Coal-Free at OPPD

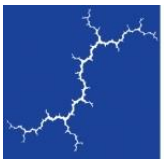
Near-term actions that enable Omaha Public Power District's long-term decarbonization

Prepared for the Sierra Club

December 3, 2021

AUTHORS

Rachel Wilson
Iain Addleton



Synapse
Energy Economics, Inc.

485 Massachusetts Avenue, Suite 3
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

CONTENTS

EXECUTIVE SUMMARY

The Omaha Public Power District (OPPD) is one of many electric utilities in the United States that has committed to reducing carbon dioxide emissions in the coming decades. Like many of these utilities, OPPD has set a target of net-zero carbon dioxide emissions by 2050 and is currently exploring scenarios that examine economy-wide decarbonization through the company's *Pathways to Decarbonization* initiative. As part of this initiative, the utility is conducting modeling and stakeholder engagement that will lay the foundation for achieving that target. OPPD presented its input assumptions, modeling methodologies, and interim results at technical workshops involving stakeholders that occurred throughout 2021. OPPD presented its initial results on October 27, 2021 and plans to present its final results on December 9, 2021. In early 2022, OPPD will also release an Integrated Resource Plan (IRP) that provides the utility's generation changes intended to meet customer demands over the next five years, as required by the Western Area Power Association. OPPD expects that both the stakeholder process and the results of its decarbonization study will inform its 2022 IRP submission.

Synapse Energy Economics (Synapse) was retained by Sierra Club to participate in the stakeholder workshops and to conduct simultaneous modeling that examined additional alternative resource portfolios. Synapse used state-of-the-art electric simulation software to compare the relative cost to ratepayers of continuing OPPD's investments in existing and new fossil-fueled resources versus scenarios that retired coal, reduced reliance on new gas, and developed portfolios of renewables, storage, and energy efficiency.

The Synapse modeling resulted in the following overarching findings:

- First, early investment in energy efficiency is a vital and cost-effective way of mitigating forecasted increases in peak load and annual energy demand.
- Second, early investments that allow OPPD clean energy development partners to capture the economic benefits of the production tax credit and investment tax credit will also allow OPPD to pass the associated cost savings on to customers.
- Third, the two Nebraska City coal units can be retired by 2030 in a way that reduces the overall cost and greenhouse gas emissions associated with OPPD's portfolio.
- Fourth, OPPD may not need both currently planned *Power with Purpose* gas plants slated to enter service in 2023 and 2024—Synapse's no new gas scenarios and scenarios in which only one of the two planned gas units were built proved to be lower cost than building the full 600 MW of planned new gas.
- Fifth, approaches to decarbonization that include the above factors result in financial savings to OPPD customers, including as much as $298 million savings from 2021 to 2035 under a scenario that includes no new gas and retires all coal generation by 2030.

Table 1 presents a summary of the Synapse modeling results. We present various key metrics associated with each scenario, including net present value of revenue requirements of each portfolio for 2021 through 2035. The table presents carbon dioxide emissions and the amount of capacity, by resource type, in OPPD's resource portfolio for 2035.

Table 1: Summary of Synapse modeling results

	Business-As-Usual (BAU)	Standing Bear Only, All Coal Retires	Turtle Creek Only, All Coal Retires	No New Gas, NC 1 Retires in 2025	No New Gas, NC 1 Retires in 2028	No New Gas, All Coal Retires
NPV With EE ($Million)	$9,081	$8,794	$9,074	$8,867	$8,625	$8,783
CO_2 Emissions (million tons)	4.9	1.9	2.2	2.8	2.8	1.7
Utility Solar (MW)	2,225	3,145	2,825	2,965	2,965	3,625
Onshore Wind (MW)	2,006	1,706	1,806	1,706	1,706	1,606
Storage (MW)	556	900	744	864	864	1,004
Gas (MW)	1,688	1,238	1,538	1,088	1,088	1,088
Coal (MW)	1,000	0	0	346	346	0

Coal-fired power plants across the country are facing both rising fuel costs and increasing capital expenditures, and OPPD's coal units are no exception. Meanwhile, the cost of renewable and battery storage resources has declined dramatically over the past decade and is expected to continue to do so. This trend has reached the point where it often costs less to build and run renewables and storage than it does to maintain and operate existing coal units. Renewables and/or storage are currently competing head-to-head with gas-fired combustion turbines and are expected to become more economic than new combined cycle units in the coming years. Investments in renewables and storage also avoid the stranded asset risk that comes with investments in new gas capacity.

As the Synapse modeling shows, a large portion of the emission reductions needed to achieve OPPD's net-zero target can be met far sooner than 2050. Replacing fossil generation with zero-carbon generation leads to dramatic emission reductions on OPPD's system. At the same time, clean energy portfolios are lower-cost than the business-as-usual approach that leans on fossil fuels. OPPD has a viable pathway to its net-zero target, but it requires that OPPD move decisively to retire existing coal, minimize reliance on new gas, and commit to renewables, storage, and demand-side resources. This will reduce emissions, save ratepayers money, and support jobs and investment in Nebraska's clean energy economy.

1. INTRODUCTION

Within the last five years, almost every utility in the United States has made a commitment to reduce its emissions of carbon dioxide (CO_2) from power generation, with some on their second iteration, targeting even greater reductions.[1] In 2018, Xcel Energy, one of the biggest investor-owned utilities in the country, was the first utility to announce a goal to generate 100 percent carbon-free electricity by 2050.[2] Six months later, it also announced that it would close its two remaining coal-fired plants, located in Minnesota, by 2030, putting it on track to be 80 percent carbon-free in that year.[3]

Planning for coal plant closure no later than 2030 is consistent with the scientific consensus that countries across the world should set emissions targets that will limit global warming to no more than 1.5° Celsius. Burning coal is emissions intensive and its continued use is inconsistent with this climate goal. Various studies have shown that this limit will require a global phase-out of uncontrolled (meaning without carbon capture technology) coal-fired electric generators in the United States by the end of 2030.[4]

In January 2020, the Omaha Public Power District (OPPD) set its own emissions reduction target of net-zero by 2050.[5] OPPD hired Energy and Environmental Economics, Inc. (E3) to model various economy-wide decarbonization scenarios and the resulting electricity infrastructure buildout that would be necessary under each of those scenarios. This modeling has taken place over the course of 2021, with various stakeholder workshops held between April and November to describe modeling inputs, develop planning assumptions, solicit feedback, and present interim results.

Fossil-fueled power plants remain prominent in E3's interim modeling in the near term. OPPD's Nebraska City Units 1 and 2 do not retire outright before 2030 in E3's modeling, but rather are repowered with gas between 2030 and 2045. As a result, coal generation in E3's *Net-Zero Balanced* scenario actually increases between 2027 and 2030. While coal generation then decreases, it makes up more than 13 percent of OPPD's generation mix in 2035. Gas capacity increases due to coal repowering

[1] Adler, Kevin. May 19, 2020. *Net-zero pledges by US utilities spotlight different timelines, benchmarks.* IHS Markit. Available at: https://ihsmarkit.com/research-analysis/netzero-pledges-by-us-utilities-spotlight-different-timelines-.html.

[2] Xcel Energy. December 4, 2018. *Xcel Energy aims for zero-carbon electricity by 2050.* Available at: https://mn.my.xcelenergy.com/s/about/newsroom/press-release/xcel-energy-aims-for-zero-carbon-electricity-by-2050-20Y2R0000008QTQUA2.

[3] Xcel Energy. May 20, 2019. *Xcel Energy to end all coal use in the Upper Midwest.* Available at: https://mn.my.xcelenergy.com/s/about/newsroom/press-release/xcel-energy-to-end-all-coal-use-in-the-upper-midwest-20Y2R0000008QQWUA2.

[4] Climate Analytics. September 2019. *Global and regional coal phase-out requirements of the Paris Agreement: Insights from the IPCC Special Report on 1.5oC.* Available at: https://climateanalytics.org/media/report_coal_phase_out_2019.pdf.

[5] Costello, Becca. January 6, 2020. *Omaha Public Power District Commits to Net-Zero Target by 2050.* Nebraska Public Media. Available at: https://nebraskapublicmedia.org/en/news/news-articles/omaha-public-power-district-commits-to-net-zero-carbon-by-2050/.

and new gas builds in 2023, 2024, and in the late 2030s. In E3's *Net-Zero Balanced* scenario, this results in gas generation making up just over 17 percent of OPPD's total in 2035.

Despite the increase in coal and gas generation at various points in the *Net-Zero Balanced* scenario, E3 expects OPPD's emissions to decrease in linear fashion between 2021 and 2050. This seems to be accomplished by virtue of exporting clean energy to the broader SPP market, which is then counted as an emissions reduction for OPPD. In E3's modeling, the amount of emission reductions credited to OPPD by virtue of exports increases over time.[6] However, as the rest of SPP decarbonizes, renewable generation exported from OPPD is less likely to displace fossil generation and therefore may not lead to the emission reductions that are currently credited to OPPD in the *Pathways to Decarbonization* study. While OPPD's full modeling results are not yet available, allowing coal and gas generation to increase into the 2030s is not an intuitive way to achieve decarbonization. Our modeling fills this gap by exploring certain dynamics omitted from the utility's existing modeling. This includes earlier coal retirements without repowering, a reduced amount of planned new gas, and additional no new gas scenarios.

