2022 Lincoln Cooperative Integrated Resource Plan

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List of Abbreviations

BACT	Best Available Control Technology
CCS	Carbon Capture and Sequestration
CEITC	Clean Electricity Investment Tax Credit
CO_2	Carbon Dioxide
COAL CCS	Ultra-Supercritical Coal with 90% CCS
CPI	Consumer Price Index
DEC	District Energy Corporation
DSM	Demand Side Management
E3	Energy and Environmental Economics, Inc.
EGEAS	Electrical Generation Expansion Analysis System
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
FOMC	U.S. Federal Open Market Committee
GGS	Gerald Gentleman Station
GGS1	Gerald Gentleman Station Unit 1
GGS2	Gerald Gentleman Station Unit 2
GWh	Gigawatt-hours
IRP	Integrated Resource Plan
ITC	Federal Investment Tax Credit
ITP	Integrated Transmission Planning
LED	Light-Emitting Diode
LES	Lincoln Electric System
LOLP	Loss of Load Probability
LRS	Laramie River Station
LRS1	Laramie River Station Unit 1

MISO	Midcontinent Independent System Operator
MMBTU	Million British Thermal Units
MW	Megawatts
NGCC CCS	Natural Gas Combined Cycle with 90% CCS
NGCT	Natural Gas Combustion Turbine - Aeroderivative
NO_X	Nitrogen Oxide
NPV	Net Present Value
PPA	Power Purchase Agreement
RFP	Request For Proposals
RICE	Natural Gas Internal Combustion Engine
RIM	Rate Impact Measure
RTO	Regional Transmission Organization
SEP	LES Sustainable Energy Program
SO_2	Sulfur Dioxide
SPP	Southwest Power Pool
UCT	Utility Cost Test
UNL	University of Nebraska – Lincoln
WACC	Weighted Average Cost of Capital
WAPA	Western Area Power Administration
WS4	Walter Scott Energy Center Unit 4

Executive Summary

Lincoln Electric System (LES) is submitting this Integrated Resource Plan (IRP) to the Western Area Power Administration (WAPA) on behalf of the Lincoln Cooperative. In addition to Lincoln Electric System, the Lincoln Cooperative also includes the University of Nebraska – Lincoln (UNL) and a collection of Nebraska State Agencies; the Lincoln Regional Center, Nebraska State Office Building, and the Nebraska State Penitentiary.

Although this IRP includes action plans for each individual Lincoln Cooperative member, a primary focus is LES' planning process, as it encompasses the load requirements and WAPA allocation of every member.

Pre-IRP LES Activities

To better inform the upcoming process, LES undertook some related initiatives and studies prior to commencing the IRP, including:

Energy Storage Request for Proposals

Analysis and preparations in the last couple years positioned LES to consider a potential energy storage pilot project in the near future as part of the IRP. LES issued a Request For Proposals (RFP) in late 2021 for a battery storage project to be located within the area served by LES' Community Microgrid, a portion of downtown Lincoln capable of being operated as an island to maintain service to critical city, county, state and federal infrastructure in the case of widespread outages. The proposals LES received provided valuable insight regarding the related project structure and pricing, and LES is currently in the midst of ongoing contract negotiations with the selected storage developer.

Sustainable Energy Program Review

LES' Sustainable Energy Program (SEP), first introduced in 2009, is a collection of demand side management measures incentivizing customers to reduce electricity consumption and thereby delay the need for future generation additions. To prepare for the IRP, LES contracted with nFront Consulting in late 2021 to review and benchmark the SEP against leading industry practices. nFront Consulting determined LES' benefit-to-cost metrics were well supported within the industry, made a number of recommendations to improve the related modeling assumptions and suggested potential new offerings for LES' consideration.

Effective Load Carrying Capability Forecasts

Starting in the summer of 2023, the Southwest Power Pool (SPP) will begin assigning accredited capacity to non-dispatchable resources – wind, solar, and energy storage – according to a new methodology. This analysis, termed the Effective Load Carrying Capability (ELCC), quantifies a resource's ability to produce energy when the grid is most likely to experience shortfalls. Resources are additionally prioritized according to a number of tiers; with Tier I assigned the highest accreditation but generally limited to (i) resources with firm

transmission service and (ii) an aggregate size based on a percentage of the utility's peak load. In order to properly model the accreditation of applicable resources in the IRP, LES contracted with Energy + Environmental Economics in late 2021 to provide forecasts of future ELCC values in SPP.

LES SEP Methodology Decisions

Based on the recommendations from nFront Consulting, LES made various revisions to its SEP modeling data as part of the IRP process. This included minor adjustments to its assumptions for inflation, future retail rate escalations and the cost structure of avoided generating capacity additions. nFront Consulting also found LES to be one of the few utilities to directly account for avoided carbon dioxide (CO_2) emissions in their cost-effectiveness tests, noting LES was using a slightly higher initial cost but an annual escalation that tended to be significantly lower than others in that subset. Following a review of these findings, LES increased their assumed annual escalation of avoided CO_2 from inflation to inflation plus 2.0%. The net impact of all the various input changes was a slight increase in LES' portfolio-level benefit-to-cost metrics.

LES also evaluated the various new measures nfront Consulting suggested they could potentially consider adding to the SEP. Following preliminary modeling of the measure-specific benefit-to-cost ratios, as well as a review of the current market penetrations, LES found high efficiency commercial kitchen equipment, direct load control of electric water heaters and variable/critical peak pricing programs to be the most justified.

LES Resource Analysis

In order to make informed decisions regarding the future of LES' resource portfolio, LES sought to evaluate a wide range of potential options, including both supply-side (i.e., generation) and demand-side (i.e., energy efficiency and demand response) resources.

LES utilized an Electric Power Research Institute (EPRI) software tool, the Electrical Generation Expansion Analysis System (EGEAS), for the analysis of the various resource alternatives. EGEAS utilizes dynamic programming, evaluating all possible resource combinations, to identify an optimal solution based on the net present value of LES' total production costs. This includes consideration of construction costs, operating costs and reliability constraints. In order to cover a wide range of possible futures, the analysis varied natural gas prices and regulatory values of CO_2, producing a matrix of results encompassing 100 possible combinations. The analysis also considered the impact of future base load resource retirements, modeling the retirement of any existing LES coal resource that reflected an annual capacity factor of less than 20% for five straight years.

To further broaden the future scenarios contemplated in the analysis, LES also examined a number of sensitivities, including adjustments to the new resource alternatives considered, changes in existing resource retirements and revisions to select modeling assumptions.

LES Decarbonization Goal

LES adopted a decarbonization goal in 2020, calling for LES to achieve net-zero CO_2 production from its generation portfolio by the year 2040, with the path and pace to achieving the goal balanced by:

- A continued commitment to maintain high electric system reliability.
- Environmental stewardship.
- A fiscally-responsible focus that carefully considers financial impacts to all customers, especially LES customers with low and fixed incomes.
- Consideration of existing contractual obligations.
- Advancements in generation, energy storage, carbon capture technologies and other emerging solutions.

Based on the results of the resource analysis, LES laid out an initial plan for achieving its corporate decarbonization goal. This initial plan includes the following steps:

- Maintain LES' allotment of Tier I wind – currently just exceeding the SPP Tier I limit – and seek to develop its allowed amount of Tier I solar resources. The prioritization of the SPP ELCC methodology made these Tier I resources valuable over a wide range of futures, while rendering the other tiers ineffective.
- Continue the SEP, as this collection of energy efficiency and demand response resources often looked to be a cost-effective alternative to building new generation.
- Seek to maintain LES' existing fleet of natural gas resources, representing both a low-cost and, because they rarely operate, relatively low-emissions foundation of its future portfolio.
- Continually watch for the right time to either retire or upgrade its existing coal resources with carbon capture technology. The financial impact of these coal plant decisions was found to be considerable, both when (i) retiring them too early, while they still brought considerable financial value to LES, and (ii) retiring them too late, when market forces and/or environmental regulations made them less economically viable.

Based on future load projections, this preliminary plan would bring LES within approximately 200 MW of meeting its SPP resource requirements in 2041, covering its peak load plus an additional reserve margin of 15%. As of right now, LES intends to leave this gap unprescribed, looking to identify the best choices in the future as more information becomes available. LES believes this preliminary decarbonization plan strikes a valuable balance, closing enough of the gap to make the goal attainable, while still recognizing that additional decisions will be required as the future unfolds.

Conclusions

The IRP analysis resulted in various recommendations, including the following:

LES Utility-Scale Solar Resource

One of the primary building blocks of LES' initial plan for pursuit of its decarbonization goal was the addition of Tier I solar. The addition of any large-scale generating resource in SPP requires a request via the SPP generator interconnection process. This process, which identifies the often substantial cost to interconnect the generator to the grid, is currently about three years behind. Given this delay, LES plans to begin evaluating the addition of a solar resource even though it is currently long on generation. Depending on the applicability of federal tax credits, LES initially plans to look at directly constructing and owning the resource, as they believe this may bring operational benefits. This would place the focus, at least initially, on a solar resource located in or around the LES service territory.

LES Battery Storage Pilot

Battery storage wasn't well represented in the resource analysis, indicating a large-scale project would not be warranted in the near term. However, LES believes its RFP for a pilot-level project – launched as a precursor to the IRP – would represent a reasonable first step in the interim. LES plans to implement and administer the pilot project as a product of the IRP, providing the opportunity to build experience with this new technology while also helping to fortify the LES Community Microgrid.

LES Community Microgrid Solar Expansion

In conjunction with the battery storage project, LES plans to evaluate the addition of more solar in the area of the LES Community Microgrid. The resources would complement each other, together helping to further strengthen the microgrid. The scope and structure of these additions is still to be determined.

LES SEP

Continuation of the SEP was identified as another key building block in LES' preliminary plan for achieving its decarbonization goal, as the SEP proved to be a preferred resource over a broad range of possible scenarios. LES intends to continue utilizing the SEP for the foreseeable future.

LES SEP – New Product Offerings

With the SEP being continued, LES sought to identify any potential new offerings in this area that may be warranted. The introduction of incentives for high efficiency commercial kitchen equipment and a new pilot-level demand-response project targeting electric water heater load – both originally recommended by nfront Consulting as part of their SEP review – appear justified for further evaluation, so LES plans to implement these measures as soon as next year.

LES Time-of-Use Rate

nFront Consulting also identified time-of-use or dynamic pricing programs as another possible demand-side management program LES could offer. LES had already started to examine time-of-use rates for its large commercial and industrial customers prior to the IRP. The early findings from that review, in conjunction with the nFront Consulting recommendation, has LES planning to develop and offer such a rate in the near future.

UNL

UNL will continue or expand programs targeting reduced energy consumption, including energy efficiency initiatives, continuous commissioning of existing building assets and existing chiller tube cleaning. UNL also plans to further optimize their chilled water production and explore the feasibility of on-campus renewable energy installations.

Nebraska State Agencies

The Nebraska State Agencies plan to continue their support of increased energy conservation through equipment efficiency and lighting improvements plus new or upgraded control systems.

Public Input and Interaction

Throughout the IRP process, the Lincoln Cooperative provided multiple opportunities for public input and interaction, over many different platforms. This included three different public meetings and two workshops encompassing the span of the entire process, as well as distribution of both the draft and final versions of this report. Additionally, the LES website provided updated information about the process over the course of the entire project, including both milestones already reached and decision points still to come.

1.0 Introduction

Lincoln Electric System (LES) is submitting this Integrated Resource Plan to the Western Area Power Administration (WAPA) on behalf of the Lincoln Cooperative.

The IRP process (i) included opportunities for public input throughout, (ii) meets the requirements of WAPA, and in the case of LES, also Nebraska State Statute 66-1060, and (iii) lays out a plan to enhance service to the Cooperative member's customers in Lincoln, Nebraska.

2.0 Lincoln Cooperative

The Lincoln Cooperative includes the following public entities who receive power under contract from WAPA.

2.1 Lincoln Electric System

Lincoln Electric System is a publicly-owned municipal utility serving approximately 200 square miles within Lancaster County in Nebraska, including the cities and towns of Lincoln, Prairie Home, Waverly, Walton, Cheney and Emerald. As of the end of 2021, LES served over 145,000 retail customers, with a total annual consumption of over 3,200 gigawatt-hours (GWh). LES set its all-time peak load of 786 megawatts (MW) in August 2011 and has approximately 500 employees. LES is also a member of the Southwest Power Pool (SPP) Regional Transmission Organization (RTO), joining on December 1, 2008. More detailed information on LES can be found at www.les.com.

2.2 University of Nebraska – Lincoln

The University of Nebraska - Lincoln (UNL) is a land grant college founded in 1869. UNL first purchased power from the Federal Government in 1966. The remainder of the power necessary to meet the electrical load is provided by LES as the supplemental power provider. The 2021 electrical peak demand and total energy consumption were about 28 MW and 152 GWh. This usage includes service to the UNL City and East Campuses and the Nebraska State Capitol. More detailed information on UNL can be found at www.unl.edu.

2.3 Other Nebraska State Agencies

Lincoln Regional Center, Nebraska State Office Building, and the Nebraska State Penitentiary

These agencies receive WAPA power under contract #1-07-60-P0117, titled *Contract for Electric Service to Nebraska State Penitentiary Load*. Total 2021 requirements were about 3 MW in peak electrical demand and 16 GWh in electrical energy. Their primary electrical needs are met by the WAPA contract and supplemental power supplied by LES.

2.4 Cooperative Planning

LES includes each of the Lincoln Cooperative members' load within its control area load forecast, regardless of whether that load is served by WAPA or is part of the supplemental load that is served by LES. LES also includes all Lincoln Cooperative members' WAPA generation allocations in its supply adequacy calculations. This is in accordance with WAPA contracts #19-UGPR-140 and #20-UGPR-45, titled *Contract for Administrative Services with Lincoln Electric System and the University of Nebraska at Lincoln, Nebraska* and *Contract for Administrative Services with Lincoln Electric System and the Nebraska State Penitentiary*, respectively. Although this IRP includes action plans for each individual Lincoln Cooperative member, a

primary focus is LES' planning process, as it encompasses the load requirements and WAPA allocation of every member.

3.0 Pre-IRP LES Activities

Prior to commencing the IRP, LES undertook some related initiatives and studies to better inform and prepare for the upcoming analysis.

3.1 Energy Storage Request for Proposals

In 2019 and 2020, LES conducted a cross-divisional internal review and contracted for related consultant studies to identify and evaluate potential use-cases for a utility-scale battery storage project. No large-scale projects were found to be necessary or warranted at that time, but LES still saw value in a smaller scale pilot project to help develop in-house experience with the technology. LES planned to consider a potential pilot project as part of the upcoming 2022 IRP, but subsequently decided to get an early jump on the related solicitation process. In the fall of 2021, LES launched an open Request for Proposals (RFP) seeking a Power Purchase Agreement (PPA) for an energy storage project. Besides providing experience, the project would also be used to support local transmission and distribution system reliability and perform load-related energy arbitrage; charging when the market price of electricity is low and discharging when the price is high. Even in aggregate though, these varied benefits were projected to fall well short of the related project cost. To further help justify the project, LES sought to locate it in the area of downtown Lincoln served by LES' Community Microgrid.

The LES Community Microgrid – commissioned near the end of 2020 – normally functions as a part of the bulk electric system. However, should the need arise, it has the ability to power a portion of the downtown Lincoln area as an island, isolated from the greater electrical grid. The most likely scenario would be an unfortunate natural disaster that separates the bulk of LES' service territory from the grid and LES' primary local generating stations. The LES Community Microgrid can serve critical city, county, state and even federal facilities, as well as valuable support infrastructure, providing a powered area to work from while those agencies are focused on rendering aid and restoring services to the community.

An overview of the Community Microgrid area and the critical loads it serves is provided in Figure 3.1. The microgrid is anchored by LES' J Street generator – a dual fuel unit capable of starting and operating while isolated from the grid – and supplemented with existing customer-owned solar and thermal energy storage resources. A battery storage project would provide additional support in the case of a microgrid event.

LES requested proposals for (i) lithium-ion battery storage projects rated from 1 MW - 3 MW with a duration of 2 - 4 hours, and (ii) non-lithium-ion energy storage projects rated at least 250 kW with a duration of no less than 2 hours. LES received 51 distinct responses from 13 different companies, ultimately commencing contact negotiations with the selected battery storage developer at the end of 2021. LES hopes to announce a contract in the near future and will then turn its attention to bringing the project online.

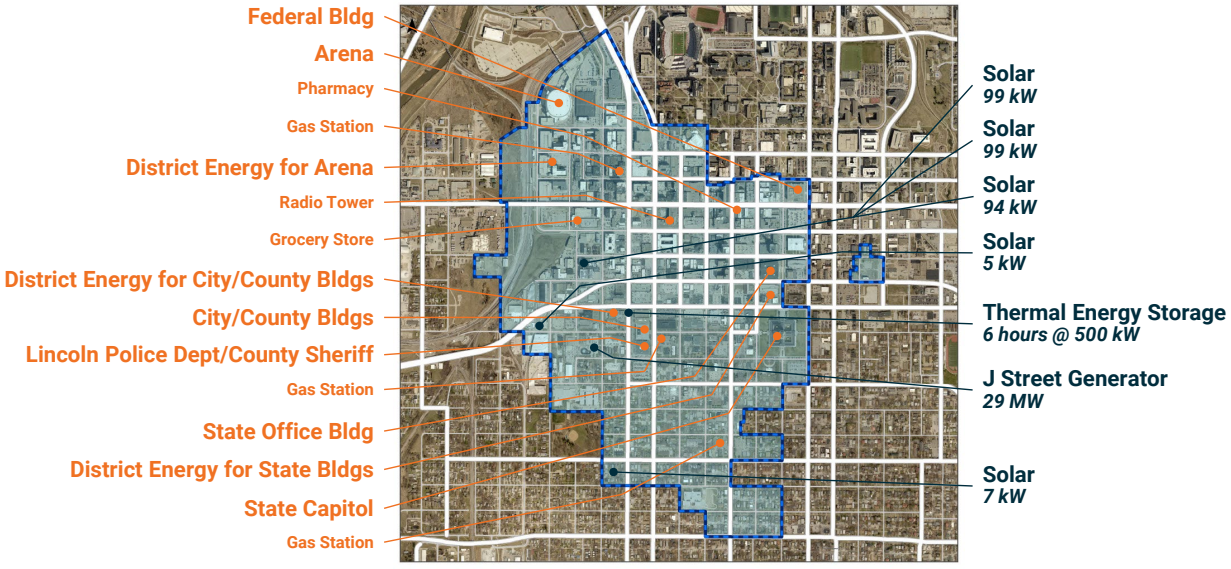

Figure 3.1 Area encompassed by the LES Community Microgrid.

3.2 LES Sustainable Energy Program Review

LES launched its Sustainable Energy Program (SEP) in 2009, a collection of Demand Side Management (DSM) measures incentivizing customers to reduce electricity consumption and thereby reduce the need for future generation additions. Some of these are energy efficiency measures designed to ensure customers use electricity more efficiently throughout the year, while others are aimed at specifically reducing consumption during only periods of peak system demand.

In order to prepare for the upcoming IRP, LES contracted with nFront Consulting in late 2021 to review the SEP against leading industry practices. nFront Consulting performed a high-level benchmarking of peer utilities, supplemented by a review of publicly available statewide energy efficiency studies and meta-analysis from nationally recognized organizations. nFront Consulting's final report is included in Appendix A, but the following represent the primary findings from the three key focus areas:

1) *LES metrics used to determine cost-effectiveness*

   The dual tests LES utilizes to assess the cost-effectiveness of current and prospective SEP measures – the primary Utility Cost Test (UCT) and an adjusted representation of the Rate Impact Measure (RIM) as a secondary test – are highly supported by the latest industry practices and are consistent with LES's carbon reduction goal. The UCT uses a typical cost-effectiveness ratio of 1.0, and the RIM test's cost-effectiveness threshold of 0.6 allows for a limited level of subsidization from non-participants while still effectively capping that limit.

2) *LES measure parameters and assumptions used in cost-effectiveness evaluations*

nFront Consulting reviewed all facets of LES' modeling data and assumptions in detail, specifically providing the following feedback:

- LES' measure-specific assumptions for energy and demand savings, measure cost, measure life, peak coincidence and net-to-gross adjustments were generally reasonable. However, LES should strive for more consistency in assumptions related to custom commercial energy efficiency projects.
- LES' static inflation assumption of 2.3% is consistent with the latest publicly available sources, but LES should update this assumption periodically based on a reputable reference.
- LES currently escalates retail rates at 1.0% per year. Current industry sources suggest a slightly higher rate of 1.3% (residential) to 1.7% (commercial).
- LES' avoided energy costs, based on market electricity prices in the Southwest Power Pool, appear reasonable.
- LES currently values avoided generating capacity costs at $30/kW-year with an annual escalation of 5.0%. This is a lower starting point than much of the industry, but it's largely compensated by the high escalation rate. Many expect this to gradually approach the long-term levelized cost of peaking capacity ($60 - $80/kW-year).
- Many utilities do not account for avoided carbon dioxide (CO_2) costs, and those that do tend to include it as something that only plays into decision-making in a limited fashion. LES is one of few utilities that directly includes avoided CO_2 emissions within their cost-effectiveness tests. For 2021, LES' value of CO_2 was $20/ton starting in 2024, escalated at 2.3% annually. Most others that value avoided CO_2 use a starting cost that is slightly lower than LES, but their annual escalation is significantly higher. To promote better consistency, nFront Consulting suggested a higher escalation rate more in line with what LES commonly uses for CO_2 valuations in its resource analysis.

3) *Additional measures endorsed by other utilities that may have applicability to LES*

The measures included in the SEP are similar to those that are active across many of LES' peer utilities, but the following may be worthy of additional consideration:

- High efficiency dehumidifiers
- Commercial kitchen equipment
- Electric water heater direct load control
- Variable/critical peak pricing
- Voltage optimization and conservation voltage reduction

3.3 Effective Load Carrying Capability Forecasts

Per SPP resource adequacy requirements at the time the IRP analysis was commenced, all load serving entities were required to have enough accredited generation to meet their peak load plus an additional 12% reserve margin. Generating capacity in SPP is accredited according to the SPP Planning Criteria.[1] Currently, dispatchable resources (i.e., coal, natural gas, hydro, etc.) are generally accredited at the capacity they've proven to be capable of serving over at least four consecutive hours during peak seasonal (i.e., summer or winter) conditions. Starting in the summer of 2023, non-dispatchable resources (i.e., wind, solar and energy storage) will be assigned accredited capacity ratings based on a widely-used statistical approach known as an Effective Load Carrying Capability (ELCC) study.[2] ELCC represents a resource's ability to produce energy when the grid is most likely to experience shortfalls and is typically expressed as a percentage of the resource's nameplate capacity.[3]

SPP calculates seasonal ELCC values by fuel type: wind, solar and energy storage. For wind and solar resources, SPP then prioritizes accreditation as follows:[4]

- Tier I: Resources with firm transmission service to load that are used to meet SPP resource adequacy requirements. Each load serving entity is limited to the following maximum nameplate amount:
  - Wind: 35% of its average seasonal peak load over the last three years.
  - Solar: 20% of its average seasonal peak load over the last three years.
- Tier II: All other resources with firm transmission service to load which are used to meet SPP resource adequacy requirements.
- Tier III: Any remaining resources.

Once the total accreditation for each tier is established, SPP allocates Tier I and Tier II wind and solar amounts to the various resources in each tier based on how well each individual resource produces during the top 3% of load hours for its associated load serving entity. For Tier III resources, this calculation is based on production during the top 3% of SPP's aggregate load hours.

Energy storage resources are handled similarly to wind and solar but with a couple important distinctions.[5] First, there is currently no nameplate limit for Tier I storage, although this is under ongoing review by SPP. For energy storage, all resources with firm transmission service to load are currently included under Tier I, with all remaining resources included under Tier II. Secondly, all energy storage resources of a common duration (i.e., 4 hours) receive the same Tier I or Tier II accreditation, without any consideration for how their use aligns with top load hours.

A summary of SPP's ELCC methodology, using wind resources as an example, is included in Figure 3.2.

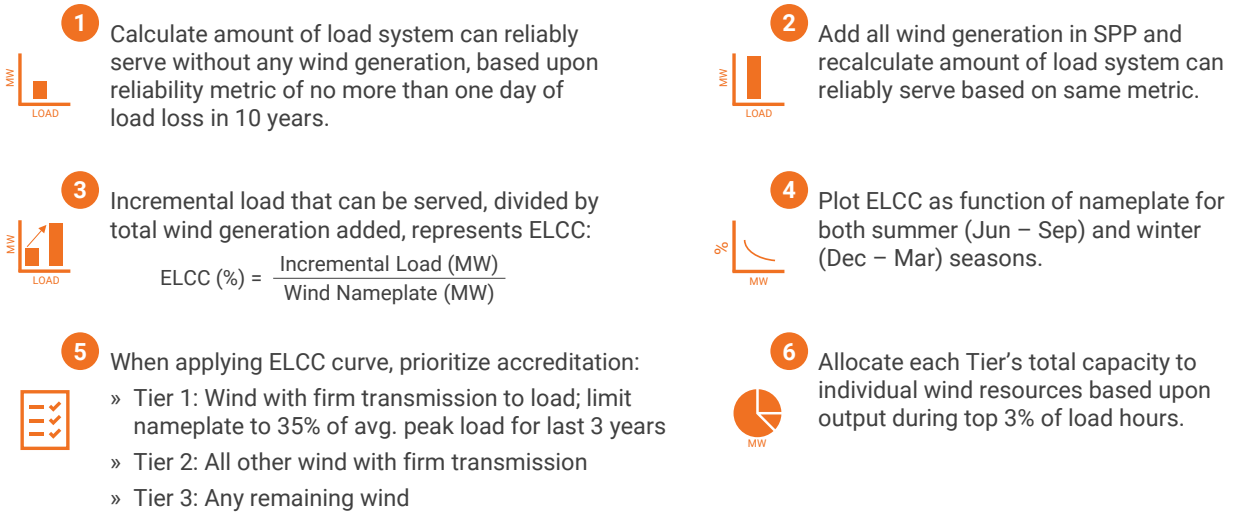

Figure 3.2 Example of the SPP ELCC methodology using wind.

In order to assess the future accreditation of non-dispatchable resources, LES contracted with Energy and Environmental Economics, Inc. (E3) in late 2021 to provide forecasts of future ELCC values in SPP. E3 conducted ELCC studies based on the future SPP resource projections developed for this IRP, yielding results for the years 2023, 2026, 2031, 2036 and 2041. The ELCC values included:

- Wind – Tier I, Tier II and Tier III
- Solar – Tier I, Tier II and Tier III
- 4-Hour Energy Storage – Tier I and Tier II

E3's final presentation is included in Appendix B, and the related ELCC projections also shown in Figure 3.3. As shown, the Tier I prioritization for wind and solar provides for a much higher accreditation than subsequent tiers. In general, the ELCC results degrade as more of a specific generation type is added to the system, which is typical of ELCC studies. The exception is Tier I wind, which trends up over time due primarily to the growth of solar resources in the region. Future increases in the amount of nameplate solar push the daily load peak later into the evening, which tends to align better with wind production in the SPP footprint, resulting in a higher ELCC value for wind. Tier I energy storage remains relatively flat over the entire study period, primarily because the projected SPP growth rate still doesn't reach a high enough penetration in 2041 to precipitate a reduction.

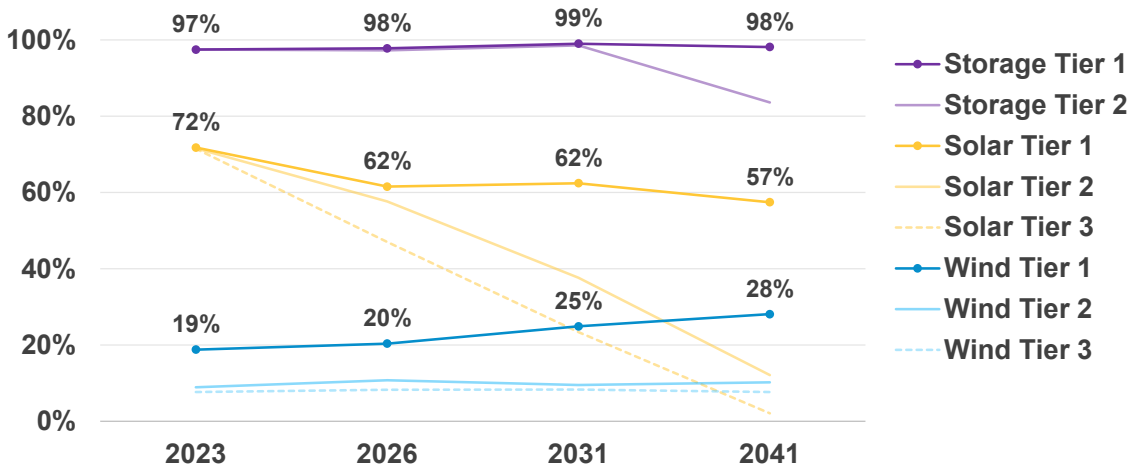

Figure 3.3 Future ELCC projections for the SPP region.

4.0 SEP Methodology Decisions

Before LES could consider the future prospects of the SEP, nFront Consulting's related recommendations needed to be addressed since at least some of the resultant decisions could impact the subsequent analysis of the overall portfolio offering.

4.1 SEP Modeling Assumptions

nFront Consulting recommended minor changes in escalation rates for a couple of metrics, specifically inflation and retail rates. For inflation, LES elected to replace their static escalation of 2.3% with the same source commonly leveraged by LES for long-term financial and resource analysis; the latest long-term target from the U.S. Federal Open Market Committee (FOMC), currently set at 2.0%.[6]

LES' previous assumption for retail rates was an annual escalation of 1.0%, representing the aggregate LES rates increases actually seen over the last decade. However, in light of the changing utility landscape and the projected upward pressures on rates, nFront Consulting recommended a slightly higher escalation mirroring more of what is seen across the industry, ranging from 1.3% to 1.7%. LES selected a new retail rate escalation of 1.5% moving forward.

As part of LES' external review of the SEP prior to the 2017 IRP, the previous consultant recommended using a market value to represent the avoided cost of generating capacity since LES' need for additional generation was so far out in the future. Although still finding this assumption to be reasonable, nFront Consulting recommended something that would more quickly reflect the levelized long-term cost of peaking capacity, typically falling within a range of $60 - $80/kW-year. Using a discount rate based on LES' Weighted Average Cost of Capital (WACC) – currently 4.5% – the levelized, 30-year Net Present Value (NPV) of the IRP's capital and fixed operations and maintenance cost assumptions for adding a new industrial frame combustion turbine were found to be roughly $59/kW-year. Upon further review in conjunction with nFront Consulting, LES found this cost to essentially be the NPV equivalent of its original assumptions; $30/kW-year escalated at 5.0% annually. This means LES' market value of capacity already reflected the capital and fixed costs of building additional peaking capacity. Although no change would have been necessary at this point, LES elected to switch to a fixed, 30-year value of $59/kW-year to allow for easier comparison to industry pricing trends in the future

Finally, nFront Consulting suggested revisions in how LES valued avoided CO_2 emissions. When compared to the few utilities that directly include avoided CO_2 emissions within their cost-effectiveness tests, LES had been using a starting cost ($20/ton) that was slightly higher, but an annual escalation (2.3%) that was significantly lower. Following nFront Consulting's guidance, LES elected to maintain their initial cost assumption, now representing $20/ton starting in 2025, but to increase the annual escalation rate to the same level utilized in the IRP's resource analysis, 4.0%.

Table 4.1 lists the benefit-cost ratios for the aggregate SEP portfolio both before and after the changes in assumptions discussed above. Although the various changes in assumptions apply pressure to the benefit-cost ratios in both directions, the net result was a slight increase in both the UCT and the RIM.

Table 4.1 SEP portfolio benefit-cost ratios.

Metric	Pre-IRP Assumptions	Post-IRP Assumptions
UCT	2.32	2.47
RIM	0.71	0.74

5.0 Analysis of Potential New SEP Measures

Although LES' offerings under the SEP are similar to those seen across the industry, nFront Consulting identified a few additional programs that LES could consider. Now that the SEP modeling assumptions had been updated, LES staff turned their attention towards evaluating these potential additions to the SEP portfolio.

5.1 Variable/Critical Peak Pricing

Time-of-Use or dynamic pricing rate structures use pricing signals to encourage customers to shift their energy use away from on-peak periods that tend to drive a utility's infrastructure investments. As identified by nFront Consulting, there are numerous ways to implement these types of programs, with varying degrees of complexity. Due to the countless options, modeling of a program such as this is not possible without first undergoing detailed rate development. LES had already started to review similar rate options prior to commencing the IRP, primarily focused on larger demand-rate customers whose existing cellular-based metering infrastructure would most easily support such a program. nFront Consulting's findings helped to reinforce those efforts, with LES now planning to offer a related rate in the near future.

5.2 Voltage Optimization

Voltage optimization programs seek to control voltage levels within the system to promote the most efficient flow of power, thereby reducing losses and energy consumption. Similar to variable/critical peak pricing though, it's difficult to model the financial impacts of such a system without first developing a defined scope and performing a detailed engineering analysis. Although LES has no firm plans to implement such a program in the near term, LES technical staff will continue to research and review this option for potential future application.

5.3 Residential High Efficiency Dehumidifier

Unlike the first two wide-ranging programs discussed above, the impact of end-user devices is defined enough that nFront Consulting could provide representative modeling assumptions. For residential dehumidifiers, they estimated a $25 incentive could influence customers to purchase a high efficiency model, driving a 0.8 kW demand savings versus standard efficiency units. Based on these preliminary assumptions, this measure results in very low benefit-cost ratios, with a UCT of 0.23 and a RIM of 0.18.

Upon subsequent review by LES, it appeared nearly all dehumidifiers sold in this region are already ENERGY STAR rated, representing a high efficiency model. In fact, the United States (U.S.) Environmental Protection Agency (EPA) estimated that 88% of all dehumidifiers shipped in the U.S. in 2020 were ENERGY STAR rated.[7]

For these reasons, LES has elected not to offer residential incentives for high efficiency dehumidifiers at this time. The preliminary benefit-cost ratios are not favorable, and given the

current state of market penetration, most customers would likely purchase a high efficiency unit regardless of any LES incentives.

5.4 Electric Water Heater Direct Load Control

Although the majority of the residential water heating in LES' service territory is fueled by natural gas, nFront Consulting's research indicated that 20% - 40% is likely electric. Electric resistance water heaters can represent one of a home's largest loads, although their operation is highly intermittent and often only spans a short duration of a few minutes. nFront Consulting estimated a demand response program could shed 0.5 kW per water heater from LES' peak demand in exchange for an annual customer incentive of $25/year. These assumptions result in preliminary benefit-cost ratios of 0.51 for both the UCT and the RIM. This UCT ratio is especially low, however, these results do not account for any other potential benefits that could be derived from the water heaters outside of deferring peak load. They could potentially also be used for energy arbitrage in the SPP market, being dispatched to store energy when the market electricity price is low or even negative.

The preliminary modeling results are not promising, and LES has ongoing questions regarding how much water heating load is actually seen during summer peak load periods. At the same time though, these devices are intriguing as a potential energy storage resource in the SPP market. Although the findings don't warrant a new incentive offering, LES would like to pursue a pilot project to gather more information and develop a better feel for the potential impacts of such a demand response program.

Based on early feedback from nFront Consulting, LES began to investigate such a pilot project in the latter part of 2021. LES ultimately partnered with a local project willing to serve as the site of a pilot; the planned 98-unit multi-family Gatehouse Rows affordable housing development being constructed by Hoppe Development.[8] In order to not impact the Gatehouse Rows construction schedule, an agreement was executed between the two companies in August 2022. The contract calls for LES to cover the incremental cost to upgrade the planned electric resistance water heaters to comparable smart models. LES would also supply the communications equipment necessary to support the project, while Hoppe Development would coordinate all related installation.

5.5 Commercial Kitchen Equipment

nFront Consulting identified high efficiency commercial kitchen equipment – combination ovens, dishwashers and steam cookers – as another potential option for LES to consider incentivizing in the future. When compared to standard efficiency models, they estimated these high efficiency counterparts could result in demand savings ranging from 3.1 kW to 3.6 kW, depending on the specific piece of equipment. Incentives required to drive their adoption were estimated to range from $735 for a combination oven to $1,800 for either a dishwasher or steam cooker. These assumptions result in strong UCT benefit-cost ratios ranging from 2.23 to 5.87, plus marginal RIMs of 0.46 – 0.69.

Unlike residential dehumidifiers, ENERGY STAR versions of this equipment are not as dominant in the market. For steam cookers, ovens and dishwashers in 2020, the U.S. EPA estimated ENERGY STAR rated equipment accounted for only 46%, 54% and 63% of shipments, respectively.

Based on the preliminary modeling results and modest market penetrations, LES intends to begin offering related incentives in the near term. To begin with, these incentives will be part of LES' custom commercial program, allowing time to better evaluate customer interest and benefit-cost impacts.

6.0 LES Load & Capability

6.1 LES Load Forecast

LES utilized their *2022 Long-Range Forecast of Energy Sales, Demand and Number of Customers*, the most current version of LES' annual forecast at the time of this analysis, to assess its need for future resources under the IRP. The 2022 forecast leveraged approximately 20 years of historic data to refine model driven projections for the 2022 - 2050 period. More information on the forecasting process can be found in the long-range forecast document, which is available upon request.

The 2022 forecast was then adjusted for the IRP to remove any consideration of existing energy efficiency and demand response programs offered under the SEP. Since the 2022 IRP process is meant to analyze the relative effectiveness of the SEP against other resource options, any related assumptions regarding its future load impact must effectively be removed from the load forecast going forward. Existing energy efficiency improvements in place in 2022 were assumed to provide their full energy savings for twelve years following their original installation date, at which point these energy savings were assumed to degrade by 20%/year as the related equipment ages out and is replaced. Demand response program impacts were discontinued immediately. Figures 6.1 and 6.2 include plots of the adjusted 2022 long-range forecast for both energy and demand, respectively.

6.2 Existing LES Resource Portfolio

Appendix C lists all of LES' existing generation resources by fuel type, including their location by state, nameplate rating and, if applicable, contractual termination date. Figure 6.3 depicts LES' current supply-side portfolio based on nameplate capacity.

Also included in Appendix C is more information regarding the individual measures currently comprising LES' SEP.

6.3 Load & Capability

Figure 6.4 details how LES' existing resource portfolio, accredited per the SPP Planning Criteria and the IRP's ELCC projections, compares to 112% of its forecasted peak demand. For the purposes of the IRP, LES skipped the last step of SPP's typical ELCC methodology which is meant to allocate each tier's total capacity across individual resources based upon their historical output levels. With no way to associate future wind and solar resources with specific load areas, the IRP analysis simply assumes that each resource within a given tier gets accredited at the same level as the tier aggregate.

As shown, LES' need for the next resource falls somewhere just outside the end of the study period in 2041. Per the chart, LES appears to add resource capacity in 2025. In actuality, this

simply reflects the end of existing short-term capacity sales by LES, which expire after the year 2024.

6.4 Decarbonization Goal

Although LES' existing resource mix provides enough accredited capacity to serve the projected load plus reserve margin over the next 20 years, significant changes are expected during that term. At the end of 2020, LES' Administrative Board established one of the more aggressive utility decarbonization goals in the U.S. today; achieving net-zero CO_2 production from its generation portfolio by the year 2040. The ultimate path and pace to achieving this goal is to be balanced by:

- A continued commitment to maintain high electric system reliability.
- Environmental stewardship.
- A fiscally-responsible focus that carefully considers financial impacts to all customers, especially LES customers with low and fixed incomes.
- Consideration of existing contractual obligations.
- Advancements in generation, energy storage, carbon capture technologies and other emerging solutions.

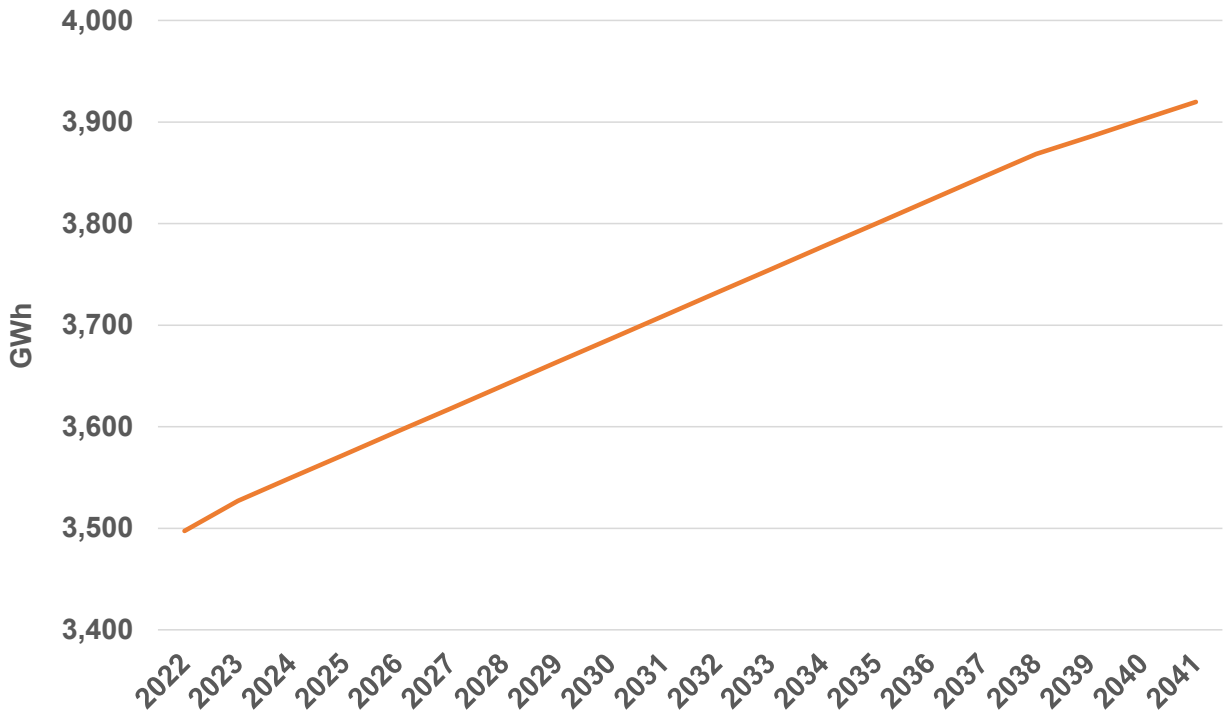

Figure 6.1 LES' load energy forecast without future consideration of the SEP.

Although the net-zero basis of this goal means LES would not need to eliminate all CO_2 emissions, it would still need to get close enough to zero to practically offset the remainder. The 2022 IRP will be the first to be guided by LES' new decarbonization goal

Even before the introduction of the new decarbonization goal, resource changes of some sort were considered highly likely. Based on their initial contract terms, all of LES' existing power purchase agreements for wind and solar will have expired by the end of 2041. In addition, many of LES' fossil assets – Gerald Gentleman Station (GGS), J Street Generating Station, Laramie River Station (LRS) and the Rokeby Generation Station – will have units near or exceeding 60 years of age by that same time. Even beyond age, changes in market pressures and environmental regulations will no doubt also impact the viability of LES' fossil fleet in the future.

Although there are far too many unknowns between now and 2040 for the 2022 IRP to develop a full plan and detailed timeline for achieving the decarbonization goal, LES does expect this process and the related analysis to identify many of the primary building blocks.

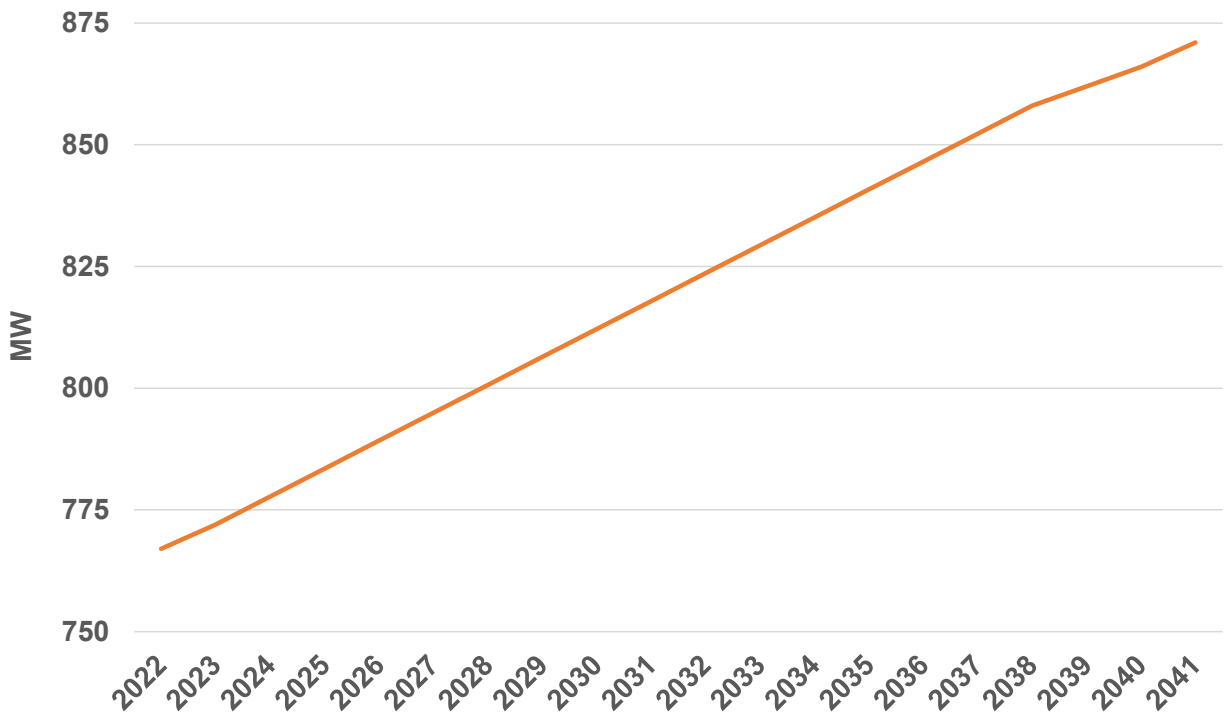

Figure 6.2 LES' peak demand forecast without future consideration of the SEP.

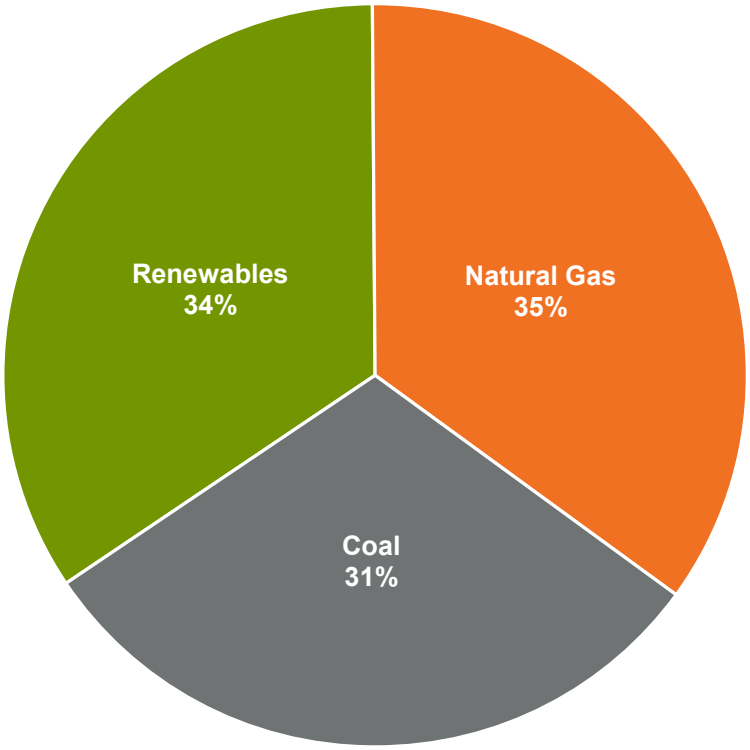

Figure 6.3 LES' 2022 aggregate nameplate rating for supply-side resources.

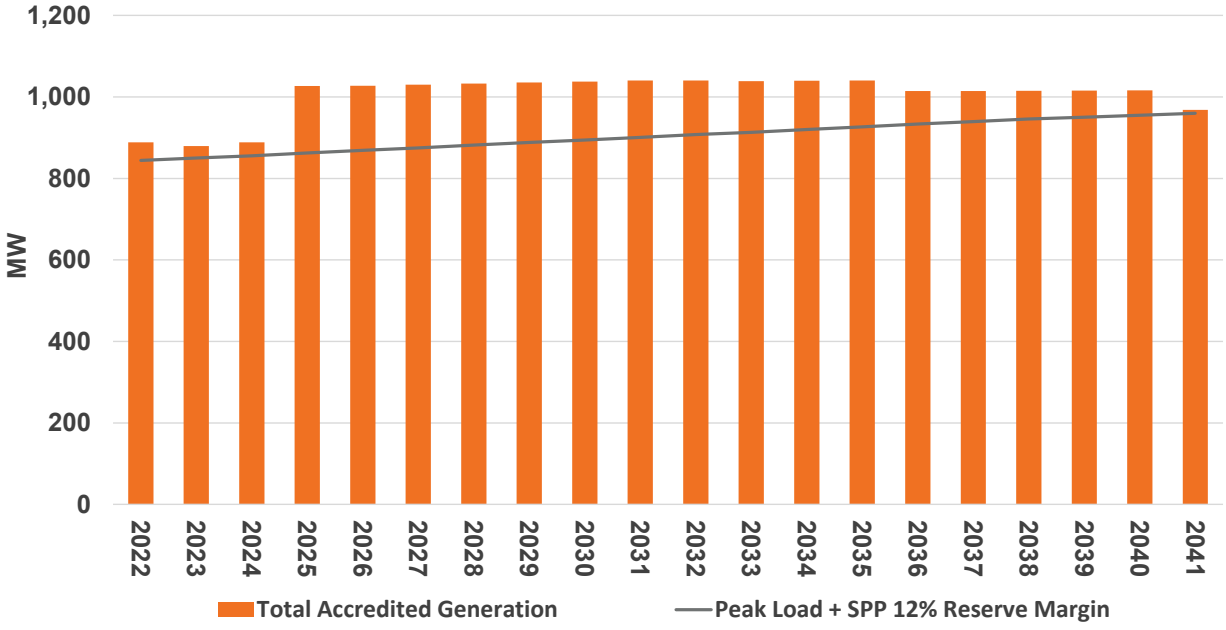

Figure 6.4 LES' future load and capability forecast with a 12% reserve margin requirement.

7.0 Resource Options Analysis – Input Data

In order to make informed decisions regarding the future of LES' resource portfolio, LES sought to evaluate a wide range of future potential options, both supply-side (i.e., generation) and demand-side (i.e., energy efficiency and demand response). To support the related modeling, LES leveraged input data from a variety of reputable, public sources.

7.1 Resource Alternatives

When evaluating different resources and technologies, it is imperative to start with a data set based upon a common set of assumptions. LES selected the U.S. Energy Information Administration's (EIA) *2022 Cost and Performance Characteristics of New Generating Technologies*, a supplement to the EIA's underlying 2020 edition of their *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*.[9,10] These references sourced the following common set of data for new generation alternatives located in SPP:

- Capital construction costs and lead times
- Fixed and variable operations and maintenance costs
- Operating performance
- Emissions performance

In response to an LES request, the EIA also provided their forced outage rate assumptions for the various resource types, which are not typically published.

This EIA dataset encompasses a wide range of supply-side resources, most of which would ultimately provide LES the flexibility to either construct the resource directly or to indirectly contract for the resource under a power purchase type arrangement. A few of these resource options were removed from consideration on the front end though, as follows:

1) The potential for a wide range of future carbon regulations suggests that investment in new fossil resources traditionally designed to operate at higher capacity factors – coal or natural gas combined cycle –would likely not be considered a viable option unless they could attain optimal CO_2 reductions of 90%. For this reason, the following options were removed from the new resource model set:
    - Ultra-supercritical pulverized coal without Carbon Capture and Sequestration (CCS)
    - Ultra-supercritical pulverized coal with 30% reduction CCS
    - Combined-cycle, both single- and multi-shaft, without CCS

2) Although it is possible to move energy from one electricity market to another, the process of serving load is greatly simplified if generators and load exist within the same market, meaning a location within the SPP area is nearly always preferred. The following resources were removed because they are not generally practical in the SPP region:

- Geothermal– The hydrothermal technology detailed in the EIA dataset requires naturally occurring geological energy sources located relatively close to the earth's surface, which are not thought to exist within the SPP region.[11]
- Hydropower – The EIA modeled a traditional plant with a dam and storage reservoir. The potential for future hydropower projects of this type is thought to be limited, with practical areas already being developed.[12]
- Municipal solid waste to landfill gas – LES has already cooperated with the City of Lincoln to leverage the Lincoln landfill's methane gas discharge for power production. The potential for LES development of another facility outside the LES service area is thought to be minimal.
- Offshore wind – The SPP region is not bordered by any ocean waters or the Great Lakes.

LES supplemented the remaining list of new options with the retrofit of CCS to its existing Walter Scott Energy Center Unit 4 (WS4) coal resource, as based on the cost and performance assumptions outlined in the U.S. EIA's *Electricity Market Module* update for 2022.[13] Per the modeling assumptions, WS4 has the best heat rate – representing the input fuel energy required to generate a single kWh – of all of LES' coal resources, giving it the best starting point to successfully navigate the inherent heat rate degradation projected after adding CCS. In addition, it's also LES' newest coal resource, with the potential remaining longevity to help justify a capital-intensive updated of this caliber.

A short description of each of these supply-side resources is listed in Appendix D. For demand-side resource options, LES considered the continuation of its existing SEP, a broad collection of various energy-efficiency and demand-response incentives. Future cost and performance data is modeled to reflect the programs' impact over the last few years.

LES escalated all EIA cost data to 2022 dollars by applying a common Consumer Price Index (CPI); an annual inflation escalator of 2.0%, equivalent to the latest long-term FOMC target used in the SEP analysis. Future fixed and variable operations and maintenance costs were assumed to continue escalating according to the CPI.

LES applied the EIA's "SPPN" regional cost adjustments to all construction cost data, fine-tuning those values to be more representative of projects located in the northern portion of SPP. Future construction cost trends for these new resources were taken from the EIA's *Annual Energy Outlook*, specifically Table 55, *Overnight Capital Costs for New Electricity Generating Plants*.[14] Future construction costs for the WS4 CCS retrofit were adjusted to reflect the EIA escalations for a new coal unit with CCS.

Federal tax credits were not assumed because at the time the IRP analysis was commenced (i) the various credits were scheduled to either expire or reach a minimal value within the first two to three years of the study period, and (ii) as a tax-exempt entity, LES could not make direct benefit of them.

Finally, LES assumed joint ownership of larger resources that resulted in roughly a 100-MW nameplate share for LES. As a general rule, LES typically plans for maximum unit ratings of around 100 MW, helping to ensure that too much significance isn't placed on any one resource.

A summary of the resultant cost and performance data for each technology is included in Appendix E.

The only broad category of resources not covered by the EIA dataset would appear to be cogeneration and district heating and cooling. This omission is of little concern in this particular case because the installation of these types of resources is generally outside of LES' purview. In 1989, the City of Lincoln and Lancaster County formed the District Energy Corporation (DEC) under the State of Nebraska's Interlocal Corporation Act, with the mission to provide low-cost, reliable and efficient thermal energy services. The DEC has successfully launched a number of district heating and cooling projects in the Lincoln area and is constantly in the process of assessing future potential opportunities. Although not ultimately responsible for the DEC, LES does serve as a contractor, providing administrative, financial, engineering, operations and general corporate functions.

7.2 Transmission Costs

The EIA resource cost data accounted for the electrical interconnection of the facility, typically assuming construction of a one-mile transmission line with no associated substation upgrades. In addition, LES included costs for generator interconnection and firm transmission service to the LES load area through SPP. In both cases, SPP identifies the system upgrades required to provide service. It is impossible to predict these costs, as they depend not only on the end points being studied but also on other interconnection and transmission service requests that are to be analyzed in aggregate under the same study queue. Therefore, based on recent history for existing or pending resources, LES assumed a uniform cost of $250,000 per nameplate MW of generation to represent the aggregate interconnection and transmission service cost.

SPP interconnection and transmission service costs do not apply to DSM options such as SEP, as inherently no transmission of generation is required to support these load curtailment resources. In addition, interconnection and transmission service costs were likewise not applied to the EIA's distributed generation resource options, as these would presumably be interconnected at the distribution level and not subject to the related SPP processes. Still, it is important to note that if large amounts of distributed generation were to be installed across the SPP footprint, typical interconnection and transmission service costs would likely be mandated by SPP to apply in the near future.

7.3 Fuel Costs

With a couple of exceptions, future fuel-specific costs were modeled per the EIA's *Annual Energy Outlook 2022*, specifically Table 3, *Energy Prices by Sector and Source*, which includes

projections out to 2050.[15] The CPI was then applied to convert those future projections to the relevant year.

The first exception was for biomass, with the 2022 price reflecting the EIA's *Monthly Densified Biomass Fuel Report*, specifically Table 7, *Domestic Sales and Average Price of Densified Biomass Fuel, 2022*.[16] Future price escalations reflected the CPI.

The second exception to this approach was natural gas prices, historically shown to be a primary driver in resource decisions while also reflecting a significant amount of volatility. In order to display results across a wide range of natural gas futures, each case was ran with annual average natural gas costs (2022 $) ranging from $1.00 per million British thermal units (MMBTU) to $10.00/MMBTU. This range is quite representative of recent history, as natural gas spot prices at the Henry Hub have spanned from an annual average low of approximately $2.03/MMBTU in 2020 to a high of $8.86/MMBTU in 2008.[17] Monthly price profiles were developed from the monthly Henry Hub averages over the historical period from 2009 - 2021. Future natural gas price escalations were represented by the CPI.

7.4 Emissions Costs

The EIA resource data accounted for emissions rates after implementation of best available control technology (BACT), including sulfur dioxide (SO_2), nitrogen oxide (NO_X), particulate matter, mercury, and where applicable, carbon dioxide (CO_2). Therefore, the related emissions controls were inherently included in the cost and performance data for all applicable resource options.

Additional regulatory costs associated with actual CO_2 emissions have the potential to be a primary driver in future resource decisions. The U.S. EPA's current strategic plan includes a long-term performance goal to issue final rules to reduce greenhouse gas emissions from electric utility generating units, including CO_2, by September 30, 2026.[18]

In order to display results across a wide range of CO_2 regulated futures, each case was ran with initial CO_2 emissions costs ranging from $0/short ton to $90/short ton (2022 $). Regulated CO_2 costs were assumed to be uniformly applied to all resources in SPP starting in 2025. A maximum $90/short ton in 2022 dollars, equating to approximately $99/metric ton, was considered a representative value for the U.S. Government's current estimates, which range from $17 - $83/metric ton in 2025 (2020 $) depending on the three different discount rates used in their cases.[19] These U.S. Government estimates include an annual price escalator ranging from 1.3% to 2.6% in 2020 dollars, with an average across the three discount rate cases of 1.9%. Again, to provide analysis representative of these estimates, starting in 2025 LES applied an annual escalation of 2.0% in addition to the CPI, for a total of 4.0%.

8.0 Resource Options Analysis

LES utilized an Electric Power Research Institute (EPRI) software tool, the Electrical Generation Expansion Analysis System (EGEAS), for the analysis of the various resource alternatives.[20] EGEAS was originally developed by EPRI in 1983, and is currently in use by numerous companies, including the Midcontinent Independent System Operator (MISO).[21]

8.1 EGEAS Model Architecture

EGEAS utilizes dynamic programming, evaluating all possible resource combinations, to identify an optimal solution based on the NPV of LES' total production costs. This includes consideration of construction costs, operating costs and reliability constraints. The first reliability constraint applied in the IRP analysis is the SPP reserve margin, assuring that LES maintains enough accredited generation to meet at least 112% of peak load. Although not required by SPP, LES also applies a maximum limit of no more than 135% of peak load. Although somewhat arbitrary, this ceiling ensures EGEAS doesn't add an unreasonable number of resources just because it thinks they may be economically beneficial under a particular scenario. In reality, LES would never plan to drastically exceed its reserve margin requirements purely for potential economic gain, as that would place undue financial risk on its customer-owners.

The second reliability constraint is maintaining a Loss of Load Probability (LOLP) for the LES system – when system demand exceeds the available generation – of no more than two days in ten years. SPP's reserve margin requirements are designed to maintain a footprint-wide LOLP of no more than one day of load loss in ten years, but SPP does not extend specific LOLP requirements to its individual members.[22] However, LES applies a slightly relaxed LOLP in its own resource planning – twice that of the SPP criteria – to ensure it is still sufficiently contributing to area reliability.

EGEAS allows for two independent systems, interconnected by a single, representative transmission tie, allowing for purchases and sales between the two areas. For the IRP, *System A* represents LES, including LES' existing resource portfolio and LES' 2022 load forecast. *System B* represents SPP, including SPP's existing resource portfolio and aggregate load forecast. SPP's future resource and load projections were both derived from SPP's 2021 Integrated Transmission Planning (ITP) model, specifically their emerging technologies future.[23] This future case was the more aggressive of the two ITP models developed by SPP, assuming higher solar, wind and energy storage resource penetrations, as well as increased adoption of electric vehicles, distributed generation, demand response and energy efficiency.

The 10-year ITP model included resource mix projections for the years 2023 (year 2), 2026 (year 5) and 2031 (year 10). LES then leveraged consistent assumptions to develop a year-20 resource mix for 2041. For both wind and solar, the assumed growth rates through year 10 were extended along their respective trajectories through year 20. In keeping with SPP's modeling, energy storage was assumed to have a penetration equivalent to 35% that of solar and consist

entirely of 4-hour battery projects. Fossil resources continued to follow the same prescribed retirements of the SPP model, with all non-LES coal and natural gas units assumed to retire at age 52+ and 48+, respectively. Finally, new natural gas combustion turbines were added any time the SPP footprint required additional generation to maintain its required 12% reserve margin. The resultant resource mix for all four model years, as well as the coincident SPP footprint peak demand, is depicted in Figure 8.1. The resource mix for intermediate years were then simply interpolated between these four milestones.

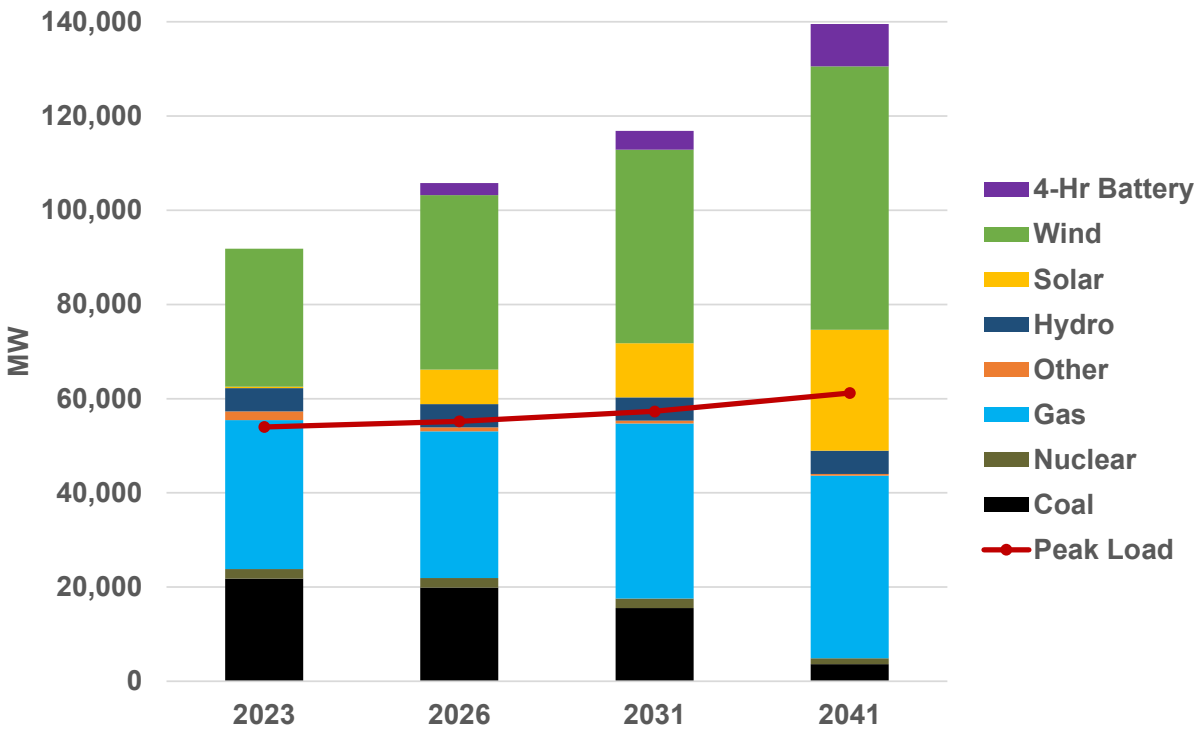

Figure 8.1 Future resource mix for the SPP region.

Unit-specific nameplate ratings, heat rates, non-dispatchable output profiles, delivered fuel costs, and fixed and variable operations & maintenance costs were derived from the 2021 ITP model, including for LES' existing units. Future operations and maintenance and fuel costs were escalated consistent with treatment of the new EIA resource alternatives.

A transmission interconnection of 250 MW was installed between the two areas. In actuality, LES' interconnection to SPP is robust enough, with all existing transmission in service, to effectively allow LES to serve its current peak load externally from SPP without operating LES' own internal units. However, LES limited the interconnection to 250 MW, a level that was large enough to mimic the role of the SPP market in LES operations, yet still not so large as to allow market purchases and/or sales to become the dominant factor in resource decisions.

Given LES' load forecast and existing resource portfolio, EGEAS develops the optimal, lowest cost resource expansion plan for LES while accounting for potential sales to, and purchases

from, SPP. EGEAS does not develop an expansion plan for SPP but does optimize the SPP area costs and ensure their load is served reliably. The LES expansion plan must maintain the reserve margin and LOLP requirements across a study period of 20 years, ranging from 2022 to 2041. To capture all of the financing costs of new unit additions, EGEAS also includes a 30-year extension period, from 2042 to 2071. During this extension period, EGEAS assumes no future load growth or new resource additions for neither LES nor SPP, but resources are automatically replaced with like substitutes at the scheduled time of retirement. For this reason, resources selections made late in the study period should generally not be valued as much as those made early in the period. Since EGEAS assumes no load growth during the extension period, the lowest cost option late in the initial study period often turns out to be the relatively smaller one that more closely meets the near-term reserve margin requirements, as EGEAS believes it isn't cost effective to install a larger resource that results in excess capacity that will never be needed.

The model utilized a discount rate of 4.5% – reflecting LES' WACC – and unless otherwise noted, the annual escalation rate for the costs of all goods and services was consistently assumed to be the CPI.

8.2 New Resource Option Screening

The complexities of EGEAS' dynamic programming, considering all possible resource combinations, inherently limits how many options can be evaluated. In order to remain within these limits, LES preliminarily screened the EIA's list of new resource options to reduce them to a more manageable subset.

For dispatchable resources, LES utilized EGEAS' built-in screening curve methodology, which provides a preliminary but quick comparison of options for a given year. EGEAS varies the capacity factor of each resource from 0% to 100% in 10% increments, recording the total production costs per nameplate kW. Resources whose per-unit production costs are consistently among the most expensive under this screening analysis are unlikely to be selected in a full dynamic model run. EGEAS' screening curve analysis was applied as follows:

1) *Analyze all dispatchable EIA resource options, eliminating any alternatives that are routinely not cost competitive.*

   LES used EGEAS to screen each of the dispatchable resource alternatives in the year 2030 across four separate scenarios; the extreme intersections of the natural gas and CO_2 price combinations. For each scenario, both the production cost results and their relative ranking by production cost are listed in Appendix F.

   The following two resource options routinely displayed the highest operating costs, somewhat separating from the rest of the alternatives, and were therefore eliminated from further consideration:

   - Biomass – For capacity factors ranging from 10% - 100% across the four scenarios, biomass was amongst the top two highest cost options 100% of the time and was the highest cost option about 93% of the time.

- Fuel cells – Again considering capacity factors from 10% - 100%, fuel cells landed in the top two highest cost options over 68% of the scenarios, taking the top spot approximately 8% of the time.

2) *Analyze all similar EIA dispatchable resources, retaining only the best performing option.*

   Leveraging the screening curve results in Appendix F, LES compared the following similar resource options for capacity factors ranging from 10% to 100%:

   - Light water reactor nuclear vs. small modular reactor nuclear – Light water reactors represented the lower cost of these two options 100% of the time, so small modular reactors were eliminated.
   - Aeroderivative vs. industrial frame combustion turbines – Industrial frame turbines were eliminated, as aeroderivative combustion turbines represented the lower cost of these two options across 60% of the cases.
   - Internal combustion engines vs. base/peak distributed generation – Internal combustion engines represented the lowest cost option amongst these three resources 60% of the time, so the two distributed generation options were removed.

To further refine the list of new resource options, LES applied one additional step of screening with regards to the non-dispatchable resources:

3) *Compare non-dispatchable EIA resources from within similar technological families, eliminating those that are uniformly inferior when considering capital construction and operations and maintenance costs.*

   - Solar thermal vs. hybrid solar photovoltaics plus battery storage – Solar thermal has drastically higher construction and fixed operations and maintenance costs, so it was eliminated. Although the solar thermal resource does provide eight hours of energy storage as opposed to only four hours for the hybrid option, the capital and fixed costs of the solar thermal option are so high that the hybrid system would still represent the lower cost alternative even if a second 4-hour battery storage project were incorporated.

Following this screening process, Table 8.1 lists the resulting final set of resource options to be evaluated by EGEAS, including the related resource name abbreviations used throughout this report.

8.3 Dynamic Modeling Process

Based on the load and capability chart in Figure 6.4, no new LES resources were required to meet SPP's reserve margin requirements over the entire study period of 2022 – 2041. However, that chart assumes all of LES' existing resources remain in service, which would not be the case under many scenarios due to the market pressure induced by the modeled natural gas and/or regulated CO_2 costs.

EGEAS has built-in functionality to identify when plant retirements would be financially beneficial, however, it may not represent all real world considerations in certain scenarios. For example, EGEAS' lowest-cost resource plan may call for holding a particular unit off the entire year, simply paying the fixed operations and maintenance costs but never actually running. EGEAS may see this as the lowest cost option for meeting reserve margin requirements, as letting an existing unit sit mostly idle may still be cheaper than building a new alternative, albeit one with lower operating costs. This approach makes perfect sense when talking about peaking units, like natural gas combustion turbines, as they were designed to fill just this niche. However, this thought process does not apply well to coal resources, which aren't quick to respond after being offline and may require far too many plant staff to routinely be down for extended periods.

To identify potential coal plant retirements, LES ran EGEAS' dynamic model in two distinct steps. A first round of analysis was conducted solely to identify whenever an existing LES coal plant exhibited an annual capacity factor of less than 20%. For example, an annual 20% capacity factor would be equivalent to a coal plant that is only operated seasonally over (i) four months in the summer season at an average 60% capacity factor, or (ii) six months in the core summer and winter seasons at an average capacity factor of 40%.[24] A unit was then slated for retirement if it fell below this threshold for five consecutive years, allowing time to ensure these low operating levels weren't temporary in nature. This bright line of less than a 20% capacity factor for five years, while somewhat arbitrary, helps to provide a reasonable litmus test for when market pressures might be on the verge of driving the closure of a coal resource. The first year a unit could be retired was 2029, ensuring all of the new resource options could be constructed and in place by that time. In reality, as a minority owner in LRS and WS4, and with a life-of-plant participation agreement in GGS, LES wouldn't have the ability to make retirement decisions at any of its coal resources. However, this capacity factor metric provides a hypothetical scenario under which to analyze the potential loss of those facilities.

Once identified, LES then built these coal retirements into the model, running a second round of analysis to see what new resources EGEAS would add to restore LES' reserve margin requirements. All resources included in Appendix D were considered, with the exception of the hybrid solar and battery storage option. In the initial analysis, solar and battery storage resources were only considered separately to develop a feel for how they would stand on their own merits.

EGEAS had the option to apply the WS4 CCS retrofit at any time if it thought the upgrade was economically justified. However, if WS4 was preliminarily slated for retirement based on a low capacity factor, then EGEAS was only allowed to preempt that retirement if it applied the CCS upgrade in the planned retirement year.

Table 8.1 Final set of resource options to be evaluated by EGEAS.

Resource	Abbreviation
Battery Storage	Battery
Natural Gas Combined Cycle with 90% CCS	NGCC CCS
Natural Gas Combustion Turbine - Aeroderivative	NGCT
Natural Gas Internal Combustion Engine	RICE
Nuclear - Light Water Reactor	Nuclear
Solar Photovoltaics + Battery Storage	Hybrid Solar
Solar Photovoltaics with Tracking	Solar
Sustainable Energy Program	DSM SEP
Ultra-Supercritical Coal with 90% CCS	Coal CCS
Wind - Onshore	Wind
WS4 90% CCS Retrofit	WS4 CCS Upgrade

9.0 Base Case

9.1 Interpreting the Results

Appendix G includes EGEAS' lowest cost resource expansion plan for each of the 100 scenarios ran under the base case model, based upon total production costs over the full extent of the 2022 – 2041 study period and the 2042 – 2071 extension period. The results are displayed in matrix format, listing the new resource additions and coal plant retirements for each possible combination of natural gas price and regulatory value of CO_2 emissions. The results also include (i) the total LES portfolio CO_2 emissions in short tons for the year 2040 (labeled as CO2), (ii) the net present value of total production costs for the full 2022 – 2041 study period (labeled as NPV), and (iii) the net present value of total production costs over the 2022 – 2041 study period plus the subsequent 30-year extension period (labeled as NPVE). An example of the expansion plan format for each scenario is shown in Figure 9.1.

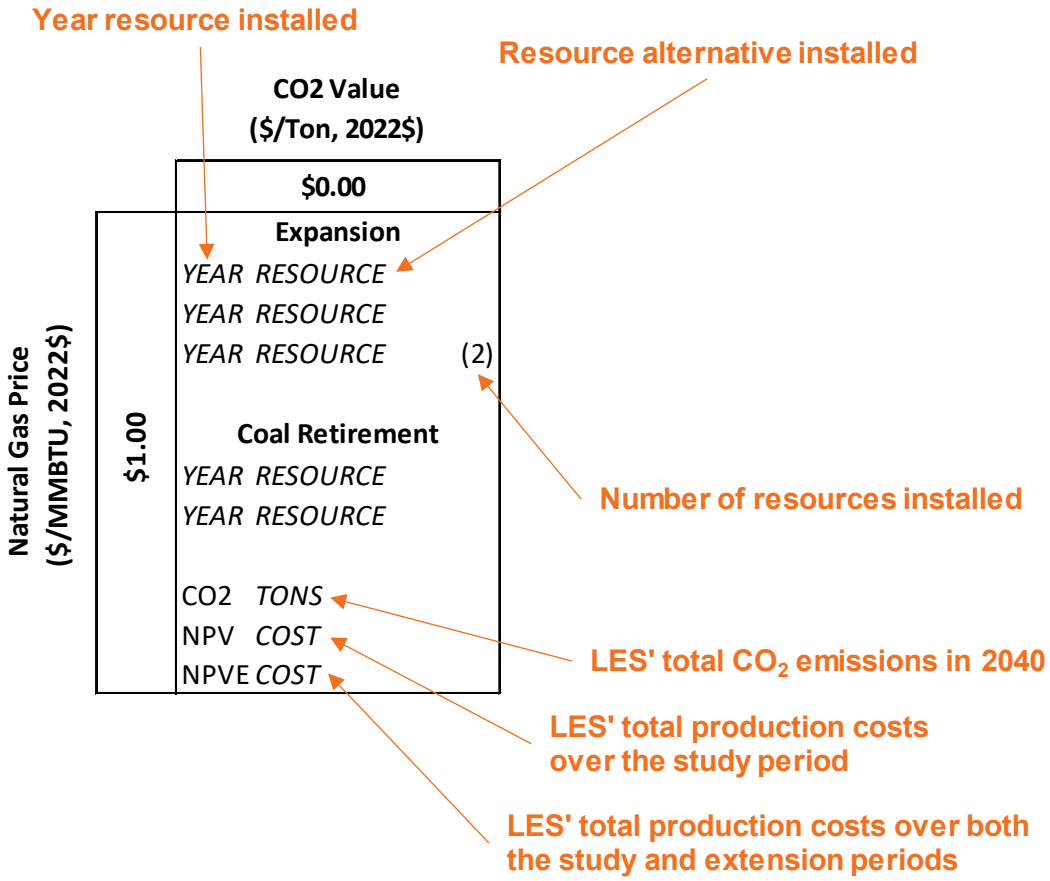

Figure 9.1 Example of expansion plan's overall results.

While the expansion plan matrix provides important, detailed results for each specific scenario, the complexity of these same details also makes it hard to identify trends across a range of potential future states. For this reason, summary tables specific to each resource are also

provided in Appendix G. Depending on the table, these identify if and when a specific resource was either first selected or retired as part of EGEAS' expansion plan for each of the 100 scenarios studied. The actual year of resource installation or retirement is identified according to a color gradient, as denoted in the example in Figure 9.2.

As shown in Figure 9.2, the darker the shading, the earlier a resource was first selected or retired in the expansion plan. Comparing these color gradients across the entire 100-case study yields a quick comparison of the relative value derived from different resource types. For example, take the results for two new sample resources shown in Figure 9.3. *Resource A* was first added as part of the optimal, lowest cost expansion plan over a much wider range of scenarios than Resource B and was also generally selected much earlier in the study period. There's no way to tell what future scenario will pay out in reality but selecting a resource with broad application increases the odds of success. Therefore, *Resource A* would appear to bring more long term value to LES than *Resource B* over a wide range of potential future states.

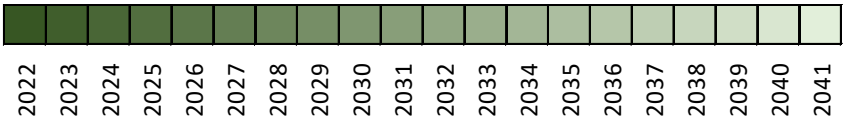

Figure 9.2 Key for expansion plan resource specific summaries, representing year installed.

9.2 Results

By examining the retirement summary tables listed on page 2 of the results in Appendix G, one can see market forces generally push the coal resources to potential retirement – again, as identified by the resource registering an annual capacity factor of less than 20% for five consecutive years – whenever natural gas prices are low and/or regulated CO_2 prices are high. Both of these scenarios render the coal resources financially less competitive in the SPP market, resulting in low capacity factors and leading to potential retirement.

Upon a closer look at the results, one can see the coal resources generally reach retirement in the following order: GGS unit 2 (GGS2), GGS unit 1 (GGS1), LRS unit 1 (LRS1) and finally WS4. Due to the single representative transmission interconnection between LES and SPP, EGEAS cannot distinguish the geographic price and demand diversity seen in the real world SPP market. For this reason, the potential coal retirements simply run in the opposite order of their estimated operating costs, with the relatively higher cost resources – at least according to the SPP model data – seeing their capacity factors reduced first. The general retirement trend should be the key takeaway of this analysis, as the order of retirement may not be indicative of reality.

Once the retirements were incorporated in the model, the analysis was rerun to identify the new resources EGEAS favors as replacements. Although nearly all of the options were selected at one point or another across the 100 diverse scenarios, a few trends do emerge, including:

- In nearly all cases, EGEAS generally favors replacing at least some portion of LES' existing Tier I Wind resources – Arbuckle, Buckeye and Prairie Breeze II – once their respective contracts expire. Except for scenarios with (i) very low natural gas prices, or (ii) a combination of higher natural gas and CO_2 prices, many of these are prioritized selections made well before the end of the study period.

  EGEAS doesn't typically select Tier II Wind though, other than in a handful of cases where it adds Tier II Wind a few years before it automatically graduates to Tier I Wind status following the expiration of an existing LES contract. This is a direct result of the ELCC advantage for Tier I Wind, providing significantly higher accreditation levels than wind resources under Tier II.

- Although not quite as uniformly as wind, EGEAS selects Tier I Solar at some point during the study period in most cases. Many of these occur in the mid-2030's on the heels of the coal retirements, indicating solid value.

  EGEAS makes no selections of Tier II Solar, again due to the related accreditation levels that are much lower than for solar resources designated as Tier I.

- Tier I battery storage (Tier I Battery) was selected in only a very few cases, driven by the confluence of the lowest natural gas and CO_2 price combinations. EGEAS' limited use of this resource, restricted to only when charging costs would be the lowest, is likely due to its relatively short service life of 10 years and its limited duration of 4 hours.

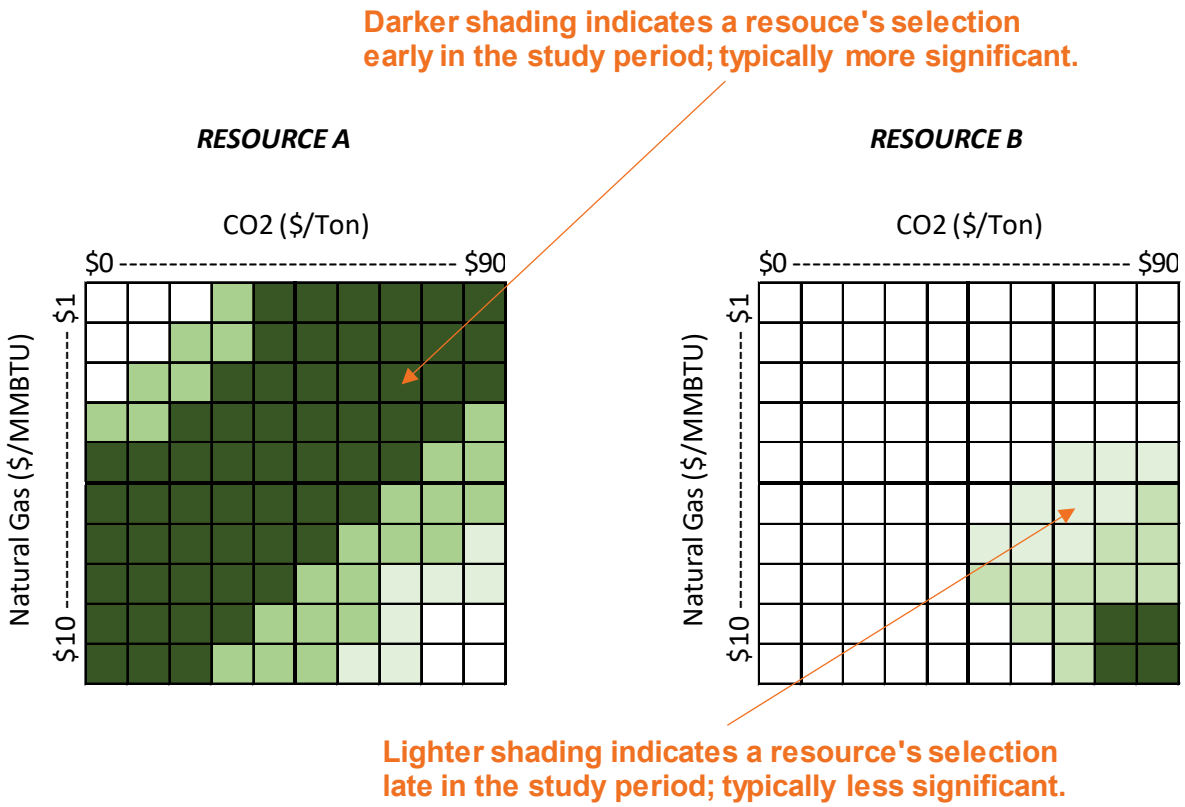

Figure 9.3 Example of expansion plan resource specific summaries.

- Although somewhat sporadic in its distribution, the continuation of the LES SEP (DSM SEP) was selected in just over half of the scenarios, with many of those coming well before the later years of the study period. The relatively smaller capacity rating of the SEP typically only delays the inevitable addition of another supply-side resource in most cases, but EGEAS often still saw enough value to make it part of the portfolio.
- Outside of cases with the highest CO_2 costs, simple cycle Natural Gas Combustion Turbines (NGCT) and Reciprocating Internal Combustion Engines (RICE) were selected relatively early in the study period for scenarios with the lowest natural gas prices. This isn't unexpected, as the low fuel costs make these resources very competitive, even with modest levels of CO_2 prices.

  Less significantly, RICE units were also selected in the last year of the study period for a number of cases, most likely due more to their relatively small size as opposed to their cost compared to other options.
- Natural Gas Combined Cycle with 90% Carbon Capture and Sequestration (NGCC CCS) was a dominant selection for scenarios with low to moderate natural gas prices and all but the lowest CO_2 costs. The majority of these selections were included as a direct replacement for retired coal resources, coming in the same year.
- The CCS retrofit of WS4 (WS4 CCS Upgrade) was a dominant selection for scenarios with both moderate to high natural gas and CO_2 prices. Again, many of these selections came in the same year as coal retirements.
- New coal resources constructed with 90% CCS (Coal CCS) and nuclear plants (Nuclear) took turns being strong selections in cases where the highest natural gas prices coincided with moderate to high CO_2 prices. About a third of these selections – mostly all Nuclear – were made in the absence of any coal retirements, showing that natural gas and CO_2 costs would drive sufficiently high enough market prices in those scenarios to justify the high capital cost of a resource addition even if not required from a reserve margin standpoint.

Total LES production costs over the 20-year study period ranged from $1.4B to $4.8B NPV. Not unsurprisingly, these production costs tend to track natural gas and CO_2 prices; lower for the combination of low natural gas and CO_2 prices and highest when natural gas and CO_2 prices are near their peak. These two indexes directly result in higher operating costs, but likely even more impactful, they also drive new capital-intensive resource additions in response to the coal retirements and/or market forces.

