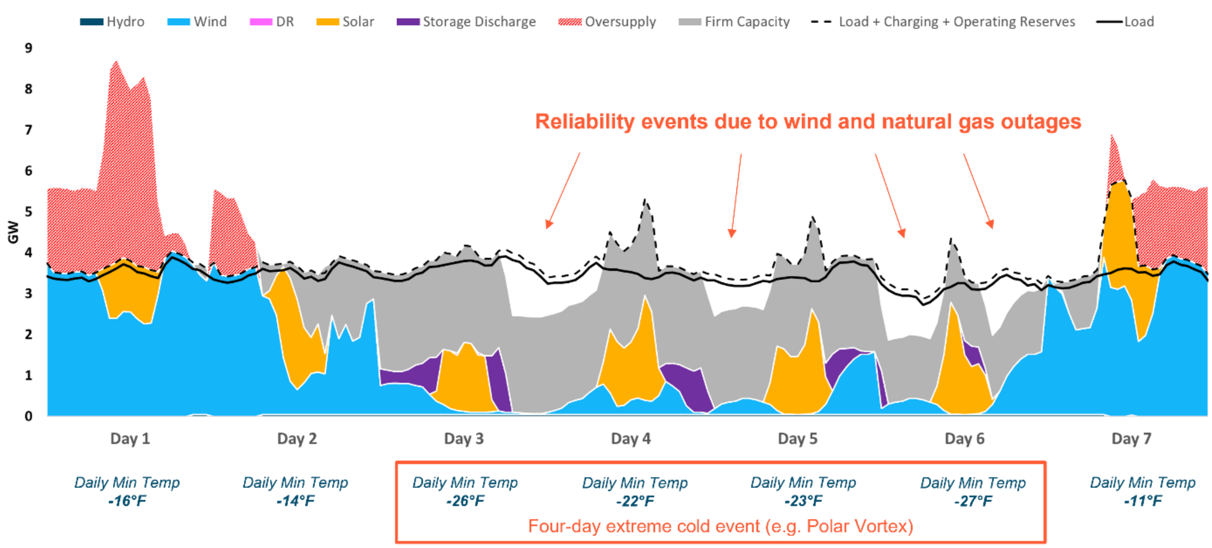
As seen in Figure 93, which builds on the low renewable condition by adding the resiliency stresses, the significant reduction in resource availability, especially in firm resources given that the wind generation was already low, triggered reliability events. These events mostly occurred during nighttime 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

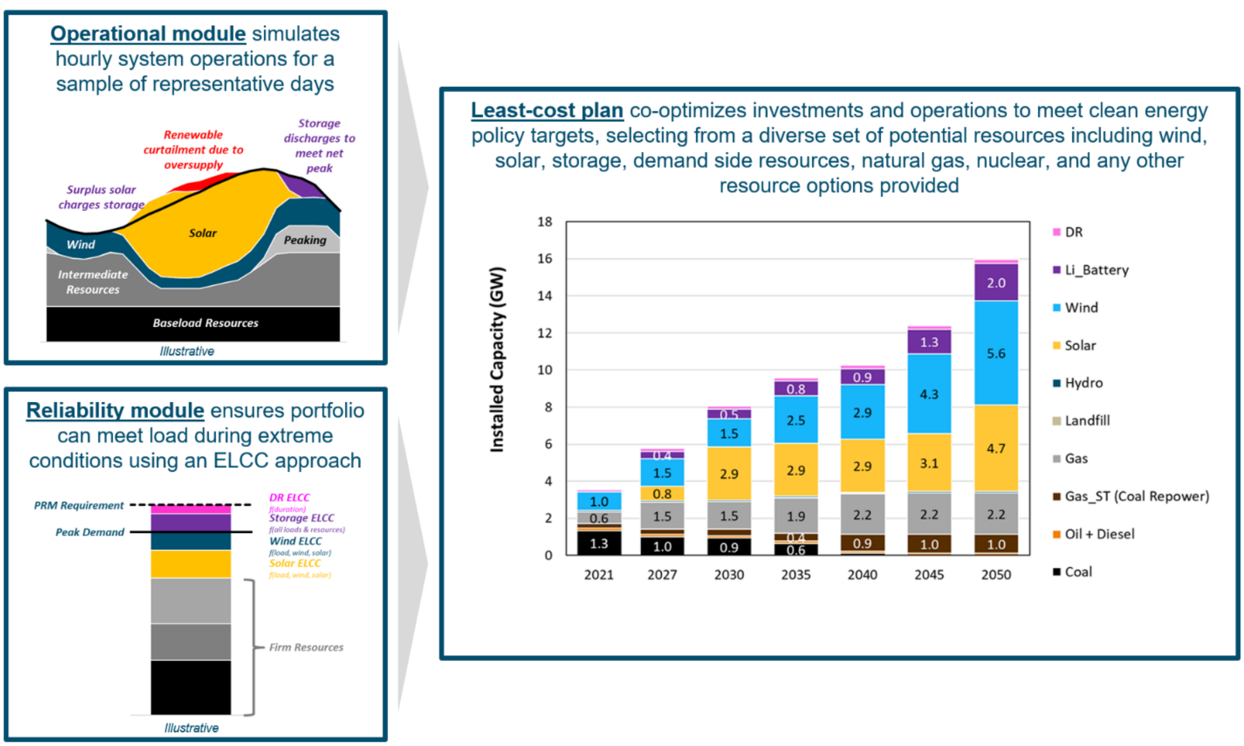
6.1 Modeling Approach

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:

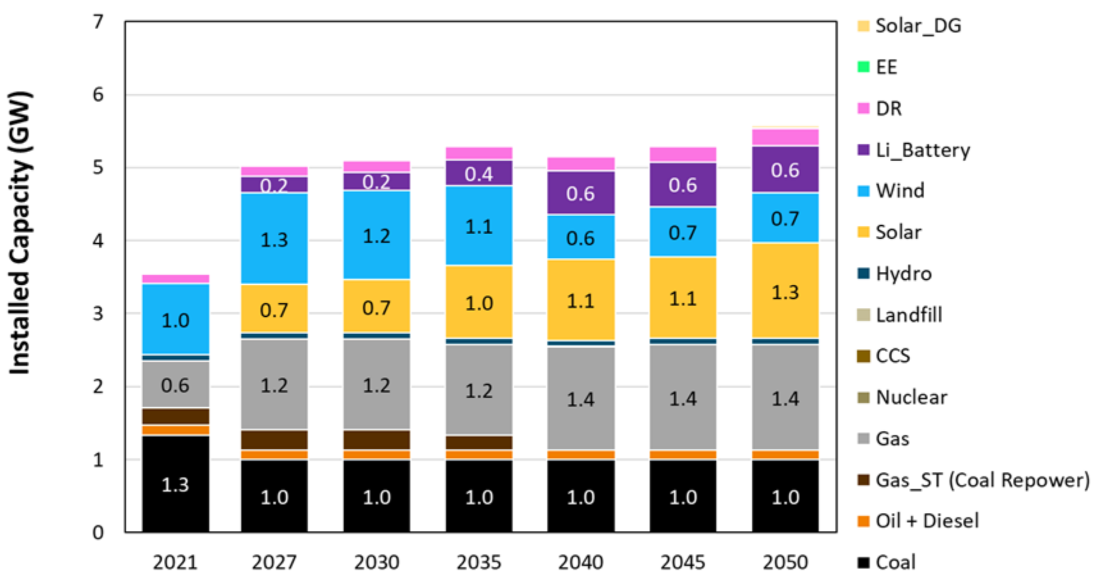
- How will OPPD's resource portfolio change without any emission target?
- What resources does OPPD need to build to achieve net zero carbon?
- How will the pace of decarbonization impact portfolio needs?
- How will load trajectories impact portfolio needs?
- How will OPPD's portfolio change if OPPD 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

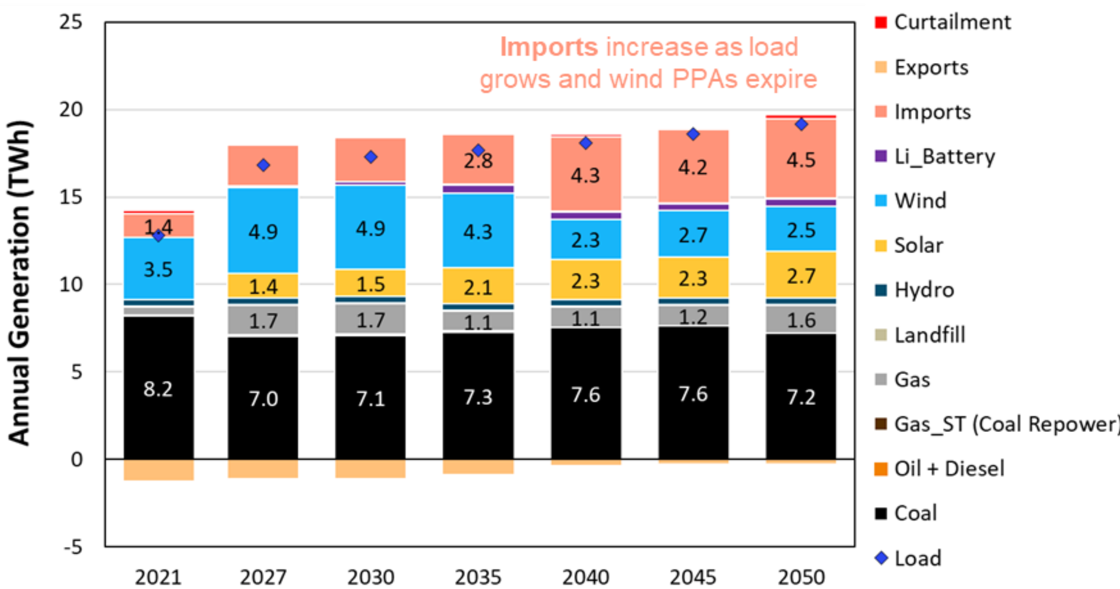
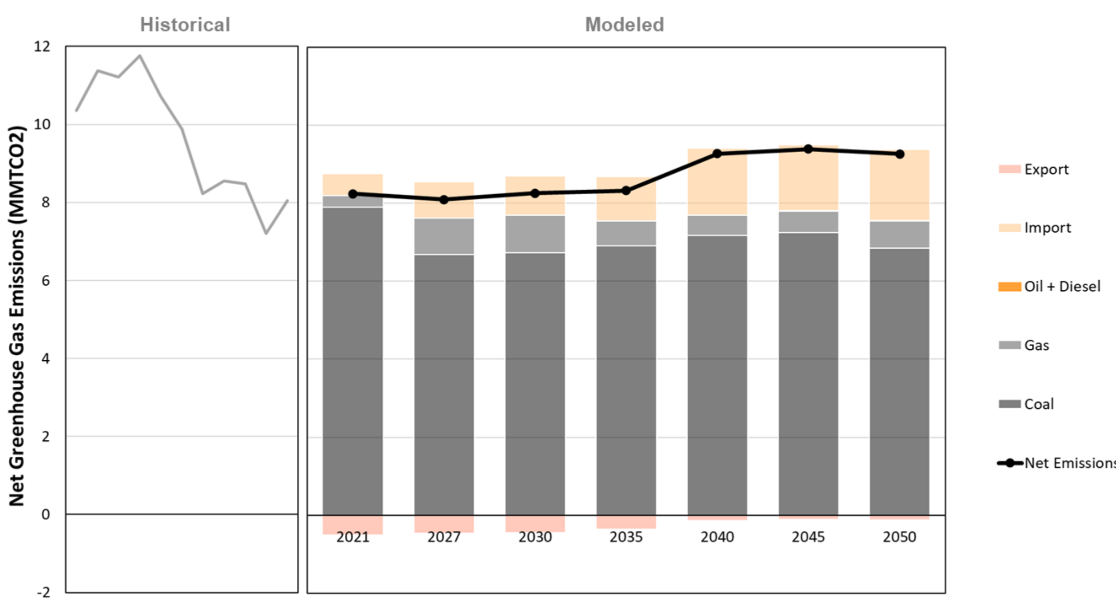