Synapse used a number of the OPPD/E3 inputs assumptions to follow the utility's own modeling as much as possible. As Sierra Club and Synapse attended OPPD's stakeholder workshops, we checked our results and adjusted inputs to analyze alternative scenarios and portfolios. While we attempted to keep many of the model inputs between our work and OPPD's work consistent, there were certain fundamental differences in our approach to electricity system modeling. E3 and OPPD, for example, conducted modeling through 2050, modeled the entirety of the Southwest Power Pool (SPP), and examined economy-wide decarbonization. By contrast, Synapse modeled through 2035, only modeled OPPD's service territory (allowing for a limited number of energy imports at a price of $500/MWh) and limited our analysis to the decarbonization of OPPD's system rather than economy-wide. Additional differences, including the different capacity expansion models used by OPPD and Synapse, are described in Section 2 of this report as well as in Appendix A.

[6] Omaha Public Power District. October 27, 2021. *Workshop 5 Slides: Energy Portfolio Initial Results.* Available at: https://www.oppdcommunityconnect.com/pathways-to-decarbonization-workshops.

Near-Term Load Growth and Data Centers

One of the most important features of any energy system model is the load and peak forecast. All energy and peak forecasts in OPPD's data release increase between 2021 and 2025. In the Reference load forecast, annual load increases 33.5 percent and annual peak increases by 16.1 percent between 2021 and 2025. OPPD's *Pathways to Decarbonization* study is thus taking place against the backdrop of both near-term energy and capacity needs.

The rapid growth in OPPD's energy and peak forecasts is driven by new data centers from large technology companies like Facebook and Google. Data centers are some of the most energy-intensive energy consumers, using between 10 and 50 times as much energy per square foot as commercial office buildings. The high level of energy use is driven by round-the-clock operations, the information technology equipment, and the need to cool the equipment while in use. In total, data centers are estimated to result in nearly as many emissions each year as the entire airline industry.

While data centers have become more efficient over time, the sheer increase in the world's use of digital services means that energy usage from data centers is projected to increase. This dynamic is already evident in OPPD's service territory, as the utility points to new data centers as the reason for the escalating load forecasts.

This reveals a fundamental disconnect between OPPD and the companies that build and operate data centers. Many technology companies have set decarbonization targets that include the need for data centers powered by clean energy. While this has previously been accomplished by purchasing carbon offsets, companies like Google now aim to achieve 24/7 carbon-free energy by 2030 (See https://sustainability.google/progress/energy/). OPPD is using the load increase from data centers to justify investments in new fossil units powered by gas; however, this choice is incompatible with the utility's own decarbonization goal and works against technology companies that are targeting 24/7 carbon-free energy.

A key difference between the Synapse analysis and the one done by E3 is that our modeling included various combinations of no new gas builds, limited new gas builds, and early coal retirements that were not present in OPPD's existing model scenarios. OPPD is currently planning for two new gas units in the next three years as part of its *Power with Purpose* initiative: the 150 MW Standing Bear plant consisting of nine reciprocating engines and coming online in 2023, and the Turtle Creek plant, which will bring 450 MW of new combustion turbines online in 2024.[7] The decision to invest in these two gas plants are fixed in OPPD's modeling—that is, OPPD has chosen not to model scenarios that do not include these new gas plants. While Synapse did model a *Business-As-Usual (BAU)* scenario that built these new gas plants, we also modeled scenarios in which OPPD builds only one of the two plants and scenarios in which it builds none of the planned gas. The goal of our modeling efforts was not to select a new portfolio for OPPD. In fact, this would have been impossible given the differences between the modeling scope of OPPD and Synapse. Instead, our goal was to explore certain key parameters in greater detail and develop an independent set of themes and lessons learned that could be used to benefit OPPD's stakeholder process and upcoming Integrated Resource Plan (IRP).

[7] Omaha Public Power District. June 16, 2021. *June 2021 Data Release Version 2.* Available at: https://www.oppdcommunityconnect.com/pathways-to-decarbonization-workshops.

A comparison of the scenarios shows four important points. First, early investment in energy efficiency is a vital and cost-effective way of mitigating forecasted increased in energy and peak demand. The addition of lower cost demand-side resources avoids more expensive supply-side resources, to the benefit of OPPD customers.

Second, early investments in renewable energy allow OPPD to offset the emissions that might be associated with increasing load by meeting at least a portion of that demand with renewable energy. These early investments that allow OPPD clean energy development partners to capture the economic benefits of the production tax credit (PTC) and investment tax credit (ITC) will also allow OPPD to pass the associated cost savings on to customers.

Third, the two Nebraska City coal units can be retired before 2030 in accordance with scientific evidence that coal-fired power plants in the United States should be phased out by that date. If allowed to run unconstrained in the model, the coal units' output stays relatively constant over time. This is because the renewables added over the analysis period go toward meeting increased load, and not toward the displacement of existing fossil generation. Under current market conditions, imposing no emissions constraints, the cessation of coal burning at the Nebraska City units is the fastest way for OPPD to lower CO_2 emissions.

Fourth, OPPD should reevaluate its need for both currently planned *Power with Purpose* gas plants slated to enter service in 2023 and 2024. Synapse's no new gas scenarios and scenarios in which only one of the two planned gas units were built proved to be lower cost than building the full 600 MW of planned new gas. OPPD's net-zero emissions target will require investments in energy efficiency, renewable generation, and storage. The cost of renewable resources has declined dramatically over the past decade and is expected to continue to do so. This trend has reached the point where it costs less to build and run renewables and storage than it does to maintain and operate existing coal units. In fact, renewable resources are now competing head-to-head with gas-fired combustion turbines and are expected to become more economic than new combined cycle units in the coming years. Investments in renewables and storage also avoid the stranded asset risk that comes with investments in new gas capacity. OPPD's net-zero target, and the possibility of federal carbon legislation, raises the risk that new gas plants—like those OPPD plans to build—could become stranded assets and burden ratepayers with long-term costs for unnecessary infrastructure.

Lastly, our results show that the early retirement of Nebraska City Unit 1 and Unit 2, along with reductions in the amount of planned new gas-fired capacity, results in savings to OPPD ratepayers over the 2021–2035 analysis period. OPPD's *Power with Purpose* plan was announced at the end of 2019, meaning that the input assumptions and forecasts that underlie the resource plan are now two years out of date. Under our updated input assumptions, renewables and storage provide a more cost-effective option for meeting customer demand while also reducing emissions. While fossil-fired capacity can, under certain circumstances with high penetrations of renewable resources, be relied upon to maintain reliability, OPPD has not yet demonstrated that the Turtle Creek and Standing Bear plants are needed for that purpose. OPPD should conduct updated modeling that seeks to retire existing coal-fired units prior to 2030 while also minimizing the construction of planned gas resources.

We describe the modeled scenarios in more detail in the next sections, including the input assumptions that differentiate those scenarios. For each scenario, we present capacity additions, generation, and CO_2 emissions, along with a comparison of the revenue requirements associated with each scenario. Finally, we present more detail on input assumptions in Appendix A.

2. SCENARIO ANALYSIS

Synapse used the EnCompass capacity expansion and production cost model, licensed from Anchor Power Solutions, to examine a number of different alternative resource portfolios in the 15-year period from 2021 to 2035. [8] The EnCompass model uses information about forecasted peak and energy demand along with the capital and operating costs of existing and new resources to produce an optimal, least-cost resource portfolio and generation mix. Specifically, the model does the following: (1) builds new resources when necessary to meet peak demand, plus a required reserve margin; (2) simulates economic dispatch of the various generating resources; and (3) calculates the total cost (capital and operating) of the respective resource portfolio options.

Synapse modeled six different scenarios, which vary the amounts of fossil-fueled capacity in OPPD's resource portfolio. In the *BAU* scenario, OPPD's coal-fired Nebraska City units remain in operation throughout the analysis period. Additional gas-fired and solar capacity that OPPD plans to bring online between now and 2024 is included as part of the company's resource portfolio. The EnCompass model calculates the costs to operate these existing and planned resources and adds additional resources as necessary over the analysis period to meet peak and annual energy requirements.

The remaining five scenarios presented in this report include varying amounts of existing coal capacity and new, planned gas. Those gas additions and coal retirement dates are shown, by scenario, in Table 2.

[8] Capacity and production cost models like EnCompass are used to simulate future utility operations under different scenarios to help determine the best strategy for minimizing costs and risks while meeting specific reliability and transmission constraints.

Table 2. Coal and gas capacity under the Synapse scenarios

	Business-As-Usual (BAU)	Standing Bear Only, All Coal Retires	Turtle Creek Only, All Coal Retires	No New Gas, Acc. NC 1 Retirement	No New Gas, NC 1 Retires	No New Gas, All Coal Retires
New Gas 2023/2024	600 MW	150 MW	450 MW	None	None	None
NC 1 Retirement	N/A	2028	2028	2025	2028	2028
NC 2 Retirement	N/A	2030	2030	N/A	N/A	2030

Business-As-Usual:

The *BAU* scenario uses a number of input assumptions from OPPD and E3's data release. Specifically, the *BAU* scenario assumes the following:

- Reference peak load and annual energy from 2021 to 2035 from the OPPD/E3 data release.
- Retirement of North Omaha Units 1-3 and conversion of North Omaha Units 4 and 5 from coal to gas on 12/31/2023.
- Addition of the planned 150 MW Standing Bear gas-fired facility in 2023 and the 450 MW Turtle Creek gas-fired facility in 2024.[9]
- Addition of 228 MW of planned solar photovoltaic resources in 2023, increasing to 419 MW in 2025.
- Resource capital and operating costs for new combined cycle, combustion turbines, standalone solar, standalone battery storage, and onshore wind.
- A system reserve margin of 12 percent.
- Coal price forecast from the U.S. Energy Information Administration's (EIA) *Annual Energy Outlook 2021*.