To provide another measure of the financial impacts, LES used its current financial model to analyze the incremental rate impact of the change in natural gas and CO_2 prices relative to a starting position of $3.00/MMBTU natural gas and no regulated value for CO_2 emissions. This evaluation was conducted for the two base case scenarios representing the minimum and maximum total production costs for the study plus extension period. The cumulative, incremental rate decreases/increases through 2041 ranged from -8% to +137%. The high-end of this range would equate to a cumulative, incremental cost of approximately $24,000 by 2041 for a typical residential customer and $58M for a typical industrial customer. These increases would be in addition to any rate impacts LES would have incurred outside the changes in total

production costs due to natural gas and CO_2 prices, such as distribution and transmission system improvements, administrative costs, etc.

2040 CO_2 emissions also vary greatly, from 365 to 2,686 kilotons. Again, as expected, these tend to go down as the regulated CO_2 price goes up. This is a result of lower fossil fuel dispatch, both with and without coal resource retirements. Although much remains to be seen in the way of related technology advancements, LES believes it may be reasonable in 2040 to offset around 500,000 tons of CO_2 emissions annually, representing about 12% of LES' total portfolio CO_2 emissions in 2010. For the time being, that provides a placeholder for the maximum post-2040 CO2 emissions allowed in order to meet its net zero decarbonization goal. Roughly 30% of the cases fall below or around this threshold, aligning with the retirement or CCS-retrofit of nearly all coal resources. This analysis reinforces that LES' entire coal fleet will need to be addressed, either through retirement or CO_2 abatement, in order to meet the decarbonization goal.

10.0 Sensitivities

In order to more fully assess the various resource alternatives, LES also undertook a number of sensitivities. The results of each of the sensitivities are included in Appendix H and utilize the same general format as the base case analysis. Where applicable, the results also include summary tables for easy comparison to the base case, depicting the relative change in LES CO_2 emissions and total production costs for both the study period and the study period plus 30-year extension period . Similar to the resource summary tables, the darker the shading, the larger the change relative to the base case. Decreases from base case levels are depicted in blue, while increases are shown in red.

Summaries of the results are included below, all referenced against the original base case.

10.1 Changes in New Resource Alternatives

10.1.1 Sensitivity 1: No CCS Resources

The base case analysis included various options with CCS. From a practical standpoint though, these technologies are not generally considered commercially available at this point. Since it's uncertain when, or even if, these resources will be viable in the future, this sensitivity reran the base case analysis without any of the CCS-enabled options; Coal CCS, NGCC CCS, or WS4 CCS Upgrade.

The bulk of the changes in new resource selections could be attributed to two options. At lower natural gas prices, NGCT was typically selected in place of NGCC CCS. At higher CO_2 prices, Nuclear was generally selected in place of NGCC CCS and the WS4 CCS upgrade.

There generally weren't any other significant changes, although Tier I Solar and DSM SEP did see some adjustments in their selections. Both gave up a little ground to Nuclear at the intersection of the highest natural gas and CO_2 prices, which would represent the highest electricity prices in SPP. Solar and DSM SEP are actually more valuable under those future scenarios, but the large amounts of low-priced energy production from nuclear represents a better financial solution. DSM SEP also gained some ground in futures with lower natural gas prices coupled with higher CO_2 prices, capturing selections originally targeting NGCC CCS.

Any cases where a CCS-enabled option was originally selected in the base case reflect a relative increase in production costs for the study period plus 30-year extension period. Although the portfolios were optimized for the study period plus extension period, production costs over just the 2022 – 2041 study period still generally tracked the same. In the absence of the preferred CCS options, EGEAS' next best resource plan in those cases came at a higher cost, typically driven at least in part by higher CO_2 emissions.

10.1.2 Sensitivity 2: No CCS or Nuclear Resources

This case builds upon the CCS resource uncertainty laid out under the previous sensitivity, while also eliminating nuclear units from the available resource options. Although the light water reactor nuclear technology considered in the base case has been around for decades, LES would likely be too small a utility to construct and own one of these plants. Small modular nuclear units may be more right-sized for LES, but similar to CCS, this technology hasn't proven to be commercially available as of yet. For these reasons, LES' primary path to incorporating nuclear in its portfolio would currently appear to be as a minority owner/participant in a large project. This configuration brings uncertainty, as LES would control neither the introduction nor timeline of such a project under this scenario.

Under Sensitivity 1, nuclear was one of the resources the model leaned heavily on in the absence of CCS options. With nuclear also eliminated from consideration, a combination of natural gas resources was generally selected to fill the void left by the coal retirements; primarily NGCT, supplemented by secondary selections of RICE units. DSM SEP also saw significantly more use at higher natural gas and CO_2 prices.

Similar to Sensitivity 1, any cases where a CCS-enabled or nuclear resource was originally selected in the base case reflect a relative increase in 2040 CO_2 emissions and production costs for the study period plus 30-year extension period. The change in CO_2 emissions and production costs over the full study period plus extension period were generally more extreme than those seen in Sensitivity 1 because more resource alternatives were removed from EGEAS' available options. Interestingly though, the increase in production costs for the 2022 – 2041 study period was reduced from the levels of Sensitivity 1 for some cases. A closer examination of the results shows this is primarily due to the expanded selection of nuclear units in Sensitivity 1. Although Nuclear was the best choice in the long run of the study period plus the 30-year extension period in these scenarios, the 20-year study period alone was not long enough to justify and overcome the high construction costs seen in Sensitivity 1.

10.1.3 Sensitivity 3: Hybrid Solar + Storage Option

The EIA resource options included a hybrid solar photovoltaic and battery storage project (Hybrid Solar). The base case evaluated these two resources independently, but this sensitivity also introduced the hybrid option, evaluating the improved financial metrics of a joint installation. Specifically, this hybrid option represents a combination of Tier I Solar and Tier I Battery.

The inherent economies-of-scale of a joint installation didn't have much impact on the results. The solar and battery hybrid generally replaced standalone solar for cases with low natural gas or CO_2 prices, but otherwise the resource selections didn't change significantly.

As one would expect, the cases where the hybrid was selected did result in relatively lower costs over the study plus 30-year extension period when compared to the base case. In addition, these same cases typically resulted in lower CO_2 emissions due to the inclusion of the battery storage.

10.2 Changes in Existing Resource Retirements

10.2.1 Sensitivity 4: Retire All LES Coal Resources in 2029

As opposed to identifying coal retirements based on low capacity factors, this sensitivity simply retired all of LES' existing coal units in 2029. A practical scenario for this sensitivity could be a common set of new environmental regulations that were considered too costly to implement.

EGEAS continued to lean heavily on dispatchable alternatives to compensate for the loss of the coal resources, which now span all 100 cases. At lower CO_2 prices it preferred NGCT, even selecting it more as natural gas prices increased. At first glance this may seem counterintuitive, but the model mostly installed these low-capital cost resources for accredited capacity at higher natural gas prices, choosing only to run them when absolutely necessary to maintain system reliability.

Compared to the base case, NGCC CCS saw much more extensive use at higher natural gas prices. Nuclear resources were still relegated to mostly higher gas prices, but now they were selected for nearly any level of regulated CO_2 price. Coal CCS also saw broader selection, but for a similar mix of natural gas and CO_2 prices as seen in the base case. Although the changes weren't nearly as extensive, Tier I Solar and DSM SEP were generally utilized more for scenarios other than the intersection of the highest natural gas and CO_2 prices, mostly surrendering ground in that quadrant to Coal CCS, NGCC CCS and Nuclear. With no reliance on natural gas and no associated CO_2 emissions, Tier I Solar and DSM SEP actually have increased value under these futures with higher market prices. However, their energy and demand impact are less than that of the CCS-enabled and Nuclear resources, explaining why those other options are the preferred choice.

As would be expected, 2040 CO_2 emissions are decreased for nearly every scenario in which the coal resources are retired earlier than in the base case. Although the CO_2 emissions and their associated cost are down, production costs are still generally increased for scenarios with lower regulated costs of CO_2. In these cases, the cost of the replacement generation overshadows the reduction in CO_2 emissions-related charges. As the regulated cost of CO_2 increases though, the replacement of the coal resources with Coal CCS, NGCC CCS and Nuclear leads to decreased production costs due to the related reduction in CO_2 emissions. This phenomenon is most pronounced for production costs over the longer period of the base study and the subsequent 30-year extension, where the low operating costs of the new plants have long enough to overcome the significant capital expenditures of initial construction.

As an additional frame of reference for the retirement sensitivities, LES used its current financial model to analyze the incremental, near-term rate impact of the change in production costs relative to the base case. These would be in addition to any rate impacts LES would have incurred outside the sensitivity-directed unit retirements, such as the cost increases previously seen in the base case and other non-power supply related increases. This evaluation was conducted for the two sensitivity cases representing the largest cost decrease/increase relative to the base case for the study plus extension period. The cumulative, incremental rate increase through 2029, the year the coal facilities were retired, ranged from 0% - 62%. The upper-end of

this range would equate to an incremental cost of approximately $2,300 by 2029 for a typical residential customer and $5.6M for a typical industrial customer. For scenarios where all LES coal facilities were retired in the base case as a financial decision in response to market forces, the incremental rate impacts of the sensitivity were zero. The case with the largest net present value reduction in total production costs over the full 2022 – 2071 period, representing the largest savings over the long term, still results in a cumulative 55% rate increase by 2029 to fund near-term replacement resources.

10.2.2 Sensitivity 5: Retire Laramie River Station in 2029

This case models the 2029 retirement of only LES' largest coal resource, Laramie River Station. Laramie River Station also represents LES' oldest owned coal resource, so a practical scenario would be an at least partially age-related retirement.

The results somewhat mirror those of Sensitivity 4. Relative to the base case, the selections of Coal CCS, NGCT, and NGCC CCS expanded in a similar manner, with Tier I Solar and SEP once again surrendering ground for high natural gas prices coupled with high CO_2 prices. Nuclear resources saw broader use than in the base case, but unlike Sensitivity 4, were once again relegated to higher CO_2 prices. The primary difference when compared to Sensitivity 4 was essentially only the number of units selected, with the sole retirement of LRS requiring less resources to backfill and maintain the reserve margin than was required under the broader coal retirements of Sensitivity 4.

The changes in CO_2 and production costs relative to the base case again somewhat track those of Sensitivity 4, albeit to a reduced level. With only one coal resource retired, the impacts are similar but less pronounced. The same can be said for the financial modeling, which resulted in cumulative incremental rate increases of 0% - 29% in 2029 when compared to the base case. These represent cumulative cost increases of up to $1,400 and $3.4M by 2029 for typical residential and industrial customers, respectively.

10.2.3 Sensitivity 6: Retire All LES Natural Gas Resources in 2029

LES' fleet of natural gas resources will range in age from nearly 40 – 70 years old in 2041, the last year of the base case study period. Even on the low end, this coincides with the 40-year life assumed by the EIA for similar new resources. To evaluate the retirement of these resources, this sensitivity models the retirement of all LES natural gas units in 2029. Although highly unlikely, this 2029 timeframe is early enough to properly evaluate the impact of replacement resources during the study period.

A few noticeable differences from the base case stand out right away. First, EGEAS selected NGCT resources across nearly all cases other than for the combination of the highest natural gas and CO_2 prices, essentially replacing the retired natural gas units with newer versions of the same thing. In addition, Tier I Battery was selected across nearly all cases, while DSM SEP saw more selections nearly everywhere except for under the lowest CO_2 prices. EGEAS needed significant amounts of accredited capacity to replace the existing natural gas units, and these uniformly represented good options. Finally, the WS4 CCS Upgrade wasn't selected at all, likely

because this upgrade results in a reduction of the accredited capacity rating of that unit. With so many natural gas resources removed from the case, EGEAS was prioritizing resources that addressed the significant reserve margin shortfall.

Although NGCC CCS and Nuclear were primarily selected over similar natural gas/CO_2 pricing scenarios as in the base case, the span of their selections expanded significantly. Coal CCS selections also expanded somewhat, but to a considerably lesser extent.

CO_2 emissions are generally reduced relative to the base case, primarily when natural gas prices are low or when the natural gas units are replaced with Nuclear and Coal CCS. Production costs are increased for the 2022 – 2041 study period in nearly all cases. When the 30-year extension period is factored in, this effect is less pronounced for the combination of the highest natural gas and regulated CO_2 prices. At these high market prices, the replacement of the natural gas units with Nuclear and Coal CCS resources leads to lower production costs.

Relative to the base case, cumulative incremental rate increases ranged from 39% - 47% by 2029, again due to the cost of constructing replacement resources. This represents a cumulative incremental cost increase of up to $1,600 by 2029 for a typical residential customer and $3.9M for a typical industrial customer. In this scenario there were no sensitivity cases with zero near-term rate impact, as no natural gas unit retirements were identified through the base case.

10.3 Changes in Model Assumptions

10.3.1 Sensitivity 7: High Natural Gas Prices

The base case evaluated natural gas prices over a broad range of $1.00/MMBTU - $10.00/MMBTU. Although natural gas prices to date in 2022 have been much higher than in recent years, they still fall far below the maximum level of the LES study. However, LES wanted to develop a feel for how even higher natural gas prices would impact the study results. LES reran the base case analysis with average natural gas prices ranging from $6.00/MMBTU - $15.00/MMBTU, again adjusted in $1.00/MMBTU increments.

Not unexpectedly, natural gas driven resources fall out of favor rather quickly as the natural gas price increases. Most other options tend to be selected less as the CO_2 price increases, with nuclear becoming the dominant option. The combination of extremely high natural gas prices and the highest CO_2 prices make it much easier to justify the high capital cost of Nuclear, whose low operating costs aren’t impacted by either of those factors. Coal retirements are essentially eliminated at the higher natural gas prices, as the existing coal resources represent a valuable financial alternative to LES and SPP’s natural gas fleet, even at the highest CO_2 prices.

The standard CO_2 and production cost comparisons to the base case aren’t relevant to this sensitivity since the base case didn’t examine natural gas prices of this magnitude.

10.3.2 Sensitivity 8: SPP Electrification

This sensitivity examines the optimal resource portfolios constructed under an extreme electrification future, seeing many more retail systems and equipment served by electricity. LES again contracted with E3 to perform ELCC studies to forecast the accreditation of wind, solar and energy storage in the SPP area under this scenario. E3 developed an SPP-specific load forecast based on previous decarbonization modeling they had conducted for the World Resources Institute, assuming high levels of electrification of transportation, space heating, water heating, industry and electrolysis for the production of hydrogen.[25] The resulting 2041 SPP load profile is shown in Figure 10.1. On average, the winter and summer system peaks are quite comparable, but the actual extremes were seen during winter evenings. Although electrification drives load growth over the entire year, it has a much more drastic impact in the winter due in large part to the expansion of electric heating.

Figure 10.2 depicts the ELCC results of the E3 analysis. Tier I battery storage and wind still closely track the base case, but there is some improvement in the 2041 results for the subsequent tiers due to the shift of peak load periods to the winter season. This is not the case for solar though, as the ELCC is reduced for all tiers, most drastically for Tier I. Experiencing peak load hours during winter evenings is extremely detrimental to the solar results, as solar resources are contributing very little energy production during that period. A full summary of the study assumptions and the resulting ELCC projections are included in Appendix B.

Figure 10.3 shows the resulting LES load and capability chart based on the updated SPP ELCC values and LES' electrification load forecast, which was adjusted similarly to the load of the SPP region. Assuming all of LES' existing assets and contracts, the next resource is required in 2037.

The dramatic change in both the magnitude and profile of the load had minimal impacts on coal retirements, although they were delayed or eliminated in a few cases. The resource selections also didn't undergo wholesale changes, although the results do show a few notable differences relative to the base case. Nuclear resources saw much broader use, being selected across nearly the entire lower right diagonal of the matrix of natural gas and CO_2 prices. Both Tier I Battery and NGCT were also prominent selections for combinations of low natural gas and CO_2 prices. More subtly, RICE units were selected for the majority of low to mid-natural gas prices and there were even a few sections of Tier II Solar, albeit for both resources most of these selections occurred in the last study year.

One would think CO_2 emissions would typically increase relative to the base case due to the heightened load requirements, and thus heightened generation, but a large number of scenarios actually show a decrease. In many cases this is due to the expansion of nuclear, which helped to serve the increased load at lower emissions levels. Production costs are increased for the 2022 – 2041 study period in all cases, primarily because more resources are required to meet the load requirements. This trend generally holds true when the 30-year extension period is factored in as well, with one exception. At the confluence of the highest natural gas and CO2 prices, a slight decrease is shown vs. the base case. The more extensive electrification portfolio, featuring among other things three Nuclear resources that fare very well in such a high

priced market, wouldn't have been allowed in the base case because it would have exceeded the 35% reserve margin ceiling. With the increase in peak load, EGEAS was allowed to add more resources that it considered to be economically beneficial.

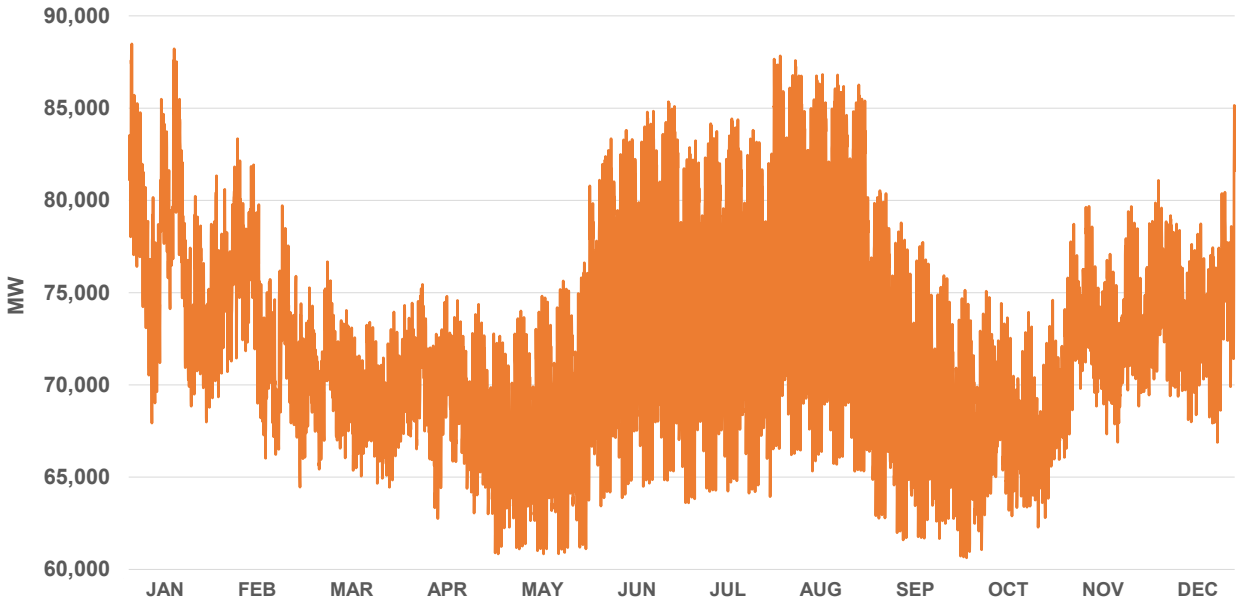

Figure 10.1 2041 SPP load profile under the electrification sensitivity.

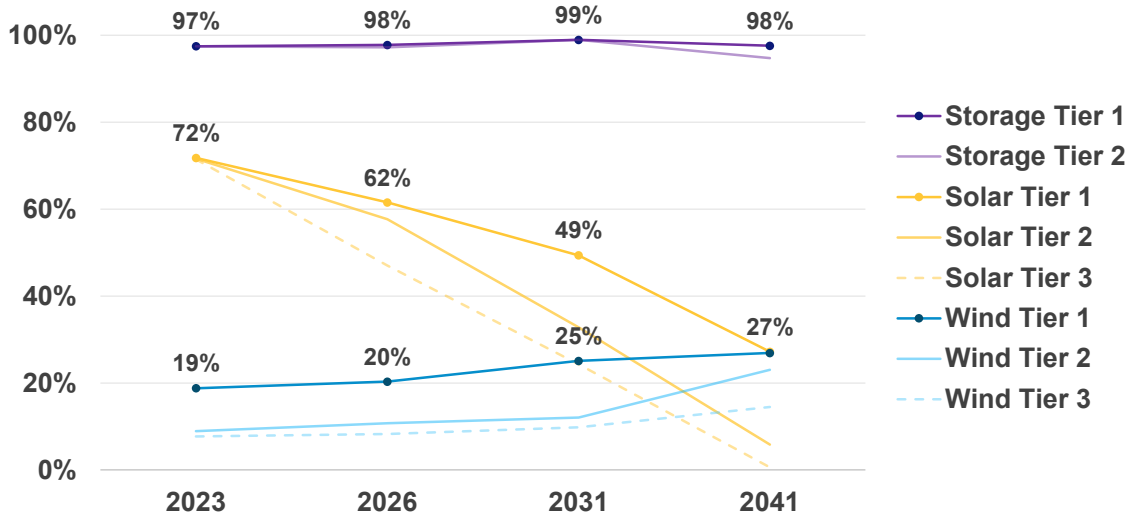

Figure 10.2 Future ELCC projections for the SPP region under the electrification sensitivity.

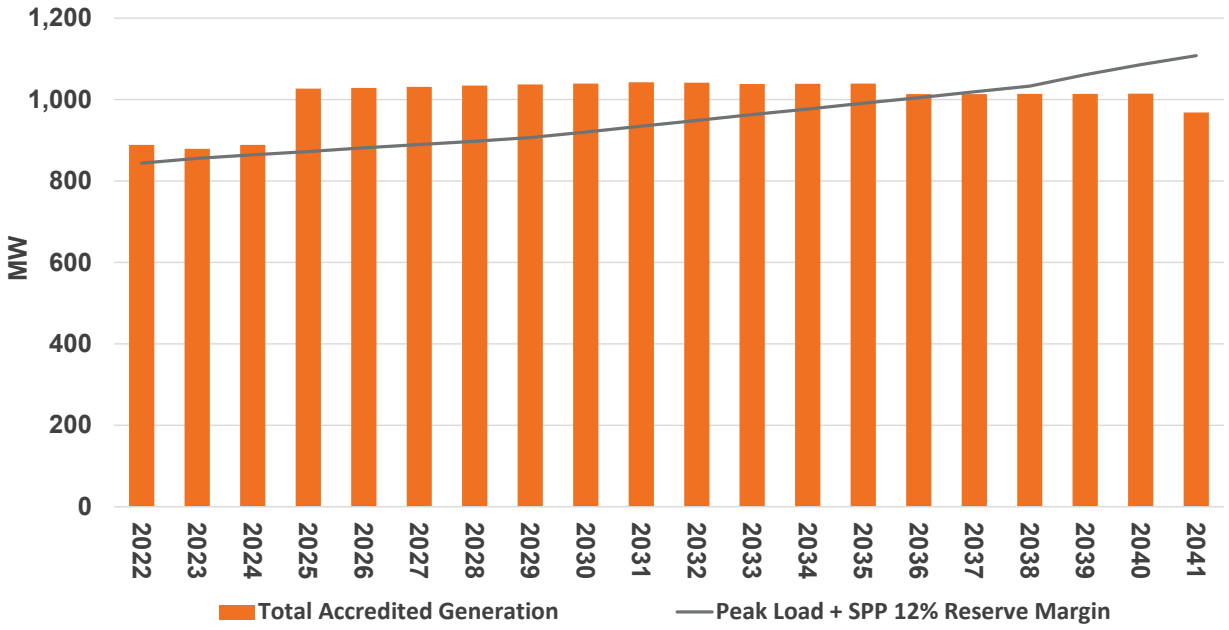

Figure 10.3 LES' future load and capability forecast assuming increased electrification.

10.3.3 Sensitivity 9: SPP 15% Reserve Margin

On July 26, 2022, the SPP Board of Directors approved a change in the SPP reserve margin requirement, increasing it from 12% to 15% of peak load starting in 2023. Unfortunately, this change came too late in the IRP process for LES to rerun all the analysis and still maintain its final public review meeting scheduled for August 25, 2022. However, LES was able to reevaluate the base case under this new assumption, providing a good feel for the relative impact.

LES was initially concerned that the SPP resource mix would need to be adjusted to maintain a 15% reserve margin in the EGEAS model. This resource mix was originally developed based on a 12% reserve margin projection, leveraging initial estimates of the ELCC assignments for wind, solar and battery storage. Upon inserting the final E3 ELCC projections, which were on average slightly higher than the initial estimates, it was found that the SPP generation portfolio still maintained a 15% reserve margin in 2041, thus requiring no further changes.

Figure 10.4 provides an updated LES load & capability chart reflecting the higher 15% reserve margin requirement. As shown, the next LES resource addition is now required within the 20-year study period, specifically by 2041.

With the exception of one case, the combination of $6.00/MMBTU natural gas and a regulated CO_2 price of $90/ton, the resource selections are identical to the base case. That's because this was the lone case out of a 100 where the reserve margin ever fell below 15%. This is primarily driven by two factors, the first being LES' relatively small peak load compared to the modeled

resources. For example, a peak load of 800 MW requires 896 MW of accredited generation to cover the load plus the additional 12% reserve margin. Under this scenario, adding a 100 MW fossil resource would equate to 996 MW of accredited generation, or a new reserve margin of about 25%. The relative size of LES makes it difficult to precisely fine tune the reserve margin, often resulting in substantial overshoots.

The second factor is consideration of the LOLP, the other primary reliability metric utilized in the analysis. To maintain the required LOLP – no more than two days of unserved load in a 10-year period – EGEAS often adds resources before they would be required to solely maintain the reserve margin. The combination of the LOLP requirements and the inherent overshoot in maintaining reserve margin drove most of the base case scenarios to maintain more than 15%, even though only 12% was targeted.

Examination of the one case where a change was required shows that the base case added Tier I Wind in 2041, equating to a reserve margin of about 13%. Under the sensitivity case, where this margin was no longer sufficient, EGEAS instead added Tier I Solar in 2041 to meet the 15% threshold.

Based on the results of this sensitivity, LES does not anticipate the heightened reserve margin to have a highly significant impact on the type of resources selected, although it could drive some of the additions to be made slightly earlier.

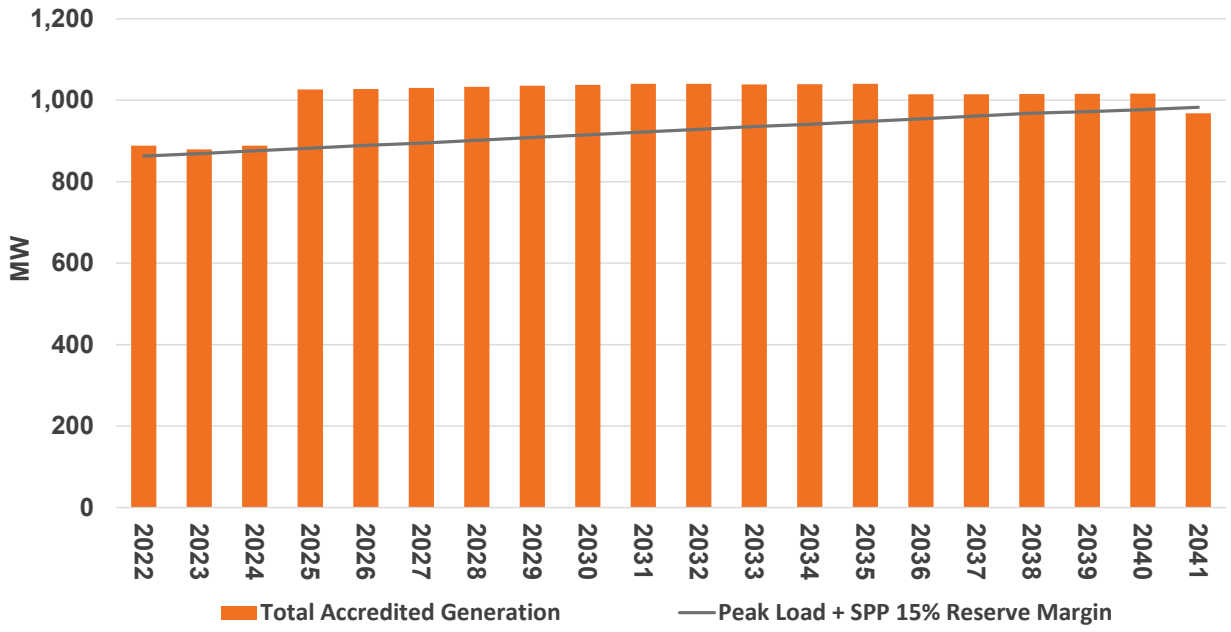

Figure 10.4 LES' future load and capability forecast with a 15% reserve margin requirement.

10.3.4 Sensitivity 10: Inflation Reduction Act

On August 16, 2022, President Joe Biden signed the Inflation Reduction Act into law. The Inflation Reduction Act reportedly includes numerous energy-focused tax benefits, many of which would likely impact the results of this analysis. As was the case with SPP's change in reserve margin, this came far too late in the IRP process for LES to rerun all the analysis and still maintain its final public review meeting scheduled for August 25, 2022. LES was at least able to reevaluate the base case though, providing an initial feel for the relative impact.

LES applied the new Clean Electricity Investment Tax Credit (CEITC) to the Nuclear, Tier I Battery Storage, Tier I Solar, Tier II Solar, Tier I Wind and Tier II Wind resources, assuming a 30% reduction in the initial construction costs. This 30% credit was modeled to begin in 2025 and extend through 2032, with the reduction ramping down to 22.5% in 2033, 15% in 2034, and then 0% thereafter.[26] The Inflation Reduction Act also reportedly includes lucrative incentives for CCS resources, but those were not evaluated at this time due to uncertainty in how they would be applied.

As one would expect, the resources with reduced construction costs saw the number of their selections increase and/or occur in an earlier year of the study. Tier I Wind and Tier I Solar saw similar selections to that of the base case, although they occurred earlier in many scenarios. EGEAS still didn't find much value in the lower accreditation of Tier II Wind and Tier II Solar though. Tier I Battery Storage expanded only slightly relative to the base case, suggesting the lower pricing did little to offset the 10-year life and 4-hour duration limitations. Nuclear saw selections over a broader range, primarily at the expense of Coal CCS, although it also replaced a few NGCC CCS and WS4 CCS Upgrade selections as well. The main impediment to Nuclear is the high capital cost of the facility, so it makes sense that a significant reduction in this area would make it more appealing.

CO_2 emissions generally were reduced relative to the base case since all of the non-CO_2 producing supply-side resources saw their construction costs reduced significantly. Likewise, total production costs over the full study plus extension period were uniformly reduced from base case levels. Total production costs for just the 20-year study period increased in about half the cases though. This is primarily due to resources being built earlier in the study period to capitalize on the CEITC.

While the Inflation Reduction Act, at least as modeled, did drive a noticeable decrease in total production costs, the types of resources selected didn't change dramatically.

11.0 LES Decarbonization Goal

Going into the 2022 IRP, LES hoped the process would help to identify an initial path to achieving its decarbonization goal; net-zero CO_2 emissions by 2040. Upon seeing the results of the resource options analysis, many of the core puzzle pieces – at least as of right now – are beginning to fall into place.

11.1 Initial Plan

Based on the IRP study results, LES believes the following building blocks will play a key role in achieving the 2040 decarbonization goal:

- *Maintain LES' allotment of Tier I Wind but avoid Tier II (or Tier III) Wind*

  Across the base case and every single sensitivity that was ran, for the vast majority of future combinations of natural gas and regulated CO_2 prices, EGEAS consistently showed a preference for replacing at least some portion of LES' existing Tier I Wind. Almost nearly as uniformly, it also showed little interest in adding Tier II Wind, save for a small handful of cases where it was selected a few years prior to automatically graduating to Tier I Wind status following the end of LES' existing contracts.

- *Develop LES' allotment of Tier I Solar but avoid Tier II (or Tier III) Solar*

  Although not nearly as definitive as Tier I Wind, EGEAS made Tier I Solar a prominent choice in the majority of base case scenarios. The various sensitivities also showed it to be a valued option following the retirement of existing fossil generation or in the absence of other future low-carbon resource alternatives. In addition, the bulk of the sensitivity cases where Tier I Solar was not selected were for combinations of high natural gas and regulated CO_2 prices. Although Tier I Solar may not have been the optimal choice in these scenarios, it's value when exposed to these market forces actually increases since neither of them have a direct impact on its financial standing, suggesting it's still a safe choice in these futures. As with wind, Tier II Solar was almost never selected due to its lower accreditation rating relative to Tier I Solar.

- *Continue the SEP*

  Similar to Tier I Solar, DSM SEP was a common choice over the broad array of futures studied under both the base case and the various sensitivities. Again, most of the sensitivity scenarios where it was not featured were based upon high natural gas and CO_2 prices, where the SEP only grows in value.

- *Maintain LES' existing natural gas resources*

  Sensitivity 6 examined the impact of retiring all of LES' existing natural gas resources in 2029, clearly establishing these assets as valuable, low-cost pieces of LES' future portfolio. In fact, in the majority of scenarios, EGEAS exchanged the retired units for new NGCT units, representing essentially a like replacement.

  Relative to the base case, production costs for this sensitivity increased over the vast majority of scenarios following their retirement. The only exceptions were at the confluence

of the highest natural gas and CO_2 prices, where EGEAS projected this would drive high enough market prices to justify the high capital cost of adding nuclear units.

On average, LES' natural gas fleet has accounted for approximately 5% of LES' annual CO_2 emissions since the last IRP, from 2017 - 2021. This low level of production, especially when coupled with the units' ability to run for relatively short durations and remain offline for long periods, establishes their future emissions as something that could potentially be offset given the net-zero construct of LES' decarbonization goal.

- *Look for the right time to phase out or add CCS to LES' existing coal resources*

  The base case identified numerous scenarios, mostly under periods of low natural gas prices and high CO_2 prices, where market forces and/or environmental regulations would limit the operation of LES' existing coal resources to the point where retirement may be financially beneficial. It also considered the option of retrofitting CCS to WS4, which EGEAS saw as a valuable upgrade when faced with both high natural gas and CO_2 prices. Finally, Sensitivities 4 and 5, which looked at either the uniform 2029 retirement of all LES coal resources or only LRS, respectively, indicated that premature retirement could also be financially detrimental.

  LES' coal fleet will either need to be retired or mitigated with a technology like CCS in order to achieve the decarbonization goal, but this analysis shows the timing of those decisions will be key to minimizing the financial impact to LES customers. The advanced age of GGS and LRS will also be a related consideration, especially when looking at potential high-cost upgrades like CCS.

Figure 11.1 identifies LES' 2041 load and capability by fuel type, both for its existing portfolio and a preliminary future decarbonization scenario incorporating the building blocks identified above. As shown, the outlined decarbonization scenario falls about 200 MW short of providing enough accredited generation to meet LES' projected peak load plus a reserve margin of 15%. Numerous options have been identified that could potentially fill this gap, including new nuclear, new CCS-enabled natural gas units, CCS upgrades to existing coal resources or new battery storage. In addition, other new technologies or carbon-neutral fuels may hopefully become available to LES in the relatively near future. For now, LES intends to leave this gap unprescribed, looking to identify the best choices in the future as more information becomes available.

LES believes this preliminary decarbonization plan strikes a valuable balance, closing enough of the gap to make the goal attainable, while also recognizing that additional decisions will be required. It should appeal to more environmentally-focused customers for its pursuit of the decarbonization goal, although they'll likely feel the pace and breadth of change should be heightened. It should also provide comfort to customers that LES is looking to move forward with reliability and affordability as key components, though many will admittedly still be concerned about the potential end of LES' coal portfolio as we know it, which has anchored those two tenants for decades. Regardless, it's only a plan for today, as the future will undoubtedly offer many opportunities and challenges that will continually require it to be refined.

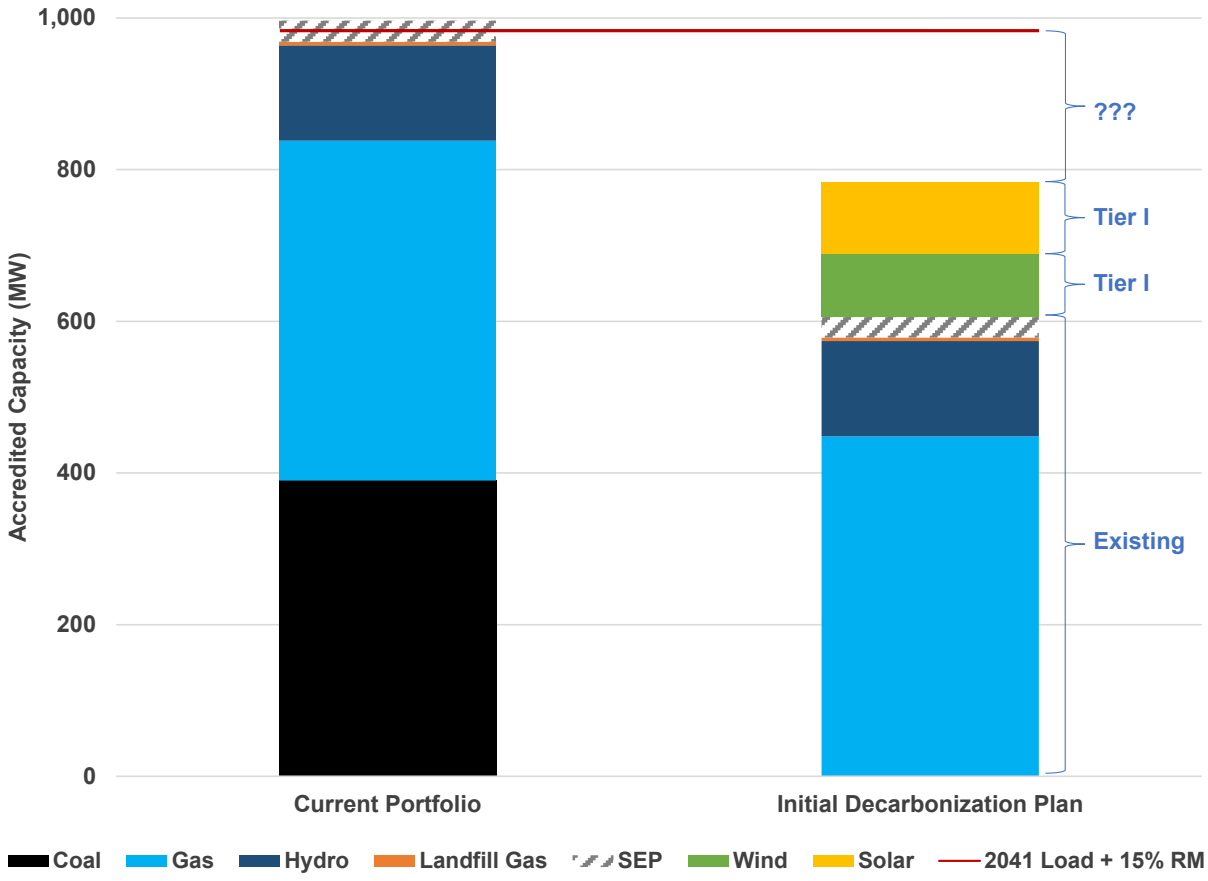

Figure 11.1 LES' 2041 load and capability forecast based on its initial decarbonization plan.

12.0 Conclusions

The following conclusions have been drawn based on the completed analysis and the input of the Lincoln Cooperative Members.

12.1 LES Local Solar Resource

One of the building blocks of LES' initial decarbonization plan is development of Tier I Solar. In the past, the federal Investment Tax Credit (ITC) had pushed governmental entities like LES – who cannot make direct use of a tax credit – to add these resources through a PPA with a third party developer who could then indirectly pass on the value of the ITC. At the time the IRP analysis commenced, the ITC had its value scheduled to decline from the original 30% of the initial project capital cost to only 10% for systems commencing construction in 2024.[27] LES thought there could potentially be financial benefit to constructing and owning a solar resource at this level, as the 10% ITC savings may reasonably be offset by the additional profit margin that would be charged by a developer. However, the newly enacted Inflation Reduction Act of 2022 – through which the CEITC would supposedly restore the historic full credit rate for solar – reportedly includes a direct payment option in lieu of traditional tax credits, allowing a tax-exempt public power entity like LES to make direct use of the benefits.[28] If the form of the ITC is truly modified such that LES could leverage it directly, it increases the likelihood that LES could potentially benefit financially from constructing and owning a solar resource as opposed to contracting for one.

Development of any generating resource larger than a few MWs, including solar, requires a generator interconnection agreement with SPP. As a precursor to this agreement, SPP identifies the system upgrades that would be required to reliably support the new interconnection. Since these interconnection costs can be significant, it's important that they be established before moving forward with a project. However, due to the large number of such requests in their area, SPP is currently dealing with a significant backlog in studying these resources. The current backlog, including interconnection requests submitted from 2017 through 2021, is not scheduled to be completed until 2024, at which point SPP will commence review of any requests submitted starting in 2022.[29]

Given that Tier I Solar was identified as a fundamental piece of LES' decarbonization plan and that all indications are it will take years before a related project could traverse the SPP interconnection process and come to fruition, LES plans to begin evaluating the addition of a solar resource even though it currently has more generation than required to meet its planning reserve margin. LES could potentially construct or contract for this resource, but the evaluation will initially focus on the prospect for LES construction, meaning it would ideally be located in or around LES' service territory.

12.2 LES Battery Storage Pilot

LES launched an RFP for a battery storage pilot project in the fall of 2021 as a precursor to the IRP process, with a contract still pending. The resource analysis indicated that a large-scale battery storage project wasn't the best option over the vast majority of future scenarios, but this is expected to change in time with advances in technology and reduction in cost. LES plans to monitor and report on implementation and administration of its pilot-level project as a product of this IRP, helping to build experience and prepare staff for a potential larger utilization in the future. In addition, the project will be located within the area served by LES' Community Microgrid, helping to ensure critical city, county, state and even federal infrastructure would remain powered during wide-scale outages.

12.3 LES Community Microgrid Solar Expansion

In conjunction with the aforementioned battery storage project, LES is interested in additional resource development to both better leverage this new infrastructure and further support the Community Microgrid. Given how well it generally compliments battery storage, and its relatively strong showing in this IRP resource analysis, solar photovoltaics would appear to be a viable option for further consideration.

LES plans to evaluate the introduction of additional solar in the community microgrid area. This solar could be developed in various forms and under numerous ownership models, so the scope and structure of such a project will be a key part of any evaluation.

12.4 LES SEP

The resource options analysis showed the SEP to be a preferred resource over a broad range of future scenarios considered under the base case. Based on various sensitivities, it also proved to be a valuable alternative if either (i) CCS-enabled units and nuclear resources are not truly viable options for LES in the future, or (ii) the retirement of LES' existing coal and natural gas units is accelerated. For these reasons, LES intends to continue the use of the SEP in the near future.

12.5 LES SEP – New Product Offerings

With the continuation of the SEP assured, LES could turn its attention to potential new offerings under its umbrella. Preliminary analysis indicated the benefit-cost metrics for high efficiency commercial kitchen equipment – combination ovens, dishwashers and steam cookers – might warrant LES incentives. At the same time, sales of this equipment do not currently dominate the market, indicating incentives could help to accelerate local adoption. LES intends to begin offering incentives for this equipment as part of the SEP, allowing time to better evaluate customer interest and the related benefit-cost impacts.

Preliminary benefit-cost modeling for a water heater control program didn't prove as promising, and the majority of the residential water heating in LES' service territory is not currently fueled by electricity. However, electric resistance water heaters can still represent one of a home's largest loads, and that reason alone prompts interest in attempting to shift this load away from LES' peak. In addition, these devices inherently represent a potential energy storage resource. LES plans to pursue an electric water heater pilot project at the new Gatehouse Rows development in Lincoln to gather more information and develop a better feel for the potential impacts of a demand response program.

12.6 LES Time-of-Use Rate

Time-of-Use or dynamic pricing rate structures use pricing signals to encourage customers to shift their energy use away from on-peak periods that tend to drive a utility's infrastructure investments. LES had already started to review time-of-use rate options for large commercial and industrial customers prior to commencing the IRP. Bolstered by the consultant's recommendation for a similar type of program, LES is now planning to offer a time-of-use retail rate to demand customers.

12.7 UNL & Nebraska State Agencies

UNL and the Nebraska State Agencies plan to compliment the LES resource and program decisions by implementing various energy-efficiency improvements at their own facilities.

UNL will continue or expand programs targeting reduced energy consumption, including energy efficiency initiatives, continuous commissioning of existing building assets and existing chiller tube cleaning. UNL also plans to further optimize their chilled water production and explore the feasibility of on-campus renewable energy installations.

The Nebraska State Agencies plan to continue their support of increased energy conservation through equipment efficiency and lighting improvements plus new or upgraded control systems.

13.0 Actions

13.1 Action Plan

Table 13.1 details the five year action plan for the Lincoln Cooperative. The Lincoln Cooperative will continue to evaluate additional opportunities for potential new resources and programs that arise during the action plan period, with each analyzed in a similar fashion on a case-by-case basis.

13.2 Measurement and Evaluation

The Lincoln Cooperative intends to monitor and evaluate the resource/program impacts based on actual field measured data whenever possible. However, this may not always be cost effective for distributed, customer based demand-side management programs or member facility installations without sufficient measurement instrumentation and/or capabilities. In these instances, impacts will be based on engineering calculations, with representative sample data collected in the field to validate the projections. Program evaluations will be provided to WAPA through the existing annual update process.

Table 13.1 Lincoln Cooperative's Five Year Action Plan

Resource/Program	2023	2024	2025	2026	2027	Type	MW [1]	GWh/year [2]
LES Local Solar Resource LES plans to evaluate the addition of a utility-scale solar resource in or around the LES service territory. Additional details will be determined as part of the evaluation process.	E	E	---	---	---	S	---	---
LES Battery Storage Pilot LES is pursuing a battery storage project to be located within the area served by LES' Community Microgrid. Negotiations of a power purchase agreement are underway, with additional details to be determined as part of that process.	I	A	A	A	A	S	---	---
LES Community Microgrid Solar LES plans to evaluate the addition of more solar photovoltaic resources in the area served by LES' Community Microgrid. These resources would supplement the recently announced energy storage pilot within the same portion of the LES service territory. Additional details will be determined as part of the evaluation process.	E	E	---	---	---	S	---	---
LES Sustainable Energy Program LES intends to continue this existing program throughout the IRP period, featuring incentives for a variety of commercial and residential demand-side management measures.	A	A	A	A	A	D	28	100
LES Water Heater Pilot LES plans to implement a pilot program for electric resistance water heaters, with the aim of benchmarking the usage habits of LES customers and the potential demand response capabilities. Additional program details will be determined as part of the implementation process.	I	A	A	---	---	D	---	---
LES Time of Use Rate LES plans to implement a new time of use rate for large commercial/industrial customers. Additional program details will be determined as part of the implementation process.	I	A	A	A	A	D	---	---
UNL Renewable Energy Installation UNL is evaluating the feasibility of installing on-campus renewable energy generation in support of its institutional sustainability goals. Actual reductions will be dependent on the feasibility analysis and resulting type and size of installations.	E	E	---	---	---	S	---	---
UNL Optimized Cooling Dispatch UNL is implementing predictive algorithms to optimize the efficient production of chilled water, reducing energy use and demand. These algorithms model future energy use based on equipment design, historical campus energy use, and forecasted weather and campus use patterns to influence operational decision-making and optimize equipment use.	I	I	A	A	A	D	0.9	1.9

Table 13.1 Lincoln Cooperative's Five Year Action Plan (continued)

Resource/Program	2023	2024	2025	2026	2027	Type	MW [1]	GWh/year [2]
UNL Chiller Tube Cleaning UNL has implemented continuous chiller tube cleaning in two existing units, which have resulted in improved heat transfer late in the cooling season from elimination of fouling that typically occurs between winter cleanings. This equipment has improved energy efficiency of UNL's cooling equipment when campus electric loads reach their peak. Use of continuous cleaning systems will be expanded to additional units prior to each cooling season. Savings will increase annually toward projected demand and energy reductions as additional units are installed.	I	I	I	I	I	D	0.4	2.9
UNL Energy Efficiency Program UNL will continue its existing goal of reducing energy use and demand by a combination of efforts. These include installing light-emitting diode (LED) lights, implementing improved control sequences and equipment scheduling, and more effective ventilation and motor speed control. This effort goes through continuous evaluation.	A	A	A	A	A	D	0.4	2.0
UNL Continuous Commissioning UNL has implemented a continuous commissioning program on building assets to reduce energy consumption. Following a building recommissioning project, savings results are tracked monthly in UNL's energy information system. This helps the campus maintain the energy savings realized by the recommissioning efforts.	A	A	A	A	A	D	0.4	1.9
Nebraska State Agencies Equipment Efficiencies The Nebraska State Agencies plan to continue their support of increased energy conservation through equipment efficiency improvements achieved during regular maintenance and capital replacement projects. Potential considerations include improved doors and roofs, replacement of steam lines and optimization by use of new or replaced building automation systems. Demand and energy reductions will depend on the actual maintenance projects undertaken during this period.	A	A	A	A	A	D	---	---
Nebraska State Agencies Controls & Lighting Efficiencies The Nebraska State Agencies will continue reducing energy use and demand by installing new controls and making upgrades to existing controls, continue upgrading to LED lights, occupancy sensors, and rolling out behavioral change initiatives for reducing energy use. This effort goes through continuous evaluation on all campuses.	A	A	A	A	A	D	---	---

Table 13.1 Lincoln Cooperative's Five Year Action Plan (continued)

Annual Status Key:
A – Administer existing program/resource
E – Evaluate potential program/resource
I – Implement new program/resource

Type Key:
D – Demand-Side program/resource
S – Supply-Side program/resource

Notes:
1. Expected total peak nameplate capacity/demand reduction. Demand reduction based on projected participation at full program maturity; impacts will depend on the structure of the actual program implemented.
2. Expected total annual energy production/reduction. Energy reduction based on projected participation at full program maturity; impacts will depend on the structure of the actual program implemented.

14.0 Public Input and Interaction

Throughout the IRP process, the Lincoln Cooperative provided multiple opportunities for public input and interaction, over many different platforms. Event announcements included local newspaper ads, emails to either all LES customers with an email address on file or attendees of a previous IRP meeting, plus organic and paid social media ads. In addition, they were also advertised in Current, LES's bill-stuffer style magazine, EnergyLine, LES's bi-weekly newsletter to commercial customers, EmPowered, LES' monthly newsletter for residential customers, and directly on LES bills themselves.

14.1 Public Meeting #1

LES hosted a public meeting on April 21, 2022, providing an overview of the IRP process and the related timeline. LES also presented a summary of the consultant's findings from the recently completed external review of the SEP. The formal presentations were followed by open group Q&A, and LES Staff were available for one-on-one discussions afterwards. Appendix I provides information on the April meeting, including samples of pre-event announcements and the presentation materials.

14.2 Workshop #1

LES held a public workshop on May 19, 2022. LES led participants through an interactive session designed to deepen their understanding of LES' regional electricity market, the Southwest Power Pool, and its role in LES resource decisions. Appendix J contains the presentation materials from the workshop and samples of the pre-meeting notices.

14.3 Public Meeting #2

LES held a second public meeting on June 23, 2022. The primary focus of this meeting was to discuss potential enhancements to the SEP, review the scope of the upcoming analysis of the LES resource portfolio and discuss key points of the two IRP workshop topics for those who could not attend. The event followed the same agenda as the March meeting; formal presentations followed by group Q&A and individual discussions. Appendix K includes information on the June meeting and samples of the related marketing efforts.

14.4 Workshop #2

LES hosted another public workshop on July 21, 2022, diving into more detail regarding SPP's resource requirements and related rating methodologies, specifically ELCC. Then with this information in mind, participants were able to build their own resource mix of the future on a computer pre-loaded with an LES-developed model. Appendix L includes the presentation materials from the workshop and samples of the pre-meeting notices.

14.5 Public Meeting #3

LES held a third and final public meeting on August 25, 2022. LES provided a formal presentation reviewing the draft final report, a copy of which was posted on LES' website one week prior to the event. All members of the public who had attended a previous meeting or workshop and/or corresponded with LES regarding the IRP were notified via email, if provided, of the posting of the draft report. Once again, a group Q&A session followed the presentation, and various LES Staff were on hand afterwards to address remaining comments and questions. Appendix M includes samples of the pre-meeting notices and all meeting materials.

14.6 Final Report

A copy of this final report was posted on les.com in conjunction with its submittal to WAPA, once again with similar media announcements to let the public know it was available. Members of the public who attended a public meeting or workshop and/or corresponded with LES regarding the IRP were notified of the completion of the report via e-mail, if provided, including a discussion of any changes that occurred since the draft version reviewed at the August public meeting. A copy of this email is provided under Appendix N.

14.7 LES Website

Throughout the IRP process, the LES website was updated with timely information regarding the IRP schedule, status and all materials presented to date. The website also provided a dedicated email address for customers to send in IRP related questions or comments. Appendix O includes a screen shot of the website following the completion of the various public meetings and posting of the draft report, displaying the full history of the process that was laid out step-by-step as the IRP progressed.

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Appendix A
nFront Consulting SEP Report

LINCOLN ELECTRIC SYSTEM

SUSTAINABLE ENERGY PROGRAM REVIEW

FINAL REPORT

MARCH 2022

nFRONT CONSULTING LLC
Power Industry Planners • Analysts • Advisors

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EXECUTIVE SUMMARY

BACKGROUND AND APPROACH

nFront Consulting was retained by Lincoln Electric System (LES) to conduct a review of the LES Sustainable Energy Program (SEP) measures, evaluation process, and measure parameters relative to those being undertaken by other utility peers and industry practice. nFront Consulting performed a high-level benchmarking analysis of five peer utilities, jointly determined with LES staff, and supplemented this with a review of publicly available statewide energy efficiency studies and meta-analysis from nationally recognized organizations to further inform the basis of leading industry practices. The benchmarking analysis conducted for the LES SEP was focused around three key areas, which are identified below.

1. Measure parameters and the basis of assumptions used in cost effectiveness evaluations
2. Whether measures are being endorsed by other utilities that have applicability to LES but have not yet previously been considered by LES, especially those with a high demand savings potential
3. Metrics used to determine cost effectiveness for purposes of endorsement

In benchmarking the metrics used by LES to determine cost effectiveness, nFront Consulting considered the related assumptions, including the treatment of avoided capacity costs, value of avoided CO_2 emissions, and other potential societal benefits.

The outcomes from this review of the SEP are intended to be reflected in LES's upcoming Integrated Resource Plan.

KEY FINDINGS

The following are the main conclusions of nFront's SEP review:

- The component measures in the SEP are similar to those that are active across many of LES's peer utilities. While many utilities have historically offered rebates for a wider variety of residential appliances, many of these utilities have been curtailing these programs over the last several years due to poor economics, high administrative costs, and obsolescence from increasing minimum efficiency standards.
- The relative level of energy and peak demand savings achieved by the SEP is comparable to many of LES's peer utilities and the average of utilities in this region of the country, particularly given LES's savings measurement methodology and relatively lower level of load growth. Like most utilities, these energy savings are dominated by the commercial class and further by conversion of lighting to high efficiency LED technology.

- The overall average cost to LES of achieving energy and peak demand reductions through the SEP is lower than the average in the industry; hence, the SEP overall serves as a relatively low-cost resource and a useful hedge against uncertain and volatile energy costs.
- The cost-effectiveness tests LES utilizes to assess current and prospective SEP measures—the Utility Cost Test (UCT) and an adjusted representation of the Rate Impact Measure (RIM) test, are highly supported by the latest industry practices and are consistent with LES's carbon reduction goal, through LES's inclusion in these calculations of an assumed benefit from avoided carbon emissions.
- LES's use of its SEP Evaluation Model and development of assumptions reflect good utility practice, though nFront Consulting offers some suggestions, mostly to improve the internal consistency of assumptions, as follows.
    - While the current general inflation assumption in the Model is reasonable, nFront has suggested herein an objective resource that LES can use to periodically update this assumption.
    - Increase the assumed escalation of retail rates to be more consistent with long-term historical data and the latest industry projections (this will generally reduce resulting RIM test metrics).
    - Consider increasing the assumed value of avoided CO_2 emissions somewhat in the later years of the study period, recognizing the need to balance LES's carbon reduction versus affordability goals and maintain consistency with supply-side evaluations (this will tend to increase UCT and RIM test metrics).
    - In terms of setting prospective incentive rates, LES should develop reasonable information regarding the economics of energy efficiency improvements from the participant perspective to ensure incentive levels are not greater than needed to encourage adoption.
    - nFront has suggested adjustments to the seasonal nature of some measures to ensure greater fidelity regarding the avoided costs and potential lost revenues that inform the resulting metrics.
- In alignment with LES's desire to reduce the need for fossil-fueled generation resources through peak demand reduction, LES should potentially consider several additional DSM measures for inclusion in the SEP that focus on reductions in peak demand. These include the following:
    - **High Efficiency Dehumidifier**. Incentivizing residential installations of higher efficiency dehumidifiers has the potential to be an effective peak reduction measure, particularly as there is likely significant dehumidifier penetration and high utilization during summer peak periods in the LES service territory.
    - **Commercial Kitchen Equipment**. The replacement of standard commercial kitchen equipment (e.g., dishwashers, combination ovens, steam cookers) with higher efficiency equipment appears likely to be an effective peak reduction measure. While

it is likely that LES already implicitly offers these types of measures through its Custom program, it may be beneficial to offer a separate, more targeted commercial program for greater visibility and higher customer engagement.

- **Electric Water Heater Direct Load Control**. Direct load control of water heaters has been a common peak demand reduction tool in use by the utility industry for many years, typically through power line carrier or radio, but more often in recent years, cellular communication technology. In exchange for a reasonable annual incentive, a load control switch would be installed on the customer's water heater that would be operated during peak system load events. Saturation of electric water heat in LES's service area should be significant, particularly for multi-family housing. While the typical duty cycle will be limited during later afternoon peak events, this program could provide an economic means of avoiding significant summer peak demand. LES may want to investigate whether Wi-Fi enabled communication technologies are being utilized or developed that could be paired with LES's existing smart thermostat AC control program. However, in recent years, cellular-based load control switches have improved their features and ability to provide feedback in tandem with more economical offerings from cellular services providers that combine to make cellular communication technology more cost-effective than as recently as a few years ago.
- **Variable/Critical Peak Pricing**. Time-varying electric rates, which encourage participants to shift load away from peak periods, have been widely adopted in the industry, to reduce both energy costs during peak periods and peak load. nFront Consulting understands that LES is in the early stages of considering time-varying demand rate options for commercial demand customers. Such a program may be similarly promising, depending on the extent to which prospective participants could consistently shift usage away from higher-priced periods. Alternatively, critical peak pricing (CPP) that would reflect higher energy rates during potential LES summer peak periods may also be useful to encourage customers to shift load away from peak load periods. This would require communication with the participant to warn of impending peak events and with meters to separately record usage during CPP events.
- **Voltage Optimization and Conservation Voltage Reduction**. A voltage optimization program involves adjusting voltage levels at key areas of the grid to promote power flow toward the lower end of the voltage range and flattening voltage across the system. These optimized voltage ranges lead to end use energy savings and reductions in immediate demand for end uses, without direct interaction with customers. Conservation voltage reduction (CVR) can then be implemented within

the allowable range without concerns regarding points of lower voltage on the system (e.g., ends of feeders).[1]

[1] Care should be taken to consider the operation of thermostatically controlled appliances, some types of motors, and certain other end uses when assessing the value of CVR, since these appliances and processes may not provide significant load reduction over longer periods of time (e.g., throughout an hour). Additionally, certain customers may have end uses that are very sensitive to voltage, which may limit the available range and require customer engagement.

Section 1
BACKGROUND

PROJECT BACKGROUND

nFront Consulting was retained by Lincoln Electric System (LES) to conduct a review of the LES Sustainable Energy Program (SEP) measures, evaluation process, and measure parameters relative to those being undertaken by other utility peers and industry practice. The review focused on the LES processes used to set measure parameters, the metrics used to determine cost effectiveness, potential additional measures for inclusion in the SEP, and considerations to improve the alignment of the SEP with LES goals. nFront Consulting also reviewed the LES SEP evaluation tool with respect to functionality and input assumptions, taking into consideration LES's program goals, key takeaways from the research above, and nFront's industry knowledge. The outcomes from this review of the SEP are intended to be reflected in LES's upcoming Integrated Resource Plan.

A previous review process was undertaken by LES in 2015, with another consulting firm being retained to perform an in-depth analysis of the SEP, including the demand and energy impacts and the cost-effectiveness of existing and potential future SEP measures. The results of this effort provided important input into LES's 2017 Integrated Resource Plan and included the provision of an evaluation model for LES's ongoing use in assessing the cost-effectiveness of the SEP measures.

LES GOALS RELATED TO THE SEP

In 2011, LES set a Sustainability Target for its resource planning to offset the projected demand growth of the next five years in any planning horizon with renewable and/or demand-side resources. While baseline growth in electricity demand has been projected to be muted since that time, this goal has combined with a purposeful reduction in LES's carbon footprint to guide LES resource planning and actions, including continued development of the SEP.

In October 2020, the Mayor of Lincoln announced the development of a Climate Action Plan with the goal for the City to achieve an 80% net reduction in greenhouse gas emissions by 2050. The Plan, published in 2021, is intended to be a community-wide effort to reduce CO_2 and other greenhouse gas emissions across the entire local energy-economy system—electricity, transportation, heating, and process fuels. Hence, while a significant portion of the Plan is outside of LES's direct purview, it should be expected that LES will play a pivotal role in helping drive forward the City's climate goals.

In November 2020, LES set a goal to achieve net zero carbon dioxide production from its generation portfolio by 2040 in a fiscally responsible way that considers the financial impact of efforts toward this goal on its customers, especially those in the low-income strata. While this goal must likely be met mostly through the transition of LES's generation fleet from fossil fuels to renewables, progress toward the goal will also be driven by the reduction in total generation capacity requirements

resulting from demand-side management resources, particularly those that are weighted toward reductions in LES's peak demand.

Importantly, LES has been on a path of decarbonization for some time, with gradual additions of wind and solar generation and its exit from a major coal resource contributing to a 45% reduction in carbon intensity from 2010-2020 (i.e., carbon emissions per MWh of generation) and a 53% reduction in total carbon emissions over the same period. Further, the latter statistic understates LES's accomplishments in this regard, as it does not include customer energy efficiency improvements funded, in part, by the SEP.

In addition to the SEP contributing toward these goals, LES considers the energy and peak demand savings resulting from the SEP as a useful hedge against volatile energy costs.

SEP DESCRIPTION

The SEP was launched by LES in 2009 and provides financial incentives for residential and commercial customers to make energy efficiency improvements using demand-side management measures, benefiting both the utility and the customer. The SEP is an important program for LES as it helps reduce the need for energy during expensive peak periods and delay the necessity to build additional high-cost and potentially fossil-fueled power plants to serve the LES system, thereby contributing toward LES's goal of having net zero carbon emissions by 2040. Over the existence of SEP, LES has distributed nearly $27 million in SEP incentives, while customers have spent $185 million on energy efficiency improvements.

Below is a listing of the current SEP measures available to LES customers.

Residential

- Whole-house and facility sealing and insulation
- High-efficiency heat pumps and air conditioners (HP/AC)
- Heat pump water heaters (HPWH)
- Smart Thermostat Demand Response Program (Peak Rewards)

Commercial & Industrial

- Whole-house and facility sealing and insulation
- High-efficiency heat pumps and air conditioners
- Heat pump water heaters
- Commercial and industrial lighting
- Custom commercial energy efficiency projects

Most of these measures are self-explanatory and involve improving the efficiency of the building shell or the purchase and installation of high efficiency end uses. The Peak Rewards measure, however, involves the remote control of a customer's air conditioner or heat pump to reduce consumption during peak events. Custom commercial projects involve situations wherein a commercial business

works with LES to scope out and implement an energy efficiency improvement specific to their business process and end uses, based on a negotiated cost sharing arrangement, for which prescriptive measures would not be applicable.

SEP PERFORMANCE

As a part of this SEP review, nFront Consulting assessed the last five years of activity and performance. The performance review of the SEP was focused on determining the overall customer engagement, energy saved, demand reduced, as well as calculating the average costs for the avoided energy and avoided demand.

Table 1 below depicts the annual energy saved over the last five years for each SEP measure category. This table illustrates the fact that the commercial sector is a primary contributor to the overall energy saved in the SEP, which is very common in the industry. Over the last five years, incremental energy savings from the SEP have been equivalent to approximately 0.4% of LES annual retail sales. While this level of saved energy appears to be trending downward over the last two years, this is instead likely driven by the on-going pandemic. The range of savings attributable to the SEP is similar to the U.S. median energy efficiency program savings rate of 0.6% of retail sales and the average of West North Central states at 0.5%, reported by the American Council for Energy Efficiency (ACEEE) in its 2020 State Energy Efficiency Scorecard report for the year 2019.[2]

Table 1: SEP Annual Incremental Energy Saved (MWh)

Year	HP/AC	Commercial Lighting	Custom Commercial EE Project	Insulation and Sealing	Peak Rewards	HPWH	Total	Percent of Retail Sales
2017	366	15,908	3,338	9	N/A	N/A	19,621	0.6%
2018	445	7,843	1,337	16	N/A	N/A	9,640	0.3%
2019	491	18,808	2,105	12	N/A	22	21,438	0.7%
2020	532	9,727	1,727	15	N/A	48	12,049	0.4%
2021	735	7,336	1,264	23	N/A	74	9,432	0.3%
Total / Average	2,478	58,777	9,482	74	N/A	104	70,914	0.4%

Table 2 below depicts the annual demand avoided over the last five years for each SEP measure category. Again, this table illustrates that the commercial sector is a primary contributor to the overall demand avoided in the SEP. On average, over the last five years, the SEP has enabled LES to avoid 0.5% of the LES system peak demand. These savings, in combination with the more general trend of improving energy efficiency, are partly responsible for LES's essentially flat to declining system loads over the last several years.

[2] Available at https://www.aceee.org/research-report/u2011.

Table 2: Annual Incremental Demand Avoided (kW)

Year	HP/AC	Commercial Lighting	Custom Commercial EE Project	Insulation and Sealing	Peak Rewards	HPWH	Total	Percent of System Peak
2017	407	3,348	884	10	N/A	0	4,649	0.6%
2018	494	1,628	301	18	859	0	3,300	0.4%
2019	546	2,396	415	14	780	0	4,151	0.5%
2020	591	1,965	469	16	625	0	3,666	0.5%
2021	817	1,750	321	92	766	0	3,248	0.4%
Cumulative / Average	2,754	10,876	2,322	82	2,981	0	19,015	0.5%

Table 3 below provides the average cost of avoided energy for each SEP measure category, represented by incentive dollars spent divided by the estimated lifetime MWh saved. The commercial lighting category result in the lowest cost energy savings for LES, which is typical. The HP/AC and Insulation and Sealing programs are less favorable, presumably as the bulk of the applicable energy savings are during the summer months only. According to a 2019 Lawrence Berkeley National Laboratory (LBNL) study, average avoided energy costs attributed to utility EE programs are typically in the $15-30 per MWh range.[3] Against this benchmark, it is evident that the SEP overall serves as a relatively low-cost resource and a useful hedge against uncertain and volatile energy costs.

Table 3: Average Cost of Avoided Lifetime Energy ($/MWh)

Year	HP/AC	Commercial Lighting	Custom Commercial EE Project	Insulation and Sealing	Peak Rewards	HPWH	Total SEP
2017	79.8	11.7	23.8	109.2	N/A	N/A	15.8
2018	80.3	6.5	32.3	117.1	N/A	N/A	12.6
2019	78.1	4.2	21.4	106.8	N/A	20.8	9.3
2020	80.0	6.6	22.9	106.3	N/A	20.8	11.5
2021	81.3	8.5	6.3	104.2	N/A	20.8	10.9

Table 4 below shows the average cost of avoided demand for each SEP measure category, based on incentive dollars spent divided by the first-year kW avoided. These values compare favorably to the LBNL study mentioned above, which showed a wide range of average avoided demand cost, the most comparable of which was approximately $1,000 per kW. These values could also be compared to the capital cost of generation facilities, which are typically in the range of $800-1000 per kW or higher,

[3] See, for example, The Cost of Saving Electricity: A Multi-Program Cost Curve for Programs Funded by U.S. Utility Customers, published by Lawrence Berkeley National Laboratory, at https://emp.lbl.gov/publications/cost-saving-electricity-multi-program.

particularly for some carbon-free resources. Of course, these generation facilities would tend to have a longer service life than the end uses impacted by the SEP.

Table 4: Average Cost of Avoided Demand ($/kW)

Year	HP/AC	Commercial Lighting	Custom Commercial EE Project	Insulation and Sealing	Peak Rewards	HPWH	Total SEP
2017	1,435	695	1,385	3,459	N/A	N/A	800
2018	1,444	388	2,209	3,632	108	N/A	604
2019	1,404	415	1,671	3,309	165	N/A	591
2020	1,442	408	1,297	3,394	251	N/A	640
2021	1,462	447	373	3,274	265	N/A	647

The HPWH program is shown above as not applicable, as LES currently does not ascribe any demand savings to this measure. However, based on nFront interaction with LES staff, LES intends to modify the historical data and assumptions going forward to reflect a reasonable avoided demand value. Given the likely relatively low duty cycle of water heating during the typical late afternoon LES peak, the peak demand savings are likely to be relatively small, such that the avoided demand costs of this measure will be relatively high.

LES SEP EVALUATION PROCESS

To assess existing SEP measures, new demand-side measures for potential inclusion in the SEP, and the overall SEP, LES utilizes an industry standard approach to measure cost effectiveness of such measures or its program. This industry standard approach (discussed more fully in Section 3) entails development of the benefits and costs of the demand-side measure and the calculation of the ratio of the total benefits versus the total costs from multiple perspectives. In its evaluations of demand-side measures, LES has adopted a dual cost effectiveness metric using both the Utility Cost Test (UCT) and the Rate Impact Measure (RIM) test, though with the latter reflecting a threshold of cost-effectiveness of 0.6, as compared to a 1.0 pass/fail threshold used for the UCT and more generally typical of this testing framework. This lower threshold for the RIM test allows for a limited level of subsidization from non-participants but effectively caps that limit. LES also recognizes that it is important to capture societal benefits when assessing the cost-effectiveness of the SEP. Hence, in alignment with the LES goal of attaining carbon-neutral generation, LES reflects the cost of carbon in its evaluations.

Section 2
SEP REVIEW APPROACH

The SEP review comprised of benchmarking the SEP measures, evaluation process, and measure parameters relative to those being undertaken by other utility peers and typical industry practices. The review focused on the LES process in setting measure parameters, the metrics used to determine cost effectiveness, potential additional measures for inclusion in the SEP, and considerations to improve the alignment of the SEP with LES goals. nFront Consulting also reviewed the LES SEP evaluation tool in relation to functionality and input assumptions, taking into consideration LES's program goals, key takeaways from the research above, and nFront Consulting's industry knowledge.

PEER UTILITY AND STATEWIDE ENERGY EFFICIENCY PROGRAM RESEARCH

Purpose

To review the LES SEP, nFront Consulting performed a high-level benchmarking analysis consisting of five peer utilities that were determined jointly with LES staff. The utilities selected as LES peers are municipal utilities that are generally located within the Midwest region, operate a similar sized electric system, and have implemented DSM programs. It was also important for LES to have peer utilities that were typically thought of as industry leaders in the DSM space. nFront Consulting supplemented this benchmarking analysis with the use of publicly available statewide energy efficiency studies and meta-analysis from nationally recognized organizations to further inform the basis of typical industry practices.

The benchmarking analysis conducted for the LES SEP was focused around three key areas, which are identified below.

1. Measure parameters and the basis of assumptions used in cost effectiveness evaluations
2. Whether any measures are being endorsed that have applicability to LES but have not yet previously been considered by LES, especially those with a high demand savings potential
3. Metrics used to determine cost effectiveness for purposes of endorsement

Sources

nFront Consulting gathered recent, publicly available information regarding demand-side management programs for peer utilities in the Midwest, as well as information prepared as part of statewide energy efficiency evaluations and technical reference manuals (TRM). The utility websites, as well as the specific documents listed below, informed this review.

Peer Utilities

- Austin Energy – 2014 DSM Potential Study Update
- Colorado Springs – 2020 DSM Potential Study

- Lansing Board of Water & Light (LBWL) – 2020 DSM Potential Study
- Omaha Public Power District – 2016 Integrated Resource Plan, 2019 Potentiality Study Update
- City Utilities of Springfield, Missouri – 2019 Integrated Resource Plan

Statewide Studies

- Iowa – Assessment of Iowa's Energy Efficiency Potential: 2018
- Michigan – Energy Measure Database: 2021
- Minnesota – Energy Efficiency Potential Study: 2020-2029

To supplement the research above, nFront Consulting also performed a meta-analysis consisting of publicly available studies and reports from various nationally recognized organizations. A list of the sources collected for the meta-analysis is presented below.

- Applied Energy Group (AEG) – 2017 State of Michigan Demand Response Potential Study
- American Council for an Energy Efficient Economy (ACEEE) – Cost-Effectiveness Tests: Overview of State Approaches to Account for Health and Environmental Benefits of Energy Efficiency
- ACEEE – Department of Energy's Better Buildings Residential Network Peer Exchange: Cost Effectiveness Testing for Energy Efficiency Programs
- National Efficiency Screening Project (NESP) – National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources
- NESP – The Resource Value Framework: Reforming Energy Efficiency Cost-Effectiveness Screening
- Synapse – 2019 New Hampshire Cost-Effectiveness Review

REVIEW AND EXTENSION OF LES SEP EVALUATION MODEL

nFront Consulting obtained a copy of the LES SEP Evaluation Model, populated with LES's current assumptions for general variables (see below) and a wide range of prescriptive and custom measures currently offered as part of the SEP. The Model assumptions are organized into the following categories:

- General Assumptions
  - Global, "static" variables (i.e., those that do not change through time, such as inflation and other escalation assumptions) and
  - Time series assumptions, such as retail rates and avoided cost rates
- Measure-specific Assumptions
  - Energy and demand savings
  - Base year incentive, participant cost contribution, and administrative cost
  - Retail rate type (to differentiate multiple energy and demand rate levels)

- Measure life
- Coincidence with LES's peak
- Net-to-gross (discounting measure savings for free ridership, leakage, and the like)
- Number of months of the year of transmission demand impacts

nFront Consulting reviewed the SEP Evaluation Model assumptions at a high level, relative to reasonable values commonly used in the utility industry and the measure-specific assumptions for general reasonability and internal consistency across the full range of measures, including a large number that had been reviewed as part of the 2015 SEP Review. Importantly, as several measures included in the SEP Evaluation Model related to large commercial HVAC measures, many of the assumptions pertained to specific situations and end use scenarios of a specific customer. nFront Consulting engaged in some discussion with LES staff to verify the reasonability of savings estimates.

nFront Consulting also engaged LES staff in several discussions to address questions and initial observations and to understand the process staff used to update assumptions and utilize the model. Finally, nFront staff developed additional functionality to calculate maximum incentive amounts to meet the minimum desired score for certain of the test metrics and worked with LES staff to ensure the fidelity of the intended process and goal of the model enhancement.

Section 3
COST-EFFECTIVENESS METRICS

Demand-side management (DSM)[4] measures are evaluated for purposes of determining whether they should be included in the portfolio of a utility's resources in a variety of ways. First, they can be evaluated within the resource planning framework, typically utilizing power system dispatch and optimization software. However, more often, they are evaluated using industry-accepted cost-effectiveness tests, first defined in a document referred to as the California Standard Practice Manual and later expanded in various industry literature. These cost-effectiveness tests are designed to compare the cost of DSM measures to the avoided cost of supply-side resources, while accounting for these and other relevant costs and benefits.

INDUSTRY STANDARD METRICS

The following are industry-standard benefit-cost metrics that have formed the basis for determining cost effectiveness of DSM measures for many years. Each reflects the ratio of benefits to costs from a particular perspective, with the value of 1.0 being the threshold of benefits exactly offsetting costs and values above or below 1.0 typically indicating a pass or fail with respect to the "test" for cost-effectiveness.

1. **Utility Cost Test (UCT)** – Indicates whether the benefits of avoided utility costs exceed the costs incurred by the utility to implement the program
2. **Rate Impact Measure (RIM) test** – Indicates whether avoided utility costs exceed the costs incurred by the utility and the revenue lost from participating customers, indicating that non-participants would NOT see an increase in retail rates as a result of measure activity
3. **Total Resource Cost (TRC) test** – Indicates whether the combined benefits to the utility and participating customers exceed the total cost of the measure, often including benefits to society as a whole (in which case, this test metric is more commonly referred to as the Societal Cost Test)
4. **Participant Cost Test (PCT)** – Indicates whether the benefits to the participant exceed the cost the participant incurs to implement the measure

Such costs and benefits would be assessed over a relevant time horizon and present valued to a current year basis using a discount rate that is more relevant to the perspective of the test—in the case of the utility's perspective (i.e., the UCT or RIM test), the utility's cost of capital, and for the PCT, perhaps the prime lending rate or the like. In the case of the TRC, as the perspective is a combination of the utility and participant, some sort of average might be considered, but most often, the utility's

[4] We use the term demand-side management (DSM) here to refer to efforts by utilities or regulatory bodies to influence consumers' demand for electricity, both at peak times and all hours, by providing for incentives and penalties, typically outside of the typical rate-setting process. These can take the form of, for example, providing incentives to install more efficient appliances or to shift consumption away from peak hours to other hours.

cost of capital would be utilized. For publicly owned utilities, like LES, that cost of capital would be the carrying cost of long-term debt.

Table 5 below summarizes the categories of benefits and costs considered in each of these industry standard cost-effectiveness tests, where checkmarks indicate whether the benefit or cost is considered in the computation of the test in question.

Table 5: Industry Standard Cost Effectiveness Metrics

Program Attribute	Utility Cost Test	Rate Impact Measure Test	Total Resource Cost Test	Participant Cost Test
Program Benefits				
Customer Bill Savings				✓
Avoided Energy Costs	✓	✓	✓	
Avoided Capacity Costs	✓	✓	✓	
Avoided Delivery Facility Costs	✓	✓	✓	
Non-Energy Benefits – to Utility	✓	✓	✓	
Non-Energy Benefits – to Participant			✓	✓
Program Costs				
Measure Cost – Utility-funded Incentive	✓	✓	✓	
Administrative Costs	✓	✓	✓	
Measure Cost – Participant Contribution			✓	✓
Lost Utility Revenues		✓		
Non-Energy Costs – to Utility	✓	✓	✓	
Non-Energy Costs – to Participant			✓	✓

Non-energy Benefits (NEB) and Non-energy Costs above refers to costs and benefits unrelated to the energy and demand characteristics of the end uses in question or the installed cost of the end use itself. Participant NEBs would include, for example, the reduction in maintenance costs associated with high efficiency lighting, which tends to last longer than legacy lighting types, improved health benefits of better insulated homes, cost savings of reduced water consumption, and the increase in property value of high efficiency end uses. Participant Non-energy Costs would include, for example, any increase in maintenance associated with higher efficiency end uses or reductions in comfort associated with many demand response programs. Non-energy benefits and costs associated with the utility would include, for example, indirect effects on system operation and maintenance that are expected to result from program load impacts. These non-energy impacts are shown above as gray check marks to indicate that they are often ignored in practice because they are difficult to quantify. We revisit this point below.

Since the 2008 Recession, most regions in the U.S. saw much lower rates of growth in energy demand and a resultant significant amount of slack in the market for capacity. In addition, as a result of the development of shale natural gas resources in several areas of the U.S., natural gas prices have

declined dramatically since that same period, driving down the cost of electricity throughout much of the U.S. and putting downward pressure on the price of coal and other competing fuels. The resulting reduction in avoided capacity and energy costs has reduced the economic value of demand-side resources. This has driven many individual current or prospective DSM measures below the cost effectiveness threshold. However, instead of abandoning such measures, many utilities and regulators additionally compute more aggregate, program-level metrics (e.g., program-wide or segment-specific measures), which allow less economic measures to be supported by those that are more economic. In this way, there is some recognition for spillover effects (i.e., cross end-use influences), reduced externalities (discussed further below), and energy equity. This program-wide approach to benefit-cost metrics is utilized by LES.

Over the last decade or so, many entities in the utility industry have begun adopting an adjusted version of the TRC test, referred to as the Societal Cost Test (SCT), that incorporates costs and benefits that may not be directly impact the utility or participant but inure to society as a whole. These might include, for example, reduced carbon emissions that contribute to climate change, improved income equality (often referred to as "energy equity"), and reduced environmental impacts of upstream resource requirements (e.g., fossil fuels, steel, copper, etc.). Additionally, an SCT would properly incorporate a present value rate that would be consistent with this perspective—the 30-year treasury yield being most often recommended, and likely lower than a rate relevant to the utility or participant (the average 30-year treasury rate over the last 10 years is approximately 3.0%, for example). Regulators and other entities that have adopted the SCT as a key test metric also tend to be more aggressive in capturing NEBs in the full range of test metrics.

In recent years, it has been recognized by many in the utility industry that NEBs are an important part of the decision-making of the participant in making choices regarding the efficiency and related operating characteristics of end use equipment. In practice, these NEBs are difficult to quantify or even identify in all cases, leading to the potential for cost-effectiveness tests incorporating the participant perspective to be "unbalanced"—capturing all participant costs but none of the participant NEBs. Hence, some industry regulatory bodies and EE advocacy organizations have argued for the exclusion of the participant perspective in determining cost-effectiveness.

This principle of symmetry is a key concept provided in the NESP's Resource Value Framework (RVF), along with other principles including the alignment of energy policy goals and public interest in the energy efficiency screening evaluation.[5] The RVF is a framework of principles and best practices that provide guidance for entities to develop and implement a primary cost-effectiveness test, denoted as the Resource Value Test (RVT). The RVT, developed by the entity in question based on this framework, would then serve as the primary test for energy efficiency resource screening and determine whether the resource is cost-effective relative to the public interest and energy policy goals. The RVT can also be supplemented with secondary tests to gain insights from additional perspectives, such as a social or even a ratepayer perspective.

[5] https://www.nationalenergyscreeningproject.org/wp-content/uploads/2017/03/The-Resource-Value-Framework-Reforming-EE-Cost-Effectiveness-14-027.pdf

Taking direction from the RVF, the New Hampshire Public Utilities Commission adopted the Granite State Test (GST) as its primary test to screen energy efficiency resources, effective January 2021. The GST is essentially a modification of the TRC test which includes all utility system impacts and non-energy benefits and costs yet excludes all participant impacts and other non-utility costs and benefits. The primary rationale for this exclusion rests on both the symmetry issue discussed above, as well as various ideas around the need to avoid complicating the utility's program decision-making with the participant perspective. The main takeaway is that applying tests in a symmetrical fashion, where corresponding costs and benefits are both captured in the analysis, will ensure a more balanced determination of cost-effectiveness.

These points of view related to the participant perspective dovetail with LES's 2015 SEP Review, which stated,

> "The Utility Cost Test is often utilized as an indicator to guide endorsement. While the Total Resource Cost test provides a more holistic view of the economics, the economics from the participant's perspective…may not be as clear…for the utility to take into account…"

nFront Consulting considers this a reasonable basis for excluding the participant perspective in assessing cost-effectiveness to the extent the evaluator does not have confidence that the costs and benefits from this perspective are accurately depicted. Given that, adherence to the UCT and its variants, including the RIM test, seems appropriate, particularly if additional societal benefits are considered, such as the avoided cost of CO_2 emissions (more on this below). As discussed in the RVT above, this provides for due consideration of the goals of LES.

METRICS USED BY PEER UTILITIES AND STATEWIDE ENTITIES

Table 6 below presents the cost effectiveness test(s) used by the peer utilities and statewide entities, focusing on the Midwest region but also capturing some other entities jointly determined to be likely comparators for LES stakeholders or separately identified given nFront familiarity with the entity/regulator. The table also shows whether societal impacts and non-energy benefits are included in the cost-effectiveness test(s) relied upon by the entity in question. "N/A" below means not available, meaning that the inclusion of these impacts could not be ascertained with certainty.

Table 6: Cost Effectiveness Test Benchmarking[6]

Entity	Primary Cost Effectiveness Test(s)					Societal Impacts Included?	
	UCT	RIM	TRC	PCT	SCT	CO_2	NEBs
Peer Utilities							
LES	X	X				Yes	No
Austin Energy			X			No	N/A
Colorado Springs			X			Yes	Yes
Lansing, MI			X			No	Yes
OPPD			X			N/A	N/A
Springfield, MO	X		X			N/A	N/A
Statewide							
Illinois			X			Yes	No
Indiana			X			No	No
Iowa					X	No	Yes
Michigan	X					No	No
Minnesota					X	Yes	No
South Carolina	X					No	No
Wisconsin			X			Yes	Yes

As depicted in Table 6 above, there is no consensus on which test is best used as the primary basis for cost effectiveness. The TRC appears to be the most common test, while the UCT is second most common. The RIM test does not typically appear to be a key metric for most other utilities, having been generally abandoned over the last few decades as being overly averse to most DSM measures. However, as noted in the section above, the industry appears to be trending away from use of the TRC as, in practice, it has the tendency to be "unbalanced," in that it includes all the participant costs but tends to ignore participant NEBs. Another takeaway from the cost effectiveness test benchmarking is that the inclusion of avoided cost of emissions and other NEBs in the primary cost effectiveness test is becoming more prevalent in the industry, even if the cost-effectiveness test being utilized is not specifically referred to as a "societal cost test," though it is not common practice.

