Reactor Power Size Impacts on Nuclear Competitiveness in a Carbon-Constrained Future

Nuclear Fuel Cycle and Supply Chain

Prepared for
U.S. Department of Energy
Systems Analysis and Integration
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Executive Summary

In 2021, the Biden-Harris administration set ambitious decarbonization goals for the electricity sector and for the U.S. economy. The System Analysis and Integration (SA&I) Campaign has analyzed various advanced reactor concept attributes which will have a bearing on nuclear energy's future contribution to these climate goals. In order for these reactors to provide value to the future energy system for decarbonization and replace a larger share of dispatchable fossil-fueled generation, they must offer sufficiently attractive economic value to induce utilities to build them over alternatives. This study therefore focused on two attributes that will be key for future advanced-reactor deployment for electrical power systems: reactor power size and appropriate operational flexibility. On the basis of the findings obtained in this work, some general observations were drawn by the multi-laboratory and multi-disciplinary team regarding carbon-constrained modeling of advanced nuclear energy:

- Previous carbon-constrained energy modeling studies did not include important design aspects of new nuclear reactor and power plant designs, including differing reactor sizes, types, and enhanced ability for flexible operations.
- Considering the limited data basis for future advanced nuclear energy systems, it is important to combine staff knowledgeable in both advanced nuclear energy systems and energy market analysis to effectively explore these impacts.
- The expertise gathered in this analysis can be applied to perform detailed analysis on specific industry concepts if specific costing data and flexible operation capability are made available.

Establishing a Reference Deep Decarbonization Scenario

As a foundation for the work in this study, grid market analyses were performed to determine a Baseline deep-decarbonization scenario which could be used to analyze how the size and flexibility of advanced reactors impact their economic competitiveness. In this Baseline scenario, a carbon price of 100 $/t CO_2 is used as a technology-neutral mechanism to reduce carbon emissions from the electricity power sector by more than 90% when compared with the 2019 level. The single grid and market region employed in this study is the Electric Reliability Council of Texas (ERCOT), which represents a large part of the U.S. State of Texas and is an ideal region for grid modeling investigations with large fractions of both nuclear and wind capacities. The selected Baseline deep-decarbonization capacity expansion scenario in ERCOT considers relatively high nuclear deployment with an Overnight Capital Cost of 4,416 $/kW (mean cost from cost distribution in the SA&I Cost Basis Report for Nth-of-a-kind, 2019 dollars) and small cost reductions across all energy technologies to permit assessment of the impact of nuclear reactors' size and flexibility on their economic competitiveness. A few sensitivity analyses were completed to understand how assumed cost reductions through learning impact different energy technologies. The nuclear deployment is dependent on the Overnight Capital Cost of new nuclear unit and cost-reduction scenarios of other technologies. For the most optimistic battery/PV/wind cost-reduction scenarios, only renewables and batteries were deployed. However, the grid modeling used in this study did not consider transmission expansion costs, long-duration energy storage needs, or reliability challenges, which will underestimate the influence of system costs to support very high variable renewable penetrations.

Impact of Reactor Power Size

Small Modular Reactors (SMRs) and Microreactors (MRs) are being developed with the promise to offer a variety of solutions to the array of economic challenges historically encountered by the U.S. nuclear industry. Several potential benefits associated with a lower power level, namely, reduced up-front capital investment, more favorable project risk profile, improved cash flow, load-following capability, and less-burdensome siting requirements, are reviewed and discussed in this report. SMR/MR concepts provide promising risk-reduction potential, considering not only the reduced total capital at risk but also the

substantial reduction of uncertainty relating to the construction project itself and the future revenues of the reactor. Furthermore, reactors that use modular and staggered construction are expected to reduce construction time and costs via learning, and improve cash flows accrued to the firm as constructed units may start generating revenues while other units are still being built. The benefits also extend to market and siting flexibility; for instance, these units may be potential candidates for re-using sites of retired coal plants and for supporting small electricity grids.

The economic competitiveness of a nuclear reactor was qualitatively assessed by modeling its capability to be economically deployed in a system-cost minimization algorithm. Reactor capacity has a complex impact on the projected cost of the system: a smaller reactor is likely less costly to build in absolute terms, but not necessarily in dollars-per-megawatt terms. The nature of the cost-to-size scaling relation is currently unknowable, as no advanced SMRs have yet been constructed. Therefore, scenarios were conducted in this work to explore the impact of small-favoring and small-disfavoring cost scaling relations in order to account for uncertainties in cost reductions achievable with different reactor sizes. This study confirms that even if the absolute capital cost is reduced in smaller reactors, they will compete with larger nuclear units only if their CAPital EXpenditure (CAPEX) is comparable or lower, without a significant increase in Operation and Maintenance (O&M) and fuel costs. The following conditions were observed in the assessed grid region of ERCOT for potential economic deployment under the Baseline scenario:

- Nuclear reactor systems with CAPEX greater than 7,000 $/kW would not be deployed under even the most favorable assumptions. SMR vendors could counter the diseconomies of scale (smaller is more expensive per kW) and keep CAPEX low through design simplification, modularization, factory build, faster construction time, potential better financing terms, etc.
- Systems with O&M costs ($/kW·yr and $/MWh) and fuel cost ($/MMBtu) increased by factors of 100% and 35%, respectively, were not deployed under the most favorable assumptions (even with baseline nuclear CAPEX). For example, fixed O&M costs ($/kW·yr) for smaller reactors could increase if staffing requirements were not reduced compared to larger reactors. Solutions considered by SMR vendors include co-siting several modules, autonomous and/or remote-control operations, etc.

More research is needed on the scaling factors and learning rates to quantify how reactor size impacts different costing components (CAPEX, fuel and O&M costs) through design simplifications, factory manufacturing, accelerated learning, etc. This analysis should also be extended by leveraging the new Agent-Based Modeling capability developed within the SA&I Campaign, which would enable modeling the transition from the current grid mix, while modeling the decision-making processes of utilities deciding between lower-risk smaller reactors and possibly more cost-efficient larger reactors.

Impact of Reactor Flexibility

Future advanced reactors are likely to coexist with substantial quantities of variable renewable energy (VRE) generation, which may make load-following capabilities operationally and economically valuable. All nuclear power plants are intrinsically capable of load following, but some SMRs and MRs are being designed with faster load-following capabilities or with thermal energy storage (TES) to better support micro-grids or future grids with high levels of VRE. In particular, TES systems may provide significant operational flexibility benefits when coupled directly to nuclear generation systems. The results obtained by this electricity market modeling work on a deep-decarbonization scenario showed that even lower levels of flexibility (in terms of slower ramp rate and lower operating level) in a few nuclear units are important to compensate for fluctuations in demand and VRE generation on the grid. The number of units needed to be associated with load-following or TES depends on the system's need for fast ramping and bulk energy storage, and the relative costs of storage technologies. This means that reactor flexibility becomes more important under higher VRE penetration scenarios.

Association of nuclear units with low-cost TES was found to be more favorable than load-following-capability. The incentive for a utility to favor TES technology would be to sell more electricity during higher-price hours without requiring a larger reactor (only a larger turbine/generator). However, battery storage vendors and advocates are promoting steep cost reductions through learning, and battery storage would thus compete directly with TES. For nuclear power with TES to be competitive, the TES system must demonstrate costs on par with battery costs. Future work should be done to extend the current analysis beyond the current ERCOT market modeling and to include non-electricity applications such as Integrated Energy Systems that would provide alternative flexible operation through coupling nuclear units directly with industrial applications.

Acknowledgment

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Acronyms

ABCE	Agent Based Capacity Expansion
A-LEAF	Argonne Low-carbon Energy Analysis Framework
ARDP	Advanced Reactor Demonstration Program
CAPEX	Capital Expenditure
CCS	Carbon Capture and Sequestration
CE	Capacity Expansion
CHP	Combined Heat and Power
CSP	Concentrated Solar Power
EPZ	Emergency Planning Zone
ERCOT	Electric Reliability Council of Texas
FOAK	First Of A Kind
GCAM	Global Change Assessment Model
INL	Idaho National Laboratory
LCOE	Levelized cost of electricity
LF	Load-following
LFR	Lead-cooled Fast Reactor
LWR	Light Water Reactor
MARKAL	MARKet ALlocation
MR	Microreactor
NGCC	Natural Gas Combined Cycle
NGCT	Natural Gas Combustion Turbine
NGIC	Natural gas internal combustion engine
NGST	Natural gas steam turbine
NOAK	Nth Of A Kind
NRC	U.S. Nuclear Regulatory Commission
OCC	Overnight Capital Cost
O&M	Operation and Maintenance
PWR	Pressurized Water Reactor
SA&I	System Analysis and Integration
SFR	Sodium-cooled Fast Reactor
SMR	Small Modular Reactor
TES	Thermal energy storage
TRISO	TRi-structural ISOtropic
UAMPS	Utah Associated Municipal Power Systems
UC/ED	Unit Commitment and Economic Dispatch
VHTR	Very High Temperature Reactor
VRE	Variable Renewable Energy
WSC	West South Central

SYSTEMS ANALYSIS AND INTEGRATION CAMPAIGN

REACTOR POWER SIZE IMPACTS ON NUCLEAR COMPETITIVENESS IN A CARBON-CONSTRAINED FUTURE

1. Introduction

The System Analysis and Integration (SA&I) Campaign has analyzed the role nuclear energy can play in deep decarbonization of the U.S. electricity grid, and how different attributes of advanced reactor concepts can favor their deployment. Numerous existing studies on limiting greenhouse gas emissions in the electricity sector have focused on renewables while considering only a large and costly generic baseload nuclear reactor [Victor et al. 2018, Levin et al. 2019, Larson et al. 2020, Cole et al. 2020]. These modeling choices unnecessarily limit the usefulness and competitiveness of nuclear energy in carbon-constrained future scenarios as perceived by such models. This study is intended to explore modeling different types and sizes of nuclear reactors and the inclusion of flexible reactor operations, such as load-following (LF) and integrated thermal energy storage (TES), to assess the potential for such reactors to replace a larger share of dispatchable fossil-fueled generation.

1.1 Background

To mitigate the expected effects of climate change, the global energy system needs to deeply and rapidly reduce greenhouse gas emissions. In 2021, the new U.S. administration set some goals:

"*President Biden set ambitious goals that will ensure America and the world can meet the urgent demands of the climate crisis, while empowering American workers and businesses to lead a clean energy revolution that achieves a carbon pollution-free power sector by 2035 and puts the United States on an irreversible path to a net-zero economy by 2050*.**"** [White House 2021]

As of 2019, the electric power sector represents 25% of the total U.S. greenhouse gas emissions [USEPA N.D.]; the rest come from transportation (25%), industry (23%), commercial & residential (13%), and agriculture (10%). One commonly proposed mechanism for reducing transportation and industrial greenhouse gas emissions is through deep electrification of those sectors, which puts a further decarbonization burden on electric power. Even though decarbonizing the electricity sector is seen as the highest priority, it is unclear how generation companies will choose to eliminate their emissions to meet such deep-decarbonization goals. Nuclear power is currently the largest source of carbon-free electricity in the U.S., representing about 20% of U.S. electricity generation, and more than half of its CO_2-free generation. It plays a critical role in the U.S. economy in terms of security of supply, job creation, and non-polluting electricity generation, a role that will likely need to be maintained or strengthened in the future.

At the same time, maintaining the nuclear portfolio is becoming increasingly challenging in the current U.S. energy market, as the low price of natural gas and the penetration of subsidized and low-marginal-cost variable renewable energy (VRE) are affecting the profitability of nuclear units [Potomac Economics 2021]. In this context, some nuclear units in the U.S. are undergoing early retirements, and there are very few planned new builds, while the vast majority of U.S. nuclear power plants will be nearing the end of their currently licensed lifetimes in the coming decades. In this context, successful deployment of new nuclear power plants or further extending licenses will require concrete realizations of increased economic competitiveness, through reduced capital and operation and maintenance (O&M) costs, reduced investment risk associated with large construction projects, and increased revenues enabled by changes in market policies.

In FY 2020, the SA&I Campaign completed electricity grid market modeling [Stauff et al. 2020] to investigate which market policies and which technologies can improve nuclear energy competitiveness in current U.S. markets, and to increase the feasibility of deploying advanced nuclear reactors. The present study looks further into certain technology options: specifically, reactor size, modularity, and flexibility of operations.

1.2 Models used in this study

The energy grid modeling and analysis methodology developed in this study relies on two modeling tools. First, the MARKet ALlocation (MARKAL) energy-systems economic optimization tool models different U.S. regions and is used in this study to provide long-term electricity demand evolution forecasts. MARKAL's results are used as inputs to the Argonne Low-carbon Energy Analysis Framework-(A-LEAF) model [Levin et al. 2019] for detailed electricity grid modeling. A-LEAF is used to solve the capacity expansion (CE) problem to find the number of units to be deployed in a future year to meet increased demand while minimizing the total system cost. A-LEAF solves multiple unit commitment and economic dispatch (UC/ED) problems using the representative-days approach to model the hourly dispatch of generation units for that future year. The market operational model in A-LEAF is representative of restructured ("deregulated") electricity markets, in which qualified generators and buyers submit bids and offers in an open wholesale market for electricity and ancillary services, in addition to possible market structures such as capacity markets. A-LEAF optimizes commitment (online-offline status) and dispatch (level of generation provided by online units), subject to operational constraints and system reserve requirements, to ensure supply-and-demand balance throughout a simulated year. Together, these models permit evaluation of a mixture of widely differing energy technologies to meet the dynamics of electricity demand.

1.3 Work scope of this study

This report discusses the future deployment potential of advanced reactor concepts in deep-decarbonization scenarios. Advanced reactor designs have been trending smaller in the past decade, with Small Modular Reactor (SMR) and even Microreactor (MR) concepts under active development across the U.S. industry. Historically, reactor designers developed increasingly larger reactors in pursuit of high fuel and operating efficiencies and to benefit from economies of scale. However, today designers and utilities are more interested in the cost- and complexity-reducing potential of smaller, more modular designs. These concepts are intended to exploit various cost-reduction techniques—including mass production, factory manufacturing, and design simplifications—but also to reduce financial risks to the utility, and to better adapt to different markets and to utilize existing sites from retired fossil generation.

Additionally, some advanced reactors, such as the Natrium concept developed by TerraPower [TerraPower 2021] under the Advanced Reactor Demonstration Program (ARDP), are integrating TES into their systems, while the X-energy concept is integrating LF capability. Both of these concepts explicitly target flexible reactor operation.

In the present work, both size-based cost scaling and flexible operation capabilities are analyzed with the aforementioned CE modeling tools, in the context of the U.S. electricity grid, in order to explore their level of impact on the market viability of future nuclear reactor concepts when compared to present-day large LWRs operated for baseload generation.

Consequently, this qualitative assessment work focuses on sensitivity analyses of the deployment potential of nuclear reactors based on various parameters in terms of costs and flexibility that will be directly influenced by the sizes and types of the reactor concepts considered. For the reactor-size market modeling analysis, cost-scaling parameters were used as surrogates for reactor size differentiation to show the deployment impact of uncertainty associated with cost-reduction strategies. In particular, this report examines the extent to which changes in Overnight Capital Costs (OCCs), O&M costs, and fuel costs can impact deployment rates of nuclear technologies, and discusses what design and implementation strategies are available for SMRs to target improvements in these cost factors. In terms of flexibility, the report discusses how deployment rates of nuclear reactors are related to LF capability and to TES, both of which enable reactors to reduce power output during low-price hours and increase it during high-price hours.

This analysis is meant to be technology-neutral, not focusing on one specific reactor design concept or promoting any individual technology (LWR, SFR, VHTR, etc.). The objective is to provide conclusions based on reactor attributes (power level, flexibility, associated costs, etc.) with minimal reference to the specific technology used, so that the conclusions of this study can be applicable to any reactor concept. These analyses are intended to provide a better understanding of potential drivers for deployment of nuclear reactors. As a complement to this assessment, this study also intends to highlight gaps in available data and modeling capabilities.