In addition to the inputs taken from the OPPD data release, Synapse added the following input assumptions to the *BAU* scenario:

- Annual capital expenditures were added for each of the coal units based on a regression equation developed by Sargent & Lundy for the U.S. EIA's *2019 Annual Energy Outlook*.
- A gas price forecast that consists of NYMEX futures (short-term) and prices from the AEO 2021 Reference case (long-term).

[9] Although OPPD announced its intention for both plants to commence operations in 2023, the OPPD/E3 data release lists the online date for the Turtle Creek facility as 2024.

- Firm capacity values for new renewables and storage were based on effective load carrying capability (ELCC) and set as a fixed value of 95 percent for storage, 50 percent for solar, and 10 percent for wind based on the ELCC study conducted by Astrapé Consulting for the SPP.[10]

- Rather than modeling the entirety of the SPP market over the 15-year analysis period, Synapse modeled OPPD's service territory on a standalone basis, with limited volumes of import energy priced at $500/MWh and escalating at inflation.

- A price on CO_2 emissions of $5/ton (nominal) starting in 2025 and escalating by $5/ton each year. This emissions price is intended to be a proxy for as-yet-unknown future CO_2 regulations at either the federal or state level.

Synapse Alternative Scenarios:

The five alternative scenarios include the input assumptions listed above for the BAU scenario, with the following changes:

- Additional energy efficiency savings that increase by 0.10-0.15 percent per year until they reach 2 percent, and then are held constant. This results in peak demand savings of 50 MW and annual energy savings of 1,725 GWh by 2035.

- A carbon constraint that reduces CO_2 emissions by 50 percent from 2021 to 2030 on a linear trajectory.

- The number of new gas builds and timing of existing coal retirements, which varies between scenarios as shown in Table 2.

Additional details on input assumptions and modeling methodology are provided in Appendix A.

3. ELECTRIC SECTOR MODELING RESULTS

Synapse used the EnCompass model to produce optimal, least-cost resource portfolios under different scenarios based on the detailed capacity expansion and electric system dispatch modeling of OPPD's service territory. This section describes the results of that modeling with respect to the changing capacity mix and resulting electricity generation in the modeled scenarios. Individual results are not shown for all scenarios; instead, we discuss capacity and generation for specific scenarios only.

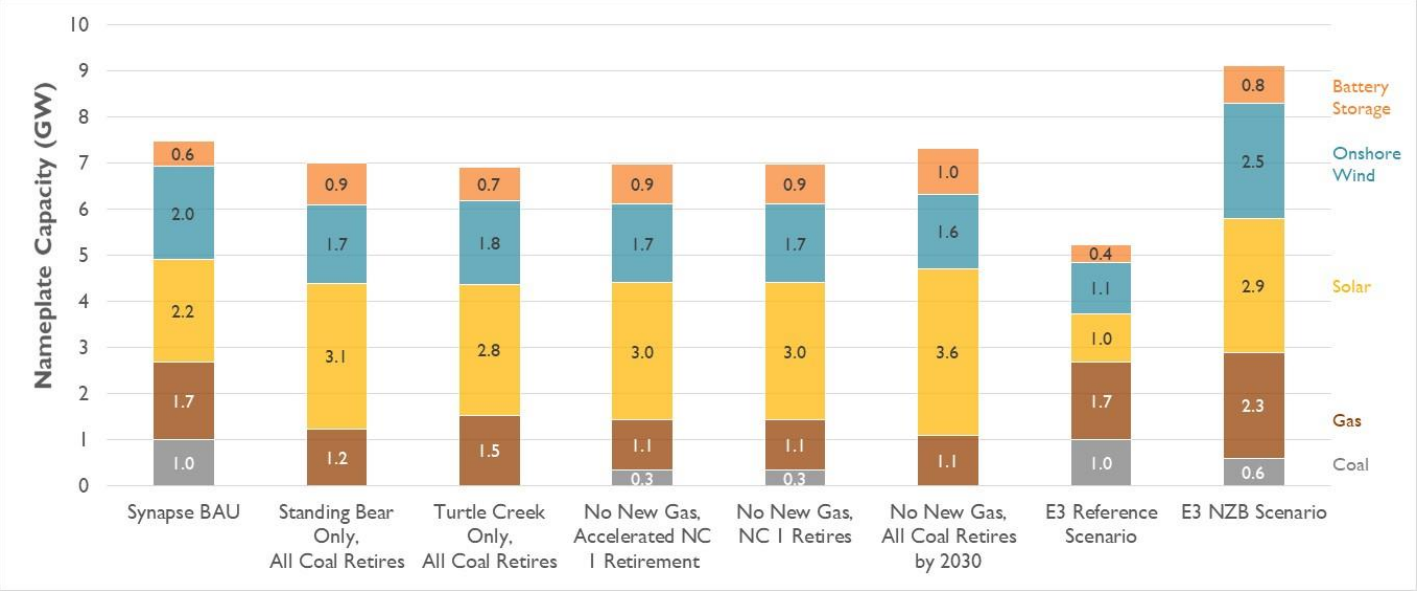
[10] Astrapé Consulting. November 1, 2021. *SPP Energy Storage Study Final Report.* Available at: https://www.spp.org/spp-documents-filings/?id=208065; Astrapé Consulting. August 13, 2021. *2020 ELCC Wind and Solar Report.* Available at: https://www.spp.org/spp-documents-filings/?id=168293.

3.1. Capacity Results

OPPD's capacity mix in 2020 was dominated by fossil-fueled generating units—coal, gas, diesel, and oil—which made up 72 percent of the resource portfolio. Renewables—hydro, wind, solar, and landfill gas—made up the remaining 28 percent. Wind resources made up the bulk of the renewable capacity on OPPD's system.

Renewable capacity grows, however, over the duration of the analysis period in all the Synapse scenarios, including the *BAU*. Figure 1 illustrates the nameplate capacity for each scenario in 2035. It also includes estimated results from two of the OPPD/E3 scenarios – the E3 *Reference* scenario and the E3 *Net-Zero Balanced* scenario. Note that the results provided for the E3 modeled scenarios are estimates based on charts provided in stakeholder workshops, rather than exact values,[11] and are presented only for the sake of a general comparison. The additional capacity shown in E3's *Net-Zero Balanced* scenario is a result of the increased peak demand coming from projected electrification.

Figure 1: Nameplate capacity in 2035



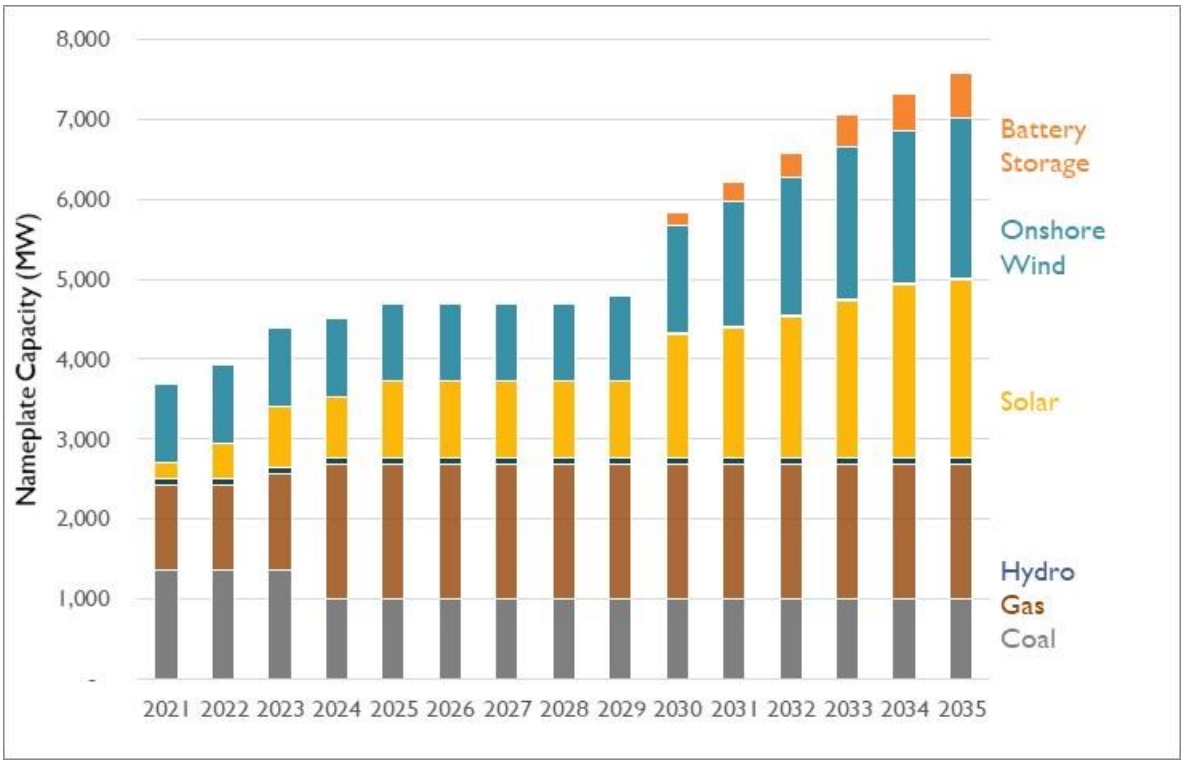
The most noticeable difference between the Synapse scenarios is the volume of fossil resources in 2035, with a minimum of 1.1 GW (*No New Gas, All Coal Retires*) and a maximum of 2.7 GW (BAU). These variations are due to the amount of planned gas-fired additions that are avoided in each scenario and the amount of existing coal that is retired. These resources are replaced by a combination of wind, solar, and battery storage. Each of the Synapse scenarios contains between 4.2 GW and 5.2 GW of wind and solar capacity, with greater increases found in scenarios that have fewer remaining fossil resources. Battery storage additions range between 0.6 GW and 1.0 GW by 2035.