CONCLUSIONS RELEVANT TO LES

LES's 2015 SEP Review evaluated the then-current SEP measures and a range of potential candidate measures utilizing the four primary industry standard cost-effectiveness tests, but in the conclusions placed the most emphasis on the UCT, for the reasons discussed at the beginning of this section. In addition, however, the 2015 SEP Review indicated that, for all test metrics, a value as low as 0.6 might be considered "marginal". After consultation with the consultant that assisted LES with the 2015 SEP

[6] Information was sourced from the publicly available studies from the utilities in question and, for statewide organizations (typically regulators), ACEEE's State and Local Policy Database, available at https://database.aceee.org/, and the National Energy Screening Project's Database of State Efficiency Screening Practices, available at https://www.nationalenergyscreeningproject.org/state-database-dsp/database-of-state-efficiency-screening-practices/.

Review, LES determined that it would adopt the combination of the UCT and the RIM test, though with the latter reflecting a threshold of cost-effectiveness of 0.6, rather than the more traditional 1.0 pass/fail threshold. This lower threshold for the RIM test allows for a limited level of subsidization from non-measure participants but quantifies that limit. Importantly, for purposes of estimating avoided costs within both tests, LES also includes an allowance for the cost of avoided CO_2 emissions, thereby incorporating a key element of the Societal Cost Test discussed above.

As discussed above, variants of the SCT are often viewed as the most appropriate basis for assessing cost-effectiveness, as it is most aligned with the regulator and stakeholder perspective. However, recognizing the limitations of the participant perspective in terms of the high potential for a lack of balance in viewing the full range of both costs and benefits has driven many jurisdictions, utilities, and other industry entities toward various hybrids of the traditional tests. These often eschew the participant perspective but incorporate benefits and costs to society, as well as making a more concerted effort to incorporate non-energy benefits into the avoided costs.

As a publicly-owned utility, it is appropriate to capture societal benefits in assessing cost-effectiveness of the SEP in aggregate or individual measures. Such societal benefits could include avoided CO_2 emissions, particularly as doing so dovetails with the stated goals of LES. In addition, this perspective provides justification for a reduction in the threshold of the RIM test, as LES has already adopted. This reduction could be viewed as a proxy for the inclusion of additional societal benefits that cannot be readily estimated but are certainly a factor in this decision. These variations from the legacy standard benefit-cost test metrics better align LES's decision-making with respect to the SEP to LES's stated long-term goal of attaining carbon-neutral generation in a fiscally responsible manner.

Section 4
ADDITIONAL POTENTIAL SEP MEASURES

In efforts to bolster the SEP, making it more capable of contributing toward the LES goal to achieve net zero carbon dioxide production from its generation portfolio by 2040 by reducing system demand, LES is interested in potential additional measures to be offered in the SEP, particularly those that are weighted toward reductions in LES's peak demand.

POTENTIAL ADDITIONAL DSM MEASURES

As a part of the review of peer utilities and statewide entities, nFront Consulting took note of measures that were currently in place or had recently been endorsed or recommended that had applicability to LES but had not yet previously been implemented by LES. Measures with a high demand savings potential were considered especially useful as these measures align with LES goals of reducing the need for fossil-fueled resources, including through peak demand reduction.

Table 7 provides additional DSM measures that nFront Consulting has identified for LES to potentially consider for further evaluation and inclusion in the SEP. The table includes initial estimates of demand impacts per participant and a potential incentive level for each measure, as well as the resulting average cost of avoided demand, excluding administrative and, in the case of the demand response programs, technology costs, which can be significant. LES should conduct more research to develop more complete and specific assumptions for such further evaluation. These measures are discussed in the subsections below.

Table 7: Potential Demand-focused Measures

Potential Measure	Representative Parameters		Average Cost [7]
	Demand Reduction (kW)	Incentive ($)	
Residential High Efficiency Dehumidifier	0.08	$25	$312.5/kW
Commercial High Efficiency Dishwasher	3.6	$1,800	$519.5/kW
Commercial High Efficiency Combination Oven	3.1	$735	$237.1/kW
Commercial High Efficiency Steam Cooker	3.2	$1,800	$568.5/kW
Electric Water Heater Load Control	0.5	$25/Yr	$50/kW-yr
Variable/Critical Peak Pricing	Varies	Varies	Varies
Voltage Optimization	Varies	Varies	Varies

[7] Excludes administrative and enabling technology capital and maintenance costs.

High Efficiency Dehumidifier

Incentivizing installation of a higher efficiency dehumidifier has been shown in various TRMs to have the potential to be an effective peak reduction measure for the residential class. This a measure that is currently offered by the City of Ames, Iowa. A High Efficiency Dehumidifier incentive has potential for LES to consider including in the SEP, as there is likely significant dehumidifier penetration across the LES service territory. According to the 2015 EIA Residential Energy Consumption Survey, dehumidifier penetration in the West North Central Census region was approximately 23%.

Commercial Kitchen Equipment

The replacement of standard commercial kitchen equipment with higher efficiency equipment, particularly for a dishwasher, combination oven, and steam cooker, has been shown to be effective peak reduction measures in various TRMs. This type of program is currently offered by Austin Energy in Texas and includes all three of the kitchen appliances identified above. While it is likely that LES offers these types of measures through its Commercial and Industrial Energy Efficiency Custom Program, LES should consider whether it would be beneficial to offer a separate commercial program more targeted toward the commercial kitchen industry. Creating a separate program may allow for more visibility to this customer sector and drive higher customer engagement for these beneficial measures.

Electric Water Heater Load Control

The State of Michigan's 2017 Demand Response Potential Study identified direct load control (DLC) of electric water heaters as a promising demand response resource. DLC programs provide incentives to customers to allow remote control of targeted end uses during potential peak periods, in the case of electric water heaters, effectively using the device as a sort of energy storage resource. Electric water heaters likely have significant saturation in LES's service area. Estimates for the region taken from the Energy Information Administration's Residential Energy Consumption Survey (RECS) and other estimates for cities similar to Lincoln suggest saturation in the range of 20-40%. For comparison, Census data for 2020 suggests that electric space heating saturation in Lincoln is 35%, which is likely to be somewhat lower than electric water heating saturation (based on typical differences between the two end uses reflected in RECS data). While Lincoln has widespread natural gas availability, there is also a significant proportion of multi-family housing in the service area. Given the on-board thermostatic control of these and most HVAC equipment, it is necessary to control these end uses so that they do not run during multiple hours to ensure achievement of expected demand reduction during the absolute peak hour.

While utilities have historically operated DLC programs utilizing one-way power line carrier or radio-based communication technologies, these do not provide useful feedback on successful operation or data for evaluation purposes. Many cellular-based programs similarly reflect control technologies that do not provide for feedback to ensure operability. Many programs around the country have found control equipment failure and disconnection incidence affecting a significant portion of equipment within only several years of installation. This outcome can be avoided through aggressive

maintenance, but either way affects the program economics. This potential problem would not be as great a concern with limited-term pilot projects.

With increasing availability of Advanced Metering Infrastructure (AMI), two-way communication is afforded, which increases the reliability of control events and impacts. Some utilities without AMI coverage have begun developing programs making use of WiFi-enabled control devices, typically in concert with smart thermostat HVAC control (often through temperature setback), to enable similar two-way communication. In recent years, cellular-based load control switches have improved their features and ability to provide feedback in tandem with more economical offerings from cellular services providers that combine to make cellular communication technology more cost-effective than as recently as a few years ago. Importantly, some of these systems include deterministic or algorithm-based system to ensure participant comfort by disabling control for brief periods. While this feature likely reduces avoided demand slightly, it is commonly viewed as critical to reduce program attrition or control event opt-outs (assuming event opt-out is enabled).

nFront Consulting understands that LES has been considering a potential pilot project for water heater control. LES would need to research the enabling technology options given its existing Wifi-enabled smart thermostat program and develop more specific program parameters with respect to technology costs, required incentives, average impacts, and participation. LES would also likely want to understand the size of this potential resource in its service area, as economics will be improved by spreading technology and implementation costs over a greater total capability.

Variable/Critical Peak Pricing

According to the State of Michigan's Demand Response Potential Study, it was recommended that utilities consider implementing dynamic pricing programs, as it was shown that these programs have the largest peak reduction potential of potential demand response resources. Dynamic pricing programs offer time-varying electric rates that encourage participants to shift load away from peak periods. The study showed that dynamic pricing was effective for both the residential and commercial sectors, as the program is widely applicable with the prospect for high participation rates.

nFront Consulting understands that LES is in the early stages of time-varying demand rates options for commercial demand customers. Such a program would likely dovetail closely with this recommendation, depending on the extent to which prospective participants could consistently shift usage away from higher-priced periods. Given the non-coincident nature of retail demand rates, this can be challenging to many types of commercial customers.

A particular type of dynamic pricing program, referred to as critical peak pricing (CPP), would instead reflect higher energy rates for brief and infrequent peak periods. This would require communication with the participant to warn of impending peak events and electronic communication with the participant's meter to separately record usage during CPP events. nFront Consulting understands that LES's largest customers, which make up nearly one-third of its load, have the necessary two-way communication to facilitate this type of program. This program structure could be very intriguing for many commercial customers as it offers the opportunity of additional financial benefits from stronger

pricing signals, targeted specifically toward the LES coincident peak. Additionally, because CPP programs are event-based, the demand reductions should be highly aligned with the LES coincident peak, thereby acting as an effective contribution to an overall reduction in LES capacity requirements.

Voltage Optimization

Voltage optimization is another program from State of Michigan's Demand Response Potential Study that was shown to be an effective demand reduction program, as it was a top performer outside of dynamic pricing programs mentioned above. Voltage optimization involves adjusting voltage levels at key areas of the distribution system to promote power flow toward the lower end of the voltage range, thereby flattening voltage across the system. This requires coordinated and automated control of distribution equipment in substations and on distribution lines, including integrating substation and distribution line voltage regulators and capacitors into a distribution management system with two-way communications. These optimized voltage ranges lead to energy savings and reductions in immediate demand for end uses, as well as reduced line losses for the electric system. Once voltage levels across the system are optimized in this way, conservation voltage reduction (CVR) could be more readily implemented without fear of violating voltage ranges at points of low voltage, for example, at the ends of feeders. Many utilities are implementing operating procedures to engage CVR targeting a small percentage reduction in system-wide voltage during peak events.

However, care should be taken to consider the operation of thermostatically controlled appliances, some types of motors, and certain other end uses when assessing the value of CVR, since these appliances and processes may not provide significant load reduction over longer periods of time (e.g., throughout an hour). Additionally, certain customers may have end uses that are very sensitive to voltage, which may limit the available range and require customer engagement.

A key difference with this program when compared to the ones discussed previously, is that a voltage optimization program is operated solely by the utility and does not involve any interaction with the customer.

Section 5
LES COST-EFFECTIVENESS EVALUATION MODEL

As discussed above, LES utilizes a spreadsheet-based model, obtained from the consultant that worked on the 2015 SEP Review, to gauge the cost-effectiveness of SEP measures. nFront Consulting performed a review of the model's functionality and input assumptions and created some additional logic to produce estimates of the maximum incentive that would still meet cost-effectiveness criteria for the two test metrics that LES has adopted—the UCT and RIM tests.

MODEL REVIEW

Description of SEP Evaluation Model

The SEP Evaluation Model[8] was designed to produce cost-effectiveness metrics for many DSM measures through the use of a template of calculations summarizing benefits and costs from each required perspective for a single DSM measure drawing from a matrix of input assumptions across multiple measures to be evaluated. The measures can be cycled through via a numbered input field, through "spinner" controls, or through a macro-driven process.

Input assumptions are arranged such that there are separate "global" assumptions affecting all measures that are fixed through time, such as inflation and certain escalation assumptions, and global time series assumptions, such as retail rates and avoided cost rates for multiple categories of rate and/or load types. Then, there are measure-specific assumptions including both static and time series data, as follows.

Measure Static Assumptions:

- Baseline and measure energy and demand usage
- Base year administrative costs
- Measure life
- Coincidence with LES's peak
- Net-to-gross (discounting measure savings for free ridership, leakage, and the like)
- Number of months of the year of transmission demand impacts
- Rate category (more on this below)
- Applicability of avoided carbon emissions
- Avoided energy cost category (currently set up for four options—Summer On-peak, Annual On-peak, Annual All Hours, and Summer Peak Only but expandable)

[8] We refer to the LES model herein in this way rather than referring to the name of the model developed by the 2015 SEP Review consultant, as that consultant's model name is a trademark and that specifically named model may have changed in functionality since the 2015 SEP Review.

Measure Time Series Assumptions:

- Numbers of participants
- Incentive and participant capital cost contribution
- Administrative costs
- Any recurring costs

Importantly, the SEP Evaluation Model is set to a particular Base Year, which controls the beginning year of all calculations on which the metrics are based and is the first year of input data for time series inputs. Hence, when the Base Year is to be updated, all base year values and all time series assumptions must be updated. While this allows most of the formulas that reference time series data to be relatively simple, updating the Base Year can be a painstaking process. nFront notes that most, if not all, of the time series references in the Model are already dynamic in nature and could accommodate a more flexible Base Year approach, specifically allowing the user to set a particular start year of the evaluation without having to adjust all the underlying Base Year or time series data.

The Model is set up to allow for a 20-year horizon of measure activity (Activity Horizon) but a 35-year horizon of downstream measure costs (if any) and benefits, as well as an "end effects" or terminal value allowance to capture impacts beyond that 35-year horizon (Study Period). In this way, participants in year 20 of the Activity Horizon in an SEP measure with a 20-year life will impact the cost-effectiveness metrics through the last year of the service life of the affected end use. The terminal value of the benefits and costs of any measure are set at the present value in the last year of the Activity Horizon of the benefits and costs in that year for the weighted average remaining life of all measure activity.

LES Use of Model

The SEP Evaluation Model is designed to be flexible, in terms of how measures are evaluated. Measures can be set up as a single instance in the start year (or any particular year), with that first year representing the efficiency investment, for example, and the years of the service life capturing the resulting benefits. This is a typical representation of a new DSM measure to test for its cost-effectiveness based on whether an investment today is cost effective, for example. The Model can also be set up with varying participation in DSM measures through time, with associated variations in investment and benefits during the entire study period. This provides a more complex test for whether engaging in a particular DSM measure over some timeframe is cost effective. These points of view should yield similar results, but the ebb and flow of participation and assumed future cost and revenue rates will cause these differing measure frameworks to have differing cost-effectiveness metrics.

LES includes its full range of prescriptive SEP measures in the input structure of the Model, with varying participation through time. Hence, the evaluation of these measures in the Model provides for an evaluation of the cost-effectiveness of LES engaging in this measure over a particular time horizon—as the Model is currently set up, 20 years. Certain complex commercial measures, such as large chiller projects, and custom commercial measures are instead entered as single instances,

specific to the participant's situation and affected end use(s), with investment occurring in the start year and future benefits and costs accruing over the study period.

LES frequently uses the Model to help determine an incentive level for these complex and custom commercial measures. In these cases, LES sets up all the inputs for a custom measure and iteratively adjusts the incentive level to understand what incentive levels just meet the minimum desired evaluation metrics, as well as what incentive level might be otherwise appropriate and meet other standards of the SEP (e.g., LES funding no more than 50% of an SEP project). Importantly, however, this does not provide any indication about the *minimum* incentive level that might drive adoption. For these measures, it will be important for LES to understand the participant perspective, recognizing some of the difficulty discussed above related to the cost-effectiveness tests. Populating those aspects of the Model so that a PCT can be computed and perhaps buttressing those calculations with a real payback or internal rate of return calculation will provide a more complete sense of what the customer is seeing in terms of economics, to devise an appropriate incentive. In some cases, benefits that are not directly related to electric consumption may also need to be considered; this would be more complicated than the Model currently addresses but could be addressed via offline calculations or an extension of the Model.

The LES Model is designed to be simple with respect to the numbers of needed inputs and the detail of calculations. There are no monthly details nor hourly load shapes. Instead, the user must consider the shape of monthly load impacts and consider load shape in setting inputs such as avoided energy costs, coincidence of reduced demand, and lost demand revenue. For example, an SEP measure affecting only summer usage, such as high efficiency air conditioning, would need to reflect the amount of energy saved during relevant periods only, the average avoided energy rate during that period, and an average retail demand rate that is consistent with only those months.[9] Accordingly, the Model has selectable inputs for avoided energy rates that are specific to differing season or combinations of seasons, retail demand rates similarly varying for summer only versus year-round demand impacts, and an input field to control the number of months of avoided transmission costs.

LES seems to be very conscious of this input structure and utilizes appropriate variations across the prescriptive measures. For certain commercial prescriptive and custom measures, given the technologies involved and the specific usage patterns that may be at play for a given customer, it is more difficult to assess the fidelity of the measure parameters. nFront Consulting has engaged with LES staff on some example custom measures to get clarification on the usage patterns and suggest potential variations in how LES develops assumptions to accommodate complex load impacts.

[9] Here we refer to air conditioning to mean cooling only or primarily. Importantly, as natural gas is widely available in the LES service area, even some heat pumps will be utilized in situations where the backup fuel is natural gas (i.e., rather than electric resistance heat), which will still reduce peak demand impacts outside of the summer months.

Input Assumptions

General Assumption

Inflation

The Model reflects an inflation assumption, which is applied to measure capital cost, including both the incentive and participant-funded portion, and administrative costs. The Model currently assumed 2.3% inflation over the Activity Horizon, based on direction from the 2015 SEP Review that was obtained from a then-current inflation forecast (a publication called the BlueChip Economic Indicators). While the publication upon which this inflation forecast is based is considerably out of date, inflation expectations had been falling slightly through 2019 and have only been heading back up in response to a variety of factors including, but not limited to, supply chain disruption and federal fiscal and monetary support that has been in place since the onset of the coronavirus pandemic. Based on the latest available publicly available sources, inflation is expected to be nearly 6% in 2021 before dropping down to the 2.0-2.5% range for 2022-2030, all as measured by the personal consumption deflator.[10] Hence, the current inflation assumption in the Model is representative of today's outlook, recognizing that the base year of the model is currently set to 2020, as discussed above. However, nFront suggests that this value be updated periodically using a resource such as the Philadelphia Federal Reserve Survey of Professional Forecasters referenced in the footnote below.

Separately, LES has indicated that incentive levels for the SEP have been static for some time, and they may be considering adjusting the Model assumptions accordingly. While this may be an appropriate assumption for the near- to medium-term (i.e., next five years), nFront suggests that inflation is typically not readily apparent over short time scales and that such incentive levels, like many retail prices, may be "sticky"—adjusting upward more periodically rather than regularly. Hence, LES should be cognizant of the longer-term influence on results of a change to escalation assumptions. Importantly, like a lot of other such factors, internal consistency across assumptions (e.g., measure cost escalation, incentive escalation, retail rate, and avoided cost escalation) is the most important consideration (more on this below).

Retail Rates and Escalation

LES has populated the model with base year retail energy and demand rates and distribution loss percentage estimates that appear to be based on best available information. Available retail rates that can be selected from the measure-specific parameters are by-class and reflect categories for both year-round and summer-only rates, capturing fidelity with respect to seasonal energy rates and demand revenue impacts over the summer season only. Escalation in retail rates over the 20-year Activity Horizon is controlled from the escalation assumptions in the static global assumptions tab.

[10] While the consumer price index is the more often quoted indicator of inflation, the personal consumption deflator is widely viewed as the most appropriate measure of inflation as experienced by the average consumer. For recent surveys, see https://www.philadelphiafed.org/surveys-and-data/real-time-data-research/survey-of-professional-forecasters.

While the model is currently set up to accommodate only six (6) rate categories, it would be a trivial expansion of the model to accommodate additional rates to allow for greater fidelity of seasonal load impacts. The time series input field for distribution losses might be more readily adjusted to a set of static input fields, potentially allowing for a more flexible set of energy and demand rate input matrices. Additionally, LES may want to consider varying assumed distribution losses for certain types of larger commercial customers that reflect higher service voltage. Such variations may have only a small impact on resulting cost-effectiveness metrics but would be a useful and relatively straightforward refinement.

LES has currently set retail rate escalation to 1.0% per year for both energy and demand rates, based on retail power cost projections obtained from the Energy Information Administration's (EIA) Annual Energy Outlook (AEO). The average retail cost of energy for LES's customers has exhibited a compound average growth rate (CAGR) of 1.4-1.5% per year over the last 10 years and 0.2-0.7% per year over the last 5 years. However, it's important to recognize that this period has reflected a considerable decrease in the cost of natural gas and other fuels. Over the last 20 years, the CAGR range for LES's retail average cost is 2.5-3.1%. Like most other electric utilities, LES has been gradually adjusting its rate structure to move fixed costs out of its energy rate and into customer charges and demand rates. Hence, the historical escalation of energy rates may be somewhat less, but it seems likely that the escalation in energy rates in the future will be similar to the overall cost escalation.

The 2021 AEO reflects nominal escalation over 2021-40 in electricity retail electricity costs for the residential and commercial sectors in the West North Central region of 1.7% and 1.3%, respectively. This suggests that LES should consider adjusting its assumed retail rate escalation upward somewhat. Importantly, the implied inflation assumption in the 2021 AEO is approximately 2.1% per year. Accordingly, nFront Consulting suggests consideration for a retail rate escalation assumption similar to the latest EIA projections at minimum.

Avoided capacity and energy costs

Avoided capacity and energy costs are derived from current and forward market indicators. Avoided capacity costs are based on approximate indications of the value of capacity from LES activity in the capacity market, primarily LES sales of excess capacity, currently $30/kW-year. Based on input from LES's consultant during the 2015 SEP Review, this value is assumed to escalate annually at 5.0% to reflect that current market conditions are significantly "soft" in that the market is generally over-supplied as a result of capacity overhang from the 2008 Recession and succeeding years of much slower load growth due to slower economic growth and improving energy efficiency. Most in the utility industry expect the market for capacity to gradually move toward equilibrium as nuclear and fossil capacity is retired, such that capacity rates will recover to a value more representative of the fixed cost of peaking capacity (i.e., amortized capital cost and fixed O&M), in the range of $60-80/kW-year (2021$). As the SEP Evaluation Model does not reach this level in nominal terms until the late 2020s, it seems likely that this assumed escalation is somewhat understated but certainly reasonable.

Avoided energy rates are set annually based on the previous year's market rates for the Lincoln area, as shown below.

Table 8: Average Base Year Avoided Energy Rates ($/MWh)

Summer Daytime Hours	Annual Daytime Hours	Annual All Hours	Summer Peak Period
35.95	25.07	18.60	41.32

Each SEP measure is set by LES to utilize one of these four avoided energy cost rates as a Base Year value depending on the shape of the avoided energy. For example, SEP measures related to air conditioning might be set to use the Summer On-Peak Hours average rate, while a commercial lighting measure might be set to use the Annual On-peak Hours average rate.

While nFront has not performed any analysis of historical energy rates in the SPP region, the rates above comport reasonably well with market data with which nFront is familiar. It is noteworthy, however, that these rates can be highly volatile and impacted by infrequent events, like the February 2021 winter storm, and should likely factor out those unusual events.

These Base Year avoided energy cost rates are assumed to escalate at 3.5% per year based on the EIA's latest projected wholesale annual growth rate. This rate of escalation, particularly from 2020 levels, seems reasonable given projected fuel cost escalation assumptions being regularly assumed by others in the utility industry.

Carbon emissions cost

The SEP Evaluation Model includes an avoided cost for CO_2 emissions, with the CO_2 rate starting at $20/ton in 2024, escalating at the rate of general inflation, or 2.3% per year. Hence, the CO_2 rate escalates to approximately $28/ton by 2039. It is nFront's experience that most planning studies that do include a cost for CO_2 emissions (or value of avoided emissions) reflect (i) a slightly lower starting cost rate but (ii) an escalation rate that is significantly higher than inflation. The latter typically reflects the idea that any regulation will be intended to allow the economy to gradually decarbonize without undue and sudden economic impacts, whether it's a gradually decreasing cap on emissions or a gradually increasing CO_2 tax. Several recent CO_2 regulation proposals reflect this effect. In addition, the likelihood of CO2 emissions regulation is typically viewed as increasing through time. The net result of these differences would be somewhat higher net present value (NPV) impacts of CO_2 emissions regulation.

However, most studies that do reflect a cost of CO_2 emissions are simply a scenario that may play into decision-making in a limited fashion. While more utilities across the country are placing greater weight on planning scenarios reflecting regulation of CO_2 emissions, typically to satisfy the utilities' stakeholders, few utilities seem to directly include a benefit of avoided CO_2 emissions within their DSM cost-effectiveness tests or potential studies. This is even true of utilities which have adopted aggressive CO2 emission reduction goals.

Given LES's net zero carbon reduction goal, nFront Consulting believes it is appropriate that LES explicitly values avoided CO_2 in SEP cost-effectiveness evaluations, as it has been doing for some time. However, the timing and extent of future regulation are highly uncertain. Importantly, LES must

consider potential SEP measures in the context of other means to reduce CO2 emissions (e.g., LES's implementation of renewable resources). For its evaluations of supply-side resources, LES considers a range of potential CO2 emissions cost rates along with other uncertain variables. LES should attempt to maintain some level of consistency in this supply-side evaluation and its demand-side evaluations with respect to the value of CO_2 emissions avoidance. Finally, LES must also balance any additional costs of such efforts to reduce emissions with its affordability goal, particularly recognizing that lower income residents tend to be less likely to participate in DSM programs due to both income and ownership constraints.

Measure Assumptions

nFront Consulting has not performed a detailed review of the assumed parameters on a by-measure basis, as this was done in the 2015 SEP Review and has helped LES to set a standard of practice and a base of assumptions that can be adapted to other prescriptive and even custom measures. Instead, the discussion below summarizes LES's current practice in setting assumptions and offers suggestions regarding important considerations to improve the fidelity and realism of the Model's results.

LES sets assumptions regarding energy and demand savings, measure cost, measure life, peak coincidence, and net-to-gross for specific prescriptive measures based on a combination of industry-standard engineering calculations, industry research (e.g., technical reference manuals published in the region, potential studies by peer utilities), guidance from the 2015 SEP Review, and estimates from prior program activity. Inputs associated with the retail rate category, avoided energy price type, and the number of months of transmission demand impact are determined based on an approximation of the energy usage profile of the affected end use. Certain commercial prescriptive and custom measures related to more complex equipment (e.g., chillers, industry-specific equipment) reflect a joint determination of the energy and demand savings and other factors that are dependent on the specific usage expectation of the prospective participant.

nFront Consulting engaged LES in a brief walk-through of the measure parameters to ask questions and offered numerous detailed assumptions. Generally, nFront considered these assumed parameters to be reasonable. However, for certain commercial measures related to large chillers, internal inconsistencies across prospective measures were noticed. Further, nFront suggested some adjustments to the seasonal nature of some measures to ensure greater fidelity regarding the avoided costs and potential lost revenues that inform the resulting metrics.

MAXIMUM INCENTIVE CALCULATION FUNCTIONALITY

As discussed above, one way in which LES uses the SEP Evaluation Model is to establish an appropriate incentive level that both motivates customer adoption of a measure and achieves the required cost-effectiveness thresholds for inclusion in the SEP, particularly for the commercial custom projects. This has historically been an iterative process for LES, that was not efficient. In effort to improve this process, nFront Consulting has developed additional logic in the SEP Evaluation Model to determine the maximum incentive levels for a modeled SEP measure that are needed to meet a UCT of 1.0 and a RIM of 0.6. The new logic utilizes all other inputs for the measure in question and is sufficiently

flexible to address both a measure with activity in a single year only (i.e., a single measure "event") and an active measure with varying participation through time. With knowledge of these maximum incentive values, LES will then can offer reasonable incentives through a much more efficient process.

Section 6
CONCLUSIONS

LES has a demand-side management program in the SEP that includes component measures that are comparable to those of its peer utilities and achieves a level of savings that is similar to many of LES's peer utilities, particularly in this region of the country. LES's decision-making regarding inclusion of measures in the SEP is consistent with both wide industry practice, in terms of the cost-effectiveness tests it employs, and LES's stated goals to make progress toward deep carbon reduction, through the inclusion of a significant avoided cost of carbon emissions and setting a RIM threshold somewhat below the traditional 1.0 level.

The LES SEP Evaluation Model allows LES staff to determine the cost-effectiveness of current and prospective DSM measures in an efficient way, and LES's use of the model and development of assumptions reflect industry best practices. nFront Consulting has offered several suggestions, both herein and via separate communication, to improve the internal consistency of assumptions, better alignment of certain assumptions with LES's carbon reduction goal, and certain extensions of the Model to better infuse the participant perspective in determining reasonable incentives for certain complex commercial SEP measures.

The SEP has been and will continue to be a key component of LES's progress toward its carbon reduction goals. The continued investigation of additional prospective measures that are focused on peak demand reductions, including those that nFront has identified herein as being implemented elsewhere in the U.S., may yield a useful expansion of the SEP and increase in its impact on that progress.

Appendix B
E3 Final ELCC Presentation

Effective Load Carrying Capability (ELCC) Forecast

Prepared for Lincoln Electric System

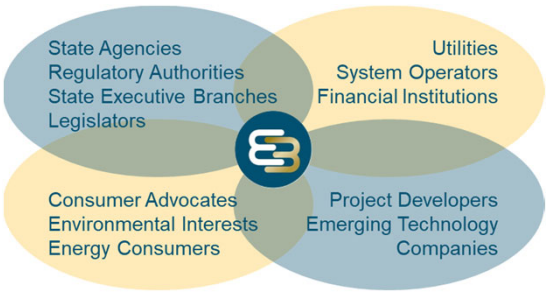
July 2022

Zach Ming, Director
Adrian Au, Senior Consultant
Karl Walter, Consultant
Sam Kramer, Consultant

Energy+Environmental Economics

About E3

- **E3 is a San Francisco-based consulting firm founded in 1989 specializing in electricity economics with approximately 100 staff**
- **E3 consults extensively for utilities, developers, government agencies, and environmental groups on clean energy issues**
- **Services for a wide variety of clients made possible through an analytical, unbiased approach**
- **Our experts provide critical thought leadership, publishing regularly in peer reviewed journals and leading industry publications**



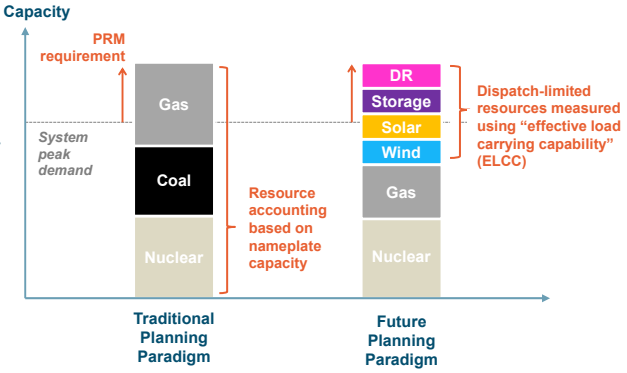
Energy+Environmental Economics

Resource Adequacy and ELCC Background

Energy+Environmental Economics

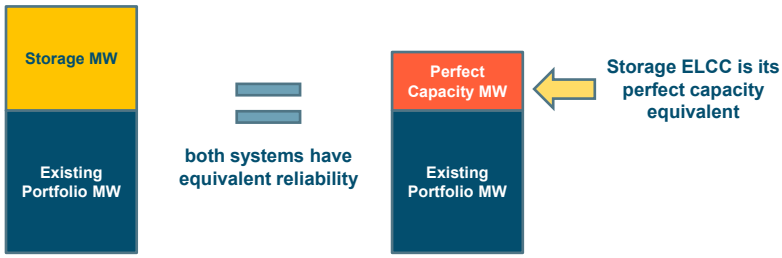
Adapting the PRM framework for a high renewable future

- **Historically, utilities have relied upon a planning reserve margin (PRM) framework to ensure enough supply is available during peak periods**
- **Introduction of significant quantities of wind, solar, and storage present significant challenges to this accounting framework because:**
  - Availability of these resources during peak periods is likely lower than nameplate capacity
  - Increasing penetrations of renewables & storage will cause reliability needs to shift to other times of day/year
- **To continue using a PRM, we must revisit how we count capacity to ensure resources are measured based on their contributions <u>across all hours</u> – not just during peak periods**
  - A resource's **<u>effective load carrying capability (ELCC)</u>** reflects its contribution to reliability considering all hours of the year, across multiple years of load + weather conditions



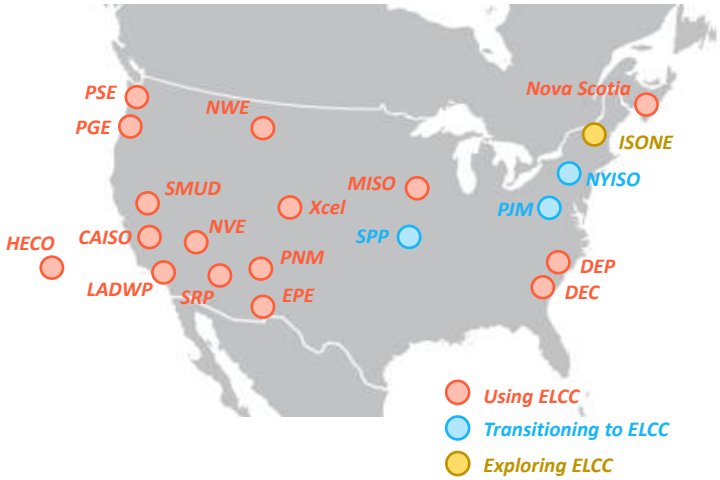
Theoretical Underpinnings of ELCC

- Effective load carrying capability ("ELCC") has been increasingly recognized by the industry as the preferred method for measuring the firm capacity equivalent of wind, solar, and storage resources
- ELCC is a technology-neutral measurement of the equivalent 'perfect' capacity of intermittent and energy-limited resources
  - *Example: if storage has an ELCC of 50%, an electricity system with 100 megawatts of additional storage would achieve the same reliability as a system with 50 megawatts of additional perfect firm resource*



ELCC has quickly gained traction among ISOs and utilities

- Many ISO/RTOs and utilities are already using or considering a transition to ELCC for renewable (e.g., solar, wind) and/or energy limited resources (e.g., storage)
- Most have applied ELCC concepts to wind and solar; application for storage and other energy-limited resources has been limited to date



ELCC is calculated using loss-of-load-probability modeling

+ **Effective Load Carrying Capability (ELCC) represents the equivalent "perfect" capacity that a resource provides in meeting the target reliability metric (e.g., 0.1 day/year LOLE)**
  - ELCC can also be thought of as the incremental load that can be met throughout the year while maintaining the same target reliability metric

1 Calculate existing system reliability and tune the system to the target

2 Add desired resource to portfolio

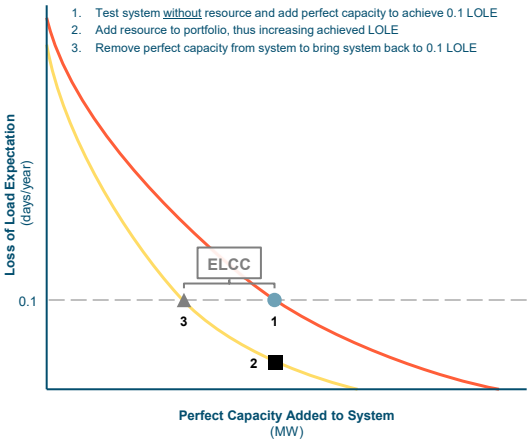
Addition of new source of generation will increase reliability relative to measurement in Step 1

3 Remove perfect capacity until target reliability is restored

Removal of perfect capacity results in decrease in reliability until original target is met

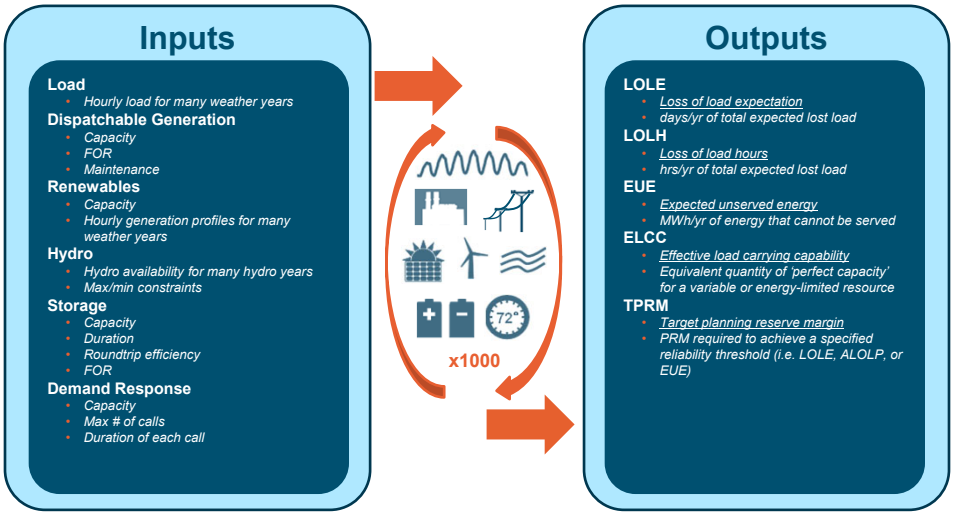
A resource's ELCC is equal to the amount of perfect capacity removed from the system in Step 3

Illustration of ELCC Calculation Approach



E3 Reliability Model: RECAP

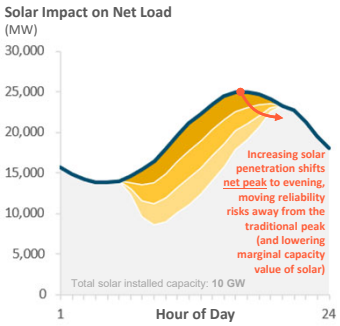
+ **RECAP calculates ELCC through time-sequential simulations over thousands of years**



Variable and energy-limited resources contribute to resource adequacy, but also add complexity

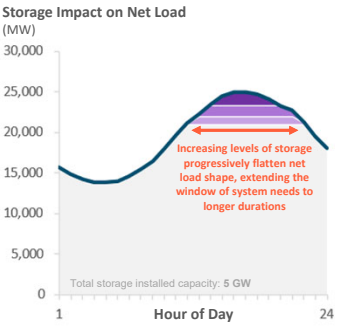
1

"Variable" resources shift reliability risks to different times of day



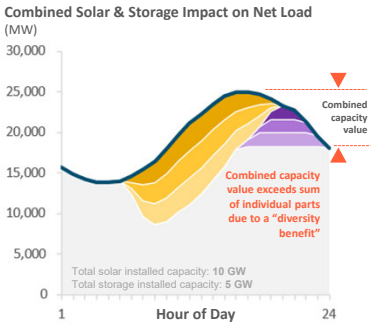
2

"Energy-limited" resources spread reliability risks across longer periods



3

A portfolio of resources exhibits complex interactive effects, where the whole may exceed the sum of its parts



Common examples of synergistic or antagonistic pairings

Common Examples of Synergistic Pairings

Solar + Wind
The profiles for many wind resources produce more energy during evening and nighttime hours when solar is not available

Solar + Storage
Solar and storage each provide what the other lacks – energy (in the case of storage) and the ability to dispatch energy in the evening and nighttime (in the case of solar)

Solar/Wind + Hydro
Hydro is an energy-limited resource so increasing penetrations of solar or wind allows hydro to save its limited production for the most resource constrained hours

Common Examples of Antagonistic Pairings

Storage + Hydro
Energy limitations on both storage and hydro require longer and longer durations after initial penetrations

Storage + Demand Response
Energy limitations on both storage and GU require longer and longer durations after initial penetrations

Project Methodology and Assumptions

Energy+Environmental Economics

Current SPP ELCC Accreditation Process

- SPP currently employs a "tiered" approach to ELCC calculations that ensure initial procurements of wind and solar for each LSE are somewhat protected from class-wide diminishing returns that manifest as increasing quantities of wind and solar are deployed across SPP more broadly

$$\text{Nameplate Capacity} = 19{,}339\ MW \text{ and } \text{ELCC Accreditation} = 3{,}845\ MW$$

$$\text{Accreditation Percentage of all wind } \frac{3845}{19339} = 19.9\,\%$$

$$\text{Tier 1 Capacity} = 12{,}185 MW \text{ and ELCC Accreditation} = 2{,}749\ MW$$

$$\text{Accreditation Percentage of Tier 1 wind } \frac{2749}{12185} = 22.6\,\%$$

$$\text{Leftover Capacity from Tier 1} = 7{,}145\ MW$$

$$\text{Tier 2 Capacity} = 4000\ MW \quad \text{Tier 2 ELCC Accreditation} = 696\ MW$$

$$\text{Accreditation Percentage of Tier 2 wind } \frac{696}{4000} = 17.4\,\%$$

$$\text{Tier 3 Capacity} = 3{,}154\ MW \quad \text{Tier 3 ELCC Accreditation} = 400\ MW$$

$$\text{Accreditation Percentage of Tier 3 wind } \frac{400}{3154} = 12.6\,\%$$

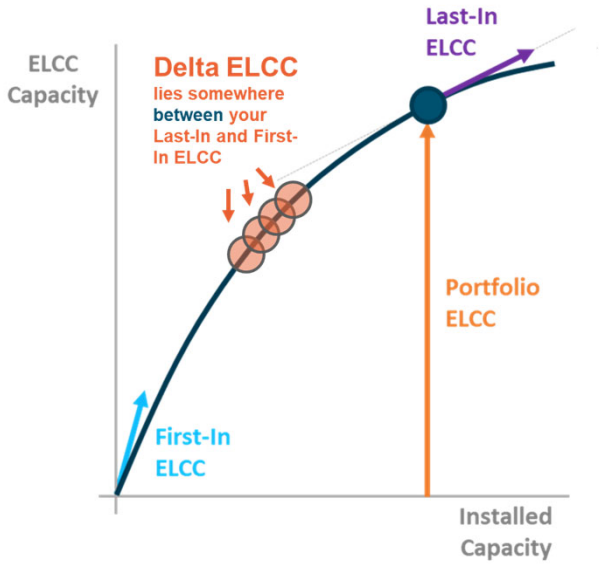
Equation Example 1: Tier 1, Tier 2 and Tier 3 Calculation

- Within this framework, SPP measures the class ELCC of solar with wind in the background portfolio and the ELCC of wind with solar in the background portfolio
- This methodology ***double counts the interactive effects*** between wind and solar and results in the total sum of accredited wind and solar ELCC to be different (greater) than the portfolio ELCC of wind and solar combined

https://www.spp.org/documents/61025/elcc%20solar%20and%20wind%20accreditation.pdf

E3 Approach

- In this project, E3 has employed the Delta Method to ensure that the sum of all accredited wind and solar ELCCs is equal to the portfolio ELCC
- The delta method is calculated for each resource using 3 different ELCC measurements
  - Total Portfolio ELCC
  - Resource's First-In ELCC
  - Resource's Last-In ELCC
- The final delta ELCC for each resource is a value that lies in between its first-in and last-in ELCC at the same proportion for all resources
- While SPP does not currently utilize the delta method, E3 believes this is a more plausible long-term end state than the current approach which will increasingly overcount total renewable ELCC as penetrations of wind and solar grow
- PJM's application of the Delta Method was recently approved by FERC



SPP Tiered Delta Method ELCC Analysis

- Each ELCC is run on a marginal basis (i.e. 100 MW)
- E3 first calculates the portfolio ELCC of all resources for a given year
- E3 then calculates the first-in and last-in ELCC of both wind, solar, and storage for each year
- Example of the underlying portfolio that a marginal quantity of wind is calculated on is shown to right

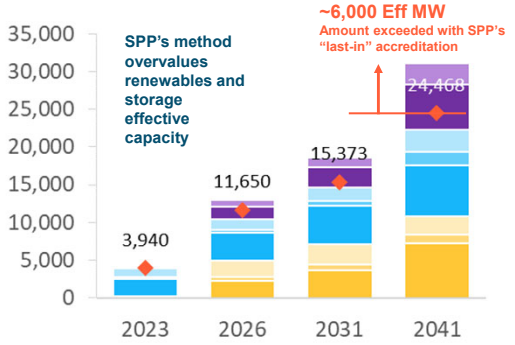
Portfolio ELCC of all resources		
Wind		
Tier 1	First-In	0 MW wind 0 MW all other resources
	Last-In	Tier 1 MW wind All other resources
Tier 2	First-In	Tier 1 MW wind 0 MW all other resources
	Last-In	Tier 1+2 MW wind All other resources
Tier 3	First-In	Tier 1+2 MW wind 0 MW all other resources
	Last-In	All wind All other resources

Magnitude of SPP Renewable Overcounting

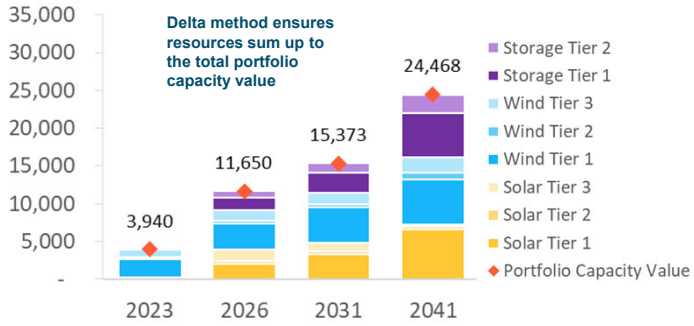
The difference between the SPP "last-in" and Delta Method ELCC increases over time as the positive interactive effects grow

Although the near-term effect is nominal, E3 estimates ~6,000 MW of excess accredited MW under current SPP methodology by 2041

SPP Capacity Value Accounting
Effective MW



E3's Delta Method Capacity Value Accounting
Effective MW



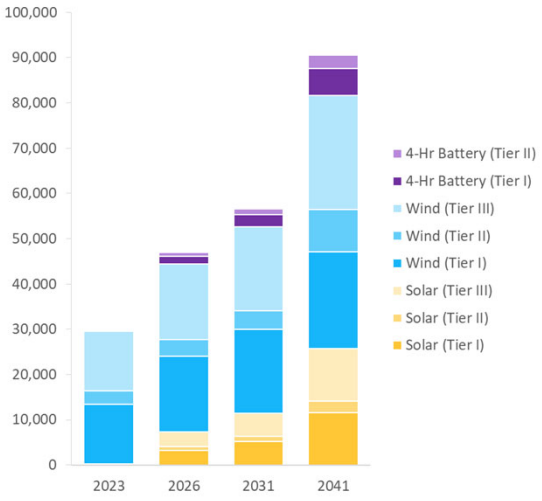
Resource Assumptions

+ Resource assumptions by class (and tier) were provided to E3 by LES

Nameplate Capacity (MW)

Resources	Tier	2023	2026	2031	2041
Coal		21,785	19,872	15,562	3,656
Gas		31,591	31,154	37,145	38,790
Hydro		4,954	4,954	4,954	4,954
Nuclear		2,044	2,044	2,044	1,234
Other		1,874	822	566	325
Solar	Tier 1	116	3,285	5,175	11,551
Solar	Tier 2	26	730	1,150	2,567
Solar	Tier 3	116	3,285	5,175	11,550
Wind	Tier 1	13,193	16,681	18,481	21,423
Wind	Tier 2	2,932	3,707	4,107	9,317
Wind	Tier 3	13,193	16,681	18,481	25,152
Storage	Tier 1	0	1,703	2,683	5,989
Storage	Tier 2	0	852	1,342	2,995
	Total	91,824	105,770	116,865	139,503

2023-2041 Renewable and Storage Capacity
Nameplate MW



Base Case Load Assumptions

- Base case load assumptions were provided to E3 by LES

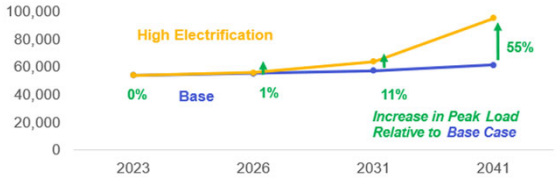
Total SPP Load and Gross Median Peak

	Units	2023	2026	2031	2041
Total Load	GWh	303,462	312,516	329,151	360,756
Total 1-in-2 Peak	MW	54,000	55,200	57,300	61,209

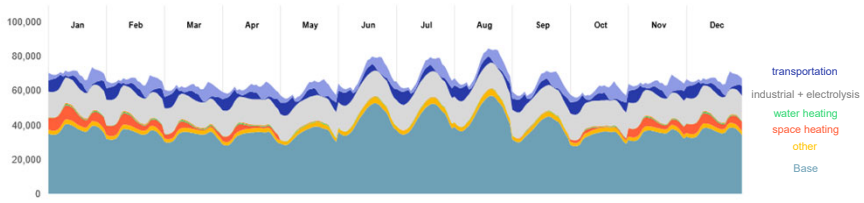
High Electrification Sensitivity Load Assumptions

- E3 ran a sensitivity case to explore the impact of high levels of electrification on ELCCs
- E3 developed a high electrification load forecast by leveraging prior nation-wide deep decarbonization load forecasts that include high levels of electrification of transportation, space heating, water heating, industry, and electrolysis*
- Resource assumptions are same as base case

Gross Median Peak Load Compared to Base Case, MW



High Electrification 2041: Gross Load Components (Month-Hr Average), MW



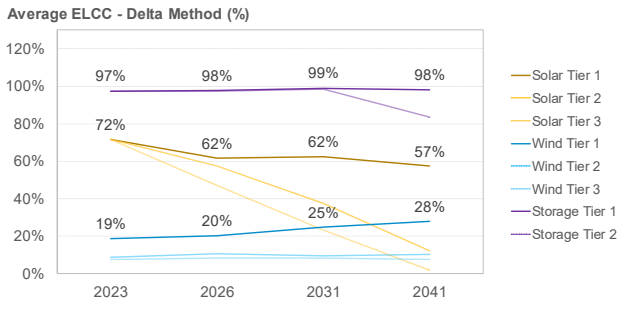
** Used Scenario 3 of the World Resources Institute – E3 Study "Building Blocks for a Low-Carbon Economy: Catalytic Policy and Infrastructure for Decarbonizing the United States by 2050"*

Results

Energy+Environmental Economics

Base Case Results

- Base case results show relatively steady tier 1 ELCC values for all resource classes across the time horizon
- Tier 2 and 3 decline to lower levels by 2041



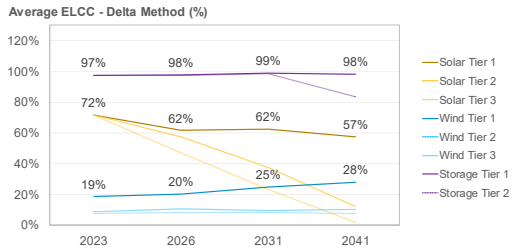
Delta Method ELCC %

Resources	Tier	2023	2026	2031	2041
Solar	Tier 1	72%	62%	62%	57%
Solar	Tier 2	72%	58%	38%	12%
Solar	Tier 3	71%	47%	23%	2%
Wind	Tier 1	19%	20%	25%	28%
Wind	Tier 2	9%	11%	9%	10%
Wind	Tier 3	8%	8%	8%	8%
Storage	Tier 1	97%	98%	99%	98%
Storage	Tier 2	97%	97%	99%	84%

Electrification Sensitivity Results

+ **High electrification case decreases the ELCC of solar and increases the ELCC of (tier 2 and 3) wind**
  - For more explanation, see following slides

Base Case



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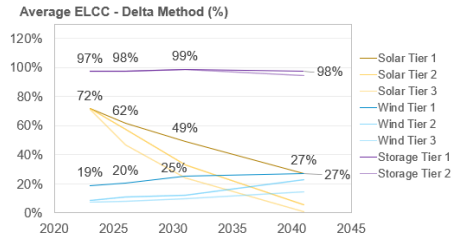
Wind	Tier 2	9%	11%	9%	10%
Wind	Tier 3	8%	8%	8%	8%
Storage	Tier 1	97%	98%	99%	98%
Storage	Tier 2	97%	97%	99%	84%

High Electrification Sensitivity



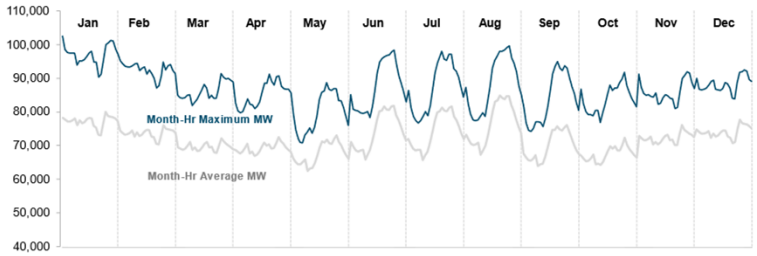
Delta Method ELCC %

Resources	Tier	2023	2026	2031	2041
Solar	Tier 1	72%	62%	49%	27%
Solar	Tier 2	72%	58%	33%	6%
Solar	Tier 3	71%	47%	24%	1%
Wind	Tier 1	19%	20%	25%	27%
Wind	Tier 2	9%	11%	12%	23%
Wind	Tier 3	8%	8%	10%	14%
Storage	Tier 1	97%	98%	99%	98%
Storage	Tier 2	97%	97%	99%	95%

Electrification Sensitivity Results - Exploration

Under high electrification reliability need shifts to Winter evenings due to new heating loads resulting in a significant decline in solar ELCC relative to the base case

High Electrification in 2041: Month-Hr Maximum Gross Load over 66 weather years, MW

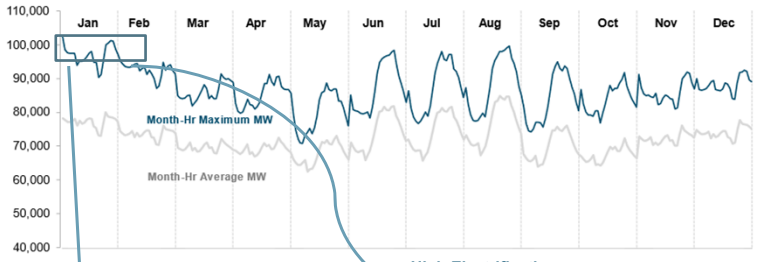


Note: gross load is shown (helps to explain the decline in Solar's first-in ELCC), but this same general pattern – the shift in reliability need to Winter evenings – is also observed when looking at the net load (last-in ELCC)

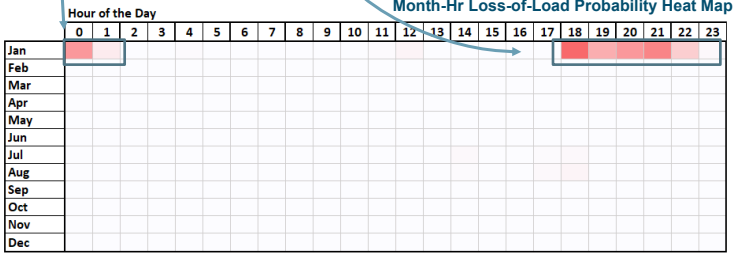
Electrification Sensitivity Results - Exploration

Under high electrification reliability need shifts to Winter evenings due to new heating loads resulting in a significant decline in solar ELCC relative to the base case

High Electrification in 2041: Month-Hr Maximum Gross Load over 66 weather years, MW



High Electrification: Month-Hr Loss-of-Load Probability Heat Map



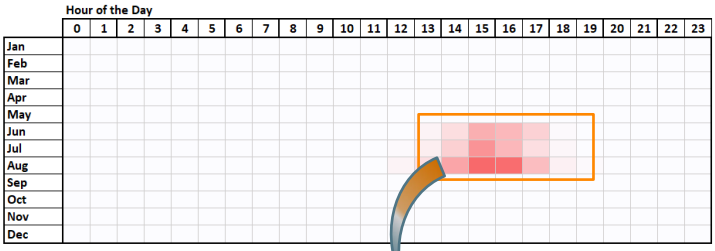
High Electrification

Note: gross load is shown (helps to explain the decline in Solar's first-in ELCC), but this same general pattern – the shift in reliability need to Winter evenings – is also observed when looking at the net load (last-in ELCC)

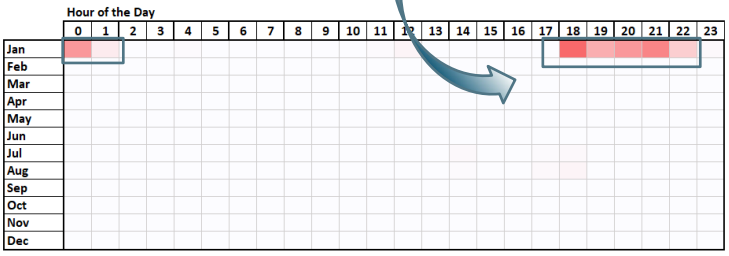
Electrification Sensitivity Results – Exploration
Gross Load

Month-Hr Loss-of-Load Probability Heat Map for 2041

Base



High Electrification



This transition in reliability need from Summer daytime (Base case) to Winter nighttime (High electrification) explains the decrease in Solar ELCCs and moderate increase in Wind ELCCs

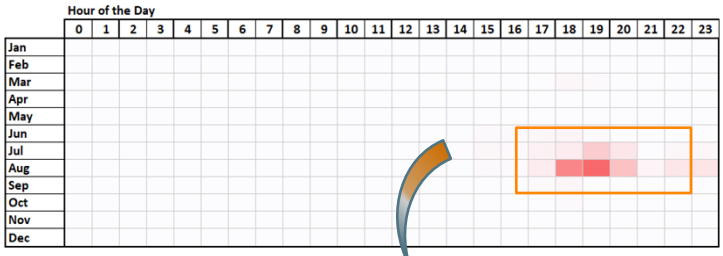
These heat maps are the times of reliability need for an empty portfolio (Gross Load), which determines the first-in ELCC value

Electrification Sensitivity Results – Exploration

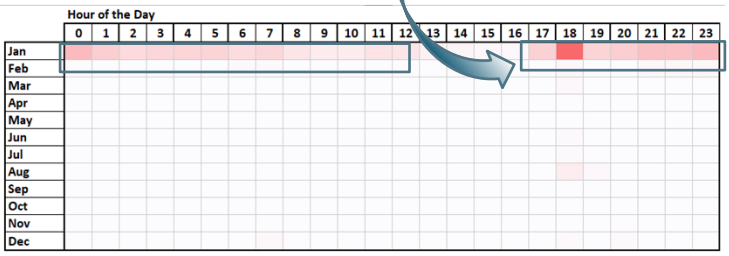
Net Load

Month-Hr Loss-of-Load Probability Heat Map for 2041

Base



High Electrification



This transition in reliability need from Summer (Base case) to Winter (High electrification) explains the decrease in Solar ELCCs and moderate increase in Wind ELCCs

These heat maps are for the planned 2041 portfolio (Net Load), which determines the last-in ELCC value

Thank You

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Energy+Environmental Economics

Appendix C
Existing LES Resources

COAL

GERALD GENTLEMAN STATION (NE)

Owned by Nebraska Public Power District, LES participates under a life-of-plant contract by purchasing 8% of the output, or approximately 109 MW. The final phase of this coal-fired plant was completed in 1982

LARAMIE RIVER STATION (WY)

LES owns 12.76% of this coal-fired power plant with approximately 10.5%, or 178 MW, available after ownership and participation sales. Construction was completed in 1982 on the three-unit, 1,710-MW plant.

WALTER SCOTT, JR. ENERGY CENTER UNIT 4 (IA)

LES owns 12.66% of Walter Scott, Jr. Energy Center Unit 4, along with MidAmerican Energy Company (MEC) and 12 other companies. The 816 MW coal-fired plant was completed in 2007 and provides LES approximately 103 MW. To further diversify generation, in January 2008, LES executed an agreement with MEC to exchange energy derived from 50 MW of Unit 4 with 50 MW of Unit 3. This Unit 3/Unit 4 exchange agreement expires in 2028.

NATURAL GAS

J STREET (NE)

LES' oil- or natural gas-fired power plant, with one simple-cycle combustion turbine totaling 29 MW, was installed in 1972. This unit anchors the LES Community Microgrid, designed to maintain service to critical city, county, state and federal infrastructure in the downtown Lincoln area in the event of wide-scale power outages.

ROKEBY GENERATION STATION (NE)

LES' power station with three oil- or natural gas-fired simple-cycle combustion turbines totals 255 MW, including a 3 MW diesel gen-set. The combustion turbines were installed in 1975, 1996, and 2001.

TERRY BUNDY GENERATING STATION (NE)

LES' oil- or natural gas-fired 164-MW plant uses waste heat from two aeroderivative combustion turbines to create steam, which is used to operate a steam turbine and generate additional power in a combined-cycle configuration. The two combustion turbines also can be operated in simple-cycle mode. A third aeroderivative combustion turbine is operated in simple cycle. The plant also has a 2-MW "Black Start" unit on-site. The combustion turbines were placed in commercial operation in 2003, with the steam turbine following in 2004.

RENEWABLE

BLUFF ROAD LANDFILL GAS TO ENERGY (NE)

LES completed construction of a 5 MW landfill gas-generated facility in 2014. The methane fuel is supplied from the Bluff Road Landfill.

WESTERN AREA POWER ADMINISTRATION

LES purchases approximately 54 MW of firm power, 72 MW of summer firm peaking, and 22 MW of winter firm peaking power from this pool of hydropower resources.

LES WIND TURBINES (NE)

LES has two wind turbines on the northeast side of Lincoln. The first wind turbine was completed in 1998 and the second in 1999. At full output, the turbines can generate a combined total of 1 MW.

ELKHORN RIDGE WIND FARM (NE)

LES began receiving energy from a share of the Elkhorn Ridge Wind Farm in 2009. LES entered into a power purchase agreement for 6 MW of the total 80 MW wind project, which consists of 27 wind turbines. This power purchase agreement expires in 2029.

LAREDO RIDGE WIND FARM (NE)

LES began receiving energy from a share of the Laredo Ridge Wind Farm in 2011. LES entered into a power purchase agreement for 10 MW of the total 80 MW wind project, consisting of 54 wind turbines. This power purchase agreement expires in 2031.

CROFTON BLUFFS WIND FARM (NE)

In 2012, LES began receiving energy from a share of the Crofton Bluffs Wind Farm. LES entered into a power purchase agreement for 3 MW of the total 42 MW wind project, which consists of 22 wind turbines. This power purchase agreement expires in 2032.

BROKEN BOW WIND FARM (NE)

LES began receiving energy from a share of the Broken Bow Wind Farm in 2012. LES entered into a power purchase agreement for 10 MW of the total 80 MW wind project, which consists of 50 wind turbines. This power purchase agreement expires in 2032.

ARBUCKLE MOUNTAIN WIND FARM (OK)

LES began receiving energy from the Arbuckle Mountain Wind Farm in 2015. LES entered into a power purchase agreement for the full 100 MW project, which consists of 50 wind turbines. This power purchase agreement expires in 2035.

BUCKEYE I WIND ENERGY CENTER (KS)

LES began receiving energy from the Buckeye I Wind Energy Center in 2015. LES entered into a power purchase agreement for the full 100 MW project, which consists of 56 wind turbines. This power purchase agreement expires in 2040.

PRAIRIE BREEZE II WIND ENERGY CENTER (NE)

LES began receiving energy from the Prairie Breeze II Wind Energy Center in 2015. LES entered into a power purchase agreement for the full 73 MW project, which consists of 41 wind turbines. This power purchase agreement expires in 2040.

COMMUNITY SOLAR FACILITY (NE)

In 2016, LES began receiving energy from this approximately 5 MW_{DC}/4 MW_{AC} solar facility. The project represents the first utility-scale solar facility in Nebraska and is still one of the largest in the region. The related power purchase agreement expires in 2036.

DEMAND-SIDE MANAGEMENT

SUSTAINABLE ENERGY PROGRAM

The Sustainable Energy Program (SEP) is a collection of measures incentivizing customers to reduce consumption and thereby reduce the need for future generation additions. Originally started in 2009, the SEP currently offsets approximately 28 MW of peak demand and 100 GWH of annual energy consumption via the following measures:

- Energy Efficiency
  - High efficiency heat pumps and air conditioners
  - Whole-house and facility sealing and insulation
  - Heat pump water heaters
  - Commercial and industrial lighting
  - Commercial and industrial improvements to energy management systems, variable frequency drives, compressed air systems, etc.
- Demand Response
  - Peak Rewards, a program under which LES makes brief, limited adjustments to customers' Wi-Fi enabled smart thermostats during periods of peak electrical demand.

Appendix D
Resource Alternatives – Descriptions

COAL

ULTRA-SUPERCRITICAL COAL WITH 90% CARBON CAPTURE & SEQUESTRATION

100-MW share of a 650-MW ultra-supercritical pulverized coal plant that operates at supercritical steam pressures and temperatures, increasing operating efficiency. Includes carbon capture technology costs and operating characteristics to remove 90% of emitted CO_2.

RETROFIT EXISTING WS4 COAL UNIT WITH 90% CCS

Upgrade the existing Water Scott Jr. Energy Center Unit 4 to include carbon capture technology capable of removing 90% of CO_2 emissions. The addition of CCS decreases net output capacity of the unit by 30% and reduces efficiency by 43%.

NATURAL GAS

COMBUSTION TURBINE - AERODERIVATIVE

105-MW, dual unit, natural gas-fired combustion turbine facility, modeled after the same aeroderivative LM-6000 units utilized at LES' Terry Bundy Generating Station. Combustion turbines draw in air at the front, compress it, mix it with fuel, and then ignite it. The hot gases expand through turbine blades connected to a generator to produce electricity.

COMBUSTION TURBINE – INDUSTRIAL FRAME

100-MW share of a 237-MW natural gas-fired combustion turbine, utilizing a larger, heavy frame "F-class" unit.

COMBINED CYCLE WITH 90% CCS

100-MW share of a 377-MW natural gas-fired combined cycle plant. A single industrial frame "H-class" combustion turbine drives a generator and exhausts heat into a special boiler called a heat recovery steam generator to produce additional electricity. Includes carbon capture technology costs and operating characteristics to remove 90% of emitted CO_2.

FUEL CELL

10-MW facility based on modular solid oxide fuel cell units. The fuel cells use natural gas and air vapor to create electricity through a chemical energy conversion.

INTERNAL COMBUSTION ENGINE

21-MW facility based on four 5.6-MW engine generating sets. The units use a spark-ignited, piston-driven engine connected to a generator to produce electricity.

DISTRIBUTED GENERATION - BASE

2-MW engine generating set operated on a continuous basis under a variety of demand levels.

DISTRIBUTED GENERATION - PEAK

1-MW engine generating set operated only when system demand levels are at their highest.

NUCLEAR

NUCLEAR – LIGHT WATER REACTOR

100-MW share of a dual unit, 2,156-MW facility using nuclear fission to release energy that can be used to generate steam, which powers a steam turbine to generate electricity.

NUCLEAR – SMALL MODULAR REACTOR

100-MW share of a 12 unit, 600-MW facility. The mechanical equipment and systems are similar to that of a light water reactor unit but much smaller, with the entire containment vessel located within a water-filled cooling pool.

RENEWABLE

BIOMASS

50-MW facility that burns up to 1,500 tons of wood chips per day to produce steam, which is then run through a steam turbine connected to a generator to produce electricity.

WIND

100-MW share of a 200-MW onshore wind project, based on 71 2.8-MW turbines.

SOLAR THERMAL

115-MW concentrated solar power facility, using dual-axis tracking mirrors to concentrate sunlight on to a tank atop a tall tower. Liquid molten salts are then heated within the tank and passed through a steam generating heat exchanger used to power a steam turbine-generator. The heated molten salt can provide 8 hours of thermal energy storage.

SOLAR PHOTOVOLTAICS (PV) WITH TRACKING

150-MW facility that employs horizontal, single-axis tracking solar panel assemblies, each tracking the sun across the sky from east to west.

STORAGE

BATTERY STORAGE

50-MW facility with 200 MWh of energy storage, consisting of 25 modular, pre-fabricated containers housing lithium-ion battery systems.

HYBRID

SOLAR PV WITH STORAGE

150-MW single-axis tracking solar PV project coupled with 50-MW/200-MWh of battery storage.

Appendix E
Resource Alternatives – Modeling Data

Resource Alternatives - Modeling Data Assumptions

Technology	Fuel	Nominal Ownership [2] (MW)	Total Number Allowed	Operating Life [1] (Years)	Financing Life (Years)	Nominal Heat Rate [1,2] (Btu/kWh)	Construction Schedule [1] (Years)	Forced Outage Rate [3,4] (%)	CO_2 Emissions [1] (lb/MMBtu)	Capital Cost [1,2] (2022 $/kW)	Fixed O&M [1,2,5] (2022 $/kW-yr)	Variable O&M [1,2,5] (2022 $/MWh)
Battery Storage (200 MWh)	N/A	50	4	10	10	N/A	1	0.0%	N/A	$1,328	$26	$0
Biomass	Biomass	50	N/A	40	30	13,500	4	9.0%	206	$4,549	$134	$5
Combined Cycle with 90% CCS	Natural Gas	100	3	40	30	7,124	3	5.5%	12	$2,700	$29	$6
Combustion Turbine - Aeroderivative	Natural Gas	105	3	40	30	9,124	2	3.6%	117	$1,227	$17	$5
Combustion Turbine - Industrial	Natural Gas	100	N/A	40	30	9,905	2	3.6%	117	$744	$7	$5
Distributed Generation - Base	Natural Gas	2	N/A	30	30	8,923	3	3.6%	117	$1,623	$21	$9
Distributed Generation - Peak	Natural Gas	1	N/A	30	30	9,907	2	3.6%	117	$1,971	$21	$9
Fuel Cells	Natural Gas	10	N/A	20	20	6,469	3	2.0%	117	$7,286	$33	$1
Internal Combustion Engine	Natural Gas	21	4	30	30	8,295	2	3.6%	117	$2,022	$38	$6
Nuclear - Light Water Reactor	Uranium	100	3	40	30	10,443	6	3.8%	0	$6,941	$130	$3
Nuclear - Small Modular Reactor	Uranium	50	N/A	40	30	10,443	6	3.8%	0.0	$7,515	$101	$3
Solar Photovoltaic with Storage	Solar	150	1	30	30	N/A	2	0.0%	0	$1,762	$34	$0
Solar Photovoltaic with Tracking	Solar	150	3	30	30	N/A	2	0.0%	0	$1,313	$16	$0
Solar Thermal	Solar	115	N/A	30	30	N/A	3	0.0%	0	$7,766	$91	$0
Sustainable Energy Program	N/A	28	1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$51	$33
Ultra-Supercritical Coal with 90% CCS	Coal	100	3	40	30	12,507	4	6.0%	21	$6,627	$64	$12
Walter Scott Unit 4 Retrofit with 90% CCS	Coal	72	1	40	30	14,561	2	6.0%	21	$1,901	$42	$7
Wind	Wind	100	7	25	25	N/A	3	0.0%	0	$1,583	$28	$0

Notes:

1) Unless otherwise noted, all data derived from the following:
   Cost and Performance Characteristics of New Generating Technologies , U.S. Energy Information Administration, March 2022.
   Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies , U.S. Energy Information Administration, February 2020.
2) Walter Scott Unit 4 CCS retrofit data derived from the following:
   Electricity Market Module , U.S. Energy Information Administration, March 2022.
3) Unless otherwise noted, all data provided by the U.S. Energy Information Administration in response to a request from LES.
4) Biomass and Fuel Cell data derived from the following:
   2017 Lincoln Cooperative Integrated Resource Plan , Lincoln Electric System, September 2017.
5) Sustainable Energy Program data reflects program attributes over recent history. Variable O&M includes lost revenue in excess of acceptable benefit-to-cost metrics.

Appendix F
Resource Alternatives – Screening Curve Results

EGEAS Screening Curve Results

Production Costs ($/KW$_{NAMEPLATE}$)

Case: $1.00 Gas/$0.00 Carbon

	Capacity Factor										
	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Nuclear - Small Modular Reactor	9,227	9,563	9,899	10,236	10,572	10,908	11,244	11,580	11,917	12,253	12,589
Nuclear - Light Water Reactor	9,190	9,513	9,836	10,160	10,483	10,806	11,129	11,453	11,776	12,099	12,422
Combustion Turbine - Aeroderivative	1,651	1,922	2,194	2,465	2,737	3,009	3,280	3,552	3,823	4,095	4,367
Combustion Turbine - Industrial Frame	1,027	1,310	1,592	1,875	2,157	2,440	2,722	3,005	3,287	3,570	3,852
Combined Cycle with 90% CCS	3,217	3,473	3,730	3,986	4,243	4,499	4,756	5,012	5,269	5,525	5,782
Ultra Supercritical Coal with 90% CCS	7,500	8,018	8,536	9,054	9,572	10,090	10,608	11,127	11,645	12,163	12,681
Fuel Cells	12,169	12,305	12,442	12,578	12,715	12,851	12,987	13,124	13,260	13,396	13,533
Biomass	7,075	10,309	13,544	16,779	20,014	23,249	26,484	29,718	32,953	36,188	39,423
Distributed Generation - Base	2,365	2,713	3,061	3,409	3,757	4,105	4,452	4,800	5,148	5,496	5,844
Distributed Generation - Peak	2,777	3,144	3,510	3,877	4,244	4,611	4,977	5,344	5,711	6,078	6,444
Internal Combustion Engine	3,228	3,504	3,780	4,056	4,332	4,608	4,884	5,161	5,437	5,713	5,989

Case: $10.00 Gas/$0.00 Carbon

	Capacity Factor										
	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Nuclear - Small Modular Reactor	9,227	9,563	9,899	10,236	10,572	10,908	11,244	11,580	11,917	12,253	12,589
Nuclear - Light Water Reactor	9,190	9,513	9,836	10,160	10,483	10,806	11,129	11,453	11,776	12,099	12,422
Combustion Turbine - Aeroderivative	1,651	3,499	5,348	7,196	9,045	10,894	12,742	14,591	16,439	18,288	20,136
Combustion Turbine - Industrial Frame	1,027	3,022	5,016	7,011	9,005	11,000	12,994	14,988	16,983	18,977	20,972
Combined Cycle with 90% CCS	3,217	4,705	6,192	7,680	9,168	10,656	12,144	13,631	15,119	16,607	18,095
Ultra Supercritical Coal with 90% CCS	7,500	8,018	8,536	9,054	9,572	10,090	10,608	11,127	11,645	12,163	12,681
Fuel Cells	12,169	13,424	14,678	15,933	17,187	18,441	19,696	20,950	22,205	23,459	24,714
Biomass	7,075	10,309	13,544	16,779	20,014	23,249	26,484	29,718	32,953	36,188	39,423
Distributed Generation - Base	2,365	4,255	6,146	8,036	9,926	11,816	13,706	15,596	17,486	19,376	21,266
Distributed Generation - Peak	2,777	4,856	6,935	9,014	11,093	13,172	15,251	17,330	19,409	21,488	23,568
Internal Combustion Engine	3,228	4,938	6,648	8,357	10,067	11,777	13,487	15,196	16,906	18,616	20,326

Case: $1.00 Gas/$90.00 Carbon

	Capacity Factor										
	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Nuclear - Small Modular Reactor	9,227	9,563	9,899	10,236	10,572	10,908	11,244	11,580	11,917	12,253	12,589
Nuclear - Light Water Reactor	9,190	9,513	9,836	10,160	10,483	10,806	11,129	11,453	11,776	12,099	12,422
Combustion Turbine - Aeroderivative	1,651	7,160	12,669	18,178	23,687	29,197	34,705	40,215	45,723	51,233	56,742
Combustion Turbine - Industrial Frame	1,027	6,996	12,964	18,932	24,900	30,869	36,837	42,806	48,774	54,742	60,710
Combined Cycle with 90% CCS	3,217	3,884	4,552	5,219	5,888	6,555	7,223	7,890	8,558	9,225	9,894
Ultra Supercritical Coal with 90% CCS	7,500	9,251	11,001	12,752	14,502	16,253	18,004	19,755	21,506	23,256	25,007
Fuel Cells	12,169	16,080	19,992	23,903	27,815	31,726	35,637	39,550	43,461	47,372	51,284
Biomass	7,075	23,189	39,304	55,419	71,534	87,649	103,765	119,879	135,994	152,109	168,224
Distributed Generation - Base	2,365	7,835	13,305	18,775	24,246	29,716	35,185	40,655	46,125	51,595	57,065
Distributed Generation - Peak	2,777	8,831	14,884	20,938	26,992	33,046	39,099	45,153	51,207	57,261	63,314
Internal Combustion Engine	3,228	8,266	13,303	18,341	23,379	28,416	33,454	38,492	43,530	48,568	53,605

Case: $10.00 Gas/$90.00 Carbon

	Capacity Factor										
	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Nuclear - Small Modular Reactor	9,227	9,563	9,899	10,236	10,572	10,908	11,244	11,580	11,917	12,253	12,589
Nuclear - Light Water Reactor	9,190	9,513	9,836	10,160	10,483	10,806	11,129	11,453	11,776	12,099	12,422
Combustion Turbine - Aeroderivative	1,651	8,737	15,823	22,909	29,995	37,082	44,167	51,254	58,339	65,426	72,511
Combustion Turbine - Industrial Frame	1,027	8,708	16,388	24,068	31,748	39,429	47,109	54,789	62,470	70,149	77,830
Combined Cycle with 90% CCS	3,217	5,116	7,014	8,913	10,813	12,712	14,611	16,509	18,408	20,307	22,207
Ultra Supercritical Coal with 90% CCS	7,500	9,251	11,001	12,752	14,502	16,253	18,004	19,755	21,506	23,256	25,007
Fuel Cells	12,169	17,199	22,228	27,258	32,287	37,316	42,346	47,376	52,406	57,435	62,465
Biomass	7,075	23,189	39,304	55,419	71,534	87,649	103,765	119,879	135,994	152,109	168,224
Distributed Generation - Base	2,365	9,377	16,390	23,402	30,415	37,427	44,439	51,451	58,463	65,475	72,487
Distributed Generation - Peak	2,777	10,543	18,309	26,075	33,841	41,607	49,373	57,139	64,905	72,671	80,438
Internal Combustion Engine	3,228	9,700	16,171	22,642	29,114	35,585	42,057	48,527	54,999	61,471	67,942

Rank (Lowest to Highest Cost)

Case: $1.00 Gas/$0.00 Carbon

	Capacity Factor										
	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Nuclear - Small Modular Reactor	10	9	9	9	9	9	9	9	9	9	8
Nuclear - Light Water Reactor	9	8	8	8	8	8	8	8	8	7	7
Combustion Turbine - Aeroderivative	2	2	2	2	2	2	2	2	2	2	2
Combustion Turbine - Industrial Frame	1	1	1	1	1	1	1	1	1	1	1
Combined Cycle with 90% CCS	5	5	5	5	4	4	4	4	4	4	3
Ultra Supercritical Coal with 90% CCS	8	7	7	7	7	7	7	7	7	8	9
Fuel Cells	11	11	10	10	10	10	10	10	10	10	10
Biomass	7	10	11	11	11	11	11	11	11	11	11
Distributed Generation - Base	3	3	3	3	3	3	3	3	3	3	4
Distributed Generation - Peak	4	4	4	4	5	6	6	6	6	6	6
Internal Combustion Engine	6	6	6	6	6	5	5	5	5	5	5

Case: $10.00 Gas/$0.00 Carbon

	Capacity Factor										
	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Nuclear - Small Modular Reactor	10	9	9	9	8	5	3	3	3	3	2
Nuclear - Light Water Reactor	9	8	8	8	7	3	2	2	2	1	1
Combustion Turbine - Aeroderivative	2	2	2	2	2	4	5	5	5	5	5
Combustion Turbine - Industrial Frame	1	1	1	1	1	6	6	6	7	7	7
Combined Cycle with 90% CCS	5	4	4	3	3	2	4	4	4	4	4
Ultra Supercritical Coal with 90% CCS	8	7	7	7	4	1	1	1	1	2	3
Fuel Cells	11	11	11	10	10	10	10	10	10	10	10
Biomass	7	10	10	11	11	11	11	11	11	11	11
Distributed Generation - Base	3	3	3	4	5	8	8	8	8	8	8
Distributed Generation - Peak	4	5	6	6	9	9	9	9	9	9	9
Internal Combustion Engine	6	6	5	5	6	7	7	7	6	6	6

Case: $1.00 Gas/$90.00 Carbon

	Capacity Factor										
	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Nuclear - Small Modular Reactor	10	9	3	3	3	3	3	3	3	3	3
Nuclear - Light Water Reactor	9	8	2	2	2	2	2	2	2	2	2
Combustion Turbine - Aeroderivative	2	3	5	5	6	6	6	7	7	7	7
Combustion Turbine - Industrial Frame	1	2	6	8	8	8	9	9	9	9	9
Combined Cycle with 90% CCS	5	1	1	1	1	1	1	1	1	1	1
Ultra Supercritical Coal with 90% CCS	8	7	4	4	4	4	4	4	4	4	4
Fuel Cells	11	10	10	10	10	9	8	6	5	5	5
Biomass	7	11	11	11	11	11	11	11	11	11	11
Distributed Generation - Base	3	4	8	7	7	7	7	8	8	8	8
Distributed Generation - Peak	4	6	9	9	9	10	10	10	10	10	10
Internal Combustion Engine	6	5	7	6	5	5	5	5	6	6	6

Case: $10.00 Gas/$90.00 Carbon

	Capacity Factor										
	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Nuclear - Small Modular Reactor	10	7	3	3	2	2	2	2	2	2	2
Nuclear - Light Water Reactor	9	6	2	2	1	1	1	1	1	1	1
Combustion Turbine - Aeroderivative	2	3	5	6	6	6	7	7	7	7	8
Combustion Turbine - Industrial Frame	1	2	7	8	8	9	9	9	9	9	9
Combined Cycle with 90% CCS	5	1	1	1	3	3	3	3	3	3	3
Ultra Supercritical Coal with 90% CCS	8	4	4	4	4	4	4	4	4	4	4
Fuel Cells	11	10	10	10	9	7	6	5	5	5	5
Biomass	7	11	11	11	11	11	11	11	11	11	11
Distributed Generation - Base	3	5	8	7	7	8	8	8	8	8	7
Distributed Generation - Peak	4	9	9	9	10	10	10	10	10	10	10
Internal Combustion Engine	6	8	6	5	5	5	5	6	6	6	6

Rank (Lowest to Highest Cost)

Average of All 4 Cases for Capacity Factor of 10% - 100%

Nuclear - Small Modular Reactor	5.2
Nuclear - Light Water Reactor	4.1
Combustion Turbine - Aeroderivative	4.5
Combustion Turbine - Industrial Frame	5.2
Combined Cycle with 90% CCS	2.8
Ultra Supercritical Coal with 90% CCS	4.8
Fuel Cells	8.8
Biomass	10.9
Distributed Generation - Base	6.0
Distributed Generation - Peak	8.1
Internal Combustion Engine	5.7

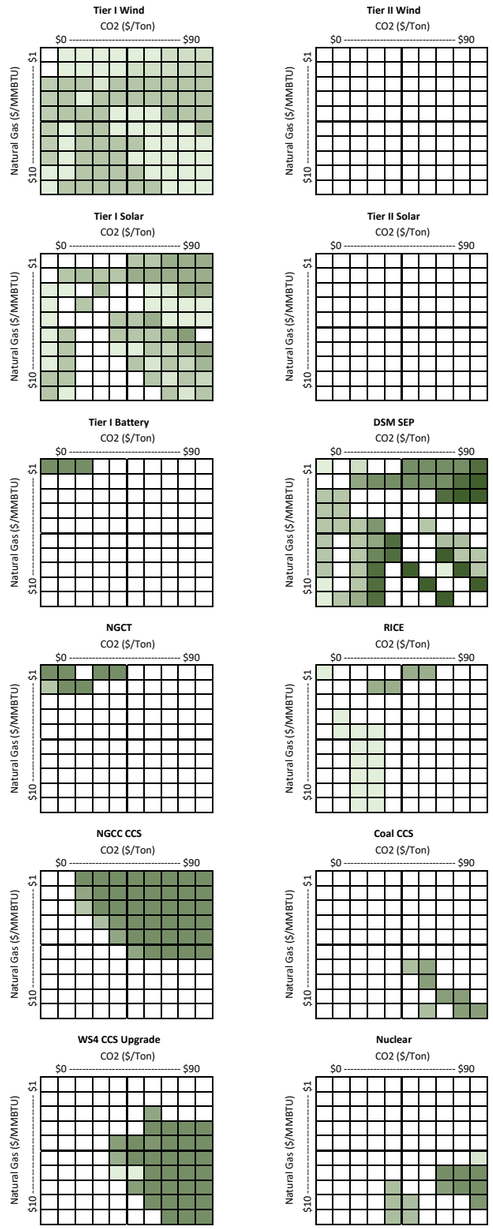
Appendix G
Expansion Plan Results – Base Case

EGEAS Expansion Plans
Base Case

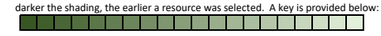
Natural Gas Price ($/MMBTU, 2022 $) | **CO2 Value ($/Short Ton, 2022 $)**

	$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
$1.00	**Expansion** 2029 NGCT 2029 Tier I Battery (4) 2034 NGCT 2041 DSM SEP 2041 RICE **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 1,394K NPV $1,462M NPVE $2,441M	**Expansion** 2029 NGCT 2029 Tier I Battery (4) 2034 NGCT 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 1,345K NPV $1,708M NPVE $3,069M	**Expansion** 2029 Tier I Battery (4) 2029 NGCC CCS 2034 NGCC CCS 2039 DSM SEP 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 609K NPV $1,978M NPVE $3,525M	**Expansion** 2029 NGCT 2029 NGCC CCS (2) 2031 NGCC CCS 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 523K NPV $2,160M NPVE $3,839M	**Expansion** 2029 NGCT 2029 NGCC CCS (2) 2031 NGCC CCS 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 528K NPV $2,275M NPVE $4,077M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (3) 2033 RICE 2036 Tier I Solar 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 423K NPV $2,367M NPVE $4,280M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (3) 2033 RICE 2036 Tier I Solar 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 423K NPV $2,471M NPVE $4,479M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2039 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 394K NPV $2,588M NPVE $4,675M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2039 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 393K NPV $2,691M NPVE $4,860M	**Expansion** 2025 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2039 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 391K NPV $2,793M NPVE $5,050M
$2.00	**Expansion** 2036 NGCT **Coal Retirement** 2029 GGS 2 2033 GGS 1 CO2 2,536K NPV $1,420M NPVE $2,658M	**Expansion** 2029 NGCT 2036 Tier I Solar 2041 Tier I Wind **Coal Retirement** 2029 GGS 2 2033 GGS 1 CO2 1,743K NPV $1,825M NPVE $3,543M	**Expansion** 2029 NGCT 2032 DSM SEP 2032 NGCC CCS 2035 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2032 LRS 1 CO2 867K NPV $2,179M NPVE $4,174M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (2) 2033 RICE 2033 NGCC CCS 2036 Tier I Solar 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2033 WS 4 CO2 424K NPV $2,460M NPVE $4,519M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (3) 2033 RICE 2036 Tier I Solar 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 425K NPV $2,595M NPVE $4,736M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2039 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 398K NPV $2,711M NPVE $4,922M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2039 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 397K NPV $2,814M NPVE $5,108M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2039 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 397K NPV $2,918M NPVE $5,297M	**Expansion** 2025 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2038 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 395K NPV $3,023M NPVE $5,485M	**Expansion** 2023 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2037 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 395K NPV $3,125M NPVE $5,668M
$3.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,686K NPV $1,451M NPVE $2,775M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,210K NPV $1,842M NPVE $3,750M	**Expansion** 2036 Tier I Wind 2036 NGCC CCS 2041 Tier I Wind (2) **Coal Retirement** 2036 GGS 2 CO2 1,347K NPV $2,228M NPVE $4,475M	**Expansion** 2029 NGCC CCS 2035 Tier I Solar 2040 Tier I Wind 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 CO2 1,048K NPV $2,541M NPVE $4,979M	**Expansion** 2029 NGCC CCS 2034 NGCC CCS (2) 2036 Tier I Wind 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2034 LRS 1 CO2 526K NPV $2,790M NPVE $5,212M	**Expansion** 2029 NGCC CCS (3) 2036 Tier I Wind 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 491K NPV $2,958M NPVE $5,437M	**Expansion** 2029 NGCC CCS (3) 2032 WS4 CCS Upgrade 2036 Tier I Wind 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 394K NPV $3,092M NPVE $5,652M	**Expansion** 2025 DSM SEP 2029 NGCC CCS (3) 2036 Tier I Wind 2040 Tier I Solar 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2040 WS 4 CO2 394K NPV $3,205M NPVE $5,878M	**Expansion** 2023 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2036 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2031 WS 4 CO2 394K NPV $3,340M NPVE $6,083M	**Expansion** 2023 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2036 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 395K NPV $3,441M NPVE $6,267M
$4.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,635K NPV $1,480M NPVE $2,844M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind **Coal Retirement** CO2 2,532K NPV $1,850M NPVE $3,791M	**Expansion** 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 2,244K NPV $2,256M NPVE $4,690M	**Expansion** 2035 NGCC CCS 2036 Tier I Wind 2041 Tier I Wind (2) **Coal Retirement** 2035 GGS 2 CO2 1,378K NPV $2,650M NPVE $5,340M	**Expansion** 2030 NGCC CCS 2036 Tier I Wind 2041 Tier I Wind (2) **Coal Retirement** 2030 GGS 2 CO2 1,226K NPV $2,929M NPVE $5,838M	**Expansion** 2029 NGCC CCS 2034 NGCC CCS 2036 Tier I Wind 2040 NGCC CCS 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2040 LRS 1 CO2 551K NPV $3,156M NPVE $5,974M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2030 NGCC CCS 2034 NGCC CCS 2036 Tier I Wind 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2034 LRS 1 CO2 384K NPV $3,297M NPVE $6,164M	**Expansion** 2029 NGCC CCS (3) 2029 WS4 CCS Upgrade 2036 Tier I Wind 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 385K NPV $3,447M NPVE $6,370M	**Expansion** 2029 NGCC CCS (3) 2029 WS4 CCS Upgrade 2036 Tier I Wind 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 386K NPV $3,569M NPVE $6,567M	**Expansion** 2029 NGCC CCS (3) 2029 WS4 CCS Upgrade 2036 Tier I Wind 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 386K NPV $3,672M NPVE $6,746M
$5.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,633K NPV $1,511M NPVE $2,916M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind **Coal Retirement** CO2 2,509K NPV $1,881M NPVE $3,866M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,485K NPV $2,237M NPVE $4,722M	**Expansion** 2030 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,054K NPV $2,638M NPVE $5,569M	**Expansion** 2031 WS4 CCS Upgrade 2032 NGCC CCS 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2034 GGS 2 CO2 1,109K NPV $3,104M NPVE $6,211M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 CO2 976K NPV $3,359M NPVE $6,646M	**Expansion** 2029 NGCC CCS 2030 WS4 CCS Upgrade 2033 Tier I Solar 2036 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2033 GGS 1 CO2 818K NPV $3,569M NPVE $7,022M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2030 NGCC CCS 2035 Tier I Wind 2040 NGCC CCS 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2040 LRS 1 CO2 365K NPV $3,652M NPVE $6,928M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2030 NGCC CCS 2034 NGCC CCS 2036 Tier I Wind 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2034 LRS 1 CO2 372K NPV $3,779M NPVE $7,083M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2030 NGCC CCS (2) 2036 Tier I Wind 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2030 LRS 1 CO2 384K NPV $3,916M NPVE $7,281M

Resource Summary Tables



Notes:
1) Shaded cells indicate a resource's inclusion within the 2022 - 2041 study period; the darker the shading, the earlier a resource was selected. A key is provided below:



2) Data reflects EGEAS' lowest cost expansion plan for each scenario, including the 30-year extension period.
3) *CO2* values reflect LES' total CO2 emissions for year 2040 in units of tons.
4) *NPV* values reflect LES' total production costs over the 2022 - 2041 study period.
5) *NPVE* values reflect LES' total production costs over the 2022 - 2041 study period plus the subequent 30-year extension period.
6) Multiple selections of the same resource in the same year are denoted by (#).
7) Tier I Wind that was installed early as Tier II Wind - but utilmately graduated to Tier I status following the end of a contract for an existing Tier I Wind resource - is denoted by (*).