Figure 97. OPPD Annual GHG Emission (MMT) under Reference Scenario



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

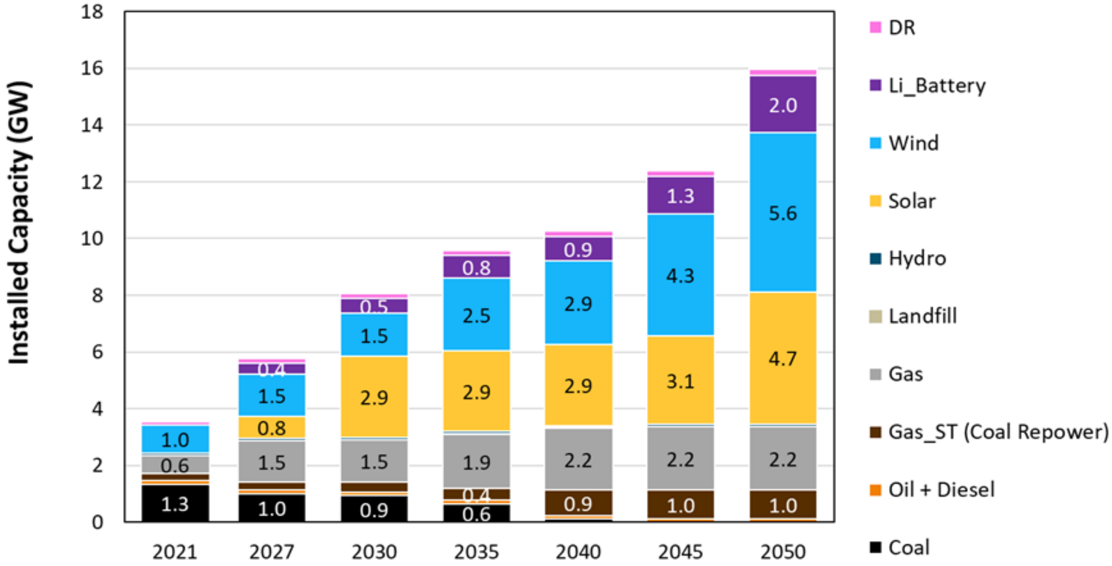


Figure 99. OPPD Annual Generation (TWh) under Net Zero Carbon Base Scenario

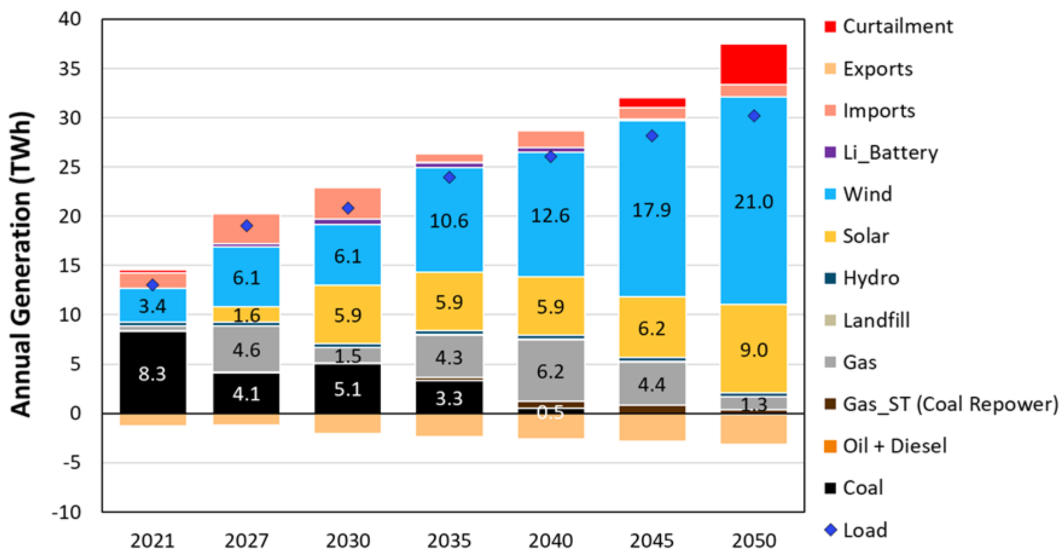
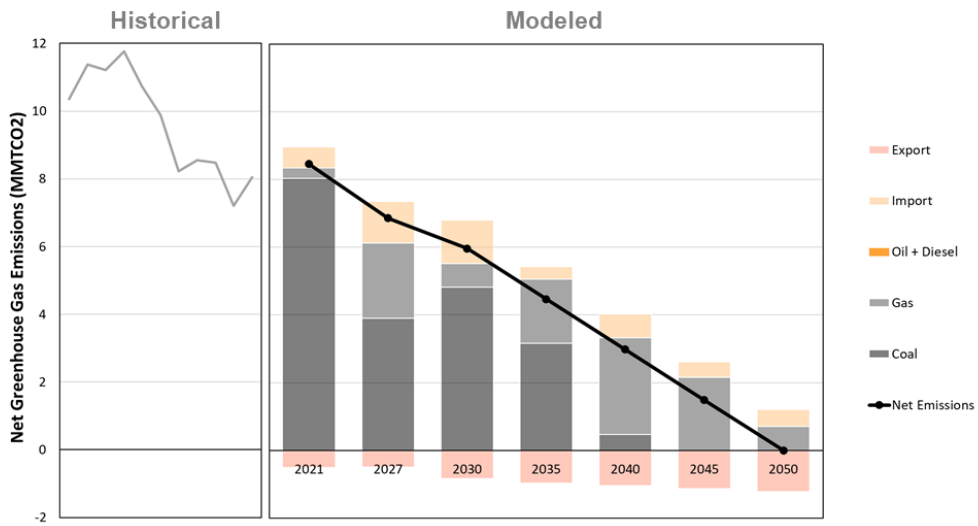


Figure 100. OPPD Annual GHG Emission (MMT) under Net Zero Carbon Base Scenario



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

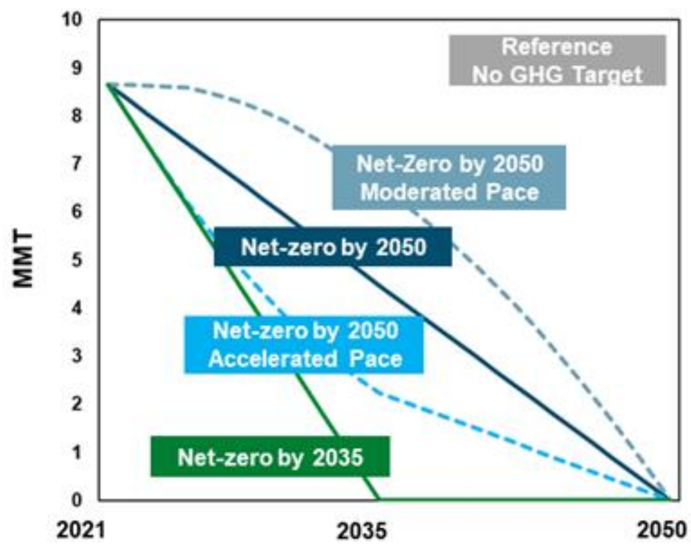
	2021	2030	2040	2050
Generation Cost Impact (2021 cent/kWh, increase from Reference)	+0	+0.4	+1.1	+1.4
(% increase vs. current system avg. rate)	(+0%)	(+5%)	(+13%)	(+16%)
Marginal Carbon Abatement Cost (2021 $/ton CO2)	-	$24	$29	$72

[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

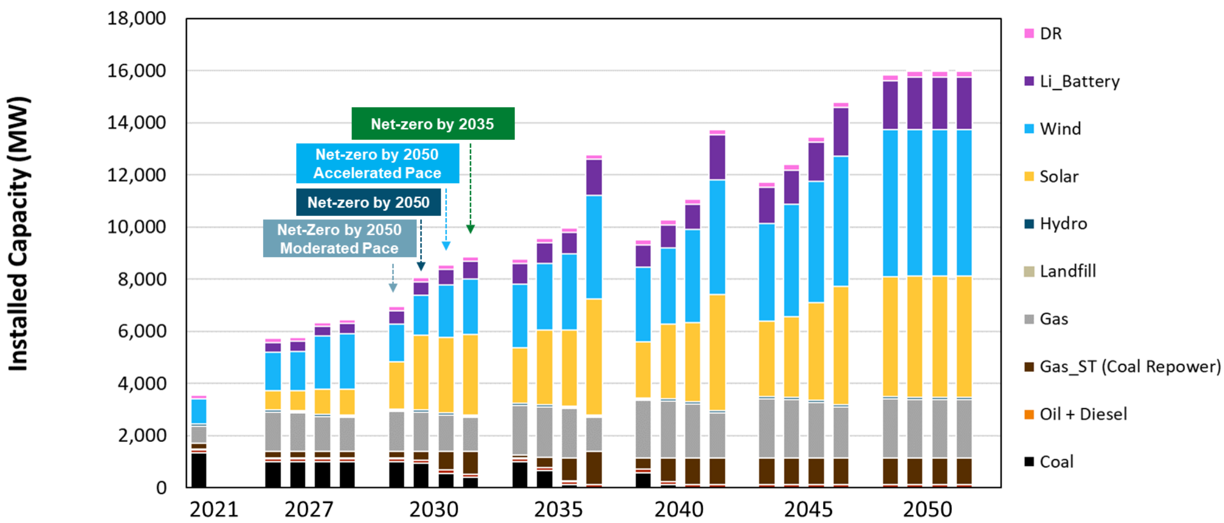


Figure 103. OPPD Annual Generation (GWh) of Pace of Decarbonization Sensitivities

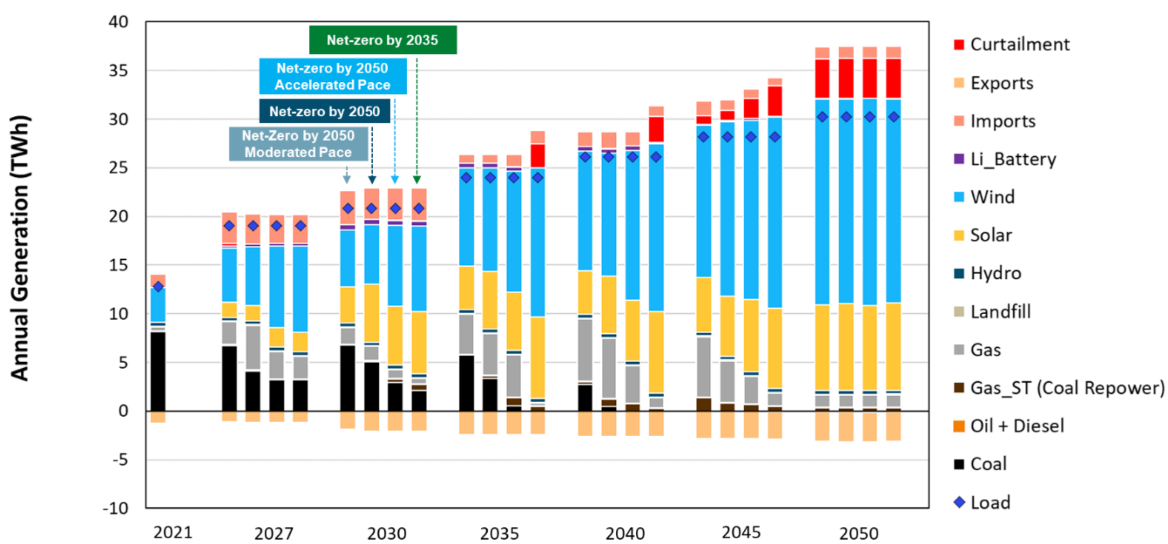
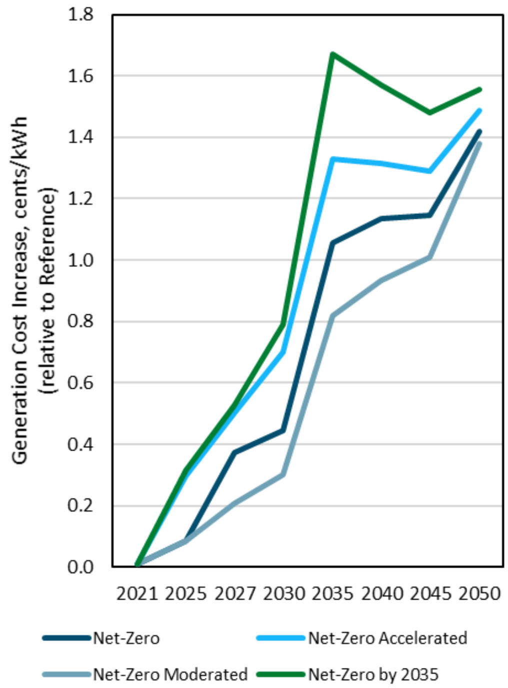


Figure 104. Generation Costs (cents/kWh) relative to Reference for Pace of Decarbonization Sensitivities