1.4 Report organization

This report is meant to be kept relatively compact by providing high-level conclusions that are supported by the aforementioned analyses. Additional descriptions of modeling tools, assumptions, and details of the analyses performed are described in the **Appendices**.

As a preliminary step, different policy scenarios are investigated in **Section 2** to assess realistic pathways toward deep decarbonization in a U.S. electricity grid market, which are needed to support this study on the impact of nuclear reactor size and flexibility. In particular, a carbon price of 100 $/t CO_2 is selected for its ability to reduce emissions from electricity generation by more than 90% when compared to current levels. Various assumptions about learning rates for different technologies are investigated to shed light on the various roles that can be observed for nuclear energy, depending on assumed cost reductions through progress and experience with different technologies. A reference Baseline deep-decarbonization scenario that shows potential for nuclear deployment is then selected as a framework for further analyses of the impact of different reactor technology types and sizes.

The impact of different reactor sizes on their deployment capability in the previously selected reference deep-decarbonization scenario is investigated in **Section 3.** This section includes qualitative assessments of the various economics and technical drivers that impact the attractiveness of small nuclear reactors. Quantitative assessment is also completed to model deployment potentials of different sizes of nuclear reactors. A sensitivity study based on different scale factors was performed because there is uncertainty as to how much cost reduction or increase is obtained through reducing the size of nuclear reactors and increasing their degree of modularity. In particular, different grid modeling simulations using A-LEAF shed light on the deployment potential of small reactors under different costing assumptions, showing the importance of maintaining low levels of OCC and O&M costs through different design considerations and operating strategies.

The impact that flexible reactor operation may have on nuclear concepts in deep-decarbonization scenarios is investigated in **Section 4**, considering both LF capability and TES implementation. This study investigates how much value is added by flexible reactor operation and how it increases deployment potential under various VRE deployment rates. In particular, different levels of LF capability and different sizes of TES (in terms of added power level and energy storage) are considered.

Section 5 of the report summarizes the findings of this study and offers conclusions on the deployment potential of advanced nuclear technologies in deep-decarbonization scenarios. The gaps identified in this analysis are discussed as opportunities for future work to further strengthen the conclusions from this study, and to address some of the remaining questions while leveraging new modeling capabilities that are under development.

2. Establishing a Reference Deep-Decarbonization Scenario

The main objective of this report is to assess the deployment potential of advanced reactor concepts with different sizes and levels of flexibility in deep-decarbonization scenarios. This type of analysis entails detailed modeling of the electricity market to solve the CE problem—considering all possible types of generators that could be added to the system and how many of each type will be deployed in future years to meet the daily demand for electricity while meeting reliability constraints and minimizing the total system generation cost.

The objective of this section is to seek a decarbonization level in the electricity grid of at least 90% of the 2019 level by 2050, while also providing an estimated cost of reaching 100%. This time frame is inconsistent with the current U.S. administration objective that "*achieves a carbon pollution-free power sector by 2035*" [White House 2021]. This modeling adjustment relative to the stated goal was required in this study because realistically, significant deployment of advanced reactor technologies cannot be achieved by 2035, given the time needed to develop projects and reach the needed cost reductions through deployment and learning. Just 14 years to full decarbonization allows no time for advanced energy technologies, especially the smaller and more flexible nuclear reactors that are the focus of Section 3 and 4, to be demonstrated and matured to large-scale deployment.

After a brief description of the deep-decarbonization scenario and modeling approach in Section 2.1, a Baseline decarbonization scenario is defined in Section 2.2. In particular, the goal is to discover under which market and grid conditions new nuclear technologies can be deployed. A few sensitivity cases are considered to assess the impact of learning rates for different generation technologies. In this section, new nuclear deployment considers only large LWR-type nuclear reactors with some LF capabilities, which will be used as a Baseline scenario. The impact of different sizes and levels of flexibility of nuclear reactors considered will be discussed in Sections 3 and 4, respectively.

2.1 Introduction to the deep-decarbonization model

2.1.1 Introduction to A-LEAF model of Electric Reliability Council of Texas

One of the primary models used in this study is the A-LEAF power system optimization code, which solves the least-cost CE problem for a given electricity system. A-LEAF minimizes the total system cost to meet load and reserve requirements by simulating daily UC/ED (with hourly or five-minute dispatch intervals) for a set of representative days over a user-defined, future one-year period. Existing generators are defined and may be retired for economic reasons only, while new candidate generators are defined for deployment as needed to minimize the total system cost objective function. An extensive description of the A-LEAF model and its capabilities is provided in **Appendix 1**.

The single grid and market region employed in this study was the Electric Reliability Council of Texas (ERCOT), which represents a large part of the U.S. State of Texas. ERCOT is an independent balancing authority with large fractions of both nuclear and wind in its portfolio, but in this report, "ERCOT" refers to the synchronous grid and market region unless otherwise noted. A well-characterized A-LEAF model of ERCOT was readily available to support the analysis [Stauff et al. 2020]. A detailed description of the A-LEAF model of ERCOT is provided in **Appendix 2**. The different policies and strategies investigated led to a variety of deployed mixes of electricity generation capacity, and the trends extracted can be extrapolated to other U.S. regions. Current policies in place in ERCOT focus on maintaining a low electricity price and targeting reliable electricity generation. Future policies, such as the carbon tax discussed in the next section, will be required to incentivize low-carbon technology deployment to meet decarbonization objectives for the electricity generation in ERCOT.

The A-LEAF model was selected for this study because it employs very fine time resolution when compared with other more widely used CE codes (MARKAL, GCAM, ReEDS, etc.). This feature makes it well-suited for modeling electricity grid markets that can experience significant short-term changes in demand and generation behavior, such as systems with large fractions of VRE and/or flexible nuclear. However, A-LEAF can be complemented with a code like MARKAL: A-LEAF solves the CE problem for a single future year (i.e., it does not model steps between the base year and the selected future year), and it does not account for energy markets beyond the grid (such as electric vehicles) that may add demand to the grid.

2.1.2 Reference MARKAL results

To ensure that reasonable assumptions are used in the A-LEAF simulation for 2050, a long-term MARKAL transition analysis was completed to provide predictions of changes in electricity demand, since it can simulate markets beyond the electricity grid (e.g., electrification of transportation). The MARKAL analysis is described in **Appendix 3**. In addition to providing for an increase in electricity demand in the Texas region by 2050, which assumes that ~23% of demand comes from electric vehicles, the MARKAL simulation provides an important verification point for the level of carbon tax that eliminates CO_2 emissions from the electricity sector.

Putting a price on carbon emissions is a widely used technology-neutral surrogate for other potential policies that could be used to incentivize clean-power deployment (Renewable Portfolio Standard, etc.). MARKAL calculated that a carbon price of 342 $/t CO_2 would lead to elimination of carbon emissions from electricity generation by 2050. Such an added cost of generating electricity from fossil-fuel plants will favor deployment of low-emitting technologies under least-cost optimization. The 342 $/t CO_2 figure initially came from CE analyses, using GCAM, that were completed in FY 2020 to simulate decarbonization pathways to limit global temperature rise to 2°C above the preindustrial average through 2100 [Kim et al. 2021a].

Both GCAM and MARKAL, despite the different methodologies employed, provided consistent results demonstrating that such a high carbon price would lead to near-zero carbon emission in the electricity sector. Such results will be confirmed with the A-LEAF model, which uses refined temporal modeling of the ERCOT electricity grid.

2.2 A-LEAF capacity expansion in ERCOT

A Baseline scenario was selected to showcase the role that nuclear power could play in a deeply decarbonized bulk power system by 2050. All other scenarios in this report are variations on the Baseline scenario. The OCC of a new nuclear power plant was 4,416 $/kW (4,100 $/kW 2014 USD, inflation-adjusted to 2019 USD) [Dixon et al. 2017], and other generator technologies were assigned fixed OCCs from 2018–2019 data sources. No cost reductions from learning through progress in technology evolution and multiple plant constructions are assumed in the Baseline scenario. Most studies include learning, which typically results in a larger fraction of VREs and a small fraction of nuclear capacity, making it difficult to assess changes within the nuclear share between reactors of different sizes. This assumption to ignore learning results in a high fraction of nuclear capacity and generation in the deep-decarbonization scenarios, because the further cost reduction provided by VRE technologies is ignored. While inconsistent with most other studies, this particular assumption was intentionally selected in this study to measure the impact of reactor size and flexibility in a high-nuclear-fraction scenario. An alternative scenario with a higher fraction of VRE deployed is also investigated in Section 4.2 (Thermal Energy Storage). The impact of such learning assumptions is quantified in Section 2.2.2. Moderate fuel price forecasts were used: 3.86 $/MMBtu for natural gas and 1.76 $/MMBtu for coal [EIA 2021a, Table 13]. Finally, various carbon prices between 0 and 342 \$/t CO_2 were considered, and a carbon price of 100 \$/t CO_2 was selected for the Baseline scenario. Although 2021 carbon prices in areas of the United States are under 20 \$/t CO_2, carbon emissions in the EU are trading at around 50 \$/t CO_2, and prices in Sweden and Switzerland have already surpassed 100 \$/t CO_2 [World Bank 2021]. To put this number into perspective, for a natural gas combined cycle (NGCC) unit in 2021 without carbon capture and sequestration (CCS), a carbon price of 100 \$/t CO_2 would result in an emissions cost of about 50 \$/MWh, which is roughly double its short-run marginal operating cost of 25 \$/MWh. Additional details about the assumptions for the Baseline scenario are provided in **Appendix 4**. All costs were adjusted to 2019 USD.

2.2.1 Reference results obtained with A-LEAF

Results of the Baseline scenario simulation obtained with A-LEAF are shown in Figure 2-1 (CE) and Figure 2-2, which display the electricity generated from different generators throughout every hour of 10 sampled days. In the Baseline scenario, nuclear made up 37% of capacity and 68% of generation in 2050 and was the main baseload generation resource, though it was still curtailed on some spring and fall days. All coal and most natural-gas steam turbines were retired, but 34% of system capacity was still accounted for by natural-gas generators of other types, and 3% of the total was from new NGCC with CCS. Natural-gas generators were primarily used for peak loads and periods of low VRE production. However, only 10% of generation was from natural gas. The remainder of capacity and generation was wind (18%/14%), solar PV (9%/7%), and batteries (2%/1%). Total CO_2 emissions from all generators in the Baseline scenario were about 17 Mt, a 91% reduction from 2019 levels. That is slightly more than the annual emissions from a single large multi-unit coal plant operating in 2019. Additional results from the Baseline scenario are discussed in **Appendix 4**.

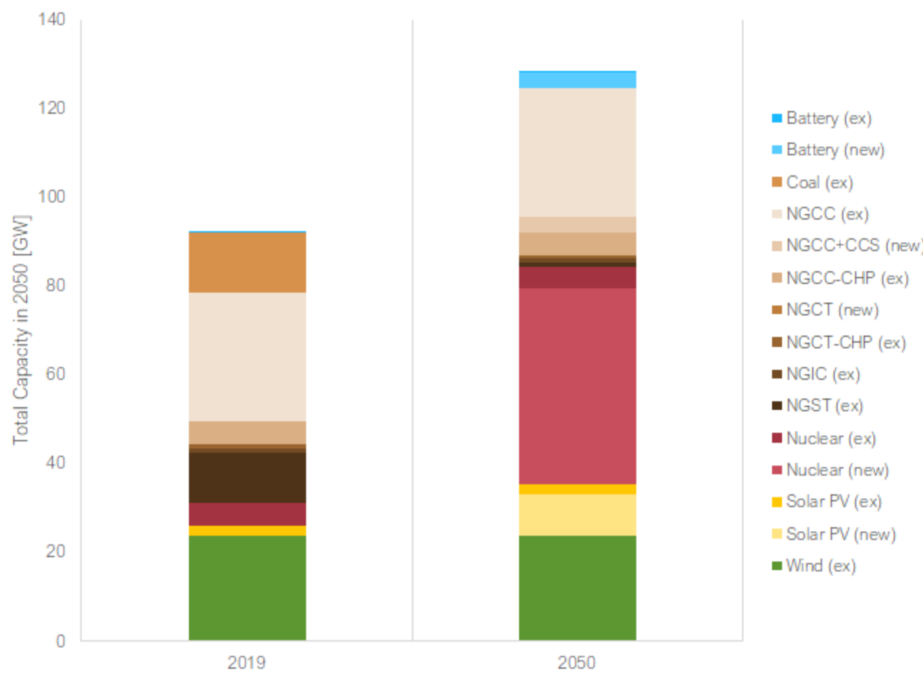


Figure 2-1. Capacity expansion results for the Baseline scenario (no learning, carbon price 100 \$/t).

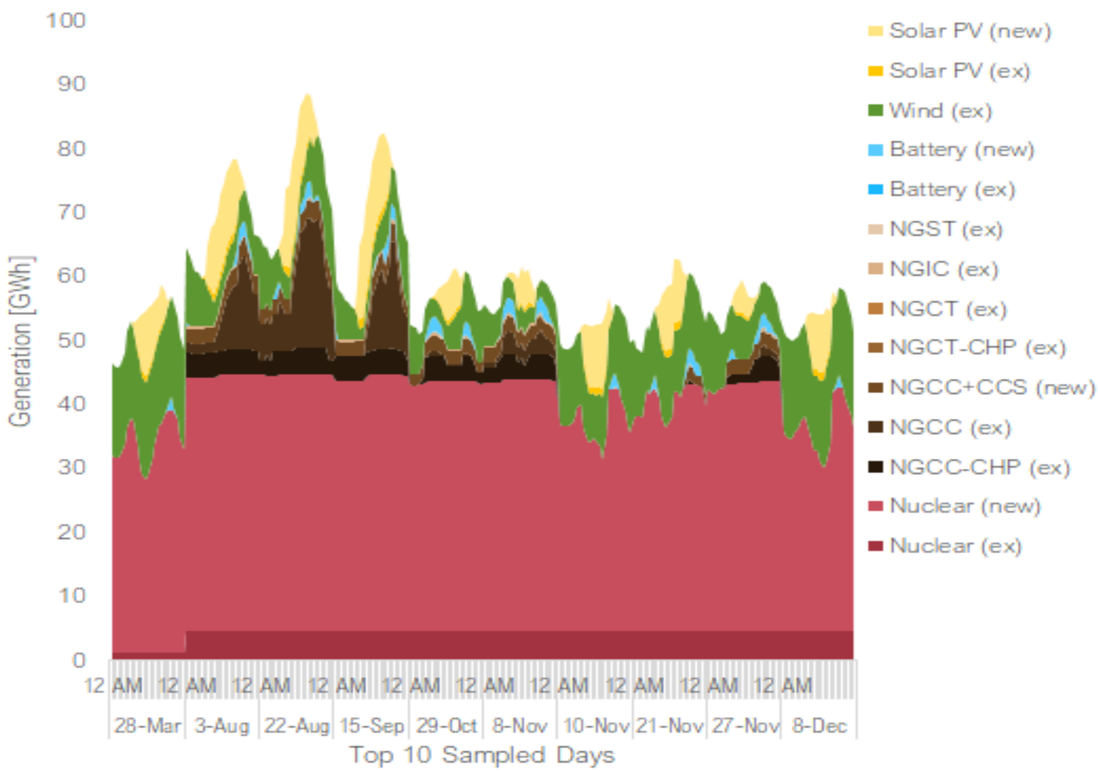


Figure 2-2. Dispatch for Baseline scenario (no learning, carbon price 100 $/t).