[11] OPPD/E3 results were estimated from the stakeholder workshop slides using WebPlotDigitizer, available at https://automeris.io/WebPlotDigitizer/.

The increased energy efficiency included in the Synapse scenarios reduces peak load by approximately 50 MW in 2035, meaning that OPPD needs less firm capacity to meet system peak load than in the *BAU* scenario. This is particularly important given the relative capacity contributions of different resources and our intention in this analysis to decrease OPPD's reliance on fossil-fueled resources. Coal and gas-fired generators are fully dispatchable in a given hour and typically contribute 100 percent of their capacity toward the utility's required reserve margin. Renewable generators operate intermittently and thus a smaller percentage of their nameplate capacity is counted as firm capacity and contributes to reserves. This firm capacity rating often decreases as penetrations increase. The 50 MW decrease in peak load that is attributable to increased energy efficiency measures would allow OPPD to avoid investment in 50 MW of replacement gas resources or would allow it to avoid investment in 100 MW of replacement solar (assuming a 50 percent firm capacity rating). Given that these supply-side resources are often more expensive than energy efficiency programs, this results in savings to OPPD customers.

Annual capacity additions in the Synapse *BAU* are shown in Figure 2. The planned *Power with Purpose* solar and gas resources are added in the early years of the analysis period along with some additional generic solar. In 2030, when the price adder on CO_2 emissions reaches $25/ton, the EnCompass model finds it economic to add wind, solar, and battery storage resources to displace a portion of the generation from existing coal and gas resources. EnCompass continues to add incremental amounts through the end of the analysis period.

Figure 2: Nameplate capacity by year, BAU scenario



In the figures below, we present the capacity expansion plan for two of the five alternative scenarios. Figure 3 shows capacity by year in the *No New Gas, All Coal Retires* scenario. In this scenario, OPPD does

not add any of the planned 600 MW of new gas additions. Instead, the model adds a block of new solar early in the planning period as well as a small amount of new battery storage. Solar capacity stays constant until the retirement of Nebraska City Unit 1 occurs and the model needs additional replacement energy. Battery storage grows annually however, providing firm capacity as load grows and to redistribute renewable generation to better match solar and wind output with demand. Larger blocks of wind, solar, and storage are needed again when Nebraska City Unit 2 retires at the end of 2030.

Figure 3: Nameplate capacity by year, *No New Gas, All Coal Retires*

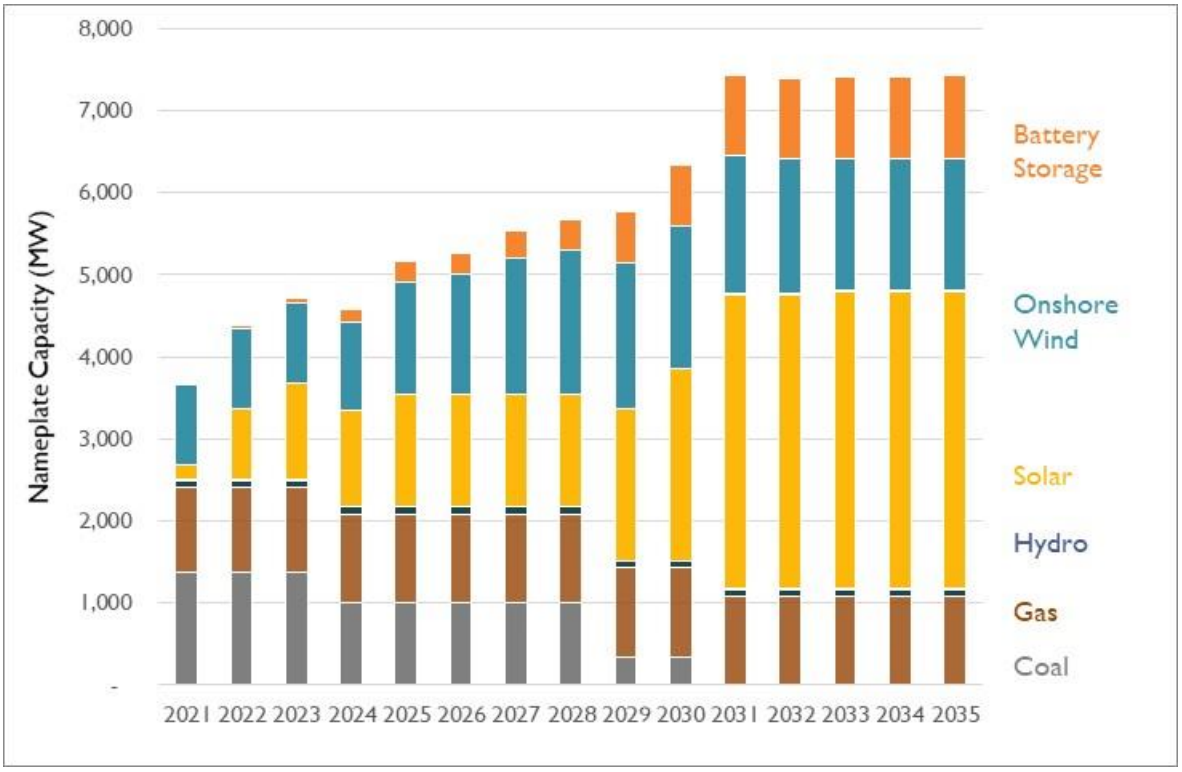
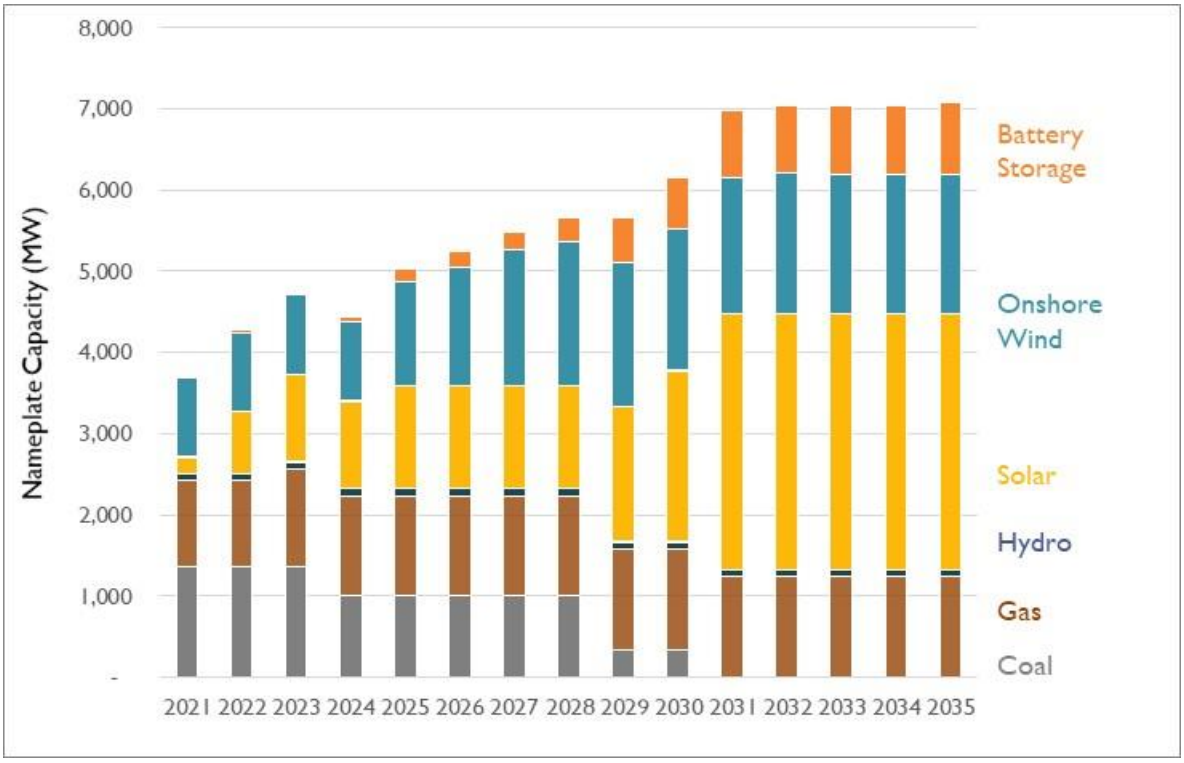


Figure 4 shows capacity by year in the *Standing Bear Only, All Coal Retires* scenario. In this scenario, OPPD adds only 150 MW of planned new gas in 2023—the Standing Bear reciprocating engines. Nebraska City Unit 1 is retired in 2028 and Unit 2 is retired in 2030. The new gas allows a deferral of some of the new renewable capacity until later in the analysis period; however, by 2035 the volumes of wind and solar are very similar between scenarios. In the later years, capital costs for wind, solar, and battery storage have come down substantially, and it becomes less expensive to build new renewables than to operate existing gas. From a firm capacity perspective, the trade-off is between gas-fired capacity and new battery storage resources. The *No New Gas, All Coal Retires* scenario has a higher amount of battery storage and builds storage earlier than those scenarios that include OPPD's planned gas, either in full or in part.