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

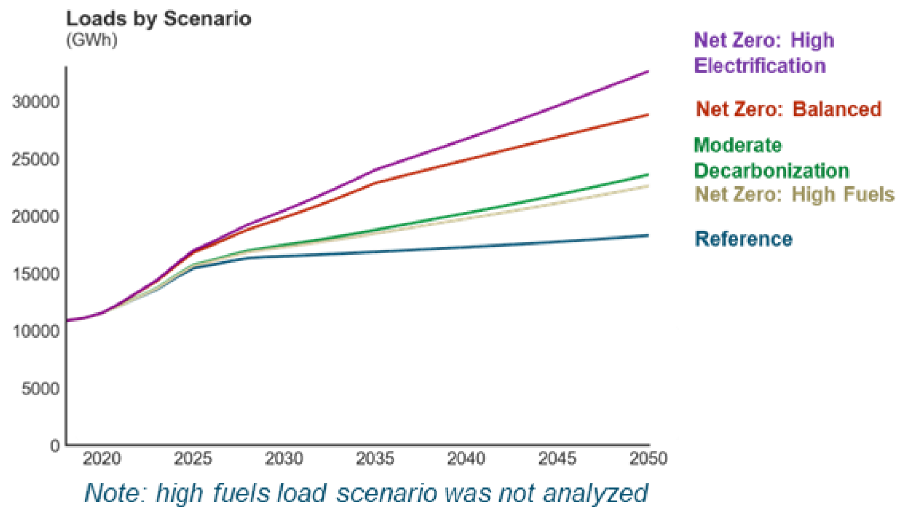


Figure 106. OPPD Installed Capacity (GW) of Load Sensitivities

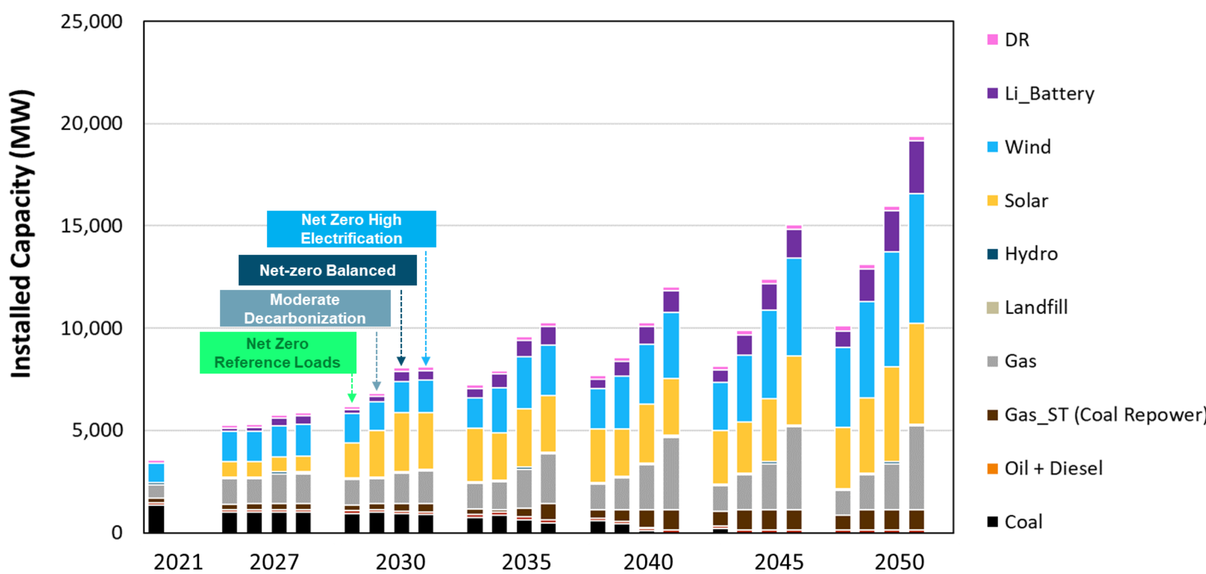


Figure 107. OPPD Annual Generation (GWh) of Load Sensitivities

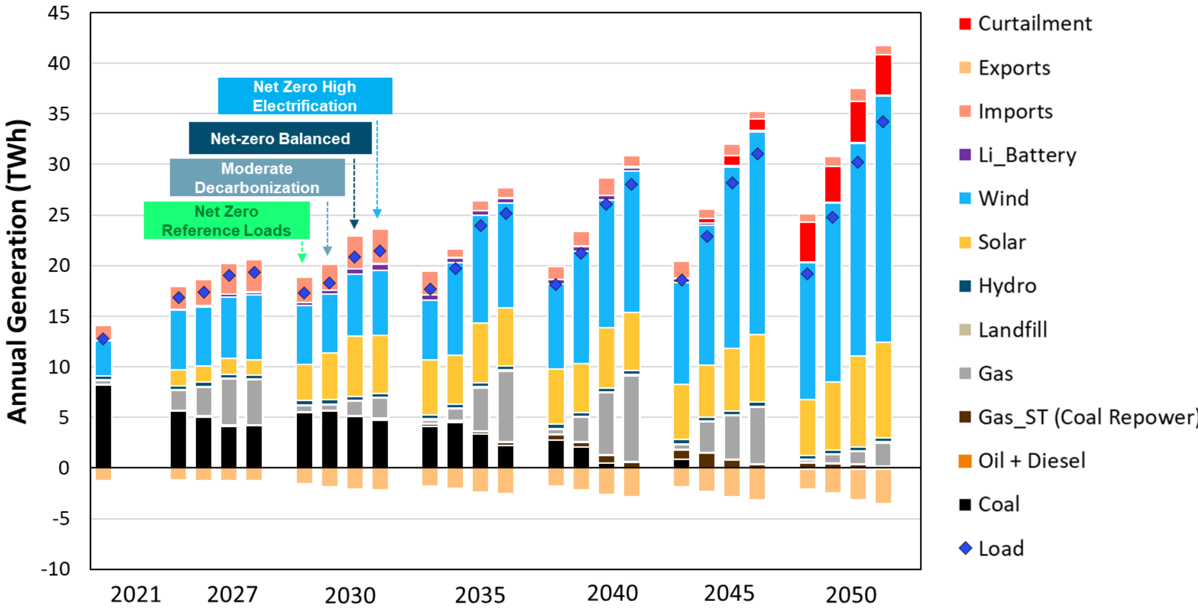
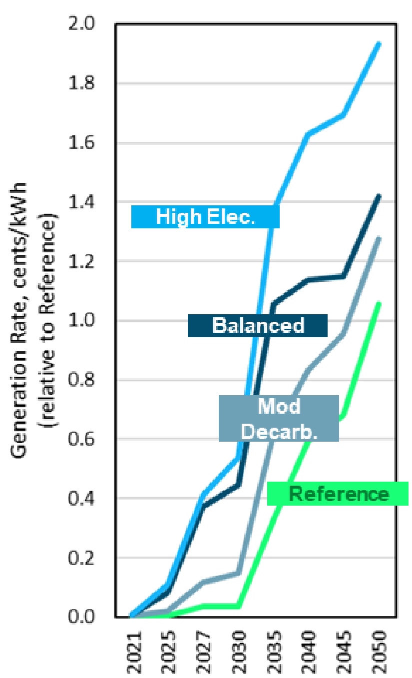


Figure 108. Generation Costs (cents/kWh) relative to Reference for Load Sensitivities



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

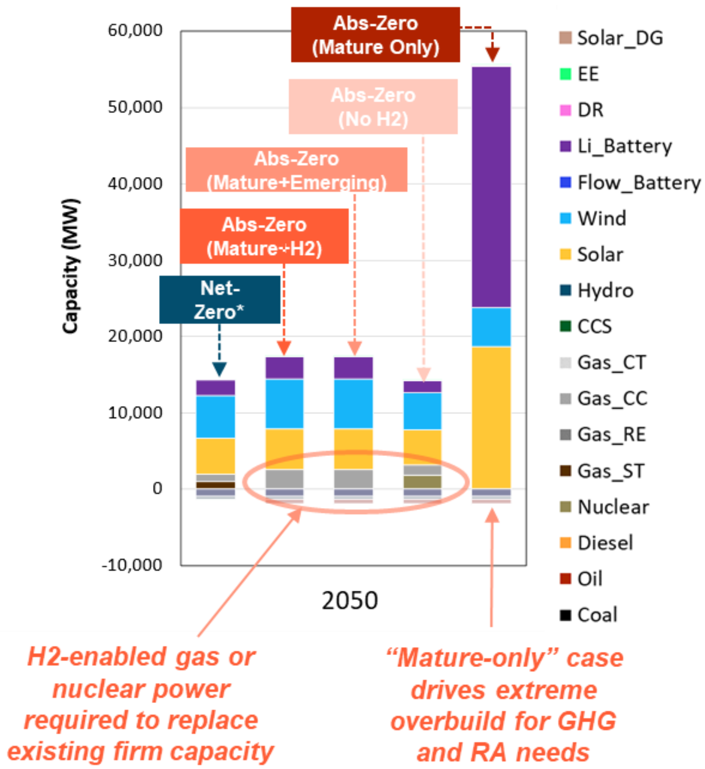
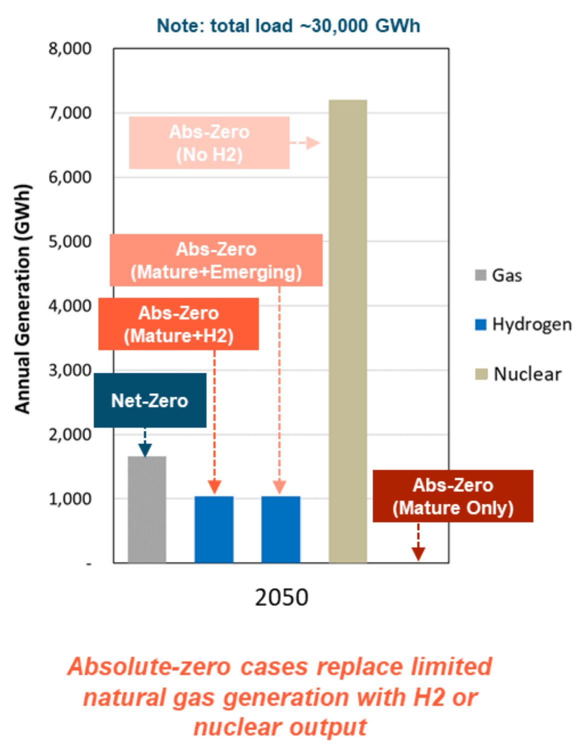


Figure 110. OPPD Firm Generation (GWh) of Absolute Zero Sensitivities in 2050



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

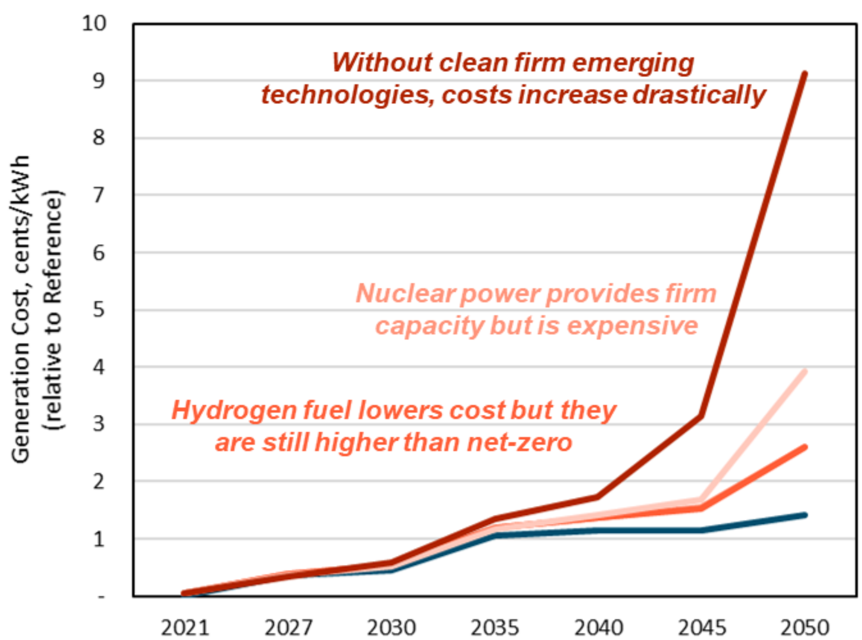
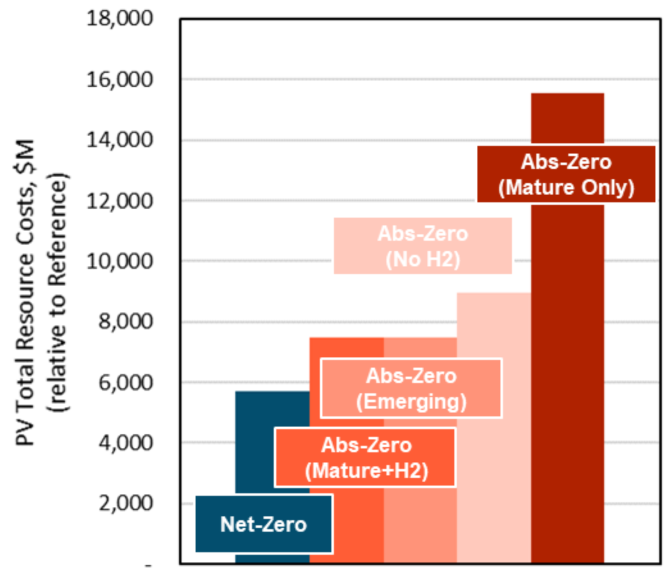


Figure 112. Total System Cost in Present Value ($M) relative to Reference for Absolute Zero Sensitivities

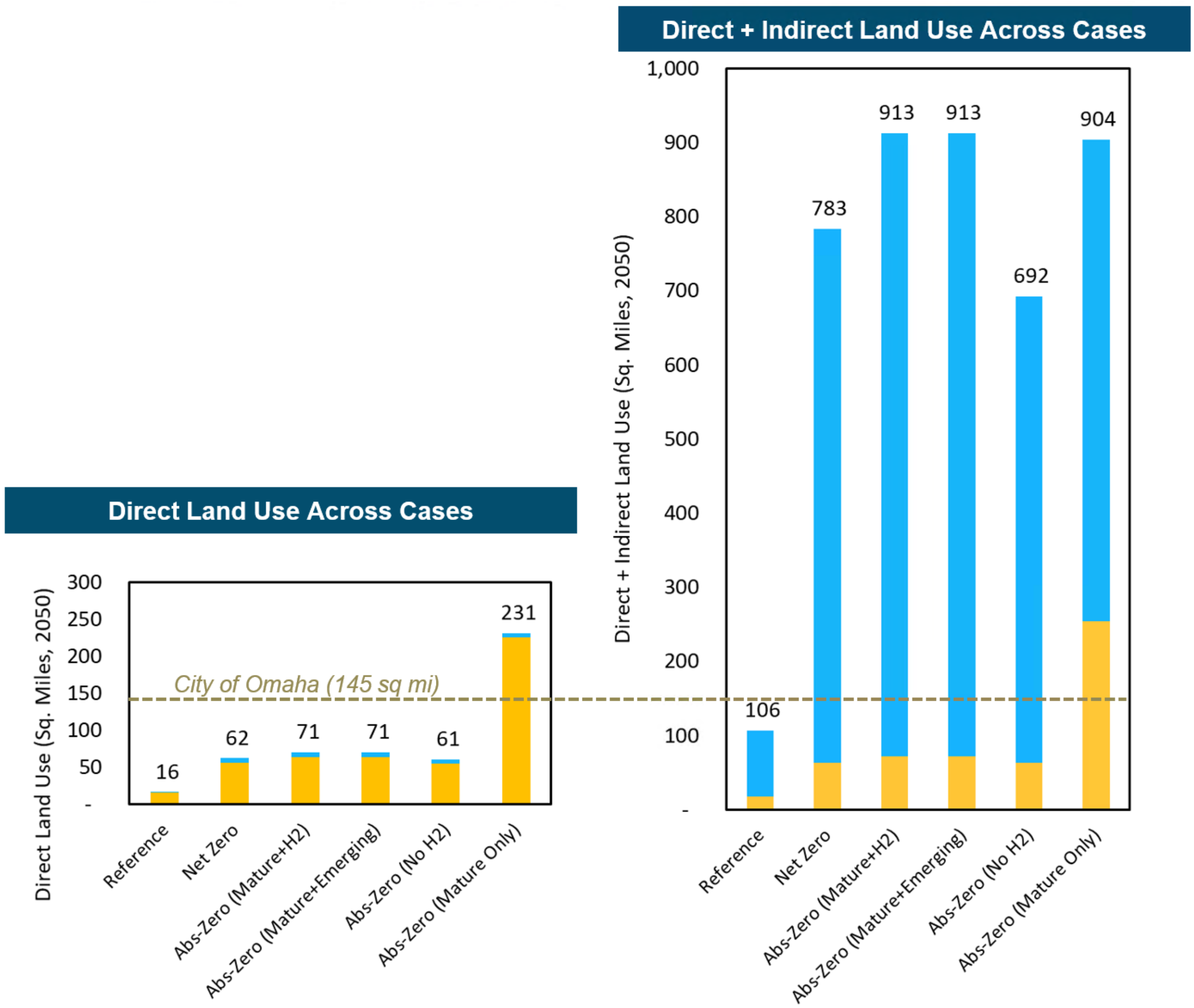


One key question arises with the significant renewable build is the impact of land use across scenarios. By accounting for both the direct[49] and indirect[50] land uses, absolute zero scenarios require more land use compared to the net zero scenarios except in the case where nuclear addition is allowed (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.