2.2.2 Sensitivity analysis for different scenarios

Sensitivity analyses were completed to explore the impact of the large uncertainties associated with the cost evolution of the different energy technologies up to the 2050 timeframe. Three generator cost-reduction scenarios are considered as alternatives to the Baseline with fixed costs, as shown in Figure 2-3. The Conservative Learning scenario reduced costs by 15–48%, and the Advanced Learning scenario reduced costs by 17–79%. The smallest reductions in costs were from coal and natural-gas technologies, and the largest reductions were from batteries and solar PV. These data were taken from NREL's Annual Technology Baseline 2020 [NREL 2020]. The Conservative Learning (Higher Nuc Cost) scenario is modified from the Conservative Learning scenario by using nuclear OCC from the Advanced Fuel Cycle Cost Basis report [Dixon et al. 2017] (also used in the No Learning scenario).

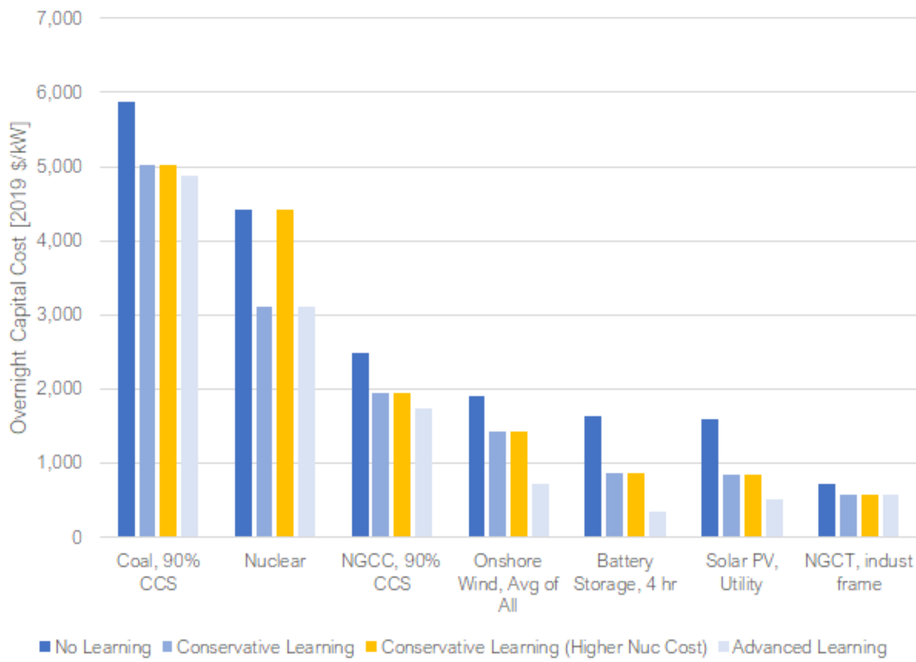


Figure 2-3. Reduction of OCC of different energy technologies under different learning assumptions.

When battery, PV, and wind costs declined much faster than fossil and nuclear costs, the nuclear share of new generation declined (Conservative) or was eliminated (Advanced), as shown in Figure 2-4. The Advanced Learning scenario results are similar to those produced by other studies that assumed much higher nuclear costs [Larson et al. 2020, Bloom et al. 2020] or did not allow new nuclear construction [Mai et al. 2012]. Also note the large amount of curtailed PV generation (47 TWh, equivalent to 8% of total annual demand) and wind generation (53 TWh, equivalent to 9% of total annual demand) when there is no new nuclear and very little new NGCC with CCS. Further analysis of such high-VRE scenarios would need to consider advanced reliability metrics (considering, for instance, extreme weather events) and potential added transmission costs and long-term storage costs, as further discussed in Section 5.2.

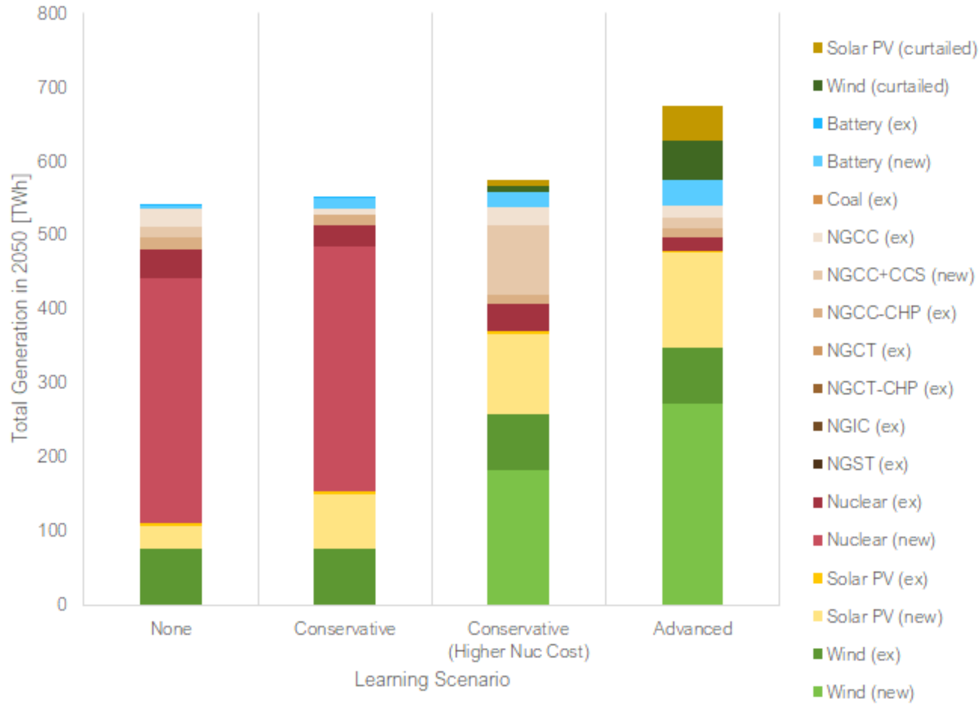


Figure 2-4. Electricity generation in 2050 under different learning scenarios, with 100 \$/t CO_2.

The cost assumptions for new generator technologies have a large impact on results, and the nuclear OCC of the Baseline scenario is low compared to other CE studies [NREL 2020]. A similar scenario was modeled for potential direct comparison, using the conservative learning scenario assumptions and costs for all generators except for nuclear technology, where OCC from the Baseline scenario was used (4,416 \$/kW).

In this Conservative Learning (Higher Nuc Cost) scenario, no new nuclear was built, but neither was existing nuclear capacity retired. Instead, large amounts of wind, solar PV, NGCC with CCS, and batteries were built (Figure 2-4). Dispatch on some days was dominated by solar PV and wind, while on other days natural-gas generators were following load (Figure 2-5). Total CO_2 emissions were 19 Mt, slightly higher than the Baseline scenario. Results for this alternative scenario with different carbon prices are provided in **Appendix 4**.

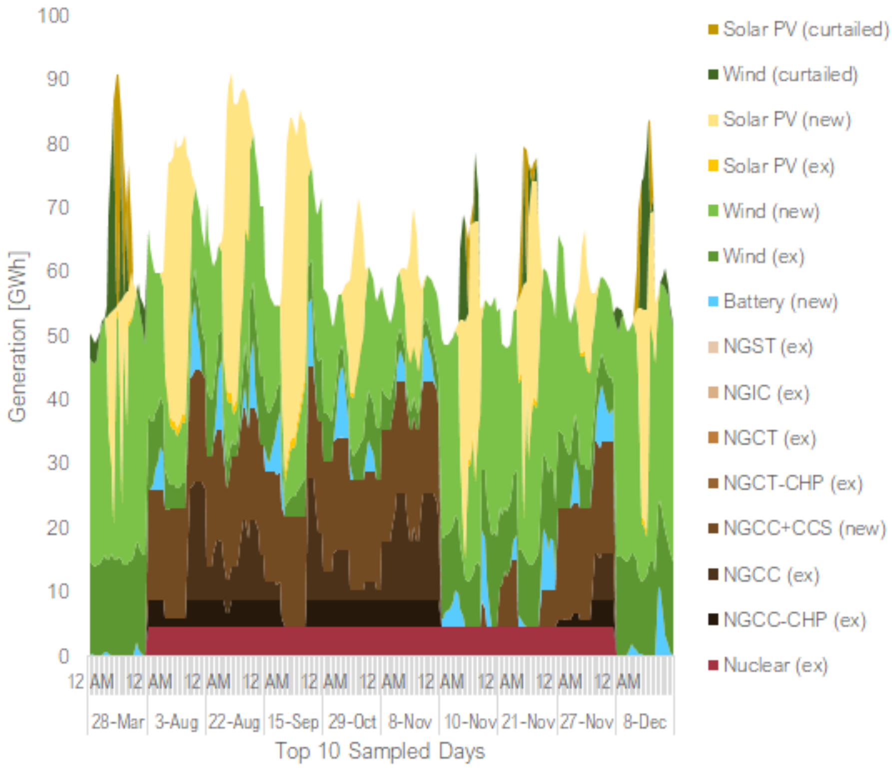


Figure 2-5. Hourly dispatch results for top 10 sampled days, alternative overnight capital costs with higher nuclear costs, 100 $/t CO_2.

We also considered the impact of fuel prices on the Baseline decarbonization scenario by modeling two alternatives: a lower fuel-price scenario with coal at 1.61 $/MMBtu and natural gas at 2.80 $/MMBtu (High Oil & Gas Supply scenario), and a higher fuel-price scenario with coal at 1.96 $/MMBtu and natural gas at 6.75 $/MMBtu (Low Oil & Gas Supply scenario) [EIA 2021a]. Lower coal and natural gas prices tended to suppress the deployment of nuclear and keep CO_2 emissions higher for the same carbon price. Conversely, higher coal and natural gas prices were associated with nuclear deployments, even without a carbon price.

Capacity payments are made in some markets to increase seasonal peak capacity, reducing the probability of emergency load shedding. Capacity payments of 50, 100, 150, and 200 $/MW·day were added to the Baseline scenario to examine their effects. These payments did slightly decrease CO_2 emissions compared to the Baseline scenario, owing to increased solar PV capacity. However, total system costs increased by over 30%. Additional details of these alternative fuel price and capacity payment scenarios are given in **Appendix 4**.

2.3 Observations and conclusions regarding the Baseline decarbonization scenario

A high carbon price of 342 $/t CO_2 led to very low emissions from electricity generation across results from GCAM, MARKAL, and A-LEAF. These were comparable to 95–100% reductions from 2019 levels, suggesting that a carbon price applied to electricity markets would be an effective decarbonization policy.

We chose the Baseline scenario to show the role that changes in size and flexibility of nuclear reactors could play in an electricity market with very low carbon emissions. This scenario featured about 70% of total generation from nuclear. For this scenario to occur, nuclear was set at 2.2× the cost of wind and 3× the cost of solar PV per kW. When nuclear costs were 4.3× the cost of wind and 6× the cost of solar PV, no nuclear was deployed except in a few cases with very high carbon prices. When nuclear was not deployed, wind, solar PV, and batteries were most often built instead. NGCC with CCS was sometimes built when natural gas prices and carbon prices were low.

3. Impact of Reactor Power Size

In many deep-decarbonization grid analyses such as the one presented in the previous section, the nuclear units are assumed to be traditional reactors of about 1,000 MW capacity each. This assumption corresponds reasonably well to the type and scale of reactors typically built worldwide since the 1970s, but as discussed previously, many advanced reactor concepts have smaller generating capacities in order to capitalize on different benefits. The work in this section intends to assess the impact of reactor capacity as an economic factor.

This section will use the terms “size” and “capacity” interchangeably, referring to the nameplate net electrical output of the plant, and it is assumed that it is possible to co-site multiple reactor units in the same plant. To study the effect of size on the economic competitiveness of nuclear reactors, Section 3.1 first discusses considerations which can make small or large reactors attractive to an electric power utility, as these firms are the “customer” for advanced reactors, and will assess these concepts on the basis of economic favorability. After this initial qualitative review, the different sizes of reactors are modeled using A-LEAF in Section 3.2, using a range of cost assumptions to assess the parameters impacting their economic competitiveness in the carbon-constrained scenario previously developed. In this report, **the economic competitiveness of a nuclear reactor is assessed by its market penetration, modeled by a system cost minimization algorithm** (A-LEAF).

3.1 Drivers for electricity utilities to build different sizes of nuclear reactors

We consider here the case of a utility with some fixed, known quantity of demand it wishes to fulfill by building a new generation asset. The utility can fulfill this objective by building a single large unit (e.g., a 1,000 MW nuclear plant) or multiple smaller units. There are a number of active factors, discussed below, that determine the overall influence of the plant’s size on this decision. In this report, reactors with capacity less than about 300 MW are described as SMRs.

SMRs comprise a wide range of technologies, including LWRs and all types of Gen-IV systems, together with new concepts such as heat-pipe cooling systems. This review intends to perform a **technology-neutral** assessment of the impact of size on nuclear reactor competitiveness. This is especially justified by the lack of data and experience available with other types of reactors beyond LWRs. The focus of this section is on assessing expected economic benefits in a long-term deployment situation rather than on providing a list of deployment challenges, including technology readiness level, fuel supply (such as HALEU), etc. Those are important aspects currently influencing utility decisions, but in this report, they are assumed to be resolved in a future deep-decarbonization scenario.

First, it is important to summarize the main design features shared by smaller-sized nuclear systems, which will drive some of the potential advantages discussed in the following sections. Reactors with smaller electrical output enable reduction (usually non-linear) of size of most components (smaller core inventory, vessel, containment, etc.), which will facilitate their manufacturability and transportability. The smaller component sizes may also enable the use of an integral design (all the components in a single vessel), which may confer benefits in terms of design simplification, inherent safety, and reduced maintenance. The inherent safety will be further enhanced by the lower power density and higher surface-to-volume ratio typically obtained in small cores, which favor passive safety systems and reduced reliance on active safety systems, with fewer and less severe failure modes expected. Finally, many smaller reactors may be designed for long-cycle operation (between 2 years and 20 years for the ARC-100), which is directly enabled by lower power density.

Utilities’ and independent power producers’ decisions to build one large versus several small nuclear units will be influenced by various drivers in terms of costing (discussed in Section 3.1.1), risk tolerance (Section

3.1.2), cash-flow (Section 3.1.3), and technical considerations such as LF capability (Section 3.1.4) and siting requirements (Section 3.1.5). To conclude this discussion, the potential benefits of siting SMRs on closed coal (or natural-gas) generation sites are discussed in Section 3.1.6.

3.1.1 Cost drivers

The cost benefits of a small versus a large reactor are challenging to assess despite their important impact on the economic competitiveness and deployability of SMRs. Smaller reactors may confer various other benefits discussed in the following sections that will facilitate their deployment and make them more attractive to a utility. However, they might not be deployed if their cost parameters cannot compete against those of larger reactors or other energy-production technologies (like VRE + battery or NGCC+CCS). The main cost drivers that need to be considered are CAPital EXpenditures (CAPEX), O&M, and fuel costs. The CAPEX is the OCC escalated by the construction financing costs. The O&M costs include both fixed and variable terms. Detailed discussion of the impact of reactor size on cost drivers is provided in **Appendix 5** and summarized below.

Impact of reactor size on Overnight Capital Cost

The OCC is typically the largest contributor to the levelized cost of electricity (LCOE) for a nuclear unit. Therefore, its dependence on reactor size will have a large impact on deployment estimates.

Historically, the size of nuclear reactors was increased from the 1960s to today to benefit from “economies of scale,” which assume that increasing the power output of a reactor concept by 50% will increase the costs by less than 50%. The largest reactors currently on the market are Framatome’s EPR (1.6 GW) and GE’s ABWR (1.8 GW). The past two decades of large-reactor construction demonstrated the limits of “economies of scale,” as large-reactor construction projects in the U.S. and Europe were plagued with delays and cost overruns, and the frequency of new builds appeared too low to achieve significant learning and cost reduction. One of the reasons is that the OCC of a well-constructed large reactor is estimated at around 4,416 $/kW [Dixon et al. 2017] (which equates to $4.4B for a 1,000 MW plant), which is not competitive with NGCC under a low-carbon policy, as observed in **Appendix 4**.