EGEAS Expansion Plans
Base Case

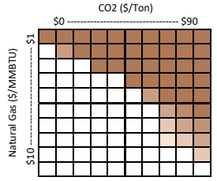
CO2 Value ($/Short Ton, 2022 $)

Natural Gas Price ($/MMBTU, 2022 $)

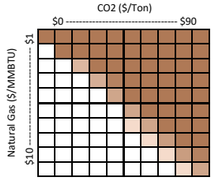
	$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
$6.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,633K NPV $1,543M NPVE $2,986M	**Expansion** 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 2,552K NPV $1,923M NPVE $3,937M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,513K NPV $2,267M NPVE $4,763M	**Expansion** 2032 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,371K NPV $2,631M NPVE $5,694M	**Expansion** 2025 DSM SEP 2033 WS4 CCS Upgrade 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 1,595K NPV $3,068M NPVE $6,427M	**Expansion** 2029 WS4 CCS Upgrade 2032 NGCC CCS 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2034 GGS 2 CO2 1,040K NPV $3,451M NPVE $6,967M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 CO2 972K NPV $3,726M NPVE $7,446M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2034 Tier I Solar 2035 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2034 GGS 1 CO2 854K NPV $3,946M NPVE $7,780M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2031 Tier I Solar 2035 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2031 GGS 1 CO2 775K NPV $4,149M NPVE $8,141M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2030 NGCC CCS 2035 Tier I Wind (*) 2040 Nuclear 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2040 LRS 1 CO2 368K NPV $4,162M NPVE $7,842M
$7.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,633K NPV $1,575M NPVE $3,057M	**Expansion** 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 2,552K NPV $1,955M NPVE $4,003M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,298M NPVE $4,835M	**Expansion** 2028 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,458K NPV $2,654M NPVE $5,704M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 Tier I Wind 2041 Tier I Solar 2041 WS4 CCS Upgrade **Coal Retirement** CO2 2,274K NPV $3,031M NPVE $6,618M	**Expansion** 2035 Coal CCS 2036 Tier I Wind 2037 Tier I Wind (*) 2041 Tier I Solar 2041 WS4 CCS Upgrade **Coal Retirement** 2040 GGS 2 CO2 1,662K NPV $3,504M NPVE $7,194M	**Expansion** 2029 WS4 CCS Upgrade 2032 Coal CCS 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2034 GGS 2 CO2 1,044K NPV $3,853M NPVE $7,666M	**Expansion** 2023 DSM SEP 2029 Nuclear 2029 WS4 CCS Upgrade 2038 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2038 GGS 1 CO2 869K NPV $4,111M NPVE $8,062M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2034 Tier I Solar 2036 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2034 GGS 1 CO2 818K NPV $4,379M NPVE $8,469M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2032 Tier I Solar 2036 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2032 GGS 1 CO2 776K NPV $4,584M NPVE $8,792M
$8.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,633K NPV $1,608M NPVE $3,128M	**Expansion** 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 2,552K NPV $1,986M NPVE $4,070M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,330M NPVE $4,904M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,462K NPV $2,685M NPVE $5,764M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2038 Tier I Wind (*) **Coal Retirement** CO2 2,220K NPV $3,134M NPVE $6,621M	**Expansion** 2023 DSM SEP 2031 WS4 CCS Upgrade 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 1,745K NPV $3,454M NPVE $7,394M	**Expansion** 2029 WS4 CCS Upgrade 2031 Coal CCS 2040 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2040 GGS 2 CO2 1,163K NPV $3,899M NPVE $7,857M	**Expansion** 2029 WS4 CCS Upgrade 2031 Nuclear 2036 Tier I Solar 2041 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2033 GGS 2 2041 GGS 1 CO2 1,012K NPV $4,168M NPVE $8,236M	**Expansion** 2023 DSM SEP 2029 Nuclear 2038 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2038 GGS 1 CO2 860K NPV $4,397M NPVE $8,664M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2034 Tier I Solar 2036 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2034 GGS 1 CO2 782K NPV $4,684M NPVE $9,080M
$9.00	**Expansion** 2036 Tier I Solar 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** CO2 2,678K NPV $1,641M NPVE $3,199M	**Expansion** 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 2,552K NPV $2,017M NPVE $4,137M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,362M NPVE $4,973M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,462K NPV $2,715M NPVE $5,832M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2038 Tier I Wind (*) **Coal Retirement** CO2 2,243K NPV $3,160M NPVE $6,651M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 2,125K NPV $3,496M NPVE $7,459M	**Expansion** 2023 DSM SEP 2029 WS4 CCS Upgrade 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 1,701K NPV $3,818M NPVE $8,184M	**Expansion** 2029 WS4 CCS Upgrade 2031 Coal CCS 2040 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2040 GGS 2 CO2 1,156K NPV $4,209M NPVE $8,508M	**Expansion** 2029 WS4 CCS Upgrade 2031 Coal CCS 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2033 GGS 2 CO2 1,011K NPV $4,486M NPVE $8,968M	**Expansion** 2023 DSM SEP 2029 WS4 CCS Upgrade 2030 Nuclear 2038 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2030 GGS 2 2038 GGS 1 CO2 839K NPV $4,700M NPVE $9,262M
$10.00	**Expansion** 2036 Tier I Solar 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** CO2 2,678K NPV $1,673M NPVE $3,270M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,507K NPV $2,042M NPVE $4,202M	**Expansion** 2033 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,393M NPVE $5,042M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,462K NPV $2,745M NPVE $5,899M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2038 Tier I Wind (*) **Coal Retirement** CO2 2,244K NPV $3,187M NPVE $6,702M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 2,187K NPV $3,520M NPVE $7,482M	**Expansion** 2035 Coal CCS 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 2,089K NPV $3,858M NPVE $8,300M	**Expansion** 2023 DSM SEP 2029 WS4 CCS Upgrade 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 1,661K NPV $4,177M NPVE $8,939M	**Expansion** 2029 WS4 CCS Upgrade 2031 Coal CCS 2040 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2040 GGS 2 CO2 1,119K NPV $4,518M NPVE $9,140M	**Expansion** 2029 WS4 CCS Upgrade 2031 Coal CCS 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2034 GGS 2 CO2 992K NPV $4,780M NPVE $9,595M

Resource Summary Tables

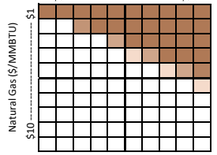
GGS 1
CO2 ($/Ton) $0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



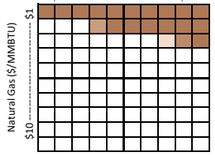
GGS 2
CO2 ($/Ton) $0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



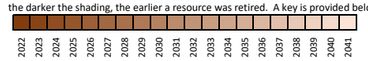
LRS 1
CO2 ($/Ton) $0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



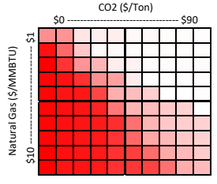
WS 4
CO2 ($/Ton) $0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



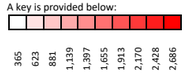
Notes:
1) Shaded cells indicate a resource's retirement within the 2022 - 2041 study period; the darker the shading, the earlier a resource was retired. A key is provided below:



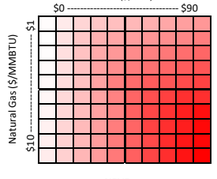
CO2
CO2 ($/Ton) $0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



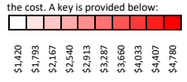
Notes:
1) Shaded cells indicate the CO2 emissions (thousand tons) for year 2040; the darker the shading, the higher the emissions.
A key is provided below:



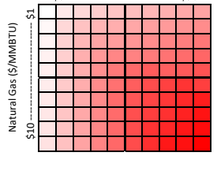
NPV
CO2 ($/Ton) $0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



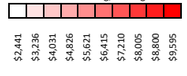
Notes:
1) Shaded cells indicate the total production costs ($M) over the 2022 - 2041 study period; the darker the shading, the higher the cost. A key is provided below:



NPVE
CO2 ($/Ton) $0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



Notes:
1) Shaded cells indicate the total production costs ($M) over the 2022 - 2041 study plus the subsequent 30-year extension period; the darker the shading, the higher the cost. A key is provided below:



Appendix H
Expansion Plan Results – Sensitivities

EGEAS Expansion Plans
Sensitivity 1: No CCS Resources

Natural Gas Price ($/MMBTU, 2022 $) — **CO2 Value ($/Short Ton, 2022 $)**

$1.00

$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
Expansion	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**
2029 NGCT	2029 NGCT	2029 NGCT (3)	2029 NGCT (3)	2029 NGCT (3)	2029 NGCT (3)	2029 NGCT (3)	2029 NGCT (3)	2029 DSM SEP	2025 DSM SEP
2029 Tier I Battery (4)	2029 Tier I Battery (4)	2034 Tier I Solar	2034 Tier I Solar	2034 Tier I Solar	2034 Tier I Solar	2034 DSM SEP	2031 DSM SEP	2029 NGCT (2)	2029 NGCT (2)
2034 NGCT	2034 NGCT	2041 Tier I Wind (2)	2041 Tier I Wind (2)	2040 Tier I Wind	2040 Tier I Wind	2036 Tier I Wind	2036 Tier I Wind	2029 Nuclear	2029 Nuclear
2041 DSM SEP	2041 Tier I Wind (2)			2041 Tier I Wind	2041 Tier I Wind	2037 RICE	2037 RICE	2036 Tier I Solar	2036 Tier I Solar
2041 RICE						2041 RICE	2041 RICE	2041 Tier I Wind (2)	2041 Tier I Wind (2)
						2041 Tier I Wind (2)	2041 Tier I Wind (2)		
Coal Retirement	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**
2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1
2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2
2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1
2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4
CO2 1,394K	CO2 1,345K	CO2 1,211K	CO2 1,286K	CO2 1,173K	CO2 1,170K	CO2 1,171K	CO2 1,173K	CO2 849K	CO2 850K
NPV $1,462M	NPV $1,708M	NPV $1,905M	NPV $2,131M	NPV $2,358M	NPV $2,576M	NPV $2,774M	NPV $2,992M	NPV $3,370M	NPV $3,540M
NPVE $2,441M	NPVE $3,069M	NPVE $3,642M	NPVE $4,155M	NPVE $4,650M	NPVE $5,135M	NPVE $5,600M	NPVE $6,064M	NPVE $6,495M	NPVE $6,854M

$2.00

$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
Expansion	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**
2036 NGCT	2029 NGCT	2029 NGCT	2029 NGCT (2)	2029 NGCT (3)	2029 NGCT (3)	2029 DSM SEP	2029 DSM SEP	2025 DSM SEP	2023 DSM SEP
	2036 Tier I Solar	2032 NGCT	2032 NGCT	2034 DSM SEP	2034 DSM SEP	2029 NGCT (3)	2029 NGCT (2)	2029 NGCT (2)	2029 Tier I Battery (3)
	2041 Tier I Wind	2032 Tier I Solar	2034 Tier I Solar	2036 Tier I Solar	2036 Tier I Wind	2036 Tier I Wind	2029 Nuclear	2029 Nuclear	2029 Nuclear
		2039 Tier I Wind	2040 Tier I Wind	2040 Tier I Wind	2037 RICE	2037 RICE	2036 Tier I Solar	2036 Tier I Solar	2030 Tier I Battery
		2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2041 RICE	2041 RICE	2041 Tier I Wind (2)	2041 Tier I Wind (2)	2034 Nuclear
					2041 Tier I Wind (2)	2041 Tier I Wind (2)			2036 Tier I Wind
									2039 Tier I Solar
									2041 Tier I Wind
Coal Retirement	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**
	2029 GGS 2	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1
	2033 GGS 1	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2
		2032 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1
			2033 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4
CO2 2,536K	CO2 1,743K	CO2 1,195K	CO2 1,177K	CO2 1,146K	CO2 1,172K	CO2 1,174K	CO2 849K	CO2 850K	CO2 531K
NPV $1,420M	NPV $1,825M	NPV $2,182M	NPV $2,477M	NPV $2,709M	NPV $2,919M	NPV $3,132M	NPV $3,493M	NPV $3,665M	NPV $3,941M
NPVE $2,658M	NPVE $3,543M	NPVE $4,220M	NPVE $4,824M	NPVE $5,328M	NPVE $5,796M	NPVE $6,255M	NPVE $6,655M	NPVE $7,016M	NPVE $7,367M

$3.00

$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
Expansion	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**
2036 DSM SEP	2036 DSM SEP	2036 RICE	2029 NGCT	2029 NGCT	2025 DSM SEP	2025 DSM SEP	2025 DSM SEP	2023 DSM SEP	2023 DSM SEP
2037 Tier I Wind	2036 Tier I Wind	2036 Tier I Solar	2036 DSM SEP	2033 DSM SEP	2029 NGCT (2)	2029 NGCT	2029 Tier I Battery (2)	2029 Nuclear (2)	2029 Nuclear
2041 Tier I Solar	2041 Tier I Solar	2037 DSM SEP	2036 Tier I Wind	2034 NGCT	2036 RICE	2029 Nuclear	2029 Nuclear	2031 Nuclear	2035 Tier I Wind
		2041 Tier I Wind (2)	2041 RICE	2036 RICE	2036 Tier I Wind	2035 Tier I Solar	2031 Tier I Battery	2035 Tier I Solar	2036 Tier I Solar
			2041 Tier I Wind (2)	2036 Tier I Wind	2040 RICE	2040 Tier I Wind	2036 Nuclear	2038 Tier I Wind	2041 Tier I Wind
				2040 RICE	2041 Tier I Wind (2)	2041 Tier I Wind	2038 Tier I Wind	2041 Tier I Wind	
				2041 Tier I Wind (2)			2040 Tier I Solar		
							2041 Tier I Wind		
Coal Retirement	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**
		2036 GGS 2	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1
			2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2
				2034 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1
							2040 WS 4	2031 WS 4	2029 WS 4
CO2 2,686K	CO2 2,210K	CO2 1,773K	CO2 1,426K	CO2 1,244K	CO2 1,191K	CO2 791K	CO2 499K	CO2 385K	CO2 386K
NPV $1,451M	NPV $1,842M	NPV $2,203M	NPV $2,550M	NPV $2,873M	NPV $3,151M	NPV $3,519M	NPV $3,824M	NPV $4,144M	NPV $4,293M
NPVE $2,775M	NPVE $3,750M	NPVE $4,504M	NPVE $5,158M	NPVE $5,775M	NPVE $6,301M	NPVE $6,694M	NPVE $7,165M	NPVE $7,425M	NPVE $7,642M

$4.00

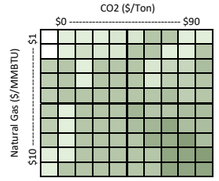
$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
Expansion	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**
2036 DSM SEP	2036 DSM SEP	2036 Tier I Solar	2035 NGCT	2025 DSM SEP	2025 DSM SEP	2025 DSM SEP	2023 DSM SEP	2023 DSM SEP	2023 DSM SEP
2037 Tier I Wind	2036 Tier I Wind	2041 Tier I Wind (2)	2036 Tier I Wind	2031 RICE	2029 Nuclear	2029 Nuclear	2029 Nuclear (2)	2029 Nuclear (2)	2029 Nuclear (2)
2041 Tier I Solar	2041 RICE		2041 Tier I Wind (2)	2035 RICE	2036 Tier I Wind	2034 NGCT	2034 Nuclear	2033 Nuclear	2032 Nuclear
	2041 Tier I Wind			2036 Tier I Wind	2040 NGCT	2035 Tier I Solar	2037 Tier I Wind	2037 Tier I Wind	2036 Tier I Wind
				2038 RICE	2040 Tier I Solar	2040 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind
				2041 Tier I Wind (2)	2041 Tier I Wind	2041 Tier I Wind			
Coal Retirement	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**
			2035 GGS 2	2030 GGS 2	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1
					2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2
					2040 LRS 1	2034 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1
CO2 2,635K	CO2 2,532K	CO2 2,244K	CO2 1,773K	CO2 1,546K	CO2 899K	CO2 894K	CO2 487K	CO2 459K	CO2 444K
NPV $1,480M	NPV $1,850M	NPV $2,256M	NPV $2,651M	NPV $2,938M	NPV $3,381M	NPV $3,647M	NPV $4,074M	NPV $4,237M	NPV $4,374M
NPVE $2,844M	NPVE $3,791M	NPVE $4,690M	NPVE $5,457M	NPVE $6,084M	NPVE $6,608M	NPVE $7,036M	NPVE $7,420M	NPVE $7,668M	NPVE $7,890M

$5.00

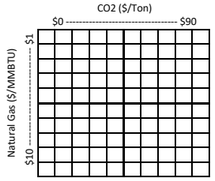
$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
Expansion	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**
2036 DSM SEP	2036 DSM SEP	2036 DSM SEP	2030 DSM SEP	2025 DSM SEP	2029 Nuclear	2029 Nuclear	2029 Nuclear	2023 DSM SEP	2023 DSM SEP
2037 Tier I Wind	2036 Tier I Wind	2036 Tier I Wind	2036 Tier I Wind	2034 Nuclear	2032 DSM SEP	2032 DSM SEP	2034 Nuclear	2029 Nuclear	2029 Nuclear
2041 Tier I Solar	2041 RICE	2041 RICE	2041 RICE	2036 Tier I Wind	2036 Tier I Wind	2036 Tier I Wind	2035 Tier I Wind (*)	2034 Nuclear (2)	2030 Nuclear
	2041 Tier I Wind	2041 Tier I Wind (2)	2041 Tier I Wind (2)	2041 Tier I Wind (2)	2041 Tier I Wind (2)	2040 Tier I Solar	2037 DSM SEP	2037 Tier I Wind	2032 Nuclear
						2041 Tier I Wind	2040 Nuclear	2041 Tier I Wind	2036 Tier I Wind
							2041 Tier I Wind		2041 Tier I Wind
Coal Retirement	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**
				2034 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 1	2029 GGS 1	2029 GGS 1
						2033 GGS 1	2029 GGS 2	2029 GGS 2	2029 GGS 2
							2040 LRS 1	2034 LRS 1	2030 LRS 1
CO2 2,633K	CO2 2,509K	CO2 2,485K	CO2 2,054K	CO2 1,419K	CO2 1,207K	CO2 1,030K	CO2 531K	CO2 527K	CO2 516K
NPV $1,511M	NPV $1,881M	NPV $2,237M	NPV $2,638M	NPV $3,160M	NPV $3,502M	NPV $3,725M	NPV $4,058M	NPV $4,273M	NPV $4,473M
NPVE $2,916M	NPVE $3,866M	NPVE $4,722M	NPVE $5,569M	NPVE $6,387M	NPVE $6,867M	NPVE $7,342M	NPVE $7,630M	NPVE $7,843M	NPVE $8,074M

Resource Summary Tables

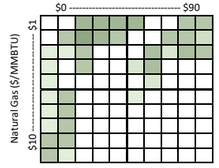
Tier I Wind



Tier II Wind



Tier I Solar



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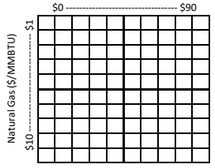
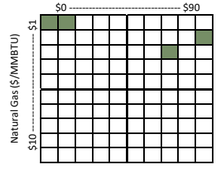
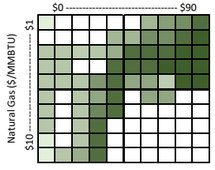


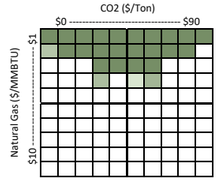
Tier I Battery



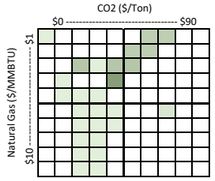
DSM SEP



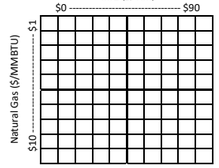
NGCT



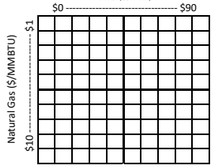
RICE



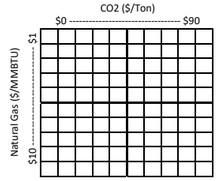
NGCC CCS



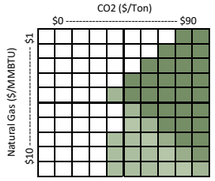
Coal CCS



WS4 CCS Upgrade



Nuclear



Notes:
1) Shaded cells indicate a resource's inclusion within the 2022 - 2041 study period; the darker the shading, the earlier a resource was selected. A key is provided below:

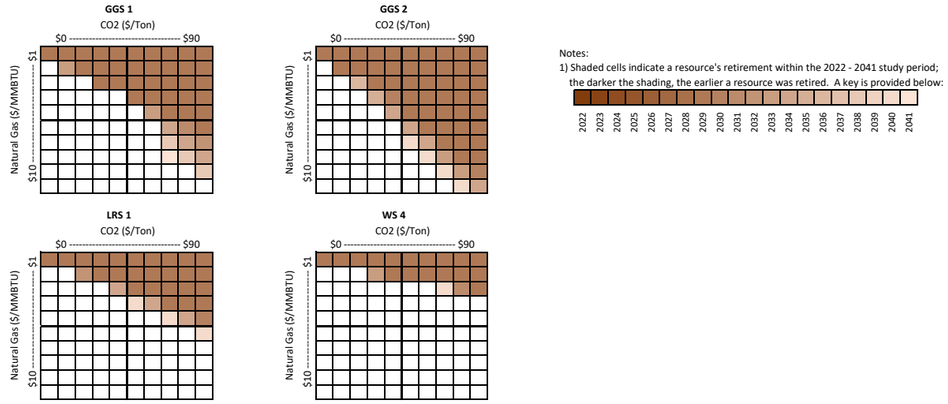
2) Data reflects EGEAS' lowest cost expansion plan for each scenario, including the 30-year extension period.
3) *CO2* values reflect LES' total CO2 emissions for year 2040 in units of tons.
4) *NPV* values reflect LES' total production costs over the 2022 - 2041 study period.
5) *NPVE* values reflect LES' total production costs over the 2022 - 2041 study period plus the subequent 30-year extension period.
6) Multiple selections of the same resource in the same year are denoted by (#).
7) Tier I Wind that was installed early as Tier II Wind - but utilmately graduated to Tier I status following the end of a contract for an existing Tier I Wind resource - is denoted by (*).

EGEAS Expansion Plans
Sensitivity 1: No CCS Resources

Natural Gas Price ($/MMBTU, 2022 $) | **CO2 Value ($/Short Ton, 2022 $)**

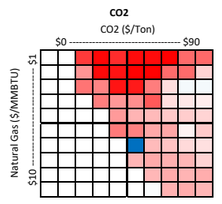
	$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
$6.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,633K NPV $1,543M NPVE $2,986M	**Expansion** 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 2,552K NPV $1,923M NPVE $3,937M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,513K NPV $2,267M NPVE $4,763M	**Expansion** 2032 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,371K NPV $2,631M NPVE $5,694M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,004K NPV $3,032M NPVE $6,466M	**Expansion** 2034 Tier I Wind (*) 2034 Nuclear 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** 2034 GGS 2 CO2 1,427K NPV $3,529M NPVE $7,158M	**Expansion** 2029 Nuclear 2032 DSM SEP 2036 Tier I Wind 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 CO2 1,239K NPV $3,849M NPVE $7,626M	**Expansion** 2029 Nuclear 2032 DSM SEP 2036 Tier I Wind 2040 RICE 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2034 GGS 1 CO2 1,126K NPV $4,089M NPVE $8,086M	**Expansion** 2029 Nuclear 2034 Nuclear 2035 Tier I Wind (*) 2041 Nuclear **Coal Retirement** 2029 GGS 2 2031 GGS 1 CO2 814K NPV $4,381M NPVE $8,433M	**Expansion** 2029 Nuclear 2034 Nuclear 2035 Tier I Wind (*) 2036 Tier I Wind 2040 Nuclear 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2040 LRS 1 CO2 529K NPV $4,568M NPVE $8,408M
$7.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,633K NPV $1,575M NPVE $3,057M	**Expansion** 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 2,552K NPV $1,955M NPVE $4,003M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,298M NPVE $4,835M	**Expansion** 2028 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,458K NPV $2,654M NPVE $5,704M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,274K NPV $3,028M NPVE $6,646M	**Expansion** 2035 Tier I Wind (*) 2036 Nuclear 2040 Nuclear 2041 Tier I Wind **Coal Retirement** 2040 GGS 2 CO2 1,440K NPV $3,511M NPVE $7,299M	**Expansion** 2034 Tier I Wind (*) 2034 Nuclear 2040 Nuclear 2041 Tier I Wind **Coal Retirement** 2034 GGS 2 CO2 1,252K NPV $3,900M NPVE $7,926M	**Expansion** 2029 Nuclear 2032 Tier I Wind (*) 2038 Nuclear 2041 Nuclear **Coal Retirement** 2029 GGS 2 2038 GGS 1 CO2 1,055K NPV $4,242M NPVE $8,322M	**Expansion** 2029 Nuclear 2034 Nuclear 2035 Tier I Wind (*) 2041 Nuclear **Coal Retirement** 2029 GGS 2 2034 GGS 1 CO2 933K NPV $4,477M NPVE $8,626M	**Expansion** 2029 Nuclear 2034 Nuclear 2035 Tier I Wind (*) 2041 Nuclear **Coal Retirement** 2029 GGS 2 2032 GGS 1 CO2 872K NPV $4,692M NPVE $8,977M
$8.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,633K NPV $1,608M NPVE $3,128M	**Expansion** 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 2,552K NPV $1,986M NPVE $4,070M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,330M NPVE $4,904M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,462K NPV $2,685M NPVE $5,764M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2038 Tier I Wind (*) **Coal Retirement** CO2 2,220K NPV $3,134M NPVE $6,621M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 1,973K NPV $3,486M NPVE $7,524M	**Expansion** 2033 Tier I Wind (*) 2036 Nuclear 2040 Nuclear 2041 Tier I Wind **Coal Retirement** 2040 GGS 2 CO2 1,424K NPV $3,879M NPVE $7,985M	**Expansion** 2033 Tier I Wind (*) 2033 Nuclear 2040 Nuclear 2041 Nuclear **Coal Retirement** 2033 GGS 2 2041 GGS 1 CO2 1,254K NPV $4,266M NPVE $8,443M	**Expansion** 2029 Nuclear 2031 Tier I Wind (*) 2038 Nuclear 2041 Nuclear **Coal Retirement** 2029 GGS 2 2038 GGS 1 CO2 1,084K NPV $4,544M NPVE $8,844M	**Expansion** 2029 Nuclear 2034 Nuclear 2035 Tier I Wind (*) 2041 Nuclear **Coal Retirement** 2029 GGS 2 2034 GGS 1 CO2 916K NPV $4,769M NPVE $9,162M
$9.00	**Expansion** 2036 Tier I Solar 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** CO2 2,678K NPV $1,641M NPVE $3,199M	**Expansion** 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 2,552K NPV $2,017M NPVE $4,137M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,362M NPVE $4,973M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,462K NPV $2,715M NPVE $5,832M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2038 Tier I Wind (*) **Coal Retirement** CO2 2,243K NPV $3,160M NPVE $6,651M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 2,125K NPV $3,496M NPVE $7,459M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 1,921K NPV $3,858M NPVE $8,358M	**Expansion** 2032 Tier I Wind (*) 2036 Nuclear 2040 Nuclear 2041 Tier I Wind **Coal Retirement** 2040 GGS 2 CO2 1,415K NPV $4,237M NPVE $8,667M	**Expansion** 2032 Tier I Wind (*) 2033 Nuclear 2040 Nuclear 2041 Tier I Wind **Coal Retirement** 2033 GGS 2 CO2 1,242K NPV $4,609M NPVE $9,218M	**Expansion** 2030 Nuclear 2031 Tier I Wind (*) 2038 Nuclear 2041 Nuclear **Coal Retirement** 2030 GGS 2 2038 GGS 1 CO2 1,092K NPV $4,870M NPVE $9,419M
$10.00	**Expansion** 2036 Tier I Solar 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** CO2 2,678K NPV $1,673M NPVE $3,270M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,507K NPV $2,042M NPVE $4,202M	**Expansion** 2033 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,393M NPVE $5,042M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,462K NPV $2,745M NPVE $5,899M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2038 Tier I Wind (*) **Coal Retirement** CO2 2,244K NPV $3,187M NPVE $6,702M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 2,187K NPV $3,520M NPVE $7,482M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 2,085K NPV $3,864M NPVE $8,301M	**Expansion** 2032 Tier I Wind (*) 2036 Nuclear 2041 Nuclear **Coal Retirement** CO2 1,899K NPV $4,254M NPVE $9,178M	**Expansion** 2032 Tier I Wind (*) 2036 Nuclear 2040 Nuclear 2041 Tier I Wind **Coal Retirement** 2040 GGS 2 CO2 1,373K NPV $4,598M NPVE $9,337M	**Expansion** 2032 Tier I Wind (*) 2034 Nuclear 2040 Nuclear 2041 Tier I Wind **Coal Retirement** 2034 GGS 2 CO2 1,217K NPV $4,953M NPVE $9,888M

Resource Summary Tables

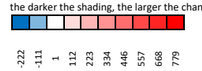


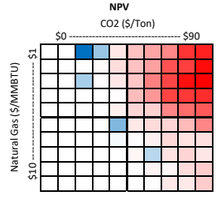
Notes:
1) Shaded cells indicate a resource's retirement within the 2022 - 2041 study period; the darker the shading, the earlier a resource was retired. A key is provided below:

Comparison to Base Case

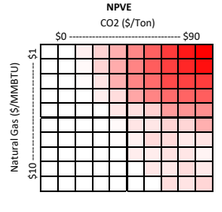


Notes:
1) Shaded cells indicate the change in CO2 emissions (thousand tons) for year 2040, relative to the base case; the darker the shading, the larger the change in emissions. A key is provided below:

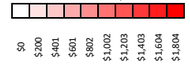




Notes:
1) Shaded cells indicate the change in total production costs ($M) over the 2022 - 2041 study period, relative to the base case; the darker the shading, the larger the change in cost. A key is provided below:



Notes:
1) Shaded cells indicate the change in total production costs ($M) over the 2022 - 2041 study plus the subsequent 30-year extension period, relative to the base case; the darker the shading, the larger the change in cost. A key is provided below:



EGEAS Expansion Plans
Sensitivity 2: No CCS or Nuclear Resources

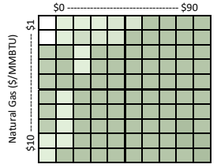
CO2 Value ($/Short Ton, 2022 $)

Natural Gas Price ($/MMBTU, 2022 $)

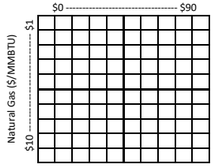
	$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
$1.00	**Expansion** 2029 NGCT 2029 Tier I Battery (4) 2034 NGCT 2041 DSM SEP 2041 RICE **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 1,394K NPV $1,462M NPVE $2,441M	**Expansion** 2029 NGCT 2029 Tier I Battery (4) 2034 NGCT 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 1,345K NPV $1,708M NPVE $3,069M	**Expansion** 2029 NGCT (3) 2034 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 1,211K NPV $1,905M NPVE $3,642M	**Expansion** 2029 NGCT (3) 2034 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 1,286K NPV $2,131M NPVE $4,155M	**Expansion** 2029 NGCT (3) 2034 Tier I Solar 2040 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 1,173K NPV $2,358M NPVE $4,650M	**Expansion** 2029 NGCT (3) 2034 Tier I Solar 2040 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 1,170K NPV $2,576M NPVE $5,135M	**Expansion** 2029 NGCT (3) 2034 DSM SEP 2036 Tier I Wind 2037 RICE 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 1,171K NPV $2,774M NPVE $5,600M	**Expansion** 2031 DSM SEP 2036 Tier I Wind 2037 RICE 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 1,173K NPV $2,992M NPVE $6,064M	**Expansion** 2029 DSM SEP 2029 NGCT (3) 2036 Tier I Wind 2037 RICE 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 1,176K NPV $3,204M NPVE $6,523M	**Expansion** 2025 DSM SEP 2029 NGCT (3) 2036 Tier I Wind 2037 RICE 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 1,178K NPV $3,414M NPVE $6,983M
$2.00	**Expansion** 2036 NGCT **Coal Retirement** 2029 GGS 2 2033 GGS 1 CO2 2,536K NPV $1,420M NPVE $2,658M	**Expansion** 2029 NGCT 2036 Tier I Solar 2041 Tier I Wind **Coal Retirement** CO2 1,743K NPV $1,825M NPVE $3,543M	**Expansion** 2029 NGCT 2032 NGCT 2032 Tier I Solar 2039 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2032 LRS 1 CO2 1,195K NPV $2,182M NPVE $4,220M	**Expansion** 2029 NGCT (2) 2032 NGCT 2034 Tier I Solar 2040 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2033 WS 4 CO2 1,177K NPV $2,477M NPVE $4,824M	**Expansion** 2029 NGCT (3) 2034 DSM SEP 2036 Tier I Solar 2040 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 1,146K NPV $2,709M NPVE $5,328M	**Expansion** 2029 NGCT (3) 2034 DSM SEP 2036 Tier I Wind 2037 RICE 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 1,172K NPV $2,919M NPVE $5,796M	**Expansion** 2029 DSM SEP 2029 NGCT (3) 2036 Tier I Wind 2037 RICE 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 1,174K NPV $3,132M NPVE $6,255M	**Expansion** 2029 DSM SEP 2029 NGCT (3) 2036 Tier I Wind 2037 RICE 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 1,176K NPV $3,346M NPVE $6,715M	**Expansion** 2025 DSM SEP 2029 NGCT (3) 2036 Tier I Wind 2037 RICE 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 1,178K NPV $3,557M NPVE $7,176M	**Expansion** 2023 DSM SEP 2029 NGCT (3) 2036 Tier I Wind 2037 RICE 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 1,181K NPV $3,767M NPVE $7,640M
$3.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,686K NPV $1,451M NPVE $2,775M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,210K NPV $1,842M NPVE $3,750M	**Expansion** 2036 RICE 2036 Tier I Solar 2037 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2036 GGS 2 CO2 1,773K NPV $2,203M NPVE $4,504M	**Expansion** 2029 NGCT 2033 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 CO2 1,426K NPV $2,550M NPVE $5,158M	**Expansion** 2029 NGCT 2033 DSM SEP 2034 NGCT 2036 RICE 2036 Tier I Wind 2040 RICE 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2034 LRS 1 CO2 1,244K NPV $2,873M NPVE $5,775M	**Expansion** 2025 DSM SEP 2029 NGCT (2) 2036 RICE 2036 Tier I Wind 2040 RICE 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 1,191K NPV $3,151M NPVE $6,301M	**Expansion** 2025 DSM SEP 2029 NGCT (2) 2036 RICE 2036 Tier I Wind 2040 RICE 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 1,170K NPV $3,384M NPVE $6,790M	**Expansion** 2025 DSM SEP 2029 NGCT (2) 2036 RICE 2036 Tier I Wind 2040 NGCT 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2040 WS 4 CO2 1,179K NPV $3,622M NPVE $7,323M	**Expansion** 2023 DSM SEP 2029 NGCT (2) 2036 RICE 2036 Tier I Wind 2037 RICE 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2031 WS 4 CO2 1,183K NPV $3,887M NPVE $7,813M	**Expansion** 2023 DSM SEP 2029 NGCT (3) 2036 Tier I Wind 2037 RICE 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 1,190K NPV $4,113M NPVE $8,285M
$4.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,635K NPV $1,480M NPVE $2,844M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind **Coal Retirement** CO2 2,532K NPV $1,850M NPVE $3,791M	**Expansion** 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 2,244K NPV $2,256M NPVE $4,690M	**Expansion** 2035 NGCT 2036 Tier I Wind 2041 Tier I Wind (2) **Coal Retirement** 2035 GGS 2 CO2 1,773K NPV $2,651M NPVE $5,457M	**Expansion** 2025 DSM SEP 2031 RICE 2035 RICE 2036 Tier I Wind 2038 RICE 2041 Tier I Wind (2) **Coal Retirement** 2030 GGS 2 CO2 1,546K NPV $2,938M NPVE $6,084M	**Expansion** 2025 DSM SEP 2029 NGCT 2036 Tier I Wind 2040 NGCT 2040 RICE (2) 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2040 LRS 1 CO2 1,282K NPV $3,275M NPVE $6,743M	**Expansion** 2025 DSM SEP 2029 NGCT 2034 NGCT 2036 RICE 2036 Tier I Wind 2040 RICE (2) 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2034 LRS 1 CO2 1,268K NPV $3,574M NPVE $7,269M	**Expansion** 2023 DSM SEP 2029 NGCT (2) 2036 RICE 2036 Tier I Wind 2040 RICE 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 1,244K NPV $3,876M NPVE $7,828M	**Expansion** 2023 DSM SEP 2029 NGCT (2) 2036 RICE 2036 Tier I Wind 2040 RICE 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 1,207K NPV $4,125M NPVE $8,337M	**Expansion** 2023 DSM SEP 2029 NGCT (2) 2036 RICE 2036 Tier I Wind 2040 RICE 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 1,155K NPV $4,353M NPVE $8,824M
$5.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,633K NPV $1,511M NPVE $2,916M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind **Coal Retirement** CO2 2,509K NPV $1,881M NPVE $3,866M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,485K NPV $2,237M NPVE $4,722M	**Expansion** 2030 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,054K NPV $2,638M NPVE $5,569M	**Expansion** 2025 DSM SEP 2034 RICE 2035 RICE 2036 Tier I Wind 2038 RICE 2041 Tier I Wind (2) **Coal Retirement** 2034 GGS 2 CO2 1,762K NPV $3,052M NPVE $6,389M	**Expansion** 2025 DSM SEP 2031 RICE 2035 RICE 2036 Tier I Wind 2038 RICE 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 CO2 1,570K NPV $3,368M NPVE $7,031M	**Expansion** 2025 DSM SEP 2031 RICE 2033 NGCT 2036 Tier I Wind 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2033 GGS 1 CO2 1,417K NPV $3,687M NPVE $7,660M	**Expansion** 2023 DSM SEP 2029 NGCT 2036 Tier I Wind 2038 Tier I Wind (*) 2040 NGCT 2040 RICE (2) 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2034 LRS 1 CO2 1,258K NPV $3,996M NPVE $8,257M	**Expansion** 2023 DSM SEP 2029 NGCT 2034 NGCT 2036 RICE 2036 Tier I Wind 2040 RICE 2040 Tier I Wind (*) 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2034 LRS 1 CO2 1,235K NPV $4,302M NPVE $8,800M	**Expansion** 2023 DSM SEP 2029 NGCT 2030 NGCT 2036 RICE 2036 Tier I Wind 2038 Tier I Wind (*) 2039 RICE 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2030 LRS 1 CO2 1,229K NPV $4,598M NPVE $9,337M

Resource Summary Tables

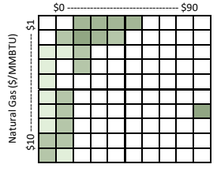
Tier I Wind
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



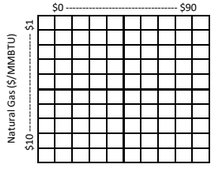
Tier II Wind
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



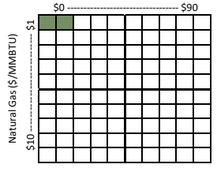
Tier I Solar
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



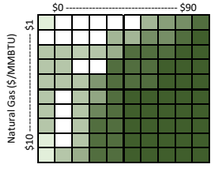
Tier II Solar
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



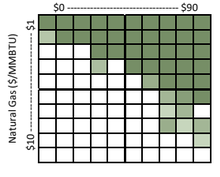
Tier I Battery
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



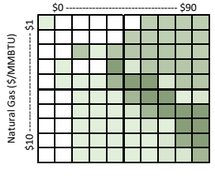
DSM SEP
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



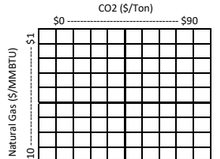
NGCT
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



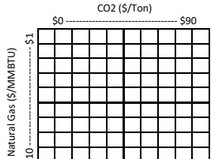
RICE
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



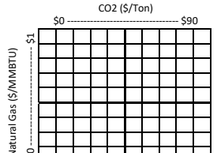
NGCC CCS
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



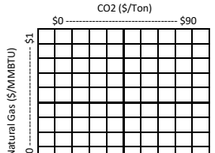
Coal CCS
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



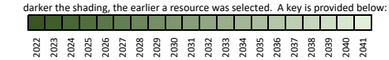
WS4 CCS Upgrade
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



Nuclear
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



Notes:
1) Shaded cells indicate a resource's inclusion within the 2022 - 2041 study period; the darker the shading, the earlier a resource was selected. A key is provided below:



2) Data reflects EGEAS' lowest cost expansion plan for each scenario, including the 30-year extension period.
3) *CO2* values reflect LES' total CO2 emissions for year 2040 in units of tons.
4) *NPV* values reflect LES' total production costs over the 2022 - 2041 study period.
5) *NPVE* values reflect LES' total production costs over the 2022 - 2041 study period plus the subequent 30-year extension period.
6) Multiple selections of the same resource in the same year are denoted by (#).
7) Tier I Wind that was installed early as Tier II Wind - but utilmately graduated to Tier I status following the end of a contract for an existing Tier I Wind resource - is denoted by (*).

EGEAS Expansion Plans

Sensitivity 2: No CCS or Nuclear Resources

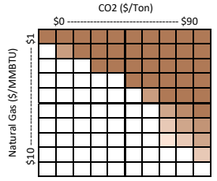
CO2 Value ($/Short Ton, 2022 $)

Natural Gas Price ($/MMBTU, 2022 $)

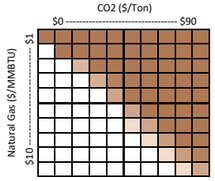
	$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
$6.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,633K NPV $1,543M NPVE $2,986M	**Expansion** 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 2,552K NPV $1,923M NPVE $3,937M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,513K NPV $2,267M NPVE $4,763M	**Expansion** 2032 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,371K NPV $2,631M NPVE $5,694M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,004K NPV $3,032M NPVE $6,466M	**Expansion** 2023 DSM SEP 2034 RICE 2035 RICE 2036 Tier I Wind 2038 RICE 2041 Tier I Wind (2) **Coal Retirement** 2034 GGS 2 CO2 1,740K NPV $3,441M NPVE $7,288M	**Expansion** 2023 DSM SEP 2031 RICE 2035 RICE 2036 Tier I Wind 2038 RICE 2039 Tier I Wind (*) 2041 Tier I Wind **Coal Retirement** 2029 GGS 2 CO2 1,541K NPV $3,794M NPVE $7,989M	**Expansion** 2023 DSM SEP 2031 RICE 2034 NGCT 2036 Tier I Wind 2038 Tier I Wind (*) 2041 Tier I Wind **Coal Retirement** 2029 GGS 2 2034 GGS 1 CO2 1,449K NPV $4,133M NPVE $8,646M	**Expansion** 2023 DSM SEP 2031 NGCT 2036 Tier I Wind 2037 Tier I Wind (*) 2041 RICE 2041 Tier I Wind **Coal Retirement** 2029 GGS 2 2031 GGS 1 CO2 1,368K NPV $4,413M NPVE $9,179M	**Expansion** 2023 DSM SEP 2029 NGCT 2036 Tier I Wind 2037 Tier I Wind (*) 2040 NGCT 2040 RICE (2) 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2040 LRS 1 CO2 1,259K NPV $4,701M NPVE $9,764M
$7.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,633K NPV $1,575M NPVE $3,057M	**Expansion** 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 2,552K NPV $1,955M NPVE $4,003M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,298M NPVE $4,835M	**Expansion** 2028 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,458K NPV $2,654M NPVE $5,704M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,274K NPV $3,028M NPVE $6,646M	**Expansion** 2023 DSM SEP 2036 Tier I Wind 2040 RICE (3) 2041 Tier I Wind (2) **Coal Retirement** 2040 GGS 2 CO2 1,900K NPV $3,435M NPVE $7,446M	**Expansion** 2023 DSM SEP 2034 RICE 2035 RICE 2036 Tier I Wind 2038 RICE 2041 Tier I Wind (2) **Coal Retirement** 2034 GGS 2 CO2 1,741K NPV $3,837M NPVE $8,191M	**Expansion** 2023 DSM SEP 2031 RICE 2035 RICE 2036 Tier I Wind 2038 NGCT 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2038 GGS 1 CO2 1,602K NPV $4,223M NPVE $9,002M	**Expansion** 2023 DSM SEP 2031 RICE 2034 NGCT 2036 Tier I Wind 2038 Tier I Wind (*) 2041 Tier I Wind **Coal Retirement** 2029 GGS 2 2034 GGS 1 CO2 1,459K NPV $4,561M NPVE $9,592M	**Expansion** 2023 DSM SEP 2031 RICE 2032 Tier I Solar 2033 RICE 2036 Tier I Wind 2037 RICE 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2032 GGS 1 CO2 1,357K NPV $4,837M NPVE $10,120M
$8.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,633K NPV $1,608M NPVE $3,128M	**Expansion** 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 2,552K NPV $1,986M NPVE $4,070M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,330M NPVE $4,904M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,462K NPV $2,685M NPVE $5,764M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,419K NPV $3,043M NPVE $6,632M	**Expansion** 2023 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,196K NPV $3,423M NPVE $7,587M	**Expansion** 2023 DSM SEP 2036 Tier I Wind 2040 RICE (3) 2041 Tier I Wind (2) **Coal Retirement** 2040 GGS 2 CO2 1,878K NPV $3,836M NPVE $8,373M	**Expansion** 2023 DSM SEP 2033 NGCT 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** 2033 GGS 2 2041 GGS 1 CO2 1,749K NPV $4,274M NPVE $9,123M	**Expansion** 2023 DSM SEP 2031 RICE 2035 Tier I Wind 2036 RICE 2038 NGCT 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2038 GGS 1 CO2 1,606K NPV $4,627M NPVE $9,898M	**Expansion** 2023 DSM SEP 2031 RICE 2034 NGCT 2036 Tier I Wind 2038 Tier I Wind (*) 2041 Tier I Wind **Coal Retirement** 2029 GGS 2 2034 GGS 1 CO2 1,462K NPV $4,977M NPVE $10,522M
$9.00	**Expansion** 2036 Tier I Solar 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** CO2 2,678K NPV $1,641M NPVE $3,199M	**Expansion** 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 2,552K NPV $2,017M NPVE $4,137M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,362M NPVE $4,973M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,462K NPV $2,715M NPVE $5,832M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,440K NPV $3,071M NPVE $6,686M	**Expansion** 2023 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,322K NPV $3,441M NPVE $7,592M	**Expansion** 2023 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,146K NPV $3,829M NPVE $8,499M	**Expansion** 2023 DSM SEP 2036 Tier I Wind 2040 RICE (3) 2040 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2040 GGS 2 CO2 1,828K NPV $4,232M NPVE $9,288M	**Expansion** 2023 DSM SEP 2033 RICE 2035 Tier I Wind (*) 2036 RICE 2037 Tier I Wind 2038 RICE 2041 Tier I Wind **Coal Retirement** 2033 GGS 2 CO2 1,662K NPV $4,661M NPVE $10,037M	**Expansion** 2023 DSM SEP 2031 RICE 2036 Tier I Wind 2038 NGCT 2041 Tier I Wind (2) **Coal Retirement** 2030 GGS 2 2038 GGS 1 CO2 1,603K NPV $5,032M NPVE $10,775M
$10.00	**Expansion** 2036 Tier I Solar 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** CO2 2,678K NPV $1,673M NPVE $3,270M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,507K NPV $2,042M NPVE $4,202M	**Expansion** 2033 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,393M NPVE $5,042M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,462K NPV $2,745M NPVE $5,899M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,440K NPV $3,101M NPVE $6,744M	**Expansion** 2023 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,383K NPV $3,469M NPVE $7,648M	**Expansion** 2023 DSM SEP 2036 Tier I Wind 2041 RICE 2040 RICE (3) 2041 Tier I Wind (2) **Coal Retirement** CO2 2,285K NPV $3,846M NPVE $8,560M	**Expansion** 2023 DSM SEP 2036 Tier I Wind 2037 Tier I Wind (*) 2040 RICE 2041 Tier I Wind **Coal Retirement** CO2 2,072K NPV $4,244M NPVE $9,413M	**Expansion** 2023 DSM SEP 2036 Tier I Wind 2040 RICE (3) 2040 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2040 GGS 2 CO2 1,775K NPV $4,623M NPVE $10,173M	**Expansion** 2023 DSM SEP 2034 RICE 2035 Tier I Wind (*) 2036 RICE 2037 Tier I Wind 2038 RICE 2041 Tier I Wind **Coal Retirement** 2034 GGS 2 CO2 1,660K NPV $5,039M NPVE $10,930M

Resource Summary Tables

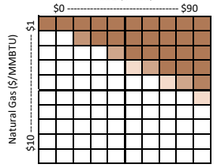
GGS 1
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



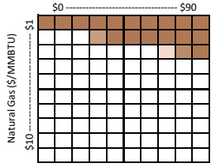
GGS 2
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



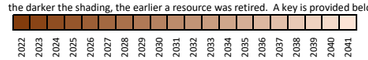
LRS 1
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



WS 4
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10

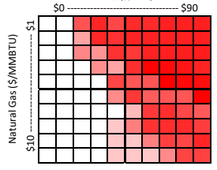


Notes:
1) Shaded cells indicate a resource's retirement within the 2022 - 2041 study period; the darker the shading, the earlier a resource was retired. A key is provided below:

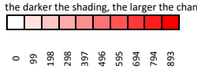


Comparison to Base Case

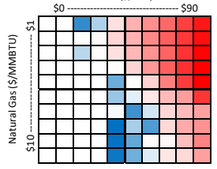
CO2
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



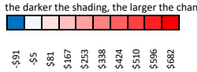
Notes:
1) Shaded cells indicate the change in CO2 emissions (thousand tons) for year 2040, relative to the base case; the darker the shading, the larger the change in emissions. A key is provided below:



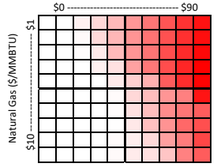
NPV
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



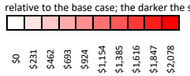
Notes:
1) Shaded cells indicate the change in total production costs ($M) over the 2022 - 2041 study period, relative to the base case; the darker the shading, the larger the change in cost. A key is provided below:



NPVE
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



Notes:
1) Shaded cells indicate the change in total production costs ($M) over the 2022 - 2041 study plus the subsequent 30-year extension period, relative to the base case; the darker the shading, the larger the change in cost. A key is provided below:



EGEAS Expansion Plans
Sensitivity 3: Hybrid Solar + Storage Option

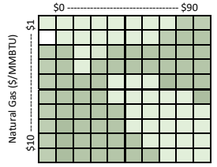
CO2 Value ($/Short Ton, 2022 $)

Natural Gas Price ($/MMBTU, 2022 $)

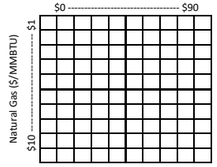
	$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
$1.00	**Expansion** 2029 Tier I Battery (4) 2029 Hybrid Solar 2029 Hybrid Solar 2034 NGCT 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 1,327K NPV $1,437M NPVE $2,377M	**Expansion** 2029 Tier I Battery (4) 2029 Hybrid Solar 2029 Hybrid Solar 2034 NGCT 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 1,233K NPV $1,668M NPVE $2,940M	**Expansion** 2029 Tier I Battery (4) 2029 Hybrid Solar 2029 Hybrid Solar 2034 NGCC CCS 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 842K NPV $1,906M NPVE $3,447M	**Expansion** 2029 NGCC CCS (2) 2029 Hybrid Solar 2029 Hybrid Solar 2030 NGCC CCS 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 396K NPV $2,129M NPVE $3,776M	**Expansion** 2029 NGCC CCS (2) 2029 Hybrid Solar 2029 Hybrid Solar 2030 NGCC CCS 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 396K NPV $2,234M NPVE $3,987M	**Expansion** 2029 NGCC CCS (2) 2029 Hybrid Solar 2029 Hybrid Solar 2030 NGCC CCS 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 396K NPV $2,340M NPVE $4,196M	**Expansion** 2029 NGCC CCS (2) 2029 Hybrid Solar 2029 Hybrid Solar 2030 NGCC CCS 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 396K NPV $2,446M NPVE $4,404M	**Expansion** 2029 NGCC CCS (3) 2029 Hybrid Solar 2029 Hybrid Solar 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 396K NPV $2,554M NPVE $4,604M	**Expansion** 2029 NGCC CCS (3) 2029 Hybrid Solar 2029 Hybrid Solar 2037 Tier I Wind 2041 DSM SEP **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 374K NPV $2,668M NPVE $4,803M	**Expansion** 2029 NGCC CCS (3) 2029 Hybrid Solar 2029 Hybrid Solar 2037 Tier I Wind 2041 DSM SEP **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 372K NPV $2,769M NPVE $5,007M
$2.00	**Expansion** 2036 NGCT **Coal Retirement** 2029 GGS 2 2033 GGS 1 CO2 2,536K NPV $1,420M NPVE $2,658M	**Expansion** 2029 Tier I Battery 2031 Tier I Battery 2034 Hybrid Solar 2034 Hybrid Solar 2041 Tier I Wind **Coal Retirement** 2029 GGS 2 2033 GGS 1 CO2 1,885K NPV $1,824M NPVE $3,473M	**Expansion** 2029 Hybrid Solar 2029 Hybrid Solar 2032 NGCC CCS (2) 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2032 LRS 1 CO2 622K NPV $2,175M NPVE $4,065M	**Expansion** 2029 NGCC CCS 2029 Hybrid Solar 2029 Hybrid Solar 2031 NGCC CCS 2033 NGCC CCS 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2033 WS 4 CO2 397K NPV $2,427M NPVE $4,428M	**Expansion** 2029 NGCC CCS 2029 Hybrid Solar 2029 Hybrid Solar 2030 NGCC CCS 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 397K NPV $2,572M NPVE $4,663M	**Expansion** 2029 NGCC CCS (2) 2029 Hybrid Solar 2029 Hybrid Solar 2030 NGCC CCS 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 398K NPV $2,679M NPVE $4,868M	**Expansion** 2029 NGCC CCS (3) 2029 Hybrid Solar 2029 Hybrid Solar 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 397K NPV $2,787M NPVE $5,069M	**Expansion** 2029 NGCC CCS (3) 2029 Hybrid Solar 2029 Hybrid Solar 2037 Tier I Wind 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 376K NPV $2,904M NPVE $5,260M	**Expansion** 2029 NGCC CCS (3) 2029 Hybrid Solar 2029 Hybrid Solar 2036 Tier I Wind 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 375K NPV $3,007M NPVE $5,447M	**Expansion** 2029 NGCC CCS (3) 2029 Hybrid Solar 2029 Hybrid Solar 2036 Tier I Wind 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 375K NPV $3,107M NPVE $5,630M
$3.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Hybrid Solar 2041 Hybrid Solar **Coal Retirement** CO2 2,686K NPV $1,449M NPVE $2,756M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 Hybrid Solar 2041 Hybrid Solar **Coal Retirement** CO2 2,210K NPV $1,841M NPVE $3,739M	**Expansion** 2036 Hybrid Solar 2036 Hybrid Solar 2041 Tier I Wind (2) **Coal Retirement** 2036 GGS 2 CO2 1,927K NPV $2,181M NPVE $4,475M	**Expansion** 2029 NGCC CCS 2035 Tier I Solar 2040 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 CO2 1,048K NPV $2,541M NPVE $4,979M	**Expansion** 2029 NGCC CCS 2034 NGCC CCS (2) 2036 Tier I Wind 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2034 LRS 1 CO2 526K NPV $2,790M NPVE $5,212M	**Expansion** 2029 NGCC CCS (3) 2036 Tier I Wind 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 491K NPV $2,958M NPVE $5,437M	**Expansion** 2029 NGCC CCS (3) 2032 WS4 CCS Upgrade 2036 Tier I Wind 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 471K NPV $3,092M NPVE $5,652M	**Expansion** 2025 DSM SEP 2029 NGCC CCS (3) 2036 Tier I Wind 2040 Hybrid Solar 2040 Hybrid Solar 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2040 WS 4 CO2 359K NPV $3,202M NPVE $5,861M	**Expansion** 2029 NGCC CCS (3) 2031 Hybrid Solar 2031 Hybrid Solar 2036 Tier I Wind 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2031 WS 4 CO2 374K NPV $3,319M NPVE $6,049M	**Expansion** 2029 NGCC CCS (3) 2029 Hybrid Solar 2036 Tier I Wind 2039 DSM SEP 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 360K NPV $3,428M NPVE $6,242M
$4.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Hybrid Solar 2041 Hybrid Solar **Coal Retirement** CO2 2,635K NPV $1,478M NPVE $2,823M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind **Coal Retirement** CO2 2,532K NPV $1,850M NPVE $3,791M	**Expansion** 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 2,244K NPV $2,256M NPVE $4,690M	**Expansion** 2035 NGCC CCS 2036 Tier I Wind 2041 Tier I Wind (2) **Coal Retirement** 2035 GGS 2 CO2 1,378K NPV $2,650M NPVE $5,340M	**Expansion** 2030 NGCC CCS 2036 Tier I Wind 2041 Tier I Wind (2) **Coal Retirement** 2030 GGS 2 CO2 1,226K NPV $2,929M NPVE $5,838M	**Expansion** 2029 NGCC CCS 2034 NGCC CCS 2036 Tier I Wind 2040 NGCC CCS 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2040 LRS 1 CO2 551K NPV $3,156M NPVE $5,974M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2030 NGCC CCS 2034 NGCC CCS 2036 Tier I Wind 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2034 LRS 1 CO2 384K NPV $3,297M NPVE $6,164M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2036 Tier I Wind 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 385K NPV $3,447M NPVE $6,370M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2036 Tier I Wind 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 386K NPV $3,569M NPVE $6,567M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2036 Tier I Wind 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 386K NPV $3,672M NPVE $6,746M
$5.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Hybrid Solar 2041 Hybrid Solar **Coal Retirement** CO2 2,633K NPV $1,509M NPVE $2,890M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 Hybrid Solar 2041 Hybrid Solar **Coal Retirement** CO2 2,509K NPV $1,879M NPVE $3,860M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,485K NPV $2,237M NPVE $4,722M	**Expansion** 2030 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,054K NPV $2,638M NPVE $5,569M	**Expansion** 2031 WS4 CCS Upgrade 2032 NGCC CCS 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 1,109K NPV $3,104M NPVE $6,211M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 CO2 976K NPV $3,359M NPVE $6,646M	**Expansion** 2029 NGCC CCS 2030 WS4 CCS Upgrade 2033 Tier I Solar 2036 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2033 GGS 1 CO2 813K NPV $3,569M NPVE $7,022M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2030 NGCC CCS 2035 Tier I Wind 2040 NGCC CCS 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2040 LRS 1 CO2 365K NPV $3,652M NPVE $6,928M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2030 NGCC CCS 2034 NGCC CCS 2036 Tier I Wind 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2034 LRS 1 CO2 372K NPV $3,779M NPVE $7,083M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2030 NGCC CCS (2) 2036 Tier I Wind 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2030 LRS 1 CO2 384K NPV $3,916M NPVE $7,281M

Resource Summary Tables

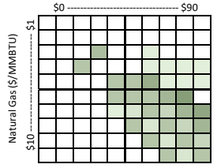
Tier I Wind
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



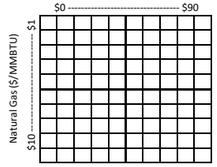
Tier II Wind
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



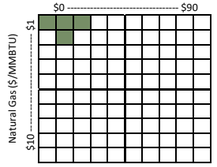
Tier I Solar
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



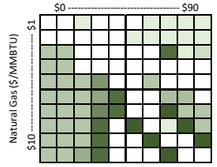
Tier II Solar
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



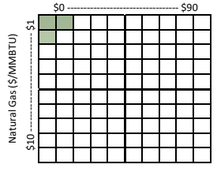
Tier I Battery
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



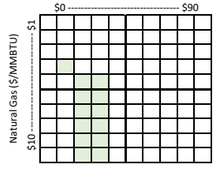
DSM SEP
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



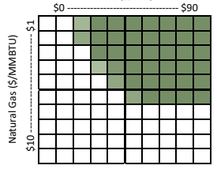
NGCT
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



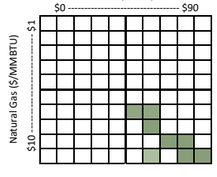
RICE
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



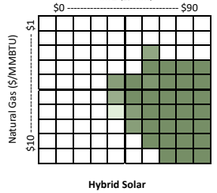
NGCC CCS
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



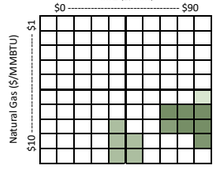
Coal CCS
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



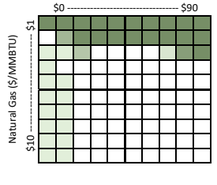
WS4 CCS Upgrade
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



Nuclear
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



Hybrid Solar
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



Notes:
1) Shaded cells indicate a resource's inclusion within the 2022 - 2041 study period; the darker the shading, the earlier a resource was selected. A key is provided below:

2) Data reflects EGEAS' lowest cost expansion plan for each scenario, including the 30-year extension period.
3) *CO2* values reflect LES' total CO2 emissions for year 2040 in units of tons.
4) *NPV* values reflect LES' total production costs over the 2022 - 2041 study period.
5) *NPVE* values reflect LES' total production costs over the 2022 - 2041 study period plus the subequent 30-year extension period.
6) Multiple selections of the same resource in the same year are denoted by (#).
7) Tier I Wind that was installed early as Tier II Wind - but utilmately graduated to Tier I status following the end of a contract for an existing Tier I Wind resource - is denoted by (*).

EGEAS Expansion Plans

Sensitivity 3: Hybrid Solar + Storage Option

CO2 Value ($/Short Ton, 2022 $)

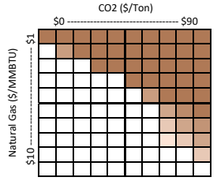
Natural Gas Price ($/MMBTU, 2022 $)

	$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
$6.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Hybrid Solar 2041 Hybrid Solar **Coal Retirement** CO2 2,633K NPV $1,541M NPVE $2,956M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 Hybrid Solar 2041 Hybrid Solar **Coal Retirement** CO2 2,507K NPV $1,910M NPVE $3,924M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,513K NPV $2,267M NPVE $4,763M	**Expansion** 2032 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,371K NPV $2,631M NPVE $5,694M	**Expansion** 2025 DSM SEP 2033 WS4 CCS Upgrade 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 1,595K NPV $3,068M NPVE $6,427M	**Expansion** 2029 WS4 CCS Upgrade 2032 NGCC CCS 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2034 GGS 2 CO2 1,040K NPV $3,451M NPVE $6,967M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 CO2 972K NPV $3,726M NPVE $7,446M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2034 Tier I Solar 2035 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2034 GGS 1 CO2 854K NPV $3,946M NPVE $7,780M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2031 Tier I Solar 2035 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2031 GGS 1 CO2 775K NPV $4,149M NPVE $8,141M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2030 NGCC CCS 2035 Tier I Wind (*) 2040 Nuclear 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2040 LRS 1 CO2 368K NPV $4,162M NPVE $7,842M
$7.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Hybrid Solar 2041 Hybrid Solar **Coal Retirement** CO2 2,633K NPV $1,573M NPVE $3,022M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 Hybrid Solar 2041 Hybrid Solar **Coal Retirement** CO2 2,507K NPV $1,941M NPVE $3,990M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,298M NPVE $4,835M	**Expansion** 2028 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,458K NPV $2,654M NPVE $5,704M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 Tier I Wind 2041 Tier I Solar 2041 WS4 CCS Upgrade **Coal Retirement** CO2 2,274K NPV $3,031M NPVE $6,618M	**Expansion** 2031 WS4 CCS Upgrade 2032 Coal CCS 2040 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2040 GGS 2 CO2 1,195K NPV $3,566M NPVE $7,194M	**Expansion** 2029 WS4 CCS Upgrade 2032 Coal CCS 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2034 GGS 2 CO2 1,044K NPV $3,853M NPVE $7,666M	**Expansion** 2023 DSM SEP 2029 Nuclear 2029 WS4 CCS Upgrade 2038 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2038 GGS 1 CO2 869K NPV $4,111M NPVE $8,062M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2034 Tier I Solar 2036 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2034 GGS 1 CO2 818K NPV $4,379M NPVE $8,469M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2032 Tier I Solar 2036 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2032 GGS 1 CO2 776K NPV $4,584M NPVE $8,792M
$8.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Hybrid Solar 2041 Hybrid Solar **Coal Retirement** CO2 2,633K NPV $1,605M NPVE $3,088M	**Expansion** 2035 Tier I Wind (*) 2036 DSM SEP 2041 Tier I Wind 2041 Hybrid Solar 2041 Hybrid Solar **Coal Retirement** CO2 2,507K NPV $1,982M NPVE $4,055M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,330M NPVE $4,904M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,462K NPV $2,685M NPVE $5,764M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2038 Tier I Wind (*) **Coal Retirement** CO2 2,220K NPV $3,134M NPVE $6,621M	**Expansion** 2023 DSM SEP 2031 WS4 CCS Upgrade 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 1,745K NPV $3,454M NPVE $7,394M	**Expansion** 2029 WS4 CCS Upgrade 2031 Coal CCS 2040 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2040 GGS 2 CO2 1,163K NPV $3,899M NPVE $7,857M	**Expansion** 2029 WS4 CCS Upgrade 2031 Nuclear 2036 Tier I Solar 2041 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2033 GGS 2 2041 GGS 1 CO2 1,012K NPV $4,168M NPVE $8,236M	**Expansion** 2023 DSM SEP 2029 Nuclear 2038 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2038 GGS 1 CO2 860K NPV $4,397M NPVE $8,664M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2034 Tier I Solar 2036 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2034 GGS 1 CO2 782K NPV $4,684M NPVE $9,080M
$9.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Hybrid Solar 2041 Hybrid Solar **Coal Retirement** CO2 2,633K NPV $1,637M NPVE $3,154M	**Expansion** 2035 Tier I Wind (*) 2036 DSM SEP 2041 Tier I Wind 2041 Hybrid Solar 2041 Hybrid Solar **Coal Retirement** CO2 2,507K NPV $2,013M NPVE $4,114M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,362M NPVE $4,973M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,462K NPV $2,715M NPVE $5,832M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2038 Tier I Wind (*) **Coal Retirement** CO2 2,243K NPV $3,160M NPVE $6,651M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 2,125K NPV $3,496M NPVE $7,459M	**Expansion** 2023 DSM SEP 2029 WS4 CCS Upgrade 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 1,701K NPV $3,818M NPVE $8,184M	**Expansion** 2029 WS4 CCS Upgrade 2031 Coal CCS 2040 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2040 GGS 2 CO2 1,156K NPV $4,209M NPVE $8,508M	**Expansion** 2029 WS4 CCS Upgrade 2031 Coal CCS 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2033 GGS 2 CO2 1,011K NPV $4,486M NPVE $8,968M	**Expansion** 2023 DSM SEP 2029 WS4 CCS Upgrade 2030 Nuclear 2038 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2030 GGS 2 2038 GGS 1 CO2 839K NPV $4,700M NPVE $9,262M
$10.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Hybrid Solar 2041 Hybrid Solar **Coal Retirement** CO2 2,633K NPV $1,669M NPVE $3,220M	**Expansion** 2035 Tier I Wind (*) 2036 DSM SEP 2041 Tier I Wind 2041 Hybrid Solar 2041 Hybrid Solar **Coal Retirement** CO2 2,507K NPV $2,044M NPVE $4,172M	**Expansion** 2033 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,393M NPVE $5,042M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,462K NPV $2,745M NPVE $5,899M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2038 Tier I Wind (*) **Coal Retirement** CO2 2,244K NPV $3,187M NPVE $6,702M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 2,187K NPV $3,520M NPVE $7,482M	**Expansion** 2035 Coal CCS 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 2,089K NPV $3,858M NPVE $8,300M	**Expansion** 2023 DSM SEP 2029 WS4 CCS Upgrade 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 1,661K NPV $4,177M NPVE $8,939M	**Expansion** 2029 WS4 CCS Upgrade 2031 Coal CCS 2040 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2040 GGS 2 CO2 1,119K NPV $4,518M NPVE $9,140M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2031 Coal CCS 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2034 GGS 2 CO2 992K NPV $4,780M NPVE $9,595M

Resource Summary Tables

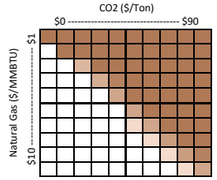
GGS 1

CO2 ($/Ton)



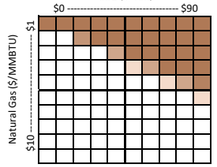
GGS 2

CO2 ($/Ton)



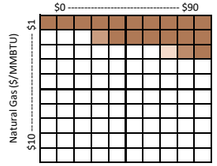
LRS 1

CO2 ($/Ton)

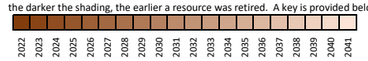


WS 4

CO2 ($/Ton)



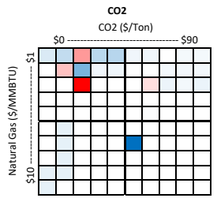
Notes:
1) Shaded cells indicate a resource's retirement within the 2022 - 2041 study period; the darker the shading, the earlier a resource was retired. A key is provided below:



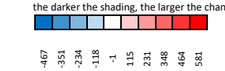
Comparison to Base Case

CO2

CO2 ($/Ton)

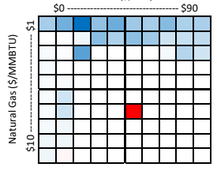


Notes:
1) Shaded cells indicate the change in CO2 emissions (thousand tons) for year 2040, relative to the base case; the darker the shading, the larger the change in emissions. A key is provided below:

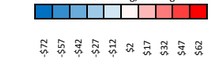


NPV

CO2 ($/Ton)

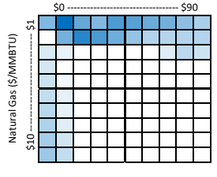


Notes:
1) Shaded cells indicate the change in total production costs ($M) over the 2022 - 2041 study period, relative to the base case; the darker the shading, the larger the change in cost. A key is provided below:



NPVE

CO2 ($/Ton)



Notes:
1) Shaded cells indicate the change in total production costs ($M) over the 2022 - 2041 study plus the subsequent 30-year extension period, relative to the base case; the darker the shading, the larger the change in cost. A key is provided below:

EGEAS Expansion Plans

Sensitivity 4: Retire All LES Coal Resources in 2029

Natural Gas Price ($/MMBTU, 2022 $) — **CO2 Value ($/Short Ton, 2022 $)**

$1.00

$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
Expansion	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**
2029 NGCT	2029 NGCT	2029 Tier I Battery (4)	2029 NGCT	2029 NGCT	2029 DSM SEP	2029 DSM SEP	2029 DSM SEP	2029 DSM SEP	2025 DSM SEP
2029 Tier I Battery (4)	2029 Tier I Battery (4)	2029 NGCC CCS	2029 NGCC CCS (2)	2029 NGCC CCS (2)	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (3)
2034 NGCT	2034 NGCT	2034 NGCC CCS	2031 NGCC CCS	2031 NGCC CCS	2033 RICE	2033 RICE	2033 Tier I Solar	2033 Tier I Solar	2033 Tier I Solar
2041 DSM SEP	2041 Tier I Wind (2)	2039 DSM SEP	2041 Tier I Wind	2041 Tier I Wind	2036 Tier I Solar	2036 Tier I Solar	2039 Tier I Wind	2039 Tier I Wind	2039 Tier I Wind
2041 RICE		2041 Tier I Wind			2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind
Coal Retirement	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**
2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1
2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2
2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1
2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4
CO2 1,394K	CO2 1,345K	CO2 609K	CO2 523K	CO2 528K	CO2 423K	CO2 423K	CO2 394K	CO2 393K	CO2 391K
NPV $1,462M	NPV $1,708M	NPV $1,978M	NPV $2,160M	NPV $2,275M	NPV $2,367M	NPV $2,471M	NPV $2,588M	NPV $2,691M	NPV $2,793M
NPVE $2,441M	NPVE $3,069M	NPVE $3,525M	NPVE $3,839M	NPVE $4,077M	NPVE $4,280M	NPVE $4,479M	NPVE $4,675M	NPVE $4,860M	NPVE $5,050M

$2.00

$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
Expansion	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**
2029 NGCT (3)	2029 NGCT (3)	2029 Tier I Battery (4)	2029 DSM SEP	2029 DSM SEP	2029 DSM SEP	2029 DSM SEP	2029 DSM SEP	2025 DSM SEP	2023 DSM SEP
2034 Tier I Solar	2034 Tier I Solar	2029 NGCC CCS	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (3)
2041 DSM SEP	2041 Tier I Wind (2)	2034 NGCC CCS	2033 RICE	2033 RICE	2033 Tier I Solar	2033 Tier I Solar	2033 Tier I Solar	2033 Tier I Solar	2033 Tier I Solar
2041 Tier I Wind		2039 DSM SEP	2036 Tier I Solar	2036 Tier I Solar	2039 Tier I Wind	2039 Tier I Wind	2039 Tier I Wind	2038 Tier I Wind	2037 Tier I Wind
		2041 Tier I Wind (2)	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind
Coal Retirement	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**
2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1
2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2
2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1
2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4
CO2 1,109K	CO2 1,185K	CO2 609K	CO2 424K	CO2 425K	CO2 398K	CO2 397K	CO2 397K	CO2 395K	CO2 395K
NPV $1,743M	NPV $1,996M	NPV $2,329M	NPV $2,486M	NPV $2,595M	NPV $2,711M	NPV $2,814M	NPV $2,918M	NPV $3,023M	NPV $3,125M
NPVE $3,227M	NPVE $3,783M	NPVE $4,254M	NPVE $4,532M	NPVE $4,736M	NPVE $4,922M	NPVE $5,108M	NPVE $5,297M	NPVE $5,485M	NPVE $5,668M

$3.00

$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
Expansion	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**
2029 NGCT (3)	2029 NGCT (3)	2029 NGCT (2)	2029 DSM SEP	2027 DSM SEP	2025 DSM SEP	2025 DSM SEP	2025 DSM SEP	2023 DSM SEP	2023 DSM SEP
2034 Tier I Solar	2034 Tier I Solar	2029 NGCC CCS	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (3)
2041 Tier I Wind (2)	2041 Tier I Wind (2)	2032 Tier I Solar	2033 Tier I Solar	2033 Tier I Solar	2033 Tier I Solar	2033 Tier I Solar	2033 Tier I Solar	2033 Tier I Solar	2033 Tier I Solar
		2039 Tier I Wind	2039 Tier I Wind	2039 Tier I Wind	2039 Tier I Wind	2038 Tier I Wind	2036 Tier I Wind	2036 Tier I Wind	2036 Tier I Wind
		2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind
Coal Retirement	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**
2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1
2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2
2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1
2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4
CO2 1,035K	CO2 1,092K	CO2 670K	CO2 375K	CO2 392K	CO2 393K	CO2 394K	CO2 394K	CO2 394K	CO2 395K
NPV $1,915M	NPV $2,189M	NPV $2,499M	NPV $2,717M	NPV $2,855M	NPV $2,991M	NPV $3,112M	NPV $3,233M	NPV $3,337M	NPV $3,441M
NPVE $3,674M	NPVE $4,270M	NPVE $4,747M	NPVE $5,051M	NPVE $5,270M	NPVE $5,487M	NPVE $5,694M	NPVE $5,893M	NPVE $6,080M	NPVE $6,267M

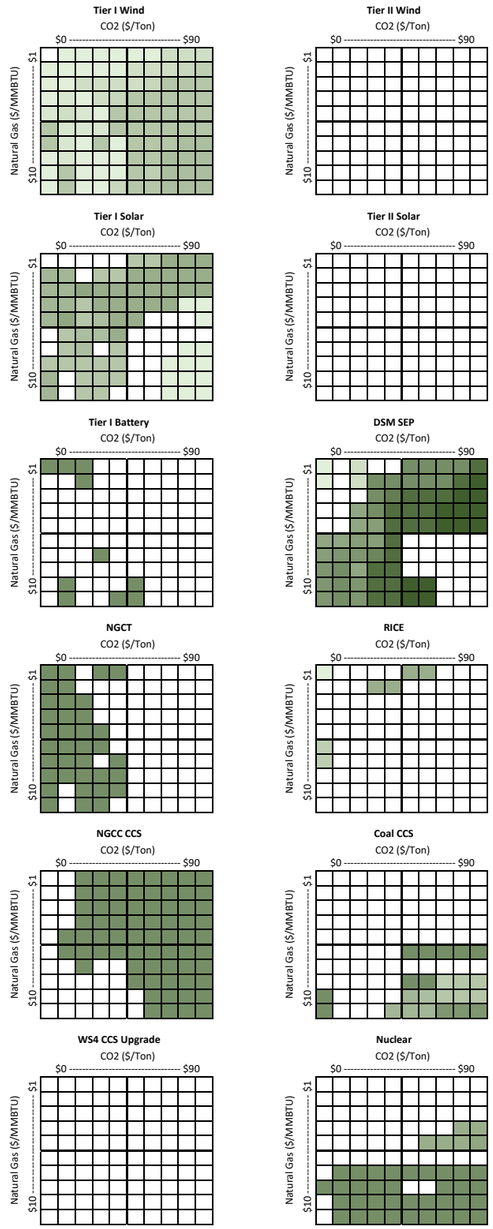
$4.00

$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
Expansion	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**
2029 NGCT (3)	2029 NGCT (3)	2029 NGCT (2)	2029 DSM SEP	2025 DSM SEP	2025 DSM SEP	2025 DSM SEP	2023 DSM SEP	2023 DSM SEP	2023 DSM SEP
2034 Tier I Solar	2034 Tier I Solar	2029 NGCC CCS	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (3)
2041 Tier I Wind (2)	2040 Tier I Wind	2032 DSM SEP	2033 Tier I Solar	2033 Tier I Solar	2033 Tier I Solar	2033 Tier I Solar	2033 Tier I Solar	2033 Nuclear	2033 Nuclear
	2041 Tier I Wind	2036 Tier I Solar	2039 Tier I Wind	2038 Tier I Wind	2036 Tier I Wind	2036 Tier I Wind	2036 Tier I Wind	2036 Tier I Wind	2036 Tier I Wind
		2041 Tier I Wind (2)	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Solar	2041 Tier I Solar
Coal Retirement	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**
2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1
2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2
2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1
2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4
CO2 1,030K	CO2 907K	CO2 610K	CO2 289K	CO2 336K	CO2 361K	CO2 388K	CO2 389K	CO2 244K	CO2 245K
NPV $2,071M	NPV $2,342M	NPV $2,613M	NPV $2,919M	NPV $3,049M	NPV $3,179M	NPV $3,315M	NPV $3,479M	NPV $3,713M	NPV $3,810M
NPVE $4,069M	NPVE $4,671M	NPVE $5,137M	NPVE $5,535M	NPVE $5,762M	NPVE $5,969M	NPVE $6,180M	NPVE $6,428M	NPVE $6,625M	NPVE $6,768M

$5.00

$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
Expansion	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**
2029 NGCT (3)	2029 NGCT (2)	2029 NGCT (2)	2029 NGCT	2025 DSM SEP	2025 DSM SEP	2025 DSM SEP	2023 DSM SEP	2023 DSM SEP	2023 DSM SEP
2034 Tier I Solar	2029 NGCC CCS	2029 NGCC CCS	2029 NGCC CCS (2)	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (3)
2040 Tier I Wind	2032 Tier I Solar	2032 DSM SEP	2031 DSM SEP	2033 Tier I Solar	2033 Tier I Solar	2033 Nuclear	2033 Nuclear	2033 Nuclear	2032 Nuclear
2041 Tier I Wind	2039 Tier I Wind	2036 Tier I Solar	2035 Tier I Solar	2036 Tier I Wind	2036 Tier I Wind	2036 Tier I Wind	2036 Tier I Wind	2036 Tier I Wind	2036 Tier I Wind
	2041 Tier I Wind	2040 Tier I Wind	2041 Tier I Wind (2)	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Solar
		2041 Tier I Wind							
Coal Retirement	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**
2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1
2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2
2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1
2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4
CO2 888K	CO2 533K	CO2 512K	CO2 348K	CO2 281K	CO2 305K	CO2 234K	CO2 240K	CO2 241K	CO2 244K
NPV $2,219M	NPV $2,536M	NPV $2,752M	NPV $3,015M	NPV $3,235M	NPV $3,380M	NPV $3,598M	NPV $3,719M	NPV $3,856M	NPV $4,014M
NPVE $4,441M	NPVE $5,046M	NPVE $5,542M	NPVE $5,917M	NPVE $6,211M	NPVE $6,452M	NPVE $6,638M	NPVE $6,803M	NPVE $6,985M	NPVE $7,180M

Resource Summary Tables



Notes:

1) Shaded cells indicate a resource's inclusion within the 2022 - 2041 study period; the darker the shading, the earlier a resource was selected. A key is provided below:

2) Data reflects EGEAS' lowest cost expansion plan for each scenario, including the 30-year extension period.
3) *CO2* values reflect LES' total CO2 emissions for year 2040 in units of tons.
4) *NPV* values reflect LES' total production costs over the 2022 - 2041 study period.
5) *NPVE* values reflect LES' total production costs over the 2022 - 2041 study period plus the subequent 30-year extension period.
6) Multiple selections of the same resource in the same year are denoted by (#).
7) Tier I Wind that was installed early as Tier II Wind - but utilmately graduated to Tier I status following the end of a contract for an existing Tier I Wind resource - is denoted by (*).