[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

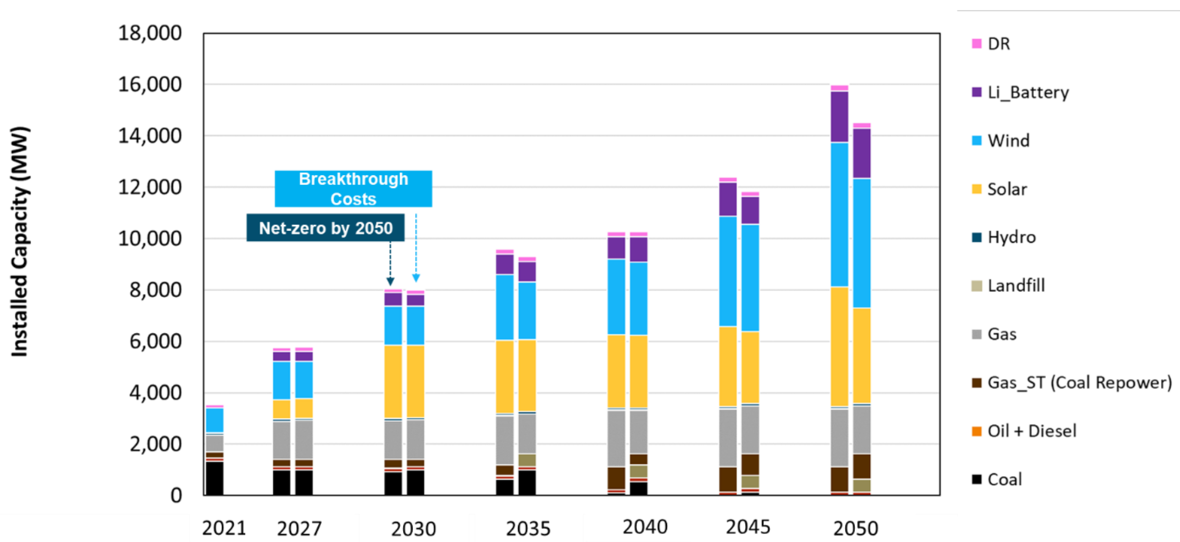


Figure 115. OPPD Annual Generation (GWh) of Breakthrough Costs Sensitivity

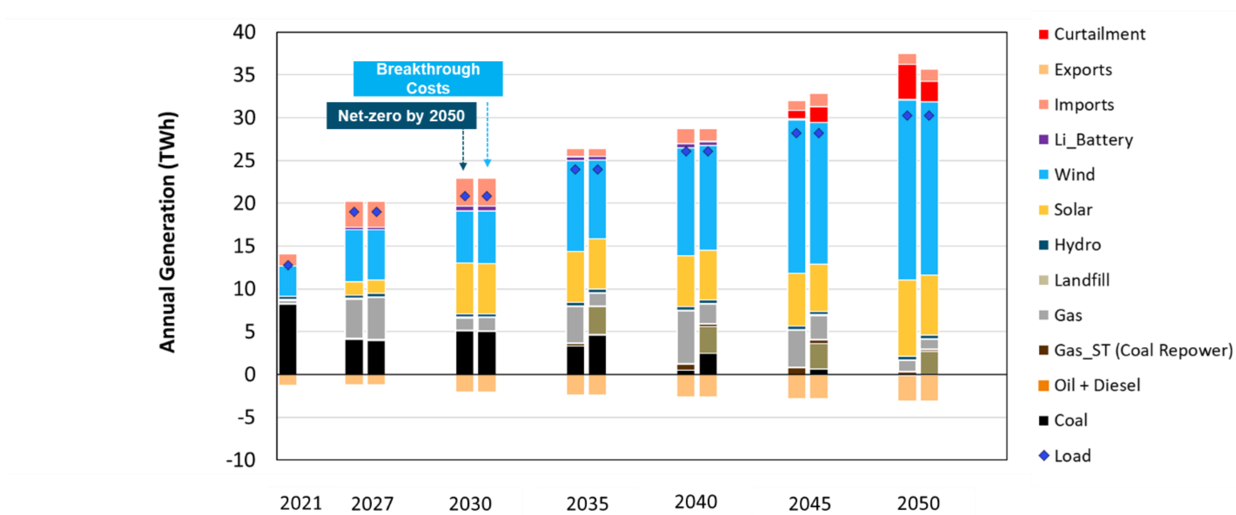
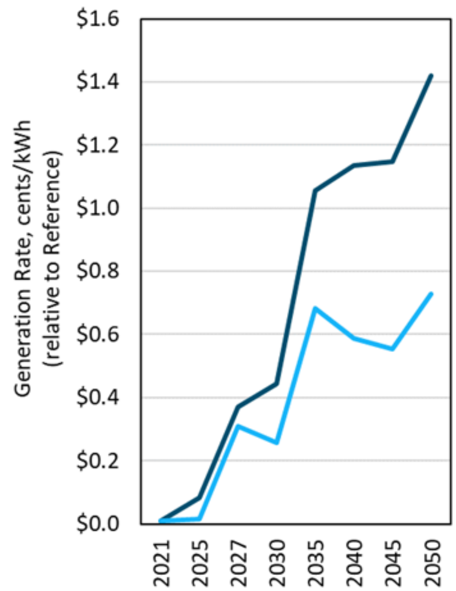


Figure 116. Generation Costs (cents/kWh) relative to Reference for Breakthrough Costs Sensitivity



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

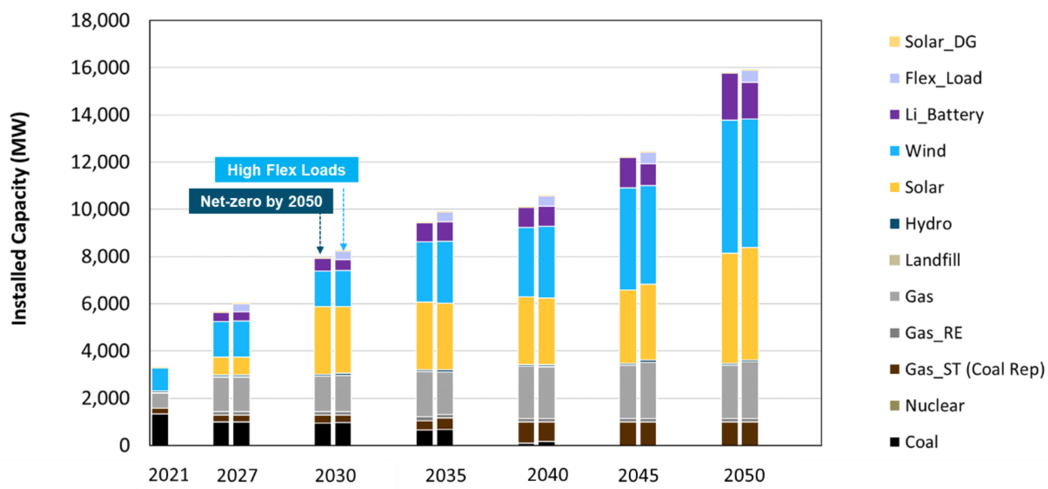


Figure 118. OPPD Annual Generation (GWh) of High Flexible Loads Sensitivity

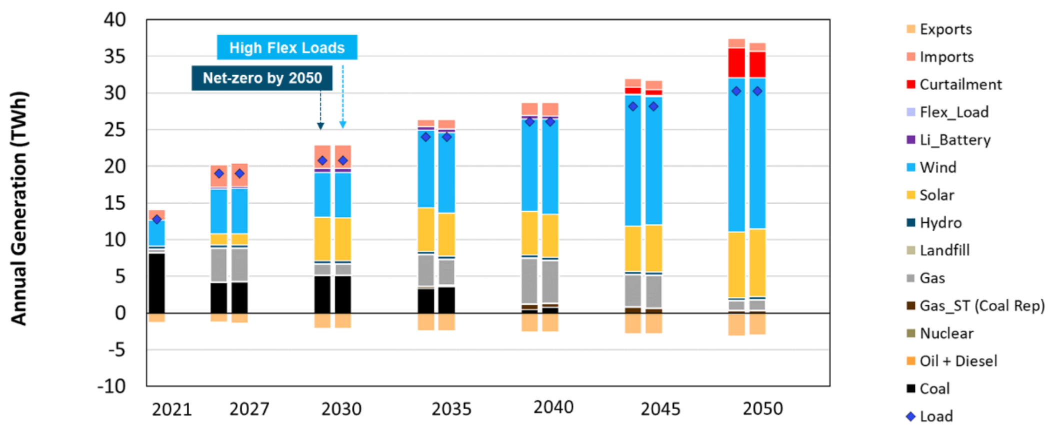
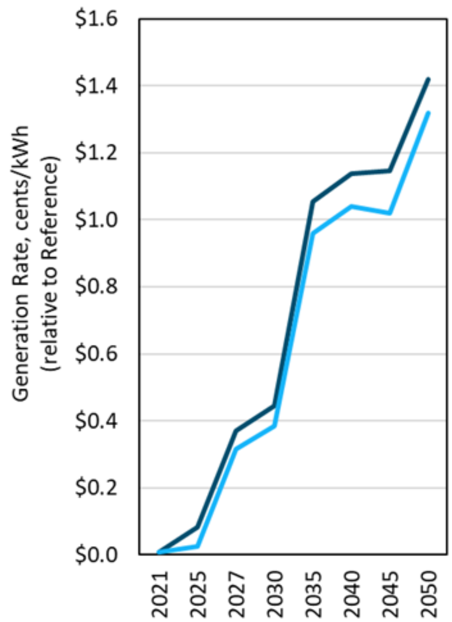


Figure 119. Generation Costs (cents/kWh) relative to Reference for High Flexible Loads Sensitivity



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.

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[52] Technical Support Document: Social Cost of Carbon, Methane, (whitehouse.gov)

Figure 120. OPPD Installed Capacity (GW) of Carbon Price Sensitivity

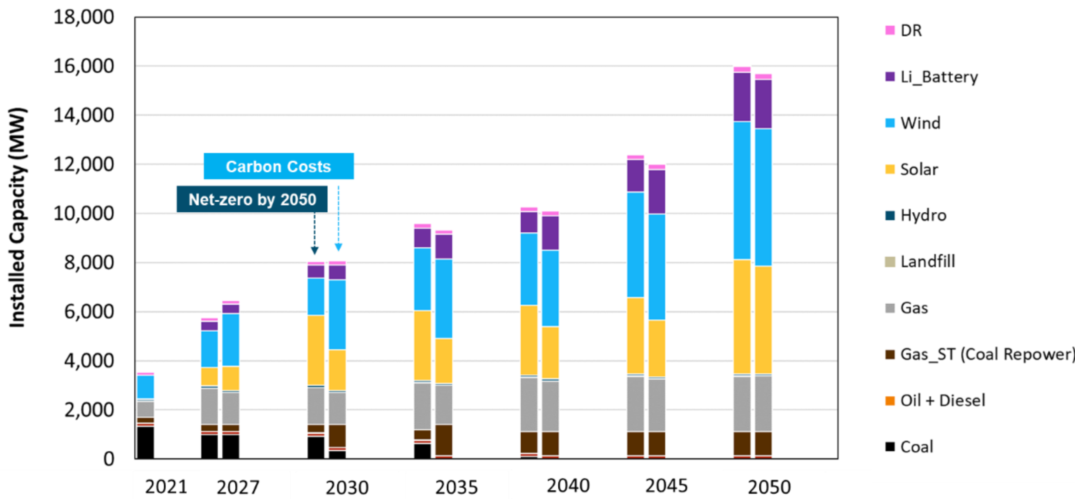


Figure 121. OPPD Annual Generation (GWh) of Carbon Price Sensitivity

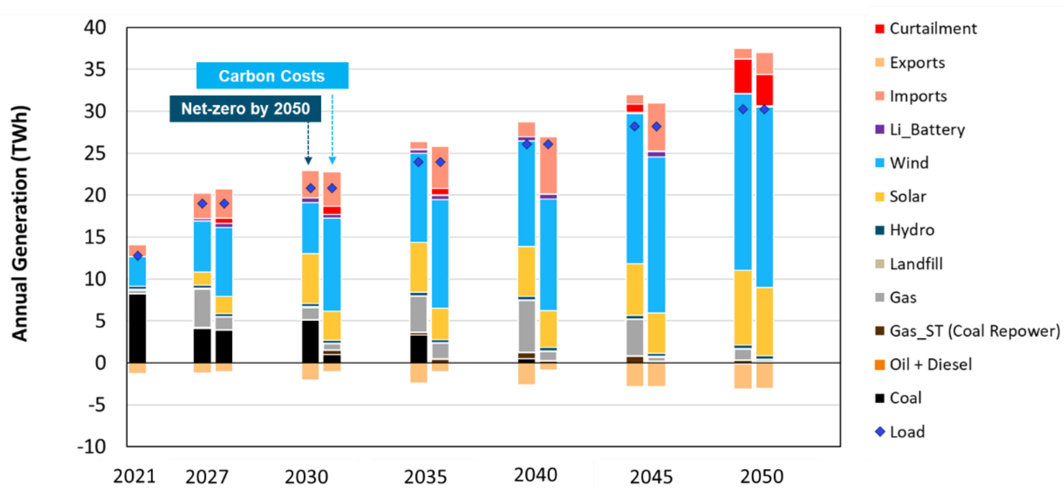


Figure 122. Generation Costs (cents/kWh) relative to Reference for Carbon Price Sensitivity