Figure 4: Nameplate capacity by year, Standing Bear Only, All Coal Retires



While OPPD did consider battery storage resources when developing *Power with Purpose*, the utility ultimately did not select any amount of storage in its preferred portfolio.[12] This is an oversight that could prove costly to OPPD ratepayers, as costs for battery storage continue to fall at the same time the technologies improve. According to a recent report by the EIA, average battery storage capital costs fell by 72 percent between 2015 and 2019, with a rate of decline of 27 percent per year, and supporting more capacity to store energy.[13] The EIA also stated its belief that, based on the planning data it collects, current structural change in U.S. power markets "will result in the installation of large-scale battery storage to contribute 10,000 MW to the grid between 2021 and 2023—10 times the capacity in 2019."[14]

OPPD's planned gas units (reciprocating engines at its Standing Bear facility and combustion turbines at Turtle Creek) are intended to serve peaking needs and are not expected to serve load over long durations. In fact, OPPD placed limits on the annual operations of its proposed gas units when it applied for permits before the Nebraska Department of Environment and Energy.[15] The short-duration operating profile makes the proposed gas units good candidates for replacement by storage resources. Analysis by GTM Research and Wood Mackenzie predicted that energy storage technologies will regularly compete head-to-head with new gas-fired peaking units by 2022, and that new gas-peaking units will be rare by 2028.[16] OPPD customers would likely realize cost savings if the utility were to replace some or all of its planned gas capacity with battery storage resources, and the utility should investigate the use of new storage, and new storage coupled with new renewables, in lieu of these planned gas investments.

From a resiliency perspective, battery storage can also be a valuable resource. Batteries provide far faster and more accurate response than gas generators to moment-to-moment fluctuations in supply and demand. They can also provide black-start service if they are outfitted with grid-forming inverters that can set their own frequency and voltage signal. This means they can be called upon to help restore the power system in the event of a widespread outage. When outfitted in this way, batteries have a strong potential for use as black-start resources because of their small modular size and extremely fast response, ramping from full charge to full discharge output in seconds or less in response to dispatch signals. In contrast, even quick-start gas generators typically take nearly 10 minutes to start and ramp up to full load.

In areas with high volumes of renewable generation, batteries have the unique ability to absorb excess renewable output by charging, which gas and conventional generators cannot do. Because of their modularity and smaller footprint, batteries can be located near renewable generators to absorb excess output that would have been curtailed, and then release that output later when transmission capacity is available. In contrast, inflexible fossil generators tend to increase renewable curtailment, as these resources cannot change their level of output as quickly and often have high minimum output levels.

---

[12] OPPD. October 15, 2019. *Power with Purpose: Continuing Our Journey.*

[13] U.S. EIA. August 2021. *Battery Storage in the United States: An Update on Market Trends*. Page 2. Available at: https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage_2021.pdf.

[14] Id. Page 1.

[15] The nine Standing Bear units are limited to 19,800 operating hours per year when firing gas, and 4,860 operating hours per year when firing fuel oil. See: OPPD. Air Quality Construction Permit Application. Standing Bear Lake – FID TBD. Omaha Nebraska. July 2021. The two Turtle Creek units are limited to 3,200 operating hours per year when firing either gas or fuel oil. See: OPPD. Air Quality Construction Permit Application. Turtle Creek Station – FID 116017. Omaha Nebraska. August 2021.

[16] Ravi Manghani. March 1, 2018. "Will Energy Storage Replace Peaker Plants?" *GreenTech Media*. Available at: https://www.greentechmedia.com/webinars/webinar/will-energy-storage-replace-peaker-plants.

3.2. Generation Results

From a generation perspective, the five alternative Synapse scenarios look very similar to each other. Figure 5 illustrates the generation mix for each scenario in 2035. As in the capacity results, the figure includes the estimated results from two of the OPPD/E3 scenarios—the E3 *Reference* scenario and the E3 *Net-Zero Balanced* scenario. Note again that the *Net-Zero Balanced* scenario uses a much higher load forecast, and so the percentage numbers shown in Figure 5 represent a higher number of megawatt-hours than do the percentages in the other scenarios under the Reference load.

Figure 5: Generation mix in 2035

Generation from fossil resources in the Synapse *BAU* scenario is just under 26 percent but falls to just under 18 percent or less in each of the five alternative scenarios. In each of the alternative scenarios, solar and wind generation are quite similar as a percent of the generation mix. The exception is the *No New Gas, All Coal Retires* scenario, which has less fossil capacity and thus greater battery storage. In this scenario, the model finds it more economic to add an increased amount of solar generation relative to the amount of wind.

Annual generation for specific scenarios is shown in Figure 6 through Figure 8. In the *BAU* scenario, shown in Figure 6, generation from coal dips when the North Omaha Units 4 and 5 are converted from coal to gas, and begins a gradual decline in 2030 as a result of CO_2 emissions prices increasing such that it becomes less expensive to add new renewable generation than to run existing coal units. A steep decline in gas generation also begins in 2030.

Figure 6: Generation by year, BAU scenario

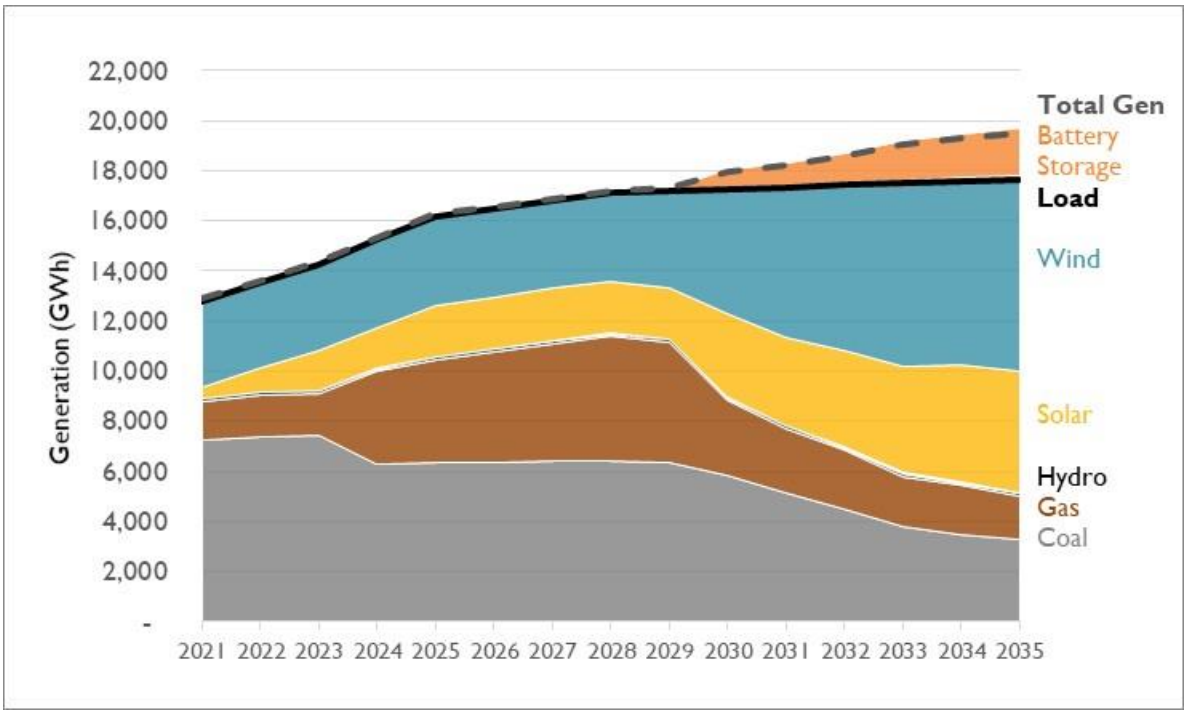


Figure 7 shows annual generation under the *No New Gas, All Coal Retires* scenario. Under the additional emission constraint layered into the Synapse alternative scenarios, generation from coal declines between 2021 and 2030, when Nebraska City Unit 2 is retired. Gas generation sees a slight uptick when the North Omaha Units 4 and 5 are converted to gas, but otherwise remains constant. Wind generation increases in 2024, but the biggest gain is in solar generation upon the retirement of Nebraska City Unit 2. The release of energy from battery storage is shown above the load line, as the batteries store energy in hours in which there is a surplus and discharges that energy in hours in which it is needed.

The effects of increased energy efficiency can be seen when we compare Figure 6 with Figure 7. In the *BAU* scenario, the annual energy demand, shown as the black line labeled "Load," is growing at a faster rate and reaches almost 18,000 GWh by 2035. In contrast, the annual energy demand in the *No New Gas, All Coal Retires* scenario is flatter after 2025 and is just under 16,000 GWh in 2035. Avoidance of the need for additional energy generation through more cost-effective energy efficiency saves money for OPPD customers. Our energy efficiency assumptions are described in more detail in Appendix A. Additional benefits, beyond what Synapse has modeled in this analysis, would accrue to customers if OPPD were to implement programs that achieve greater savings in the years prior to 2025 than those we have included here.