EGEAS Expansion Plans

Sensitivity 4: Retire All LES Coal Resources in 2029

CO2 Value ($/Short Ton, 2022 $)

Natural Gas Price ($/MMBTU, 2022 $)

$6.00

$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
Expansion	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**
2029 NGCT (3)	2029 NGCT (2)	2029 NGCT	2029 NGCT	2025 DSM SEP	2029 Coal CCS	2029 Coal CCS	2029 Coal CCS	2029 Coal CCS	2029 Coal CCS
2032 DSM SEP	2029 NGCC CCS	2029 NGCC CCS (2)	2029 NGCC CCS (2)	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (3)
2036 Tier I Wind	2032 DSM SEP	2031 DSM SEP	2031 DSM SEP	2033 Tier I Solar	2036 Tier I Wind	2036 Tier I Wind	2036 Tier I Wind	2036 Tier I Wind	2036 Tier I Wind
2037 RICE	2036 Tier I Solar	2035 Tier I Solar	2035 Tier I Solar	2036 Tier I Wind	2041 Tier I Wind (2)	2041 Tier I Wind (2)	2041 Tier I Wind (2)	2039 Tier I Wind (*)	2039 Tier I Wind (*)
2041 RICE	2040 Tier I Wind	2040 Tier I Wind	2040 Tier I Wind	2041 Tier I Wind				2041 Tier I Wind	2041 Tier I Wind
2041 Tier I Wind (2)	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind						
Coal Retirement	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**
2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1
2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2
2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1
2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4
CO2 879K	CO2 510K	CO2 249K	CO2 271K	CO2 238K	CO2 223K	CO2 239K	CO2 252K	CO2 229K	CO2 237K
NPV $2,343M	NPV $2,643M	NPV $2,926M	NPV $3,141M	NPV $3,356M	NPV $3,690M	NPV $3,845M	NPV $3,977M	NPV $4,099M	NPV $4,206M
NPVE $4,806M	NPVE $5,382M	NPVE $5,853M	NPVE $6,276M	NPVE $6,584M	NPVE $6,799M	NPVE $6,998M	NPVE $7,179M	NPVE $7,334M	NPVE $7,492M

$7.00

$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
Expansion	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**
2029 NGCT (3)	2029 NGCT (2)	2029 NGCT	2028 DSM SEP	2025 DSM SEP	2029 Nuclear	2029 Nuclear	2029 Nuclear	2029 Nuclear	2029 Nuclear
2031 DSM SEP	2029 Nuclear	2029 Nuclear	2029 Tier I Battery (3)	2029 NGCT	2029 NGCC CCS (2)	2029 NGCC CCS (2)	2029 NGCC CCS (2)	2029 NGCC CCS (2)	2029 NGCC CCS (2)
2036 Tier I Wind	2030 DSM SEP	2029 NGCC CCS	2029 Nuclear	2029 Nuclear (2)	2030 Nuclear	2030 Nuclear	2030 Nuclear	2030 Nuclear	2030 Nuclear
2037 RICE	2036 Tier I Solar	2030 DSM SEP	2030 Tier I Battery	2036 Tier I Solar	2036 Tier I Wind	2036 Tier I Wind	2036 Tier I Wind	2035 Tier I Wind (*)	2035 Tier I Wind (*)
2041 RICE	2040 Tier I Wind	2035 Tier I Solar	2034 Nuclear	2041 Tier I Wind (2)	2040 Tier I Wind	2040 Tier I Wind	2039 Tier I Wind (*)	2036 NGCC CCS	2036 NGCC CCS
2041 Tier I Wind (2)	2041 Tier I Wind	2041 Tier I Wind (2)	2036 Tier I Wind		2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Solar	2041 Tier I Solar
			2041 Tier I Wind (2)						
Coal Retirement	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**
2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1
2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2
2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1
2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4
CO2 880K	CO2 489K	CO2 262K	CO2 208K	CO2 273K	CO2 170K	CO2 187K	CO2 196K	CO2 67K	CO2 68K
NPV $2,480M	NPV $2,859M	NPV $3,110M	NPV $3,407M	NPV $3,597M	NPV $3,855M	NPV $4,005M	NPV $4,178M	NPV $4,339M	NPV $4,451M
NPVE $5,146M	NPVE $5,648M	NPVE $6,079M	NPVE $6,463M	NPVE $6,847M	NPVE $7,072M	NPVE $7,280M	NPVE $7,493M	NPVE $7,653M	NPVE $7,788M

$8.00

$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
Expansion	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**
2029 NGCT (2)	2029 DSM SEP	2029 NGCT	2025 DSM SEP	2025 DSM SEP	2029 Coal CCS (2)	2029 Coal CCS (2)	2029 Nuclear (2)	2029 Nuclear (2)	2029 Nuclear (2)
2029 Nuclear	2029 NGCT (2)	2029 Nuclear (2)	2029 NGCT	2029 NGCT	2029 NGCC CCS (2)	2029 NGCC CCS (2)	2029 NGCC CCS (2)	2029 NGCC CCS	2029 NGCC CCS
2030 DSM SEP	2029 Nuclear	2032 DSM SEP	2029 Nuclear (2)	2029 Nuclear (2)	2036 Tier I Wind	2036 Tier I Wind	2030 Nuclear	2030 NGCC CCS	2030 NGCC CCS
2036 Tier I Solar	2036 Tier I Solar	2036 Tier I Solar	2036 Tier I Solar	2036 Tier I Solar	2039 Tier I Wind (*)	2038 Tier I Wind (*)	2035 Tier I Wind (*)	2035 Tier I Wind (*)	2035 Tier I Wind (*)
2041 Tier I Wind (2)	2040 Tier I Wind	2041 Tier I Wind (2)	2041 Tier I Wind (2)	2041 Tier I Wind (2)	2041 Tier I Wind	2041 Tier I Wind	2037 Coal CCS	2036 Coal CCS	2036 Coal CCS
	2041 Tier I Wind						2041 Tier I Solar	2041 Tier I Solar	2041 Tier I Solar
Coal Retirement	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**
2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1
2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2
2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1
2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4
CO2 557K	CO2 490K	CO2 256K	CO2 256K	CO2 258K	CO2 145K	CO2 185K	CO2 73K	CO2 74K	CO2 74K
NPV $2,719M	NPV $2,941M	NPV $3,302M	NPV $3,473M	NPV $3,642M	NPV $3,945M	NPV $4,087M	NPV $4,277M	NPV $4,451M	NPV $4,599M
NPVE $5,376M	NPVE $5,857M	NPVE $6,260M	NPVE $6,607M	NPVE $6,942M	NPVE $7,259M	NPVE $7,460M	NPVE $7,622M	NPVE $7,810M	NPVE $7,976M

$9.00

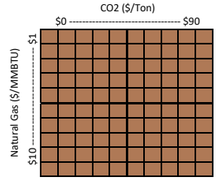
$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
Expansion	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**
2029 NGCT	2029 DSM SEP	2029 NGCT	2025 DSM SEP	2025 DSM SEP	2023 DSM SEP	2023 DSM SEP	2029 Nuclear (2)	2029 Nuclear (2)	2029 Nuclear (2)
2029 Coal CCS (2)	2029 Tier I Battery (3)	2029 Nuclear (2)	2029 NGCT	2029 NGCT	2029 Tier I Battery (2)	2029 Nuclear (2)	2029 NGCC CCS	2029 NGCC CCS	2029 NGCC CCS
2030 DSM SEP	2029 Nuclear	2030 DSM SEP	2029 Nuclear (2)	2029 Nuclear (2)	2029 Nuclear (2)	2029 NGCC CCS	2030 NGCC CCS	2030 NGCC CCS	2030 NGCC CCS
2034 Tier I Solar	2030 Tier I Battery	2036 Tier I Solar	2036 Tier I Solar	2036 Tier I Solar	2034 Coal CCS	2035 Coal CCS	2035 Tier I Wind (*)	2035 Tier I Wind (*)	2035 Tier I Wind (*)
2041 Tier I Wind (2)	2034 Nuclear	2041 Tier I Wind (2)	2041 Tier I Wind (2)	2041 Tier I Wind (2)	2036 Tier I Wind	2037 Tier I Wind	2036 Coal CCS	2036 Coal CCS	2036 Coal CCS
	2036 Tier I Wind				2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Solar	2041 Tier I Solar	2041 Tier I Solar
	2041 Tier I Wind (2)								
Coal Retirement	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**
2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1
2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2
2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1
2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4
CO2 295K	CO2 206K	CO2 256K	CO2 256K	CO2 256K	CO2 166K	CO2 132K	CO2 72K	CO2 73K	CO2 74K
NPV $2,943M	NPV $3,144M	NPV $3,350M	NPV $3,521M	NPV $3,692M	NPV $3,968M	NPV $4,094M	NPV $4,321M	NPV $4,473M	NPV $4,633M
NPVE $5,571M	NPVE $5,983M	NPVE $6,373M	NPVE $6,723M	NPVE $7,080M	NPVE $7,389M	NPVE $7,578M	NPVE $7,754M	NPVE $7,906M	NPVE $8,099M

$10.00

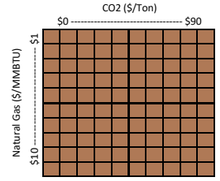
$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
Expansion	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**
2029 NGCT	2029 DSM SEP	2029 NGCT	2025 DSM SEP	2025 DSM SEP	2023 DSM SEP	2023 DSM SEP	2029 Nuclear (2)	2029 Nuclear (2)	2029 Nuclear (2)
2029 Coal CCS (2)	2029 Tier I Battery (3)	2029 Nuclear (2)	2029 NGCT	2029 Tier I Battery (2)	2029 Tier I Battery (2)	2029 Nuclear (2)	2029 NGCC CCS	2029 NGCC CCS	2029 NGCC CCS
2030 DSM SEP	2029 Nuclear	2030 DSM SEP	2029 Nuclear (2)	2029 Nuclear (2)	2029 Nuclear (2)	2029 NGCC CCS	2030 Coal CCS	2030 Coal CCS	2030 Coal CCS
2034 Tier I Solar	2030 Tier I Battery	2036 Tier I Solar	2036 Tier I Solar	2034 Coal CCS	2034 Coal CCS	2034 Coal CCS	2035 Tier I Wind (*)	2035 Tier I Wind (*)	2035 Tier I Wind (*)
2041 Tier I Wind (2)	2033 Nuclear	2041 Tier I Wind (2)	2041 Tier I Wind (2)	2038 Tier I Wind	2036 Tier I Wind	2036 Tier I Wind	2037 NGCC CCS	2036 NGCC CCS	2036 NGCC CCS
	2036 Tier I Wind			2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Solar	2041 Tier I Solar	2041 Tier I Solar
	2041 Tier I Wind (2)								
Coal Retirement	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**
2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1
2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2
2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1
2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4
CO2 295K	CO2 206K	CO2 256K	CO2 256K	CO2 164K	CO2 164K	CO2 112K	CO2 70K	CO2 72K	CO2 73K
NPV $2,984M	NPV $3,216M	NPV $3,399M	NPV $3,569M	NPV $3,850M	NPV $4,007M	NPV $4,158M	NPV $4,395M	NPV $4,530M	NPV $4,685M
NPVE $5,674M	NPVE $6,108M	NPVE $6,485M	NPVE $6,834M	NPVE $7,224M	NPVE $7,513M	NPVE $7,685M	NPVE $7,876M	NPVE $8,031M	NPVE $8,185M

Resource Summary Tables

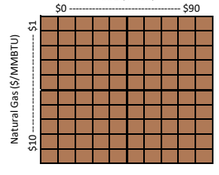
GGS 1



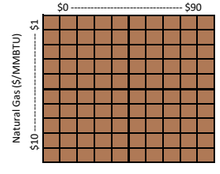
GGS 2



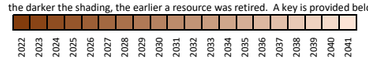
LRS 1



WS 4

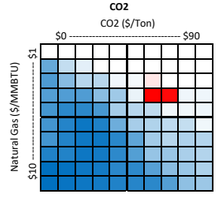


Notes:
1) Shaded cells indicate a resource's retirement within the 2022 - 2041 study period;
the darker the shading, the earlier a resource was retired. A key is provided below:

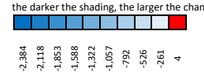


Comparison to Base Case

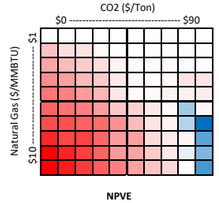
CO2



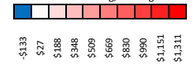
Notes:
1) Shaded cells indicate the change in CO2 emissions (thousand tons) for year 2040, relative to the base case;
the darker the shading, the larger the change in emissions. A key is provided below:



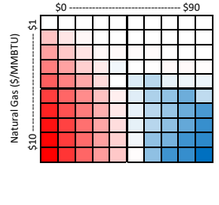
NPV



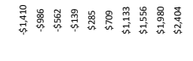
Notes:
1) Shaded cells indicate the change in total production costs ($M) over the 2022 - 2041 study period, relative to the base case;
the darker the shading, the larger the change in cost. A key is provided below:



NPVE



Notes:
1) Shaded cells indicate the change in total production costs ($M) over the 2022 - 2041 study plus the subsequent 30-year extension period,
relative to the base case; the darker the shading, the larger the change in cost. A key is provided below:



EGEAS Expansion Plans

Sensitivity 5: Retire Laramie River Station in 2029

Natural Gas Price ($/MMBTU, 2022 $) × **CO2 Value ($/Short Ton, 2022 $)**

$1.00 / $0.00

Expansion
2029 NGCT
2029 Tier I Battery (4)
2034 NGCT
2041 DSM SEP
2041 RICE

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1
2029 WS 4

CO2 1,394K
NPV $1,462M
NPVE $2,441M

$1.00 / $10.00

Expansion
2029 NGCT
2029 Tier I Battery (4)
2034 NGCT
2041 Tier I Wind (2)

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1
2029 WS 4

CO2 1,345K
NPV $1,708M
NPVE $3,069M

$1.00 / $20.00

Expansion
2029 Tier I Battery (4)
2029 NGCC CCS
2034 NGCC CCS
2039 DSM SEP
2041 Tier I Wind

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1
2029 WS 4

CO2 609K
NPV $1,978M
NPVE $3,525M

$1.00 / $30.00

Expansion
2029 NGCC CCS (2)
2031 NGCC CCS
2041 Tier I Wind

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1
2029 WS 4

CO2 523K
NPV $2,160M
NPVE $3,839M

$1.00 / $40.00

Expansion
2029 NGCC CCS (2)
2031 NGCC CCS
2041 Tier I Wind

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1
2029 WS 4

CO2 528K
NPV $2,275M
NPVE $4,077M

$1.00 / $50.00

Expansion
2029 DSM SEP
2029 NGCC CCS (3)
2033 RICE
2036 Tier I Solar
2041 Tier I Wind

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1
2029 WS 4

CO2 423K
NPV $2,367M
NPVE $4,280M

$1.00 / $60.00

Expansion
2029 DSM SEP
2029 NGCC CCS (3)
2033 RICE
2036 Tier I Solar
2041 Tier I Wind

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1
2029 WS 4

CO2 423K
NPV $2,471M
NPVE $4,479M

$1.00 / $70.00

Expansion
2029 DSM SEP
2029 NGCC CCS (3)
2033 Tier I Solar
2039 Tier I Wind
2041 Tier I Wind

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1
2029 WS 4

CO2 394K
NPV $2,588M
NPVE $4,675M

$1.00 / $80.00

Expansion
2029 DSM SEP
2029 NGCC CCS (3)
2033 Tier I Solar
2039 Tier I Wind
2041 Tier I Wind

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1
2029 WS 4

CO2 393K
NPV $2,691M
NPVE $4,860M

$1.00 / $90.00

Expansion
2025 DSM SEP
2029 NGCC CCS (3)
2033 Tier I Solar
2039 Tier I Wind
2041 Tier I Wind

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1
2029 WS 4

CO2 391K
NPV $2,793M
NPVE $5,050M

$2.00 / $0.00

Expansion
2029 Tier I Battery (2)
2031 Tier I Battery
2034 NGCT

Coal Retirement
2029 LRS 1

CO2 1,933K
NPV $1,609M
NPVE $2,884M

$2.00 / $10.00

Expansion
2029 NGCT (2)
2033 Tier I Solar
2039 Tier I Wind
2041 Tier I Wind

Coal Retirement
2029 GGS 2
2029 LRS 1
2033 GGS 1

CO2 1,243K
NPV $1,938M
NPVE $3,678M

$2.00 / $20.00

Expansion
2029 Tier I Battery (4)
2034 NGCC CCS
2037 Tier I Wind
2041 DSM SEP
2041 Tier I Wind

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1

CO2 843K
NPV $2,227M
NPVE $4,164M

$2.00 / $30.00

Expansion
2029 DSM SEP
2029 NGCC CCS (2)
2033 RICE
2033 NGCC CCS
2036 Tier I Solar
2041 Tier I Wind

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1
2033 WS 4

CO2 424K
NPV $2,460M
NPVE $4,519M

$2.00 / $40.00

Expansion
2029 DSM SEP
2029 NGCC CCS (3)
2033 RICE
2036 Tier I Solar
2041 Tier I Wind

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1
2029 WS 4

CO2 425K
NPV $2,595M
NPVE $4,736M

$2.00 / $50.00

Expansion
2029 DSM SEP
2029 NGCC CCS (3)
2033 Tier I Solar
2039 Tier I Wind
2041 Tier I Wind

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1
2029 WS 4

CO2 398K
NPV $2,711M
NPVE $4,922M

$2.00 / $60.00

Expansion
2029 DSM SEP
2029 NGCC CCS (3)
2033 Tier I Solar
2039 Tier I Wind
2041 Tier I Wind

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1
2029 WS 4

CO2 397K
NPV $2,814M
NPVE $5,108M

$2.00 / $70.00

Expansion
2029 DSM SEP
2029 NGCC CCS (3)
2033 Tier I Solar
2039 Tier I Wind
2041 Tier I Wind

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1
2029 WS 4

CO2 397K
NPV $2,918M
NPVE $5,297M

$2.00 / $80.00

Expansion
2029 DSM SEP
2029 NGCC CCS (3)
2033 Tier I Solar
2038 Tier I Wind
2041 Tier I Wind

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1
2029 WS 4

CO2 395K
NPV $3,023M
NPVE $5,485M

$2.00 / $90.00

Expansion
2023 DSM SEP
2029 NGCC CCS (3)
2033 Tier I Solar
2037 Tier I Wind
2041 Tier I Wind

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1
2029 WS 4

CO2 395K
NPV $3,125M
NPVE $5,668M

$3.00 / $0.00

Expansion
2029 Tier I Battery (2)
2031 Tier I Battery (2)
2041 Tier I Wind (2)

Coal Retirement
2029 LRS 1

CO2 1,875K
NPV $1,688M
NPVE $3,105M

$3.00 / $10.00

Expansion
2029 NGCT
2032 Tier I Solar
2039 Tier I Wind
2041 Tier I Wind

Coal Retirement
2029 LRS 1

CO2 1,538K
NPV $2,002M
NPVE $3,930M

$3.00 / $20.00

Expansion
2029 NGCT
2032 DSM SEP
2036 Tier I Wind
2036 NGCC CCS
2041 Tier I Wind (2)

Coal Retirement
2029 LRS 1
2036 GGS 2

CO2 959K
NPV $2,316M
NPVE $4,588M

$3.00 / $30.00

Expansion
2029 DSM SEP
2029 NGCC CCS (2)
2033 NGCC CCS
2036 Tier I Wind
2041 Tier I Wind

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1

CO2 540K
NPV $2,639M
NPVE $4,950M

$3.00 / $40.00

Expansion
2029 NGCC CCS (3)
2036 Tier I Wind
2041 Tier I Wind (2)

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1

CO2 526K
NPV $2,812M
NPVE $5,198M

$3.00 / $50.00

Expansion
2029 NGCC CCS (3)
2036 Tier I Wind
2041 Tier I Wind (2)

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1

CO2 491K
NPV $2,958M
NPVE $5,437M

$3.00 / $60.00

Expansion
2029 NGCC CCS (2)
2032 WS4 CCS Upgrade
2036 Tier I Wind
2041 Tier I Solar

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1

CO2 394K
NPV $3,092M
NPVE $5,652M

$3.00 / $70.00

Expansion
2025 DSM SEP
2029 NGCC CCS (3)
2036 Tier I Wind
2040 Tier I Solar
2041 Tier I Wind

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1
2040 WS 4

CO2 394K
NPV $3,205M
NPVE $5,878M

$3.00 / $80.00

Expansion
2023 DSM SEP
2029 NGCC CCS (3)
2033 Tier I Solar
2036 Tier I Wind
2041 Tier I Wind

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1
2031 WS 4

CO2 394K
NPV $3,340M
NPVE $6,083M

$3.00 / $90.00

Expansion
2023 DSM SEP
2029 NGCC CCS (3)
2033 Tier I Solar
2036 Tier I Wind
2041 Tier I Wind

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1
2029 WS 4

CO2 395K
NPV $3,441M
NPVE $6,267M

$4.00 / $0.00

Expansion
2029 Tier I Battery (2)
2031 Tier I Battery (2)
2036 Tier I Wind
2041 Tier I Wind

Coal Retirement
2029 LRS 1

CO2 1,839K
NPV $1,758M
NPVE $3,302M

$4.00 / $10.00

Expansion
2029 NGCT
2032 Tier I Solar
2039 Tier I Wind
2041 Tier I Wind

Coal Retirement
2029 LRS 1

CO2 1,686K
NPV $2,052M
NPVE $4,111M

$4.00 / $20.00

Expansion
2029 NGCT
2032 Tier I Solar
2039 Tier I Wind
2041 Tier I Wind

Coal Retirement
2029 LRS 1

CO2 1,541K
NPV $2,397M
NPVE $4,861M

$4.00 / $30.00

Expansion
2029 NGCC CCS
2030 DSM SEP
2034 NGCC CCS
2036 Tier I Wind
2041 Tier I Wind

Coal Retirement
2029 LRS 1
2035 GGS 2

CO2 805K
NPV $2,739M
NPVE $5,424M

$4.00 / $40.00

Expansion
2029 NGCC CCS
2030 NGCC CCS
2032 NGCC CCS
2036 Tier I Wind
2041 Tier I Wind

Coal Retirement
2029 LRS 1
2030 GGS 2

CO2 584K
NPV $2,985M
NPVE $5,736M

$4.00 / $50.00

Expansion
2029 NGCC CCS (3)
2036 Tier I Wind
2041 Tier I Wind (2)

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1

CO2 551K
NPV $3,130M
NPVE $5,872M

$4.00 / $60.00

Expansion
2029 NGCC CCS (3)
2036 Tier I Wind
2041 Tier I Wind (2)

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1

CO2 554K
NPV $3,278M
NPVE $6,112M

$4.00 / $70.00

Expansion
2029 NGCC CCS (3)
2036 Tier I Wind
2038 Tier I Wind (*)
2041 Tier I Wind

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1

CO2 385K
NPV $3,447M
NPVE $6,370M

$4.00 / $80.00

Expansion
2029 NGCC CCS (3)
2029 WS4 CCS Upgrade
2036 Tier I Wind
2041 Tier I Solar

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1

CO2 386K
NPV $3,569M
NPVE $6,567M

$4.00 / $90.00

Expansion
2029 NGCC CCS (3)
2029 WS4 CCS Upgrade
2036 Tier I Wind
2041 Tier I Solar

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1

CO2 386K
NPV $3,672M
NPVE $6,746M

$5.00 / $0.00

Expansion
2029 NGCT
2032 Tier I Solar
2039 Tier I Wind
2041 Tier I Wind

Coal Retirement
2029 LRS 1

CO2 1,717K
NPV $1,765M
NPVE $3,471M

$5.00 / $10.00

Expansion
2029 NGCT
2032 Tier I Solar
2039 Tier I Wind
2041 Tier I Wind

Coal Retirement
2029 LRS 1

CO2 1,669K
NPV $2,100M
NPVE $4,252M

$5.00 / $20.00

Expansion
2029 NGCT
2032 DSM SEP
2036 Tier I Solar
2041 Tier I Wind (2)

Coal Retirement
2029 LRS 1

CO2 1,748K
NPV $2,408M
NPVE $5,024M

$5.00 / $30.00

Expansion
2029 NGCC CCS
2030 NGCC CCS
2036 Tier I Wind
2041 Tier I Wind (2)

Coal Retirement
2029 LRS 1

CO2 1,085K
NPV $2,846M
NPVE $5,678M

$5.00 / $40.00

Expansion
2029 NGCC CCS
2030 NGCC CCS
2034 NGCC CCS
2036 Tier I Wind
2041 Tier I Wind

Coal Retirement
2029 LRS 1
2034 GGS 2

CO2 720K
NPV $3,120M
NPVE $6,146M

$5.00 / $50.00

Expansion
2029 NGCC CCS (2)
2031 NGCC CCS
2036 Tier I Wind
2041 Tier I Wind

Coal Retirement
2029 GGS 2
2029 LRS 1

CO2 598K
NPV $3,319M
NPVE $6,466M

$5.00 / $60.00

Expansion
2029 NGCC CCS (2)
2031 NGCC CCS
2036 Tier I Wind
2039 Tier I Wind (*)
2041 Tier I Wind

Coal Retirement
2029 GGS 2
2029 LRS 1
2033 GGS 1

CO2 531K
NPV $3,475M
NPVE $6,584M

$5.00 / $70.00

Expansion
2029 NGCC CCS (3)
2036 Tier I Wind
2038 Tier I Wind (*)
2041 Tier I Wind

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1

CO2 536K
NPV $3,615M
NPVE $6,797M

$5.00 / $80.00

Expansion
2029 NGCC CCS (3)
2029 WS4 CCS Upgrade
2036 Tier I Wind
2041 Tier I Solar

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1

CO2 372K
NPV $3,744M
NPVE $7,028M

$5.00 / $90.00

Expansion
2029 NGCC CCS (3)
2029 WS4 CCS Upgrade
2036 Tier I Wind
2041 Tier I Solar

Coal Retirement
2029 GGS 1
2029 GGS 2
2029 LRS 1

CO2 384K
NPV $3,895M
NPVE $7,256M

Resource Summary Tables

Notes:

1) Shaded cells indicate a resource's inclusion within the 2022 - 2041 study period; the darker the shading, the earlier a resource was selected. A key is provided below:

2) Data reflects EGEAS' lowest cost expansion plan for each scenario, including the 30-year extension period.
3) *CO2* values reflect LES' total CO2 emissions for year 2040 in units of tons.
4) *NPV* values reflect LES' total production costs over the 2022 - 2041 study period.
5) *NPVE* values reflect LES' total production costs over the 2022 - 2041 study period plus the subequent 30-year extension period.
6) Multiple selections of the same resource in the same year are denoted by (#).
7) Tier I Wind that was installed early as Tier II Wind - but utilmately graduated to Tier I status following the end of a contract for an existing Tier I Wind resource - is denoted by (*).

EGEAS Expansion Plans

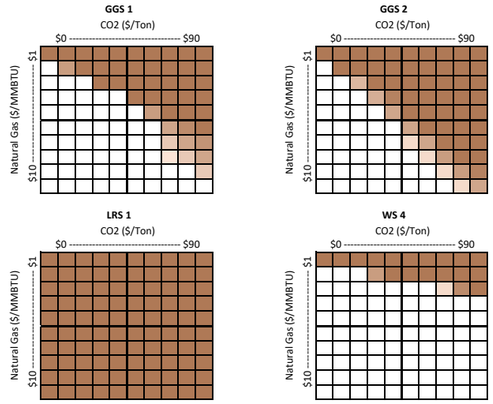
Sensitivity 5: Retire Laramie River Station in 2029

CO2 Value ($/Short Ton, 2022 $)

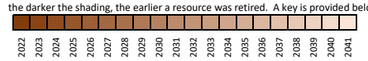
Natural Gas Price ($/MMBTU, 2022 $)

	$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
$6.00	**Expansion** 2029 NGCT 2032 Tier I Solar 2039 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 LRS 1 CO2 1,718K NPV $1,817M NPVE $3,607M	**Expansion** 2029 NGCT 2032 DSM SEP 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 LRS 1 CO2 1,768K NPV $2,123M NPVE $4,387M	**Expansion** 2029 NGCT 2032 DSM SEP 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 LRS 1 CO2 1,772K NPV $2,460M NPVE $5,187M	**Expansion** 2029 NGCC CCS 2030 NGCC CCS 2036 Tier I Wind 2041 Tier I Wind (2) **Coal Retirement** 2029 LRS 1 CO2 1,255K NPV $2,933M NPVE $5,907M	**Expansion** 2029 NGCC CCS 2030 NGCC CCS 2036 Tier I Wind 2039 Tier I Wind (*) 2041 Tier I Wind **Coal Retirement** 2029 LRS 1 CO2 1,039K NPV $3,185M NPVE $6,413M	**Expansion** 2029 NGCC CCS (2) 2034 NGCC CCS 2036 Tier I Wind 2039 Tier I Wind (*) **Coal Retirement** 2029 LRS 1 2034 GGS 2 CO2 729K NPV $3,430M NPVE $6,829M	**Expansion** 2029 NGCC CCS (2) 2029 WS4 CCS Upgrade 2033 Tier I Solar 2036 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 2 2029 LRS 1 CO2 464K NPV $3,675M NPVE $7,168M	**Expansion** 2029 NGCC CCS (2) 2031 NGCC CCS 2034 Tier I Wind (*) 2036 Nuclear 2041 Tier I Wind **Coal Retirement** 2029 GGS 2 2029 LRS 1 2034 GGS 1 CO2 318K NPV $3,879M NPVE $7,270M	**Expansion** 2029 NGCC CCS (2) 2031 NGCC CCS 2033 Tier I Wind (*) 2036 Nuclear 2041 Tier I Wind **Coal Retirement** 2029 GGS 2 2029 LRS 1 2031 GGS 1 CO2 317K NPV $4,020M NPVE $7,460M	**Expansion** 2029 NGCC CCS (3) 2033 Tier I Wind (*) 2036 Nuclear 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 317K NPV $4,122M NPVE $7,615M
$7.00	**Expansion** 2029 NGCT 2032 Tier I Solar 2039 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 LRS 1 CO2 1,719K NPV $1,869M NPVE $3,747M	**Expansion** 2029 NGCT 2032 DSM SEP 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 LRS 1 CO2 1,768K NPV $2,175M NPVE $4,519M	**Expansion** 2029 NGCT 2032 DSM SEP 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 LRS 1 CO2 1,772K NPV $2,511M NPVE $5,320M	**Expansion** 2029 NGCT 2030 DSM SEP 2036 Tier I Solar 2040 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 LRS 1 CO2 1,641K NPV $2,851M NPVE $6,102M	**Expansion** 2025 DSM SEP 2029 Nuclear 2035 Tier I Solar 2038 RICE 2038 WS4 CCS Upgrade 2041 Tier I Wind (2) **Coal Retirement** 2029 LRS 1 CO2 769K NPV $3,293M NPVE $6,578M	**Expansion** 2029 Nuclear 2031 Nuclear 2034 Tier I Wind (*) 2036 NGCC CCS 2040 Tier I Wind **Coal Retirement** 2029 LRS 1 2040 GGS 2 CO2 769K NPV $3,665M NPVE $6,985M	**Expansion** 2029 Nuclear 2029 NGCC CCS 2034 Nuclear 2035 Tier I Wind (*) 2038 Tier I Wind **Coal Retirement** 2029 LRS 1 2034 GGS 2 CO2 734K NPV $3,866M NPVE $7,379M	**Expansion** 2029 Nuclear 2029 NGCC CCS 2031 Nuclear 2035 Tier I Wind 2038 NGCC CCS 2041 Tier I Wind **Coal Retirement** 2029 GGS 2 2029 LRS 1 2038 GGS 1 CO2 408K NPV $4,091M NPVE $7,497M	**Expansion** 2029 Nuclear 2029 NGCC CCS 2031 Nuclear 2034 Tier I Wind (*) 2036 NGCC CCS 2041 Tier I Wind **Coal Retirement** 2029 GGS 2 2029 LRS 1 2034 GGS 1 CO2 340K NPV $4,279M NPVE $7,760M	**Expansion** 2029 Nuclear 2029 NGCC CCS 2031 Nuclear 2033 Tier I Wind (*) 2036 NGCC CCS 2041 Tier I Wind **Coal Retirement** 2029 GGS 2 2029 LRS 1 2032 GGS 1 CO2 312K NPV $4,433M NPVE $7,962M
$8.00	**Expansion** 2029 NGCT 2032 DSM SEP 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 LRS 1 CO2 1,807K NPV $1,892M NPVE $3,884M	**Expansion** 2029 NGCT 2032 DSM SEP 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 LRS 1 CO2 1,768K NPV $2,225M NPVE $4,650M	**Expansion** 2029 NGCT 2032 DSM SEP 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 LRS 1 CO2 1,772K NPV $2,562M NPVE $5,450M	**Expansion** 2029 Coal CCS 2030 Coal CCS 2036 Tier I Wind 2041 Tier I Wind (2) **Coal Retirement** 2029 LRS 1 CO2 1,352K NPV $3,238M NPVE $6,173M	**Expansion** 2029 Coal CCS 2030 Coal CCS 2036 Tier I Wind 2039 Tier I Wind (*) 2041 Tier I Wind **Coal Retirement** 2029 LRS 1 CO2 1,290K NPV $3,449M NPVE $6,612M	**Expansion** 2029 Nuclear 2031 Nuclear 2035 Tier I Wind (*) 2036 Coal CCS 2041 Tier I Wind **Coal Retirement** 2029 LRS 1 CO2 962K NPV $3,718M NPVE $7,069M	**Expansion** 2029 Nuclear (2) 2034 Tier I Wind (*) 2036 Coal CCS 2040 Tier I Wind **Coal Retirement** 2029 LRS 1 2040 GGS 2 CO2 766K NPV $3,961M NPVE $7,430M	**Expansion** 2029 Nuclear (2) 2033 NGCC CCS 2035 Tier I Wind (*) 2036 Coal CCS 2041 Tier I Solar 2041 Coal CCS **Coal Retirement** 2029 LRS 1 2033 GGS 2 2041 GGS 1 CO2 773K NPV $4,119M NPVE $7,553M	**Expansion** 2029 Nuclear (2) 2031 NGCC CCS 2034 Tier I Wind (*) 2038 Coal CCS 2041 Tier I Wind **Coal Retirement** 2029 GGS 2 2029 LRS 1 2038 GGS 1 CO2 423K NPV $4,335M NPVE $7,832M	**Expansion** 2029 Nuclear (2) 2031 NGCC CCS 2033 Tier I Wind (*) 2036 Coal CCS 2041 Tier I Wind **Coal Retirement** 2029 GGS 2 2029 LRS 1 2034 GGS 1 CO2 367K NPV $4,549M NPVE $8,136M
$9.00	**Expansion** 2029 NGCT 2032 DSM SEP 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 LRS 1 CO2 1,807K NPV $1,943M NPVE $4,019M	**Expansion** 2029 NGCT 2032 DSM SEP 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 LRS 1 CO2 1,769K NPV $2,276M NPVE $4,781M	**Expansion** 2029 NGCT 2030 DSM SEP 2036 Tier I Solar 2040 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 LRS 1 CO2 1,647K NPV $2,615M NPVE $5,581M	**Expansion** 2029 Coal CCS 2030 Coal CCS 2036 Tier I Wind 2041 Tier I Wind (2) **Coal Retirement** 2029 LRS 1 CO2 1,352K NPV $3,268M NPVE $6,239M	**Expansion** 2029 Coal CCS 2030 Coal CCS 2036 Tier I Wind 2039 Tier I Wind (*) 2041 Tier I Wind **Coal Retirement** 2029 LRS 1 CO2 1,313K NPV $3,477M NPVE $6,666M	**Expansion** 2029 Nuclear 2031 Nuclear 2035 Tier I Wind (*) 2036 Coal CCS 2041 Tier I Wind **Coal Retirement** 2029 LRS 1 CO2 1,027K NPV $3,730M NPVE $7,046M	**Expansion** 2029 Nuclear (2) 2034 Tier I Wind (*) 2036 Nuclear 2041 Tier I Wind **Coal Retirement** 2029 LRS 1 CO2 899K NPV $3,957M NPVE $7,464M	**Expansion** 2029 Nuclear (2) 2032 Tier I Wind (*) 2036 Coal CCS 2040 Tier I Wind **Coal Retirement** 2029 LRS 1 2040 GGS 2 CO2 770K NPV $4,166M NPVE $7,812M	**Expansion** 2029 Nuclear (2) 2033 Coal CCS 2035 Tier I Wind 2041 Nuclear **Coal Retirement** 2029 LRS 1 2033 GGS 2 CO2 777K NPV $4,398M NPVE $8,090M	**Expansion** 2029 Nuclear (2) 2031 NGCC CCS 2033 Tier I Wind (*) 2038 Nuclear 2041 Tier I Wind **Coal Retirement** 2029 LRS 1 2030 GGS 2 2038 GGS 1 CO2 398K NPV $4,529M NPVE $8,130M
$10.00	**Expansion** 2029 NGCT 2032 DSM SEP 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 LRS 1 CO2 1,807K NPV $1,995M NPVE $4,155M	**Expansion** 2029 NGCT 2032 DSM SEP 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 LRS 1 CO2 1,769K NPV $2,327M NPVE $4,912M	**Expansion** 2029 NGCT 2030 DSM SEP 2036 Tier I Solar 2040 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 LRS 1 CO2 1,647K NPV $2,665M NPVE $5,711M	**Expansion** 2029 Coal CCS 2030 Coal CCS 2036 Tier I Wind 2041 Tier I Wind (2) **Coal Retirement** 2029 LRS 1 CO2 1,352K NPV $3,299M NPVE $6,304M	**Expansion** 2029 Coal CCS 2030 Coal CCS 2036 Tier I Wind 2039 Tier I Wind (*) 2041 Tier I Wind **Coal Retirement** 2029 LRS 1 CO2 1,312K NPV $3,507M NPVE $6,724M	**Expansion** 2029 Nuclear 2031 Nuclear 2035 Tier I Wind (*) 2036 Coal CCS 2041 Tier I Wind **Coal Retirement** 2029 LRS 1 CO2 1,045K NPV $3,753M NPVE $7,079M	**Expansion** 2029 Nuclear (2) 2034 Tier I Wind (*) 2036 Coal CCS 2041 Tier I Wind **Coal Retirement** 2029 LRS 1 CO2 1,004K NPV $3,954M NPVE $7,433M	**Expansion** 2029 Nuclear (2) 2033 NGCC CCS 2035 Tier I Wind (*) 2041 Tier I Solar 2041 Coal CCS **Coal Retirement** 2029 LRS 1 CO2 894K NPV $4,160M NPVE $7,841M	**Expansion** 2029 Nuclear (2) 2031 NGCC CCS 2034 Tier I Wind (*) 2038 Coal CCS 2041 Tier I Wind **Coal Retirement** 2029 LRS 1 2040 GGS 2 CO2 809K NPV $4,374M NPVE $8,132M	**Expansion** 2029 Nuclear (2) 2031 NGCC CCS 2033 Tier I Wind (*) 2036 Coal CCS 2041 Tier I Wind **Coal Retirement** 2029 LRS 1 2034 GGS 2 CO2 781K NPV $4,584M NPVE $8,385M

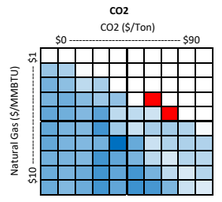
Resource Summary Tables



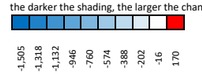
Notes:
1) Shaded cells indicate a resource's retirement within the 2022 - 2041 study period; the darker the shading, the earlier a resource was retired. A key is provided below:

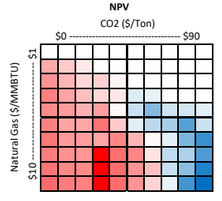


Comparison to Base Case

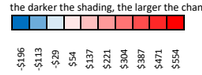


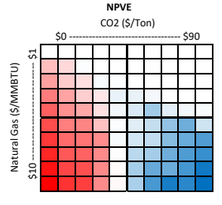
Notes:
1) Shaded cells indicate the change in CO2 emissions (thousand tons) for year 2040, relative to the base case; the darker the shading, the larger the change in emissions. A key is provided below:



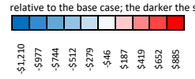


Notes:
1) Shaded cells indicate the change in total production costs ($M) over the 2022 - 2041 study period, relative to the base case; the darker the shading, the larger the change in cost. A key is provided below:





Notes:
1) Shaded cells indicate the change in total production costs ($M) over the 2022 - 2041 study plus the subsequent 30-year extension period, relative to the base case; the darker the shading, the larger the change in cost. A key is provided below:



EGEAS Expansion Plans

Sensitivity 6: Retire All LES Natural Gas Resources in 2029

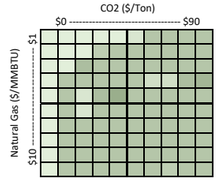
CO2 Value ($/Short Ton, 2022 $)

Natural Gas Price ($/MMBTU, 2022 $)

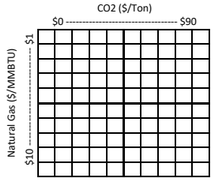
	$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
$1.00	**Expansion** 2029 NGCT (3) 2029 RICE 2029 Tier I Battery (4) 2029 NGCC CCS (2) 2032 RICE 2034 NGCC CCS 2039 Tier I Solar 2041 RICE 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 210K NPV $2,267M NPVE $3,925M	**Expansion** 2029 NGCT (3) 2029 RICE 2029 Tier I Battery (4) 2029 NGCC CCS (2) 2032 RICE 2034 NGCC CCS 2039 Tier I Solar 2041 RICE 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 236K NPV $2,411M NPVE $4,200M	**Expansion** 2029 DSM SEP 2029 NGCT (3) 2029 Tier I Battery (4) 2029 NGCC CCS (2) 2033 NGCC CCS 2037 RICE 2039 Tier I Solar 2041 RICE 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 279K NPV $2,520M NPVE $4,414M	**Expansion** 2029 DSM SEP 2029 NGCT (3) 2029 Tier I Battery (4) 2029 NGCC CCS (2) 2033 NGCC CCS 2037 RICE 2039 Tier I Solar 2041 RICE 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 378K NPV $2,638M NPVE $4,637M	**Expansion** 2029 DSM SEP 2029 NGCT (3) 2029 Tier I Battery (4) 2029 NGCC CCS (2) 2033 NGCC CCS 2037 RICE 2039 Tier I Solar 2041 RICE 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 390K NPV $2,752M NPVE $4,843M	**Expansion** 2029 DSM SEP 2029 NGCT (2) 2029 Tier I Battery (4) 2029 NGCC CCS (3) 2031 RICE 2034 NGCT 2039 RICE (2) 2040 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 411K NPV $2,862M NPVE $5,050M	**Expansion** 2029 DSM SEP 2029 NGCT (2) 2029 Tier I Battery (4) 2029 NGCC CCS (3) 2031 RICE 2034 NGCT 2036 Tier I Wind 2039 RICE (2) 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 416K NPV $2,970M NPVE $5,235M	**Expansion** 2029 DSM SEP 2029 NGCT (2) 2029 Tier I Battery (4) 2029 NGCC CCS (3) 2031 RICE 2034 NGCT 2036 Tier I Wind 2039 RICE (2) 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 420K NPV $3,068M NPVE $5,420M	**Expansion** 2029 DSM SEP 2029 NGCT (2) 2029 Tier I Battery (4) 2029 NGCC CCS (3) 2031 RICE 2034 NGCT 2036 Tier I Wind 2039 RICE (2) 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 423K NPV $3,166M NPVE $5,606M	**Expansion** 2025 DSM SEP 2029 NGCT (2) 2029 Tier I Battery (4) 2029 NGCC CCS (3) 2031 RICE 2034 NGCT 2036 Tier I Wind 2039 RICE (2) 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 424K NPV $3,264M NPVE $5,795M
$2.00	**Expansion** 2029 NGCT (2) 2029 Tier I Battery (4) 2034 NGCT 2039 Tier I Solar 2040 RICE 2041 Tier I Wind **Coal Retirement** CO2 2,337K NPV $1,905M NPVE $3,409M	**Expansion** 2029 NGCT (3) 2029 Tier I Battery (3) 2031 Tier I Battery 2034 NGCC CCS 2039 DSM SEP 2039 RICE (2) 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2033 GGS 1 CO2 1,437K NPV $2,360M NPVE $4,420M	**Expansion** 2029 NGCT (2) 2029 Tier I Battery (4) 2029 NGCC CCS 2032 NGCT 2032 NGCC CCS 2036 Tier I Solar 2039 DSM SEP 2039 RICE 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2032 LRS 1 CO2 559K NPV $2,717M NPVE $4,937M	**Expansion** 2029 DSM SEP 2029 NGCT (3) 2029 Tier I Battery (4) 2029 NGCC CCS 2032 NGCC CCS 2033 NGCC CCS (2) 2037 Tier I Wind 2039 RICE (3) 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2033 WS 4 CO2 405K NPV $2,956M NPVE $5,287M	**Expansion** 2029 DSM SEP 2029 NGCT (3) 2029 Tier I Battery (4) 2029 NGCC CCS (3) 2031 RICE 2034 NGCT 2036 Tier I Wind 2039 RICE (2) 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 417K NPV $3,103M NPVE $5,502M	**Expansion** 2029 DSM SEP 2029 NGCT (2) 2029 Tier I Battery (4) 2029 NGCC CCS (3) 2031 RICE 2034 NGCT 2036 Tier I Wind 2039 Tier I Solar 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 393K NPV $3,206M NPVE $5,674M	**Expansion** 2029 DSM SEP 2029 NGCT (2) 2029 Tier I Battery (4) 2029 NGCC CCS (3) 2031 RICE 2034 NGCT 2036 Tier I Wind 2039 Tier I Solar 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 396K NPV $3,302M NPVE $5,848M	**Expansion** 2029 DSM SEP 2029 NGCT (2) 2029 Tier I Battery (4) 2029 NGCC CCS (3) 2031 RICE 2034 NGCT 2036 Tier I Wind 2039 Tier I Solar 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 397K NPV $3,401M NPVE $6,031M	**Expansion** 2025 DSM SEP 2029 NGCT (2) 2029 Tier I Battery (4) 2029 NGCC CCS (3) 2031 RICE 2034 NGCT 2036 Tier I Wind 2039 Tier I Solar 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 399K NPV $3,500M NPVE $6,214M	**Expansion** 2023 DSM SEP 2029 NGCT (3) 2029 Tier I Battery (2) 2029 NGCC CCS (3) 2030 Tier I Battery 2031 Tier I Battery 2036 Tier I Wind 2039 Coal CCS 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 219K NPV $3,638M NPVE $6,445M
$3.00	**Expansion** 2029 NGCT (2) 2029 Tier I Battery (4) 2034 NGCT 2039 Tier I Solar 2040 DSM SEP 2041 Tier I Wind **Coal Retirement** CO2 2,646K NPV $1,928M NPVE $3,462M	**Expansion** 2029 NGCT (2) 2029 Tier I Battery (4) 2034 NGCT 2039 Tier I Solar 2040 DSM SEP 2041 Tier I Wind **Coal Retirement** CO2 2,176K NPV $2,333M NPVE $4,434M	**Expansion** 2029 NGCT (3) 2029 NGCC CCS 2031 DSM SEP 2035 Tier I Wind (*) 2036 NGCC CCS 2041 Tier I Wind **Coal Retirement** 2036 GGS 2 CO2 1,110K NPV $2,706M NPVE $5,212M	**Expansion** 2029 NGCT 2029 Tier I Battery (4) 2029 NGCC CCS (2) 2031 DSM SEP 2034 NGCT 2036 Tier I Wind 2039 Tier I Solar 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 CO2 769K NPV $3,026M NPVE $5,622M	**Expansion** 2025 DSM SEP 2029 NGCT 2029 Tier I Battery (4) 2029 NGCC CCS (2) 2031 DSM SEP 2034 NGCT (2) 2036 Tier I Wind 2039 RICE 2039 Tier I Solar 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2034 LRS 1 CO2 627K NPV $3,256M NPVE $6,032M	**Expansion** 2025 DSM SEP 2029 NGCT 2029 Tier I Battery (4) 2029 NGCC CCS (2) 2029 Tier I Wind (2) 2034 NGCT 2036 Tier I Wind 2039 Tier I Solar 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 582K NPV $3,467M NPVE $6,364M	**Expansion** 2025 DSM SEP 2029 NGCT 2029 Tier I Battery (4) 2029 NGCC CCS (2) 2031 RICE 2034 NGCT 2036 Tier I Wind 2039 Tier I Solar 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 561K NPV $3,616M NPVE $6,651M	**Expansion** 2025 DSM SEP 2029 NGCT (2) 2029 Tier I Battery (4) 2029 NGCC CCS (2) 2031 RICE 2034 NGCT 2036 Tier I Wind 2039 Tier I Solar 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2040 WS 4 CO2 367K NPV $3,661M NPVE $6,599M	**Expansion** 2023 DSM SEP 2029 NGCT (2) 2029 Tier I Battery (3) 2029 Nuclear 2029 NGCC CCS (2) 2031 Tier I Battery 2035 Tier I Wind 2036 Nuclear 2039 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2031 WS 4 CO2 169K NPV $3,904M NPVE $6,814M	**Expansion** 2023 DSM SEP 2029 NGCT (2) 2029 Tier I Battery 2029 Nuclear 2029 NGCC CCS (2) 2031 Tier I Battery 2034 Tier I Wind (*) 2036 Nuclear 2039 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 205K NPV $4,011M NPVE $6,964M
$4.00	**Expansion** 2029 NGCT (2) 2029 Tier I Battery (4) 2034 NGCT 2039 Tier I Solar 2040 DSM SEP 2041 Tier I Wind **Coal Retirement** CO2 2,651K NPV $1,955M NPVE $3,533M	**Expansion** 2029 NGCT (2) 2029 Tier I Battery (4) 2034 NGCT 2036 Tier I Wind 2039 DSM SEP 2039 RICE 2041 RICE 2041 Tier I Wind **Coal Retirement** CO2 2,504K NPV $2,360M NPVE $4,545M	**Expansion** 2029 Tier I Battery (4) 2029 NGCC CCS (2) 2031 DSM SEP 2034 NGCC CCS 2036 Tier I Wind 2039 Tier I Solar 2041 RICE 2041 Tier I Wind **Coal Retirement** CO2 1,011K NPV $2,825M NPVE $5,324M	**Expansion** 2029 NGCT (3) 2029 NGCC CCS 2031 DSM SEP 2035 NGCC CCS 2036 Tier I Wind 2041 Tier I Wind (2) **Coal Retirement** 2035 GGS 2 CO2 1,148K NPV $3,067M NPVE $5,970M	**Expansion** 2025 DSM SEP 2029 NGCT 2029 Tier I Battery (2) 2029 NGCC CCS (2) 2030 Tier I Battery 2034 NGCT 2036 Tier I Wind 2039 Tier I Solar 2041 Tier I Wind **Coal Retirement** 2030 GGS 2 CO2 890K NPV $3,323M NPVE $6,349M	**Expansion** 2025 DSM SEP 2029 NGCT 2029 Tier I Battery (4) 2029 NGCC CCS (2) 2034 NGCT 2036 Tier I Wind 2039 Tier I Solar 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2040 LRS 1 CO2 724K NPV $3,561M NPVE $6,778M	**Expansion** 2025 DSM SEP 2029 NGCT (2) 2029 Tier I Battery (3) 2029 Nuclear 2029 NGCC CCS (2) 2031 Tier I Battery 2034 Nuclear 2036 Tier I Wind 2039 RICE (2) 2040 RICE 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2033 GGS 1 CO2 269K NPV $3,997M NPVE $7,197M	**Expansion** 2023 DSM SEP 2029 Tier I Battery (3) 2029 Nuclear 2029 NGCC CCS (2) 2034 Nuclear 2036 Tier I Wind 2039 NGCT 2040 NGCT 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2040 LRS 1 CO2 330K NPV $4,161M NPVE $7,453M	**Expansion** 2023 DSM SEP 2029 Tier I Battery (4) 2029 Nuclear 2029 NGCC CCS (2) 2033 Nuclear 2034 NGCT 2036 Tier I Wind 2037 RICE 2039 RICE (2) 2040 RICE 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2034 LRS 1 CO2 238K NPV $4,357M NPVE $7,683M	**Expansion** 2023 DSM SEP 2029 NGCT 2029 Tier I Battery (2) 2029 Nuclear 2029 NGCC CCS (2) 2030 Tier I Battery (2) 2031 Nuclear 2036 Tier I Wind 2037 RICE 2039 RICE (3) 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2030 LRS 1 CO2 220K NPV $4,538M NPVE $7,878M
$5.00	**Expansion** 2029 NGCT (2) 2029 Tier I Battery (4) 2034 NGCT 2039 Tier I Solar 2040 DSM SEP 2041 Tier I Wind **Coal Retirement** CO2 2,654K NPV $1,980M NPVE $3,599M	**Expansion** 2029 NGCT (2) 2029 Tier I Battery (4) 2034 NGCT 2036 Tier I Wind 2039 Tier I Solar 2041 Tier I Wind **Coal Retirement** CO2 2,510K NPV $2,394M NPVE $4,573M	**Expansion** 2029 NGCT (3) 2029 NGCC CCS 2031 DSM SEP 2035 Tier I Solar 2040 Tier I Wind 2041 Tier I Wind **Coal Retirement** CO2 2,323K NPV $2,740M NPVE $5,413M	**Expansion** 2029 DSM SEP 2029 NGCT 2029 NGCC CCS (3) 2032 RICE 2035 Tier I Wind 2036 Tier I Solar 2041 Tier I Wind **Coal Retirement** 2034 GGS 2 CO2 989K NPV $3,116M NPVE $5,945M	**Expansion** 2025 DSM SEP 2029 NGCT (2) 2029 NGCC CCS (2) 2033 Tier I Wind (*) 2034 Coal CCS 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 917K NPV $3,446M NPVE $6,588M	**Expansion** 2025 DSM SEP 2029 Tier I Battery (3) 2029 Nuclear 2029 NGCC CCS (2) 2031 Tier I Battery 2034 Nuclear 2036 Tier I Wind 2039 RICE (2) 2040 RICE 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2033 GGS 1 CO2 360K NPV $3,856M NPVE $6,952M	**Expansion** 2023 DSM SEP 2029 Tier I Battery (3) 2029 Nuclear 2029 NGCC CCS (2) 2034 Nuclear 2036 Tier I Wind 2039 NGCT 2040 NGCT 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2040 LRS 1 CO2 269K NPV $3,997M NPVE $7,197M	**Expansion** 2023 DSM SEP 2029 Tier I Battery (4) 2029 Nuclear 2029 NGCC CCS (2) 2033 Nuclear 2034 NGCT 2036 Tier I Wind 2037 RICE 2039 RICE (2) 2040 RICE 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2034 LRS 1 CO2 238K NPV $4,357M NPVE $7,683M	**Expansion** 2023 DSM SEP 2029 NGCT 2029 Tier I Battery (2) 2029 Nuclear 2029 NGCC CCS (2) 2030 Tier I Battery (2) 2031 Nuclear 2036 Tier I Wind 2037 RICE 2039 RICE (3) 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2030 LRS 1 CO2 220K NPV $4,538M NPVE $7,878M

Resource Summary Tables

Tier I Wind



Tier II Wind



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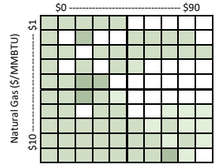
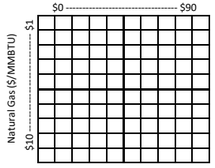
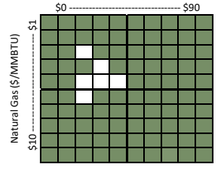


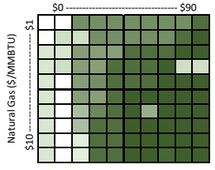
Tier II Solar



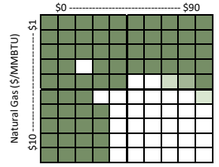
Tier I Battery



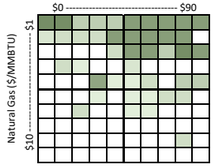
DSM SEP



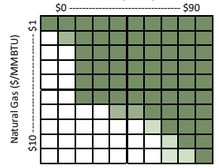
NGCT



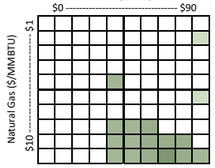
RICE



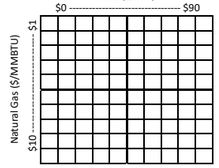
NGCC CCS



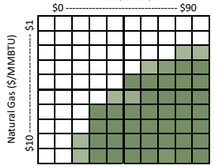
Coal CCS



WS4 CCS Upgrade



Nuclear



Notes:

1) Shaded cells indicate a resource's inclusion within the 2022 - 2041 study period; the darker the shading, the earlier a resource was selected. A key is provided below:

2) Data reflects EGEAS' lowest cost expansion plan for each scenario, including the 30-year extension period.
3) *CO2* values reflect LES' total CO2 emissions for year 2040 in units of tons.
4) *NPV* values reflect LES' total production costs over the 2022 - 2041 study period.
5) *NPVE* values reflect LES' total production costs over the 2022 - 2041 study period plus the subequent 30-year extension period.
6) Multiple selections of the same resource in the same year are denoted by (#).
7) Tier I Wind that was installed early as Tier II Wind - but utilmately graduated to Tier I status following the end of a contract for an existing Tier I Wind resource - is denoted by (*).

EGEAS Expansion Plans

Sensitivity 6: Retire All LES Natural Gas Resources in 2029

CO2 Value ($/Short Ton, 2022 $)

Natural Gas Price ($/MMBTU, 2022 $)

$6.00

$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
Expansion	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**
2029 NGCT (2)	2029 NGCT (2)	2029 NGCT (3)	2029 Tier I Battery (4)	2025 DSM SEP	2023 DSM SEP	2023 DSM SEP	2023 DSM SEP	2023 DSM SEP	2023 DSM SEP
2029 Tier I Battery (4)	2029 Tier I Battery (4)	2029 NGCC CCS	2029 NGCC CCS (2)	2029 Tier I Battery (2)	2029 Tier I Battery (4)	2029 Tier I Battery (3)	2029 Tier I Battery (3)	2029 Tier I Battery (3)	2029 Tier I Battery (4)
2034 NGCT	2034 NGCT	2031 DSM SEP	2029 NGCC CCS (3)	2031 Tier I Battery	2029 NGCC CCS (2)	2029 Nuclear	2029 Nuclear	2029 Nuclear	2029 Nuclear
2039 Tier I Solar	2036 Tier I Wind	2035 Tier I Solar	2031 Tier I Battery	2034 Nuclear	2033 Nuclear	2029 NGCC CCS (2)	2029 NGCC CCS (2)	2029 NGCC CCS (2)	2029 NGCC CCS (2)
2040 DSM SEP	2039 Tier I Solar	2040 Tier I Wind	2034 Nuclear	2036 Tier I Wind	2034 Nuclear	2031 Tier I Battery	2031 Tier I Battery	2032 Nuclear	2032 Nuclear
2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2036 Tier I Wind	2039 Tier I Wind	2036 Tier I Wind	2034 Nuclear	2034 Nuclear	2036 Tier I Wind	2036 Tier I Wind
			2039 Tier I Solar	2041 Tier I Wind	2039 Tier I Wind	2036 Tier I Wind	2036 Tier I Wind	2039 Tier I Wind	2039 Coal CCS
			2041 RICE	2041 Tier I Wind	2041 RICE	2039 Tier I Wind	2039 RICE (2)	2039 RICE (2)	2040 NGCT
			2041 Tier I Wind	2041 Tier I Solar	2041 Tier I Wind (2)	2041 RICE	2040 RICE	2040 RICE	2041 Tier I Wind (2)
						2041 Tier I Wind (2)	2041 Tier I Wind (2)	2041 Tier I Wind (2)	
Coal Retirement	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**
					2034 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 1
							2034 GGS 1	2031 GGS 1	2029 GGS 2
									2040 LRS 1
CO2 2,657K	CO2 2,511K	CO2 2,483K	CO2 1,049K	CO2 419K	CO2 414K	CO2 365K	CO2 283K	CO2 267K	CO2 82K
NPV $2,007M	NPV $2,419M	NPV $2,792M	NPV $3,209M	NPV $3,504M	NPV $3,832M	NPV $4,053M	NPV $4,221M	NPV $4,371M	NPV $4,551M
NPVE $3,664M	NPVE $4,634M	NPVE $5,525M	NPVE $6,159M	NPVE $6,562M	NPVE $6,983M	NPVE $7,294M	NPVE $7,567M	NPVE $7,749M	NPVE $7,948M

$7.00

$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
Expansion	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**
2029 NGCT (2)	2029 NGCT (2)	2029 NGCT (2)	2028 DSM SEP	2025 DSM SEP	2023 DSM SEP	2029 Tier I Battery (2)	2023 DSM SEP	2023 DSM SEP	2023 DSM SEP
2029 Tier I Battery (4)	2029 Tier I Battery (4)	2029 Tier I Battery (4)	2029 NGCT	2029 Tier I Battery (4)	2029 Tier I Battery (4)	2029 Nuclear (2)	2029 Tier I Battery (3)	2029 Tier I Battery (3)	2029 Tier I Battery (3)
2034 NGCT	2034 NGCT	2034 NGCT	2029 Tier I Battery (4)	2029 Nuclear (2)	2029 Nuclear (2)	2029 NGCC CCS	2029 Nuclear (2)	2029 Nuclear (2)	2029 Nuclear
2039 Tier I Solar	2036 Tier I Wind	2035 DSM SEP	2029 Nuclear	2034 NGCC CCS	2033 NGCC CCS	2030 Tier I Battery	2029 NGCC CCS	2029 NGCC CCS	2029 NGCC CCS (2)
2040 DSM SEP	2039 Tier I Solar	2036 Tier I Wind	2034 Nuclear	2036 Tier I Wind	2036 Tier I Wind	2031 Tier I Battery	2033 NGCC CCS	2033 NGCC CCS	2032 Nuclear
2041 Tier I Wind	2041 Tier I Wind	2039 RICE	2036 Tier I Wind	2039 Tier I Solar	2039 NGCC CCS	2033 DSM SEP	2036 Tier I Wind	2034 Nuclear	2034 Nuclear
		2041 RICE	2039 Tier I Solar	2041 Tier I Wind	2041 RICE	2034 NGCC CCS	2038 Nuclear	2036 Tier I Wind	2036 Tier I Wind
		2041 Tier I Wind (2)	2041 Tier I Wind		2041 Tier I Wind (2)	2036 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind
						2041 RICE	2041 Tier I Solar	2041 Tier I Solar	2041 Tier I Solar
						2041 Tier I Wind (2)			
Coal Retirement	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**
					2040 GGS 2	2034 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2
							2038 GGS 1	2034 GGS 1	2032 GGS 1
CO2 2,658K	CO2 2,512K	CO2 2,517K	CO2 1,685K	CO2 999K	CO2 421K	CO2 383K	CO2 73K	CO2 73K	CO2 72K
NPV $2,033M	NPV $2,443M	NPV $2,813M	NPV $3,365M	NPV $3,616M	NPV $3,820M	NPV $4,081M	NPV $4,293M	NPV $4,537M	NPV $4,651M
NPVE $3,729M	NPVE $4,694M	NPVE $5,591M	NPVE $6,246M	NPVE $6,583M	NPVE $6,993M	NPVE $7,294M	NPVE $7,557M	NPVE $7,772M	NPVE $7,920M

$8.00

$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
Expansion	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**
2029 NGCT (2)	2029 NGCT (2)	2029 NGCT (4)	2025 DSM SEP	2025 DSM SEP	2023 DSM SEP	2023 DSM SEP	2023 DSM SEP	2023 DSM SEP	2023 DSM SEP
2029 Tier I Battery (4)	2029 Tier I Battery (4)	2029 Tier I Battery (4)	2029 NGCT	2029 Tier I Battery (4)	2029 Tier I Battery (4)	2029 Tier I Battery (4)	2029 Tier I Battery (2)	2029 Tier I Battery (3)	2029 Tier I Battery (3)
2034 NGCT	2034 NGCT	2034 NGCT	2029 Tier I Battery (4)	2029 Nuclear (2)	2029 Nuclear (2)	2029 Nuclear (2)	2029 Nuclear (2)	2029 Nuclear (2)	2029 Nuclear (2)
2039 Tier I Solar	2036 Tier I Wind	2035 DSM SEP	2029 Nuclear	2034 Coal CCS	2034 Coal CCS	2033 Coal CCS	2029 NGCC CCS	2033 NGCC CCS	2033 NGCC CCS
2040 DSM SEP	2039 Tier I Solar	2036 Tier I Wind	2034 Nuclear	2036 Tier I Wind	2036 Tier I Wind	2036 Tier I Wind	2031 Tier I Battery	2036 Tier I Wind	2034 Nuclear
2041 Tier I Wind	2041 Tier I Wind	2039 Tier I Solar	2036 Tier I Wind	2039 Tier I Solar	2039 Tier I Solar	2039 NGCC CCS	2034 Nuclear	2038 Nuclear	2036 Tier I Wind
		2041 Tier I Wind	2039 Tier I Solar	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2036 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind
			2041 Tier I Wind		2041 Tier I Wind	2041 Tier I Solar	2039 Tier I Solar	2041 Tier I Solar	2041 Tier I Solar
							2041 Tier I Wind		
							2041 NGCC CCS		
Coal Retirement	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**
						2040 GGS 2	2033 GGS 2	2029 GGS 2	2029 GGS 2
							2041 GGS 1	2038 GGS 1	2034 GGS 1
CO2 2,658K	CO2 2,512K	CO2 2,507K	CO2 1,688K	CO2 1,018K	CO2 1,000K	CO2 428K	CO2 296K	CO2 73K	CO2 73K
NPV $2,059M	NPV $2,468M	NPV $2,843M	NPV $3,382M	NPV $3,710M	NPV $3,856M	NPV $4,078M	NPV $4,268M	NPV $4,444M	NPV $4,685M
NPVE $3,793M	NPVE $4,754M	NPVE $5,639M	NPVE $6,272M	NPVE $6,658M	NPVE $6,939M	NPVE $7,291M	NPVE $7,517M	NPVE $7,754M	NPVE $7,985M

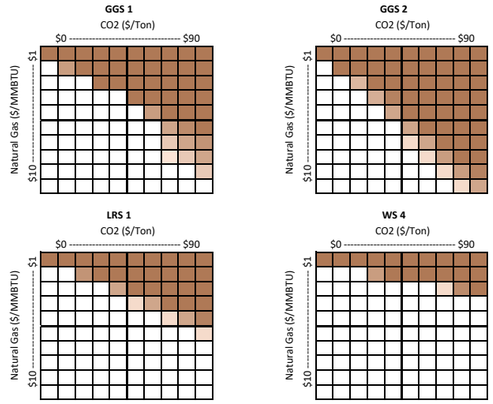
$9.00

$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
Expansion	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**
2029 NGCT (2)	2029 NGCT (2)	2029 NGCT (2)	2025 DSM SEP	2025 DSM SEP	2023 DSM SEP	2023 DSM SEP	2023 DSM SEP	2023 DSM SEP	2023 DSM SEP
2029 Tier I Battery (4)	2029 Tier I Battery (4)	2029 Tier I Battery (4)	2029 NGCT	2029 Tier I Battery (4)	2029 Tier I Battery (4)	2029 Tier I Battery (4)	2029 Tier I Battery (4)	2029 Tier I Battery (2)	2029 Tier I Battery (2)
2034 NGCT	2034 NGCT	2034 Nuclear	2029 Tier I Battery (4)	2029 Nuclear (2)	2029 Nuclear (2)	2029 Nuclear (2)	2029 Nuclear (2)	2029 Nuclear (2)	2029 Nuclear (2)
2039 Tier I Solar	2036 Tier I Wind	2036 Tier I Wind	2029 Nuclear	2034 Coal CCS	2034 Coal CCS	2033 Coal CCS	2033 Coal CCS	2029 NGCC CCS	2029 NGCC CCS
2040 DSM SEP	2039 Tier I Solar	2039 Tier I Solar	2034 Nuclear	2036 Tier I Wind	2036 Tier I Wind	2036 Tier I Wind	2036 Tier I Wind	2031 Tier I Battery	2030 Tier I Battery
2041 Tier I Wind	2041 Tier I Wind	2041 DSM SEP	2036 Tier I Wind	2039 Tier I Solar	2039 Tier I Solar	2039 NGCC CCS	2039 NGCC CCS	2033 Coal CCS	2033 Coal CCS
		2041 Tier I Wind	2039 Tier I Solar	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2036 Tier I Wind	2036 Tier I Wind
			2041 Tier I Wind			2041 Tier I Solar	2041 Tier I Solar	2039 RICE	2038 NGCC CCS
								2039 Tier I Solar	2041 Tier I Wind
								2041 Tier I Wind	2041 Tier I Solar
Coal Retirement	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**
							2040 GGS 2	2033 GGS 2	2030 GGS 2
									2038 GGS 1
CO2 2,659K	CO2 2,514K	CO2 2,303K	CO2 1,688K	CO2 1,019K	CO2 1,015K	CO2 996K	CO2 428K	CO2 317K	CO2 73K
NPV $2,084M	NPV $2,493M	NPV $2,973M	NPV $3,400M	NPV $3,727M	NPV $3,864M	NPV $4,037M	NPV $4,236M	NPV $4,410M	NPV $4,625M
NPVE $3,859M	NPVE $4,814M	NPVE $5,732M	NPVE $6,297M	NPVE $6,683M	NPVE $6,912M	NPVE $7,241M	NPVE $7,542M	NPVE $7,745M	NPVE $7,946M

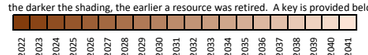
$10.00

$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
Expansion	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**
2029 NGCT (2)	2029 NGCT (2)	2029 NGCT (2)	2025 DSM SEP	2025 DSM SEP	2023 DSM SEP	2023 DSM SEP	2024 DSM SEP	2023 DSM SEP	2023 DSM SEP
2029 Tier I Battery (4)	2029 Tier I Battery (4)	2029 Tier I Battery (4)	2029 NGCT	2029 Tier I Battery (4)	2029 Tier I Battery (4)	2029 Tier I Battery (4)	2030 Tier I Battery (2)	2029 Tier I Battery (4)	2029 Tier I Battery (2)
2034 NGCT	2034 NGCT	2034 Nuclear	2029 Tier I Battery (4)	2029 Nuclear (2)	2029 Nuclear (2)	2029 Nuclear (2)	2030 Nuclear (2)	2029 Nuclear (2)	2029 Nuclear (2)
2039 Tier I Solar	2036 Tier I Wind	2036 Tier I Wind	2029 Nuclear	2034 Coal CCS	2034 Coal CCS	2033 Coal CCS	2030 Coal CCS	2033 Coal CCS	2029 NGCC CCS
2040 DSM SEP	2039 Tier I Solar	2039 Tier I Solar	2034 Nuclear	2036 Tier I Wind	2036 Tier I Wind	2036 Tier I Wind	2032 Tier I Battery	2036 Tier I Wind	2031 Tier I Battery
2041 Tier I Wind	2041 Tier I Wind	2041 DSM SEP	2036 Tier I Wind	2039 Tier I Solar	2039 Tier I Solar	2039 Tier I Solar	2035 Tier I Solar	2039 NGCC CCS	2034 Coal CCS
		2041 Tier I Wind	2039 Tier I Solar	2041 Tier I Wind	2041 Tier I Wind	2041 Tier I Wind	2037 Tier I Wind	2041 Tier I Wind	2036 Tier I Wind
			2041 Tier I Wind				2040 NGCC CCS	2041 Tier I Solar	2039 NGCC CCS
									2041 Tier I Wind (2)
Coal Retirement	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**
								2040 GGS 2	2034 GGS 2
CO2 2,661K	CO2 2,515K	CO2 2,304K	CO2 1,688K	CO2 1,019K	CO2 1,018K	CO2 1,012K	CO2 420K	CO2 425K	CO2 79K
NPV $2,110M	NPV $2,517M	NPV $2,994M	NPV $3,417M	NPV $3,744M	NPV $3,880M	NPV $4,041M	NPV $4,208M	NPV $4,394M	NPV $4,554M
NPVE $3,923M	NPVE $4,874M	NPVE $5,769M	NPVE $6,323M	NPVE $6,708M	NPVE $6,930M	NPVE $7,178M	NPVE $7,442M	NPVE $7,784M	NPVE $7,995M

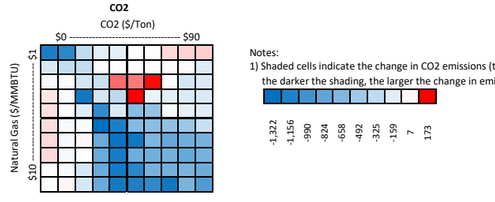
Resource Summary Tables



Notes:
1) Shaded cells indicate a resource's retirement within the 2022 - 2041 study period; the darker the shading, the earlier a resource was retired. A key is provided below:

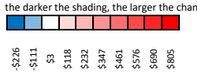


Comparison to Base Case

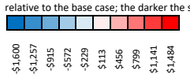


Notes:
1) Shaded cells indicate the change in CO2 emissions (thousand tons) for year 2040, relative to the base case; the darker the shading, the larger the change in emissions. A key is provided below:

Notes:
1) Shaded cells indicate the change in total production costs ($M) over the 2022 - 2041 study period, relative to the base case; the darker the shading, the larger the change in cost. A key is provided below:



Notes:
1) Shaded cells indicate the change in total production costs ($M) over the 2022 - 2041 study plus the subsequent 30-year extension period, relative to the base case; the darker the shading, the larger the change in cost. A key is provided below:



EGEAS Expansion Plans
Sensitivity 7: High Natural Gas Price

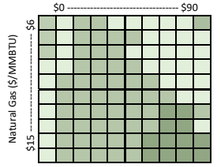
CO2 Value ($/Short Ton, 2022 $)

Natural Gas Price ($/MMBTU, 2022 $)

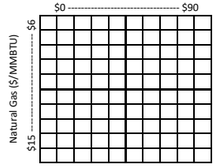
	$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
$6.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,633K NPV $1,543M NPVE $2,986M	**Expansion** 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 2,552K NPV $1,923M NPVE $3,937M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,513K NPV $2,267M NPVE $4,763M	**Expansion** 2032 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,371K NPV $2,631M NPVE $5,694M	**Expansion** 2025 DSM SEP 2033 WS4 CCS Upgrade 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 1,595K NPV $3,068M NPVE $6,427M	**Expansion** 2029 WS4 CCS Upgrade 2032 NGCC CCS 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2034 GGS 2 CO2 1,040K NPV $3,451M NPVE $6,967M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 CO2 972K NPV $3,726M NPVE $7,446M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2034 Tier I Solar 2035 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2034 GGS 1 CO2 854K NPV $3,946M NPVE $7,780M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2031 Tier I Solar 2035 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2030 GGS 1 CO2 775K NPV $4,148M NPVE $8,140M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2030 NGCC CCS 2035 Tier I Wind (*) 2040 Nuclear 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2040 LRS 1 CO2 368K NPV $4,162M NPVE $7,842M
$7.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,633K NPV $1,575M NPVE $3,057M	**Expansion** 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 2,552K NPV $1,955M NPVE $4,003M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,298M NPVE $4,835M	**Expansion** 2028 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,458K NPV $2,654M NPVE $5,704M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 Tier I Wind 2041 Tier I Solar 2041 WS4 CCS Upgrade **Coal Retirement** CO2 2,274K NPV $3,031M NPVE $6,618M	**Expansion** 2035 Coal CCS 2036 Tier I Wind 2037 Tier I Wind (*) 2041 Tier I Solar 2041 WS4 CCS Upgrade **Coal Retirement** 2040 GGS 2 CO2 1,662K NPV $3,504M NPVE $7,194M	**Expansion** 2029 WS4 CCS Upgrade 2032 Coal CCS 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2033 GGS 2 CO2 1,044K NPV $3,852M NPVE $7,664M	**Expansion** 2023 DSM SEP 2029 Nuclear 2029 WS4 CCS Upgrade 2038 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2038 GGS 1 CO2 869K NPV $4,111M NPVE $8,062M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2034 Tier I Solar 2036 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2034 GGS 1 CO2 818K NPV $4,379M NPVE $8,469M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2032 Tier I Solar 2036 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2032 GGS 1 CO2 776K NPV $4,584M NPVE $8,792M
$8.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,633K NPV $1,608M NPVE $3,128M	**Expansion** 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 2,552K NPV $1,986M NPVE $4,070M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,330M NPVE $4,904M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,462K NPV $2,685M NPVE $5,764M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2038 Tier I Wind (*) **Coal Retirement** CO2 2,220K NPV $3,134M NPVE $6,621M	**Expansion** 2023 DSM SEP 2031 WS4 CCS Upgrade 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 1,745K NPV $3,454M NPVE $7,394M	**Expansion** 2029 WS4 CCS Upgrade 2031 Coal CCS 2040 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2040 GGS 2 CO2 1,163K NPV $3,899M NPVE $7,857M	**Expansion** 2029 WS4 CCS Upgrade 2031 Nuclear 2036 Tier I Solar 2041 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2033 GGS 2 2041 GGS 1 CO2 1,012K NPV $4,168M NPVE $8,236M	**Expansion** 2023 DSM SEP 2029 Nuclear 2029 WS4 CCS Upgrade 2038 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2038 GGS 1 CO2 860K NPV $4,397M NPVE $8,664M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2034 Tier I Solar 2036 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2034 GGS 1 CO2 782K NPV $4,684M NPVE $9,080M
$9.00	**Expansion** 2036 Tier I Solar 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** CO2 2,678K NPV $1,641M NPVE $3,199M	**Expansion** 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 2,552K NPV $2,017M NPVE $4,137M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,362M NPVE $4,973M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,462K NPV $2,715M NPVE $5,832M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2038 Tier I Wind (*) **Coal Retirement** CO2 2,243K NPV $3,160M NPVE $6,651M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 2,125K NPV $3,496M NPVE $7,459M	**Expansion** 2023 DSM SEP 2029 WS4 CCS Upgrade 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 1,701K NPV $3,818M NPVE $8,184M	**Expansion** 2029 WS4 CCS Upgrade 2031 Coal CCS 2036 Tier I Solar 2040 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2040 GGS 2 CO2 1,156K NPV $4,209M NPVE $8,508M	**Expansion** 2029 WS4 CCS Upgrade 2031 Coal CCS 2040 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2033 GGS 2 CO2 1,011K NPV $4,486M NPVE $8,968M	**Expansion** 2023 DSM SEP 2029 WS4 CCS Upgrade 2030 Nuclear 2038 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2030 GGS 2 2038 GGS 1 CO2 839K NPV $4,700M NPVE $9,262M
$10.00	**Expansion** 2036 Tier I Solar 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** CO2 2,678K NPV $1,673M NPVE $3,270M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,507K NPV $2,042M NPVE $4,202M	**Expansion** 2033 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,393M NPVE $5,042M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,462K NPV $2,745M NPVE $5,899M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2038 Tier I Wind (*) **Coal Retirement** CO2 2,244K NPV $3,187M NPVE $6,702M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 2,187K NPV $3,520M NPVE $7,482M	**Expansion** 2035 Coal CCS 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 2,089K NPV $3,858M NPVE $8,300M	**Expansion** 2023 DSM SEP 2029 WS4 CCS Upgrade 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 1,661K NPV $4,177M NPVE $8,939M	**Expansion** 2029 WS4 CCS Upgrade 2031 Coal CCS 2040 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2040 GGS 2 CO2 1,119K NPV $4,518M NPVE $9,140M	**Expansion** 2029 WS4 CCS Upgrade 2031 Coal CCS 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2034 GGS 2 CO2 992K NPV $4,780M NPVE $9,595M

Resource Summary Tables

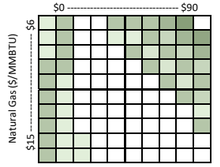
Tier I Wind
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $6 ---------- $15



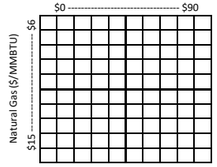
Tier II Wind
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $6 ---------- $15



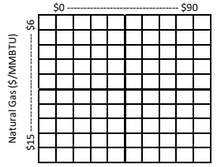
Tier I Solar
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $6 ---------- $15



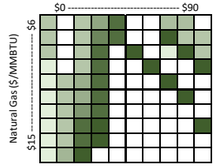
Tier II Solar
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $6 ---------- $15



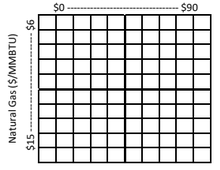
Tier I Battery
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $6 ---------- $15



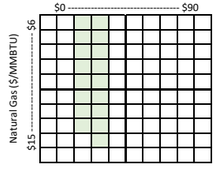
DSM SEP
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $6 ---------- $15



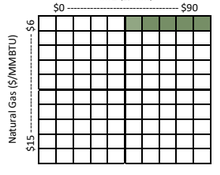
NGCT
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $6 ---------- $15



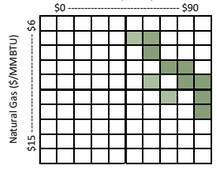
RICE
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $6 ---------- $15



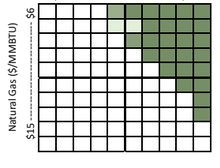
NGCC CCS
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $6 ---------- $15



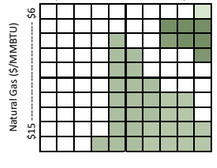
Coal CCS
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $6 ---------- $15



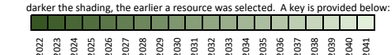
WS4 CCS Upgrade
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $6 ---------- $15



Nuclear
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $6 ---------- $15



Notes:
1) Shaded cells indicate a resource's inclusion within the 2022 - 2041 study period; the darker the shading, the earlier a resource was selected. A key is provided below:



2) Data reflects EGEAS' lowest cost expansion plan for each scenario, including the 30-year extension period.
3) *CO2* values reflect LES' total CO2 emissions for year 2040 in units of tons.
4) *NPV* values reflect LES' total production costs over the 2022 - 2041 study period.
5) *NPVE* values reflect LES' total production costs over the 2022 - 2041 study period plus the subequent 30-year extension period.
6) Multiple selections of the same resource in the same year are denoted by (#).
7) Tier I Wind that was installed early as Tier II Wind - but utilmately graduated to Tier I status following the end of a contract for an existing Tier I Wind resource - is denoted by (*).