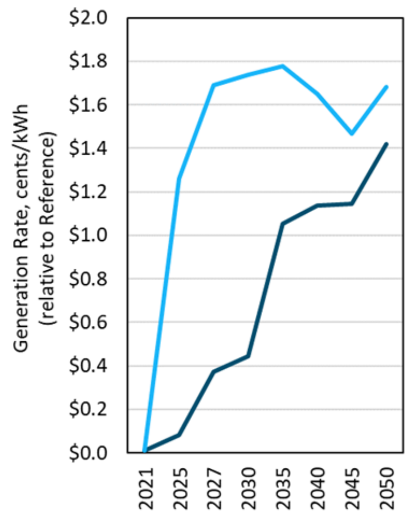
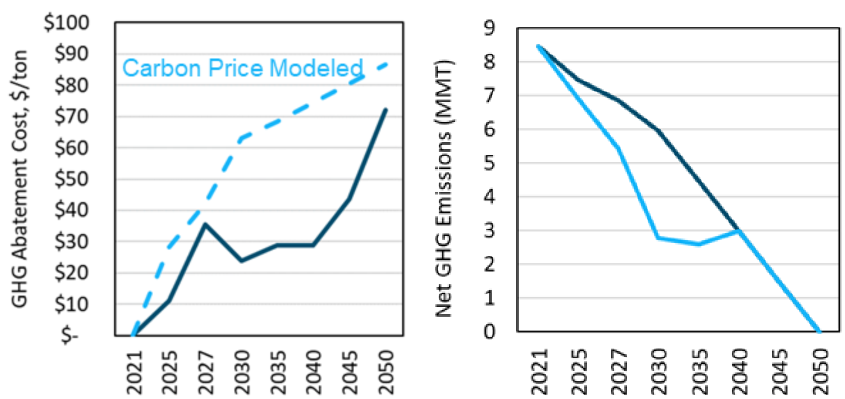


Figure 123. Carbon Cost and Emissions of Carbon Price Sensitivity



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

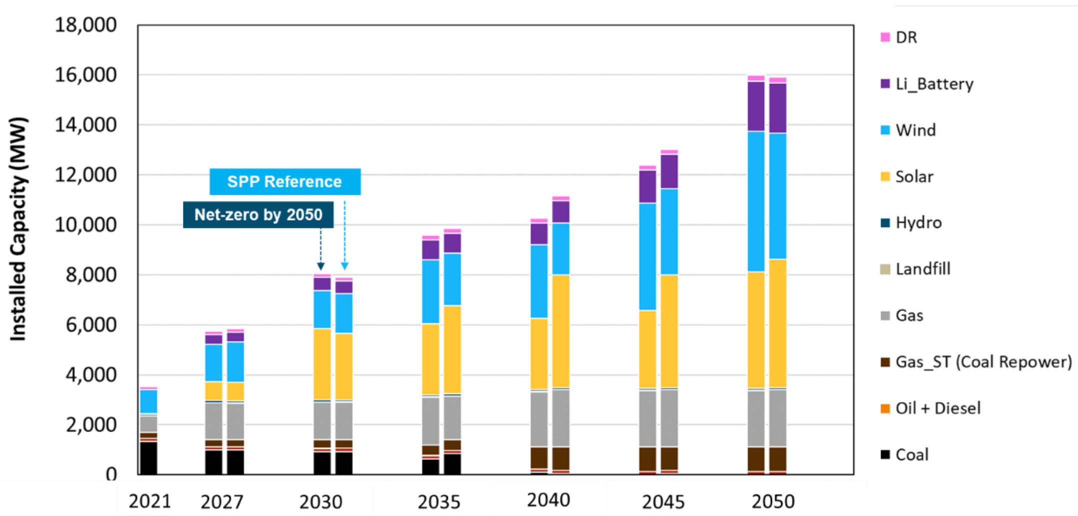


Figure 125. OPPD Annual Generation (GWh) of SPP Resource Portfolio Sensitivity

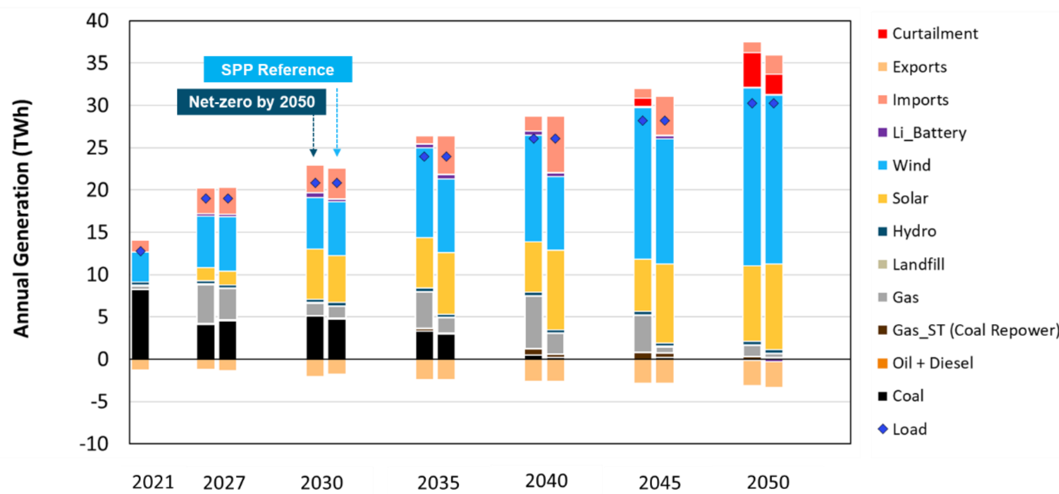
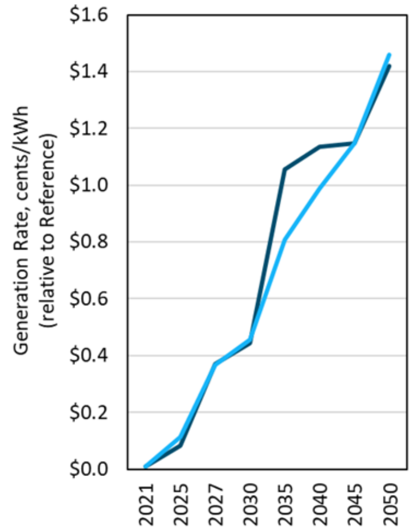


Figure 126. Generation Costs (cents/kWh) relative to Reference for SPP Resource Portfolio Sensitivity



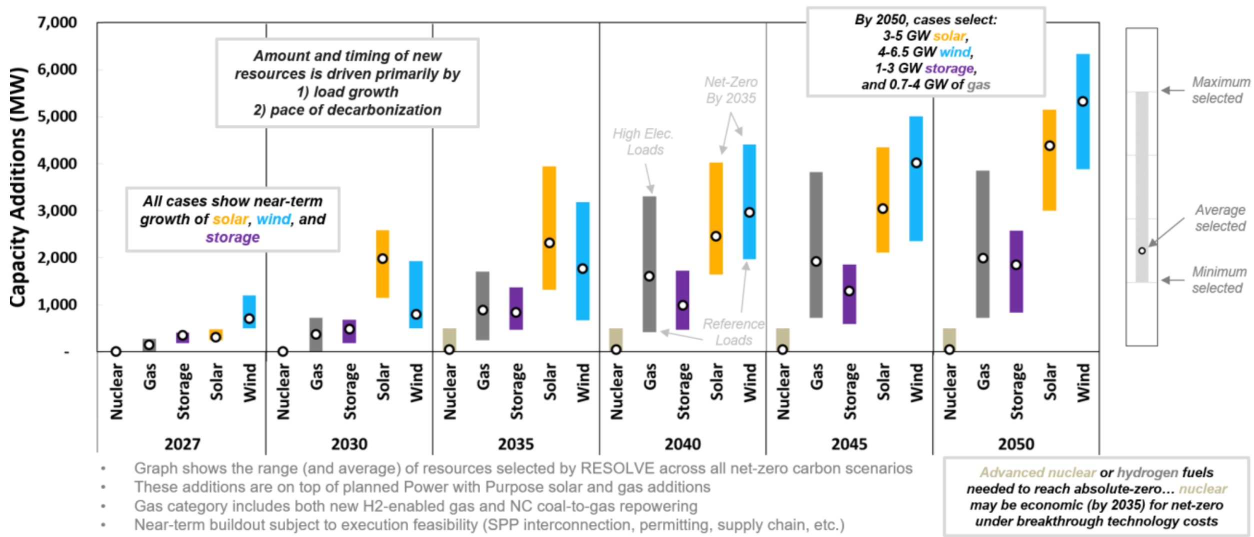
6.4 Summary of Key Results Across Scenarios

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



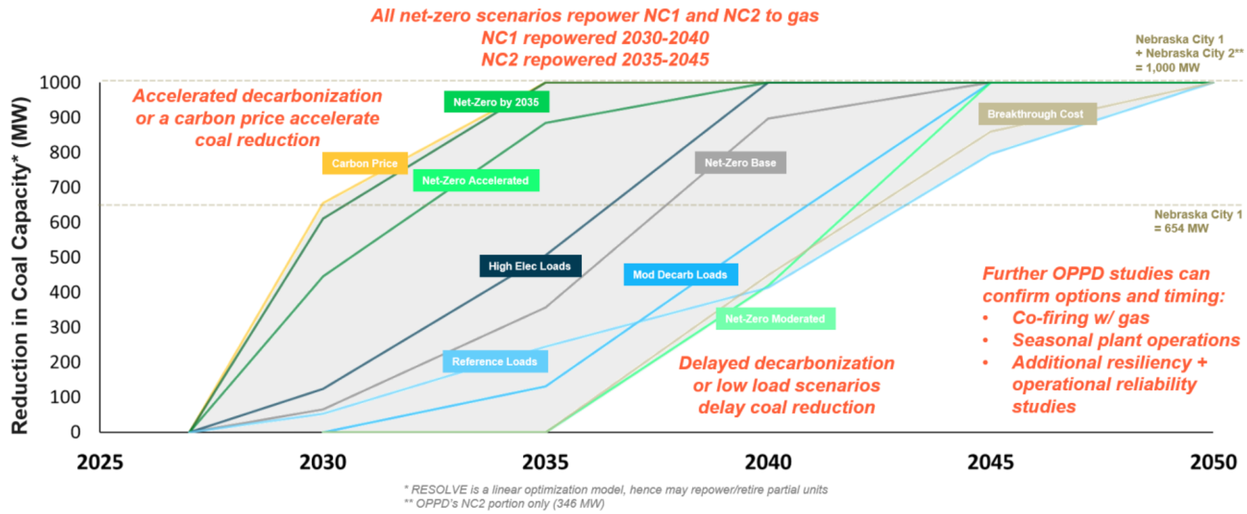
6.4.2 Coal Repowering

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

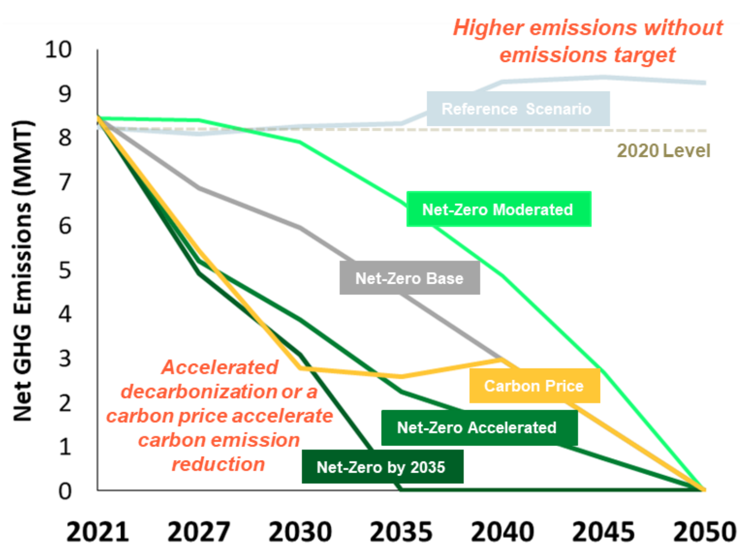
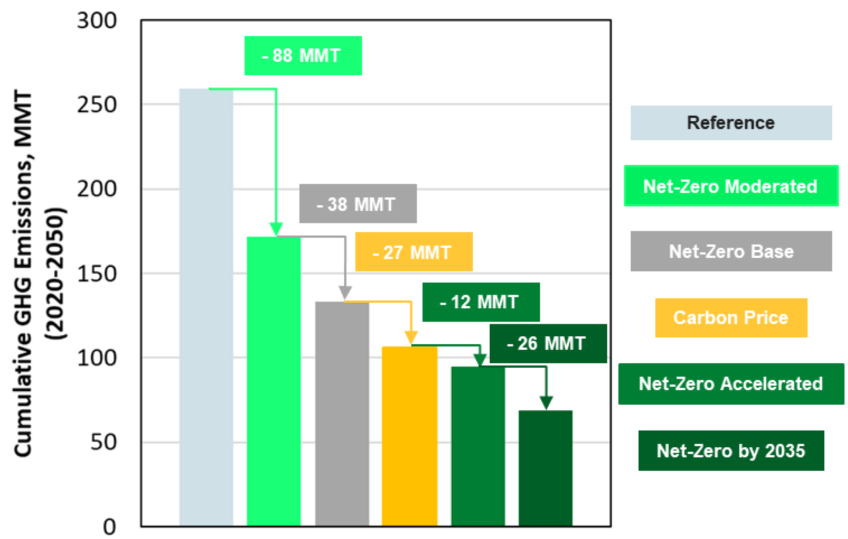