Figure 7: Generation by year, *No New Gas, All Coal Retires*

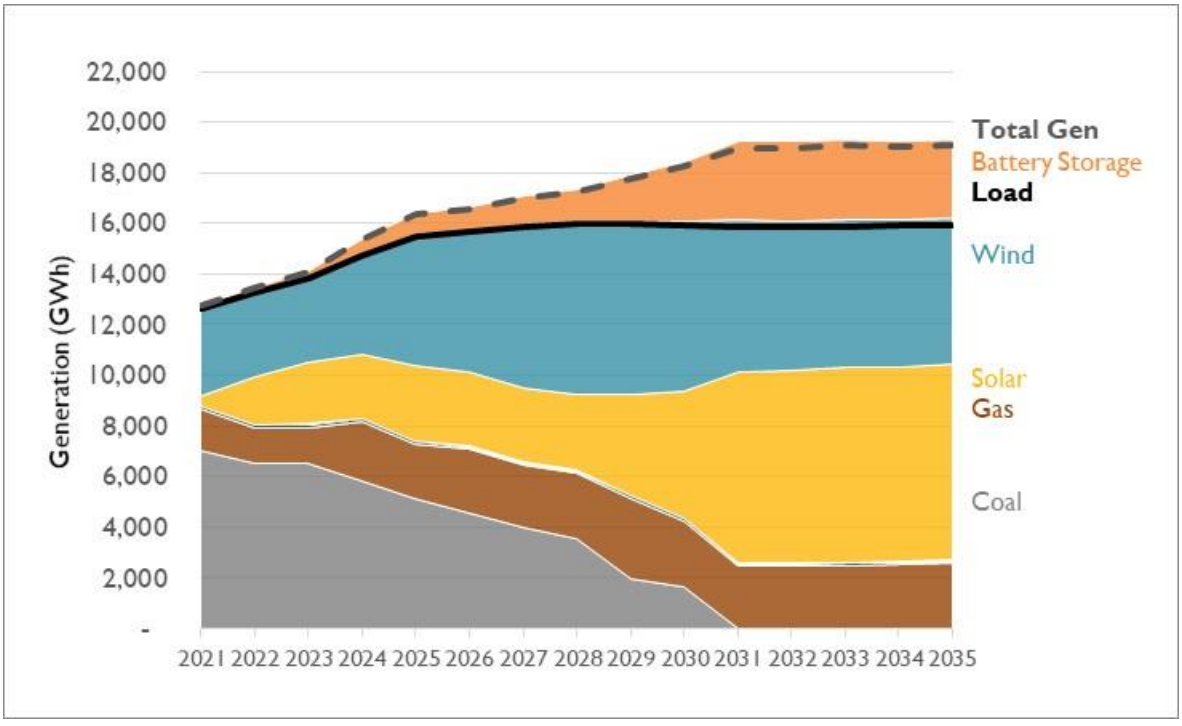
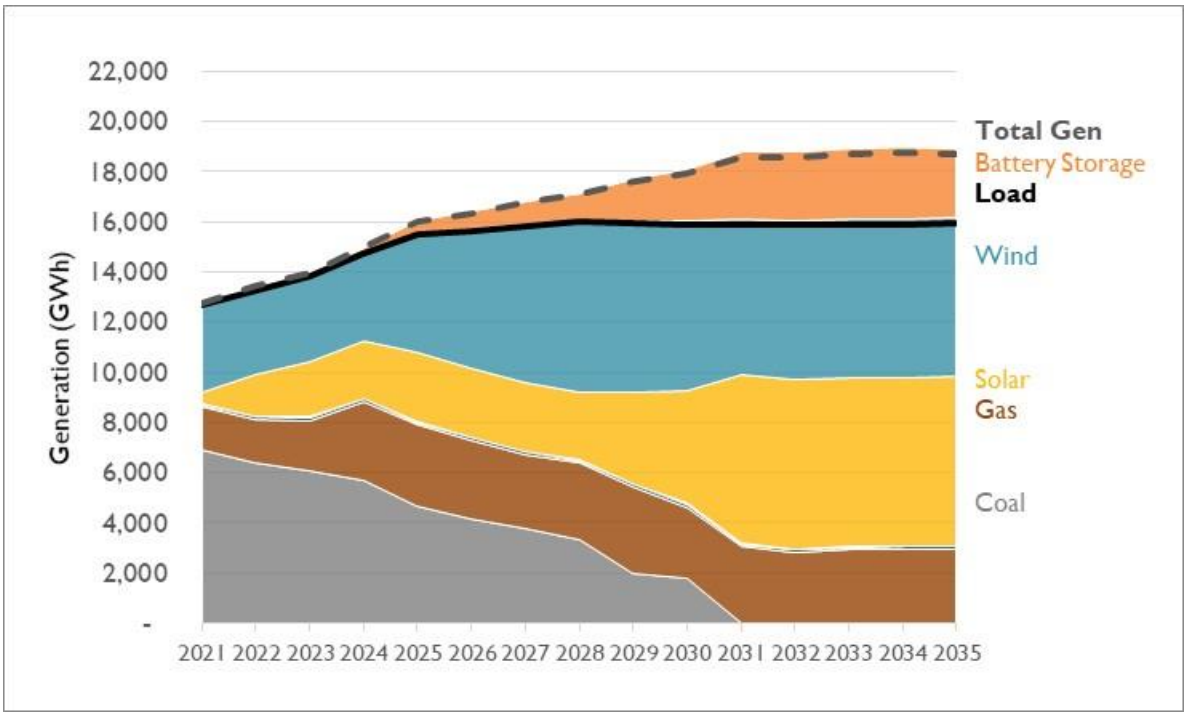


Figure 8 shows annual generation in the *Standing Bear Only, All Coal Retires* scenario. This scenario looks very similar to the *No New Gas, All Coal Retires* scenario, with a few notable exceptions. First, there is additional generation from gas in the scenario that includes the Standing Bear reciprocating engines. The existence of the gas capacity means that the EnCompass model adds fewer storage resources, and thus there is less discharge from batteries. These dynamics also change the additions of solar and wind, with the *Standing Bear Only* scenario relying less on solar as a percentage of generation and slightly more on wind, relative to the scenario that does not add any of OPPD's planned gas.

Figure 8: Generation by year, *Standing Bear Only, All Coal Retires*



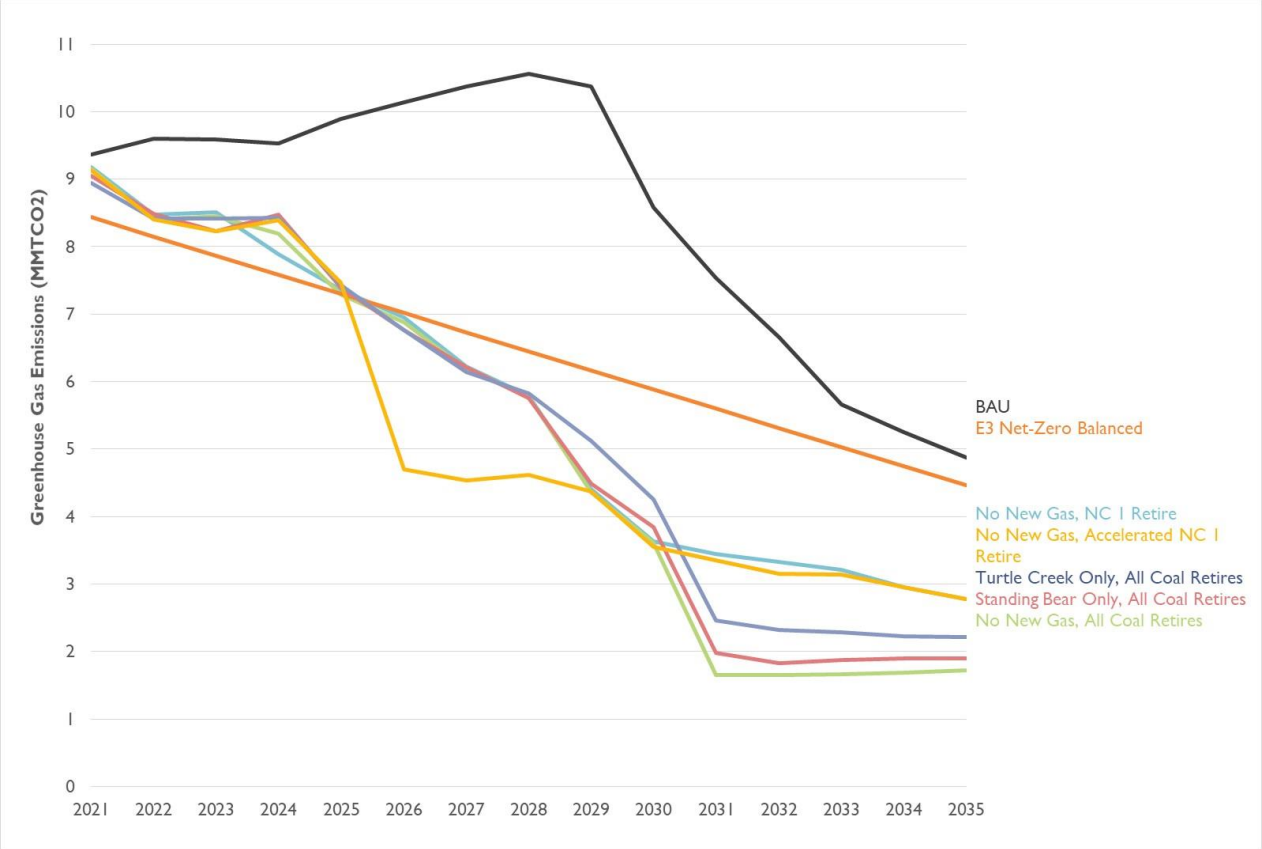
3.3. Carbon Dioxide Emissions

The importance of near-term investments in energy efficiency and renewable generation is most evident in the greenhouse gas emission results from our scenario. The *BAU* scenario, which includes 600 MW of new gas and does not retire coal, leads to an increase in emissions from 2021 through 2029. Although emissions in the *BAU* scenario do begin to decline, the delayed start leads to far higher cumulative emissions.