SMR concepts are now being designed to utilize cost-reduction techniques such as factory efficiency, enabled by their smaller size, instead of trying to benefit from “economies of scale,” as discussed by OECD/NEA [2021]: “*The business case of SMRs is supported by economies of series production, which rely on four key costs drivers: design simplification, standardization and modularization, while maximizing factory fabrication and minimizing on-site construction.*”

Diseconomies of scale are observed for GW reactors because of the large radiological source term and the resulting regulatory and design burden. OCC reductions are expected for SMRs because of **design simplifications**, with fewer active systems such as cooling pumps or fuel reloading systems in long-life SMRs, and fewer active safety systems, enabled by inherent and passive safety features. **Modularity** of SMRs enables reducing some costs in terms of siting and sharing of buildings and components. Modularity is an important cost-reduction strategy already implemented by multi-unit large reactors [Krautmann and Solow 1988] and leveraged by SMR concepts.

Serial construction is a well-documented approach involving planned construction of several units successively. It is used in many industries (such as shipbuilding and aircraft) to accelerate learning and reduce construction costs by 10–20%, while amortizing research and licensing costs [OECD/NEA 2021]. It is typically combined with **factory manufacturing**, which leverages the smaller size of various SMR components to minimize on-site manufacturing and assembly. The main benefits of manufacturing in a factory that are expected to reduce the OCC are the higher labor productivity (leveraging an experienced on-site workforce working in a controlled environment, as opposed to temporary construction crews often working in the open) and better quality-control mechanisms, along with the use of some advanced manufacturing techniques. "*Advanced manufacturing techniques, such as laser welding or additive manufacturing, lower costs and shorten delivery times through the reduction of the number of welds and the elimination of costly in-service inspections. The opportunities offered through the digitalization and the higher connectivity of manufacturing chains – the so-called "Industry 4.0" – could also lead to additional cost and time savings*." [OECD/NEA 2021] Reduced sizes of components facilitate their transportability (via rail and truck, instead of barges) and reduce associated costs, while also being a key enabler of factory manufacturing.

However, implementing factory fabrication requires certainty about the size of the market to justify construction of the initial capital-intensive factories, while bringing associated financial risks. Additional research is required to understand the capital price that would be needed for such an initial factory to assess amortization factors. "*J. Wallenius here stated, based on his conversations with Canadian automotive industry, that automated factory manufacture only becomes profitable when much larger series are produced. For reference, the intention of LeadCold is that its factories each would manufacture one reactor unit per month, for a total life-time production of 200 units. The cost of constructing such a factory has been estimated by partners of LeadCold to be about 300 M€.*" [IAEA 2021]

Summary: OCC reduction with smaller reactors is theoretically possible through design simplification, modularity, factory manufacturing, and serial construction, but associated with large uncertainty due to the absence of demonstration in the nuclear industry and uncertain demand. Implementing factory fabrication requires important up-front costs that need to be justified through market certainty. Finally, it hasn't been demonstrated yet whether OCC cost reduction enabled for smaller reactors will be able to over-compensate the gains coming from the economy of scale.

Impact of reactor size on Operation & Maintenance costs

Fixed and variable O&M costs have lately been the determining factors in the financial health of currently operating plants.

Fixed O&M costs are those associated with plant staff and predictable acquisition of materials for plant O&M, which occur regardless of electricity generation. Currently, several hundred full-time staff are required for 1,000 MW plants. To enable the economic viability of SMRs, the number of staff required must roughly correlate with reactor size. Small reactor companies recognize this cost, and most are proposing technological advances in instrumentation and control, and improved nuclear safety measures to reduce staffing. Multi-unit efficiencies must be realized, like the multi-unit control rooms proposed for plants like NuScale. Other proposed cost reductions for small plants are related to the site boundaries and associated security and radiological monitoring costs. Long-life SMRs will have reduced operating costs associated with fewer fuel-reloading procedures, but higher upfront capital costs for the relatively larger initial cores [IAEA 2021, p. 193]. Very small plants may require remote monitoring and intermittent in-person O&M for economic viability, if technically achievable and permitted by regulators. Security-force requirements are a specific uncertainty.

Variable O&M costs are those that are linked to generation, such as "wear and tear" of components. When it comes to reactor size, variable O&M will certainly scale with the size and complexity of the power block. Power conversion technology-specific O&M changes may also apply. For example, it might be expected that O&M would be higher for non-steam/water-power conversion cycles, at least until sufficient learning has occurred. Unexpected parts and maintenance associated with new systems may be accounted for in the variable O&M category.

Reduction in O&M costs is likely to be enabled through learning by sharing experience and applying best operating practices for each similar unit, as is currently done in the U.S. nuclear industry.

Summary: Keeping O&M costs low in small reactors is going to be necessary and is attempted by the industry through reduced staffing, design simplifications, and learning. However, it is uncertain at this time if lower O&M will be achievable when compared with that of the current large reactors.

Impact of size on fuel costs

Fuel costs currently make a small contribution to the operating cost of producing nuclear power (on average, $6/MWh out of the $30/MWh of total operating cost [NEI 2021]). However, fuel costs in some SMR concepts may represent a much larger contribution that would significantly affect operating cost and competitiveness. Many factors considered in SMRs affect the cost of their fuel, such as the fuel enrichment, form, and fuel utilization.

When considering reactor size, specific fuel costs are expected to increase slightly with reduced reactor size within the same fuel-technology paradigm, with consideration for possible losses in fuel efficiency due to increased neutron leakage and reduced burnup, and to potential reduced thermal efficiency in some SMR concepts (such as LWR-type SMRs) [OECD/NEA 2021]. Owing to decades of experience, the LWR fuel-production industry is mature, and costs are known. This cannot be said of the various SMR concepts proposing alternate fuel forms, such as TRi-structural ISOtropic (TRISO) with uranium enrichment >5%, which will likely significantly increase specific fuel costs. In fact, the DOE-NE 2014 Evaluation and Screening study estimated that most potential fuel cycles will lead to average cost estimates similar to or higher than those for the current fuel cycle (EG01) [Wigeland et al. 2014]. Some advanced fuel cycles that are associated with high uncertainty (such as long-life SFRs in EG04) have the potential for lower costs, especially if provided with sufficient technological maturation.

Long-life SMRs with no fuel reloading may eliminate refueling costs during reactor operation, while pushing these costs upfront into increased capital cost. The potential benefit of this approach is to maintain the operating costs low and reduce risks associated with long-term competitiveness (as further discussed in Section 3.1.2).

Summary: Fuel costs are likely to increase at least slightly as reactor size decreases. There is yet some uncertainty in the base-case fuel cost, as it is very technology-specific.

Impact of size on construction cost

A direct outcome of factory manufacturing will be design **standardization,** which has proven benefits in terms of reduced construction cost. For a utility, building and operating a fleet of similar reactors brings many advantages [Roche 1998], ranging from reduced engineering on different designs to increased learning and improved mobilization of the supply chain, especially when associated with a long-term new-build program. The benefits of standardization were already shown by EDF for large PWRs: reduction of construction costs by 30–40% was demonstrated with the French fleet of standardized PWRs. In the U.S., such cost reduction in large standardized PWRs has not been observed, owing to the limited number of standardized units being built.

Smaller plants have the potential for increased learning rates, owing to the necessity of building many units to achieve a required installed power level. For example, ten 100-MW electric units can be built to meet the same demand as a single 1,000-MW plant. During the construction of the ten small units, workers and project managers will become more experienced, which will result in meaningful construction cost savings by the time the tenth plant is built. If construction follows a staggered schedule, a group of workers can move from building one unit to the next while applying the lessons learned along the way. Additionally, if small reactors can be built quickly, then specific financing costs may be lower, as discussed in Section 3.1.2.

Summary: There is a technical basis for expecting reduced construction costs for smaller reactors through leveraging their standardized design, assembling factory-fabricated components, and implementing faster and staggered construction that will benefit cost reduction through learning.

3.1.2 Risk reduction and financial implications

In addition to total capital cost, financial risk is also a key factor that influences corporate decision-making about large projects. Because the outcome of any future project is uncertain, firms must evaluate the level of risk involved in any undertaking of significant size, and the importance of this risk only increases as the total dollar value at stake becomes larger.

Taking on high-risk projects can have both direct and indirect consequences. Directly, a risky project can see its potential for cost overruns and schedule delays materialize, incurring extra costs and delaying the receipt of revenues. This outcome reduces the overall profitability of the firm and can potentially cause it significant financial harm. Indirectly, a risky project alters the overall risk profile of the firm, which can impact the firm's cost of acquiring external capital via both debt and equity. A firm that engages in riskier projects must compensate its investors commensurately with those risks, via interest rates on debt or dividend rates on equity.

The scope of the present study relates to decisions among ready-to-build electricity generation technologies of comparable technological readiness. Therefore, aspects of risk related to the deployment of as-yet-undemonstrated advanced-reactor concepts, such as licensing risk, were not considered. Furthermore, decommissioning-related financial risk will also be left aside, as it is both beyond the scope of the study and a relatively minor factor compared to construction and revenue risks. See IAEA-TECDOC-1972 [IAEA 2021] for a more extended discussion of these factors.

Capital at risk

An SMR generally costs less to construct than a gigawatt-scale reactor, in absolute terms. A smaller reactor may or may not be costlier on a per-MW basis, but because the overall installation is smaller, the total CAPEX on the project will be less than for a gigawatt reactor. This difference is crucial because utility firms must be more risk-averse for projects that cost more.

For a smaller project, one which does not represent a substantial fraction of the firm's overall portfolio of projects and operations, cost escalation is a negative but not necessarily existentially threatening outcome. However, for a large project, unanticipated increases in cost or delays to the scheduled operation date can have substantial, even solvency-threatening, consequences. For this reason, since 2000, all proposals to build gigawatt-scale reactors have been by large, regionally diversified utilities in regulated markets (e.g., Southern Company) and/or consortia of multiple medium- and large-sized utilities engaged in a cost- and risk-sharing agreement (e.g., the Calvert Cliffs 3 Nuclear Project LLC).

Therefore, projects that are less costly reduce these existential risks and increase the pool of potential utility firms for which such projects are feasible.

Risk drivers

Two critical types of risk will be discussed in this section: construction risk and revenue risk. As a utility firm considers the option to build a new, non-First Of A Kind (FOAK) nuclear unit, these will be among the principal financial risks considered.

Construction risk

Construction risk relates to the uncertain cost and schedule outcome of the plant's construction process. This risk is two-pronged: it encompasses both primary cost increases (e.g., increase in quantity of direct funds spent) and financing costs (i.e. the amount of interest accrued on financing during the construction period). A delay in the completion of a project also delays the receipt of its associated revenues, and increases the extent to which interest payments on debt must be issued without receiving revenue.

Primary cost risk can also be broken into two categories. First, there is *input cost risk:* uncertainty associated with the amount and cost of materials, labor, and equipment needed to complete the project. An unexpected hike in the price of steel is a realization of input cost risk. Second, there is *technical risk*: uncertainty associated with technical project-specific factors. A pour of nuclear-grade concrete that fails, and must be torn out and redone, is a realization of technical risk.

A smaller reactor necessarily involves reduced quantities of materials and labor, so its input cost risk is also reduced in a roughly linear fashion. Whether this risk is greater or less per MW than for a gigawatt-scale reactor depends on whether the SMR's overall input costs are greater or less per MW than the large reactor.

A smaller reactor may also be less technically complex, and less complex to construct, than a larger reactor. Many SMR concepts pivot on the premise of maximizing factory construction to replace in situ "stick-building" wherever possible, which reduces the amount of risk involved in on-site construction. Many of these advanced reactor concepts also feature greater intrinsic safety and therefore fewer engineered safety systems, further reducing the span of construction activities required.

Revenue risk

Revenues are also uncertain at the time of the decision to proceed with a project. These may be uncertain for several reasons, including irresolvable uncertainty about the profitability of future energy markets and operational risks regarding participation in such markets.

Nuclear power plants are designed and operated as extremely long-lived assets. Long-term trends in electricity prices are very difficult to predict, especially as the composition of generation portfolios naturally shifts from carbon-intensive to low-carbon in the coming decades. Even if a plant seems profitable to construct and operate in the short term, its long-term economic viability depends on sufficient revenue potential across its entire lifespan (although the nearest-to-present years are the most critical). If a nuclear plant becomes uneconomical and must be retired early, the effect is more harmful if the plant has $5B of financing left to repay than if it only has $500M left to repay. Therefore, the smaller nuclear plant represents less of a stranded-asset risk in the face of rapidly evolving market dynamics.

Some types of modular reactors can reduce the impact of uncertainty in revenue forecasting by allowing for incremental commissioning. For example, some advanced reactors, such as NuScale, may confer the ability to power up some system modules while the remainder are not fully installed. This reduces the impact of revenue-projection risk, as the accrual of revenues to the plant owner begins sooner (more discussion on cash-flow benefits is provided in Section 3.1.3). Future revenues are more uncertain than current revenues because the future is more unknowable; therefore, advanced reactors that can be commissioned incrementally as the necessary construction activities are completed reduce revenue risk.

With regard to market-participation risk, a smaller plant is exposed to a smaller degree of risk than a larger plant. For example, some electricity markets impose special penalties for non-provision of power during reserves shortages. At the regional transmission organization PJM, a dispatched unit that fails to generate during a reserves shortage event can be penalized up to $3000/MWh (equivalent to $3M for each hour of outage of a 1-GW unit during a reserves shortage event). Reserves shortages typically occur when a significant amount of reserve capacity is dispatched; this is usually a response to unforeseen outages by large grid units [Potomac Economics 2021].

Large nuclear units frequently account for the largest single units in their generation environment; therefore, the trip of a gigawatt-scale reactor can singlehandedly cause a reserves shortage. In such a scenario, not only would the large reactor's operators lose out on electricity generation revenues, they would also instantly incur non-generation penalties because of the system shortage that the unit itself caused.

Furthermore, nuclear operators frequently bid into forward-capacity auctions in markets that include them. If a prospective nuclear unit is successfully bid into such a market, and the unit in question fails to be completed in time or is unable to operate at its nominal nameplate capacity during the auctioned period, then the owner must pay to acquire replacement capacity. The absolute value of this risk is roughly proportional to the size of the plant [Potomac Economics 2021].

Risk in nuclear power plant construction projects

When compared to other types of generation asset investments, nuclear power plant construction projects have a particularly marked history of severe cost and schedule overruns, even prior to the Three Mile Island accident in 1979. In the history of commercial nuclear power in the United States, no commercial reactors have ever been completed on budget, and only one has been completed on schedule (the Palisades Nuclear Generating Station in Michigan) [EIA 1986]. The Washington Public Power Supply System defaulted on $2.25B of municipal bonds in 1983 because of severe cost overruns and schedule delays at the nuclear reactors it was building at the time [Moody's Investors Service 2020]. Most recently, the extensive cost overruns and schedule delays at the Vogtle Units 3 and 4 projects and the cancellation of the V.C. Summer Unit 3 project continue to indicate that constructing nuclear power plants carries greater risk to the firm than, for instance, building a highly-standardized NGCC plant. Regardless of the causes, the signal of financial risk is clear.