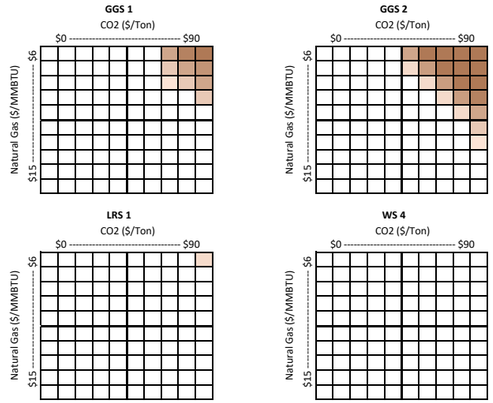
EGEAS Expansion Plans
Sensitivity 7: High Natural Gas Price

CO2 Value ($/Short Ton, 2022 $)

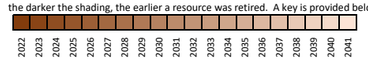
Natural Gas Price ($/MMBTU, 2022 $)

	$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
$11.00	**Expansion** 2036 Tier I Solar 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** CO2 2,678K NPV $1,705M NPVE $3,341M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,507K NPV $2,073M NPVE $4,266M	**Expansion** 2033 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,424M NPVE $5,110M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,462K NPV $2,776M NPVE $5,966M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2038 Tier I Wind (*) **Coal Retirement** CO2 2,244K NPV $3,215M NPVE $6,752M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 2,191K NPV $3,547M NPVE $7,527M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 2,158K NPV $3,886M NPVE $8,285M	**Expansion** 2035 Coal CCS 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 2,053K NPV $4,220M NPVE $9,155M	**Expansion** 2023 DSM SEP 2029 WS4 CCS Upgrade 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 1,631K NPV $4,516M NPVE $9,705M	**Expansion** 2029 WS4 CCS Upgrade 2031 Coal CCS 2038 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2038 GGS 2 CO2 1,111K NPV $4,800M NPVE $9,737M
$12.00	**Expansion** 2036 Tier I Solar 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** CO2 2,678K NPV $1,736M NPVE $3,411M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,507K NPV $2,105M NPVE $4,331M	**Expansion** 2030 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,455M NPVE $5,179M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,462K NPV $2,806M NPVE $6,034M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2038 Tier I Wind (*) **Coal Retirement** CO2 2,244K NPV $3,242M NPVE $6,803M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 2,191K NPV $3,575M NPVE $7,583M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 2,173K NPV $3,912M NPVE $8,327M	**Expansion** 2032 Tier I Wind (*) 2036 Nuclear 2041 Nuclear **Coal Retirement** CO2 2,152K NPV $4,267M NPVE $9,112M	**Expansion** 2032 Tier I Wind (*) 2036 Nuclear 2041 Nuclear **Coal Retirement** CO2 1,981K NPV $4,629M NPVE $9,961M	**Expansion** 2029 WS4 CCS Upgrade 2031 Coal CCS 2036 Tier I Wind 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** 2041 GGS 2 CO2 1,284K NPV $4,733M NPVE $9,748M
$13.00	**Expansion** 2036 Tier I Solar 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** CO2 2,678K NPV $1,767M NPVE $3,482M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,507K NPV $2,136M NPVE $4,395M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,486M NPVE $5,246M	**Expansion** 2023 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,462K NPV $2,836M NPVE $6,101M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2038 Tier I Wind (*) **Coal Retirement** CO2 2,244K NPV $3,269M NPVE $6,854M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 2,191K NPV $3,602M NPVE $7,633M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 2,173K NPV $3,939M NPVE $8,382M	**Expansion** 2032 Tier I Wind (*) 2036 Nuclear 2041 Nuclear **Coal Retirement** CO2 2,190K NPV $4,293M NPVE $9,118M	**Expansion** 2032 Tier I Wind (*) 2036 Nuclear 2041 Nuclear **Coal Retirement** CO2 2,086K NPV $4,637M NPVE $9,896M	**Expansion** 2023 DSM SEP 2029 WS4 CCS Upgrade 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 1,696K NPV $4,936M NPVE $10,701M
$14.00	**Expansion** 2036 Tier I Solar 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** CO2 2,678K NPV $1,798M NPVE $3,551M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,507K NPV $2,167M NPVE $4,459M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,511K NPV $2,514M NPVE $5,310M	**Expansion** 2023 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,462K NPV $2,865M NPVE $6,167M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2038 Tier I Wind (*) **Coal Retirement** CO2 2,243K NPV $3,297M NPVE $6,905M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 2,191K NPV $3,628M NPVE $7,683M	**Expansion** 2032 Tier I Wind (*) 2036 Nuclear 2041 Nuclear **Coal Retirement** CO2 2,195K NPV $3,983M NPVE $8,432M	**Expansion** 2032 Tier I Wind (*) 2036 Nuclear 2041 Nuclear **Coal Retirement** CO2 2,195K NPV $4,320M NPVE $9,152M	**Expansion** 2032 Tier I Wind (*) 2036 Nuclear 2041 Nuclear **Coal Retirement** CO2 2,132K NPV $4,662M NPVE $9,866M	**Expansion** 2032 Tier I Wind (*) 2036 Nuclear 2041 Nuclear **Coal Retirement** CO2 2,042K NPV $5,010M NPVE $10,704M
$15.00	**Expansion** 2036 Tier I Solar 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** CO2 2,678K NPV $1,829M NPVE $3,620M	**Expansion** 2034 DSM SEP 2036 Tier I Wind 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,507K NPV $2,198M NPVE $4,522M	**Expansion** 2023 DSM SEP 2036 Tier I Wind 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,511K NPV $2,544M NPVE $5,372M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2041 Tier I Wind **Coal Retirement** CO2 2,297K NPV $2,999M NPVE $6,221M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2038 Tier I Wind (*) **Coal Retirement** CO2 2,243K NPV $3,324M NPVE $6,953M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 2,191K NPV $3,655M NPVE $7,731M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 2,195K NPV $4,010M NPVE $8,472M	**Expansion** 2032 Tier I Wind (*) 2036 Nuclear 2041 Nuclear **Coal Retirement** CO2 2,195K NPV $4,347M NPVE $9,197M	**Expansion** 2032 Tier I Wind (*) 2036 Nuclear 2041 Nuclear **Coal Retirement** CO2 2,148K NPV $4,688M NPVE $9,886M	**Expansion** 2032 Tier I Wind (*) 2036 Nuclear 2041 Nuclear **Coal Retirement** CO2 2,093K NPV $5,033M NPVE $10,651M

Resource Summary Tables



Notes:
1) Shaded cells indicate a resource's retirement within the 2022 - 2041 study period; the darker the shading, the earlier a resource was retired. A key is provided below:



EGEAS Expansion Plans
Sensitivity 8: SPP Electrification

CO2 Value ($/Short Ton, 2022 $)

Natural Gas Price ($/MMBTU, 2022 $)

$1.00

$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
Expansion	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**
2029 NGCT	2029 NGCT (2)	2029 DSM SEP	2029 NGCT (2)	2029 NGCT (2)	2029 NGCT (2)	2029 NGCT (2)	2029 NGCT	2029 Tier I Battery (3)	2029 Tier I Battery (3)
2029 Tier I Battery (4)	2029 Tier I Battery (3)	2029 NGCT (3)	2029 NGCC CCS (2)	2029 NGCC CCS (2)	2029 NGCC CCS (2)	2029 NGCC CCS (2)	2029 Tier I Battery	2029 NGCC CCS (2)	2029 NGCC CCS (2)
2030 NGCT	2033 NGCT	2031 NGCC CCS	2035 DSM SEP	2035 Tier I Wind	2035 Tier I Wind	2033 Tier I Wind (*)	2029 NGCC CCS (2)	2031 Tier I Wind (*)	2031 Tier I Wind (*)
2034 NGCT	2036 NGCC CCS	2036 NGCC CCS	2036 NGCT	2036 NGCT	2036 Tier I Solar	2036 Tier I Solar	2031 Tier I Battery	2033 NGCT	2033 Nuclear
2038 RICE	2040 NGCC CCS	2040 RICE	2039 Tier I Wind	2039 Tier I Solar	2037 NGCT	2037 NGCT	2034 NGCT	2036 Nuclear	2036 Tier I Solar
2039 RICE		2041 Tier I Wind (2)	2040 RICE	2041 DSM SEP	2039 DSM SEP	2039 DSM SEP	2035 Tier I Wind	2037 Tier I Solar	2037 NGCT
2040 NGCC CCS		2041 Tier I Solar	2041 Tier I Wind	2041 Tier I Wind	2041 RICE	2041 Tier I Wind (2)	2036 DSM SEP	2040 Tier I Wind	2039 DSM SEP
			2041 Tier I Solar	2041 Tier II Solar	2041 Tier I Wind (2)		2037 Tier I Solar	2041 DSM SEP	2041 RICE
							2040 RICE	2041 RICE	2041 Tier I Wind (2)
							2040 Tier I Wind	2041 Tier I Wind	
							2041 RICE (2)		
							2041 Tier I Wind (1)		
Coal Retirement	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**
2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1
2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2
2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1
2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4
CO2 2,401K	CO2 1,626K	CO2 1,550K	CO2 1,334K	CO2 1,272K	CO2 1,246K	CO2 1,199K	CO2 1,115K	CO2 736K	CO2 775K
NPV $1,716M	NPV $1,995M	NPV $2,218M	NPV $2,418M	NPV $2,592M	NPV $2,748M	NPV $2,905M	NPV $3,079M	NPV $3,302M	NPV $3,453M
NPVE $3,209M	NPVE $3,916M	NPVE $4,440M	NPVE $4,824M	NPVE $5,188M	NPVE $5,524M	NPVE $5,850M	NPVE $6,182M	NPVE $6,492M	NPVE $6,725M

$2.00

$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
Expansion	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**
2030 Tier I Battery	2029 NGCT	2029 NGCT	2029 NGCC CCS (3)	2029 NGCT (2)	2029 NGCT (2)	2029 NGCT (2)	2029 Tier I Battery (3)	2029 Tier I Battery (3)	2025 DSM SEP
2034 NGCT	2030 NGCC CCS	2030 NGCC CCS	2034 NGCT	2029 NGCC CCS (2)	2029 NGCC CCS (2)	2029 NGCC CCS (2)	2029 NGCC CCS (2)	2029 NGCC CCS (2)	2029 Tier I Battery (2)
2036 NGCT	2036 NGCT	2036 NGCC CCS	2036 Tier I Wind	2033 Tier I Wind (*)	2032 Tier I Wind (*)	2032 Tier I Wind (*)	2031 Tier I Wind (*)	2030 Tier I Wind (*)	2029 NGCC CCS (2)
2040 NGCT	2040 Tier I Solar	2039 Tier I Solar	2039 Tier I Solar	2036 Tier I Solar	2036 Tier I Solar	2036 Tier I Solar	2033 Nuclear	2033 Nuclear	2030 Tier I Battery
	2041 Tier I Wind (2)	2039 NGCC CCS	2041 RICE (2)	2037 NGCT	2037 NGCT	2037 NGCT	2036 Tier I Solar	2036 Tier I Solar	2031 Tier I Wind (*)
		2040 Tier I Wind	2041 Tier I Wind	2041 DSM SEP	2039 DSM SEP	2039 DSM SEP	2037 NGCT	2037 NGCT	2034 Nuclear
		2041 RICE (2)		2041 RICE	2041 RICE	2041 RICE	2040 Tier I Wind	2039 DSM SEP	2036 Coal CCS
		2041 Tier I Wind		2041 Tier I Wind (2)	2041 Tier I Wind (2)	2041 Tier I Wind (2)	2041 DSM SEP	2041 RICE	2039 Tier I Solar
							2041 RICE	2041 Tier I Wind (2)	2040 Tier I Wind
							2041 Tier I Wind		2041 RICE (2)
									2041 Tier I Wind
Coal Retirement	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**
	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1
	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2
		2039 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1
				2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4	2029 WS 4
CO2 3,798K	CO2 2,654K	CO2 881K	CO2 876K	CO2 1,246K	CO2 1,199K	CO2 1,199K	CO2 736K	CO2 775K	CO2 364K
NPV $1,671M	NPV $2,177M	NPV $2,479M	NPV $2,718M	NPV $2,975M	NPV $3,127M	NPV $3,274M	NPV $3,548M	NPV $3,666M	NPV $3,834M
NPVE $3,317M	NPVE $4,466M	NPVE $5,032M	NPVE $5,332M	NPVE $5,933M	NPVE $6,259M	NPVE $6,582M	NPVE $6,873M	NPVE $7,106M	NPVE $7,324M

$3.00

$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
Expansion	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**
2030 RICE	2030 Tier I Battery	2030 Tier I Wind (*)	2029 RICE	2029 RICE	2029 RICE	2025 DSM SEP	2025 DSM SEP	2029 Tier I Battery	2029 Tier I Battery
2032 NGCT	2034 NGCT	2031 NGCC CCS	2029 NGCC CCS	2029 NGCC CCS	2031 Tier I Wind (*)	2029 NGCC CCS (3)	2029 NGCC CCS (3)	2029 NGCC CCS (2)	2029 NGCC CCS (2)
2037 NGCT	2035 Tier I Wind (*)	2036 NGCC CCS	2031 Tier I Wind (*)	2031 Tier I Wind (*)	2032 NGCC CCS	2032 Tier I Wind (*)	2032 Tier I Wind (*)	2030 Tier I Wind (*)	2030 Tier I Wind (*)
2041 Tier I Wind	2036 NGCT	2040 NGCC CCS	2032 NGCC CCS	2032 NGCC CCS	2035 NGCC CCS	2036 NGCT	2036 Nuclear	2031 Tier I Battery (2)	2031 Tier I Battery (2)
2041 Tier I Solar	2041 Tier I Wind	2041 Tier I Wind	2037 NGCC CCS	2037 NGCC CCS	2036 NGCT	2038 Tier I Solar	2038 Tier I Solar	2032 Nuclear	2032 Nuclear
	2041 Tier I Solar	2041 Tier I Solar	2041 Tier I Wind (2)	2041 Tier I Wind (2)	2038 Tier I Solar	2041 RICE (2)	2041 RICE (2)	2036 Tier I Solar	2036 Nuclear
			2041 Tier I Solar	2041 Tier I Solar	2041 DSM SEP	2041 Tier I Wind (2)	2041 Tier I Wind (2)	2037 Nuclear	2037 Tier I Solar
					2041 RICE			2040 Tier I Wind	2040 Tier I Wind
					2041 Tier I Wind (2)			2041 DSM SEP	2041 DSM SEP
								2041 RICE	2041 RICE
								2041 Tier I Wind	2041 Tier I Wind
Coal Retirement	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**
		2040 GGS 2	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1
			2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2
					2035 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1	2029 LRS 1
								2031 WS 4	2031 WS 4
CO2 3,830K	CO2 3,511K	CO2 1,295K	CO2 1,173K	CO2 1,084K	CO2 838K	CO2 811K	CO2 440K	CO2 353K	CO2 353K
NPV $1,734M	NPV $2,192M	NPV $2,588M	NPV $2,892M	NPV $3,104M	NPV $3,326M	NPV $3,408M	NPV $3,605M	NPV $4,029M	NPV $4,153M
NPVE $3,592M	NPVE $4,674M	NPVE $5,417M	NPVE $5,833M	NPVE $6,183M	NPVE $6,553M	NPVE $6,721M	NPVE $6,956M	NPVE $7,621M	NPVE $7,794M

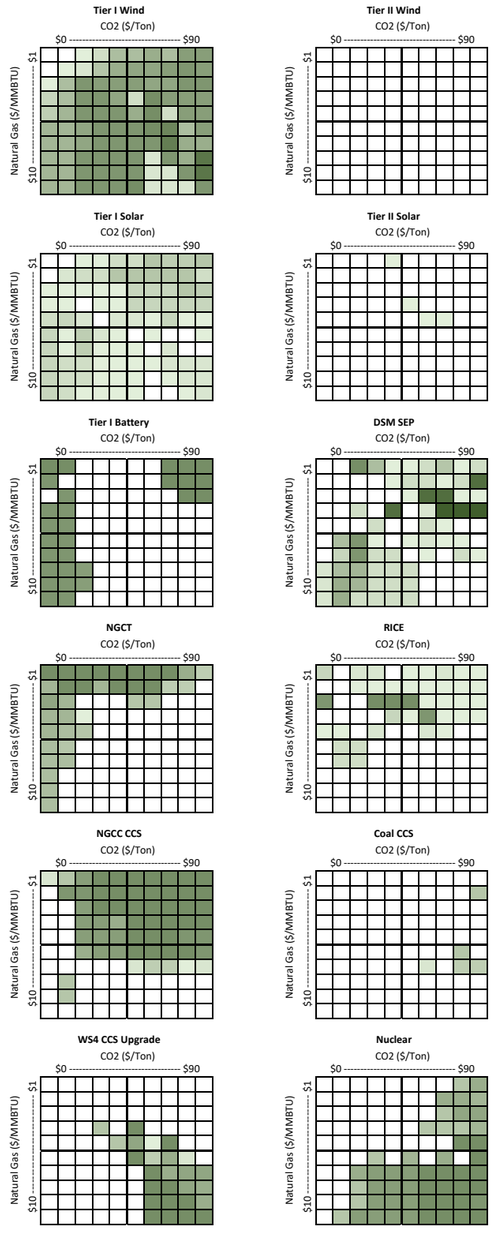
$4.00

$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
Expansion	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**
2030 Tier I Battery	2030 Tier I Battery	2030 Tier I Wind (*)	2030 Tier I Wind (*)	2025 DSM SEP	2029 NGCC CCS (2)	2029 Tier I Wind (*)	2023 DSM SEP	2023 DSM SEP	2023 DSM SEP
2034 NGCT	2034 NGCT	2031 NGCC CCS	2031 NGCC CCS	2032 Tier I Wind (*)	2029 WS4 CCS Upgrade	2029 NGCC CCS	2029 NGCC CCS	2029 NGCC CCS (3)	2029 NGCC CCS (3)
2036 NGCT	2035 Tier I Wind (*)	2036 NGCC CCS	2035 NGCC CCS	2033 NGCC CCS	2034 NGCC CCS	2030 RICE	2031 Tier I Wind (*)	2031 Tier I Wind (*)	2031 Tier I Wind (*)
2038 Tier I Wind	2036 NGCT	2039 DSM SEP	2036 WS4 CCS Upgrade	2036 NGCC CCS	2038 Tier I Solar	2032 NGCC CCS	2031 NGCC CCS (2)	2036 Nuclear	2034 Nuclear
2041 Tier I Wind	2041 Tier I Wind (2)	2041 NGCT	2037 NGCC CCS	2038 RICE	2039 Tier I Wind	2034 NGCC CCS	2036 Nuclear	2038 Tier I Solar	2038 Tier I Solar
2041 Tier I Solar	2041 Tier I Solar	2041 Tier I Wind (2)	2041 Tier I Wind (2)	2039 NGCC CCS	2041 RICE	2036 Nuclear	2038 Tier I Solar	2041 RICE (2)	2041 RICE (2)
			2041 Tier I Solar	2041 Tier I Wind	2041 Tier I Wind (2)	2038 Tier I Solar	2041 RICE (2)	2041 Tier I Wind (2)	2041 Tier I Wind (2)
				2041 Tier I Solar	2041 Tier II Solar	2040 DSM SEP	2041 Tier I Wind (2)		
						2041 RICE			
						2041 Tier I Wind (2)			
Coal Retirement	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**
		2041 GGS 2	2035 GGS 2	2036 GGS 2	2029 GGS 2	2029 GGS 1	2029 GGS 1	2029 GGS 1	2029 GGS 1
				2039 GGS 1	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 2
						2034 LRS 1	2031 LRS 1	2029 LRS 1	2029 LRS 1
CO2 3,618K	CO2 3,596K	CO2 2,211K	CO2 1,045K	CO2 945K	CO2 727K	CO2 453K	CO2 457K	CO2 440K	CO2 440K
NPV $1,825M	NPV $2,252M	NPV $2,654M	NPV $3,060M	NPV $3,269M	NPV $3,505M	NPV $3,775M	NPV $3,887M	NPV $3,984M	NPV $4,121M
NPVE $3,809M	NPVE $4,849M	NPVE $5,755M	NPVE $6,310M	NPVE $6,698M	NPVE $6,979M	NPVE $7,333M	NPVE $7,500M	NPVE $7,653M	NPVE $7,823M

$5.00

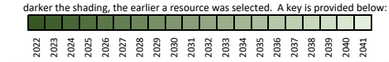
$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
Expansion	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**	**Expansion**
2030 Tier I Battery	2030 Tier I Battery	2030 Tier I Wind (*)	2030 Tier I Wind (*)	2030 Tier I Wind (*)	2029 NGCC CCS (2)	2029 Tier I Wind (*)	2029 NGCC CCS (2)	2029 Nuclear	2029 Nuclear
2031 Tier I Battery	2031 Tier I Battery	2031 NGCC CCS	2031 NGCC CCS	2031 NGCC CCS	2032 NGCC CCS	2029 NGCC CCS	2029 WS4 CCS Upgrade	2030 NGCC CCS	2030 NGCC CCS
2034 NGCT	2034 Tier I Wind (*)	2036 NGCT	2036 NGCC CCS	2034 NGCC CCS	2032 WS4 CCS Upgrade	2034 NGCC CCS	2034 NGCC CCS	2031 Tier I Wind (*)	2031 Tier I Wind (*)
2037 Tier I Wind	2035 NGCT	2040 Tier I Solar	2038 Tier I Wind	2036 WS4 CCS Upgrade	2033 Tier I Wind (*)	2035 Tier I Wind (*)	2038 Tier I Solar	2035 NGCC CCS (2)	2031 NGCC CCS
2039 Tier I Solar	2038 Tier I Solar	2041 Tier I Wind (2)	2039 DSM SEP	2037 NGCC CCS	2037 NGCC CCS	2036 NGCC CCS	2039 Tier I Wind	2036 Tier I Wind	2032 NGCC CCS
2041 RICE (2)	2041 RICE (2)		2040 RICE	2040 Tier I Solar	2040 Tier I Solar	2039 DSM SEP	2039 Tier I Wind (*)	2038 Nuclear	2036 Tier I Wind
2041 Tier I Wind	2041 Tier I Wind (2)		2041 Tier I Wind	2041 Tier I Wind (2)	2041 Tier I Wind (2)	2040 RICE	2041 DSM SEP	2041 Tier I Wind	2038 Nuclear
			2041 NGCC CCS			2041 Tier I Solar	2041 RICE	2041 Tier I Solar	2041 Tier I Wind
						2041 Tier II Solar	2041 Tier I Wind		2041 Tier I Solar
						2041 WS4 CCS Upgrade	2041 Tier II Solar		
Coal Retirement	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**	**Coal Retirement**
			2041 GGS 2	2034 GGS 2	2029 GGS 2	2029 GGS 2	2029 GGS 1	2029 GGS 1	2029 GGS 1
						2035 GGS 1	2029 GGS 2	2029 GGS 2	2029 GGS 2
								2035 LRS 1	2031 LRS 1
CO2 3,497K	CO2 3,497K	CO2 2,891K	CO2 1,941K	CO2 870K	CO2 797K	CO2 920K	CO2 590K	CO2 227K	CO2 227K
NPV $1,903M	NPV $2,324M	NPV $2,714M	NPV $3,051M	NPV $3,439M	NPV $3,686M	NPV $3,879M	NPV $4,053M	NPV $4,415M	NPV $4,527M
NPVE $4,000M	NPVE $5,014M	NPVE $5,914M	NPVE $6,628M	NPVE $7,073M	NPVE $7,440M	NPVE $7,830M	NPVE $8,000M	NPVE $8,223M	NPVE $8,336M

Resource Summary Tables



Notes:

1) Shaded cells indicate a resource's inclusion within the 2022 - 2041 study period; the darker the shading, the earlier a resource was selected. A key is provided below:



2) Data reflects EGEAS' lowest cost expansion plan for each scenario, including the 30-year extension period.
3) *CO2* values reflect LES' total CO2 emissions for year 2040 in units of tons.
4) *NPV* values reflect LES' total production costs over the 2022 - 2041 study period.
5) *NPVE* values reflect LES' total production costs over the 2022 - 2041 study period plus the subsequent 30-year extension period.
6) Multiple selections of the same resource in the same year are denoted by (#).
7) Tier I Wind that was installed early as Tier II Wind - but utilmately graduated to Tier I status following the end of a contract for an existing Tier I Wind resource - is denoted by (*).

EGEAS Expansion Plans
Sensitivity 8: SPP Electrification

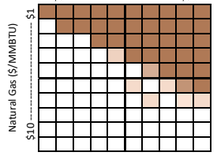
CO2 Value ($/Short Ton, 2022 $)

Natural Gas Price ($/MMBTU, 2022 $)

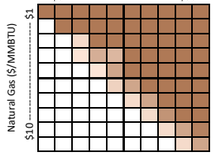
	$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
$6.00	**Expansion** 2030 Tier I Battery 2031 Tier I Battery 2034 Tier I Wind (*) 2035 NGCT 2038 Tier I Solar 2041 Tier I Battery 2041 Tier I Wind (2) **Coal Retirement** CO2 3,497K NPV $1,963M NPVE $4,154M	**Expansion** 2030 Tier I Battery 2031 Tier I Battery 2034 Tier I Wind (*) 2035 DSM SEP 2036 NGCT 2038 Tier I Wind 2039 RICE 2040 RICE 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 3,356K NPV $2,370M NPVE $5,166M	**Expansion** 2030 DSM SEP 2032 Tier I Wind (*) 2033 NGCC CCS 2037 Tier I Solar 2039 RICE 2040 RICE 2041 RICE (2) 2041 Tier I Wind (2) **Coal Retirement** CO2 3,085K NPV $2,720M NPVE $6,091M	**Expansion** 2030 Tier I Wind (*) 2031 NGCC CCS 2035 Tier I Wind (*) 2036 Nuclear 2040 Tier I Solar 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** CO2 2,058K NPV $3,172M NPVE $6,809M	**Expansion** 2030 Tier I Wind (*) 2031 NGCC CCS 2035 Tier I Wind (*) 2036 NGCC CCS 2039 NGCC CCS 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** 2039 GGS 2 CO2 1,343K NPV $3,446M NPVE $7,394M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2030 Tier I Wind (*) 2034 Nuclear 2037 NGCC CCS 2038 Tier I Wind 2040 NGCC CCS 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** 2034 GGS 2 2040 GGS 1 CO2 435K NPV $3,860M NPVE $7,808M	**Expansion** 2029 Tier I Wind (*) 2029 NGCC CCS 2034 NGCC CCS 2035 Tier I Wind (*) 2037 NGCC CCS 2037 WS4 CCS Upgrade 2040 DSM SEP 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** 2029 GGS 2 CO2 727K NPV $4,055M NPVE $8,202M	**Expansion** 2028 Tier I Wind (*) 2029 NGCC CCS 2033 Nuclear 2033 WS4 CCS Upgrade 2037 NGCC CCS 2038 Tier I Wind 2040 NGCC CCS 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** 2029 GGS 2 2040 GGS 1 CO2 410K NPV $4,326M NPVE $8,432M	**Expansion** 2029 NGCC CCS 2032 NGCC CCS 2035 Tier I Wind 2036 Coal CCS 2040 Tier I Wind (*) 2040 NGCC CCS 2040 WS4 CCS Upgrade 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** 2029 GGS 2 2032 GGS 1 CO2 395K NPV $4,571M NPVE $8,850M	**Expansion** 2029 Nuclear 2030 NGCC CCS 2031 Tier I Wind (*) 2036 Nuclear 2040 NGCC CCS 2041 Tier I Wind (2) 2041 Tier I Solar 2041 NGCC CCS **Coal Retirement** 2029 GGS 1 2029 GGS 2 2041 LRS 1 CO2 623K NPV $4,788M NPVE $8,864M
$7.00	**Expansion** 2030 Tier I Battery 2031 Tier I Battery 2034 Tier I Wind (*) 2035 NGCT 2038 Tier I Solar 2041 Tier I Battery 2041 Tier I Wind (2) **Coal Retirement** CO2 3,497K NPV $2,017M NPVE $4,306M	**Expansion** 2030 Tier I Battery 2031 Tier I Battery 2034 Tier I Wind (*) 2036 Tier I Wind 2038 DSM SEP 2039 RICE 2040 RICE 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 3,356K NPV $2,428M NPVE $5,313M	**Expansion** 2030 DSM SEP 2032 Tier I Wind (*) 2033 Nuclear 2037 Tier I Solar 2039 RICE 2040 RICE 2041 RICE (2) 2041 Tier I Wind (2) **Coal Retirement** CO2 2,804K NPV $2,849M NPVE $6,223M	**Expansion** 2030 Tier I Wind (*) 2031 Nuclear 2036 Nuclear 2038 Tier I Wind 2039 DSM SEP 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,044K NPV $3,283M NPVE $6,886M	**Expansion** 2030 Tier I Wind (*) 2031 Nuclear 2035 Tier I Wind (*) 2036 Nuclear 2039 DSM SEP 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,043K NPV $3,566M NPVE $7,479M	**Expansion** 2030 Tier I Wind (*) 2031 Nuclear 2035 Tier I Wind (*) 2036 Nuclear 2039 DSM SEP 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** 2040 GGS 2 CO2 1,166K NPV $3,888M NPVE $8,013M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2030 Tier I Wind (*) 2034 Nuclear 2037 NGCC CCS 2038 Tier I Wind 2040 Coal CCS 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** 2034 GGS 2 2040 GGS 1 CO2 451K NPV $4,242M NPVE $8,339M	**Expansion** 2027 Tier I Wind (*) 2029 Nuclear 2033 Nuclear 2033 WS4 CCS Upgrade 2037 NGCC CCS 2040 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 CO2 775K NPV $4,512M NPVE $8,715M	**Expansion** 2029 Nuclear 2032 Nuclear 2032 WS4 CCS Upgrade 2033 Tier I Wind (*) 2037 Coal CCS 2039 DSM SEP 2041 Tier I Wind (2) 2041 NGCC CCS **Coal Retirement** 2029 GGS 2 2041 GGS 1 CO2 876K NPV $4,783M NPVE $9,027M	**Expansion** 2029 Nuclear 2032 Nuclear 2032 WS4 CCS Upgrade 2033 Tier I Wind (*) 2037 Coal CCS 2038 Tier I Wind 2040 NGCC CCS 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** 2029 GGS 2 2040 GGS 1 CO2 398K NPV $4,965M NPVE $9,275M
$8.00	**Expansion** 2030 Tier I Battery 2031 Tier I Battery 2034 Tier I Wind (*) 2035 NGCT 2038 Tier I Solar 2040 DSM SEP 2041 Tier I Battery 2041 Tier I Wind (2) **Coal Retirement** CO2 3,446K NPV $2,070M NPVE $4,457M	**Expansion** 2030 Tier I Battery 2031 Tier I Battery 2034 Tier I Wind (*) 2035 DSM SEP 2036 NGCC CCS 2039 Tier I Solar 2041 Tier I Battery 2041 Tier I Wind (2) **Coal Retirement** CO2 3,146K NPV $2,476M NPVE $5,444M	**Expansion** 2030 Tier I Wind (*) 2031 Tier I Battery (2) 2034 DSM SEP 2036 Nuclear 2039 Tier I Solar 2041 Tier I Battery 2041 Tier I Wind (2) **Coal Retirement** CO2 2,891K NPV $2,899M NPVE $6,314M	**Expansion** 2030 Tier I Wind (*) 2031 Nuclear 2035 Tier I Wind (*) 2036 Nuclear 2039 DSM SEP 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,044K NPV $3,318M NPVE $6,939M	**Expansion** 2030 Tier I Wind (*) 2031 Nuclear 2035 Tier I Wind (*) 2036 Nuclear 2039 DSM SEP 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,045K NPV $3,593M NPVE $7,530M	**Expansion** 2030 Tier I Wind (*) 2031 Nuclear 2035 Tier I Wind (*) 2036 Nuclear 2039 DSM SEP 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,012K NPV $3,874M NPVE $8,128M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2035 Nuclear 2039 Nuclear 2040 Tier I Wind 2041 Tier I Wind (2) 2041 Tier I Solar **Coal Retirement** 2040 GGS 2 CO2 1,141K NPV $4,312M NPVE $8,475M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2030 Tier I Wind (*) 2032 Nuclear 2037 Nuclear 2040 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2032 GGS 2 CO2 793K NPV $4,512M NPVE $8,711M	**Expansion** 2029 Nuclear 2032 Nuclear 2032 WS4 CCS Upgrade 2037 Nuclear 2040 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 CO2 755K NPV $4,815M NPVE $9,186M	**Expansion** 2026 Tier I Wind (*) 2029 Nuclear 2033 WS4 CCS Upgrade 2037 Nuclear 2040 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 CO2 755K NPV $5,039M NPVE $9,494M
$9.00	**Expansion** 2030 Tier I Battery 2031 Tier I Battery 2034 Tier I Wind (*) 2035 NGCT 2038 Tier I Solar 2040 DSM SEP 2041 Tier I Battery 2041 Tier I Wind (2) **Coal Retirement** CO2 3,446K NPV $2,123M NPVE $4,602M	**Expansion** 2030 Tier I Battery 2031 Tier I Battery 2033 DSM SEP 2034 Tier I Wind (*) 2036 NGCC CCS 2039 Tier I Solar 2041 Tier I Battery 2041 Tier I Wind (2) **Coal Retirement** CO2 3,146K NPV $2,523M NPVE $5,575M	**Expansion** 2030 Tier I Wind (*) 2031 Tier I Battery (2) 2034 DSM SEP 2036 Nuclear 2039 Tier I Solar 2041 Tier I Battery 2041 Tier I Wind (2) **Coal Retirement** CO2 2,891K NPV $2,935M NPVE $6,397M	**Expansion** 2030 Tier I Wind (*) 2031 Nuclear 2035 Tier I Wind (*) 2036 Nuclear 2039 DSM SEP 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,044K NPV $3,347M NPVE $6,992M	**Expansion** 2030 Tier I Wind (*) 2031 Nuclear 2035 Tier I Wind (*) 2036 Nuclear 2039 DSM SEP 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,044K NPV $3,621M NPVE $7,580M	**Expansion** 2030 Tier I Wind (*) 2031 Nuclear 2035 Tier I Wind (*) 2036 Nuclear 2039 DSM SEP 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,045K NPV $3,900M NPVE $8,173M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2030 Tier I Wind (*) 2034 Nuclear 2037 NGCC CCS 2038 Tier I Wind 2040 Coal CCS 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** 2034 GGS 2 2040 GGS 1 CO2 1,029K NPV $4,308M NPVE $8,642M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2033 Nuclear 2033 WS4 CCS Upgrade 2037 NGCC CCS 2040 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 CO2 1,141K NPV $4,595M NPVE $8,930M	**Expansion** 2029 Nuclear 2032 Nuclear 2032 WS4 CCS Upgrade 2033 Tier I Wind (*) 2037 Coal CCS 2039 DSM SEP 2041 Tier I Wind (2) 2041 NGCC CCS **Coal Retirement** 2029 GGS 2 2041 GGS 1 CO2 793K NPV $4,757M NPVE $9,155M	**Expansion** 2029 Nuclear 2032 Nuclear 2032 WS4 CCS Upgrade 2033 Tier I Wind (*) 2037 Coal CCS 2038 Tier I Wind 2040 NGCC CCS 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** 2029 GGS 2 2040 GGS 1 CO2 755K NPV $5,075M NPVE $9,588M
$10.00	**Expansion** 2030 Tier I Battery 2031 Tier I Battery 2034 Tier I Wind (*) 2035 NGCT 2038 Tier I Solar 2040 DSM SEP 2041 Tier I Battery 2041 Tier I Wind (2) **Coal Retirement** CO2 3,446K NPV $2,176M NPVE $4,746M	**Expansion** 2030 Tier I Battery 2031 Tier I Battery 2033 DSM SEP 2034 Tier I Wind (*) 2036 Nuclear 2039 Tier I Solar 2041 Tier I Battery 2041 Tier I Wind (2) **Coal Retirement** CO2 2,864K NPV $2,611M NPVE $5,663M	**Expansion** 2030 Tier I Wind (*) 2031 Nuclear 2038 Tier I Wind 2039 DSM SEP 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,044K NPV $3,097M NPVE $6,458M	**Expansion** 2030 Tier I Wind (*) 2031 Nuclear 2035 Tier I Wind (*) 2036 Nuclear 2039 DSM SEP 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,044K NPV $3,376M NPVE $7,045M	**Expansion** 2030 Tier I Wind (*) 2031 Nuclear 2035 Tier I Wind (*) 2036 Nuclear 2039 DSM SEP 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,044K NPV $3,651M NPVE $7,633M	**Expansion** 2029 Tier I Wind (*) 2031 Nuclear 2035 Tier I Wind (*) 2036 Nuclear 2039 DSM SEP 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,044K NPV $3,928M NPVE $8,225M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2035 Nuclear 2039 Nuclear 2040 Tier I Wind 2040 Tier I Wind (*) 2041 Tier I Solar **Coal Retirement** CO2 1,051K NPV $4,336M NPVE $8,682M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2035 Nuclear 2039 Nuclear 2040 Tier I Wind 2040 Tier I Wind (*) 2041 Tier I Wind **Coal Retirement** CO2 1,026K NPV $4,594M NPVE $9,137M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2035 Nuclear 2039 Nuclear 2040 Tier I Wind 2041 Tier I Wind (*) 2041 Tier I Solar **Coal Retirement** 2040 GGS 2 CO2 1,139K NPV $4,882M NPVE $9,387M	**Expansion** 2026 Tier I Wind (*) 2029 Nuclear 2033 Nuclear 2033 WS4 CCS Upgrade 2037 Nuclear 2040 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2034 GGS 2 CO2 822K NPV $5,002M NPVE $9,570M

Resource Summary Tables

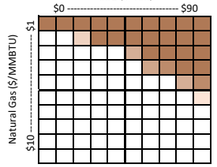
GGS 1
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



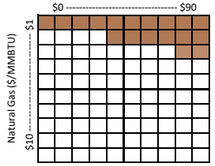
GGS 2
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



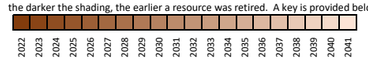
LRS 1
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



WS 4
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10

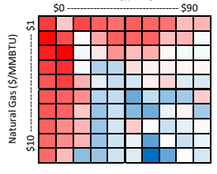


Notes:
1) Shaded cells indicate a resource's retirement within the 2022 - 2041 study period; the darker the shading, the earlier a resource was retired. A key is provided below:

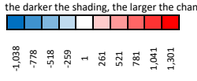


Comparison to Base Case

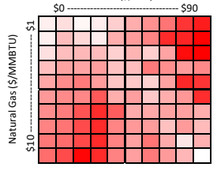
CO2
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



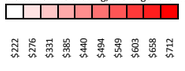
Notes:
1) Shaded cells indicate the change in CO2 emissions (thousand tons) for year 2040, relative to the base case; the darker the shading, the larger the change in emissions. A key is provided below:



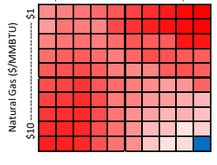
NPV
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



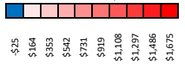
Notes:
1) Shaded cells indicate the change in total production costs ($M) over the 2022 - 2041 study period, relative to the base case; the darker the shading, the larger the change in cost. A key is provided below:



NPVE
CO2 ($/Ton)
$0 ---------- $90
Natural Gas ($/MMBTU) $1 ---------- $10



Notes:
1) Shaded cells indicate the change in total production costs ($M) over the 2022 - 2041 study plus the subsequent 30-year extension period, relative to the base case; the darker the shading, the larger the change in cost. A key is provided below:

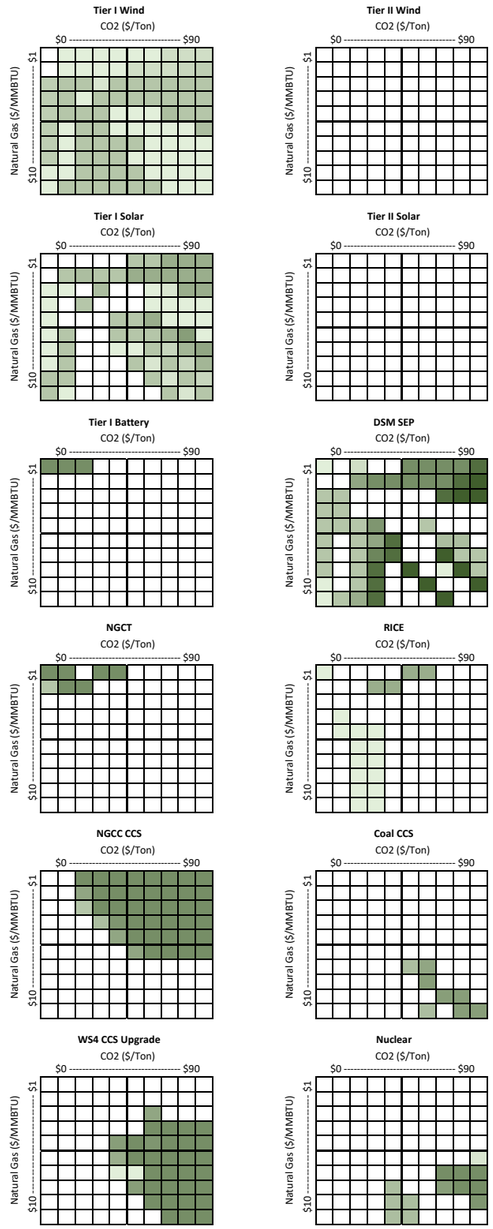


EGEAS Expansion Plans
Sensitivity 9: SPP 15% Reserve Margin

Natural Gas Price ($/MMBTU, 2022 $) / **CO2 Value ($/Short Ton, 2022 $)**

	$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
$1.00	**Expansion** 2029 NGCT 2029 Tier I Battery (4) 2034 NGCT 2041 DSM SEP 2041 RICE **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 1,394K NPV $1,462M NPVE $2,441M	**Expansion** 2029 NGCT 2029 Tier I Battery (4) 2034 NGCT 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 1,345K NPV $1,708M NPVE $3,069M	**Expansion** 2029 Tier I Battery (4) 2029 NGCC CCS 2034 NGCC CCS 2039 DSM SEP 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 609K NPV $1,978M NPVE $3,525M	**Expansion** 2029 NGCT 2029 NGCC CCS (2) 2031 NGCC CCS 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 523K NPV $2,160M NPVE $3,839M	**Expansion** 2029 NGCT 2029 NGCC CCS (2) 2031 NGCC CCS 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 528K NPV $2,275M NPVE $4,077M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (3) 2033 RICE 2036 Tier I Solar 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 423K NPV $2,367M NPVE $4,280M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (3) 2033 RICE 2036 Tier I Solar 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 423K NPV $2,471M NPVE $4,479M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2039 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 394K NPV $2,588M NPVE $4,675M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2039 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 393K NPV $2,691M NPVE $4,860M	**Expansion** 2025 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2039 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 391K NPV $2,793M NPVE $5,050M
$2.00	**Expansion** 2036 NGCT **Coal Retirement** 2029 GGS 2 2033 GGS 1 CO2 2,536K NPV $1,420M NPVE $2,658M	**Expansion** 2029 NGCT 2036 Tier I Solar 2041 Tier I Wind **Coal Retirement** 2029 GGS 2 2033 GGS 1 CO2 1,743K NPV $1,825M NPVE $3,543M	**Expansion** 2029 NGCT 2032 DSM SEP 2032 NGCC CCS 2035 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2032 LRS 1 CO2 867K NPV $2,179M NPVE $4,174M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (2) 2033 NGCC CCS 2036 Tier I Solar 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2033 WS 4 CO2 424K NPV $2,460M NPVE $4,519M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (3) 2033 RICE 2036 Tier I Solar 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 425K NPV $2,595M NPVE $4,736M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2039 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 398K NPV $2,711M NPVE $4,922M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2039 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 397K NPV $2,814M NPVE $5,108M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2039 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 397K NPV $2,918M NPVE $5,297M	**Expansion** 2025 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2038 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 395K NPV $3,023M NPVE $5,485M	**Expansion** 2023 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2037 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 395K NPV $3,125M NPVE $5,668M
$3.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,686K NPV $1,451M NPVE $2,775M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,210K NPV $1,842M NPVE $3,750M	**Expansion** 2036 Tier I Wind 2036 NGCC CCS 2041 Tier I Wind (2) **Coal Retirement** 2036 GGS 2 CO2 1,347K NPV $2,228M NPVE $4,475M	**Expansion** 2029 NGCC CCS 2035 Tier I Solar 2040 Tier I Wind 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 CO2 1,048K NPV $2,541M NPVE $4,979M	**Expansion** 2029 NGCC CCS 2034 NGCC CCS (2) 2036 Tier I Wind 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2034 LRS 1 CO2 526K NPV $2,790M NPVE $5,212M	**Expansion** 2029 NGCC CCS (3) 2036 Tier I Wind 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 491K NPV $2,958M NPVE $5,437M	**Expansion** 2029 NGCC CCS (3) 2032 WS4 CCS Upgrade 2036 Tier I Wind 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 394K NPV $3,092M NPVE $5,652M	**Expansion** 2025 DSM SEP 2029 NGCC CCS (3) 2036 Tier I Wind 2040 Tier I Solar 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2040 WS 4 CO2 394K NPV $3,205M NPVE $5,878M	**Expansion** 2023 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2036 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2031 WS 4 CO2 394K NPV $3,340M NPVE $6,083M	**Expansion** 2023 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2036 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 395K NPV $3,441M NPVE $6,267M
$4.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,635K NPV $1,480M NPVE $2,844M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind **Coal Retirement** CO2 2,532K NPV $1,850M NPVE $3,791M	**Expansion** 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 2,244K NPV $2,256M NPVE $4,690M	**Expansion** 2035 NGCC CCS 2036 Tier I Wind 2041 Tier I Wind (2) **Coal Retirement** 2035 GGS 2 CO2 1,378K NPV $2,650M NPVE $5,340M	**Expansion** 2030 NGCC CCS 2036 Tier I Wind 2041 Tier I Wind (2) **Coal Retirement** 2030 GGS 2 CO2 1,226K NPV $2,929M NPVE $5,838M	**Expansion** 2029 NGCC CCS 2034 NGCC CCS 2036 Tier I Wind 2040 NGCC CCS 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2040 LRS 1 CO2 551K NPV $3,156M NPVE $5,974M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2030 NGCC CCS 2034 NGCC CCS 2036 Tier I Wind 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2034 LRS 1 CO2 384K NPV $3,297M NPVE $6,164M	**Expansion** 2029 NGCC CCS (3) 2029 WS4 CCS Upgrade 2036 Tier I Wind 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 385K NPV $3,447M NPVE $6,370M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2036 Tier I Wind 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 386K NPV $3,569M NPVE $6,567M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2036 Tier I Wind 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 386K NPV $3,672M NPVE $6,746M
$5.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,633K NPV $1,511M NPVE $2,916M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind **Coal Retirement** CO2 2,509K NPV $1,881M NPVE $3,866M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,485K NPV $2,237M NPVE $4,722M	**Expansion** 2030 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,054K NPV $2,638M NPVE $5,569M	**Expansion** 2031 WS4 CCS Upgrade 2032 NGCC CCS 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 1,109K NPV $3,104M NPVE $6,211M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 CO2 976K NPV $3,359M NPVE $6,646M	**Expansion** 2029 NGCC CCS 2030 WS4 CCS Upgrade 2033 Tier I Solar 2036 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2033 GGS 1 CO2 818K NPV $3,569M NPVE $7,022M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2030 NGCC CCS 2035 Tier I Wind 2040 NGCC CCS 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2040 LRS 1 CO2 365K NPV $3,652M NPVE $6,928M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2030 NGCC CCS 2034 NGCC CCS 2036 Tier I Wind 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2034 LRS 1 CO2 372K NPV $3,779M NPVE $7,083M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2030 NGCC CCS (2) 2036 Tier I Wind 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2030 LRS 1 CO2 384K NPV $3,916M NPVE $7,281M

Resource Summary Tables



Notes:

1) Shaded cells indicate a resource's inclusion within the 2022 - 2041 study period; the darker the shading, the earlier a resource was selected. A key is provided below:

2) Data reflects EGEAS' lowest cost expansion plan for each scenario, including the 30-year extension period.
3) *CO2* values reflect LES' total CO2 emissions for year 2040 in units of tons.
4) *NPV* values reflect LES' total production costs over the 2022 - 2041 study period.
5) *NPVE* values reflect LES' total production costs over the 2022 - 2041 study period plus the subequent 30-year extension period.
6) Multiple selections of the same resource in the same year are denoted by (#).
7) Tier I Wind that was installed early as Tier II Wind - but utilmately graduated to Tier I status following the end of a contract for an existing Tier I Wind resource - is denoted by (*).

EGEAS Expansion Plans
Sensitivity 9: SPP 15% Reserve Margin

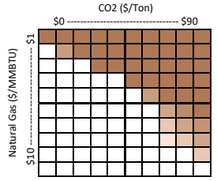
CO2 Value ($/Short Ton, 2022 $)

Natural Gas Price ($/MMBTU, 2022 $)

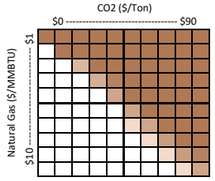
	$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
$6.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,633K NPV $1,543M NPVE $2,986M	**Expansion** 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 2,552K NPV $1,923M NPVE $3,937M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,513K NPV $2,267M NPVE $4,763M	**Expansion** 2032 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,371K NPV $2,631M NPVE $5,694M	**Expansion** 2025 DSM SEP 2033 WS4 CCS Upgrade 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 1,595K NPV $3,068M NPVE $6,427M	**Expansion** 2029 WS4 CCS Upgrade 2032 NGCC CCS 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2034 GGS 2 CO2 1,040K NPV $3,451M NPVE $6,967M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 CO2 972K NPV $3,726M NPVE $7,446M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2034 Tier I Solar 2035 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2034 GGS 1 CO2 854K NPV $3,946M NPVE $7,780M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2031 Tier I Solar 2035 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2031 GGS 1 CO2 775K NPV $4,149M NPVE $8,141M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2030 NGCC CCS 2035 Tier I Wind (*) 2040 Nuclear 2041 Tier I Solar **Coal Retirement** 2040 LRS 1 2029 GGS 1 2029 GGS 2 CO2 368K NPV $4,169M NPVE $7,877M
$7.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,633K NPV $1,575M NPVE $3,057M	**Expansion** 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 2,552K NPV $1,955M NPVE $4,003M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,298M NPVE $4,835M	**Expansion** 2028 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,458K NPV $2,654M NPVE $5,704M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 Tier I Wind 2041 Tier I Solar 2041 WS4 CCS Upgrade **Coal Retirement** CO2 2,274K NPV $3,031M NPVE $6,618M	**Expansion** 2035 Coal CCS 2036 Tier I Wind 2037 Tier I Wind (*) 2041 Tier I Solar 2041 WS4 CCS Upgrade **Coal Retirement** 2040 GGS 2 CO2 1,662K NPV $3,504M NPVE $7,194M	**Expansion** 2029 WS4 CCS Upgrade 2032 Coal CCS 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2034 GGS 2 CO2 1,044K NPV $3,853M NPVE $7,666M	**Expansion** 2023 DSM SEP 2029 Nuclear 2029 WS4 CCS Upgrade 2038 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2038 GGS 1 CO2 869K NPV $4,111M NPVE $8,062M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2034 Tier I Solar 2036 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2034 GGS 1 CO2 818K NPV $4,379M NPVE $8,469M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2032 Tier I Solar 2036 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2032 GGS 1 CO2 776K NPV $4,584M NPVE $8,792M
$8.00	**Expansion** 2036 DSM SEP 2037 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,633K NPV $1,608M NPVE $3,128M	**Expansion** 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 2,552K NPV $1,986M NPVE $4,070M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,330M NPVE $4,904M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,462K NPV $2,685M NPVE $5,764M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2038 Tier I Wind (*) **Coal Retirement** CO2 2,220K NPV $3,134M NPVE $6,621M	**Expansion** 2023 DSM SEP 2031 WS4 CCS Upgrade 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 1,745K NPV $3,454M NPVE $7,394M	**Expansion** 2029 WS4 CCS Upgrade 2031 Coal CCS 2040 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2040 GGS 2 CO2 1,163K NPV $3,899M NPVE $7,857M	**Expansion** 2029 WS4 CCS Upgrade 2031 Nuclear 2036 Tier I Solar 2041 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2033 GGS 2 2041 GGS 1 CO2 1,012K NPV $4,168M NPVE $8,236M	**Expansion** 2023 DSM SEP 2029 Nuclear 2036 Tier I Solar 2038 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2038 GGS 1 CO2 860K NPV $4,397M NPVE $8,664M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2034 Tier I Solar 2036 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2034 GGS 1 CO2 782K NPV $4,684M NPVE $9,080M
$9.00	**Expansion** 2036 Tier I Solar 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** CO2 2,678K NPV $1,641M NPVE $3,199M	**Expansion** 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 2,552K NPV $2,017M NPVE $4,137M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,362M NPVE $4,973M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,462K NPV $2,715M NPVE $5,832M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2038 Tier I Wind (*) **Coal Retirement** CO2 2,243K NPV $3,160M NPVE $6,651M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 2,125K NPV $3,496M NPVE $7,459M	**Expansion** 2023 DSM SEP 2029 WS4 CCS Upgrade 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 1,701K NPV $3,818M NPVE $8,184M	**Expansion** 2029 WS4 CCS Upgrade 2031 Coal CCS 2040 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2040 GGS 2 CO2 1,156K NPV $4,209M NPVE $8,508M	**Expansion** 2029 WS4 CCS Upgrade 2031 Coal CCS 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2033 GGS 2 CO2 1,011K NPV $4,486M NPVE $8,968M	**Expansion** 2023 DSM SEP 2029 WS4 CCS Upgrade 2030 Nuclear 2038 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2030 GGS 2 2038 GGS 1 CO2 839K NPV $4,700M NPVE $9,262M
$10.00	**Expansion** 2036 Tier I Solar 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** CO2 2,678K NPV $1,673M NPVE $3,270M	**Expansion** 2036 DSM SEP 2036 Tier I Wind 2041 Tier I Wind 2041 Tier I Solar **Coal Retirement** CO2 2,507K NPV $2,042M NPVE $4,202M	**Expansion** 2033 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,511K NPV $2,393M NPVE $5,042M	**Expansion** 2025 DSM SEP 2036 Tier I Wind 2041 RICE 2041 Tier I Wind (2) **Coal Retirement** CO2 2,462K NPV $2,745M NPVE $5,899M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2038 Tier I Wind (*) **Coal Retirement** CO2 2,244K NPV $3,187M NPVE $6,702M	**Expansion** 2035 Nuclear 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 2,187K NPV $3,520M NPVE $7,482M	**Expansion** 2035 Coal CCS 2036 Tier I Wind 2037 Tier I Wind (*) **Coal Retirement** CO2 2,089K NPV $3,858M NPVE $8,300M	**Expansion** 2023 DSM SEP 2029 WS4 CCS Upgrade 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** CO2 1,661K NPV $4,177M NPVE $8,939M	**Expansion** 2029 WS4 CCS Upgrade 2031 Coal CCS 2040 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2040 GGS 2 CO2 1,119K NPV $4,518M NPVE $9,140M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2031 Coal CCS 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2034 GGS 2 CO2 992K NPV $4,780M NPVE $9,595M

Resource Summary Tables

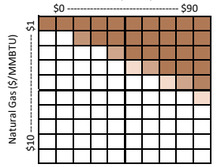
GGS 1
CO2 ($/Ton)



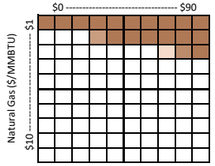
GGS 2
CO2 ($/Ton)



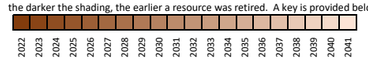
LRS 1
CO2 ($/Ton)



WS 4
CO2 ($/Ton)

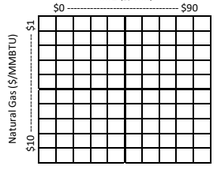


Notes:
1) Shaded cells indicate a resource's retirement within the 2022 - 2041 study period; the darker the shading, the earlier a resource was retired. A key is provided below:

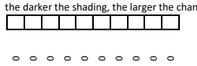


Comparison to Base Case

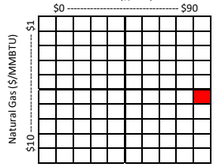
CO2
CO2 ($/Ton)



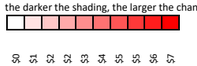
Notes:
1) Shaded cells indicate the change in CO2 emissions (thousand tons) for year 2040, relative to the base case; the darker the shading, the larger the change in emissions. A key is provided below:



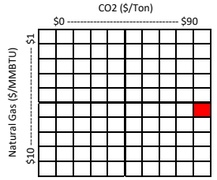
NPV
CO2 ($/Ton)



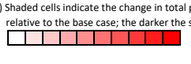
Notes:
1) Shaded cells indicate the change in total production costs ($M) over the 2022 - 2041 study period, relative to the base case; the darker the shading, the larger the change in cost. A key is provided below:



NPVE
CO2 ($/Ton)



Notes:
1) Shaded cells indicate the change in total production costs ($M) over the 2022 - 2041 study plus the subsequent 30-year extension period, relative to the base case; the darker the shading, the larger the change in cost. A key is provided below:

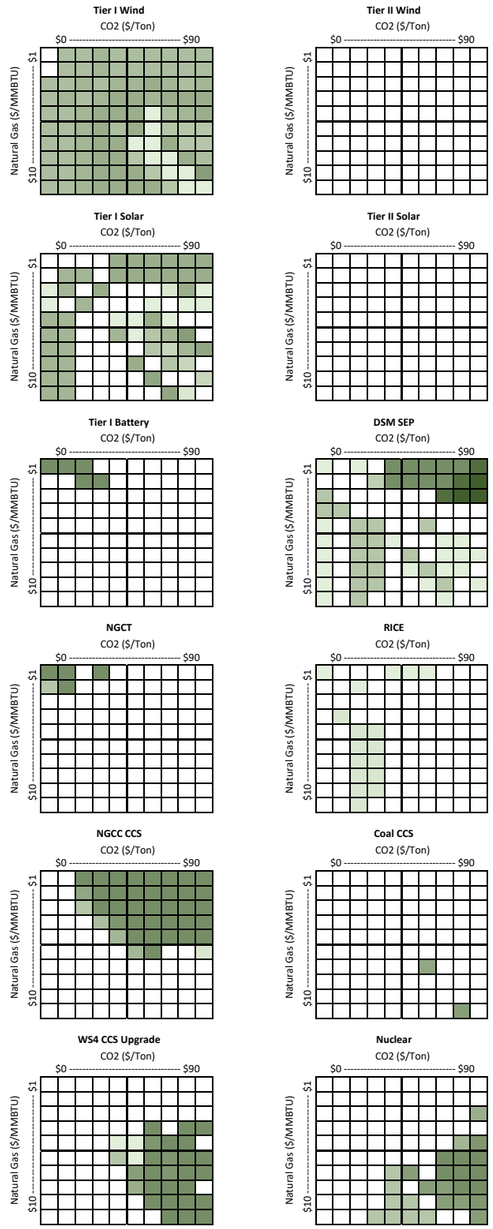


EGEAS Expansion Plans
Sensitivity 10: Inflation Reduction Act

Natural Gas Price ($/MMBTU, 2022 $) — **CO2 Value ($/Short Ton, 2022 $)**

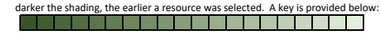
Natural Gas Price	$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
$1.00	**Expansion** 2029 NGCT 2029 Tier I Battery (4) 2034 NGCT 2041 DSM SEP 2041 RICE **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 1,394K NPV $1,418M NPVE $2,397M	**Expansion** 2029 NGCT 2029 Tier I Battery (4) 2034 NGCT 2035 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 1,116K NPV $1,685M NPVE $3,011M	**Expansion** 2029 Tier I Battery (4) 2029 NGCC CCS 2034 NGCC CCS 2035 Tier I Wind 2041 DSM SEP **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 577K NPV $1,957M NPVE $3,470M	**Expansion** 2029 NGCT 2029 NGCC CCS (2) 2031 NGCC CCS 2034 Tier I Wind (*) **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 471K NPV $2,180M NPVE $3,824M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2035 Tier I Wind (*) 2041 RICE **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 395K NPV $2,270M NPVE $4,035M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2035 Tier I Wind (*) 2041 RICE **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 395K NPV $2,369M NPVE $4,229M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2035 Tier I Wind (*) 2041 RICE **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 394K NPV $2,470M NPVE $4,425M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2035 Tier I Wind (*) 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 394K NPV $2,575M NPVE $4,615M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2035 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 393K NPV $2,676M NPVE $4,799M	**Expansion** 2025 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2035 Tier I Wind (*) 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 391K NPV $2,776M NPVE $4,987M
$2.00	**Expansion** 2036 NGCT **Coal Retirement** CO2 2,536K NPV $1,420M NPVE $2,658M	**Expansion** 2029 NGCT 2034 Tier I Solar 2035 Tier I Wind (*) **Coal Retirement** 2029 GGS 2 2033 GGS 1 CO2 1,609K NPV $1,851M NPVE $3,514M	**Expansion** 2029 Tier I Battery (2) 2031 Tier I Battery 2032 NGCC CCS 2034 Tier I Solar 2035 Tier I Wind 2041 RICE **Coal Retirement** 2029 GGS 1 2029 GGS 2 2032 LRS 1 CO2 857K NPV $2,197M NPVE $4,089M	**Expansion** 2029 Tier I Battery (2) 2029 NGCC CCS 2032 NGCC CCS 2033 NGCC CCS 2034 Tier I Wind (*) 2035 Tier I Wind 2037 DSM SEP **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2033 WS 4 CO2 411K NPV $2,494M NPVE $4,457M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2035 Tier I Wind (*) 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 398K NPV $2,596M NPVE $4,678M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2035 Tier I Wind (*) 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 398K NPV $2,697M NPVE $4,861M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2035 Tier I Wind (*) 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 397K NPV $2,799M NPVE $5,046M	**Expansion** 2029 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2035 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 397K NPV $2,901M NPVE $5,233M	**Expansion** 2025 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2035 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 395K NPV $3,003M NPVE $5,420M	**Expansion** 2023 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2035 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 395K NPV $3,102M NPVE $5,603M
$3.00	**Expansion** 2035 Tier I Wind (*) 2036 DSM SEP 2041 Tier I Solar **Coal Retirement** CO2 2,686K NPV $1,452M NPVE $2,752M	**Expansion** 2034 Tier I Solar 2035 Tier I Wind (*) 2041 Tier I Wind **Coal Retirement** CO2 2,212K NPV $1,874M NPVE $3,719M	**Expansion** 2034 Tier I Wind (*) 2035 Tier I Wind 2036 NGCC CCS 2041 Tier I Wind **Coal Retirement** 2036 GGS 2 CO2 1,318K NPV $2,250M NPVE $4,440M	**Expansion** 2033 Tier I Solar 2035 Tier I Wind (*) 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 CO2 1,048K NPV $2,550M NPVE $4,935M	**Expansion** 2029 NGCC CCS 2034 Tier I Wind (*) 2034 NGCC CCS (2) 2035 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2034 LRS 1 CO2 502K NPV $2,802M NPVE $5,168M	**Expansion** 2029 NGCC CCS (3) 2034 Tier I Wind (*) 2035 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 467K NPV $2,967M NPVE $5,390M	**Expansion** 2029 NGCC CCS (3) 2033 Tier I Wind (*) 2035 Tier I Wind (*) 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 446K NPV $3,090M NPVE $5,604M	**Expansion** 2029 NGCC CCS (3) 2034 Tier I Wind (*) 2035 Tier I Wind (*) 2040 Tier I Solar 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2040 WS 4 CO2 394K NPV $3,195M NPVE $5,846M	**Expansion** 2025 DSM SEP 2029 NGCC CCS (3) 2033 Tier I Solar 2034 Tier I Wind (*) 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2031 WS 4 CO2 394K NPV $3,314M NPVE $6,017M	**Expansion** 2023 DSM SEP 2029 NGCC CCS (3) 2033 Nuclear 2034 Tier I Wind (*) 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 2029 WS 4 CO2 245K NPV $3,504M NPVE $6,167M
$4.00	**Expansion** 2035 Tier I Wind (*) 2036 DSM SEP 2041 Tier I Solar **Coal Retirement** CO2 2,635K NPV $1,481M NPVE $2,821M	**Expansion** 2034 Tier I Wind (*) 2035 Tier I Wind (*) 2036 DSM SEP 2040 RICE **Coal Retirement** CO2 2,520K NPV $1,876M NPVE $3,760M	**Expansion** 2034 Tier I Solar 2035 Tier I Wind (*) 2041 Tier I Wind **Coal Retirement** CO2 2,170K NPV $2,269M NPVE $4,648M	**Expansion** 2034 Tier I Wind (*) 2035 Tier I Wind 2035 NGCC CCS 2041 Tier I Wind **Coal Retirement** 2035 GGS 2 CO2 1,352K NPV $2,666M NPVE $5,300M	**Expansion** 2030 NGCC CCS 2033 Tier I Wind (*) 2035 Tier I Wind 2041 Tier I Wind **Coal Retirement** 2030 GGS 2 CO2 1,191K NPV $2,940M NPVE $5,792M	**Expansion** 2029 NGCC CCS 2033 Tier I Wind (*) 2035 Tier I Wind 2036 NGCC CCS 2040 NGCC CCS 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2040 LRS 1 CO2 537K NPV $3,161M NPVE $5,935M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2030 NGCC CCS 2034 Tier I Wind (*) 2034 NGCC CCS 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2034 LRS 1 CO2 384K NPV $3,287M NPVE $6,131M	**Expansion** 2029 NGCC CCS 2033 Tier I Wind (*) 2035 Tier I Wind (*) 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 485K NPV $3,453M NPVE $6,324M	**Expansion** 2029 NGCC CCS 2033 Tier I Wind (*) 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 386K NPV $3,557M NPVE $6,533M	**Expansion** 2029 NGCC CCS 2033 Tier I Wind (*) 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2029 LRS 1 CO2 386K NPV $3,660M NPVE $6,711M
$5.00	**Expansion** 2034 Tier I Solar 2035 Tier I Wind (*) 2041 DSM SEP **Coal Retirement** CO2 2,637K NPV $1,544M NPVE $2,892M	**Expansion** 2034 Tier I Solar 2035 Tier I Wind (*) 2041 Tier I Wind **Coal Retirement** CO2 2,511K NPV $1,910M NPVE $3,831M	**Expansion** 2034 Tier I Wind (*) 2035 Tier I Wind 2036 DSM SEP 2040 RICE 2041 Tier I Wind **Coal Retirement** CO2 2,474K NPV $2,256M NPVE $4,684M	**Expansion** 2033 Tier I Wind (*) 2035 Tier I Wind 2036 DSM SEP 2040 RICE 2041 Tier I Wind **Coal Retirement** CO2 2,037K NPV $2,655M NPVE $5,529M	**Expansion** 2033 Tier I Wind (*) 2034 NGCC CCS 2035 Tier I Wind 2041 Tier I Solar 2041 WS4 CCS Upgrade **Coal Retirement** 2034 GGS 2 CO2 1,418K NPV $3,063M NPVE $6,166M	**Expansion** 2029 NGCC CCS 2033 Tier I Wind (*) 2035 Tier I Wind 2041 Tier I Solar 2041 WS4 CCS Upgrade **Coal Retirement** 2029 GGS 2 CO2 1,197K NPV $3,344M NPVE $6,616M	**Expansion** 2029 NGCC CCS 2030 WS4 CCS Upgrade 2033 Tier I Solar 2036 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 2033 GGS 1 CO2 818K NPV $3,548M NPVE $6,983M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2030 NGCC CCS 2035 Tier I Wind (*) 2040 NGCC CCS 2041 Tier I Solar **Coal Retirement** 2029 GGS 1 2029 GGS 2 2040 LRS 1 CO2 365K NPV $3,639M NPVE $6,895M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2030 NGCC CCS 2034 Tier I Wind (*) 2034 Nuclear 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2034 LRS 1 CO2 375K NPV $3,820M NPVE $7,027M	**Expansion** 2029 NGCC CCS 2030 Nuclear 2030 NGCC CCS 2033 Tier I Wind (*) 2036 NGCC CCS 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2030 LRS 1 CO2 303K NPV $4,006M NPVE $7,188M

Resource Summary Tables



Notes:

1) Shaded cells indicate a resource's inclusion within the 2022 - 2041 study period; the darker the shading, the earlier a resource was selected. A key is provided below:



2) Data reflects EGEAS' lowest cost expansion plan for each scenario, including the 30-year extension period.
3) *CO2* values reflect LES' total CO2 emissions for year 2040 in units of tons.
4) *NPV* values reflect LES' total production costs over the 2022 - 2041 study period.
5) *NPVE* values reflect LES' total production costs over the 2022 - 2041 study period plus the subequent 30-year extension period.
6) Multiple selections of the same resource in the same year are denoted by (#).
7) Tier I Wind that was installed early as Tier II Wind - but utilmately graduated to Tier I status following the end of a contract for an existing Tier I Wind resource - is denoted by (*).

EGEAS Expansion Plans
Sensitivity 10: Inflation Reduction Act

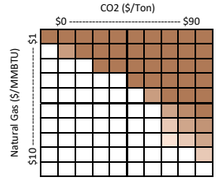
CO2 Value ($/Short Ton, 2022 $)

Natural Gas Price ($/MMBTU, 2022 $)

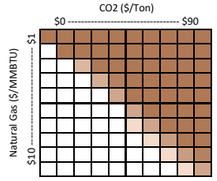
	$0.00	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00	$90.00
$6.00	**Expansion** 2034 Tier I Solar 2035 Tier I Wind (*) 2041 DSM SEP **Coal Retirement** CO2 2,637K NPV $1,575M NPVE $2,960M	**Expansion** 2034 Tier I Solar 2035 Tier I Wind (*) 2041 Tier I Wind **Coal Retirement** CO2 2,510K NPV $1,940M NPVE $3,898M	**Expansion** 2034 Tier I Wind (*) 2035 Tier I Wind 2036 DSM SEP 2040 RICE 2041 Tier I Wind **Coal Retirement** CO2 2,502K NPV $2,285M NPVE $4,724M	**Expansion** 2033 Tier I Wind (*) 2035 Tier I Wind (*) 2036 DSM SEP 2040 RICE 2041 Tier I Wind **Coal Retirement** CO2 2,358K NPV $2,644M NPVE $5,651M	**Expansion** 2034 Tier I Solar 2035 Tier I Wind (*) 2036 WS4 CCS Upgrade 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** CO2 1,545K NPV $3,069M NPVE $6,385M	**Expansion** 2033 Tier I Wind (*) 2034 NGCC CCS 2035 Tier I Wind 2041 Tier I Solar 2041 WS4 CCS Upgrade **Coal Retirement** 2034 GGS 2 CO2 1,406K NPV $3,439M NPVE $6,953M	**Expansion** 2029 NGCC CCS 2029 WS4 CCS Upgrade 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2029 GGS 2 CO2 972K NPV $3,722M NPVE $7,436M	**Expansion** 2029 Nuclear 2030 WS4 CCS Upgrade 2034 Tier I Solar 2036 Tier I Wind 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** 2029 GGS 2 2034 GGS 1 CO2 842K NPV $3,982M NPVE $7,670M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2031 Tier I Solar 2036 Tier I Wind 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** 2029 GGS 2 2031 GGS 1 CO2 758K NPV $4,170M NPVE $8,022M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2030 Nuclear 2036 Tier I Wind 2040 NGCC CCS 2041 Tier I Wind **Coal Retirement** 2029 GGS 1 2029 GGS 2 2040 LRS 1 CO2 364K NPV $4,225M NPVE $7,663M
$7.00	**Expansion** 2034 Tier I Solar 2035 Tier I Wind (*) 2041 DSM SEP **Coal Retirement** CO2 2,636K NPV $1,606M NPVE $3,030M	**Expansion** 2034 Tier I Solar 2035 Tier I Wind (*) 2041 Tier I Wind **Coal Retirement** CO2 2,509K NPV $1,971M NPVE $3,965M	**Expansion** 2034 Tier I Wind (*) 2035 Tier I Wind 2036 DSM SEP 2040 RICE 2041 Tier I Wind **Coal Retirement** CO2 2,500K NPV $2,316M NPVE $4,796M	**Expansion** 2033 Tier I Wind (*) 2035 Tier I Wind (*) 2036 DSM SEP 2040 RICE 2041 Tier I Wind **Coal Retirement** CO2 2,447K NPV $2,667M NPVE $5,660M	**Expansion** 2033 Tier I Wind (*) 2035 Tier I Wind (*) 2036 Nuclear **Coal Retirement** CO2 2,060K NPV $3,073M NPVE $6,534M	**Expansion** 2031 Nuclear 2031 WS4 CCS Upgrade 2036 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2040 GGS 2 CO2 1,256K NPV $3,465M NPVE $7,130M	**Expansion** 2029 WS4 CCS Upgrade 2032 Coal CCS 2036 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2034 GGS 2 CO2 1,044K NPV $3,850M NPVE $7,657M	**Expansion** 2029 Nuclear 2030 WS4 CCS Upgrade 2033 Tier I Wind (*) 2038 Tier I Solar 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** 2029 GGS 2 2038 GGS 1 CO2 866K NPV $4,049M NPVE $7,926M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2034 Tier I Solar 2036 Tier I Wind 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** 2029 GGS 2 2034 GGS 1 CO2 810K NPV $4,291M NPVE $8,305M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2032 Tier I Solar 2036 Tier I Wind 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** 2029 GGS 2 2032 GGS 1 CO2 769K NPV $4,487M NPVE $8,621M
$8.00	**Expansion** 2034 Tier I Solar 2035 Tier I Wind (*) 2041 DSM SEP **Coal Retirement** CO2 2,636K NPV $1,637M NPVE $3,100M	**Expansion** 2034 Tier I Solar 2035 Tier I Wind (*) 2041 Tier I Wind **Coal Retirement** CO2 2,509K NPV $2,001M NPVE $4,030M	**Expansion** 2034 Tier I Wind (*) 2035 Tier I Wind 2036 DSM SEP 2040 RICE 2041 Tier I Wind **Coal Retirement** CO2 2,500K NPV $2,347M NPVE $4,864M	**Expansion** 2033 Tier I Wind (*) 2035 Tier I Wind (*) 2036 DSM SEP 2040 RICE 2041 Tier I Wind **Coal Retirement** CO2 2,451K NPV $2,699M NPVE $5,721M	**Expansion** 2033 Tier I Wind (*) 2035 Tier I Wind (*) 2036 Nuclear **Coal Retirement** CO2 2,220K NPV $3,084M NPVE $6,503M	**Expansion** 2033 Tier I Solar 2033 WS4 CCS Upgrade 2036 Tier I Wind 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** CO2 1,681K NPV $3,462M NPVE $7,359M	**Expansion** 2029 WS4 CCS Upgrade 2031 Nuclear 2036 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2040 GGS 2 CO2 1,200K NPV $3,783M NPVE $7,829M	**Expansion** 2029 WS4 CCS Upgrade 2031 Nuclear 2036 Tier I Solar 2041 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2033 GGS 2 2041 GGS 1 CO2 1,012K NPV $4,086M NPVE $8,099M	**Expansion** 2029 Nuclear 2029 WS4 CCS Upgrade 2033 Tier I Wind (*) 2038 Tier I Solar 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** 2029 GGS 2 2038 GGS 1 CO2 852K NPV $4,336M NPVE $8,535M	**Expansion** 2029 Nuclear 2034 Nuclear 2035 Tier I Wind (*) 2041 Nuclear **Coal Retirement** 2029 GGS 2 2034 GGS 1 CO2 916K NPV $4,624M NPVE $8,908M
$9.00	**Expansion** 2034 Tier I Solar 2035 Tier I Wind (*) 2041 DSM SEP **Coal Retirement** CO2 2,636K NPV $1,667M NPVE $3,170M	**Expansion** 2034 Tier I Solar 2035 Tier I Wind (*) 2041 Tier I Wind **Coal Retirement** CO2 2,509K NPV $2,032M NPVE $4,097M	**Expansion** 2034 Tier I Wind (*) 2035 Tier I Wind 2036 DSM SEP 2040 RICE 2041 Tier I Wind **Coal Retirement** CO2 2,500K NPV $2,379M NPVE $4,933M	**Expansion** 2033 Tier I Wind (*) 2035 Tier I Wind (*) 2036 DSM SEP 2040 RICE 2041 Tier I Wind **Coal Retirement** CO2 2,451K NPV $2,730M NPVE $5,790M	**Expansion** 2033 Tier I Wind (*) 2035 Tier I Wind (*) 2036 Nuclear **Coal Retirement** CO2 2,243K NPV $3,111M NPVE $6,534M	**Expansion** 2033 Tier I Wind (*) 2035 Tier I Wind (*) 2036 Nuclear **Coal Retirement** CO2 2,125K NPV $3,447M NPVE $7,344M	**Expansion** 2029 WS4 CCS Upgrade 2032 Tier I Solar 2036 Tier I Wind 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** CO2 1,660K NPV $3,837M NPVE $8,158M	**Expansion** 2029 WS4 CCS Upgrade 2031 Nuclear 2036 DSM SEP 2041 Tier I Wind (2) **Coal Retirement** 2040 GGS 2 CO2 1,194K NPV $4,090M NPVE $8,501M	**Expansion** 2029 WS4 CCS Upgrade 2031 Nuclear 2036 Nuclear 2041 Tier I Wind **Coal Retirement** 2033 GGS 2 CO2 862K NPV $4,382M NPVE $8,922M	**Expansion** 2029 WS4 CCS Upgrade 2030 Nuclear 2031 Tier I Wind (*) 2038 Tier I Solar 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** 2030 GGS 2 2038 GGS 1 CO2 829K NPV $4,633M NPVE $9,122M
$10.00	**Expansion** 2034 Tier I Solar 2035 Tier I Wind (*) 2041 DSM SEP **Coal Retirement** CO2 2,636K NPV $1,698M NPVE $3,240M	**Expansion** 2034 Tier I Solar 2035 Tier I Wind (*) 2041 Tier I Wind **Coal Retirement** CO2 2,509K NPV $2,062M NPVE $4,163M	**Expansion** 2034 Tier I Wind (*) 2035 Tier I Wind 2036 DSM SEP 2040 RICE 2041 Tier I Wind **Coal Retirement** CO2 2,500K NPV $2,410M NPVE $5,001M	**Expansion** 2033 Tier I Wind (*) 2035 Tier I Wind (*) 2036 Nuclear **Coal Retirement** CO2 2,267K NPV $2,821M NPVE $5,852M	**Expansion** 2033 Tier I Wind (*) 2035 Tier I Wind (*) 2036 Nuclear **Coal Retirement** CO2 2,244K NPV $3,139M NPVE $6,585M	**Expansion** 2033 Tier I Wind (*) 2035 Tier I Wind (*) 2036 Nuclear **Coal Retirement** CO2 2,187K NPV $3,472M NPVE $7,367M	**Expansion** 2033 Tier I Wind (*) 2035 Tier I Wind (*) 2036 Nuclear **Coal Retirement** CO2 2,085K NPV $3,817M NPVE $8,188M	**Expansion** 2029 WS4 CCS Upgrade 2032 Tier I Solar 2036 Tier I Wind 2041 DSM SEP 2041 Tier I Wind **Coal Retirement** 2033 GGS 2 2041 GGS 1 CO2 1,607K NPV $4,203M NPVE $8,919M	**Expansion** 2029 WS4 CCS Upgrade 2031 Coal CCS 2040 Tier I Solar 2041 Tier I Wind (2) **Coal Retirement** 2040 GGS 2 CO2 1,119K NPV $4,518M NPVE $9,140M	**Expansion** 2029 WS4 CCS Upgrade 2031 Nuclear 2036 Nuclear 2041 Tier I Wind **Coal Retirement** 2034 GGS 2 CO2 829K NPV $4,653M NPVE $9,503M

Resource Summary Tables

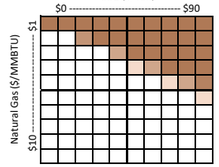
GGS 1



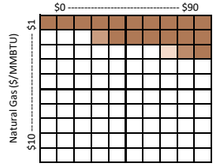
GGS 2



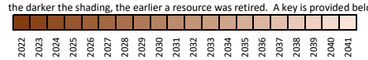
LRS 1



WS 4

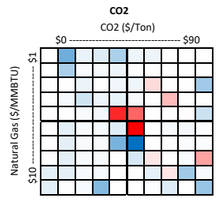


Notes:
1) Shaded cells indicate a resource's retirement within the 2022 - 2041 study period; the darker the shading, the earlier a resource was retired. A key is provided below:



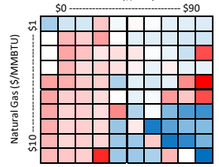
Comparison to Base Case

CO2



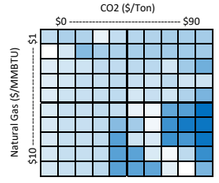
Notes:
1) Shaded cells indicate the change in CO2 emissions (thousand tons) for year 2040, relative to the base case; the darker the shading, the larger the change in emissions. A key is provided below:

NPV

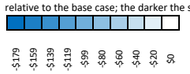


Notes:
1) Shaded cells indicate the change in total production costs ($M) over the 2022 - 2041 study period, relative to the base case; the darker the shading, the larger the change in cost. A key is provided below:

NPVE



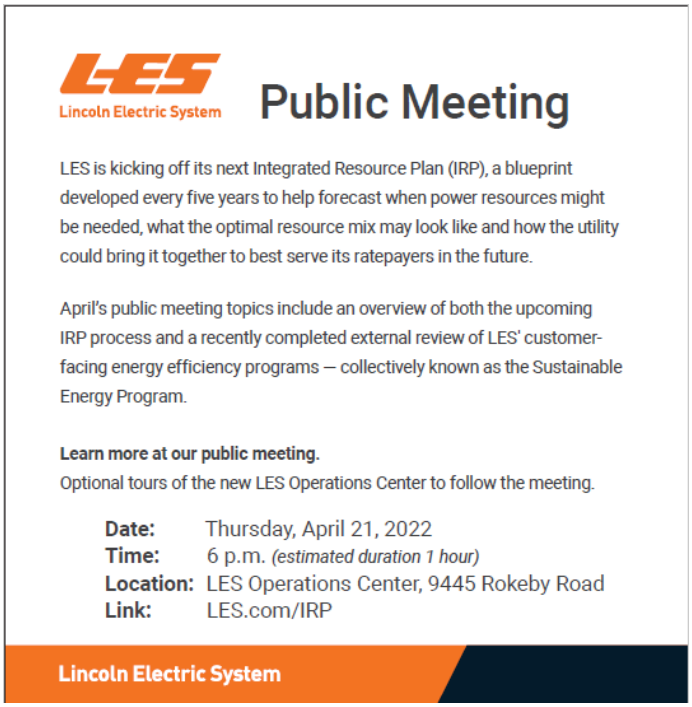
Notes:
1) Shaded cells indicate the change in total production costs ($M) over the 2022 - 2041 study plus the subsequent 30-year extension period, relative to the base case; the darker the shading, the larger the change in cost. A key is provided below:



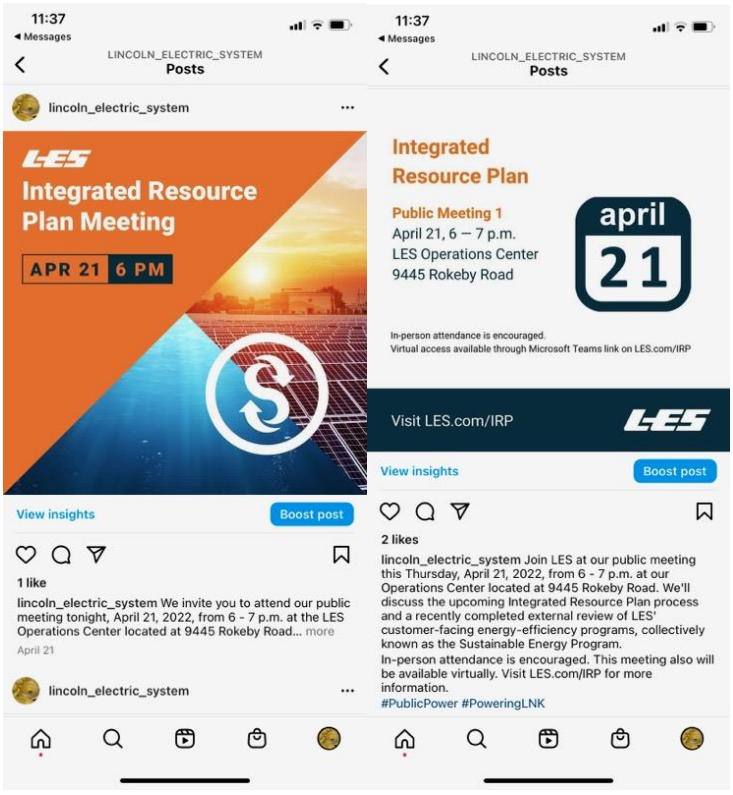
Appendix I
Public Meeting #1 Materials

2022 IRP Meeting #1 Promotion Samples

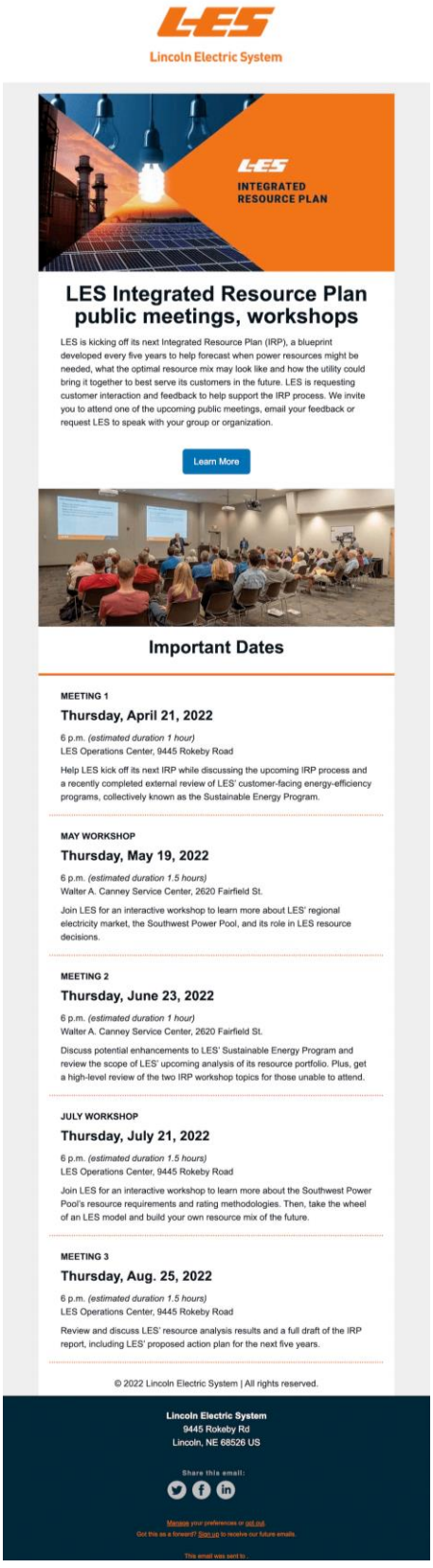
Print Ad



Organic Social Media



All Customer Email



Bill Message

Lincoln Electric System

Account Number:
Customer Name:
Service Address:
Billing Date:

Account Information

Your account is on AutoPay. If you need to make any changes, you can login at LES.com.