Figure 130. Total GHG Emissions from 2020 to 2050



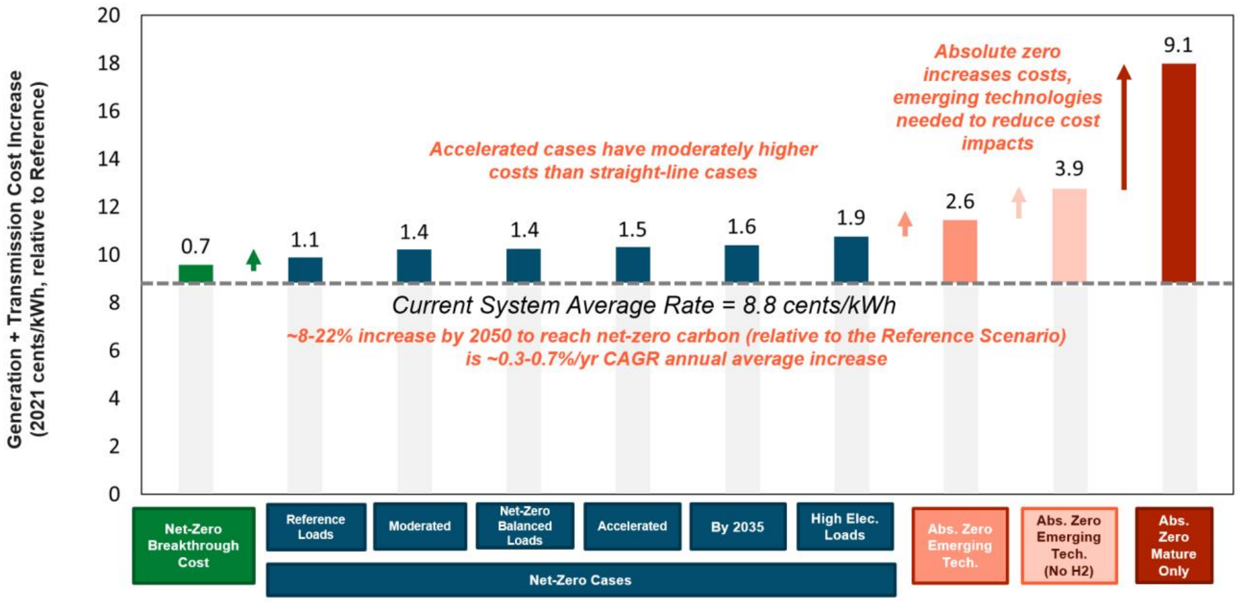
6.4.4 Costs Impacts

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

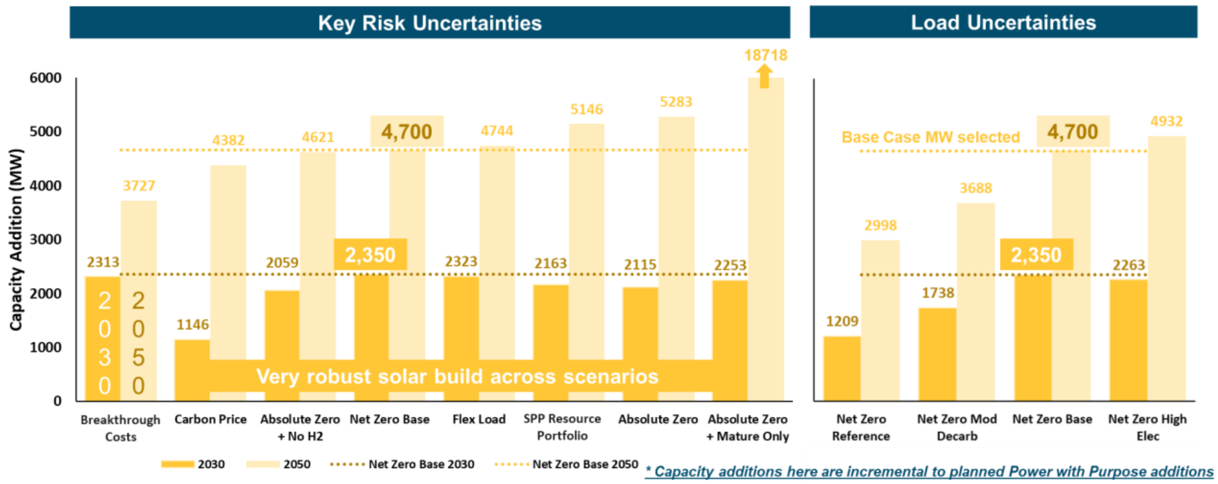
7.2.1 Solar Risk Analysis

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.

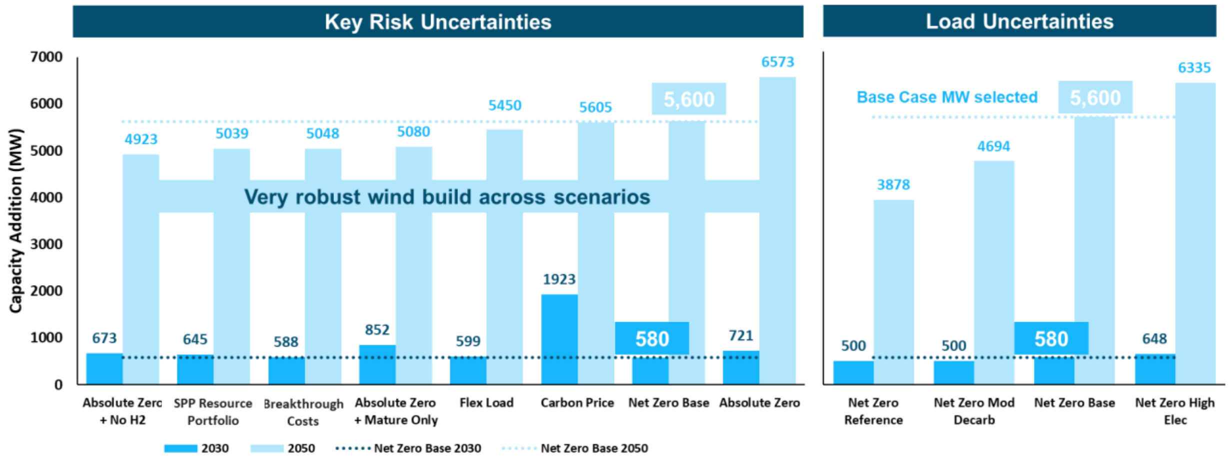
Figure 132. Solar Capacity Addition Uncertainties by Scenarios



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.

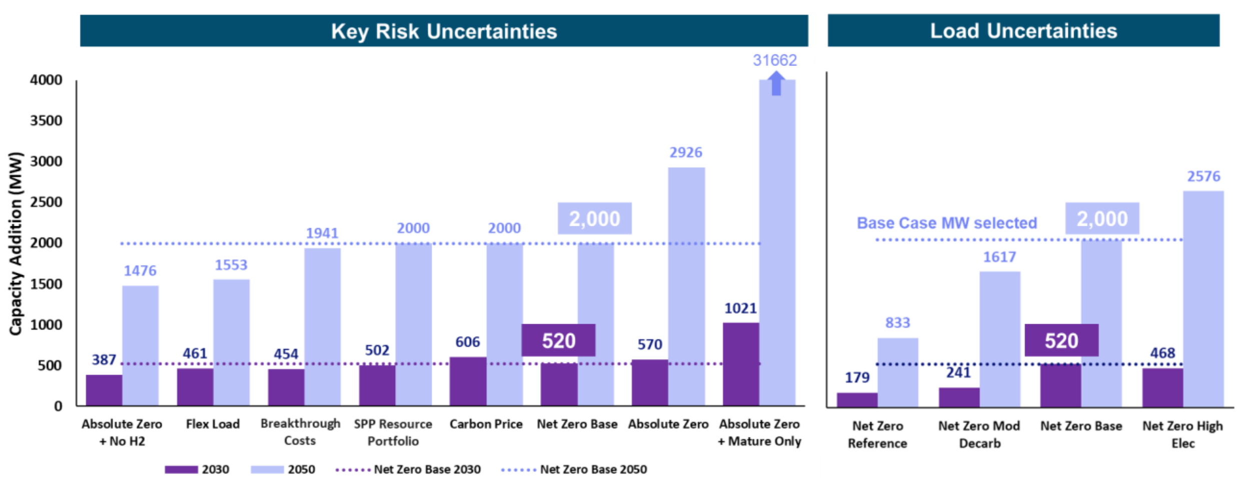
Figure 133. Wind Capacity Addition Uncertainties by Scenarios



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.

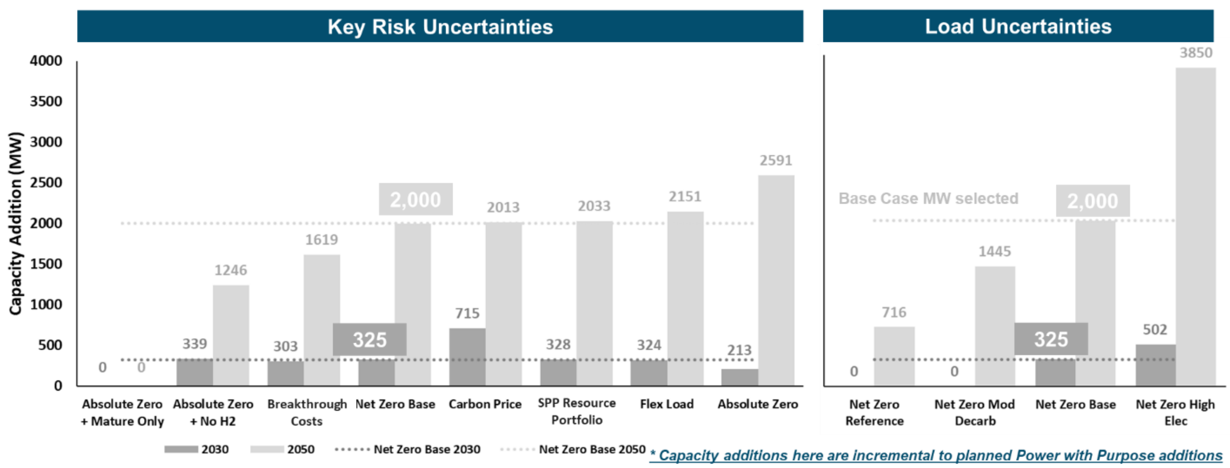
Figure 134. Energy Storage Capacity Addition Uncertainties by Scenarios



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.

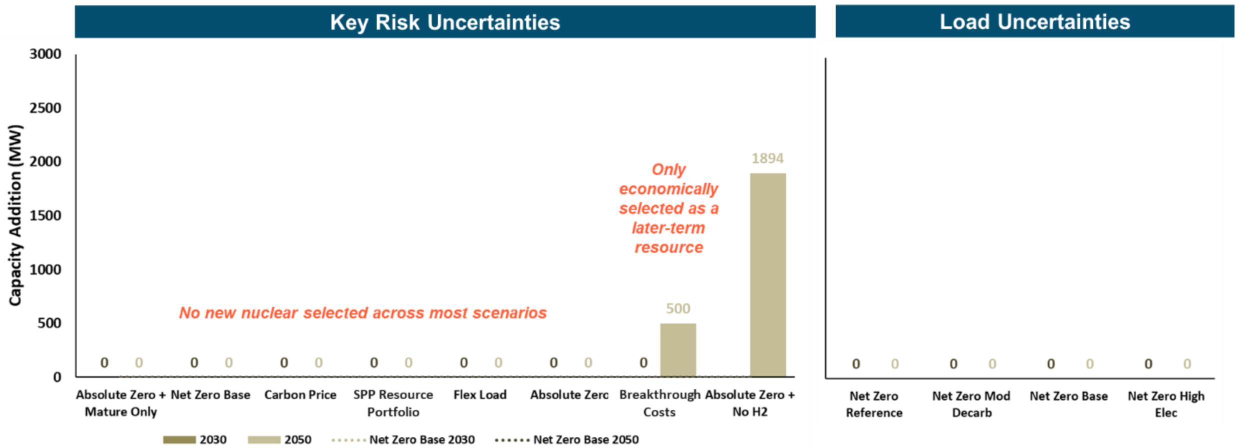
Figure 135. New Firm Capacity Addition Uncertainties by Scenarios



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.