Small utilities can pool resources to collectively engage in large, risky projects. For example, the Utah Associated Municipal Power Systems (UAMPS) is a State of Utah government agency that coordinates power services among member power-services entities located in various mountain-west U.S. states. Some members of UAMPS have formed a special-purpose consortium to sponsor the construction of the first NuScale SMR at the Idaho National Laboratory (INL), comprising six 77-MW modules totaling 462 MW [Pfannenstiel 2021]. For the original 12-module design, the estimated final cost was $6.1B, of which about

$1.4B was to be funded through a Department of Energy cost-sharing agreement, and the remaining $4.7B was to be funded by UAMPS [Patel 2020].

Such a project would be far out of reach for any of the consortium's individual members, some of which serve only thousands of customers. Their combined resources and pooled risk tolerance allow the consortium to tackle a much larger project. However, the limited absolute risk tolerance of the group's individual members still limits how much cost escalation can be tolerated on the project. After cost escalation was announced in 2020 and 2021, seven UAMPS utilities withdrew from the project, reducing the number of participants from 35 to 28 as of August 2021. This reduces the level of risk and asset pooling available to the remaining group, and likely reduces surviving members' tolerance for cost escalation.

Summary: Financial risk imposes key decision-making criteria and boundaries on utility firms making decisions about costly projects whose outcomes are uncertain. Smaller reactors not only cost less in absolute terms, but also offer the opportunity to engage in nuclear energy projects while engaging in a substantially reduced degree of financial risk. The improved risk profiles of SMRs may allow smaller utilities, or less-cumbersome consortia, to consider engaging in nuclear projects. Smaller reactors may also allow utilities to offer less-costly financing terms to investors, as they will incur less risk of insolvency due to unfavorable construction or revenue outcomes.

3.1.3 Cash-flow benefits of SMRs

In addition to reduced absolute cost and lower risks, some SMR concepts also offer the possibility of starting up the plant incrementally. Once balance-of-plant systems are in place, it may be possible to commission and start up modules as they are installed, rather than waiting for all reactor modules to be fully installed. This approach can accelerate the date at which the plant's owner begins receiving revenues, reducing the risks inherent in the project. Units that come on-line earlier benefit from decreased revenue risk, as revenues begin to accrue sooner; units that come on-line later benefit from learning and efficiency gains during earlier completed portions of the project. Therefore, utilities engaging in such projects may be able to secure more favorable financing terms because of the decreased project risk.

However, the choice to accelerate deployment of some modules requires some project costs to be shifted earlier in the construction timeline, as infrastructure that is common to all reactor modules (such as NuScale's reactor pool hall) must be completed before any modules can be installed and powered up. The effects of commissioning a modular reactor plant piecemeal therefore should be carefully studied, using tools that can decompose plant costs into common-infrastructure cost accounts and module-specific cost accounts.

The impact of stage-wise commissioning of SMR concepts can reduce the risk a utility and its investors must bear. Therefore, the possibility of this option in some SMR proposals has financial value, which may make such projects more worthwhile and more feasible for utility firms to execute.

3.1.4 Load-following capability

Nuclear reactors in the U.S. have traditionally been operating in baseload mode, but some operating reactors are moving toward more flexible operation to readily compensate for variations in renewable generation [Siphers 2018]. New large or small reactor concepts are generally designed by the industry with some flexible operation capabilities, whether through LF operation or through coupling with TES. Those features are especially emphasized for SMRs and MRs that are targeting markets with clear requirements in terms of electrical power size and modulation (e.g., micro-grids).

As discussed in detail by Stauff et al. [2017], a smaller reactor power would not display significant improved operational flexibility when compared with a larger reactor power, when considering identical reactor technologies. Smaller units are expected to be more easily operated down to low power, especially by directly dumping the extra heat to the environment through turbine bypass, as discussed by Ingersoll et al. [2015].

However, the potential modular features of SMRs confer inherent benefits in terms of operational flexibility. The modularity provides the utility with additional flexibility to increase the operability of its different reactors and better modulate the total station power output compared with a standalone operation. In particular, standalone units are typically limited to a lower operation at 20% of the power rated (Pr), which is typically constrained by the characteristics of the rotating machinery (pumps, turbines, etc.), meaning reactors cannot generally operate between 0 and 20% of Pr. This low-power generation can be more easily supported using several smaller reactors with a modular operation: some units can be completely shut down while others can operate at their minimum power level. Thermal nuclear reactors (such as PWRs) are typically less flexible at the end of cycle because of reduced excess reactivity that needs to be compensated during xenon buildup following a power transient. A modular reactor design presents potential advantages over a standalone larger reactor, as it allows staggering of the fuel cycle between different units on the same site [Ingersoll et al. 2015].

Summary: Small power and modular reactors offer the potential for further enhanced flexible operation when compared to large standalone reactors. The objective of section 4 of this report is to analyze the value of flexibility in a future ERCOT-type electricity grid.

3.1.5 Siting compatibility

Beyond these financial risk factors, operational flexibility, and reactor cost components, there are additional parameters that determine nuclear build compatibility with a particular region and market. Generally, these factors can be considered as siting compatibility issues, as they are related to the location where a utility can deploy new nuclear plants. Siting factors include the local environment, cooling water access (if necessary), local population, transmission availability, ground transportation access, water transportation access (if necessary), and non-electric utility access.

Market flexibility

The smaller power level provided by SMRs can better meet the needs of certain electricity markets, potentially extending the number of electricity utilities that could host them. For a regional balancing authority, the total reserves requirement is primarily determined by the size of its largest expected contingency (e.g., loss of a power plant's generation due to transformer fires) [NERC 2018]. In a large market like ERCOT, there are several hundred power plants, and the capacity of the largest single power plant (W. A. Parish coal- and gas-fired power plant, with capacity of 4,000 MW) is much smaller than the typical load range (2019 minimum 27,612 MW, mean 43,818 MW, maximum 74,666 MW). Assuming that there is a high probability of expected plant performance [Mann et al. 2021], there is almost always enough contingency capacity available, and that capacity is spread among many generators in terms of unit count and geography.

In some areas, there are significant transmission constraints such that a generation loss within that area could not be replaced by reserve generation from outside that area. In these situations, additional generation can be added behind the transmission constraint to provide the contingency reserve.

For transmission-constrained areas and smaller islanded networks, having many smaller, geographically dispersed generating units would reduce the contingency reserve requirement and potentially improve reliability. However, if a nuclear power plant with many individual reactors (e.g., 10 or more) has a large capacity relative to the system (e.g., SMR plant of 600 MW in an islanded system with peak load of 6,000 MW), the contingency reserve requirement could go up.

If a nuclear power plant with many individual reactors also had multiple, independent turbogenerators, the plant could have a lower minimum stable level compared to a single turbogenerator. This is because several turbogenerators could be disconnected while other remained online. Several SMR plant designs have this 1×1 reactor–turbogenerator configuration, including EM^2, NuScale Power Module, mPower, Westinghouse SMR, and Xe-100 [IAEA 2020]. The many-reactor plant would also have a smaller impact on grid operations if one reactor or turbogenerator failed to start, compared to a few-reactor plant.

Various attributes of SMR technologies (e.g., high outlet temperature) will also make them attractive for other types of markets, as discussed elsewhere [OECD/NEA 2021; Forsberg and Foss 2021], but this topic goes beyond the work scope of the present study.

Siting flexibility

Listed below are examples of siting flexibility provided by the inherent advantages associated with the small power and reactor size of SMRs.

Cooling water access

Because of the lower power level of a small reactor, and the potentially lower power level of the full plant, the cooling water requirements may be reduced. This is a critical advantage that would enable deployment in regions with limited water access. For instance, large portion of the U.S. are expecting to see a hotter, drier climate that would restrain water cooling of power plants during dry seasons [van Vliet et al. 2012]. Specific designs can employ technologies directed at further reducing cooling-water need, with enhanced thermal efficiency (up to ~45% in VHTR concepts), or with dry cooling. Dry cooling can be enabled by air-cooling, but entails higher cost and reduced thermal efficiency. The SMR-160 concept from Holtec [Holtec International 2020] considers dry cooling to provide greater siting flexibility. Dry cooling is also being considered for the NuScale units under development on the INL site.

Potential reduction in Emergency Planning Zone [Smith et al. 2021]

Emergency Planning Zones (EPZs) are established surrounding nuclear facilities to protect the health and safety of the public. The current EPZ requirements under siting regulations in 10CFR Part 100 specify an exclusion area and a low-population zone. In the U.S., the typical radius for an EPZ that requires emergency planning is 10 miles (plume exposure pathway EPZ), while a larger-radius zone of around 50 miles (ingestion pathway EPZ) will require plans to protect the public from exposure through potential food ingestion.

This EPZ definition was developed for the current fleet of large LWRs. It is now evolving to leverage the better understanding of the physical process behind source terms and the ability to model them more accurately. Reduction of the EPZ requirements would be especially justified for SMRs because of their drastically different design when compared to currently deployed large LWRs, and their lower fissile inventory, which ultimately reduces potential radioactivity release through reduced source terms.

Reducing EPZs would be important for increasing nuclear-reactor siting options in areas closer to cities (for instance, on existing fossil-fuel plant sites, as discussed in Section 3.1.6), but also for reducing some of the O&M costs associated with emergency planning.

A shift towards risk-informed, performance-based EPZ determination has recently been proposed by the U.S. Nuclear Regulatory Commission (NRC) in a draft regulatory guide (DG-1350). Such an approach will require understanding of source terms of advanced reactors [Alfonsi et al. 2020], which would inform the selection of EPZ boundaries. A similar approach was recently implemented in 2020 for the NRC issuance of the NuScale final safety evaluation. Through this rigorous approach, the EPZ zones of small reactors and microreactors may be decreased, depending on technology and site-specific licensing basis events.

Unconventional siting

Because of their small size, some SMRs are adopting unconventional types of siting, in contrast to the conventional dedicated above-ground site. For instance, for the SMR-160, Holtec is considering siting parts of its nuclear island below grade, which brings advantages in terms of protection from human-caused hazards (terrorist attacks, etc.) or natural hazards (earthquakes).

Other SMRs are being considered for siting on boats [ThorCon 2021], or even underseas [FlexBlue 2011], while being connected to the main grid. The floating power plant concepts developed in Russia by Rosatom are currently under deployment: the first boat containing two 35-MW KLT-40s began commercial operation in 2020 to generate electricity and provide process heat to the remote city of Pevek. Some benefits of these unconventional approaches are unlimited access to water cooling, a deployment strategy that leverages complete factory-built units, and the potential for mobility to serve changing customers throughout the plant's lifetime.

Summary: SMRs confer promising benefits in terms of siting flexibility and for supporting small electricity grids.

3.1.6 Reviewing potential for siting SMRs at retired coal generation plants

In deep-decarbonization scenarios, most fossil thermal units will be replaced by low-carbon solutions, whether by implementing CCS technology or by retiring the CO2-emitting unit and replacing it with a non-emitting power-generating solution (nuclear, VRE, biomass, geothermal, etc.). Small nuclear units may be deployed on sites of retiring coal or gas power plants with similar power ratings to take advantage of existing infrastructure and manpower, while providing continuous electricity generation. Various studies were completed to investigate siting availability [Belles et al. 2013] and economic viability [Qvist et al. 2021] of SMRs to replace existing coal power plants. This option is currently being considered by TerraPower for its Natrium concept, developed under the ARDP [TerraPower 2021]. NuScale [NuScale 2020] and Kairos Power [Bartela et al. 2021] are also investigating and promoting this siting option for their SMR systems.

Number and sizes of coal units that would be applicable for retrofitting

In 2019, there were 386 power plants in the U.S. that burned coal as their primary fuel and another 57 that used coal as a secondary fuel. There were 1,299 coal-fired generators at these sites with an average capacity of about 270 MW, and the total national coal-generator capacity was about 348 GW [USEPA 2021a]. A previous study [Belles 2013] showed that **about half** of the coal units sampled (which were spread throughout the U.S.) would be suitable to host SMRs of similar power sizes in light of various criteria such as low neighboring population density, water-cooling availability, and low potential for flooding or earthquake events. Coal units cover >50 ha, an area that was assumed to be sufficient to host more than one SMR module. Future work should extend this siting study by considering a wider range of candidates for replacement (coal plants in the 50 to 500 MW range, including newer units, and other thermal generators such as NGCT and NGCC), to investigate the total number of nuclear units that could potentially replace fossil units in deep-decarbonization scenarios.

Cost reduction obtained when repurposing coal units as SMR units

The main cost savings from retrofitting a coal unit into a nuclear unit of similar power size, as identified by Qvist et al. [2021], result from the potential to reuse high-voltage transmission lines and grid-connection components, cooling towers, auxiliary buildings, and potentially some existing steam-cycle components. A large fraction of the coal power plants studied by Qvist et al. [2021] operate with steam temperatures in the 530–570°C range or above 600°C, using a subcritical (<22.1-MPa) or ultra-supercritical (>25-MPa) steam cycle. Coal plants should be chosen for retrofitting on the basis of the monetary value of each of these re-useable components and their compatibility with the SMR technology considered. Advanced GEN-IV technologies (SFR, LFR, SMR, some VHTRs) would be more readily able to re-use some of the steam-cycle components from the coal units, owing to similar operating temperatures, while LWR-type SMRs (NuScale) would only benefit from some electrical components and cooling-water systems. This study concluded that the LCOE can be reduced by 9 to 28% thanks to the reduction in upfront CAPEX when an advanced SMR is built on a retrofitted coal unit of similar power output, when compared to greenfield deployment. This saving needs to be balanced against the cost of decommissioning and cleanup of some of the coal plant components (coal storage areas, old buildings, etc.), and needs to account for upcoming maintenance/replacement of some older components from the original coal unit.

Expected benefits to the society and surrounding communities

In addition to the reduction in CO_2 emissions, from which the whole society will benefit, the surrounding communities will benefit from the reduction in other air pollutants. An average coal plant in the U.S. emits around 4.2 t CO_2/MWh, which contributes to climate change, and 3.7 kg SO_2/kWh and 2.7 kg NO_2/kWh [USEPA 2021a], which contribute to acid rain, smog, and respiratory illnesses, while other particulates and heavy-metal emissions have other harmful effects on the health of surrounding populations and on the environment.

The other clear benefit to the surrounding community will be in terms of job retention and creation. Nuclear construction projects typically require thousands of short-term jobs, while reactor operation provides several hundred long-term, high-paying jobs. "*The NuScale plant employs more plant staff and at a higher average annual wage when compared to coal or natural gas plants.*" [NuScale 2020] The larger number of highly paid jobs in the surrounding community will lead to clear economic benefits.

Many of these long-term jobs are expected to be available to current coal power plant workers, with different levels of retraining effort to accommodate the specific experience and certification requirements of the nuclear industry. *"NuAB [The NuScale Advisory Board] evaluated the plant staffing data for eleven coal power plants and the results of the evaluation demonstrated that many job positions and their job requirements are similar to those found at most nuclear power plants."* [NuScale 2020] The potential for job creation in the local community still needs to be balanced against reduced jobs in other sectors of the coal industry (such as mining) that are going to be affected by coal phase-out.

Summary: There is a priori a large potential for small nuclear units to be located at some existing coal sites in the U.S. First, there are many coal power plant sites that will be available in a deep-decarbonization scenario and that would be suitable candidates for retrofitting. SMR deployment on these sites would make sense, as it would be bringing a clear economic benefit to the utility (reduction in OCC) in addition to clear societal benefits.

3.2 Assessment of nuclear deployment perspectives for different unit sizes

The quantitative assessment in this section shows how nuclear reactors with different sizes might be competitively deployed in a U.S. grid market based on the ERCOT region. Such analysis first requires discussion of economic models utilized for costing different sizes of nuclear reactors. In section 3.2.1, the cost estimates for each cost category based on reactor size are discussed. Then, in Section 3.2.2, using A-LEAF as an electricity market modeling optimization tool, the deployment perspectives of different sizes of reactors are discussed under different costing assumptions.