Summary of Charges

Previous Balance	$148.72
Payments	(148.72)
	$0.00
Current Energy Charges	92.83
Taxes & Other Charges/Credits	9.95
Balance as of 04/27/22	**$102.78**

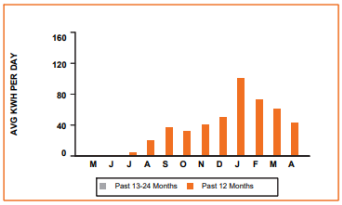
See reverse side for details

LES News

Join LES online and in-person for our 2022 Sustainability Series. Visit us at Lincoln Earth Day, April 23, while we celebrate environmental stewardship in the Lincoln area. Find a complete list of our Sustainability Series events at **LES.com/Sustain**.

SAVE THE DATE: LES will host its first meeting for this year's Integrated Resource Plan on April 21 at the LES Operations Center. This meeting offers an overview of the IRP process and LES' Sustainable Energy Program. Go to **LES.com/IRP** for more.

Usage



Billing Period	Billing Days	kWh	Avg. kWh per day	Avg. High Temp	Avg. Low Temp
Apr 2021	0	0	0	64°	38°
Apr 2022	29	1,240	43	62°	34°

Please remember to include the payment coupon below with your payment. If paying by check, please write your account number on the check.

Paid Social Ads (carousel that showed each meeting date/time)

Lincoln Electric System (LES)
Sponsored ·

Join LES as we discuss an external review of our customer-facing energy-efficiency program known as the Sustainable Energy Program. Take part in discussion as we talk about potential enhancements to our Sustainable Energy Program, and get a high-level review of our two workshop topics. We'll wrap this up on August 25th with our proposed action plan for the next five years, stemming from these previous community discussions.

Join the Discussion
We'll discuss potential en...
Learn more

Join the Discussion
We'll discuss our propose...
Learn more

Customer e-newsletter

Take part in LES' 2022 Integrated Resource Plan View in Browser

em powered *Simple* ways to take charge of your energy use and costs.

Take part in LES' 2022 Integrated Resource Plan

Lincoln Electric System always plans for tomorrow, constantly looking for opportunities to improve its generation portfolio and help deliver clean, reliable power to area residents at an affordable cost. Community-members are invited to participate in LES' upcoming integrated resource planning process. The utility's IRP is one of many important decision-making tools, and we'd like your collaboration to build on how LES will continue to meet our area's current and future energy demand.

Take part in LES' 2022 Integrated Resource Plan View in Browser

EnergyLine

Take part in LES' 2022 Integrated Resource Plan

Lincoln Electric System always plans for tomorrow, constantly looking for opportunities to improve its generation portfolio and help deliver clean, reliable power to area residents at an affordable cost. Community-members are invited to participate in LES' upcoming integrated resource planning process. The utility's IRP is one of many important decision-making tools, and we'd like your collaboration to build on how LES will continue to meet our area's current and future energy demand.

READ MORE

2022 Integrated Resource Plan

Frequently Asked Questions

Scott Benson
Manager, Resource & Transmission Planning

April 21, 2022

What Requirements Does LES Fulfill by Conducting an IRP?

Under Nebraska state law, public utilities are required to practice integrated resource planning and include least cost options when evaluating alternatives for providing energy supply and managing energy demand in Nebraska.

Source: Nebraska Revised Statute 66-1060, Nebraska Legislature

In accordance with Section 114 of the U.S. Energy Policy Act of 1992, the Western Area Power Administration (WAPA) requires all long-term firm power customers to submit an integrated resource plan every five years.

Source: Energy Planning and Management Program – IRP, Western Area Power Administration, 2/11/2020 Update
IRP Compliance Training - Reporting Deadlines, Western Area Power Administration, 2/19/2020 Update

What is an IRP?

Per WAPA, integrated resource planning is a process by which a power provider evaluates the full range of energy resources to ensure adequate and reliable service to its electric customers at the lowest system cost. Resource alternatives include:

- New generating capacity
- Power purchases
- Energy conservation and efficiency
- Cogeneration and district heating and cooling applications
- Renewable energy resources

The process must account for the necessary features of system operation, such as diversity, reliability, dispatchability and other risk factors.

The IRP must include the means to verify energy savings from energy conservation and efficiency measures, and projected savings from the measures over time; and shall treat demand and supply resources on an equal basis.

Source: IRP Compliance Training – Overview, Western Area Power Administration, 2/11/2020 Update

What is Required of the IRP?

WAPA requires IRPs to:

- Identify and compare all practicable energy-efficiency and energy-supply resource options.
- Include an action plan with timing set by the customer.
- Describe efforts to minimize adverse environmental effects on new resource acquisitions.
- Provide ample opportunity for full public participation.
- Conduct load forecasting.

Source: IRP Compliance Training – Overview, Western Area Power Administration, 2/11/2020 Update

What is the Primary Deliverable of the IRP?

The IRP culminates in a five-year action plan, identifying programs/resources that LES intends to implement or evaluate over the next five years.

LES is then required to provide annual progress reports to WAPA.

Source: IRP Compliance Training - Reporting Deadlines, Western Area Power Administration, 2/19/2020 Update

LES' 2017 IRP Action Plan included:

- 30-year extension of the WAPA hydro-electric power contract (2021 – 2050).
- Continuation of the Sustainable Energy Program (SEP).
- Development of a bring-your-own-thermostat air conditioner demand response program, which ultimately became Peak Rewards in 2018.
- Evaluation of a potential heat pump water heater incentive under the SEP, ultimately added in 2019.
- Evaluation of a potential plug-in electric vehicle pilot, which ultimately became the 2019 – 2021 study.

Who Coordinates with LES on the IRP?

LES historically submits an IRP on behalf of the Lincoln Cooperative, a collection of local WAPA customers, including:

- Lincoln Electric System
- University of Nebraska - Lincoln (UNL)
- Lincoln Regional Center
- Nebraska State Office Building
- Nebraska State Penitentiary

How Will the IRP Tie into LES' New Decarbonization Goal?

The analysis of the 2022 IRP will be the first to be guided by LES' new decarbonization goal; net-zero CO2 production from our generation portfolio by 2040.

Although there are too many unknowns between now and 2040 for this IRP to develop a full plan and a detailed timeline for achieving the goal, LES does expect this process to identify some of the primary building blocks.

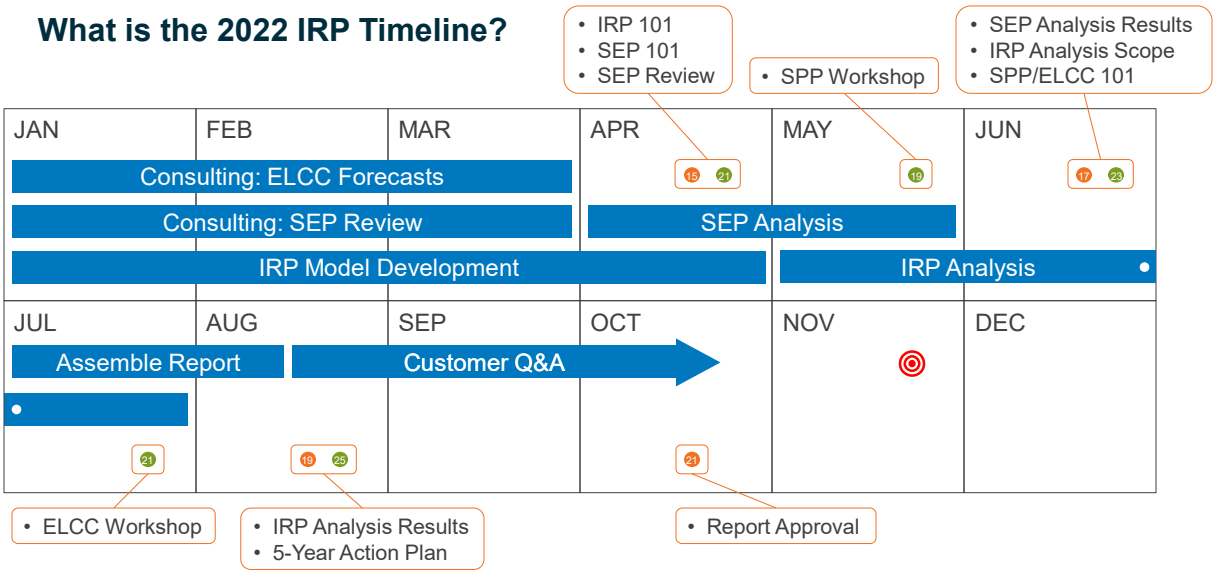
What are Some of the Limitations of the IRP?

The IRP is a significant, strategic undertaking that helps to outline LES' future, but it still only represents an analysis at a single point in time. To account for an ever-changing landscape, LES is continually assessing and evaluating options, constantly conducting similar analysis specific to the decisions at hand.

Although many substantial projects have come out of the five-year IRP process, there are always significant decisions not foreseen by the IRP, including:

- The addition of 273 MW of wind resources (Arbuckle Mountain, Buckeye & Prairie Breeze II) in 2015.
- The development of Nebraska's first utility-scale solar project in 2016, the 4 MW_{AC}/5 MW_{DC} Holdrege Solar Center.
- LES' exit from the Sheldon Station coal plant contract in 2017.

What is the 2022 IRP Timeline?



ELCC = Effective Load Carrying Capability
SPP = Southwest Power Pool

Sustainable Energy Program Overview

Marc Shkolnick
Manager, Energy Services
April 21, 2022

Sustainability Customer Programs:

- Net-Metering/Renewable Generation
- Community Solar
- Renewable Energy Credits (RECs)
- Paperless billing
- Electric Vehicles
  - Outreach and education
  - Research
  - Grant-funded incentives
- *Sustainable Energy Program

*Solely funded from designated energy efficiency incentive budget.

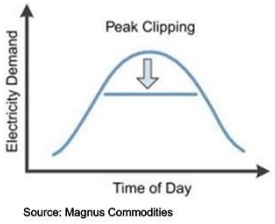
Source: Sustainability Academy

Sustainable Energy Program Overview

- SEP 101
  - Primary Objectives
  - Programs
  - Cost Effectiveness
- 2022 SEP Review Summary

SEP Primary Objectives

Peak Reduction



Source: Magnus Commodities

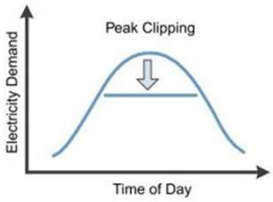
Market Transformation

Balance

Source: Unit Owners Association

SEP Primary Objectives

Peak Reduction



Source: Magnus Commodities

- Incent technologies that reduce power requirements during summer weekday afternoons.
- Defer the need to build or purchase energy from new generating resources.
- Allow time for the development of new, low/zero carbon generating technologies.

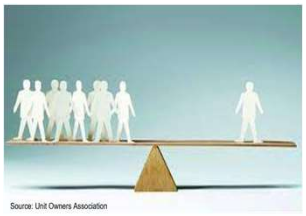
SEP Primary Objectives

Market Transformation

- Markets transform when adoption "tips" beyond early adopters and innovators.
- Incentives are meaningful when they sufficiently reduce first cost as a barrier.
- Once codes/appliance standards increase or adoption is widespread, incentives are no longer effective or necessary.

SEP Primary Objectives

Balance



Source: Unit Owners Association

- SEP incentives need to be high enough to incent AND justified by avoided costs that benefit all non-participants.
- Incentives set too low:
  - Free ridership: demand and energy savings can't be claimed.
- Incentives set too high:
  - Non-participant costs are more than benefits they receive.
  - Subsidization.

Sustainable Energy Programs

Residential

Program	Year	Projects	Incentives to Date	Net Annual Demand	Net Annual Energy
Heat Pump & AC	2009	11,500	$8 MM	9.0 MW	6,400 MWh
Sealing & Insulation	2010	1,100	$0.8 MM	0.3 MW	310 MWh
Heat Pump Water Heater	2019	70	$0.04 MM	0.0 MW	145 MWh
Peak Rewards	2018	2,300	$0.25 MM	3.3 MW	0 MWh
Total		**14,970**	**$9.1 MM**	**12.6 MW**	**6,855 MWh**

Sustainable Energy Programs

Commercial & Industrial

Program	Year	Projects	Incentives to Date	Net Annual Demand	Net Annual Energy
Commercial Lighting	2009	4,200	$13.5 MM	17.5 MW	93,300 MWh
Commercial & Industrial Prescriptive/Custom (Chillers, Variable Frequency Drives/Pumps, Compressed Air, etc.)	2010	860	$6.0 MM	5.0 MW	34,200 MWh
Total		**5,060**	**$19.5 MM**	**22.5 MW**	**127,500 MWh**

SEP Cost Effectiveness

Primary Test

Utility Cost Test (UCT) ≥ 1

Benefits
- Avoided utility capacity, energy and emission costs.

Costs
- Program administrative costs.
- Incentives.

Indicates whether the benefits of avoided utility costs exceed the costs incurred by the utility to implement the program.

SEP Cost Effectiveness

Secondary Test

Ratepayer Impact Measure Test (RIM) ≥ 0.6

(Minimizes Level of Subsidization)

Benefits

- Avoided utility capacity, energy and emission costs.

Costs

- Program administrative costs.
- Incentives.
- Lost revenue.

A measure of the potential pressure on retail rates to make up for lost revenue brought about by energy efficiency. Not a primary cost test.

2022 SEP Review Summary

nFront Consulting performed a high-level benchmark review with peer utilities and statewide energy efficiency studies and meta-analysis focused on the following:

- Cost Effectiveness Tests
- Input Assumptions
- Potential New Measures

2022 SEP Review Summary

Cost Effectiveness

- Use of primary UCT and secondary RIM is appropriate.
- UCT becoming more widely adopted as primary test.

2022 SEP Review Summary

Assumptions

- Assumed energy & demand savings, measure costs & life, net-to-gross adjustments were supported.
- Strive for more consistency for assumptions used in custom commercial & industrial projects.

2022 SEP Review Summary

Assumptions

- Static inflation of 2.3% is appropriate but update periodically.
- Retail rate escalation at 1.0% may be a bit low compared to industry sources. Consider 1.3% to 1.7%.

2022 SEP Review Summary

Assumptions

- Avoided SPP wholesale energy costs are appropriate.
- Avoided capacity costs at $30/kW is lower than much of the industry but 5% escalation rate is higher. May consider $60 to $80/kW with lower annual escalation.

2022 SEP Review Summary

Assumptions

- LES is one of the few utilities that directly includes avoided costs of CO_2 in cost effectiveness modeling.
- Avoided CO_2 emissions at $20/ton is higher than much of the industry but 2.3% annual escalation rate is lower. May consider higher annual escalation.

2022 SEP Review Summary

Additional Measures to Explore

- High efficiency humidifiers.
- Commercial kitchen equipment.
- Electric water heater direct load control.
- Variable/critical peak pricing.
- Voltage optimization and conservation voltage reduction.

2022 SEP Review Summary

Next Steps

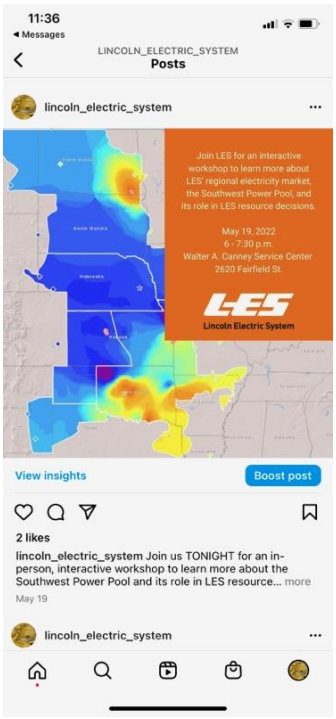
- Consideration of recommended input assumptions.
- Consideration of potential new measures.

Discussion

Appendix J
Public Workshop #1 Materials

2022 IRP Workshop #1 Promotion Samples

Organic Social Media



Previous Attendee Email

Scott Benson

From: Scott Benson
Sent: Thursday, May 12, 2022 12:30 PM
Subject: Reminder: LES IRP Workshop on 5/19

Good afternoon,

As an attendee of our Integrated Resource Plan (IRP) kickoff meeting last month, I wanted to remind you that a week from tonight is our first of two IRP workshops. This one will focus on LES' regional electricity market, the Southwest Power Pool, and its role in LES resource decisions. We've done this interactive and hands-on workshop many times, and it's always been both informative and fun. The workshop is from 6:00 p.m. – 7:30 p.m. on May 19th at LES' Walter A. Canney Service Center, located at 2620 Fairfield St.

Thank you for your interest in LES' IRP process, and I hope to see you next Thursday.

Scott Benson | Manager, Resource & Transmission Planning

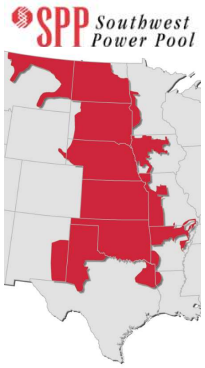
Office: 402-473-3390
Mobile: 402-937-4461

LES.com | 9445 Rokeby Road | Lincoln, NE 68526

CONNECT

SPP Market Workshop

2022 Integrated Resource Plan



Scott Benson
Manager, Resource & Transmission Planning

May 19, 2022

Generation: Understanding Capacity vs. Energy

Capacity
The amount of power a generating resource is producing at a single point in time, expressed in units of megawatts (MW).

Energy
The amount of power a generating resource actually produces over a period of time, expressed in units of megawatt-hours (MWh).

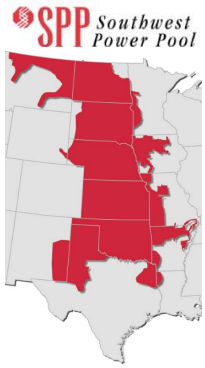
A resource with a rated **capacity** of 100 MW, operating at its full rating for 4 hours, would produce **energy** equivalent to the following:

100 MW x 4 hours = 400 MWh

A resource with a rated **capacity** of 100 MW, operating at 50% of its full rating (50 MW) for 4 hours, would produce **energy** equivalent to the following:

50 MW x 4 hours = 200 MWh

SPP Market Workshop
Capacity



Generation: SPP Capacity Requirements

Nameplate Capacity
The capability of a generating resource at its full rated output.

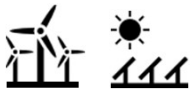
Accredited Capacity
Under SPP rules, each utility must secure **accredited capacity** equal to at least their peak load plus a 12% reserve margin.

Dispatchable Resources

Accredited ≈ Nameplate

SPP Accreditation: Seasonal capability of unit over at least a 4-hour period.

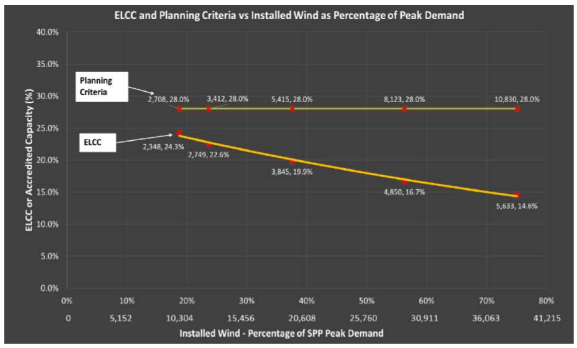
Non-Dispatchable Resources



Accredited < Nameplate

SPP Accreditation: New methodology to be in place for 2023 summer.

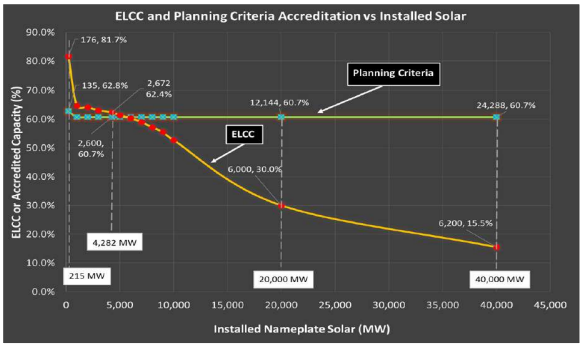
SPP Accredited Capacity – Wind & Solar Resources



"Because of wind and solar generation intermittency, the capacity value…are lower than their nameplate values and will decrease as their penetration increases..."

Solar and Wind ELCC Accreditation, August 2019.

Effective Load Carrying Capability (ELCC)
The incremental load a resource can dependably and reliably serve.



Activity: SPP Capacity Requirements

On your table is a series of glasses and an empty pitcher.

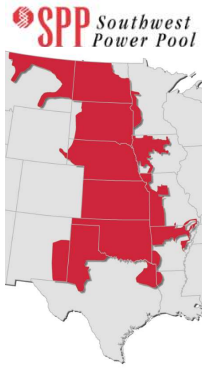
Each glass represents a different resource with a ***nameplate capacity*** of 100 MW. The resource's associated ***accredited capacity*** is marked with a line.

Each empty pitcher represents a utility's total load of 446 MW.

Using a variety of resources, accumulate enough **accredited capacity** (fill the pitcher) to cover the utility's load plus a reserve margin of 12%:

446 MW + (446 MW x 12%) = 500 MW

SPP Market Workshop
Energy Market

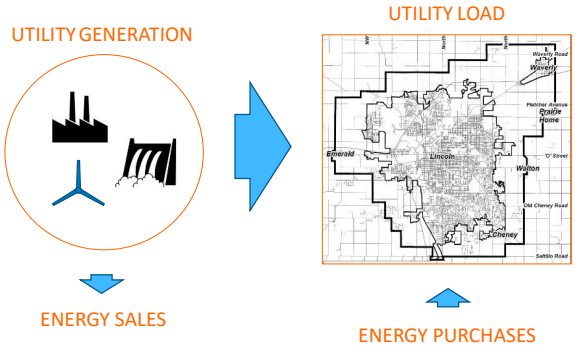


SPP Energy Market

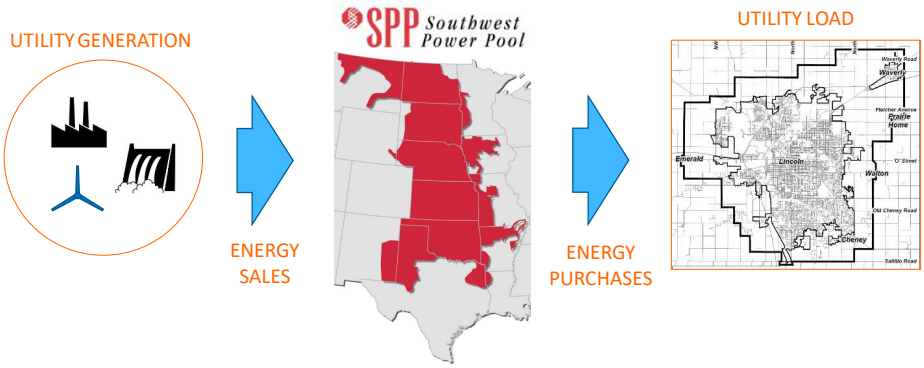
A utility's portfolio must be constructed to fulfill SPP capacity requirements, but the portfolio's standing in the SPP market goes a long ways toward determining its economic viability.

Unless out of service, each of a utility's resources must be offered to serve the SPP energy market.

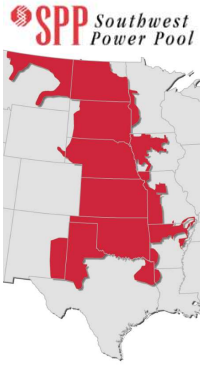
Historical Utility Operations

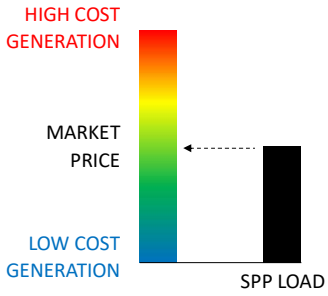


Operations within the Southwest Power Pool (SPP)

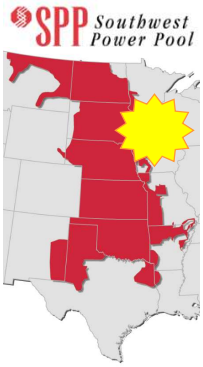


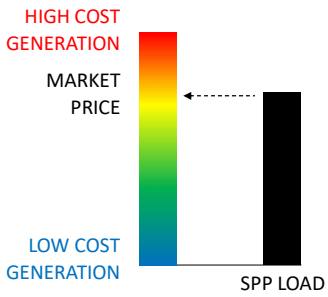
SPP Energy Market Operations



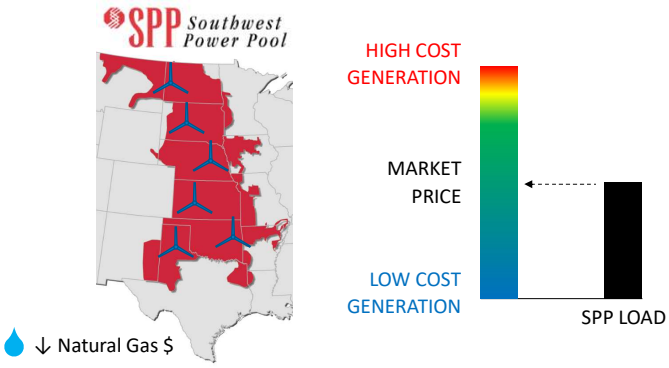


SPP Energy Market Operations





SPP Energy Market Operations



Components of the SPP Market Price

The SPP market price is specifically represented by thousands of Location Marginal Pricing (LMP) nodes spread across the entire footprint.

LMP ($/MWh) =

Cost of Energy — Price to serve next MW; same over entire footprint. Generation is *paid* this price; Load *pays* this price.

+ Cost of Transmission System Congestion
+ Cost of Marginal Transmission System Losses

} Source of geographic variance.

The LMP represents only the variable costs of producing energy. Capital construction costs and fixed operating costs are not included and are not meant to be recovered in the market.

SPP price contour map

Generating Unit Energy Offers

Dispatchable Resources

Variable costs include fuel and variable operations & maintenance (VOM).

Offer ($/MWh) = Fuel + VOM

Representative offers:

Nuclear	$10/MWh
Coal	$20/MWh
Natural Gas Combined Cycle	$25/MWh
Hydro	$28/MWh
Natural Gas Simple Cycle	$40/MWh

Generating Unit Energy Offers

Non-Dispatchable Resources: Wind

Federal Production Tax Credit (PTC) valued at $27/MWh for every MWh generated in the first 10 years.

Under a Power Purchase Agreement (PPA), utility typically must pay wind developer for each MWh that is curtailed due to economics, plus associated lost PTC and related income taxes.

Offer ($/MWh) = ($27) + ($8) = ($35)

PTC — Income Taxes

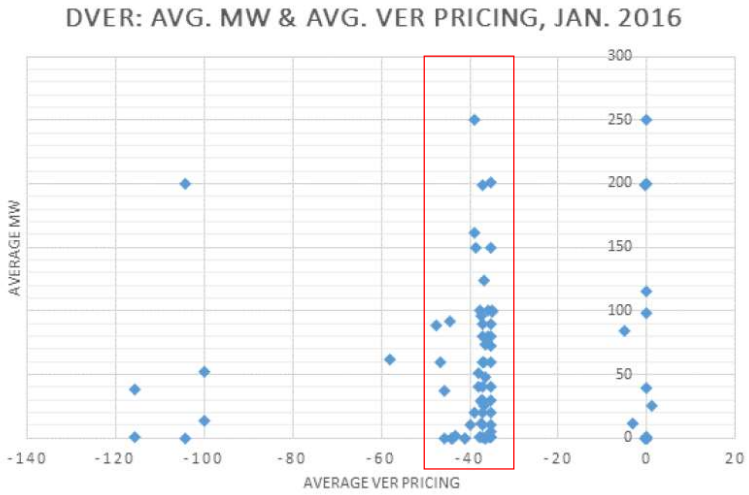
Non-Dispatchable Resources: Solar

Federal Investment Tax Credit (ITC), valued at 30% of initial capital expenditure.

ITC represents upfront consideration and doesn't impact operating costs. Under a PPA, utility typically must pay solar developer for only each MWh that is curtailed due to economics.

Offer ($/MWh) = $0

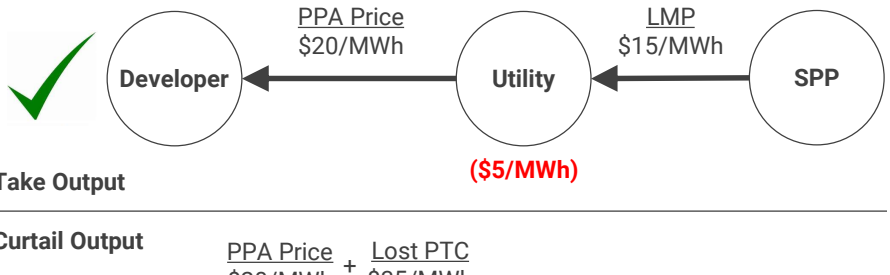
Wind Energy Offers: SPP Market Data



Source: December 1, 2016 SPP Strategic Planning Committee Meeting, Real Time Operational Impacts of Renewable Energy Resources presentation, slide 14

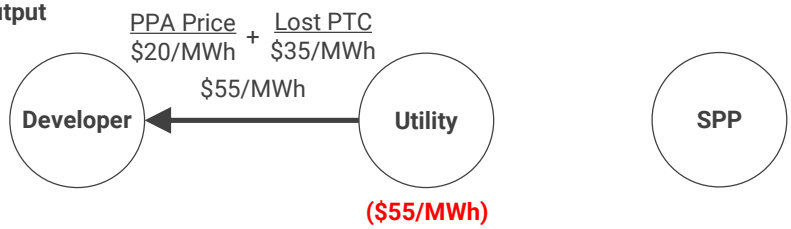
Wind PPA – Net Utility Position

PPA Price: $20/MWh
SPP LMP: $15/MWh



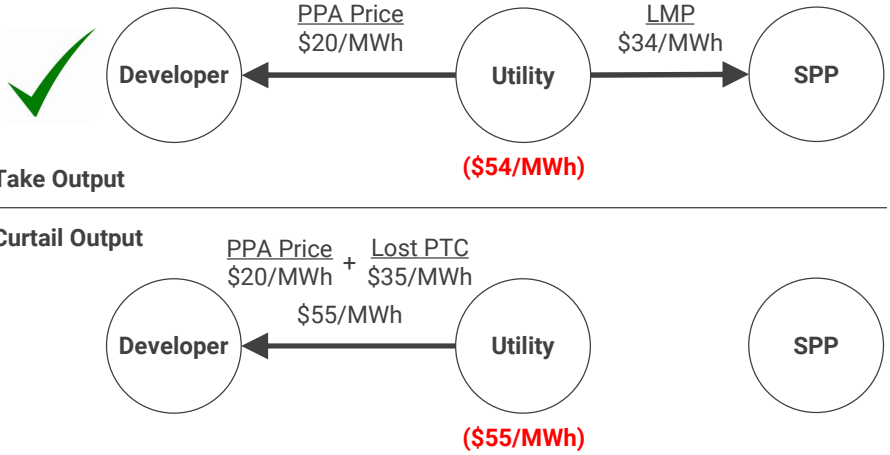
Take Output

Curtail Output



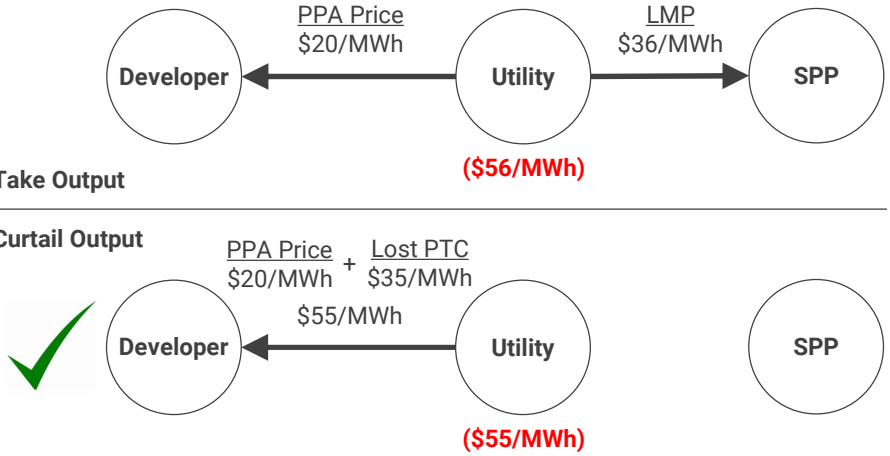
Wind PPA – Net Utility Position

PPA Price: $20/MWh
SPP LMP: ($34/MWh)



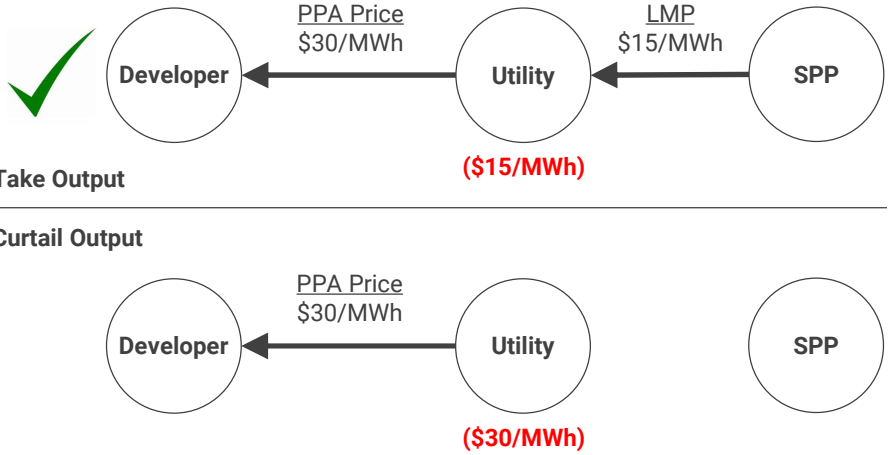
Wind PPA – Net Utility Position

PPA Price: $20/MWh
SPP LMP: ($36/MWh)



Solar PPA – Net Utility Position

PPA Price: $30/MWh
SPP LMP: $15/MWh

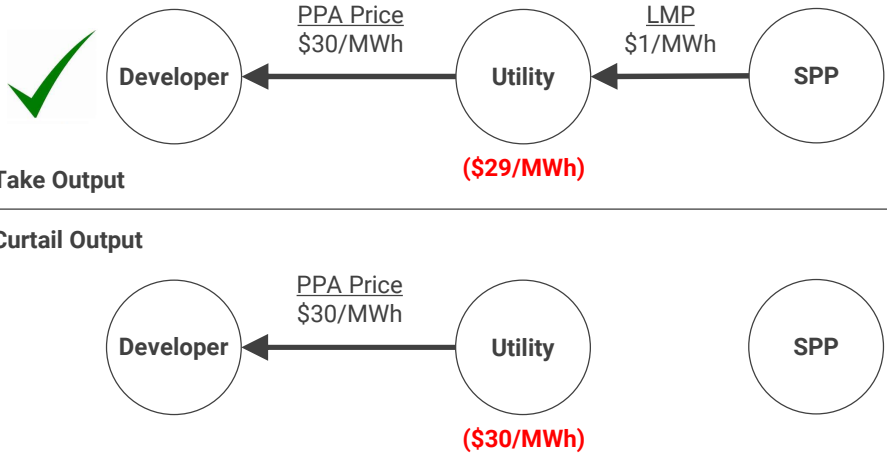


Take Output

Curtail Output

Solar PPA – Net Utility Position

PPA Price: $30/MWh
SPP LMP: $1/MWh

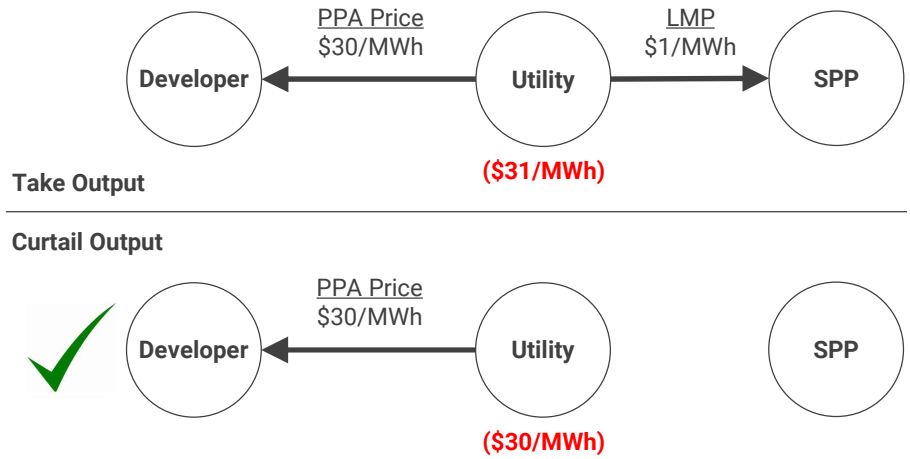


Take Output

Curtail Output

Solar PPA – Net Utility Position

PPA Price: $30/MWh
SPP LMP: ($1/MWh)



SPP Energy Market – Negative Pricing

In SPP today, wind PPAs and their resultant market offers drive more and more negative market prices.

Under negative market prices, generation actually *pays* to supply energy and load gets *paid* to consume energy.

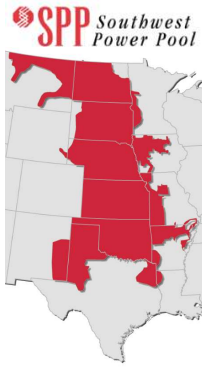
In 2021, approximately 15% of the 5-minute LMPs in SPP were negative.

Activity: SPP Energy Market Dispatch

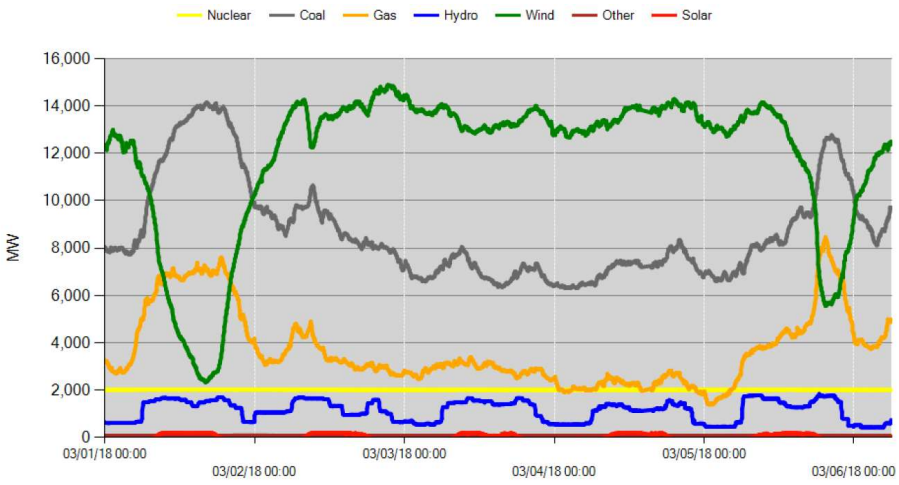
Participants will each play the role of a resource in the SPP energy market, with a nameplate rating of 100 MW.

The SPP market will perform an economic dispatch to meet a 450 MW load at the lowest possible cost. This activity will reflect a simplified version of the SPP market using only the energy component of the LMP; congestion and losses will not be considered.

SPP Market Workshop
System Reliability

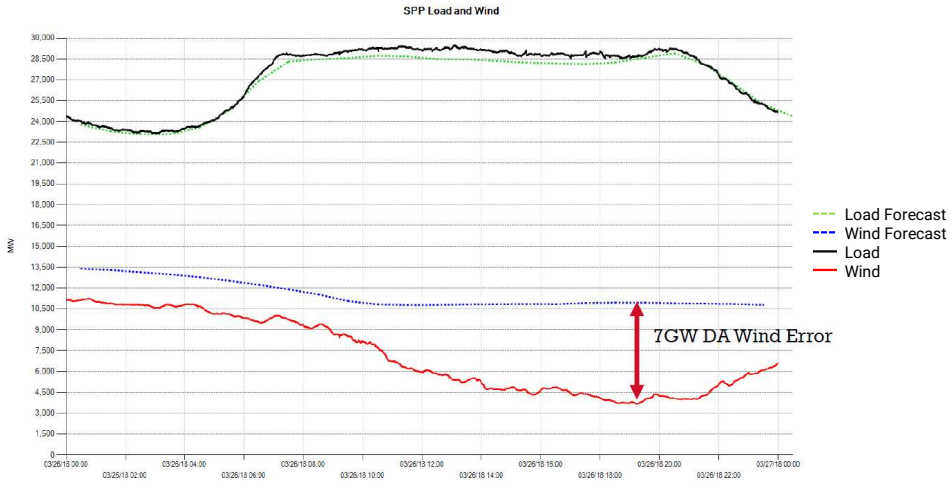


SPP Generation Dispatch (3/1/18 – 3/6/18)



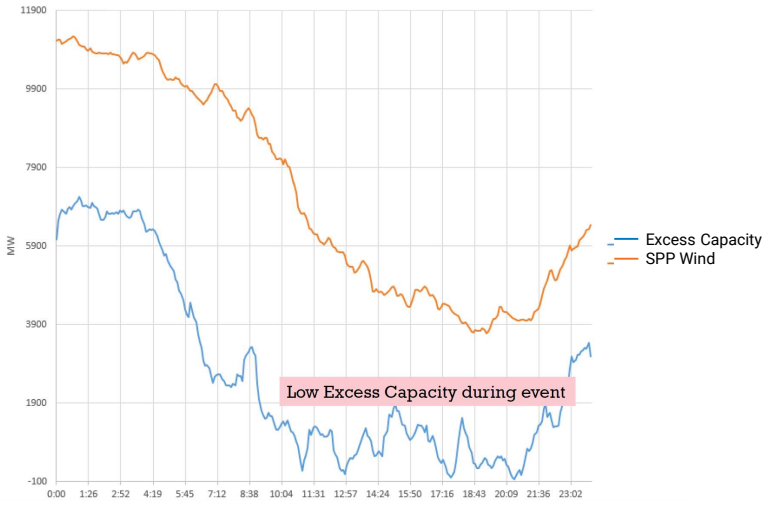
Source: May 3, 2018 SPP Planning Summit, Grid Resilience presentation, slide 25

SPP Load & Wind Forecast vs. Actual (3/26/18)



Source: May 3, 2018 SPP Planning Summit, Grid Resilience presentation, slide 40

SPP Wind Production & Excess Capacity (3/26/18)



Source: May 3, 2018 SPP Planning Summit, Grid Resilience presentation, slide 43

Generation Considerations in SPP
Summary

Capacity Considerations:

- Utilities are required to bring enough accredited capacity to SPP to cover their peak load plus a 12% reserve margin.
- The utility controls the make up of this capacity, and thus the related energy *offered* to the SPP market.

Energy Market Considerations:

- SPP controls how a utility's resources are actually dispatched, and thus the energy *supplied* to the market.
- SPP dispatches resources in economic order, working to reliably serve their footprint's load in the most cost-effective manner.
- All generators are *paid* the same energy price, and load *pay*s this same price.

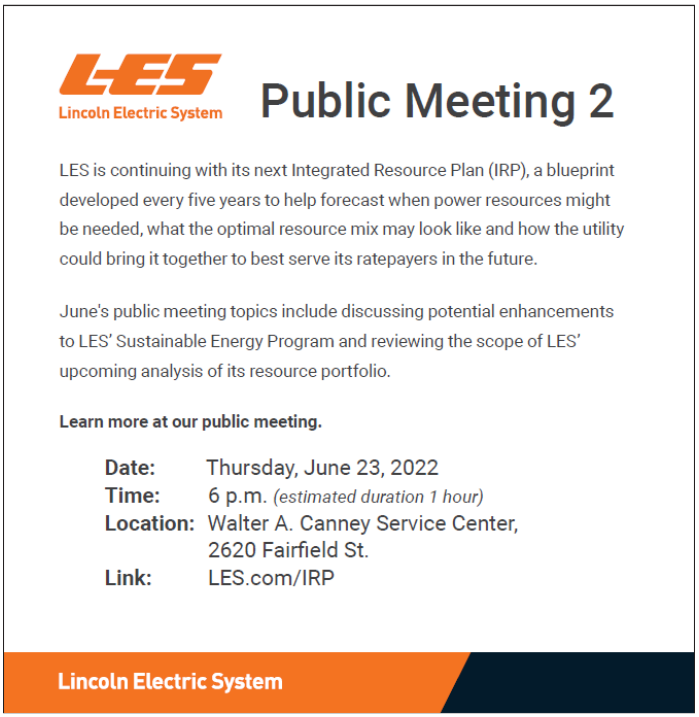
System Reliability Considerations:

- SPP is responsible for balancing load and generation within their footprint.
- This task is growing more and more challenging with the expansion of non-dispatchable generation.

Appendix K
Public Meeting #2 Materials

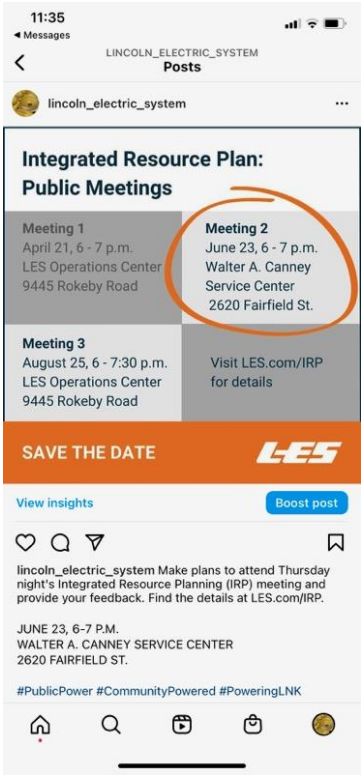
2022 IRP Meeting #2 Promotion Samples

Print Ad

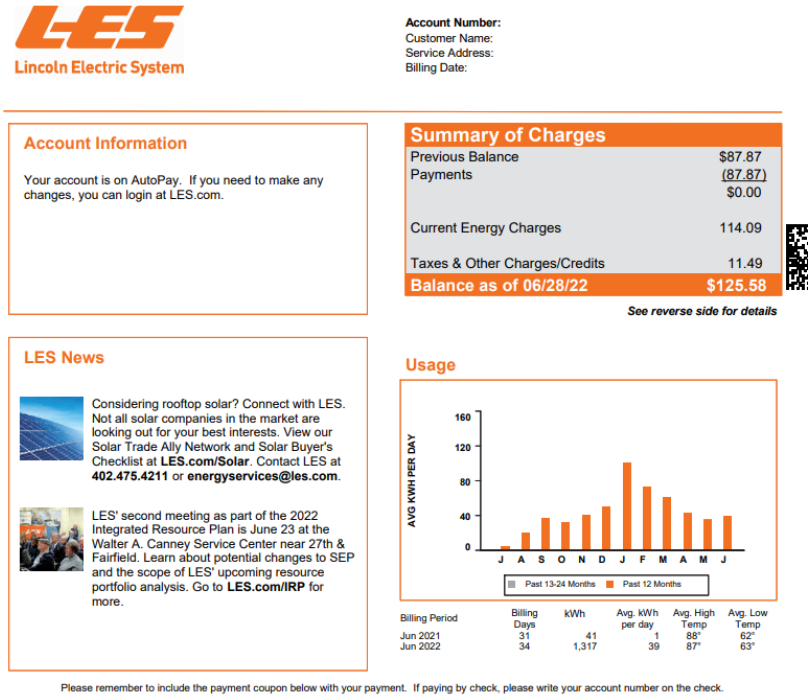


All Customer Email

Organic Social Media



Bill Messages



Lincoln Electric System

Account Number:
Customer Name:
Service Address:
Billing Date:

Account Information

Your account is on AutoPay. If you need to make any changes, you can login at LES.com.

Summary of Charges

Previous Balance	$87.87
Payments	(87.87)
	$0.00
Current Energy Charges	114.09
Taxes & Other Charges/Credits	11.49
Balance as of 06/28/22	**$125.58**

See reverse side for details

LES News

Considering rooftop solar? Connect with LES. Not all solar companies in the market are looking out for your best interests. View our Solar Trade Ally Network and Solar Buyer's Checklist at **LES.com/Solar**. Contact LES at **402.475.4211** or **energyservices@les.com**.

LES' second meeting as part of the 2022 Integrated Resource Plan is June 23 at the Walter A. Canney Service Center near 27th & Fairfield. Learn about potential changes to SEP and the scope of LES' upcoming resource portfolio analysis. Go to **LES.com/IRP** for more.

Usage

Billing Period	Billing Days	kWh	Avg. kWh per day	Avg. High Temp	Avg. Low Temp
Jun 2021	31	41	1	88°	62°
Jun 2022	34	1,317	39	87°	63°

Please remember to include the payment coupon below with your payment. If paying by check, please write your account number on the check.

Paid Social Ads (carousel that showed each meeting date/time)

Lincoln Electric System (LES)
Sponsored ·

Join LES as we discuss an external review of our customer-facing energy-efficiency program known as the Sustainable Energy Program. Take part in discussion as we talk about potential enhancements to our Sustainable Energy Program, and get a high-level review of our two workshop topics. We'll wrap this up on August 25th with our proposed action plan for the next five years, stemming from these previous community discussions.

Join the Discussion
We'll discuss potential en...
Learn more

Join the Discussion
We'll discuss our propose...
Learn more

Current Customer Newsletter

Help LES put together its 5-year Integrated Resource Plan

LES develops an Integrated Resource Plan every five years, per its contract for hydroelectric power with the Western Area Power Administration. IRPs are common tools in the industry, designed to examine and compare supply-side (e.g., generation) and demand-side (e.g., energy efficiency) resource investments to identify a reliable energy supply while keeping costs affordable.

The 2022 study will be LES' first IRP guided by its new decarbonization goal, seeking to achieve net-zero carbon dioxide emissions from its generation portfolio by 2040.

Creating an IRP

The IRP is one of many tools LES staff and administrators use for analyzing various resource-planning choices to meet the community's growing energy demand. Staff have been simulating many different scenarios for the future of our area's electric needs, and will continue throughout the process. This helps to identify power supply options that will be successful over the broadest range of possible futures.

In essence, rather than a roadmap of definite destinations, LES' IRP is like a playbook, exploring options based on the situation, which informs LES' future resource decisions.

Community collaboration

"A fundamental part of creating our IRP is community collaboration," said Scott Benson, manager, LES Resource & Transmission Planning. "During the IRP process, we make time for public meetings where we can update the public about what we've evaluated and solicit their input."

To make sound choices on behalf of customer-owners, staff weigh long-term goals with short-term needs. While carbon emissions will be a primary consideration in this year's IRP, CO_2 will not be the only factor considered. In addition to environmental impacts, key considerations include cost, feasibility and reliability. Together, these are always balanced to best fit the community's changing needs.

Through the IRP, LES can form a future-focused vision of the community's needs. This allows LES to make near-term decisions that align with a long-term view of the future.

Join us at 6 p.m. on June 23 at the LES Service Center near 27th and Fairfield streets in Lincoln for the next IRP public meeting. The meeting will cover potential enhancements to LES' Sustainable Energy Program and review the scope of the utility's resource portfolio analysis.

Learn more at LES.com/IRP.

Sustainable Energy Program Cost Effectiveness Analysis

Marc Shkolnick
Manager, Energy Services
June 23, 2022

Sustainable Energy Program Analysis Overview

- nFront Modeling Input Recommendations
- Modeling Cost Effectiveness Results
- nFront New Measure Recommendations

SEP Modeling Input Recommendations

Use of static inflation of 2.3% is appropriate, but update periodically.

Consistent with the upcoming IRP analysis, will use *Federal Reserve's long-term inflation benchmark at 2%.

*https://www.federalreserve.gov/faqs/economy_14400.htm

SEP Modeling Input Recommendations

Retail rate escalation at 1.0% may be a bit low compared to industry sources. Consider 1.3% for residential and 1.7% for commercial rates.

LES' 10-year historical increases reflect 1.0%, but a slightly higher escalation seems warranted going forward. Will use 1.5% retail rate inflation as model allows for one input.

SEP Modeling Input Recommendations

Avoided market capacity costs at $30/kW-year is lower than much of the industry, but 5% escalation rate is higher. Consider $60 to $80/kW-year based on construction.

Found current market value and construction cost of generation to be comparable on an NPV basis. For simplicity, will use fixed construction capacity of $59/kW-year.

SEP Modeling Input Recommendations

LES is one of the few utilities that directly includes avoided costs of CO2 in cost effectiveness modeling. $20/ton is higher than rest of industry, but 2.3% annual escalation rate is lower. Consider higher annual escalation.

Consistent with the upcoming IRP analysis, and corresponding with US interim estimates, will escalate value of CO2 by inflation plus 2%.

Benefit/Cost Modeling Results

Current SEP Measures/Incentives

Cost Effectiveness Test	Required Minimum	Pre-IRP Assumptions	Updated Assumptions
Utility Cost Test (UCT)	1.00	2.32	2.47
Ratepayer Impact Measure Test (RIM)	0.60	0.71	0.74

Potential New Measures for Consideration

Evaluate the following measures for inclusion in the SEP:

- *High efficiency dehumidifiers.*
- *Commercial kitchen equipment.*
- *Electric water heater direct load control.*
- *Variable/critical peak pricing.*
- *Voltage optimization and conservation voltage reduction.*

Evaluated viability and cost effectiveness of dehumidifiers, kitchen equipment and water heaters. Consideration of time-of-use and voltage optimization outside the scope of the DSM model.

Preliminary Analysis of Measures

Based on Consultant's Initial Assumptions

	Measure	kW	kWh	Incentive	*Mkt %	UCT	RIM
✗	Residential Dehumidifier	0.08	236	$25	88%	0.23	0.18
✓	Commercial Dishwasher	3.60	26,280	$1,800	63%	5.31	0.69
✓	Comm. Combination Oven	3.10	13,578	$735	54%	5.87	0.58
✓	Commercial Steam Cooker	3.20	11,614	$1,800	46%	2.23	0.46
✓	Water Heater Load Control	0.50	0	$25	0%	0.51	0.51

*Market saturation according to the 2020 Energy Star Unit Shipment and Market Penetration Report:
https://www.energystar.gov/sites/default/files/asset/document/2020%20USD%20Summary%20Report_Lighting%20%20EVSE%20Update.pdf

- Incentives for dehumidifiers likely wouldn't influence much improvement, as nearly all units sold are already EnergyStar rated.
- Commercial kitchen equipment and water heater load control may warrant further investigation to refine the related assumptions and benefit/cost metrics.

Discussion

2022 Integrated Resource Plan

Analysis Scope & Workshop Review

Scott Benson
Manager, Resource & Transmission Planning

June 23, 2022

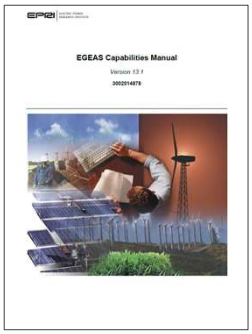
EGEAS Software

IRP analysis is being conducted with EGEAS (Electrical Generation Expansion Analysis System); a software tool developed by the Electric Power Research Institute (EPRI).

EGEAS is used by numerous companies for future resource planning, including the Midcontinent Independent System Operator (MISO).

EGEAS utilizes dynamic programming, evaluating all possible resource combinations, to identify an optimal solution based on the Net Present Value (NPV) of total production costs, including:

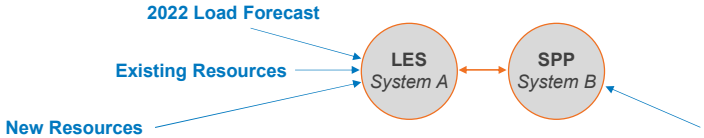
- Construction costs.
- Operating costs.
- Reliability constraints.



Source: *The Electric Generation Expansion Analysis System (EGEAS) Software, 2019 EPRI Update*, Electric Power Research Institute, January 24, 2018.

EGEAS Analysis Scope

Model Architecture



New Resources

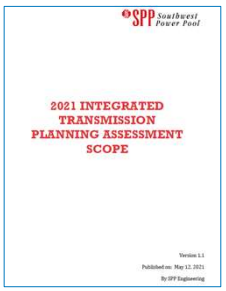
Source: *Cost and Performance Characteristics of New Generating Technologies*, U.S. Energy Information Administration, March 2022.

Methodology

EGEAS develops optimal, lowest cost resource expansion plan for LES (System A) while accounting for potential sales to, and purchases from, SPP (System B).

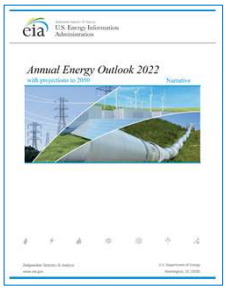
Expansion plan must maintain SPP reserve margin requirement (112% of peak load) for LES over 20-year study period (2022 – 2041).

Load & Resources



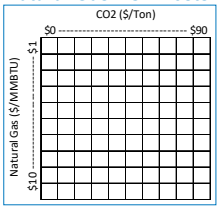
Source: *2021 Integrated Transmission Planning Assessment Scope*, Southwest Power Pool, May 12, 2021.

Fuel Costs



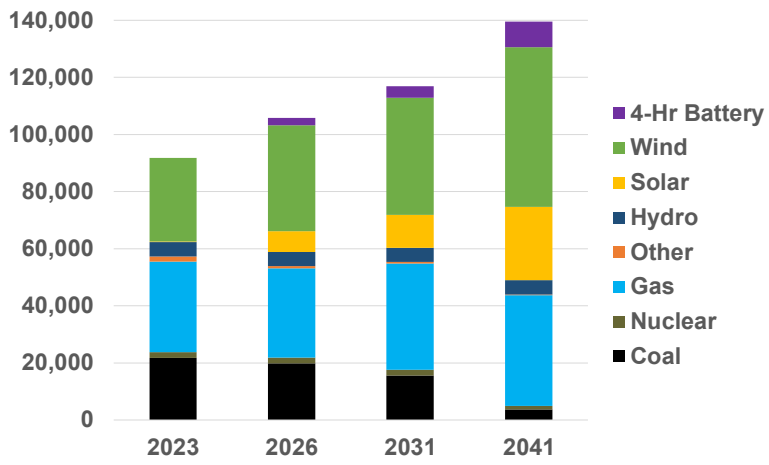
Source: *Annual Energy Outlook 2022*, U.S. Energy Information Administration, March 2022.

Natural Gas/CO2 Costs



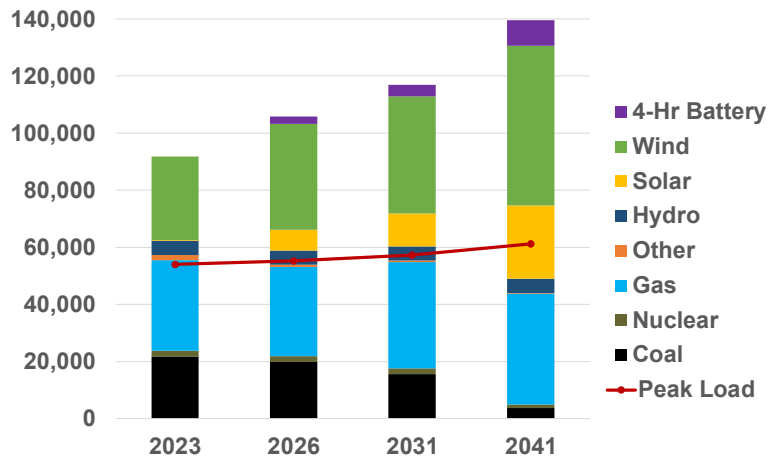
SPP Resource Mix Projections for IRP

Nameplate capacity by fuel type (MW)



SPP Resource Mix Projections for IRP

Nameplate capacity by fuel type (MW)



SPP Capacity Requirements

Nameplate Capacity
The capability of a generating resource at its full rated output.

Accredited Capacity
Under SPP rules, each utility must secure **accredited capacity** equal to at least their peak load plus a 12% reserve margin.

Dispatchable Resources

Accredited ≈ Nameplate

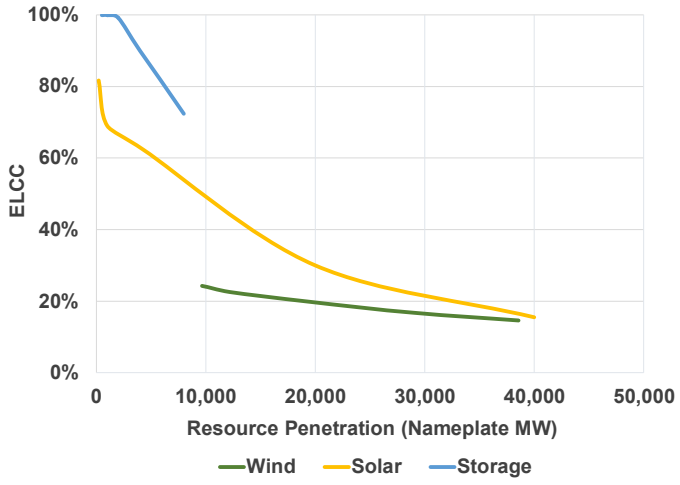
SPP Accreditation: Seasonal capability of unit over at least a 4-hour period.

Non-Dispatchable Resources

Accredited < Nameplate

SPP Accreditation: New methodology to be in place for 2023 summer.

SPP Accreditation Methodology
Non-dispatchable resources



Source: Solar and Wind ELCC Accreditation, Southwest Power Pool, August 2019.
Energy Storage Accreditation Methodology, Southwest Power Pool, January 2020.

Effective Load Carrying Capability (ELCC)
The incremental load a resource can dependably and reliably serve.

"Because of wind and solar generation intermittency, the capacity value[s]…are lower than their nameplate values and will decrease as their penetration increases..."

Source: Solar and Wind ELCC Accreditation, Southwest Power Pool, August 2019.

SPP ELCC Methodology
Wind example

1. Calculate amount of load system can reliably serve without any wind generation in SPP.

2. Add all wind generation and recalculate load system can reliably serve.

3. Incremental load that can be served, divided by total wind generation added, represents ELCC:

$$\text{ELCC (\%)} = \frac{\text{Incremental Load (MW)}}{\text{Wind Nameplate (MW)}}$$

4. Plot ELCC over a range of nameplate wind levels for summer and winter seasons.

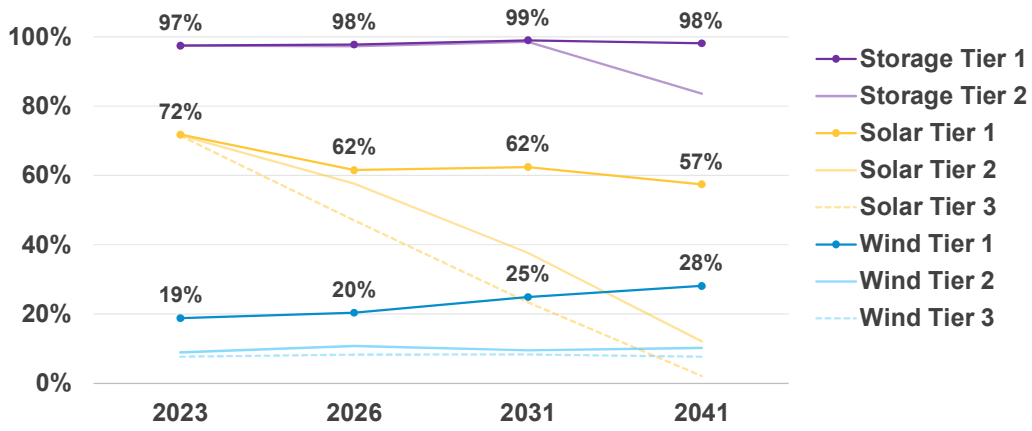
5. Prioritize when applying ELCC curve:
   - » Tier 1: Wind with firm transmission to load; nameplate limited to 35% of avg. peak load.*
   - » Tier 2: All other wind with firm transmission.
   - » Tier 3: Any remaining wind.

   ** Solar limit is 20% of peak; no limit for energy storage.*

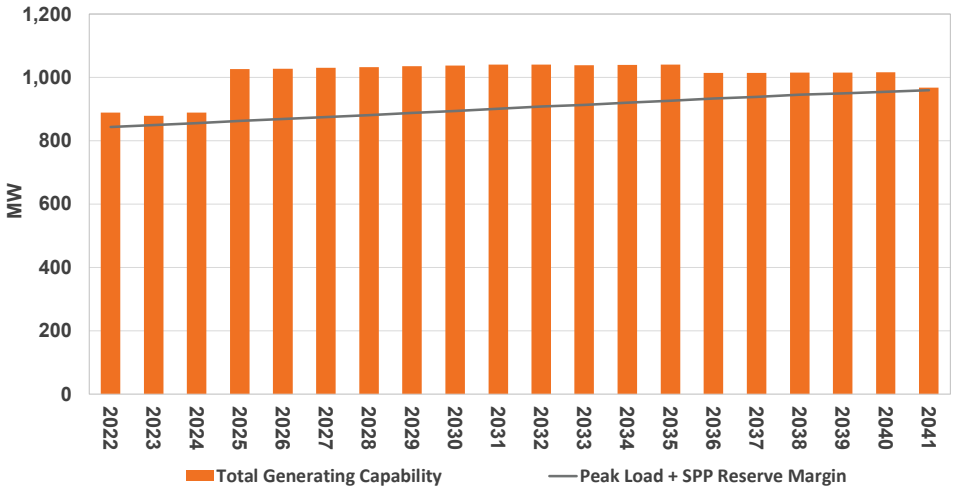
6. Allocate each Tier's total capacity to individual wind resources based upon output during peak load periods.

Consultant ELCC Projections for IRP

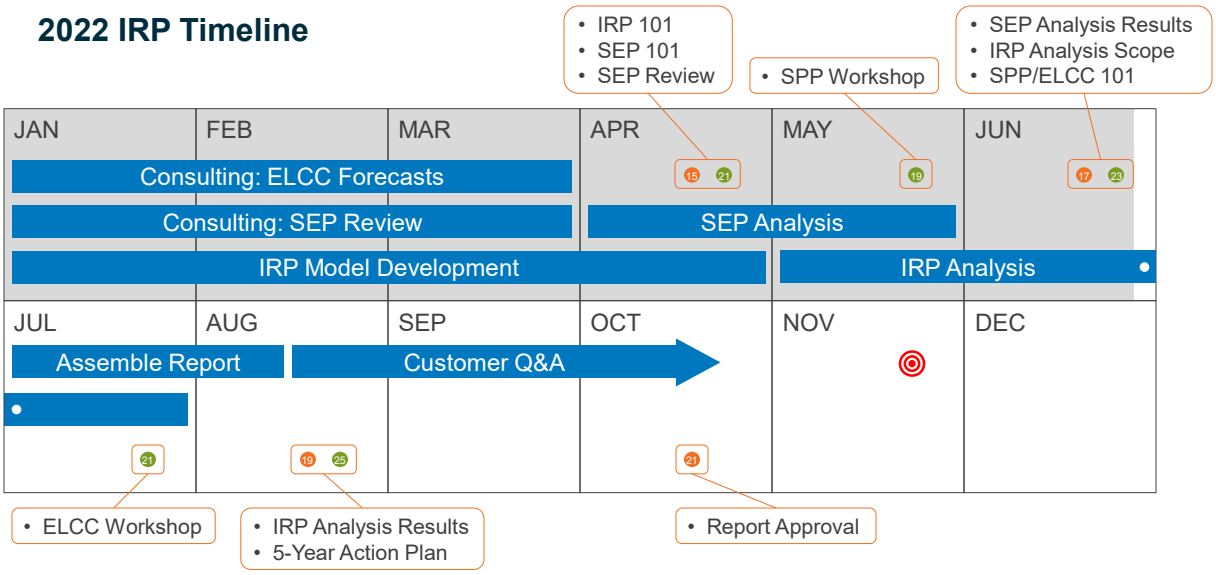
SPP accredited capacity as percentage of nameplate capacity



LES Load & Capability Projections for IRP



2022 IRP Timeline

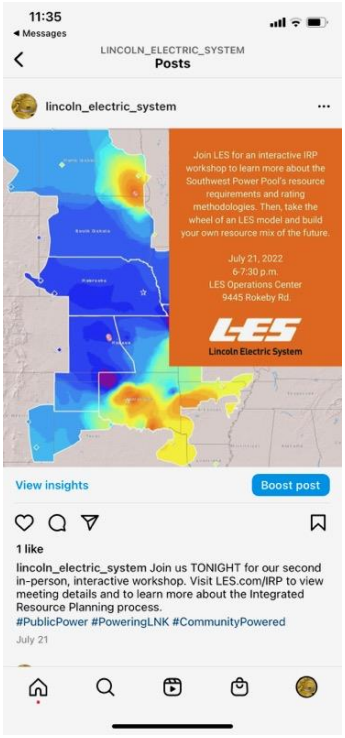


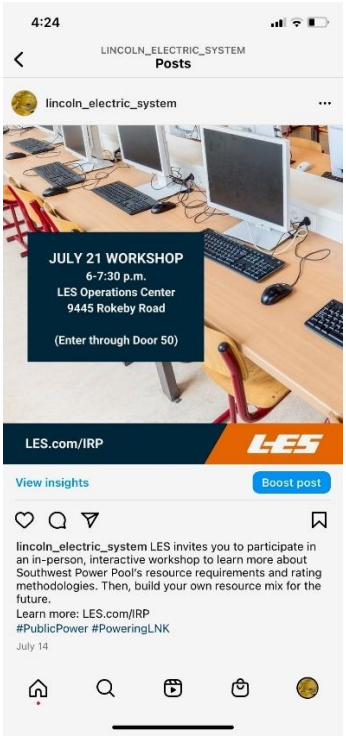
ELCC = Effective Load Carrying Capability
SPP = Southwest Power Pool

Appendix L
Public Workshop #2 Materials

2022 IRP Workshop #2 Promotion Samples

Organic Social Media





Previous Attendee Email

Scott Benson

From: Scott Benson
Sent: Tuesday, July 12, 2022 12:00 PM
Subject: Reminder: LES IRP Workshop on 7/21

Good afternoon,

As an attendee of a previous Integrated Resource Plan (IRP) meeting, I wanted to remind you that a week from this Thursday is our last IRP workshop. This one will focus on LES' regional electricity market, the Southwest Power Pool, and how its resource requirements and related rating methodologies influence LES resource decisions. With this information in mind, everyone will then get to take the wheel of an LES model and build their own resource mix of the future. The workshop is from 6:00 p.m. – 7:30 p.m. on July 21st at the LES Operations Center, located at 9445 Rokeby Road.

Thank you for your interest in LES' IRP process, and I hope to see you next week.

Scott Benson | Manager, Resource & Transmission Planning

Office: 402-473-3390
Mobile: 402-937-4461

LES.com | 9445 Rokeby Road | Lincoln, NE 68526

CONNECT

Effective Load Carrying Capability
SPP Methodology

Scott Benson
Manager, Resource & Transmission Planning

July 21, 2022

SPP Capacity Requirements

Nameplate Capacity
The capability of a generating resource at its full rated output.

Accredited Capacity
Under SPP rules, each utility must secure **accredited capacity** equal to at least their peak load plus a 12% reserve margin.

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Accredited ≈ Nameplate

SPP Accreditation: Seasonal capability of unit over at least a 4-hour period.

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Effective Load Carrying Capability
Accreditation of non-dispatchable resources

Effective Load Carrying Capability (ELCC)
The incremental load a resource can dependably and reliably serve.

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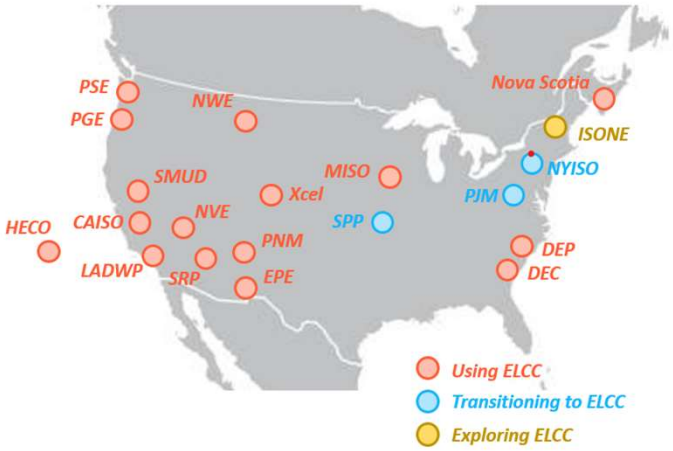
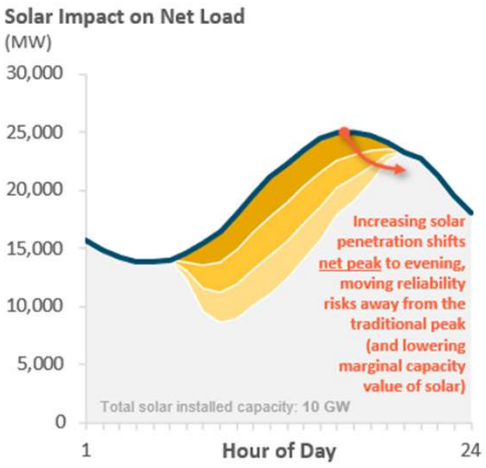
Source: Solar and Wind ELCC Accreditation, Southwest Power Pool, August 2019.



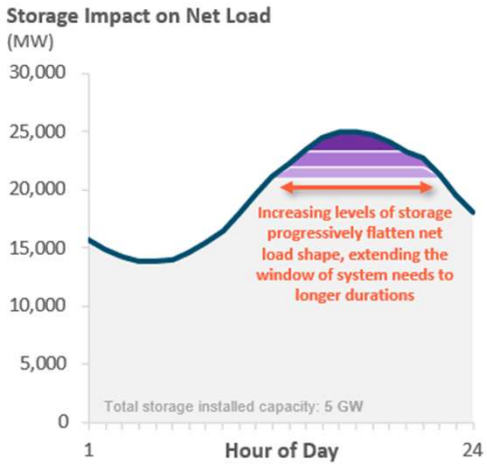
Source: Effective Load Carrying Capability (ELCC) Forecast, Energy + Environmental Economics, July 2022.

Effective Load Carrying Capability
Accreditation of non-dispatchable resources



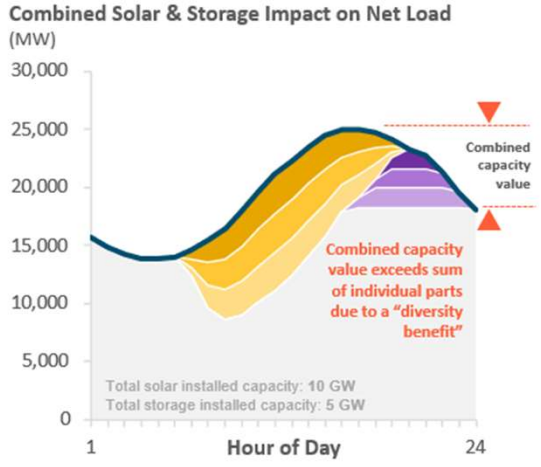
Source: Effective Load Carrying Capability (ELCC) Forecast, Energy + Environmental Economics, July 2022.

Effective Load Carrying Capability
Accreditation of non-dispatchable resources



Source: **Effective Load Carrying Capability (ELCC) Forecast**, Energy + Environmental Economics, July 2022.

Effective Load Carrying Capability
Accreditation of non-dispatchable resources



Source: **Effective Load Carrying Capability (ELCC) Forecast**, Energy + Environmental Economics, July 2022.

Effective Load Carrying Capability
Accreditation of non-dispatchable resources

Common Examples of Synergistic Pairings

Solar + Wind
The profiles for many wind resources produce more energy during evening and nighttime hours when solar is not available

Solar + Storage
Solar and storage each provide what the other lacks – energy (in the case of storage) and the ability to dispatch energy in the evening and nighttime (in the case of solar)

Solar/Wind + Hydro
Hydro is an energy-limited resource so increasing penetrations of solar or wind allows hydro to save its limited production for the most resource constrained hours

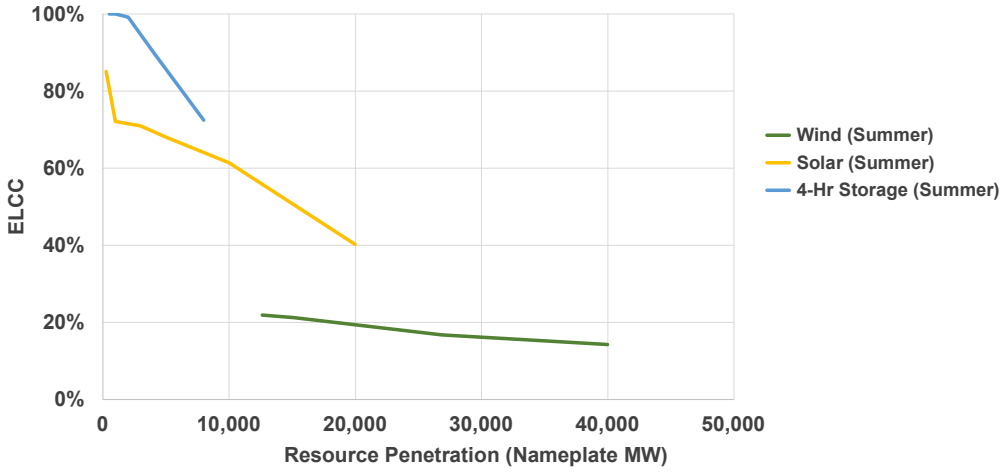
Common Examples of Antagonistic Pairings

Storage + Hydro
Energy limitations on both storage and hydro require longer and longer durations after initial penetrations

Storage + Demand Response
Energy limitations on both storage and DR require longer and longer durations after initial penetrations

Source: **Effective Load Carrying Capability (ELCC) Forecast**, Energy + Environmental Economics, July 2022.

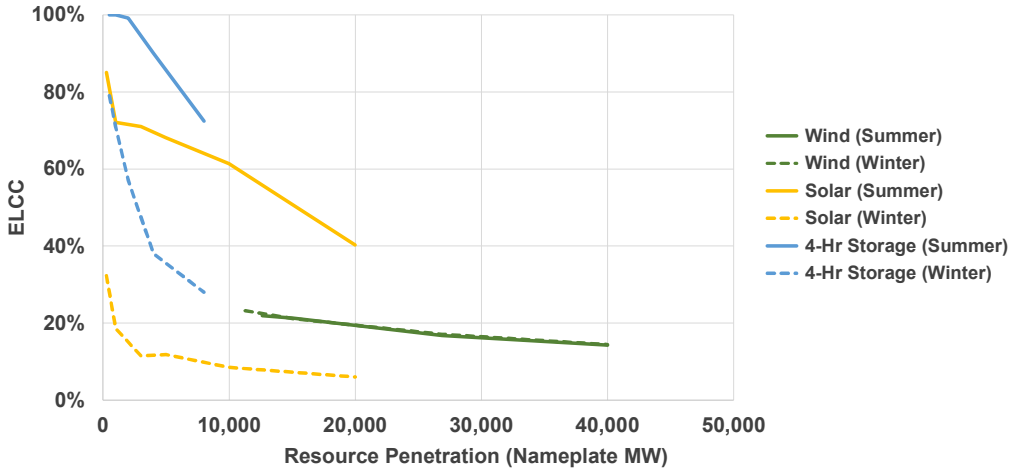
SPP ELCC Methodology
Accreditation of non-dispatchable resources



Source: 2020 ELCC Wind and Solar Study Report, Southwest Power Pool, July 2021.
SPP Energy Storage Study, Astrape Consulting, November 12, 2019.

SPP ELCC Methodology

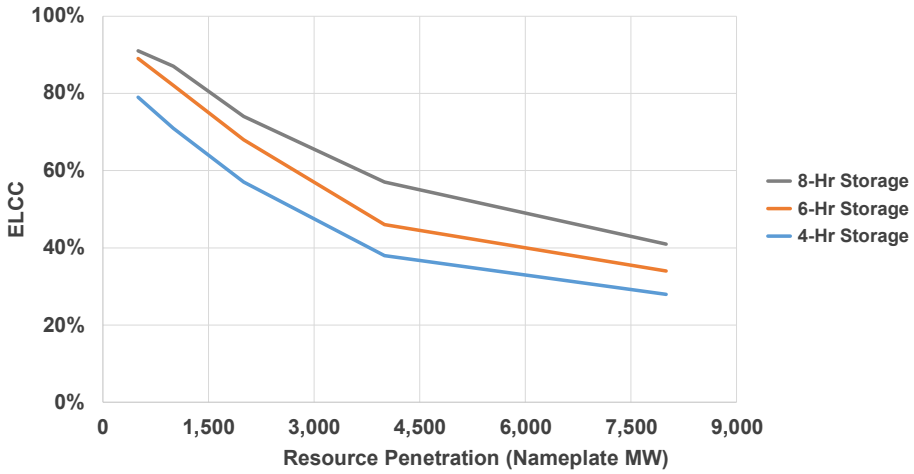
Accreditation of non-dispatchable resources



Source: 2020 ELCC Wind and Solar Study Report, Southwest Power Pool, July 2021.
SPP Energy Storage Study, Astrape Consulting, November 12, 2019.

SPP ELCC Methodology

Winter season storage



Source: SPP Energy Storage Study, Astrape Consulting, November 12, 2019.

SPP ELCC Methodology

Wind example

1. Calculate amount of load system can reliably serve without any wind generation in SPP; use reliability metric of no more than one day of load loss in 10 years.

2. Add all wind generation and recalculate load system can reliably serve.

3. Incremental load that can be served, divided by total wind generation added, represents ELCC:

$$\text{ELCC (\%)} = \frac{\text{Incremental Load (MW)}}{\text{Wind Nameplate (MW)}}$$

4. Plot ELCC over a range of nameplate wind levels for summer (Jun – Sep) and winter (Dec – Mar) seasons.

5. Prioritize when applying ELCC curve:
   - » Tier 1: Wind with firm transmission to load; nameplate limited to 35% of avg. peak load.*
   - » Tier 2: All other wind with firm transmission.
   - » Tier 3: Any remaining wind.