We also include an estimate of emissions from the E3 *Net-Zero Balanced* scenario, which charts a linear emissions reduction pathway. While this scenario is based on a higher load forecast, the pathway results in higher emissions than any of Synapse's partial new gas and no new gas scenarios.

Synapse modeled an enforced carbon cap that put OPPD on track to achieve 50 percent emission reductions by 2030. Aside from the *BAU* scenario, this means that the Synapse scenarios achieve the same level of annual emissions at some point between 2026 and 2030 as E3's *Net-Zero Balanced* scenario by 2035. The partial new gas and no new gas scenarios modeled by Synapse are thus not only lower cost than the Synapse *BAU*, but they also result in a more rapid decrease in emissions and lower cumulative emissions than the E3 *Net-Zero Balanced* scenario.

Figure 9: Greenhouse gas emissions by scenario (includes E3's *Net-Zero Balanced* scenario)



3.4. Revenue Requirements

The metric for measuring cost in the Synapse analysis was the net present value of revenue requirements (NPVRR). A utility revenue requirement is the amount of revenue that will need to be collected from ratepayers to pay for the resource portfolio over the course of the study period, discounted to present dollars using a discount rate of six percent. As shown in Table 3, the *BAU* scenario is the most expensive, and all modeled alternative scenarios would yield savings to ratepayers. Put another way, OPPD customers would benefit from the utility adding fewer MW of planned gas, retiring existing coal, or both.

Table 3: Net present value revenue requirement, by scenario

Scenario	Synapse BAU	Turtle Creek Only, All Coal Retires	Standing Bear Only, All Coal Retires	No New Gas, Accelerated NC 1 Retirement	No New Gas, NC 1 Retires	No New Gas, All Coal Retires by 2030
NPVRR With EE ($Millions)	$9,081	$8,794	$9,074	$8,867	$8,625	$8,783
Delta from BAU ($Millions)	N/A	($287)	($7)	($214)	($456)	($298)

Synapse included the cost of additional energy efficiency programs in our alternative scenarios in the NPVRR totals above. Those cost assumptions are provided in Appendix A.

Figure 10 shows the revenue requirements broken down by component: operating cost for all OPPD resources (fuel and operations and maintenance costs), capital cost for new resources, and the costs for additional energy efficiency programs. Compared to the *BAU*, all the Synapse alternative scenarios have higher capital costs that result from the addition of more solar, wind, and battery storage resources, but because these resources have zero fuel costs, these additional resources lead to much greater operating cost savings in the alternative scenarios.

Figure 10. Revenue requirement comparison, by cost category

4. CONCLUSIONS

The results of the Synapse modeling analysis show that OPPD can economically meet its customers' needs for capacity and energy without relying on continued coal generation or new gas units. Instead, limits on new gas, early coal retirements, early investment in energy efficiency, and the deployment of new solar, wind, and battery resources can result in a least-cost portfolio that also accelerates OPPD's pathway towards decarbonization.

This report presented several potential pathways that meet forecasted demand while also seeking to minimize both costs and CO_2 emissions, and there may be other paths that would do the same. The intention here was not to recommend a specific pathway, but rather to highlight several key conclusions that should influence any future OPPD modeling analysis.

First, early investment in energy efficiency is a vital and cost-effective way of mitigating forecasted increased in energy and peak demand. There are no silver bullets in the energy transition. The need to balance reliability, affordability, emission reductions, and intermittent generation demands a portfolio

approach that considers each type of resource. Energy efficiency is the "first fuel," and should be considered alongside more traditional supply-side resources as a solution to energy and capacity needs. A full consideration of energy efficiency opportunities is especially important in the context of OPPD's system, which faces near-term capacity and near-term energy needs.

Second, early investments that allow OPPD clean energy development partners to capture the economic benefits of the PTC and ITC tax incentives will also allow OPPD to pass the associated cost savings on to customers. Early deployment of renewables has many benefits—job creation, reduced cumulative emissions, and zero-marginal cost energy that reduces system operating costs and saves ratepayers money. The partial new gas and no new gas scenarios modeled by Synapse deploy more renewable capacity in the near term when compared to the *BAU* scenario, which allows renewable projects to be built at lower cost due to the current ITC/PTC timeline. These lower costs, coupled with the myriad benefits of early renewable adoption, demonstrate the importance of proactive renewable additions to OPPD's system.

Third, the two Nebraska City coal units can be retired before 2030 in way that reduces the overall cost of OPPD's portfolio without affecting reliability. Synapse modeled several retirement dates for Nebraska City 1 and Nebraska City 2, retiring Unit 1 between 2025 and 2028 and retiring Unit 2 between 2030 and 2035. In each scenario, this resulted in a lower cost OPPD electricity system. Even before outright retirement, generation from these units was largely displaced by low-cost renewables when an emissions constraint was imposed.

Synapse did not consider the repowering of Nebraska City Unit 1 and Unit 2 with gas as part of this analysis. While the use of some gas-fired capacity on OPPD's system may be necessary for reliability, particularly as the utility begins to integrate higher volumes of renewables, we expect that OPPD will try to minimize the amount of new gas it adds to its system, particularly as it gets closer to 2050 and its net-zero emissions goal. Utilities have stated, and independent studies have shown, that emissions reductions of 80 percent are possible using the technologies that exist today, but that achieving the remaining 20 percent of emissions reductions will require technological advances.[17]

Fourth, OPPD may not need both planned gas plants slated to enter service in 2023 and 2024. Synapse's no new gas and partial gas scenarios, in which only one of the two planned gas units were built, proved to be lower cost than building the full 600 MW of planned new gas. The decision to build a full 600 MW of new gas should be revisited, with the intention of planning for only the 150 MW Standing Bear plant or only the 450 MW Turtle Creek plant. Renewable resources can be built in a modular fashion with smaller system sizes, tailoring the size of the resource build to more closely match anticipated load growth. This makes overbuilding less likely and also allows the resources to be spread over a larger area.

[17] Energy Innovation. April 26, 2021. *2030 Report: Powering America's Clean Economy.* Available at: https://energyinnovation.org/publication/2030-report-powering-americas-clean-economy/.

This provides both reliability benefits in terms of geographic diversity, while also creating renewable energy jobs over a wider area.

Lastly, our results show that the early retirement of Nebraska City Unit 1 and Unit 2, along with reductions in the amount of planned new gas-fired capacity, results in savings to OPPD ratepayers over the 2021-2035 analysis period. OPPD's *Power with Purpose* plan was announced at the end of 2019, meaning that the input assumptions and forecasts that underlie the resource plan are now two years out of date. Under our updated input assumptions, renewables and storage provide a more cost-effective option for meeting customer demand while also reducing emissions. While fossil-fired capacity can, under certain circumstances with high penetrations of renewable resources, be relied upon to maintain reliability, OPPD has not yet demonstrated that the Turtle Creek and Standing Bear plants are needed for that purpose. OPPD should conduct updated modeling that seeks to retire existing coal-fired units prior to 2030 while also minimizing the construction of planned gas resources.

Going forward, we recommend that OPPD make additional investments in energy efficiency and compare the costs of new and enhanced programs to the costs of adding new supply-side resources. We recommend that the company examine modeling scenarios in which it stops burning coal by the year 2030. OPPD should also target a resource portfolio that adds as little new gas-fired capacity as is technically feasible while maintaining reliability. While the future is highly uncertain, we know that OPPD can kick-start its efforts at decarbonization by minimizing the use of coal and gas in the near term, resulting in both emissions reductions and customer savings.

Appendix A. MODELING INPUTS

Synapse used EnCompass to model resource choice impacts in OPPD's service territory in Nebraska. Developed by Anchor Power Solutions, EnCompass is a single, fully integrated power system platform that provides an enterprise solution for utility-scale generation planning and operations analysis. EnCompass is an optimization model that covers all facets of power system planning, including:

- Short-term scheduling, including detailed unit commitment and economic dispatch, with modeling of load shaping and shifting capabilities;
- Mid-term energy budgeting analysis, including maintenance scheduling and risk analysis;
- Long-term integrated resource planning, including capital project optimization, economic generating unit retirements, and environmental compliance; and
- Market price forecasting for energy, ancillary services, capacity, and environmental programs.

Synapse used the EnCompass National Database created by Horizons Energy to model OPPD's service territory. Horizons Energy has benchmarked dispatch and prices resulting from its comprehensive dataset to actual, historical data across all modeling zones. More information on EnCompass and the Horizons dataset is available at www.anchor-power.com.