3.2.1 Economics model for different sizes of nuclear units

The objective of this work is to investigate how different smaller reactors will get deployed under different levels of optimism in terms of cost reduction (OCC, O&M and fuel costs) in the deep-decarbonization scenarios. Consequently, one must determine a basis for size-based cost estimates for each cost category. Details of the cost estimates for this report can be found in **Appendix 5**, and the results are summarized in Table A5-7. Four representative sizes were selected: 1,000 MW, 300 MW, 100 MW, and 30 MW. These sizes were chosen so that the results would be differentiated and meaningful across a range of potential reactor sizes. The 1,000-MW size corresponds to typical large reactors that are currently operating. The 300-MW and 100-MW sizes correspond to SMRs. The 30-MW size corresponds to large MRs for grid applications.

Given the uncertainty of how the OCCs will scale with reactor size, various scaling factors illustrated in Figure A5-5 are used to estimate OCCs as a function of reactor size. Scaling functions between the OCC and reactor power size take the following form:

$$\frac{Cost_1}{Cost_2} = \left(\frac{Power_1}{Power_2}\right)^{n-1},$$

where $Cost_x$ is the specific OCC of technology x, $Power_x$ is the electric power of technology x, and n is the scaling factor. The SMR's OCC does not vary with its power level for the scaling factor of 1.0 but decreases or increases when the scaling factor is larger or smaller than 1.0, respectively. The impact of reactor size on nuclear deployment in the deep-decarbonization scenarios was evaluated for three cases in this work: specific OCC decreases with the scaling factor larger than 1.0, specific OCC increases with the scaling factor smaller than 1.0, and specific OCC is independent of the reactor size with scaling factor equal to 1.0. These scaling factors and the associated cost estimates are selected to envelop cost estimations from commercial companies and a literature review of OCC cost projections.

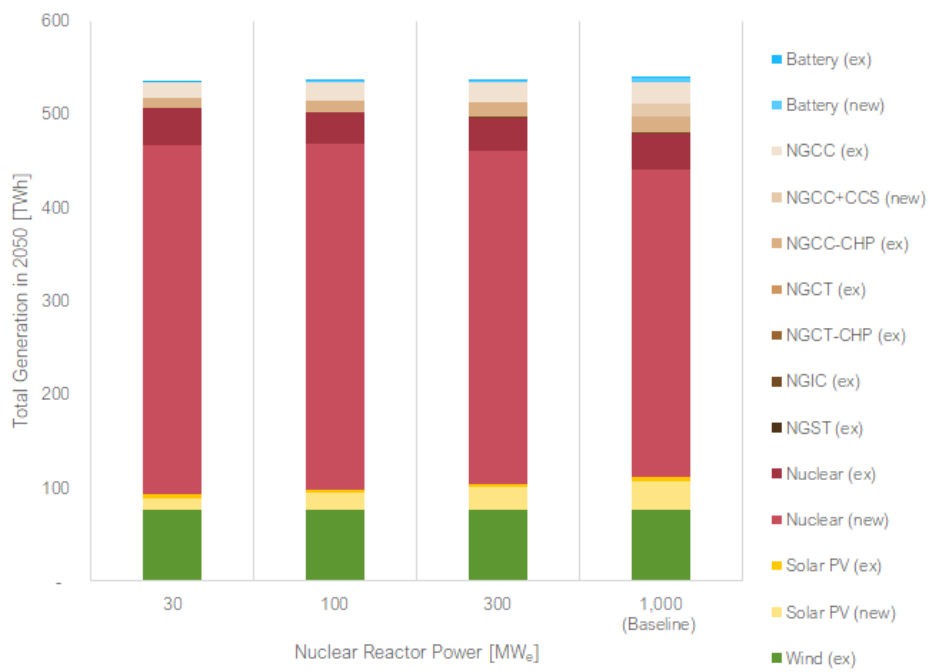
Construction risk and financing costs were discussed in section 3.1.2, and several financing scenarios were proposed to investigate the effect of small-reactor construction time and associated improved financing terms on deployment. Additional scenarios are proposed in which specific O&M costs are varied with reactor size. Fuel costs also contribute to the cost of producing nuclear power. As discussed in Section 3.1.1, for every scenario considered, the fuel costs are assumed to increase as reactor size decreases.

Detailed reasoning behind the selection of the different scaling factors (for OCC, O&M, fuel) used in this analysis is provided in **Appendix 5**.

3.2.2 Nuclear deployment with different reactor sizes

Sensitivity scenario: SMR has lower OCC

In the case where smaller reactors have lower specific OCC ($/kW) than larger reactors (scaling factor n = 1.2), nuclear power plant deployment increased slightly as reactor power size was reduced, as shown in Figure 3-1. Since the nuclear capacity in the Baseline scenario was already significant, the need for additional nuclear units to reduce total costs was small, and many nuclear units were operating in LF mode. Some of the market was still taken by NGCC, PV, and wind. Additional nuclear generation reduced carbon emissions by several metric tons of CO_2 compared to the Baseline scenario.

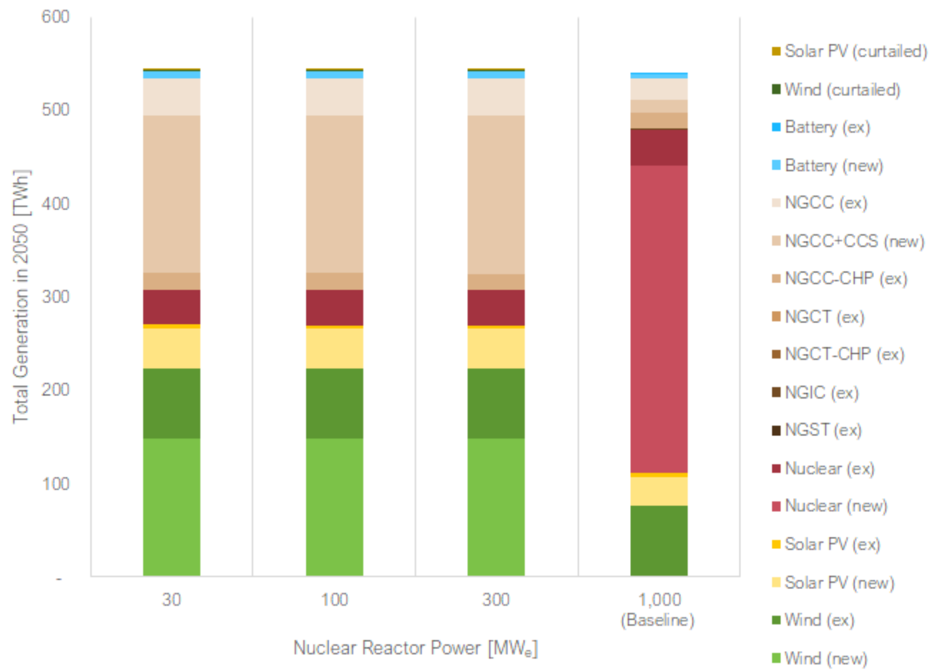


Power [MW]	30	100	300	1,000
OCC [$/kW]	2,190	2,786	3,471	4,416
CapEx [$/kW]	2,474	3,148	3,921	4,989

Figure 3-1. **Total generation mix in 2050 when considering deployment of various reactor sizes with associated capital cost, assuming smaller reactor has smaller OCC (n=1.2).**

Sensitivity scenario: SMR has higher OCC

When smaller reactors have higher specific OCCs ($/kW) than larger reactors (scaling factor n = 0.6), no new nuclear power plants were built, as shown in Figure 3-2. With these higher OCCs, even a 100 $/t CO_2 carbon price did not create enough financial incentive to make smaller nuclear power plants competitive. It is not surprising that increased OCC would disfavor nuclear deployment under this Baseline scenario, especially since it is not associated with potentially impactful benefits (such as operating cost reduction or increased flexibility) beyond the reduced power level. Instead of new nuclear, wind and NGCC with CCS were built to serve additional demand. CO_2 emissions went up compared to the Baseline scenario as a result of the additional natural gas generation (10% of emissions were not captured through the modeled CCS technology).

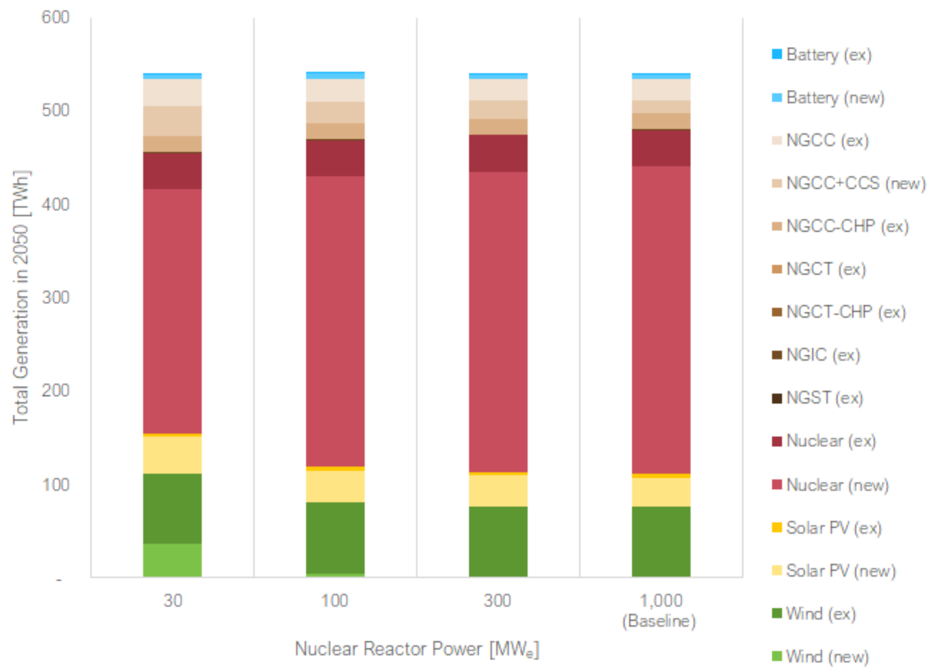


Power [MW]	30	100	300	1,000
OCC [$/kW]	17,955	11,092	7,148	4,416
CapEx [$/kW]	20,284	12,531	8,075	4,989

Figure 3-2. Total generation mix in 2050 when considering deployment of various reactor sizes with associated capital cost, assuming smaller reactor has higher OCC (n=0.6).

Sensitivity scenario: SMR has same OCC

With no difference in specific OCCs ($/kW) for smaller and larger reactors (scaling factor n = 1.0), the total capacity of new nuclear power plants declined as reactor size decreased (e.g., 20% less nuclear capacity was built in the form of 30-MW reactors compared to the Baseline 1,000-MW reactor). The results, shown in Figure 3-3, are due to the assumed increase in fuel costs for smaller reactors (fuel-cost scaling factor n = 0.87).



Power [MW]	30	100	300	1,000
OCC [$/kW]	4,416	4,416	4,416	4,416
CapEx [$/kW]	4,989	4,989	4,989	4,989

Figure 3-3. **Total generation mix in 2050 when considering deployment of various reactor sizes with associated capital cost, assuming smaller reactor has same OCC (n=1.0).**

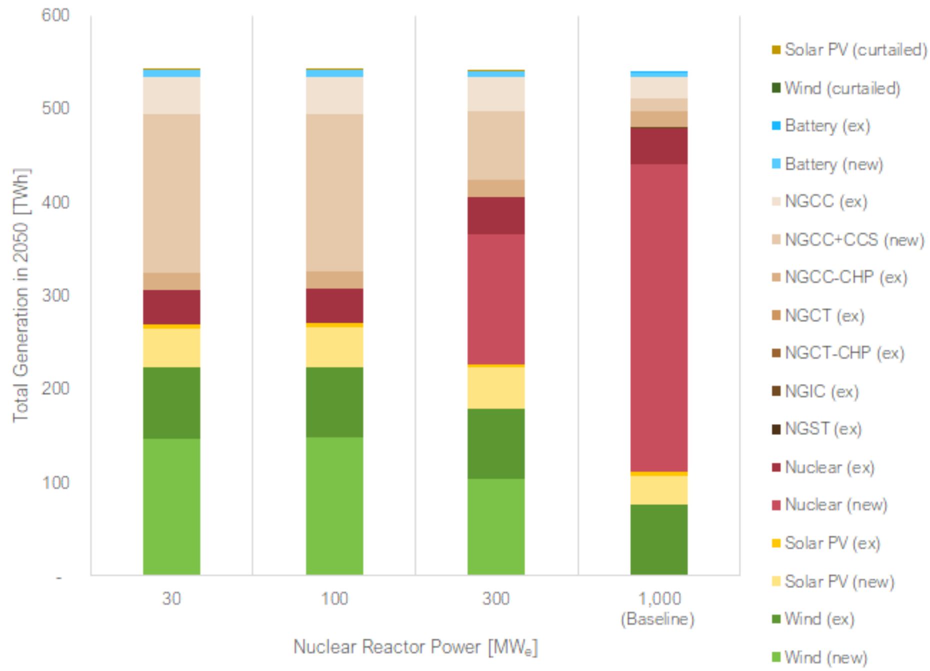
Sensitivity scenario: SMR has higher O&M costs

To evaluate the impact of increasing O&M costs on the deployment of SMRs in the deep-decarbonization scenario, the fixed O&M cost ($/kW·yr) and variable O&M costs ($/MWh) were increased using a scaling factor of n = 0.7. In this case, the OCC scaling factor assumes n=1. With this scaling factor, an order-of-magnitude size reduction resulted in a near doubling of specific costs, as displayed in Table 3-1.

Table 3-1. O&M and fuel costs assumed for different reactor sizes.

Power	[MW]		30	100	300	1,000
OCC	[$/kW]	n=1.0	4,416			
Fixed O&M	[$/kW-yr]	n=0.70	218	151	109	76
Variable O&M	[$/MWh]	n=0.70	5.35	3.73	2.68	1.87
Fuel	[$/MWh]	n=0.87	8.17	6.99	6.06	5.18

Compared to the Baseline scenario, the increase in O&M costs substantially reduced nuclear deployment, as shown in Figure 3-4. For the 300-MW reactor, less than half as much new capacity was built, and no new nuclear capacity was built for the 100-MW or 30-MW reactors. Instead of nuclear, new wind and NGCC with CCS capacity was built instead, showing the same response as the cases where specific OCC increased for smaller reactors (n = 0.6).

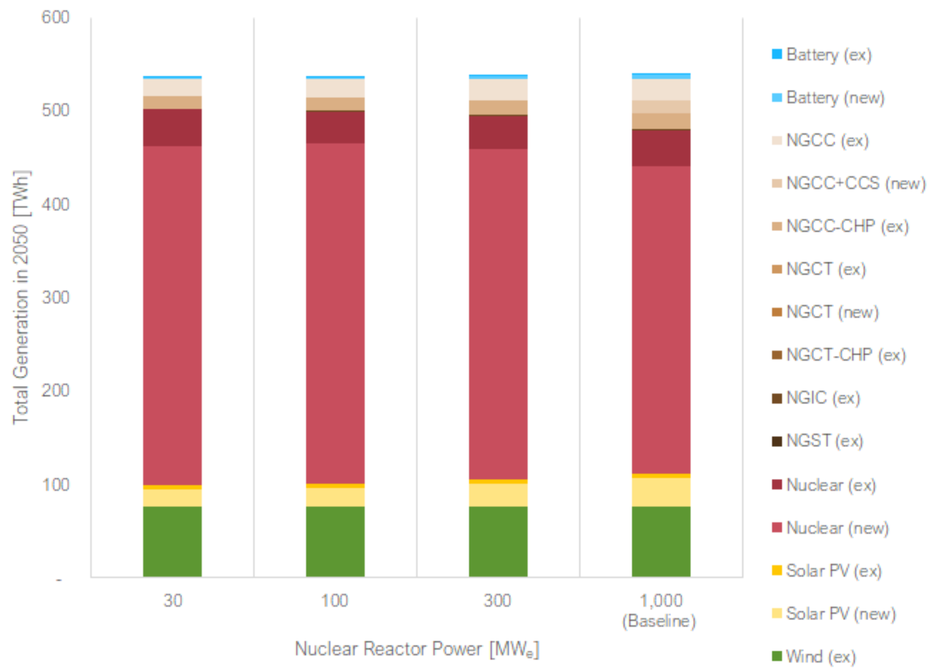


Power [MW]	30	100	300	1,000
OCC [$/kW]	4,416	4,416	4,416	4,416
CapEx [$/kW]	4,989	4,989	4,989	4,989

Figure 3-4. Total generation mix in 2050 when considering deployment of various reactor sizes with associated O&M costs, assuming smaller reactor has higher O&M (n=0.7).