   ** Solar limit is 20% of peak; no limit for energy storage.*

6. Allocate each Tier's total capacity to individual wind resources based upon output during peak load periods.

SPP ELCC Methodology

2020 summer season wind results

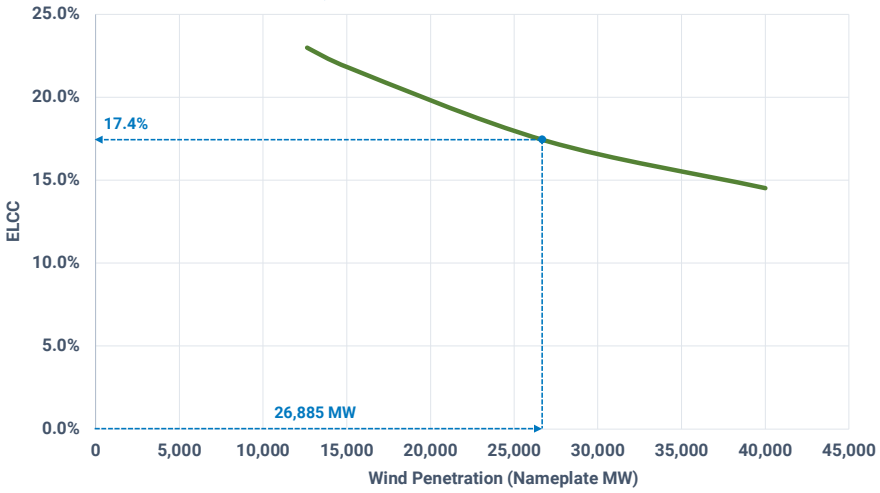
Total Nameplate
26,885 MW

Total Accreditation
4,670 MW

Tier Nameplate
Tier 1: 12,634 MW
Tier 2: 2,507 MW
Tier 3: 11,744 MW

Tier Accreditation
Tier 1:
Tier 2:
Tier 3:

Total Accreditation (MW) = Total Nameplate (MW) * Total Accreditation (%)
= 26,885 MW x 17.4%
= 4,670 MW



SPP ELCC Methodology

2020 summer season wind results

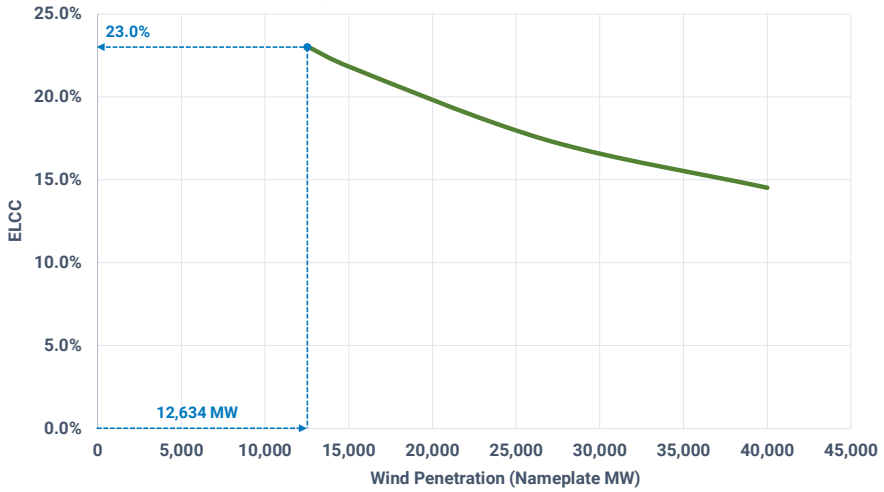
Tier 1 Accreditation (MW) = Tier 1 Nameplate (MW) * Tier 1 Accreditation (%)
= 12,634 MW x 23.0%
= 2,903 MW

Total Nameplate
26,885 MW

Total Accreditation
4,670 MW

Tier Nameplate
Tier 1: 12,634 MW
Tier 2: 2,507 MW
Tier 3: 11,744 MW

Tier Accreditation
Tier 1: 2,903 MW
Tier 2:
Tier 3:



SPP ELCC Methodology

2020 summer season wind results

Tier 1&2 Accreditation (MW) = Tier 1&2 Nameplate (MW) * Tier 1&2 Accreditation (%)
= 15,141 MW x 21.8%
= 3,294 MW

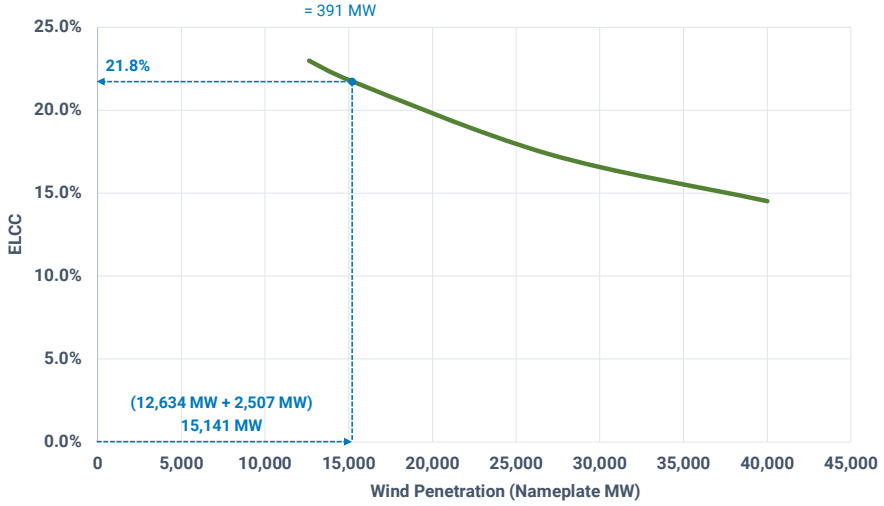
Tier 2 Accreditation (MW) = Tier 1&2 Accreditation (MW) – Tier 1 Accreditation (MW)
= 3,294 MW – 2,903 MW
= 391 MW

Total Nameplate
26,885 MW

Total Accreditation
4,670 MW

Tier Nameplate
Tier 1: 12,634 MW
Tier 2: 2,507 MW
Tier 3: 11,744 MW

Tier Accreditation
Tier 1: 2,903 MW
Tier 2: 391 MW
Tier 3:



SPP ELCC Methodology

2020 summer season wind results

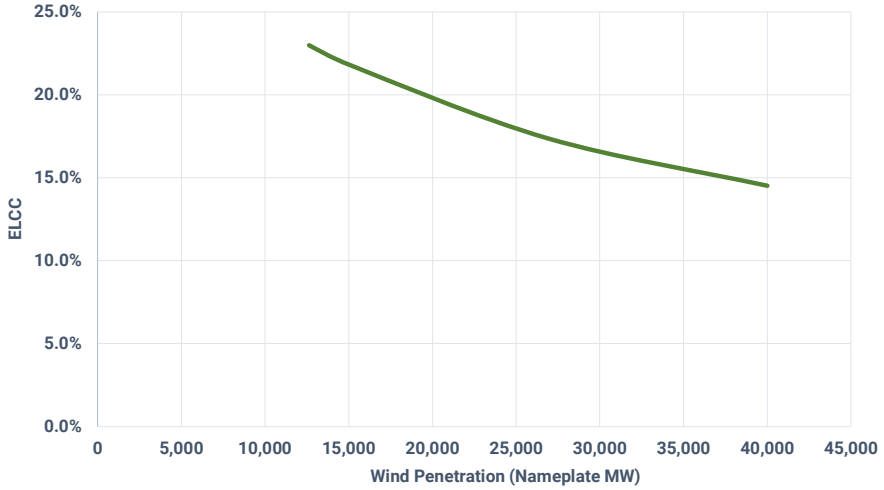
Tier 3 Accreditation (MW) = Total Accreditation (MW) – Tier 1 Accreditation (MW) – Tier 2 Accreditation (MW)
= 4,670 MW – 2,903 MW – 391 MW
= 1,376 MW

Total Nameplate
26,885 MW

Total Accreditation
4,670 MW

Tier Nameplate
Tier 1: 12,634 MW
Tier 2: 2,507 MW
Tier 3: 11,744 MW

Tier Accreditation
Tier 1: 2,903 MW
Tier 2: 391 MW
Tier 3: 1,376MW



SPP ELCC Methodology

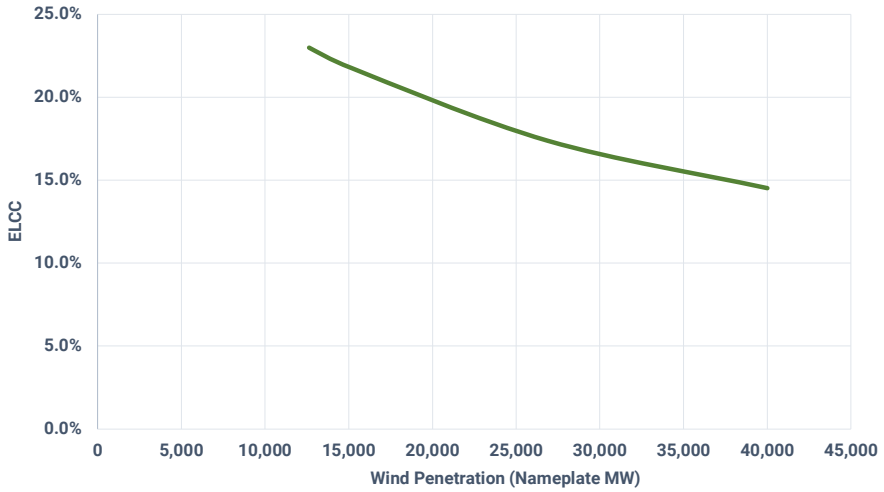
2020 summer season wind results

Total Nameplate
26,885 MW

Total Accreditation
4,670 MW

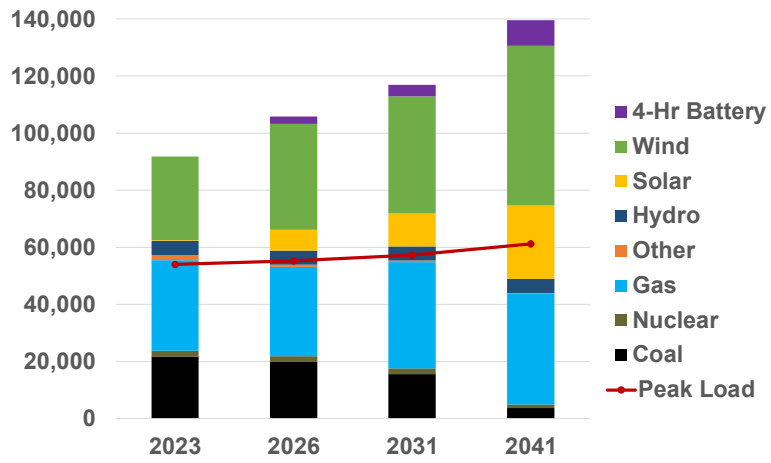
Tier Nameplate
Tier 1: 12,634 MW
Tier 2: 2,507 MW
Tier 3: 11,744 MW

Tier Accreditation
Tier 1: 2,903 MW
Tier 2: 391 MW
Tier 3: 1,376MW



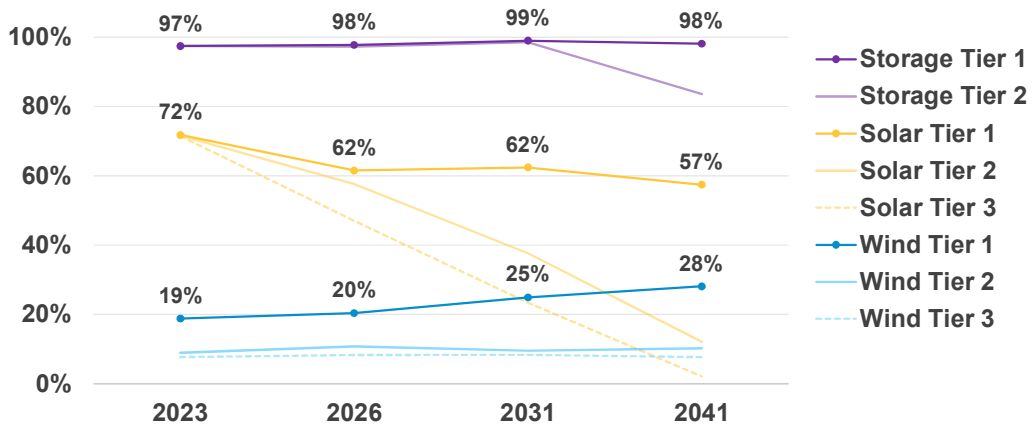
SPP Resource Mix Projections for IRP

Nameplate capacity by fuel type (MW)



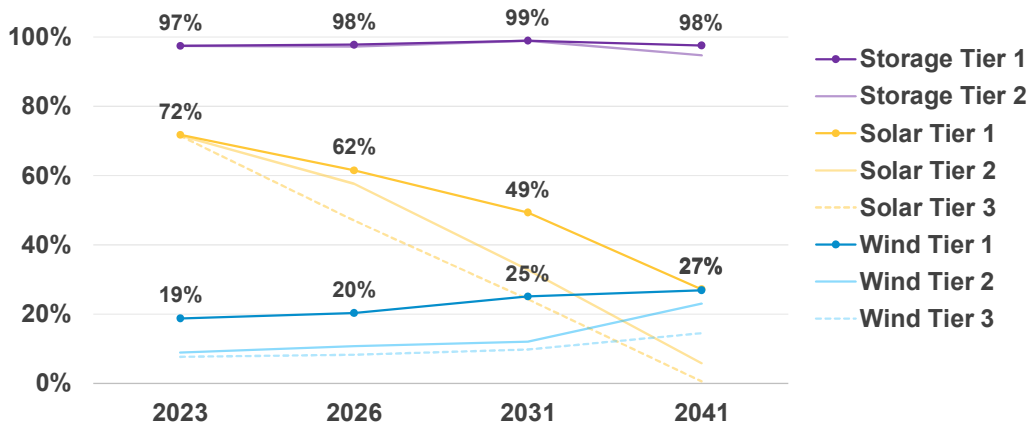
Consultant ELCC Projections for IRP

SPP accredited capacity as percentage of nameplate capacity



Consultant ELCC Projections for IRP Electrification Sensitivity

SPP accredited capacity as percentage of nameplate capacity



Activity: 2041 LES Resource Portfolio

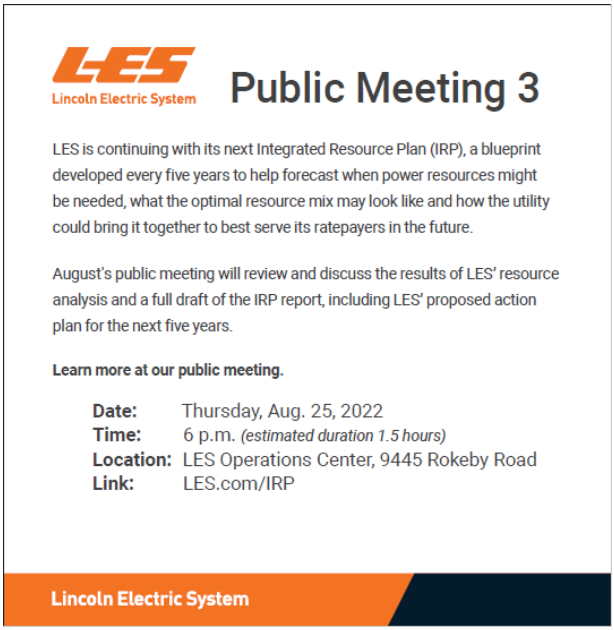
Using the model provided, participants will each develop LES' future resource portfolio.

Participants may retire and add resources of their choosing but must ensure LES maintains enough accredited capacity to meet its peak load plus SPP's mandated 12% reserve margin in 2041.

Appendix M
Public Meeting #3 Materials

2022 IRP Meeting #3 Promotion Samples

Print Ad



Lincoln Electric System

Public Meeting 3

LES is continuing with its next Integrated Resource Plan (IRP), a blueprint developed every five years to help forecast when power resources might be needed, what the optimal resource mix may look like and how the utility could bring it together to best serve its ratepayers in the future.

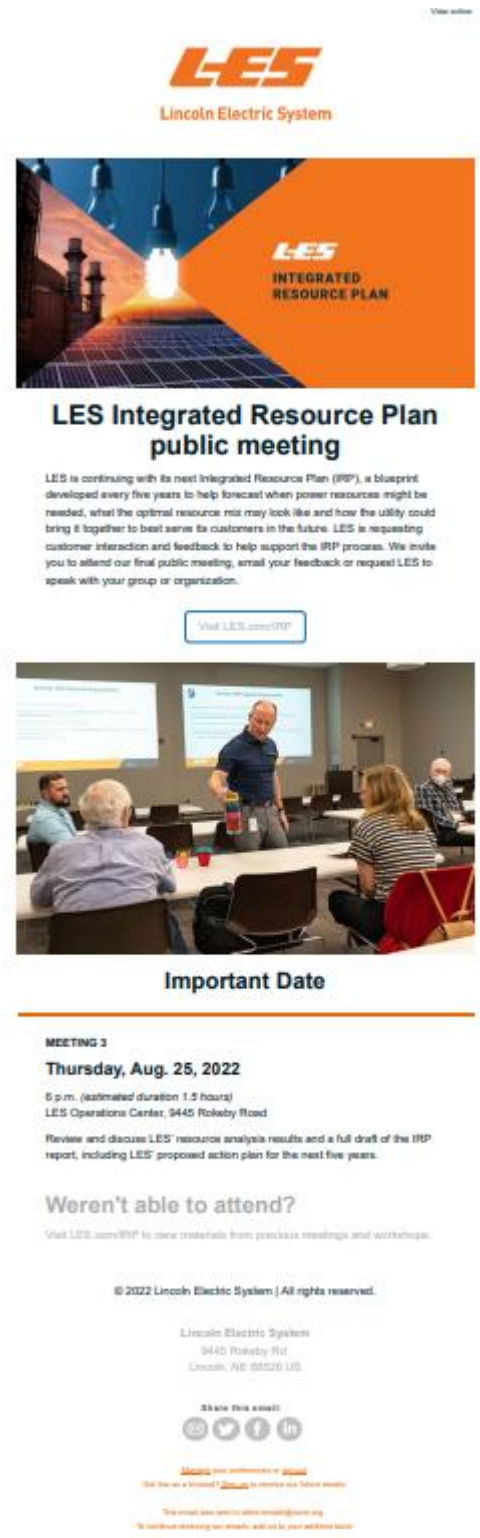
August's public meeting will review and discuss the results of LES' resource analysis and a full draft of the IRP report, including LES' proposed action plan for the next five years.

Learn more at our public meeting.

Date: Thursday, Aug. 25, 2022
Time: 6 p.m. *(estimated duration 1.5 hours)*
Location: LES Operations Center, 9445 Rokeby Road
Link: LES.com/IRP

Lincoln Electric System

All Customer Email



Lincoln Electric System

INTEGRATED RESOURCE PLAN

LES Integrated Resource Plan public meeting

LES is continuing with its next Integrated Resource Plan (IRP), a blueprint developed every five years to help forecast when power resources might be needed, what the optimal resource mix may look like and how the utility could bring it together to best serve its customers in the future. LES is requesting customer interaction and feedback to help support the IRP process. We invite you to attend our final public meeting, email your feedback or request LES to speak with your group or organization.

Visit LES.com/IRP

Important Date

MEETING 3

Thursday, Aug. 25, 2022

6 p.m. *(estimated duration 1.5 hours)*
LES Operations Center, 9445 Rokeby Road

Review and discuss LES' resource analysis results and a full draft of the IRP report, including LES' proposed action plan for the next five years.

Weren't able to attend?

Visit LES.com/IRP to view materials from previous meetings and workshops.

Lincoln Electric System
9445 Rokeby Rd
Lincoln, NE 68520 US

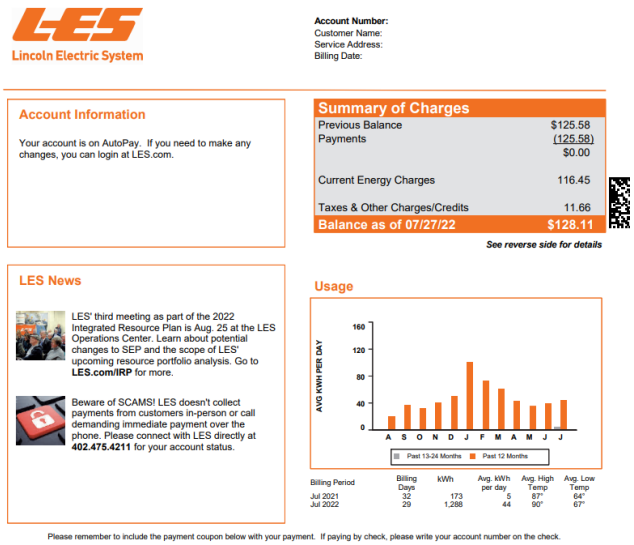
Share this email:

Manage your preferences or unsubscribe

Not that we'd forward it. Sign up to receive our future emails.

This email was sent to [redacted]
To continue receiving our emails, add us to your address book.

Bill Messages



Lincoln Electric System

Account Number:
Customer Name:
Service Address:
Billing Date:

Account Information

Your account is on AutoPay. If you need to make any changes, you can login at LES.com.

Summary of Charges

Previous Balance	$125.58
Payments	(125.58)
	$0.00
Current Energy Charges	116.45
Taxes & Other Charges/Credits	11.66
Balance as of 07/27/22	**$128.11**

See reverse side for details

LES News

LES' third meeting as part of the 2022 Integrated Resource Plan is Aug. 25 at the LES Operations Center. Learn about potential changes to SEP and the scope of LES' upcoming resource portfolio analysis. Go to **LES.com/IRP** for more.

Beware of SCAMS! LES doesn't collect payments from customers in-person or call demanding immediate payment over the phone. Please connect with LES directly at **402.475.4211** for your account status.

Usage

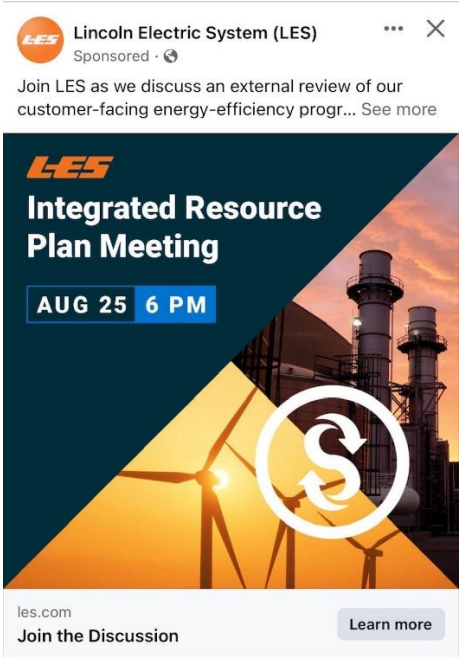
AVG KWH PER DAY
160
120
80
40
0
A S O N D J F M A M J J
Past 13-24 Months
Past 12 Months

Billing Period	Billing Days	kWh	Avg. kWh per day	Avg. High Temp	Avg. Low Temp
Jul 2021	32	173	5	87°	64°
Jul 2022	29	1,288	44	90°	67°

Please remember to include the payment coupon below with your payment. If paying by check, please write your account number on the check.

Organic Social Media

Paid Social Ad



News Release

FOR IMMEDIATE RELEASE // Call LES' media line at 402-540-0306 for all media inquiries.

LES Integrated Resource Plan reaches final public meeting

LINCOLN – Lincoln Electric System will reach the next step in its latest long-range planning process with its third and final public meeting for the LES Integrated Resource Plan on Thursday, Aug. 25, 6-7:30 p.m. at the LES Operations Center, 9445 Rokeby Road. The Integrated Resource Plan, or IRP, is a blueprint developed every five years to help forecast when power resources will be needed, what the power-generation mix should look like and how the utility will bring it together to best serve its ratepayers in the future.

This public meeting will focus on reviewing the final draft of the report and the related action plan, which includes details on LES' optimal resource mix, the LES Sustainable Energy Program and LES' pursuit of its decarbonization goal. The LES Administrative Board will take action on the report at its Oct. 21 meeting.

LES reviewed the IRP's timeline and a consultant's recommendations for the Sustainable Energy Program at its first public meeting on April 21. The second public meeting held July 23, reviewed changes to the Sustainable Energy Program assumptions based on the consultant's findings and the scope of the upcoming analysis of LES' future resource mix. LES held two interactive IRP workshops to give customers an opportunity to learn more about LES' regional electricity market, the Southwest Power Pool, and its role in LES resource decisions.

Required as part of LES' hydroelectric power contract with the Western Area Power Administration, LES' IRP is part of the utility's strategic planning efforts that keep it among the best power companies in the nation. The last IRP was produced and filed with the Western Area Power Administration in 2017.

Merging industry knowledge and insight from LES customer-owners in the IRP process, LES keeps its goal of maintaining the lowest possible rates for its customers while meeting their energy needs with efficiency and reliability on the leading edge of the power industry.

To learn more about LES' 2022 IRP, visit LES.com/IRP. Related comments and questions may also be submitted to IRP@LES.com.

LES.com | 9445 Rokeby Rd. | Lincoln, NE 68526

Previous Attendee Email

From: Scott Benson <sbenson@les.com>
Sent: Friday, August 19, 2022 4:34 PM
Subject: LES IRP Draft Report

Good afternoon,

As an attendee of a previous Integrated Resource Plan (IRP) meeting, I wanted to let you know that the final draft of the IRP report has been posted on LES.com. Feel free to shoot me an email or give me a call if you have any comments or questions on the report. Also, don't forget that our last public meeting is scheduled for next Thursday, August 25th, from 6:00 p.m. – 7:30 p.m. at the LES Operations Center, located at 9445 Rokeby Road. We plan to walk through the high points of the report and then open up the floor for Q&A.

Thank you again for your interest in LES' IRP process. Hopefully we'll get to see you next week.

Scott Benson | Manager, Resource & Transmission Planning

LES

Office: 402-473-3390
Mobile: 402-937-4461

LES.com | 9445 Rokeby Road | Lincoln, NE 68526

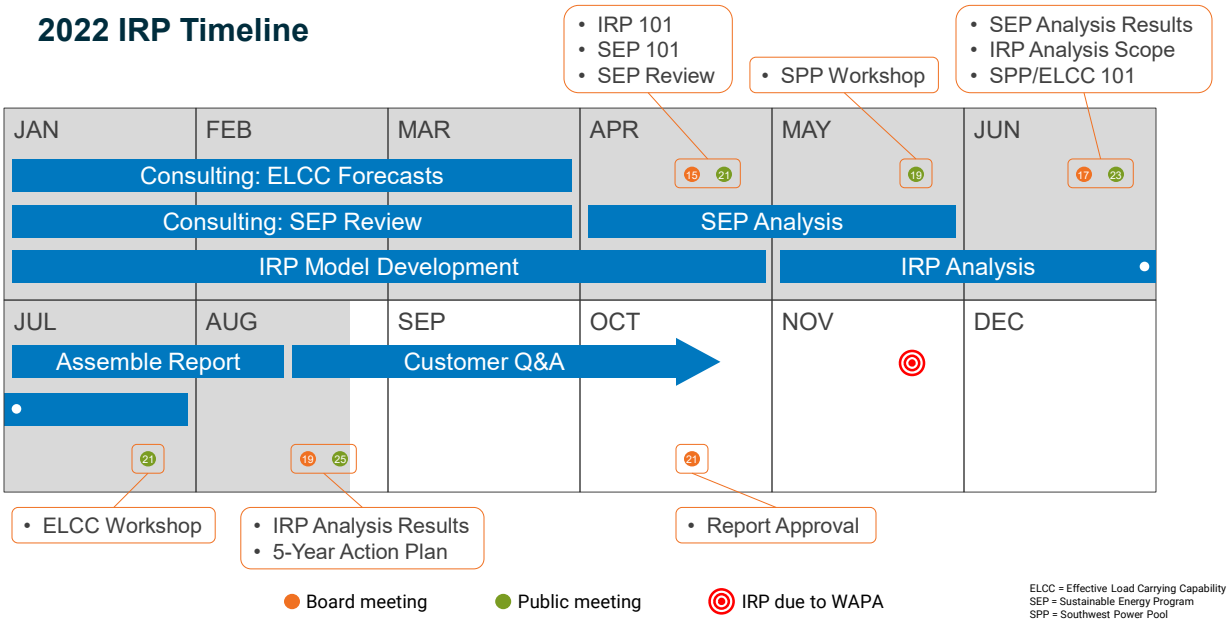
2022 Integrated Resource Plan

Results and Action Plan

Scott Benson
Manager, Resource & Transmission Planning

August 25, 2022

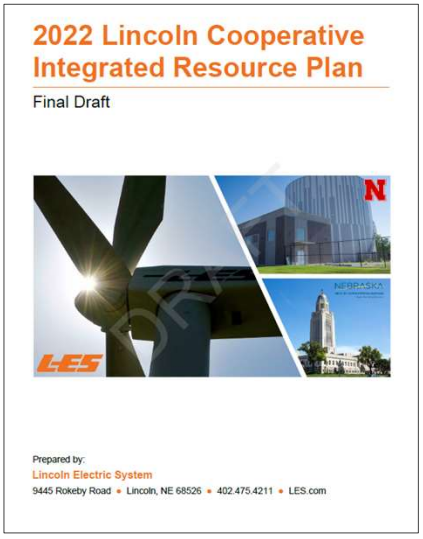
2022 IRP Timeline



ELCC = Effective Load Carrying Capability
SEP = Sustainable Energy Program
SPP = Southwest Power Pool

Agenda

- IRP Analysis
  - Modeling Architecture
  - Preliminary Resource Screening
  - Base Case Results
  - Sensitivities
- IRP Actions
  - Preliminary Decarbonization Goal Plan
  - Proposed 5-Year Action Plan



Source: 2022 Lincoln Cooperative Integrated Resource Plan – Final Draft, Lincoln Electric System, August 2020.

2022 IRP ANALYSIS

Modeling Architecture

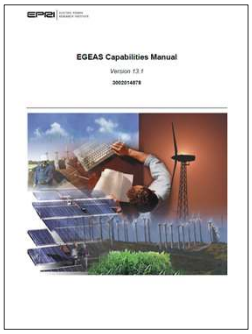
IRP Analysis
Software

IRP analysis was conducted with EGEAS (Electrical Generation Expansion Analysis System); a software tool developed by the Electric Power Research Institute (EPRI).

EGEAS is used by numerous companies for future resource planning, including the Midcontinent Independent System Operator (MISO).

EGEAS utilizes dynamic programming, evaluating all possible resource combinations, to identify an optimal solution based on the Net Present Value (NPV) of total production costs, including:

- Construction costs.
- Operating costs.
- Reliability constraints.



Source: *The Electric Generation Expansion Analysis System (EGEAS) Software, 2019 EPRI Update*, Electric Power Research Institute, January 24, 2018.

IRP Analysis
Software Model

Coal Retirements

Retire an existing LES coal unit whenever it registers a Capacity Factor (CF) of 20% or less for 5 straight years.

2022 Load Forecast

Existing Resources

LES *System A* ↔ **SPP** *System B*

New Resources

Source: *Cost and Performance Characteristics of New Generating Technologies*, U.S. Energy Information Administration, March 2022.

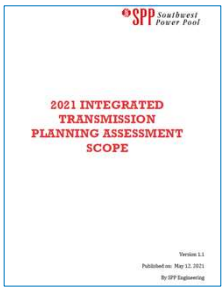
Methodology

EGEAS develops the optimal, lowest cost resource expansion plan for LES (System A) while accounting for potential sales to, and purchases from, SPP (System B). EGEAS analyzes a 20-year study period (2022 – 2041) plus a 30-year extension period.

Expansion plan must maintain LES reliability:

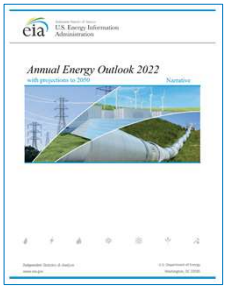
1) Accredited generation equating to at least 112% of peak load, per historical SPP reserve margin requirements.
2) A loss of load probability of no more than 2 days of unserved load in 10 years.

Load & Resources



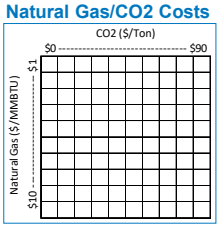
Source: *2021 Integrated Transmission Planning Assessment Scope*, Southwest Power Pool, May 12, 2021.

Fuel Costs



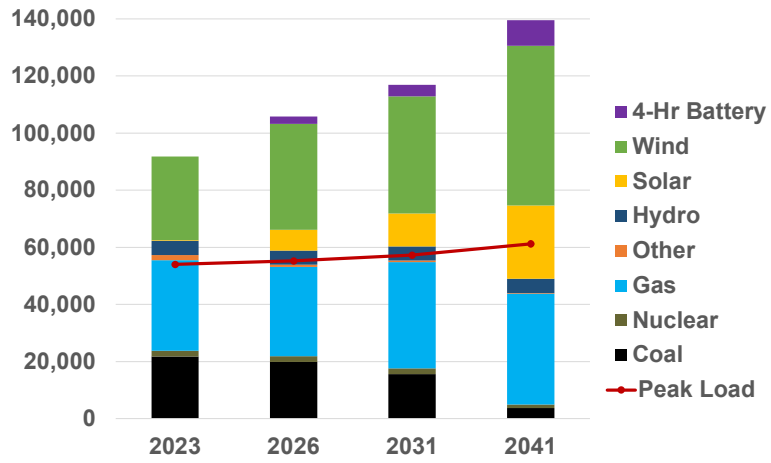
Source: *Annual Energy Outlook 2022*, U.S. Energy Information Administration, March 2022.

Natural Gas/CO2 Costs



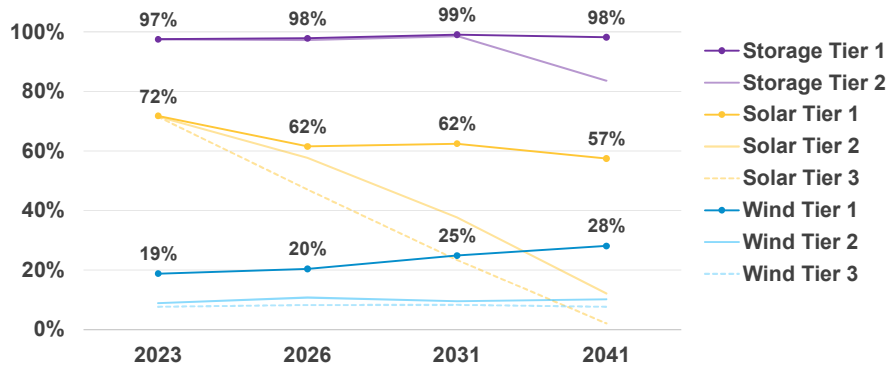
IRP Analysis

SPP nameplate resource capacity by fuel type (MW)



IRP Analysis

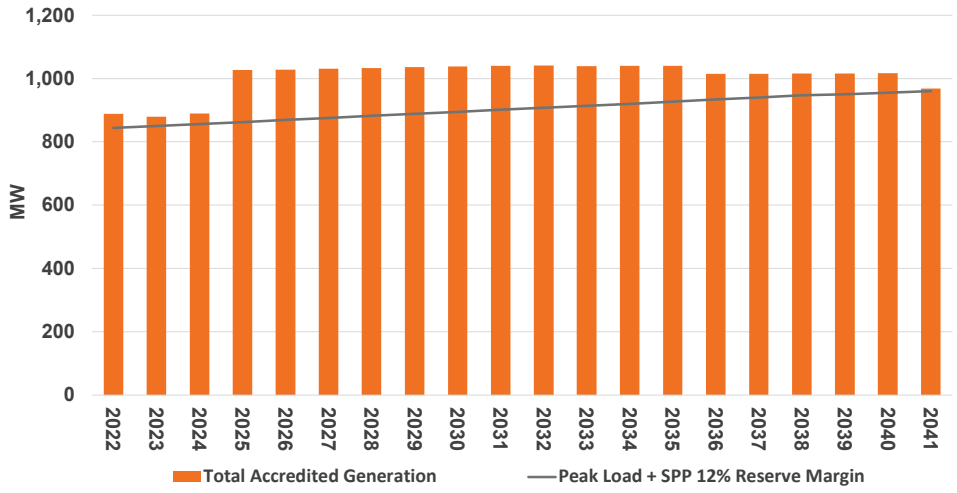
Consultant projections of SPP accredited capacity as percentage of nameplate capacity



LES' 2041 Tier I Limits	
Wind	292 MW
Solar	167 MW
Battery Storage	N/A

- Tier 1: Firm transmission to load; nameplate limited to 35% of avg. peak load for wind, 20% for solar.
- Tier 2: Non-Tier I with firm transmission to load.
- Tier 3: No firm transmission to load.

IRP Analysis
LES Load and Capability Projections



2022 IRP ANALYSIS
Preliminary Resource Screening

New Resource Options
Preliminary Screening

- Battery Storage (4-hour)
- Biomass
- Fuel Cells
- Geothermal
- Hydropower
- Landfill Gas
- Natural Gas Combustion Turbine
  Aeroderivative
- Natural Gas Combustion Turbine
  Industrial Frame
- Natural Gas Combined Cycle
- Natural Gas Combined Cycle
  90% CCS
- Natural Gas Distributed Generation
  Base & Peak
- Natural Gas Internal Combustion Engine
- Nuclear
  Light Water Reactor
- Nuclear
  Small Modular Reactor
- Solar Photovoltaics
  Single-Axis Tracking
- Solar Photovoltaics + Battery Storage
  Hybrid
- Solar Thermal
- Wind
  Offshore
- Wind
  Onshore
- Ultra-Supercritical Coal
- Ultra-Supercritical Coal
  30% CCS
- Ultra-Supercritical Coal
  90% CCS

New Resource Options
Preliminary Screening

1) Remove any base load or intermediate fossil resources without optimal 90% Carbon Capture & Sequestration (CCS).

- Battery Storage (4-hour)
- Biomass
- Fuel Cells
- Geothermal
- Hydropower
- Landfill Gas
- Natural Gas Combustion Turbine
  Aeroderivative
- Natural Gas Combustion Turbine
  Industrial Frame
- Natural Gas Combined Cycle
- Natural Gas Combined Cycle
  90% CCS
- Natural Gas Distributed Generation
  Base & Peak
- Natural Gas Internal Combustion Engine
- Nuclear
  Light Water Reactor
- Nuclear
  Small Modular Reactor
- Solar Photovoltaics
  Single-Axis Tracking
- Solar Photovoltaics + Battery Storage
  Hybrid
- Solar Thermal
- Wind
  Offshore
- Wind
  Onshore
- Ultra-Supercritical Coal
- Ultra-Supercritical Coal
  30% CCS
- Ultra-Supercritical Coal
  90% CCS

New Resource Options
Preliminary Screening

1) Remove any base load or intermediate fossil resources without optimal 90% Carbon Capture & Sequestration (CCS).

- Battery Storage (4-hour)
- Biomass
- Fuel Cells
- Geothermal
- Hydropower
- Landfill Gas
- Natural Gas Combustion Turbine *Aeroderivative*
- Natural Gas Combustion Turbine *Industrial Frame*
- Natural Gas Combined Cycle
- Natural Gas Combined Cycle *90% CCS*
- Natural Gas Distributed Generation *Base & Peak*
- Natural Gas Internal Combustion Engine
- Nuclear *Light Water Reactor*
- Nuclear *Small Modular Reactor*
- Solar Photovoltaics *Single-Axis Tracking*
- Solar Photovoltaics + Battery Storage *Hybrid*
- Solar Thermal
- Wind *Offshore*
- Wind *Onshore*
- Ultra-Supercritical Coal
- Ultra-Supercritical Coal *30% CCS*
- Ultra-Supercritical Coal *90% CCS*

New Resource Options
Preliminary Screening

2) Remove any resources that are not practical within the SPP footprint.

- Battery Storage (4-hour)
- Biomass
- Fuel Cells
- Geothermal
- Hydropower
- Landfill Gas
- Natural Gas Combustion Turbine *Aeroderivative*
- Natural Gas Combustion Turbine *Industrial Frame*
- Natural Gas Combined Cycle *90% CCS*
- Natural Gas Distributed Generation *Base & Peak*
- Natural Gas Internal Combustion Engine
- Nuclear *Light Water Reactor*
- Nuclear *Small Modular Reactor*
- Solar Photovoltaics *Single-Axis Tracking*
- Solar Photovoltaics + Battery Storage *Hybrid*
- Solar Thermal
- Wind *Offshore*
- Wind *Onshore*
- Ultra-Supercritical Coal *90% CCS*

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Preliminary Screening

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- Geothermal
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  Hybrid
- Solar Thermal
- Wind
  Offshore
- Wind
  Onshore
- Ultra-Supercritical Coal
  90% CCS

New Resource Options
Preliminary Screening

3) Use EGEAS screening function – varies CF of dispatchable units in 10% intervals and compares cost per nameplate kW – at four extreme combinations of natural gas and CO_2 prices to eliminate consistently highest cost options.

- Battery Storage (4-hour)
- Biomass
- Fuel Cells
- Natural Gas Combustion Turbine
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- Natural Gas Combustion Turbine
  Industrial Frame
- Natural Gas Combined Cycle
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Lincoln Electric System
LES.com 20

New Resource Options
Preliminary Screening

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New Resource Options
Preliminary Screening

5) Compare similar non-dispatchable options and remove any alternative with uniformly higher capital and operations and maintenance costs.

- Battery Storage (4-hour)
- Natural Gas Combustion Turbine
  Aeroderivative
- Natural Gas Combined Cycle
  90% CCS
- Natural Gas Internal Combustion Engine
- Nuclear
  Light Water Reactor
- Solar Photovoltaics
  Single-Axis Tracking
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  Hybrid
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New Resource Options
Preliminary Screening

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New Resource Options
Final Evaluation Set

Resource	Nameplate (MW)	Max Number	Abbreviation
Battery Storage (4-hour)	50	4	Battery
Natural Gas Combined Cycle w/90% CCS	100	3	NGCC CCS
Natural Gas Combustion Turbine	105	3	NGCT
Natural Gas Internal Combustion Engine	21	4	RICE
Nuclear	100	3	Nuclear
Solar Photovoltaics	150	3	Solar
Solar Photovoltaics + Battery Storage (4-hour)	150	1*	Hybrid Solar
Ultra-Supercritical Coal w/90% CCS	100	3	Coal CCS
Wind	100	7	Wind

* To evaluate how the solar and battery resources fared on their own merits, the hybrid option was only applied in select sensitivity analysis.

New Resource Options
Final Evaluation Set

Resource	Nameplate (MW)	Max Number	Abbreviation
Battery Storage (4-hour)	50	4	Battery
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Natural Gas Internal Combustion Engine	21	4	RICE
Nuclear	100	3	Nuclear
Solar Photovoltaics	150	3	Solar
Solar Photovoltaics + Battery Storage (4-hour)	115	1*	Hybrid Solar
Ultra-Supercritical Coal w/90% CCS	100	3	Coal CCS
Wind	100	7	Wind
Sustainable Energy Program	28	1	DSM SEP
WSEC Unit 4 Retrofit w/90% CCS	72	1	WS4 CCS Upgrade

* To evaluate how the solar and battery resources fared on their own merits, the hybrid option was only applied in select sensitivity analysis.

2022 IRP ANALYSIS

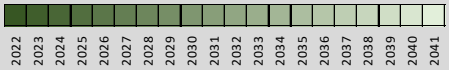
Base Case Results

Example

Interpreting IRP Results

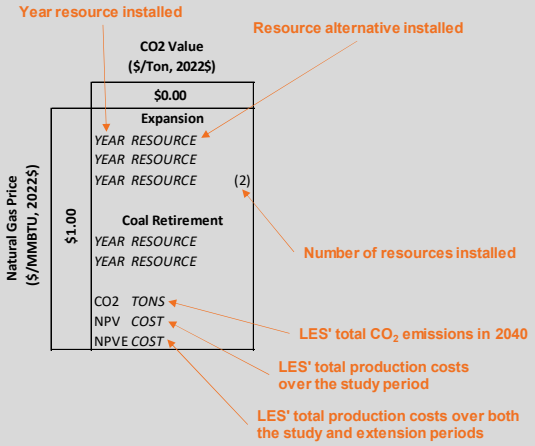
- Results include the top-rated expansion plan for each study scenario and a color-coded summary per resource. Shaded cells indicate a resource's inclusion within the 2022 - 2041 study period; the darker the shading, the earlier the unit was selected.

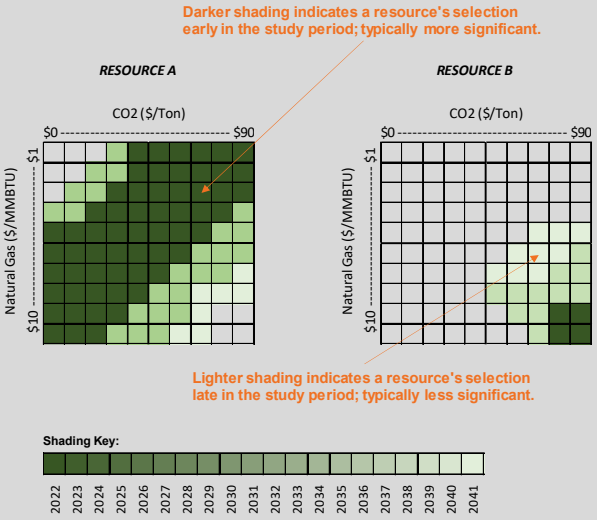
Shading Key:



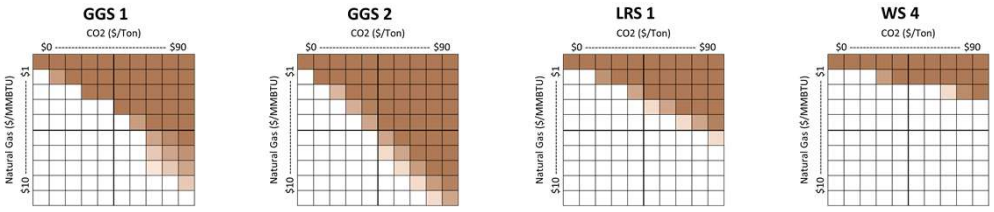
- Typically, more value should be placed on unit selections made earlier in the study period.
- EGEAS assumes no new load growth and no new resource additions during the subsequent 30-year extension period.
- Because of this approach, it often places too much importance on not “over building” late in the study period, attempting to pick resources whose size more closely matches the near-term reserve margin requirements.

Example
Interpreting IRP Results



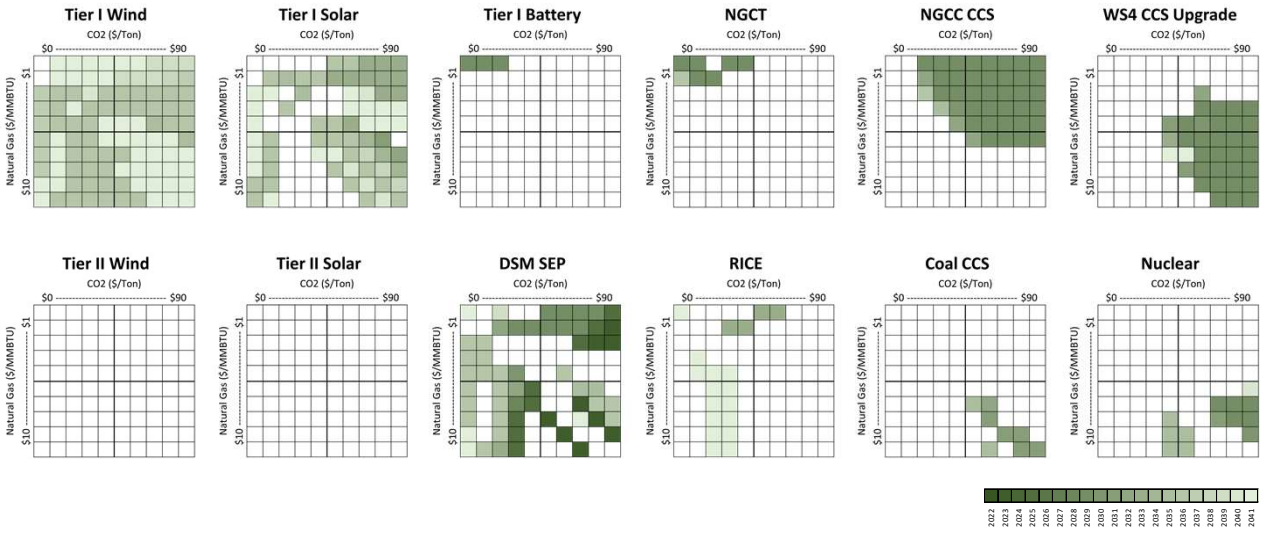


Base Case Results
Coal Retirements

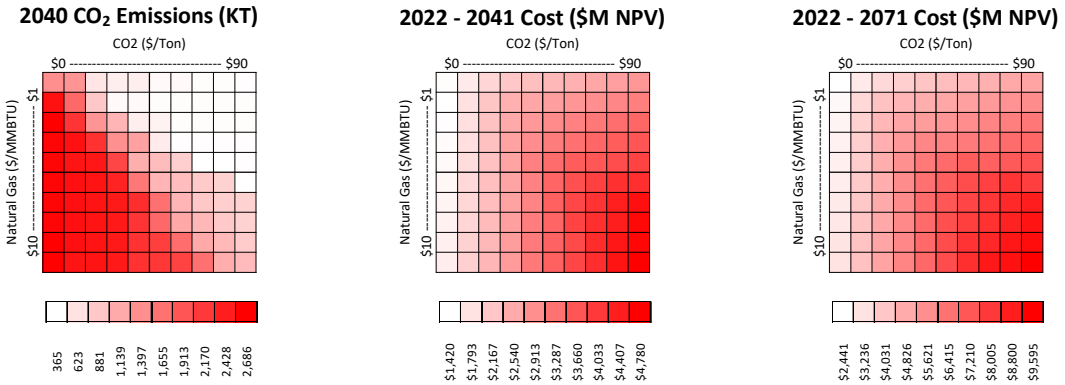


GGS 1/GGS 2 = Gerald Gentleman Station Units 1 and 2
LRS 1 = Laramie River Station Unit 1
WS 4 = Walter Scott Jr. Energy Center Unit 4

Base Case Results
Resource Additions

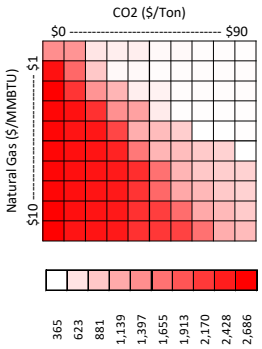


Base Case Results
Metrics

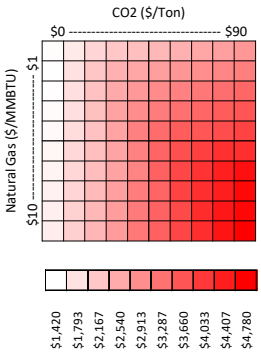


Base Case Results
Metrics

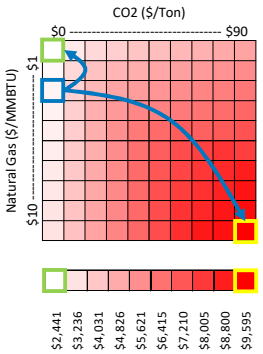
2040 CO_2 Emissions (KT)



2022 - 2041 Cost ($M NPV)



2022 - 2071 Cost ($M NPV)



Cumulative, Incremental Impacts Through 2041 vs. Current Financial Model	
Rate Increase	-8% to +137%
Residential Cost *Typical Customer*	Up to $24,000
Industrial Cost *Typical Customer*	Up to $58M

2022 IRP ANALYSIS
Sensitivities

Sensitivity Cases

- Changes in new resource alternatives:
  1) No CCS resources
  2) No CCS or nuclear resources
  3) Add hybrid solar + battery storage resource
- Changes in existing resource retirements:
  4) Retire all LES coal resources in 2029
  5) Retire Laramie River Station coal resource in 2029
  6) Retire all LES natural gas resources in 2029
- Changes in model assumptions:
  7) High natural gas prices
  8) SPP electrification
  9) SPP 15% reserve margin
  10) Inflation Reduction Act

Sensitivity Cases

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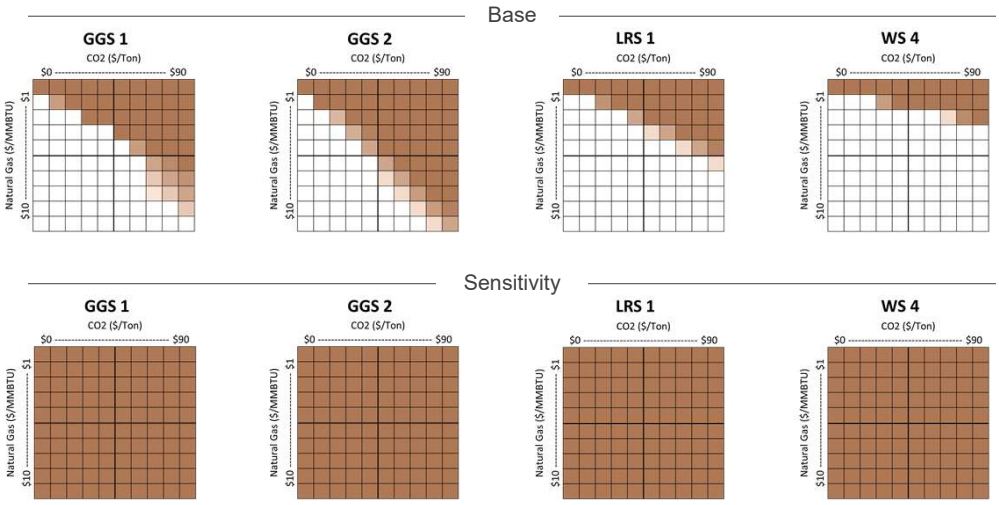
2022 IRP ANALYSIS

Sensitivity 4: Retire all LES coal resources in 2029

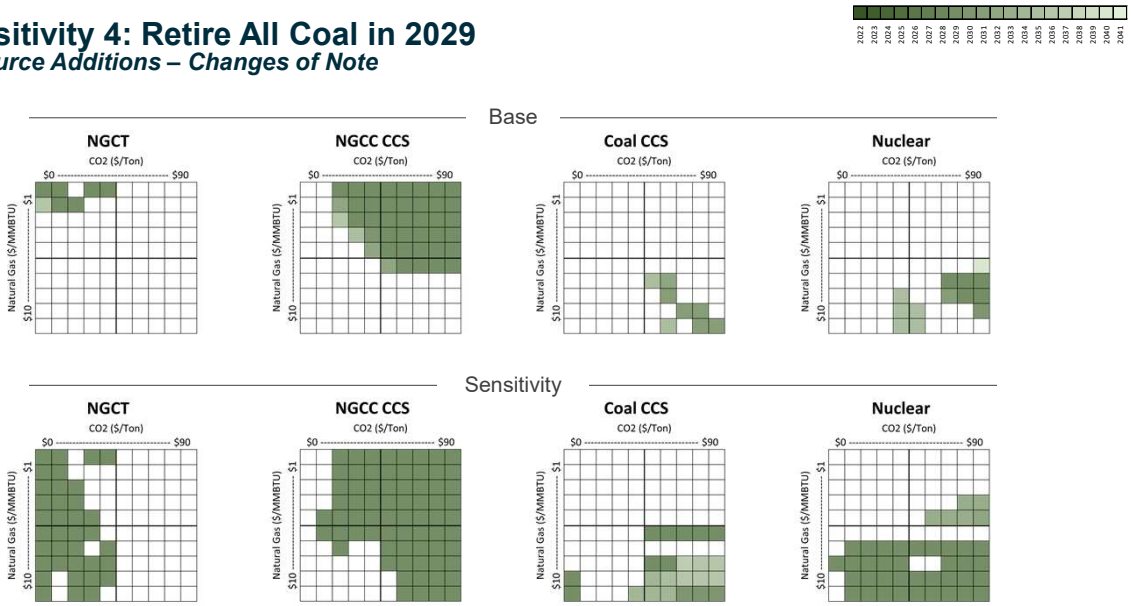
Sensitivity 4: Retire All Coal in 2029

Coal Retirements



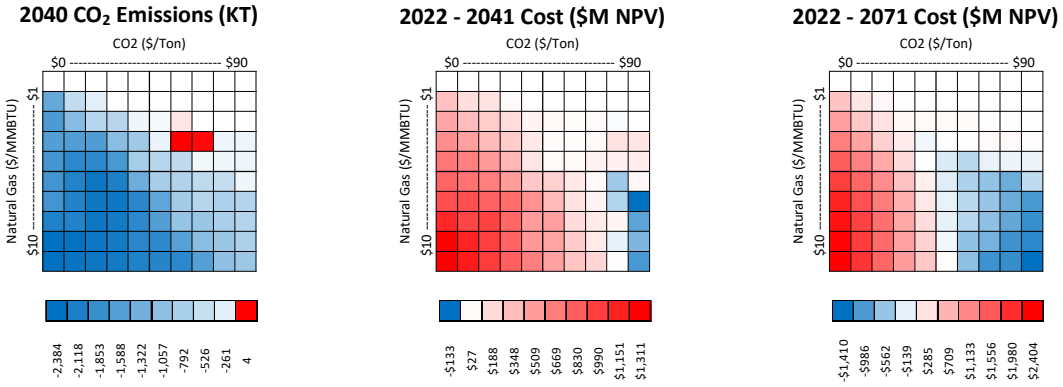
Sensitivity 4: Retire All Coal in 2029

Resource Additions – Changes of Note



Sensitivity 4: Retire All Coal in 2029

Metric Changes Relative to Base Case



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Metric Changes Relative to Base Case

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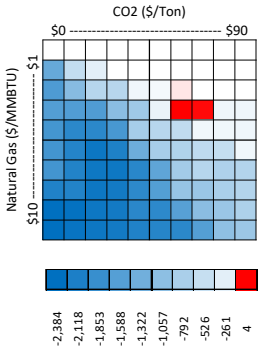
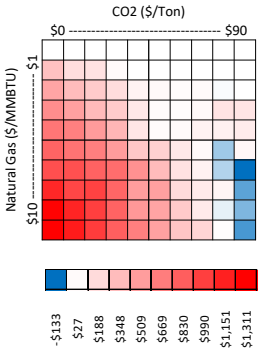
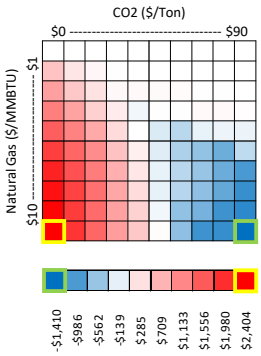


2022 - 2041 Cost ($M NPV)



2022 - 2071 Cost ($M NPV)



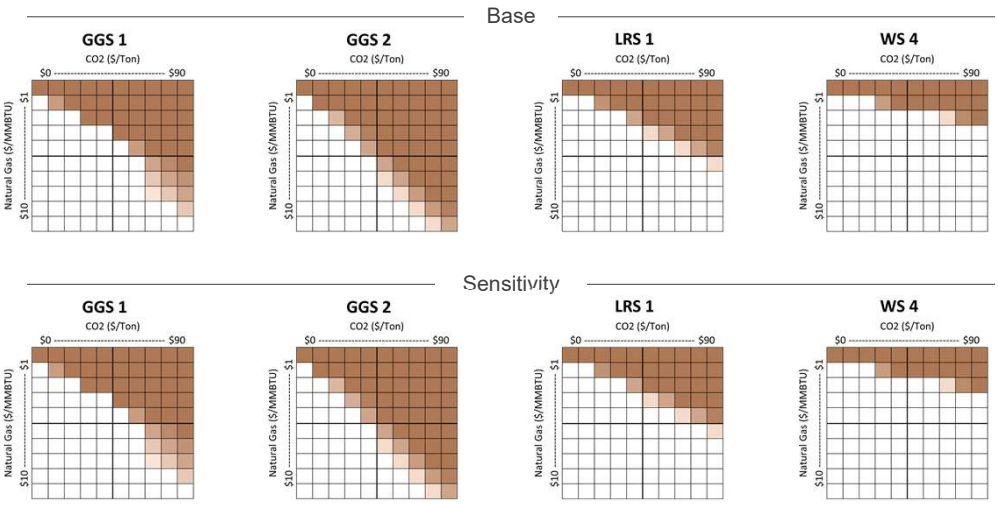
Cumulative, Incremental Impacts Through 2029 vs. Base Case	
Rate Increase	0% - 62%
Residential Cost *Typical Customer*	$0 - $2,300
Industrial Cost *Typical Customer*	$0 - $5.6M

2022 IRP ANALYSIS

Sensitivity 10: Inflation Reduction Act

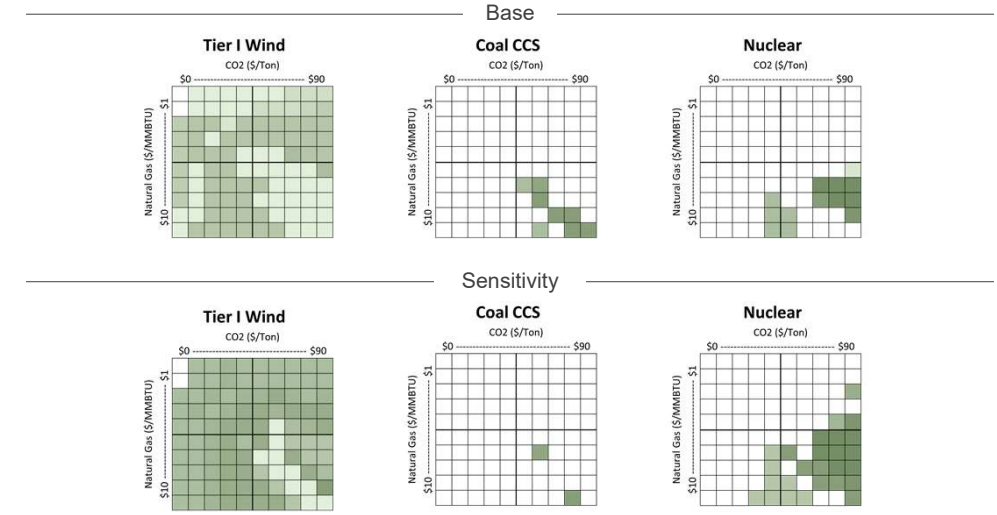
Sensitivity 10: Inflation Reduction Act

Coal Retirements



Sensitivity 10: Inflation Reduction Act

Resource Additions – Changes of Note



Sensitivity 10: Inflation Reduction Act

Metric Changes Relative to Base Case

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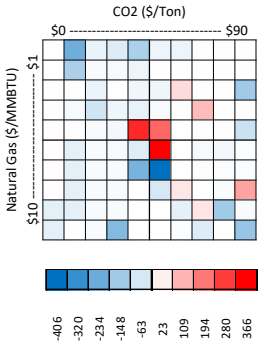

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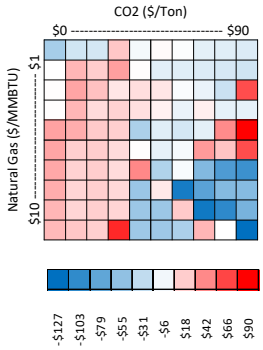

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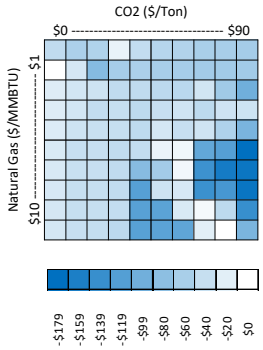


2022 IRP ACTIONS

Preliminary Decarbonization Goal Plan

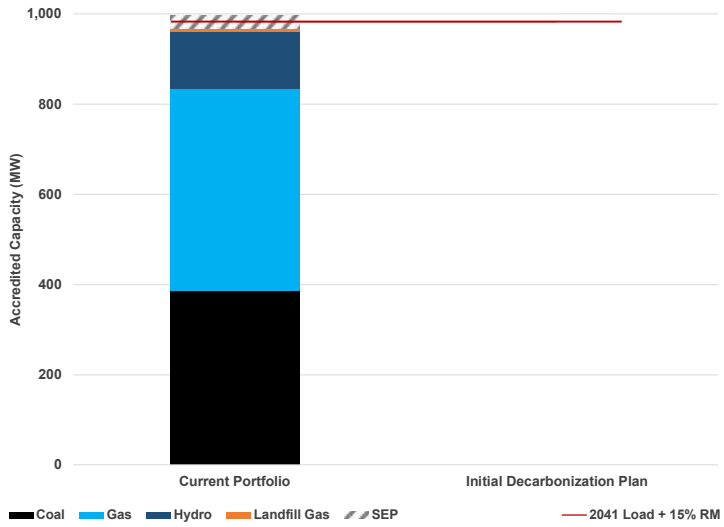
LES Decarbonization Goal
Board resolution excerpts

Achieve net zero carbon dioxide production from the LES generation portfolio by 2040.

The ultimate path and pace to achieving such goal must be balanced by:

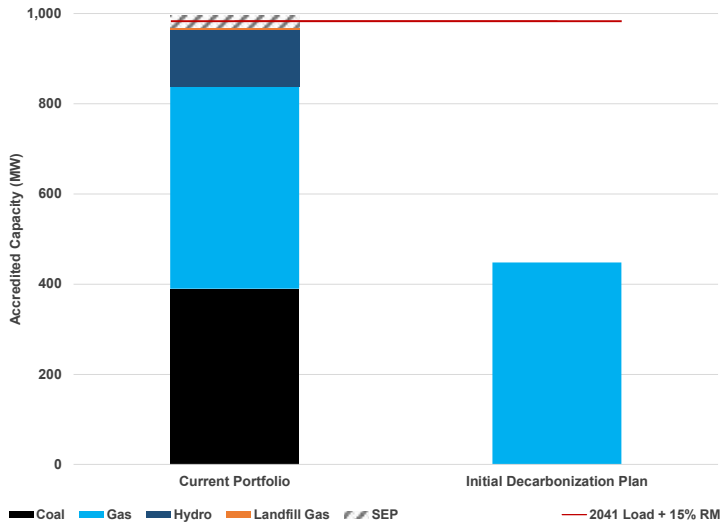
- A continued commitment to maintain high electric system reliability.
- Environmental stewardship.
- A fiscally-responsible focus that carefully considers financial impacts to all customers, especially LES customers with low and fixed incomes.
- Consideration of existing contractual obligations.
- Advancements in generation, energy storage, carbon capture technologies and other emerging solutions.

LES Decarbonization Goal
Preliminary Plan



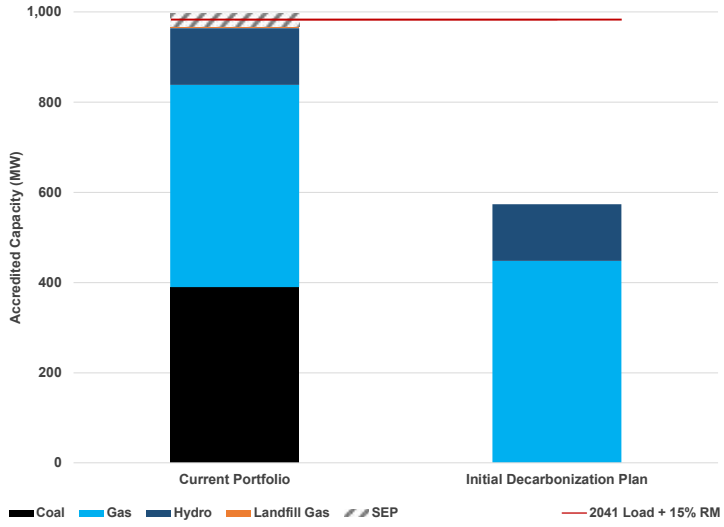
1. Look for the right time to phase out or add CCS to LES' existing coal resources.

LES Decarbonization Goal
Preliminary Plan

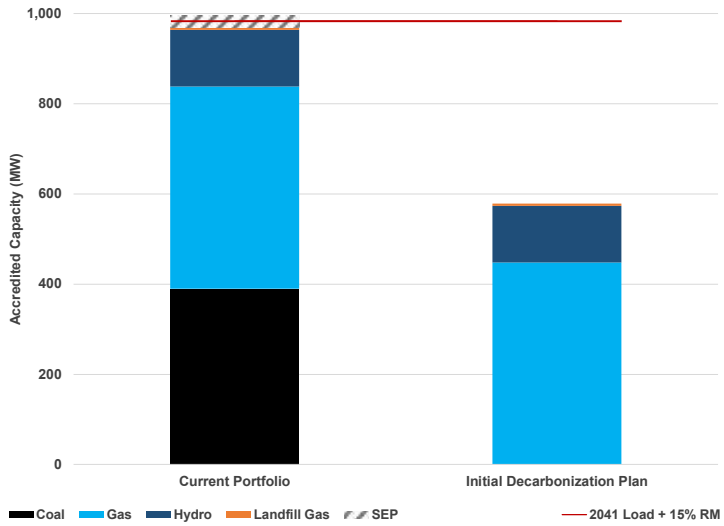


② Maintain LES' existing natural gas resources.

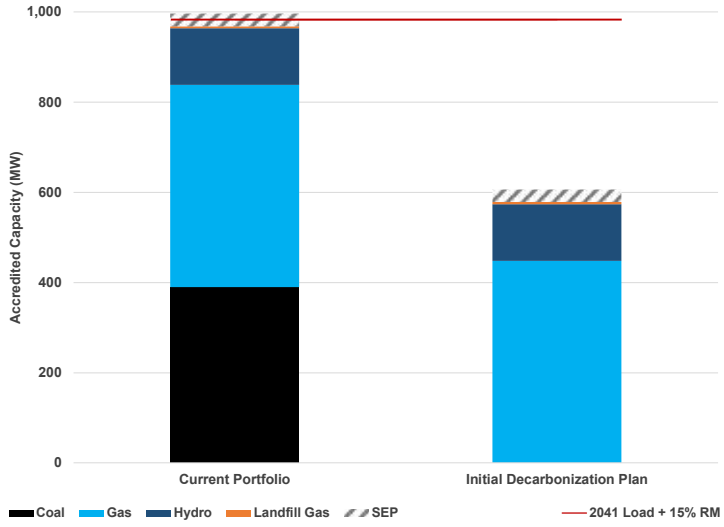
LES Decarbonization Goal
Preliminary Plan



LES Decarbonization Goal
Preliminary Plan

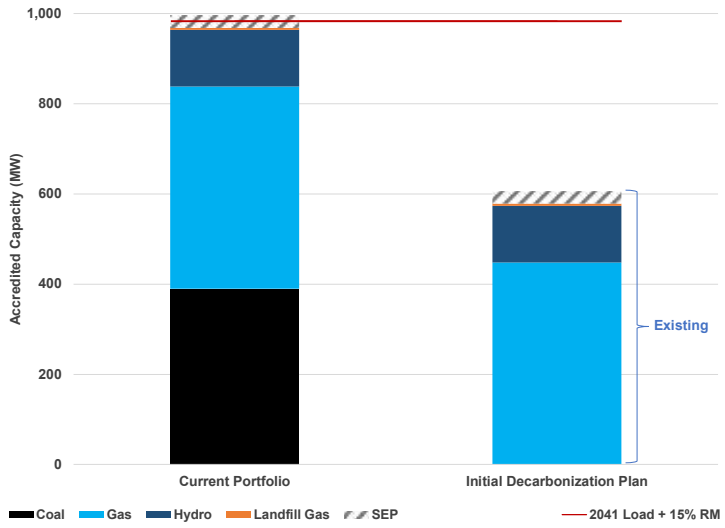


LES Decarbonization Goal
Preliminary Plan

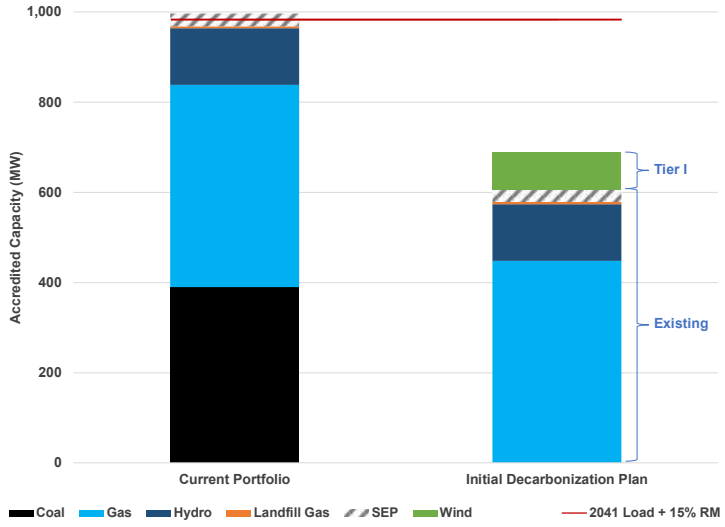


3. Continue the Sustainable Energy Program.

LES Decarbonization Goal
Preliminary Plan

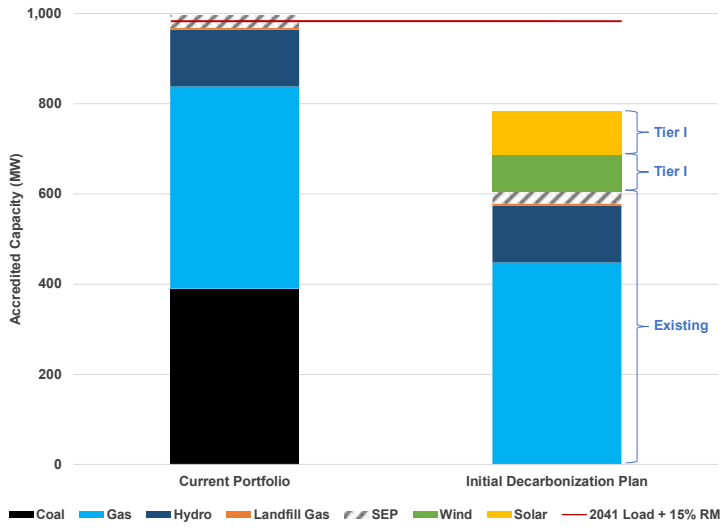


LES Decarbonization Goal
Preliminary Plan



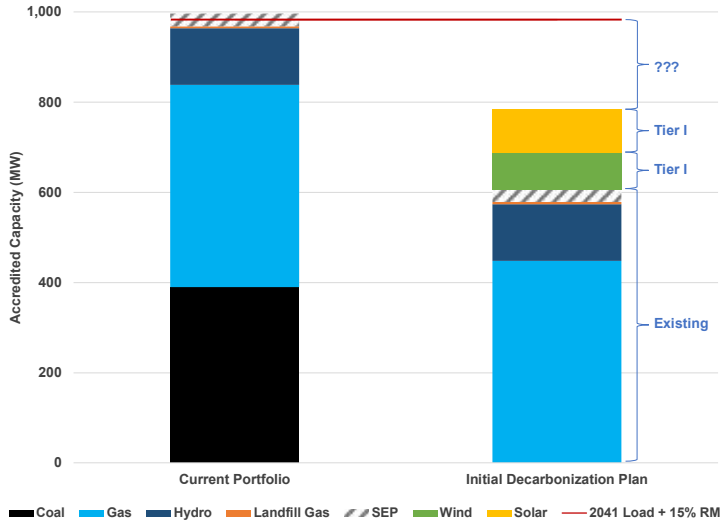
4 Maintain LES' allotment of Tier I Wind but avoid Tier II (or Tier III) Wind.

LES Decarbonization Goal
Preliminary Plan



5 Develop LES' allotment of Tier I Solar but avoid Tier II (or Tier III) Solar.

LES Decarbonization Goal
Preliminary Plan



6 Leave the final 200 MW unprescribed for now; seek to identify the best choices in the future as more information becomes available.

2022 IRP ACTIONS

Proposed 5-Year Action Plan

Proposed Action Plan

LES Actions

Local Solar Resource

- Based on the IRP resource analysis, Tier I Solar was identified as a fundamental piece of LES' decarbonization plan.
- LES is currently long on generation, but development of any new project is likely years away due to SPP's existing generator interconnection backlog.
- LES was interested in solar beforehand, but the new Inflation Reduction Act of 2022 would reportedly allow LES to directly capture the benefit of a renewed solar ITC.

» *LES will begin evaluating the addition of a solar resource to LES' portfolio, initially focusing on the prospect for LES construction and ownership of a local asset.*

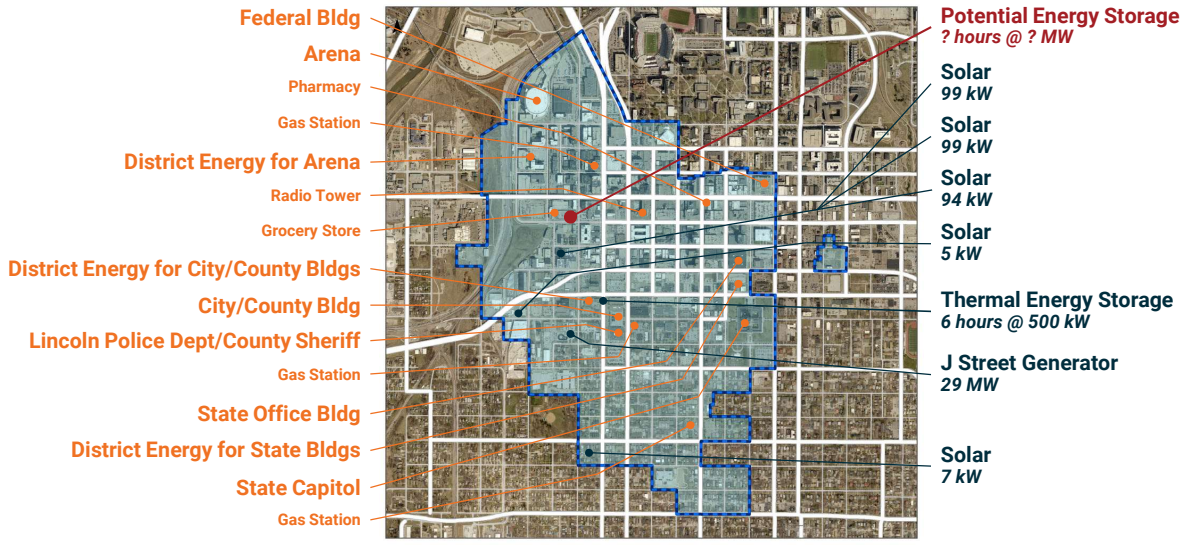
Proposed Action Plan
LES Actions

Battery Storage Pilot

- LES launched a Request for Proposals for a battery storage pilot project as precursor to the IRP. The project would be located within LES' Community Microgrid and contract negotiations are ongoing.
- The IRP resource analysis didn't identify large scale battery storage as a primary selection, but that will likely change as costs decrease and duration and longevity increase.

» *LES will pursue implementation of a pilot battery storage project, building experience and preparing staff for a potential larger utilization in the future.*

LES Community Microgrid



Proposed Action Plan
LES Actions

Battery Storage Pilot

- LES launched a Request for Proposals for a battery storage pilot project as precursor to the IRP. The project would be located within LES' Community Microgrid and contract negotiations are ongoing.
- The IRP resource analysis didn't identify large scale battery storage as a primary selection, but that will likely change as costs decrease and duration and longevity increase.

» *LES will pursue implementation of a pilot battery storage project, building experience and preparing staff for a potential larger utilization in the future.*

Community Microgrid Solar Expansion

- LES is interested in additional resource development within the area of the community microgrid, both to support the microgrid and complement the new battery storage pilot project.

» *LES will evaluate the introduction of additional distributed solar in the community microgrid area.*

Proposed Action Plan
LES Actions

Sustainable Energy Program

- Based on the IRP resource analysis, the SEP was identified as another fundamental piece of LES' decarbonization plan.

» *LES will continue the SEP in the near-term while also watching for cost-effective opportunities to expand its reach.*

Sustainable Energy Program – New Product Offerings

- Preliminary IRP analysis indicated benefit-cost metrics for high efficiency commercial kitchen equipment may warrant incentives which would help to boost local adoption.
- Water heater demand response metrics didn't prove as promising, plus the majority of residential water heating is not electric. However, these units represent one of the largest loads in a home and have the potential to provide energy storage and related market benefits.

» *LES will begin offering incentives for high efficiency commercial kitchen equipment and pursue an electric water heating pilot project at the new Gatehouse Rows multi-family development in Lincoln.*

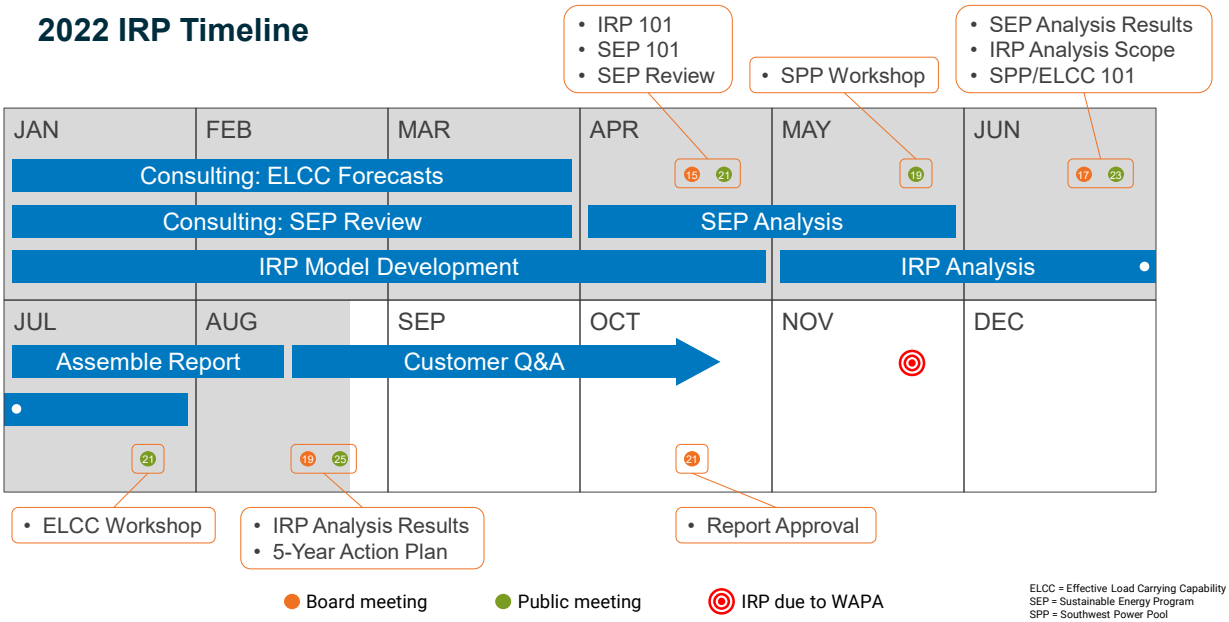
Proposed Action Plan
LES Actions

Time-of-Use Rate

- The IRP process identified time-of-use rates as a potential tool for driving customer energy consumption away from periods of peak load.
- LES had already started to review the potential application for large commercial and industrial customers where existing metering infrastructure would more easily support a project.

» *LES plans to offer time-of-use rates to large commercial and industrial customers in the near term.*

2022 IRP Timeline



ELCC = Effective Load Carrying Capability
SEP = Sustainable Energy Program
SPP = Southwest Power Pool

Appendix N
Notification of Posting of Final Report

Subject: LES 2022 IRP - Posting of Final Report

Good afternoon,

On behalf of LES, I want to thank you for taking an active part in our 2022 Integrated Resource Planning (IRP) process, either through attendance at the LES public meetings or through the feedback you provided along the way. Public input is a core part of the IRP, and your thoughts and questions helped form the final product. I'm pleased to say the final report was approved by the LES Administrative Board earlier this afternoon and is now available on LES.com. We added a table of abbreviations and made a few typographical and formatting improvements, but the content is essentially identical to the draft report available previously.

Please don't hesitate to reach out if you have any further questions or comments, and thank you again for your interest and involvement in the 2022 IRP.

Scott Benson | Manager, Resource & Transmission Planning

Office: 402-473-3390
Mobile: 402-937-4461

LES.com | 9445 Rokeby Road | Lincoln, NE 68526

Appendix O
LES Website IRP Page

Integrated Resource Plan

PROCESS CONTINUES WITH RESULTS & PROPOSED ACTION PLAN

An Integrated Resource Plan, or IRP, is a blueprint developed every five years to help forecast when power resources will be needed, what the optimal resource mix may look like and how LES will bring it together to best serve its customers in the future.

LES is developing a new plan in 2022 – the first IRP guided by LES' decarbonization goal – and throughout the process has encouraged customer involvement via three public meetings and two interactive workshops. We continue to invite customers to email feedback or request LES to speak with individuals, groups or organizations about the IRP.

Below, see the IRP results and action plan, the full draft of the 2022 IRP report and all meeting and workshop presentations.

LES Integrated Resource Plan results and action plan

LES reached the next step in its latest long-range planning process with its third and final public meeting Aug. 25, 2022, for the Integrated Resource Plan. This meeting focused on reviewing the final draft of the report and the related action plan. The LES Administrative Board will take action on the report at its Oct. 21 meeting.

VIEW THE IRP RESULTS AND ACTION PLAN

LES reviewed the IRP timeline and a consultant's recent recommendations for the Sustainable Energy Program at its first public meeting April 21. The second public meeting July 23 reviewed changes to the SEP assumptions based on the consultant's findings and the scope of the upcoming analysis of LES' future resource mix. LES held two interactive IRP workshops to give customers an opportunity to learn more about LES' regional electricity market, the Southwest Power Pool, and its role in LES resource decisions. ***Scroll down this page to view all meeting and workshop presentations.***

Required as part of LES' hydroelectric power contract with the Western Area Power Administration, LES' IRP is part of the utility's strategic planning efforts that keep it among the best power companies in the nation. The last IRP was produced and filed with the Western Area Power Administration in 2017.

Merging industry knowledge and insight from LES customer-owners in the IRP process, LES keeps its goal of maintaining the lowest possible rates for its customers while meeting their energy needs with efficiency and reliability on the leading edge of the power industry.

Integrated Resource Plan resources

View the Integrated Resource Plans

'DRAFT' 2022 IRP
(Please email customerservice@les.com if you experience any issues reading this draft).

CURRENT IRP DEVELOPED IN 2017

Thoughts, comments or questions about the IRP?

EMAIL IRP@LES.COM

See public meeting and workshop details and resources below.

Integrated Resource Plan Timeline

Meeting 3

AUG. 25, 6-7:30 P.M.
LES OPERATIONS CENTER
9445 ROKEBY ROAD

LES reviewed and discussed the results of LES' resource analysis and a full draft of the 2022 IRP report,* including LES' proposed action plan for the next five years.

- **VIEW THE IRP RESULTS AND ACTION PLAN**
- **VIEW THE AUG. 25 MEETING REPLAY VIDEO**

**(Please email customerservice@les.com if you experience any issues reading this draft).*

Meeting 2

JUNE 23, 6-7 P.M.
WALTER A. CANNEY SERVICE CENTER
2620 FAIRFIELD ST.

At the Integrated Resource Plan public meeting June 23, LES staff discussed potential enhancements to LES' Sustainable Energy Program, reviewed the scope of LES' upcoming analysis of its resource portfolio, and provided a high-level review of the two IRP workshop topics. Catch up on LES' IRP Meeting 2 by checking out the links below.

- **VIEW THE SUSTAINABLE ENERGY PROGRAM COST-EFFECTIVENESS ANALYSIS**
- **VIEW THE IRP ANALYSIS SCOPE & WORKSHOP REVIEW**
- **VIEW THE JUNE 23 MEETING REPLAY VIDEO**

Meeting 1

APRIL 21, 6-7 P.M.
LES OPERATIONS CENTER
9445 ROKEBY ROAD

LES kicked off its 2022 Integrated Resource Plan by providing attendees an overview of the process, its benefits and what to expect regarding the IRP as LES completes its diligence throughout 2022. Staff also presented a synopsis of the recently completed external review of LES' Sustainable Energy Program, the spearhead of the utility's customer-facing energy-efficiency initiatives. Catch up on LES' IRP Meeting 1 by checking out the links below.

- **VIEW THE 2022 SUSTAINABLE ENERGY PROGRAM REVIEW**
- **VIEW THE IRP FREQUENTLY ASKED QUESTIONS**
- **VIEW THE APRIL 21 MEETING REPLAY VIDEO**

LES Integrated Resource Plan workshops

JULY 21 WORKSHOP

At this interactive IRP workshop, participants learned more about the Southwest Power Pool's resource requirements and rating methodologies and then took the wheel of an LES model to build their own resource mix of the future.

- **VIEW THE WORKSHOP PRESENTATION**

MAY 19 WORKSHOP

LES held its first interactive IRP workshop May 19 to give customers an opportunity to learn more about LES' regional electricity market, the Southwest Power Pool, and its role in LES resource decisions.

- **VIEW THE WORKSHOP PRESENTATION**