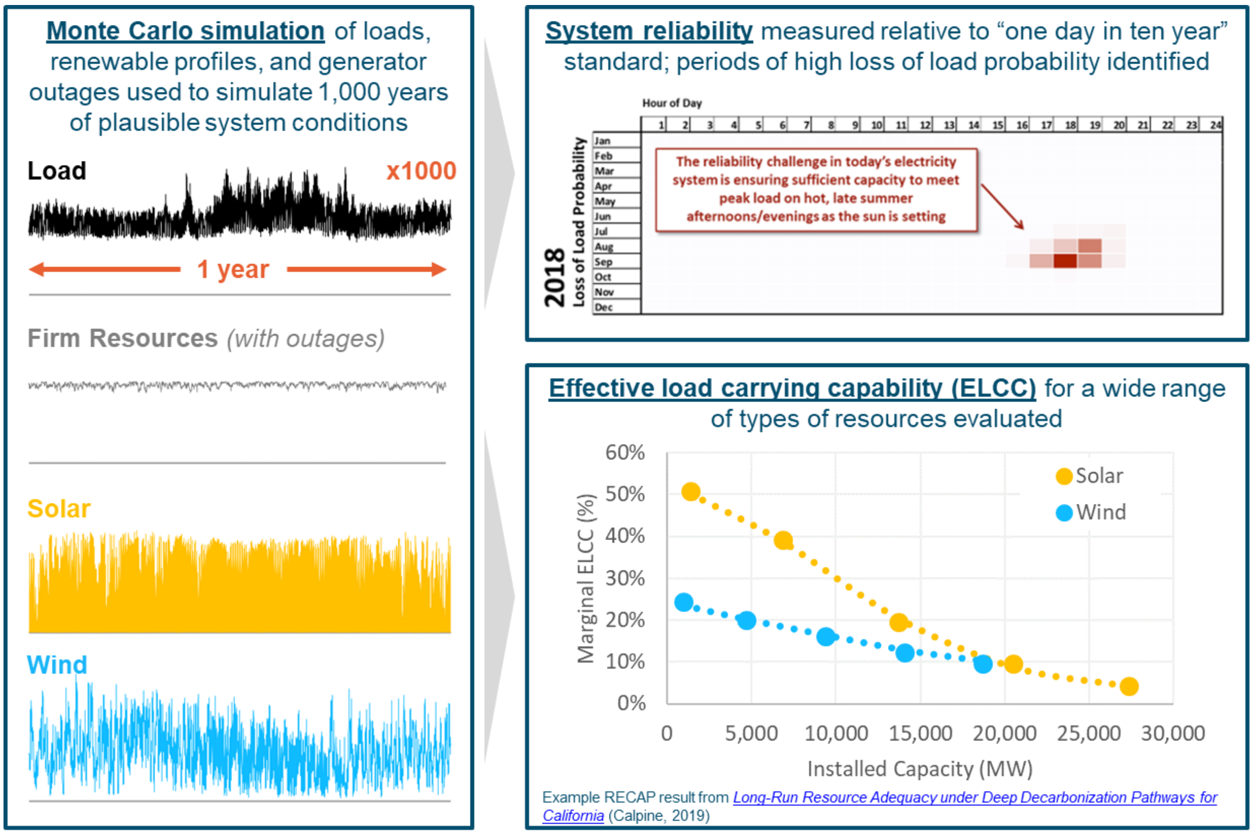
The focus of this decarbonization study is to inform OPPD's procurement decisions in the next decade and ensure near-term procurement decisions are consistent with OPPD's long-term goal in 2050. As technology matures and load grows, **OPPD should continue to monitor long-term uncertainties and risks 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*

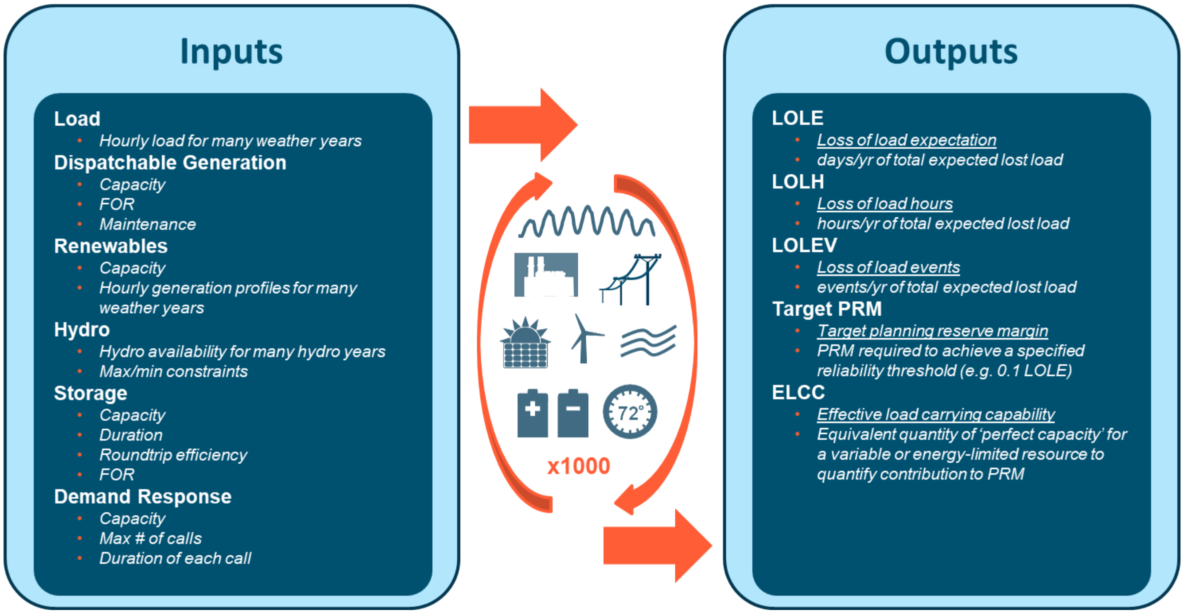
[56] California PUC, Portland General Electric, Sacramento Municipal Utilities District, Los Angeles Department of Water and Power, El Paso Electric, Xcel Minnesota, WECC, Florida Power and Light, New York State Research and Development Authority, New England ISO, Nova Scotia Power, and more.

4 stakeholder process to evaluate the capacity contribution of "shed" demand response programs in California.

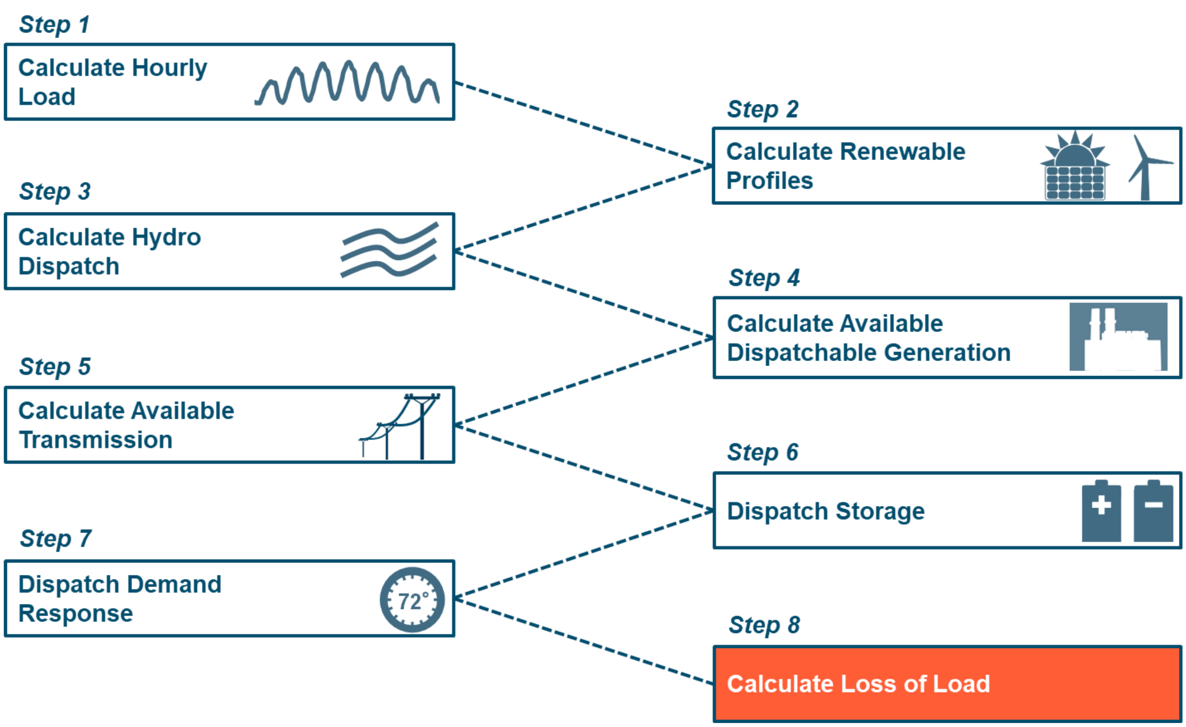
Figure 138. Map of E3 RECAP Projects

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.

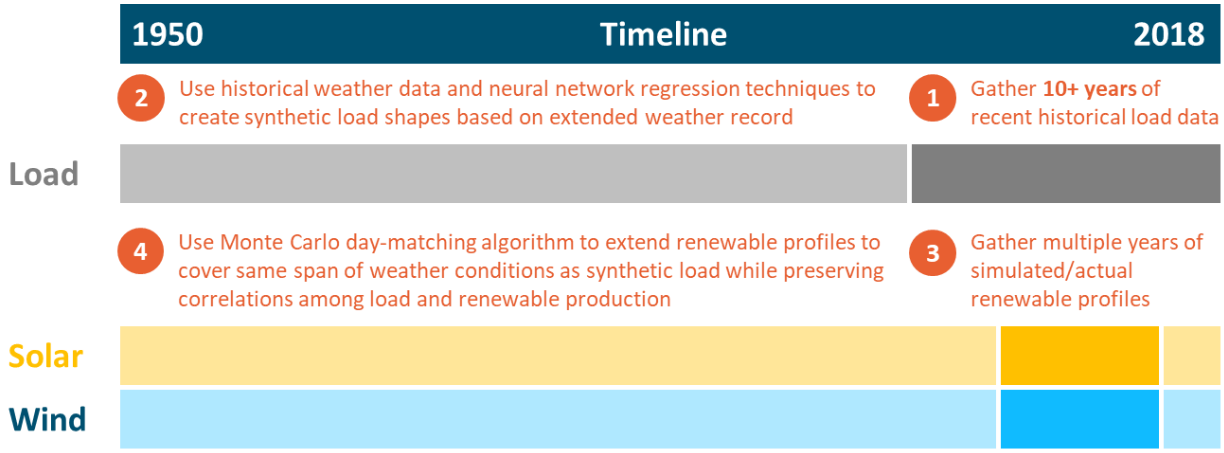


A broad overview of the time-sequential methodology of the model is shown in the diagram below.



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.

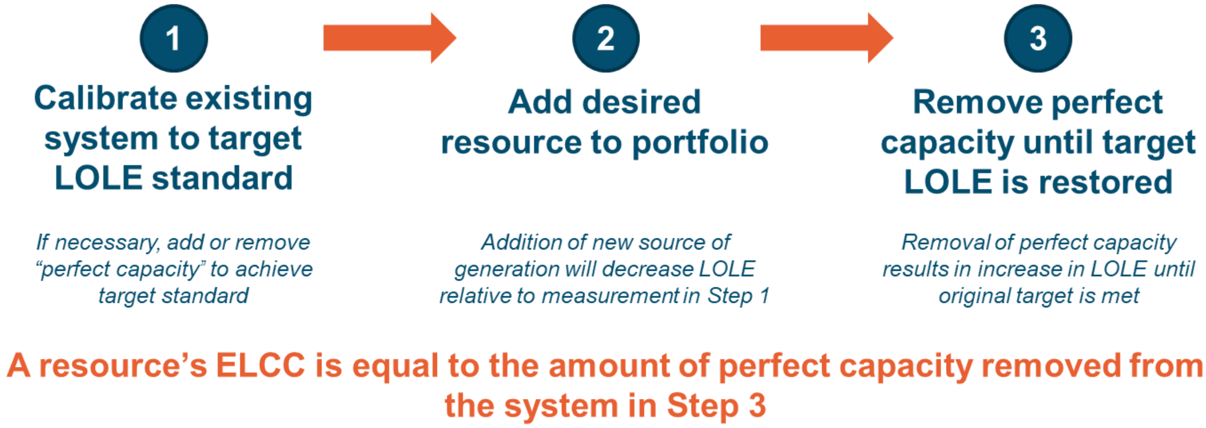
This metric was first introduced in the 1960's as a method of estimating the effect of a change in a conventional unit's capacity or forced outage rate but it has been adapted for evaluating the capacity contribution of variable resources such as wind, solar, and non-dispatchable hydro. ELCC is the most 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