Sensitivity scenario: SMR has lower construction time and improved financing terms

In the Baseline scenario, large 1,000 MW reactors are assumed to be built in 5 years with a 5% interest rate (OCC 4,416 $/kW, CAPEX 4,989 $/kW). To analyze the response to construction time and interest rate, the construction times and finance factors for smaller reactors were reduced (Table A5-6). For the 30-MW reactor, construction time was reduced to 2 years and interest rate was reduced to 2.5%. This led to a reduction in CAPEX from $4,989/kW (for 1GW reactor) to $4,504/kW for the smaller 30 MW reactor. The increased deployment of smaller reactors associated with reduced CAPEX is shown in Figure 3-5. This reduction in construction time and interest rates overcompensated for the increased fuel costs assumed for smaller reactors. Additional details of this scenario are given in **Appendix 4**.



Power [MW]	30	100	300	1,000
OCC [$/kW]	4,416	4,416	4,416	4,416
CapEx [$/kW]	4,504	4,616	4,776	4,989

Figure 3-5. Total generation mix in 2050 when considering deployment of various reactor sizes with reduced construction time and financing terms for smaller reactors.

3.3 Observations and conclusions on the impact of reactor size on deployment potential

The U.S. industry is moving forward with development of small nuclear reactor concepts with financial assistance from U.S. federal agencies for deployment of the first concepts (for instance, under the DOE ARDP). It is critical to understand what makes such concepts attractive for deployment in a future decarbonization scenario. There are two main aspects to deployment feasibility:

First, the SMRs must be attractive to a customer, meaning that electric utilities could have an interest in purchasing them. When compared to large GW-scale reactors, SMRs bring clear benefits to a utility in terms of risk reduction, considering not only reduced capital at risk, but also the reductions in risk on the construction project, and on their future revenues. SMRs also bring clear benefits in terms of siting—for instance, as prime candidates for re-using sites of retired coal plants—and of supporting small electricity grids, and they also potentially offer some benefits in terms of operational flexibility. Another significant benefit expected for SMRs that use modular and staggered construction will be in terms of reduced construction time/cost throughout the project and improved cash flow as constructed units will start generating revenues as other units are being built.

Second, the SMRs must be economically competitive, which means that the combination of capital and operating costs should be at least as attractive as for other zero-carbon generation technologies. To account for uncertainties in cost reductions achievable with different sizes of reactors, scaling factors are proposed to take the known, well-established data of operating LWRs and quantify the costs of reactors based on size. Using the A-LEAF optimization-based CE simulations, the present analysis showed that SMRs will be able to compete with other technologies and be deployed on the future grid if they can confirm reduction of cost factors relative to large grid costs (CAPEX comparable or lower without increase in O&M and fuel costs). There are technical solutions for reducing the capital cost of SMRs, such as modularization, design simplifications, reduced construction cost and time, and improved financing terms. However, the operating costs including O&M and fuel costs also need to remain low. SMR vendors are researching and implementing various solutions such as reduced staffing. Specific nuclear reactor concepts developed by the industry could be modeled to assess their deployment potential in an ERCOT-like region, if economics and operating parameters are made available.

4. Impact of Reactor Flexibility

Most nuclear power plants have traditionally been operating as baseload units in the U.S. Recently, some utilities (such as Exelon [NICE Future 2020] and Duke Energy [Siphers 2018]) have been implementing LF operation to reduce power output during transmission congestion and low-market-price events that are the consequence of increased system reliance on VRE. In fact, neglecting the ability of nuclear plants to load-follow in CE modeling will lead to undervaluation of the services reactors can render to future grids that are expected to rely on high levels of VRE. The objective of the study summarized in this section is to quantify the value of nuclear flexibility in a future zero-carbon grid system. Two future grid configurations are considered: one that relies on a high proportion of nuclear (using the reference decarbonization scenario discussed in Section 2.2.1), and one alternative scenario that relies on a high fraction of VRE.

The idea of "nuclear flexibility" includes a number of possible features that are discussed by Stauff [2017], including daily duty cycles to follow intra-day demand trends, short-time-scale participation in frequency regulation, and very-short-time-scale ability to navigate rapid transients. The analysis completed in this report will focus on the daily LF type of transients that are being modeled in A-LEAF to solve the challenge of balancing power demand with generation. Discussion of fast frequency response (including rotational inertia), frequency regulation, and rapid transient capabilities involves different classes of tools that model sub-minute time scales [Denholm et al. 2021]. Even though such analyses are critical to assess the viability of a future grid, they are typically beyond the scope of economics optimization of a future grid, as most of these services are not remunerated in many current electricity markets.

All nuclear power plants are intrinsically capable of LF, but some new concepts are being designed to permit aggressive flexible operation that would be required in future high-VRE grid operation or in a micro-grid market. The two main operational options considered in this report for flexible operation in a nuclear reactor are intrinsic LF capability (Section 4.1), and coupling with TES (Section 4.2). Other flexible types of operation scenarios beyond the scope of this analysis could involve an Integrated Energy System, where the nuclear unit is coupled to an industrial system [Bragg-Sitton et al. 2020].

4.1 Load Following

Even though most nuclear power plants in the U.S. are operated as baseload units, they can be modified for some level of LF to enable ramping of the electric power output. There is already established knowledge and experience surrounding flexible operation of existing and future nuclear power plants in the U.S. and internationally [NICE Future 2020]. In a competitive wholesale market where a generator seeks to maximize profit, LF creates opportunities for voluntary generation curtailment during low-price events, to avoid mandatory participation in markets when prices are unfavorable. As confirmed by Exelon [NICE Future 2020], "*nuclear load cycling has proven to be a safe and successful method to eliminate localized negative pricing in real time and day ahead conditions while increasing nuclear plant profitability.*"

The two main technical parameters for flexible operations are the unit's ramp rate and minimum stable level. The new nuclear power plant candidate (1,000 MW) in the Baseline scenario had a ramp rate of 5%/min and a minimum stable level of 20% ("adv-LF"), which is consistent with current flexibility requirements for new units [EPRI 1999]. This Baseline candidate was replaced in two alternative scenarios: "limited-LF" has a less-flexible nuclear plant (ramp rate 1%/min and minimum stable level 70%, representing the level of flexibility currently obtained in some U.S. plants [Siphers 2018]), and "no-LF" considers an inflexible nuclear plant (no ramping allowed, plant at maximum output or off only). Costs were identical for all three candidates.

As shown in Figure 4-1, the less-flexible nuclear plant was deployed at the same level as the Baseline nuclear plant, while the inflexible nuclear plant had 14% less nuclear capacity deployed compared to the Baseline nuclear plant. Compared to the maximum assumed fleet-wide capacity factor of 91%, the adv-LF and limited-LF nuclear fleet average was 86%, and the no-LF nuclear fleet average was 90%. The lower capacity factors for adv-LF and limited-LF were due to the reductions in generation inherent in LF operations. A faster ramp rate and a lower minimum stable level were beneficial to nuclear deployment.

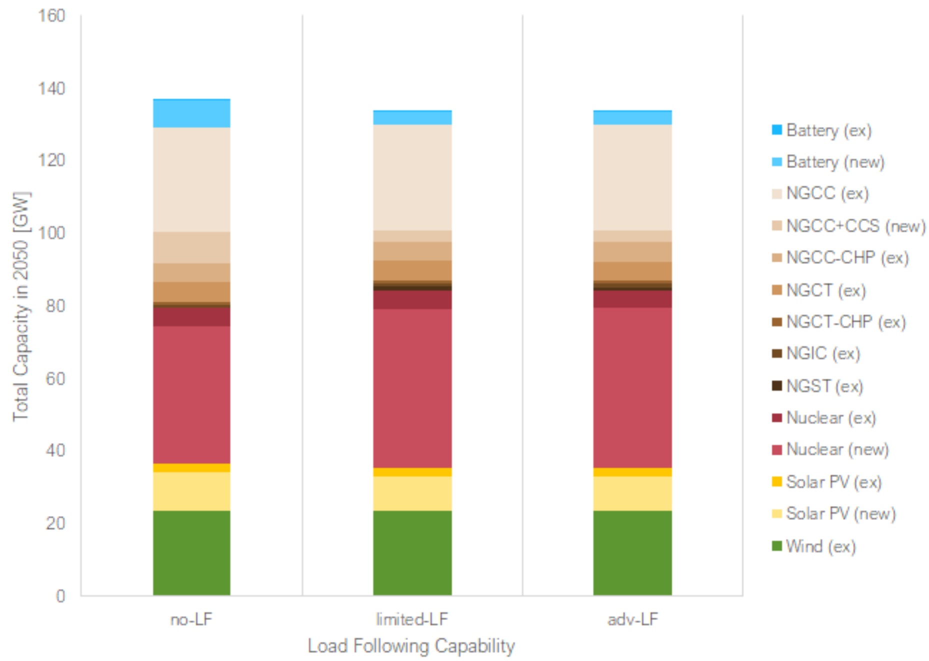


Figure 4-1. Estimated deployment in 2050 of nuclear units with different LF capabilities.

4.2 Thermal Energy Storage

New SMR concepts developed by the utility industry, such as the Westinghouse LFR [Westinghouse 2021], USNC Microreactor [USNC 2021], and TerraPower's Natrium [TerraPower 2021], are using TES as part of their design. The technical feasibility of TES systems has been demonstrated at large power plants over the past 100 years (e.g., steam accumulators at the Charlottenburg coal plant (1929); steam, salt, and oil at concentrated solar power plants), so there are no significant technical hurdles to integrating TES at a nuclear power plant. Such a system is described schematically in Figure 4-2. The heat generated by the nuclear island is transferred to a secondary heat-transfer fluid that incorporates one or more insulated tanks (thermal reservoirs). The secondary system is coupled to a tertiary power conversion loop. In this way, the heat generation rate from the nuclear reactor can remain constant, and the stored heat in the secondary loop can be transferred to the power conversion loop at a variable rate. Various TES technologies are being considered for integration with nuclear power plants; plants described by Forsberg et al. [2017, 2019] and Landsberger et al. [2019], and TerraPower's Natrium [TerraPower 2021], are using TES as part of their design.

In a competitive wholesale market where a generator seeks to maximize profit, energy storage creates opportunities for generation **time shifting**. For a nuclear power plant with energy storage, the reactor power output could remain constant, while the power conversion cycle could withhold energy when prices are lower, and then release it when prices are higher and provide a higher peak power than the reactor core is designed for in baseload mode. This type of operation could increase plant revenues compared to a continuous operating mode, both by avoiding low-prices on the grid and by selling excess electricity during high-price events.

However, the revenue streams will be highly variable, and it is uncertain whether the additional costs of an energy storage system would be covered by the additional revenues. The objective of this section to help determine whether nuclear units associated with TES would be competitively deployed under different deep-decarbonization scenarios.

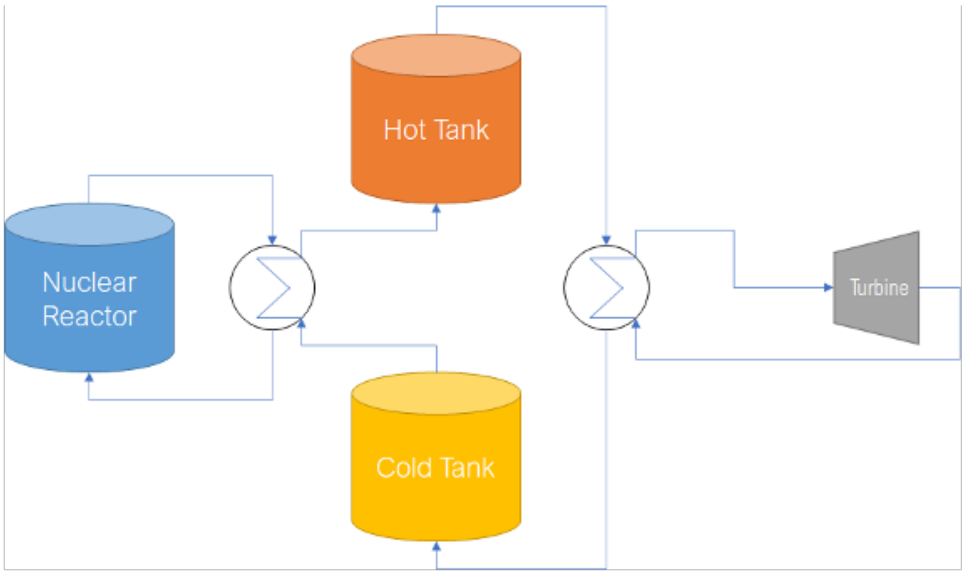


Figure 4-2. Schematic description of nuclear reactor coupled with TES system.

4.2.1 Economics model for thermal energy storage

TES is modeled in A-LEAF as an add-on cost to the nuclear power plant, since additional capital and O&M costs are expected, even for reactor concepts where TES is tightly integrated into the reactor design (as considered in Natrium). The additional costs are associated with purchase and installation of new equipment, modification or augmentation of equipment needed for non-TES installation, and additional maintenance of equipment caused by cyclic loading. The main objective of the market simulations performed with A-LEAF is to assess whether these additional costs are justified by the added benefits provided to the grid.

The list of TES costs associated with a **300-MW nuclear unit** (selected as baseline to be consistent with the size of the reactors that are currently considering TES) is displayed in Table A5-8, and further discussed in **Appendix 5**. When associated with TES, the nuclear unit is considered with baseload operation, while the TES is providing the flexibility required by the grid. Different sizes of TES systems are considered, with added power of 150 MW, 300 MW or 600 MW, and with storage duration of two or four hours (all power [MW] and energy [MWh] units for TES refer to electrical power or energy). Scaling of the OCC is assumed to occur independently on the basis of power-block size and energy storage size. A constant factor of $600/kW was used for TES power-block scaling, and a value of $60/MWh was used for energy. For this study, it is assumed that a TES system does not increase the O&M costs of a nuclear plant, but instead has its own attributable O&M costs of $0.0545/kW/MWh, which were derived from the work of Herrmann et al. [2004]. Understandably, such costing estimates obtained from the literature do not account for potential future cost reductions through technology improvements, and for cost savings that could be obtained through tight integration with the nuclear system.

4.2.2 Assessment of nuclear deployment perspectives for nuclear associated with thermal energy storage

Thermal energy storage deployment in baseline no-learning scenario with high-nuclear fraction (Figure 4-3)

For TES with a 2-hour storage time, the smallest and cheapest TES (150 MW, 300 MWh) led to the largest installed TES capacity for the system, and by extension the largest number of new nuclear power plants with TES. Larger TES systems were built less often because they were more expensive. The 1,200-MWh system wasn't deployed in this scenario. The cost escalation was driven by both OCC and O&M increases per unit size (kW, MWh). Low-cost TES capacity replaced most new battery capacity, but some batteries were still built because of their extremely fast ramp rates.