Energy Efficiency

Synapse developed an internal energy efficiency forecast and modeled energy efficiency as a load modifier, revising the OPPD reference energy and peak forecast for all scenarios except the BAU. The BAU scenario was modeled using the exact OPPD reference energy and peak forecasts provided in the OPPD data release.

For the other scenarios, Synapse developed an internal energy efficiency forecast because of the low level of planned energy efficiency included in the OPPD's energy forecasts and uncertainty regarding embedded energy efficiency savings. After the conclusion of Synapse's modeling, OPPD did release interim results that included additional detail on the utility's energy efficiency forecast, including information on embedded energy efficiency. While both Synapse's energy efficiency forecast and OPPD's energy efficiency forecast reach an almost identical level of annual incremental savings by 2035, OPPD's energy efficiency pathway is more gradual and achieves the majority of energy efficiency savings after 2035. By contrast, Synapse's energy efficiency projections emphasize near-term investment and result in more cumulative savings between 2021 and 2035.

Synapse developed its energy efficiency forecast based on the American Council for an Energy Efficient Economy (ACEEE) 2020 Utility Scorecard report.[18] ACEEE collects energy efficiency data for the 52 largest utilities in the United States by retail sales volume, relying on utility annual reports, regulatory filings, and other public data sources. Because energy efficiency measures are dependent on region, Synapse narrowed down the 52 utilities in ACEEE 2020 to a subset of 19 utilities that are in close proximity to Nebraska.

The first step in developing an energy efficiency forecast was to establish first-year incremental savings. We based this on the average of annual incremental savings from the ACEEE 2020 utility subset, which gave a first-year incremental savings value of 1.01 percent. ACEEE 2020 reports data from two years previously, so our first-year energy efficiency forecast sets OPPD savings in 2021 to the average incremental savings of similar utilities in 2018.

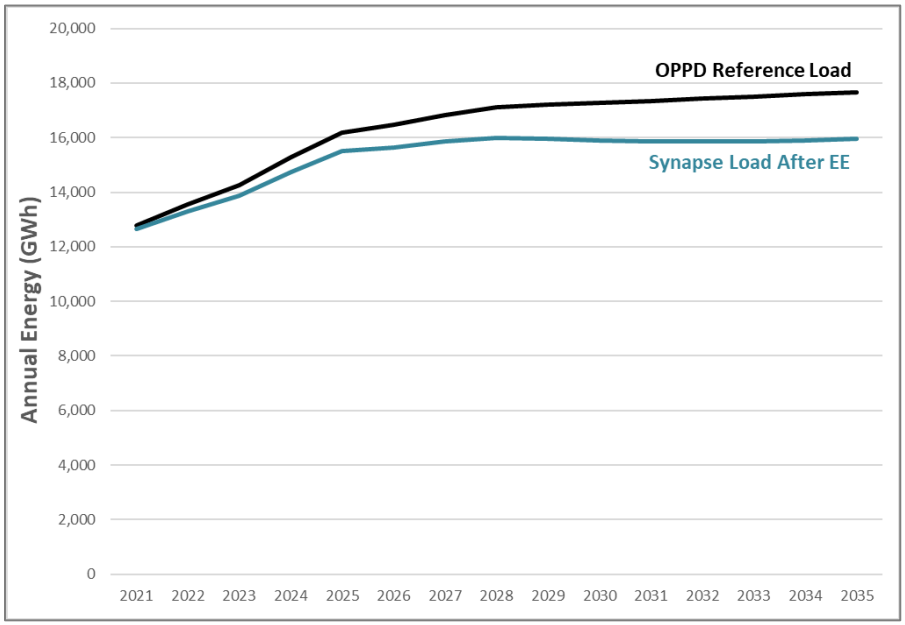
After establishing a first-year incremental savings amount, Synapse set a target of 1.5 percent incremental savings by 2025 and 2 percent incremental savings by 2030. According to ACEEE 2020, several utilities have already reached greater than 2 percent incremental savings. Achieving 2 percent incremental savings by 2030 is a conservative target, with leading utilities aiming for between 2-3 percent. The incremental savings percentage is held constant once the 2 percent target is achieved in 2030.

The growth rate in energy efficiency savings required for OPPD to achieve 2 percent incremental savings by 2030 is gradual. In Synapse's energy efficiency forecast, OPPD would need to increase the percentage of annual incremental savings by 0.12 percent each year. This trajectory is at the lower end of studies by the Lawrence Berkley National Laboratory (LBNL), which found that utilities were able to increase the percentage of annual incremental savings by between 0.10 and 0.40 percent per year.[19] The energy efficiency savings from Synapse's forecast were applied to the reference energy forecast in OPPD's data release and modeled as a reduced load in all partial new gas and no new scenarios.

[18] American Council for an Energy Efficient Economy. February 20, 2020. *2020 Utility Energy Efficiency Scorecard.* Available at: https://www.aceee.org/research-report/u2004.

[19] U.S. Environmental Protection Agency. June 10, 2014. *GHG Abatement Measures, Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants*. Available at: https://archive.epa.gov/epa/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf.

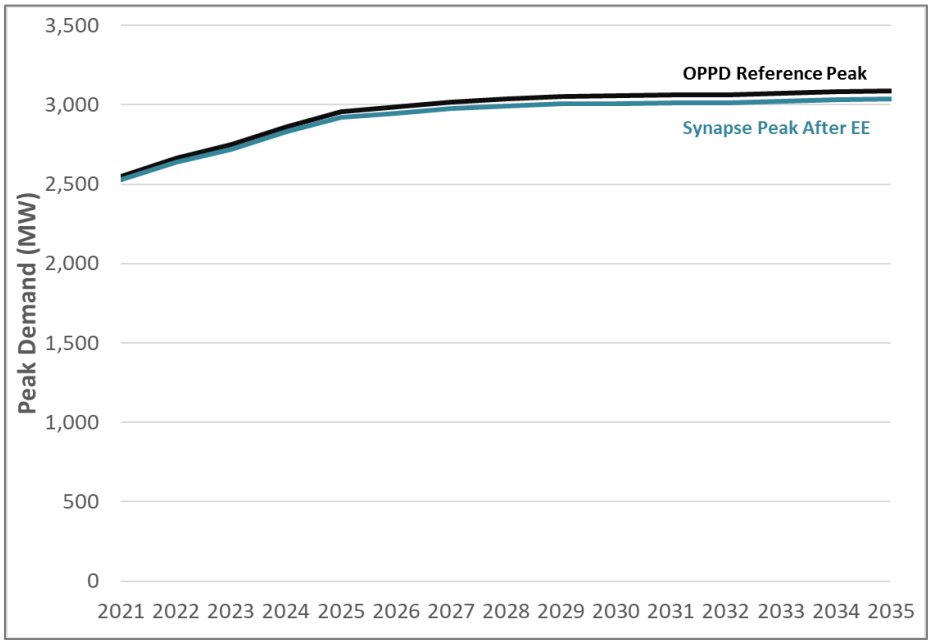
Figure 11: Synapse energy efficiency forecast, energy savings



In addition to energy savings, energy efficiency measures can also impact the peak forecast. The ACEEE 2020 report also includes the peak reduction impact from energy efficiency for each of the assessed utilities. Synapse took the average percentage peak reduction from the subset of 19 utilities, 0.82 percent, and used it as OPPD's peak reduction from energy efficiency in 2021. This percentage was escalated at the same rate as the energy savings forecast, resulting in a peak reduction of 50 MW by 2030.[20] As with the energy efficiency savings forecast, the energy efficiency peak reduction forecast was held constant after 2030.

[20] Another method of estimating peak reductions from energy efficiency is to use EIA-861 data and create a MW/MWh ratio based on a subset of utilities in similar regions. Synapse created a ratio based on the energy and peak savings for utilities in Nebraska as reported in EIA-861. We found that this implied greater peak reductions from energy efficiency, but in order to remain conservative we selected the lower peak reduction value using the method described in the report.

Figure 12: Synapse energy efficiency forecast, peak reduction



Because the energy efficiency forecast was added as a load-modifier, the cost of energy efficiency was added back into the NPVRR during post-processing. A cost of 1.5 cents per kWh was used based on a LBNL study of utility energy efficiency costs from 2011 to 2017. LBNL found that energy efficiency costs in the Midwest were 1.4 cents per kWh in 2017 dollars, equating to 1.5 cents per kWh in 2021 dollars.[21]

Fuel Prices

In addition to energy efficiency, Synapse developed an internal gas price forecast that blends near-term NYMEX futures with the Annual Energy Outlook's (AEO) long-term gas price trajectory. While OPPD did provide a gas price forecast in the data release, this information was provided on an annual basis. Using an internal forecast allowed us to develop a monthly gas price forecast, capturing the seasonal variation in gas prices. Synapse's internal forecast still closely tracks the OPPD forecast, except for slightly higher prices in the near term based on the current level of NYMEX futures through 2023.

[21] Schwartz, Lisa et al. November 2019. *Cost of Saving Electricity Through Efficiency Programs Funded by Customers of Publicly Owned Utilities: 2012-2017.* Lawrence Berkeley National Laboratory. Available at: https://eta-publications.lbl.gov/sites/default/files/public_power_cost_of_saving_electricity_final.pdf.

Figure 13: Comparison of OPPD and Synapse gas price forecasts