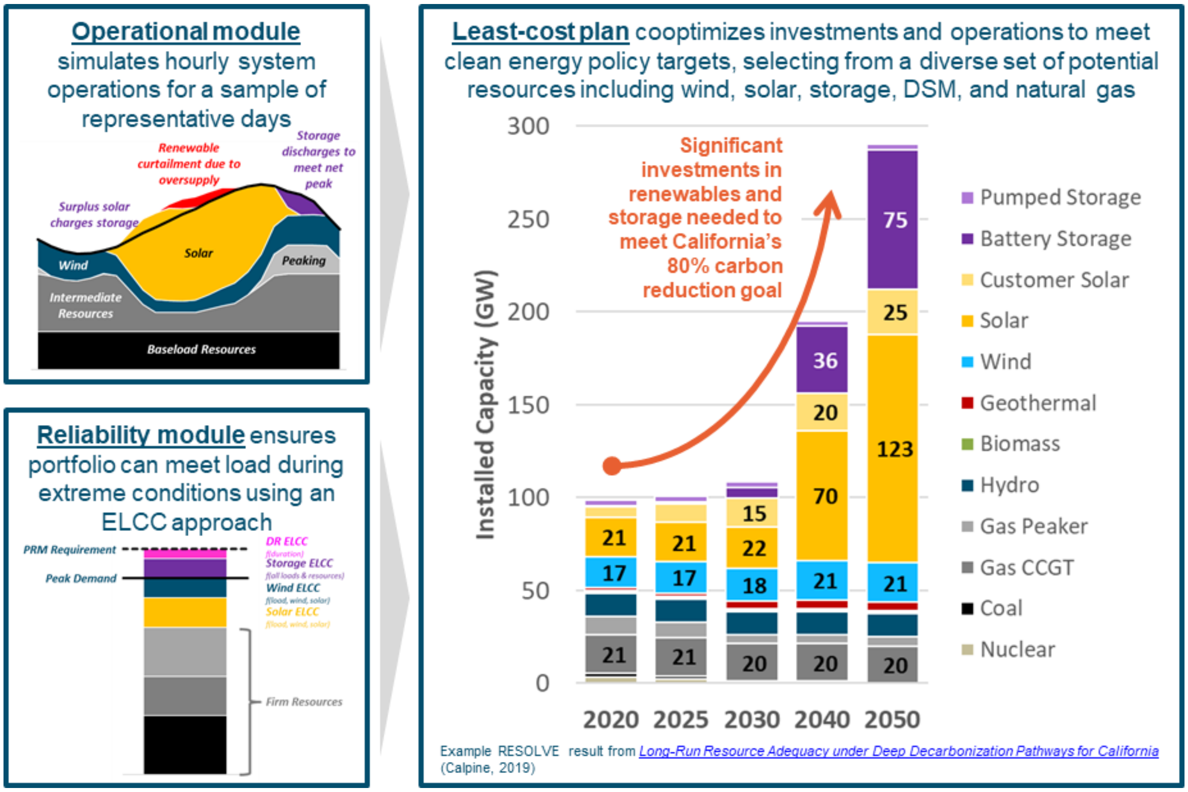


B. RESOLVE Model Methodology

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

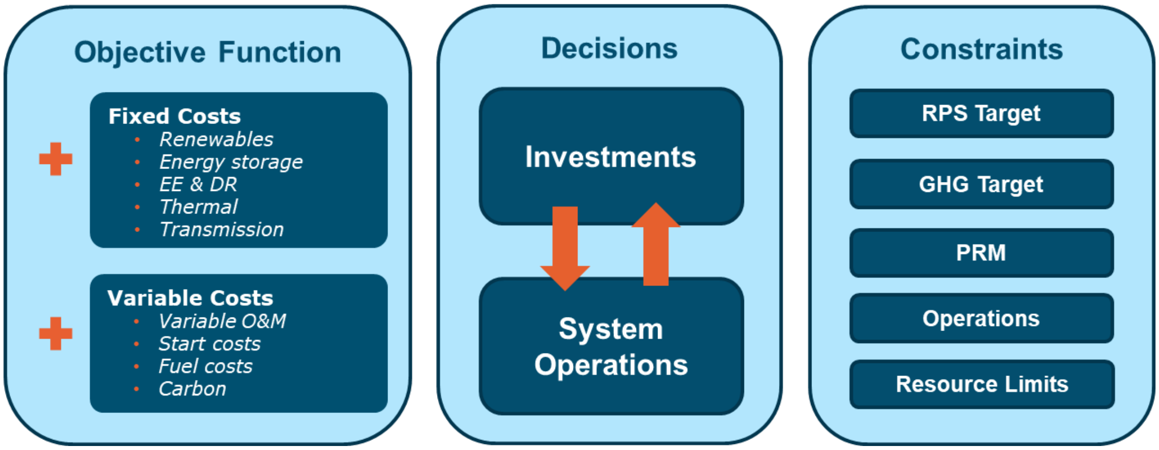


RESOLVE co-optimizes investment and dispatch over a multi-year horizon for a study area. RESOLVE solves for the optimal investments in energy efficiency and renewable resources as well as complementary resources such as new gas plants, gas plant retrofits, demand response, and various energy storage 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.

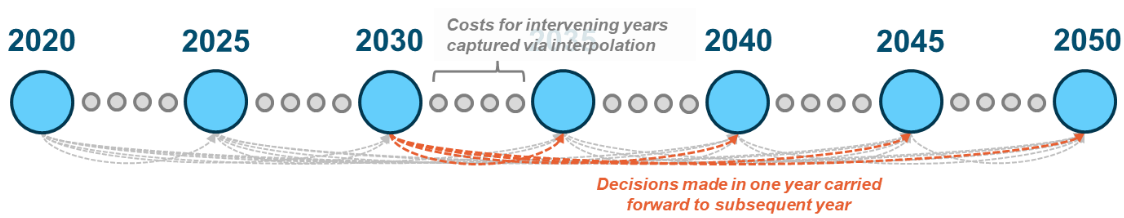
Figure 142. Summary of Key Components of RESOLVE



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.

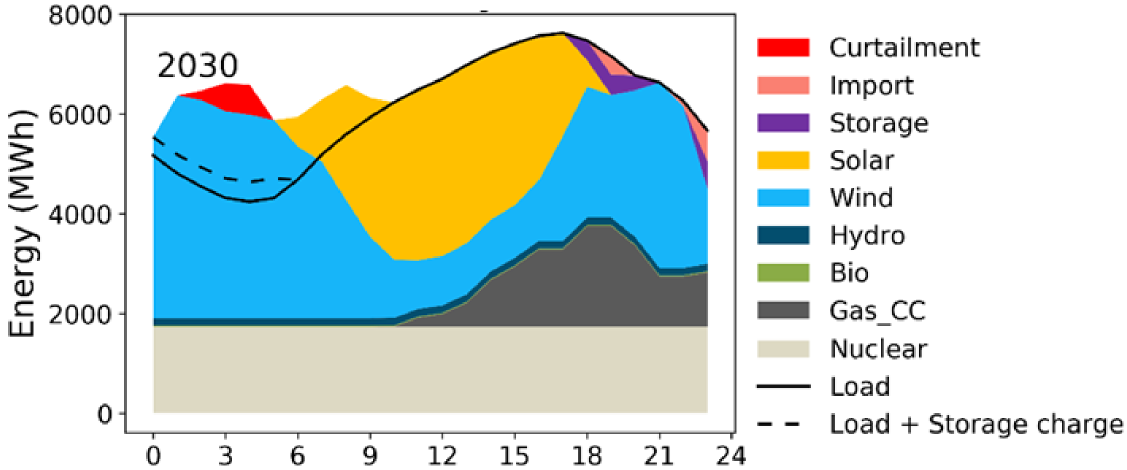
By modeling hourly operations of the electricity system explicitly as part of its optimization, RESOLVE's investment plan is directly informed by the dynamics of system operations and the associated costs to serve load throughout the year. This is especially important for systems with large amounts of 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

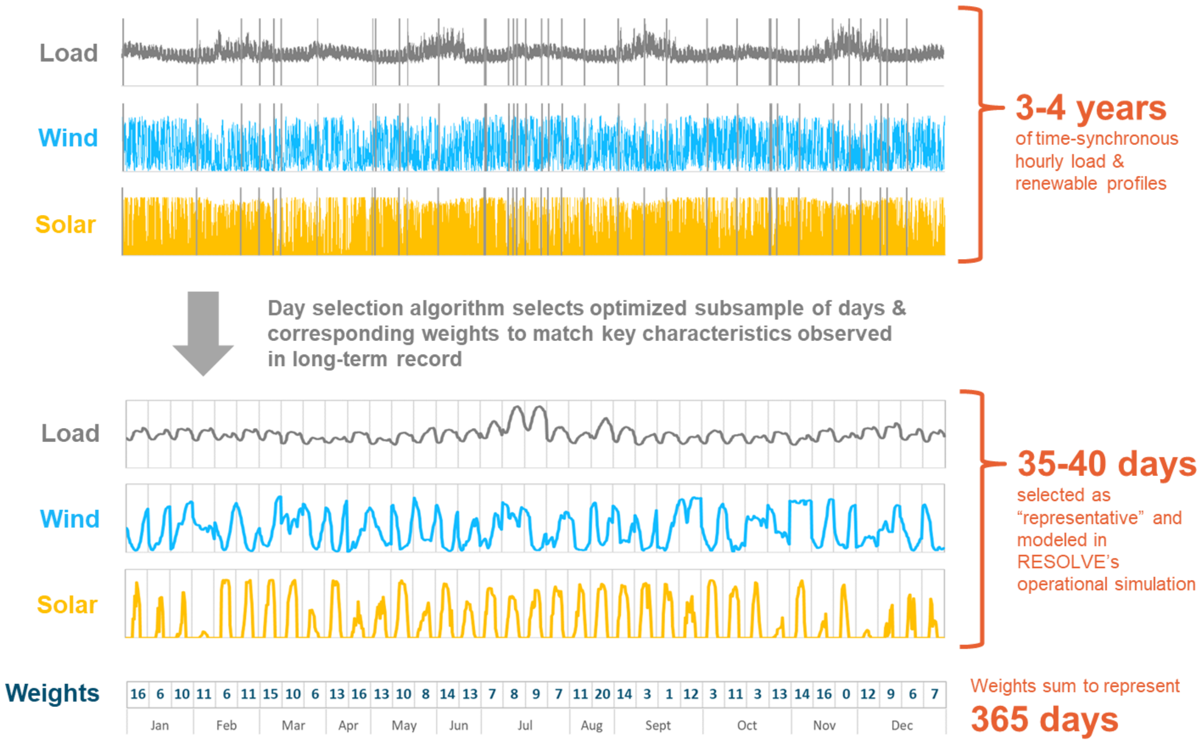


RESOLVE's sample of operating days is selected to match the full distribution of conditions that a system would experience based on multiple years of historical data.

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.

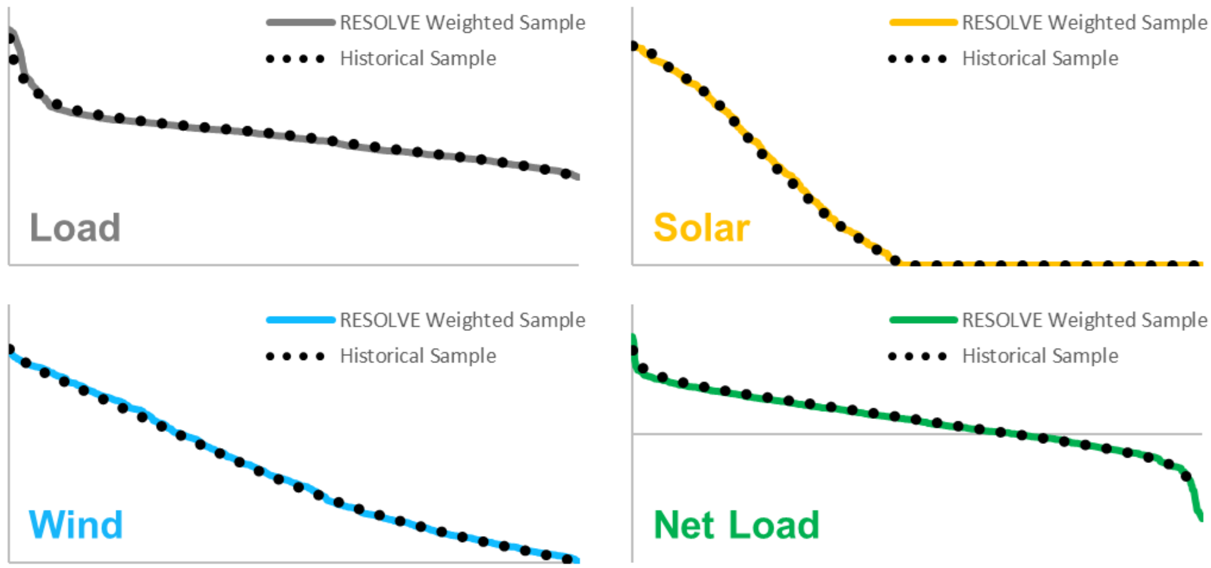
In contrast, RESOLVE uses an optimization algorithm to select a sample of approximately 40 days whose characteristics are broadly representative of the conditions that a system would encounter over the course of multiple years. The day-sampling optimization results in representative days where the correlation 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

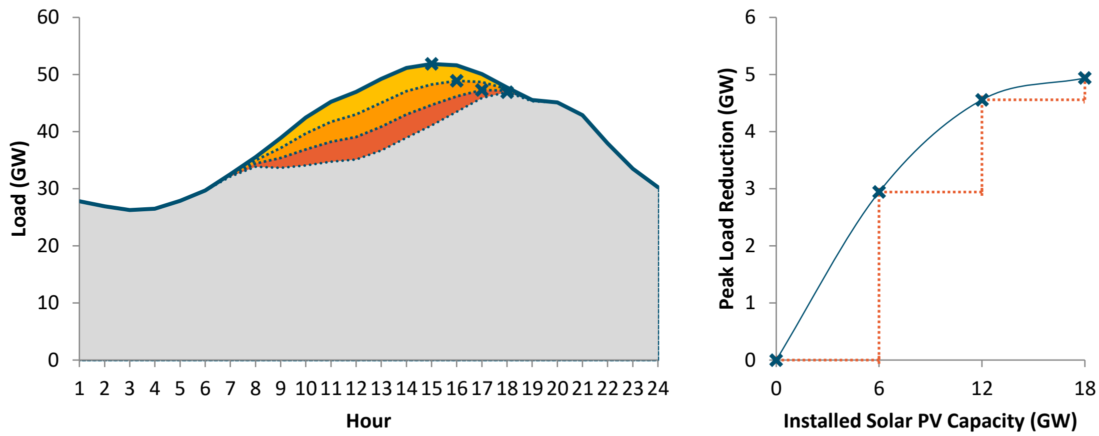


RESOLVE designs each portfolio to meet a system's resource adequacy needs, capturing the declining value of renewables and storage using "effective load carrying capability" (ELCC).

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**