For TES with a 4-hour storage time, the smallest and cheapest TES system (150 MW, 600 MWh) was built at several reactors, but fewer than the comparable 2-hour system. The 2,400 MWh system wasn't deployed in this scenario. Compared to the 2-hour storage-time cases with the same power output, fewer 4-hour TES systems were built because they were more expensive.

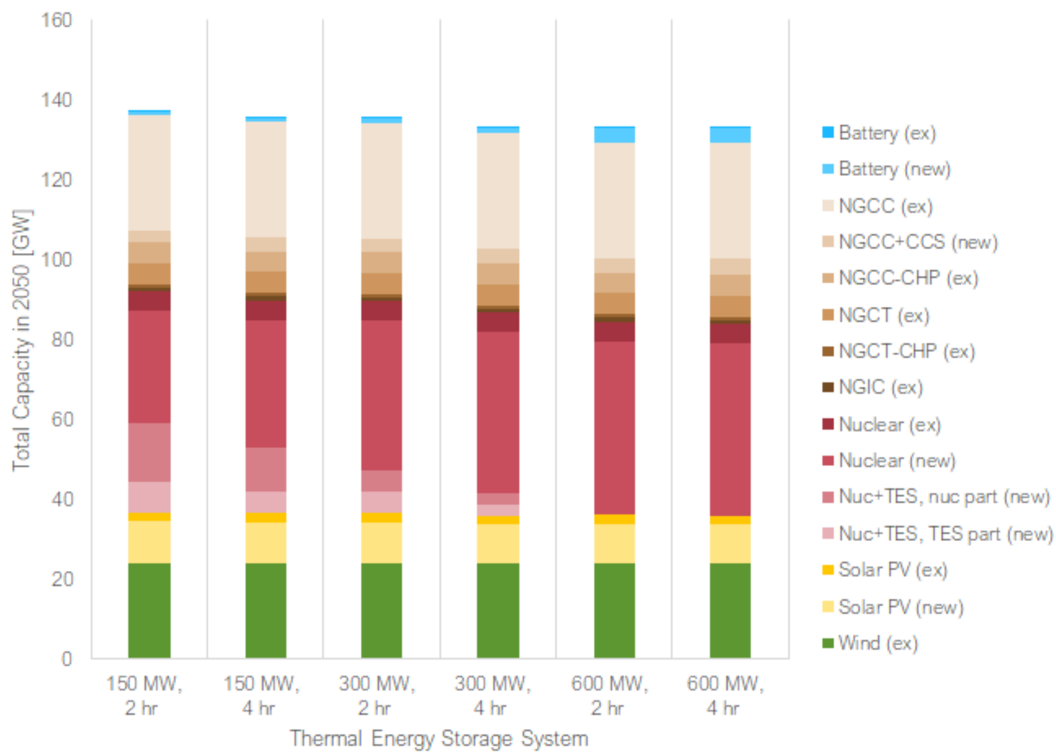


Figure 4-3. Total capacity deployed for different power and storage sizes of TES in Baseline scenario.

Across all TES sizes, the total amount of new nuclear capacity was essentially unchanged in the Baseline scenario. Some of the new nuclear units were associated with TES instead of LF. For a given maximum power output, a nuclear reactor can be smaller if TES is used compared to a LF design. This is because reactor heat production and electricity conversion can be operated more independently. Some of the heat produced by the reactor can be diverted to a heat storage medium (charging) instead of immediately generating electricity. Later, this stored heat can be used to generate electricity, and simultaneously, heat being produced by the reactor is converted to electricity. The nuclear reactor size would be reduced, lowering costs, but these savings would be partially offset by the TES system costs. There might be O&M cost reductions for reactor operations, since the reactor could be operated at steady state most of the time, but O&M costs on the turbogenerator side should be similar to a purely LF plant. It is unclear whether the overall system cost would be lower compared to a LF design. Another advantage is that the generation time-shifting of TES would allow more electricity to be sold at higher prices and less at lower prices. However, the electricity price differences that TES could take advantage of are uncertain, and other energy storage systems will compete for those opportunities, driving prices down.

TES deployment in alternative conservative-learning scenario with high-VRE fraction (Figure 4-4)

Although several gigawatts of TES capacity were built in some scenarios, total generation from the TES systems was very small because of a lack of demand for energy storage generally. In other scenarios, increases in energy storage capacity were accompanied by increases in solar PV capacity. To see if increased PV capacity influenced nuclear TES deployment, the Baseline scenario was modified to use the OCC from the Conservative Learning (Higher Nuc Cost) scenario (see Figure 2-3). A carbon tax of 342 \$/t CO_2, which enables deployment of a few new nuclear units, was implemented, as shown in **Appendix 4**.

Compared to the Baseline scenario, this scenario led to more deployment of batteries, solar PV, and wind, and less deployment of nuclear. In this 2050 scenario, nuclear generation accounted for 23%, while VRE accounted for 59%. No nuclear TES system of any size was built. Although solar PV and wind deployments increased, the cost of batteries declined below that currently considered for TES, giving batteries the energy storage role for the system. No cost reductions for TES via learning were included in this study. Additional details of this scenario are in **Appendix 4**.

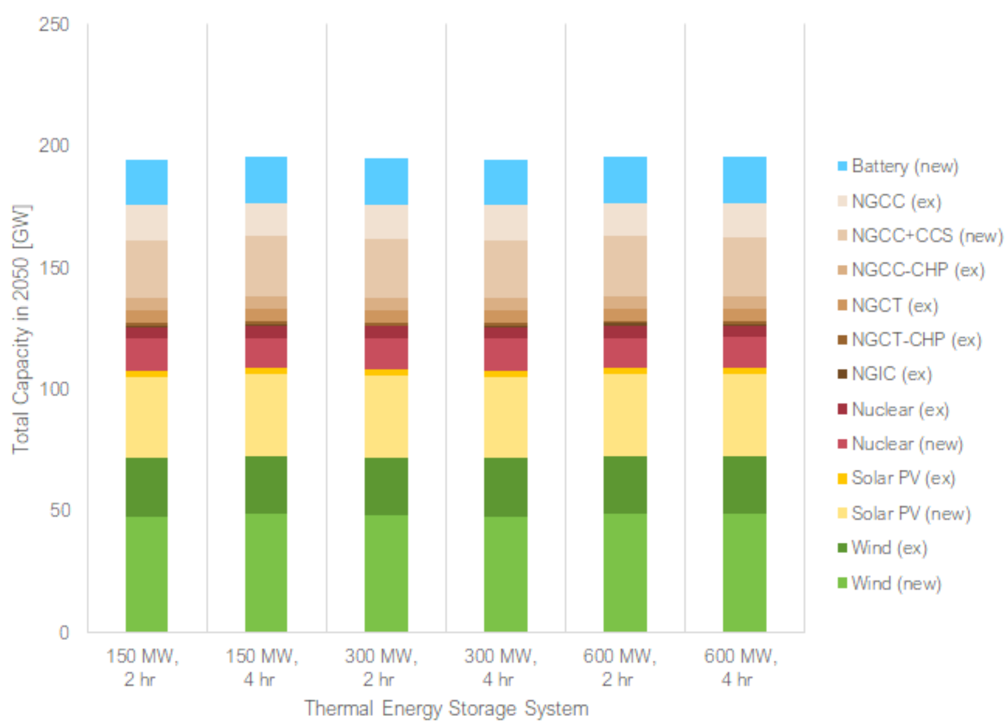


Figure 4-4. Total capacity deployed for different power and storage sizes of TES in high-VRE scenario.

4.3 Observations and conclusions on the impact of reactor flexibility on deployment potential

This study quantified the benefits of flexible operations (LF and TES) on new nuclear power plant deployment in a deep-decarbonization scenario. Nuclear power plants with faster ramp rates and lower minimum stable levels were deployed more than comparable plants that only operated continuously at maximum power.

Adding TES to nuclear power plants did not change the deployed nuclear capacity relative to the Baseline scenario because TES and LF played similar roles in the system. However, lower-cost TES systems were built in some cases and replaced some battery capacity. The lowest-cost TES systems were the smallest in terms of MW and MWh, and were deployed the most. Total generation from TES systems and batteries was low because of small solar PV capacity as a proportion of total system capacity. TES might increase nuclear capacity relative to LF in scenarios with larger solar PV and wind capacity and higher relative battery costs.

These results were sensitive to the relative costs of other generation technologies. When batteries, solar PV, and wind costs were much lower than the Baseline scenario, very little nuclear was built, and no TES was built. If TES is cost-competitive with other bulk/grid-scale energy storage technologies (e.g., pumped hydro, various batteries)—whether integral to the whole plant design (e.g., Natrium) or added to the power block later—then it could be a feasible and attractive alternative to LF nuclear operation.

5. Conclusions and Observations

The current U.S. administration has set ambitious decarbonization goals for the electricity sector and the U.S. economy as a whole. The SA&I Campaign has analyzed the role nuclear energy can play in deep decarbonization of the U.S. electricity grid, and how different attributes of advanced reactor concepts can favor their deployments. This study used detailed electricity market modeling of the Electric Reliability Council of Texas (ERCOT) like grid to model future nuclear reactor deployment. Some general observations, based on findings discussed in Sections 3 and 4 above, are provided regarding carbon-constrained modeling of advanced nuclear energy:

- Previous carbon-constrained energy modeling studies did not include important design aspects of new nuclear reactor and power plant designs, including differing reactor sizes, types, and flexible operations.
- Considering the limited database for future advanced nuclear energy systems, it is important to combine staff knowledgeable in both advanced nuclear energy systems and energy market analysis to effectively explore these impacts.
- The tools and methods used in this analysis can be applied to perform detailed analysis on specific industry concepts if specific costing data and flexible operation capability are made available.

5.1 Summary

Grid market analyses were performed and reported in **Section 2** to determine a baseline deep-decarbonization scenario used in Sections 3 and 4 to analyze how size and flexibility impact the economic competitiveness of nuclear reactors. Using carbon price as a technology-neutral mechanism to meet the electricity decarbonization target, the study found that a carbon price of 100 $/t CO_2 reduced carbon emissions of the electricity power sector by more than 90% in 2050 when compared with the 2019 level. A carbon price of 342 $/t CO_2 brought the CO_2 emissions of the ERCOT grid close to zero in 2050 in both the A-LEAF and MARKAL models, despite using different cost assumptions and modeling approaches.

In the A-LEAF scenarios, new nuclear units were deployed, with cost assumptions based on the SA&I Cost Basis Report (OCC of 4,416 $/kW, 2019 dollars, for Nth Of A Kind or NOAK), in deep-decarbonization scenarios with carbon prices greater than 50 $/t CO_2, except when the scenario also included optimistic battery/PV/wind cost reductions (with costs reduced by 79%/68%/62%, respectively). Under these lowest-cost battery/PV/wind scenarios, only renewables and batteries were deployed. However, the A-LEAF model did not include transmission expansion costs, long-duration energy storage needs, or reliability challenges associated with very high Variable Renewable Energy (VRE) penetrations [Denholm 2021].

The analyses indicated that, from a minimum-system-cost perspective, a large share of nuclear produced the lowest system costs under No Learning or Conservative Learning costing assumptions and a carbon price of 100 $/t or greater. However, other factors not accounted for in the modeling approach, such as public perception, individual state policies mandating specific technologies, deployment feasibility, and siting availability, will likely reduce the share of nuclear energy that can be deployed. Smaller shares of generation from nuclear were seen with lower carbon prices and when solar PV, wind, and battery costs were significantly lower than nuclear costs.

The U.S. nuclear industry is aggressively developing small and micro nuclear reactors, and those developments are partly supported by the U.S. government through various funding mechanisms such as the Advanced Reactor Demonstration Program (ARDP). When compared to large GW-scale reactors, SMRs promise benefits to a utility in terms of risk reduction, considering not only reduced capital at risk, but also the reductions in risk related to the construction project and future revenues, as discussed in **Section 3**. SMRs also promise benefits in terms of siting—for instance, because of their potential to re-use sites of retired coal plants—and of supporting small electricity grids. Another significant benefit expected for SMRs that use modular and staggered construction will be in terms of reduced construction time, reduced cost throughout the project, and improved cash flow as constructed units start generating revenues while other units are being built.

However, to achieve successful deployment in decarbonization scenarios, SMRs must be economically competitive, which means that their combined capital and operating costs should be at least as attractive as those from other zero-carbon generation technologies. To account for uncertainties in cost reductions achievable with different sizes of reactors, scaling factors were used to quantify the cost of reactors based on size. This study confirms that even if the absolute capital cost is reduced in smaller reactors, they will compete with larger nuclear units only if their CAPital EXpenditure (CAPEX) is comparable or lower, and without significant increase in O&M and fuel costs. The following minimum conditions were needed in the assessed ERCOT-like market region for potential economic deployment under the Baseline scenario:

- Reactor systems with CAPEX greater than 7,000 $/kW would not be deployed under even the most favorable assumptions. SMR vendors could counter the diseconomies of scale (smaller is more expensive per kW) and keep CAPEX low through design simplification, modularization, factory build, faster construction time, better financing terms, etc.
- Systems with O&M costs ($/kW·yr and $/MWh) and fuel costs ($/MMBtu) increased by factors of 100% and 35%, respectively, were not deployed under the most favorable assumptions (even with baseline nuclear CAPEX). For example, fixed O&M costs ($/kW·yr) for smaller reactors could increase if staffing requirements were not reduced compared to larger reactors. Solutions considered by SMR vendors include co-siting several modules, autonomous and/or remote-control operations, etc.

All nuclear power plants are intrinsically capable of load following (LF) operation, but some SMRs and MRs are being designed with faster LF capabilities or with Thermal Energy Storage (TES) to better support micro-grids or future grids with high levels of VRE. The results from the analysis summarized in **Section 4** showed that even lower levels of flexibility (in terms of slower ramp rate and lower operating level) in a few nuclear units are important to compensate for fluctuation in demand and VRE generation on the grid as flexible fossil units are retired to reduce carbon emissions.

The number of nuclear units needed for load following or associated with TES depends on the system need for fast ramping, bulk energy storage, and the relative costs of storage technologies. This means that reactor flexibility becomes more important under higher-VRE-deployment scenarios. Nuclear associated with low-cost TES was favored instead of LF-capable nuclear units. The incentive for a utility to favor TES technology would be to sell more electricity during higher-price hours without requiring larger reactors (only a larger turbine/generator). However, battery-storage vendors and advocates are promoting steep cost reductions through learning, and these would compete directly with TES. For nuclear with TES to be competitive, the additional costs of the TES components must be counterbalanced by the cost reductions from reduced reactor size, maintenance and cost reductions from fewer reactor power changes, and the expected revenue increase from selling more electricity at higher prices.

5.2 Gaps and future work

Various opportunities to extend the current analysis are discussed in this section:

- More research is needed on the scaling factors and learning rates to assess how reactor size impacts different costing components (CAPEX, fuel and O&M costs) through design simplifications, factory manufacturing, accelerated learning, etc. Such work would require development of dynamic costing models that are integrated into system dynamic models to account for the significant effect of time. This requirement applies most heavily to SMRs and MRs, but is also important for accounting for the cost of large reactors deployed in significant numbers. Afterward, specific cost parameters could be obtained on different specific reactor technologies that would be representative of various sizes. These cost parameters should also account for the time-dependent learning and for other costs (e.g., shared resources such as centralized operations and maintenance) that depend on the entire nuclear energy system.
- The market-based conclusions in this study are for an ERCOT-like market, and the results could differ for other U.S. regions. In particular, ERCOT does not have large hydropower capacity, and load, weather, and climate vary substantially across the U.S. Future work should extend these analyses to other U.S. markets and regions to verify their generality. This study focused on nuclear deployment for large electricity grid applications in deep-decarbonization scenarios. However, nuclear deployment can play an important role in decarbonizing other sectors of the economy beyond the electrical grid. The impact of electric-vehicle deployment on the electrical grid and on the decarbonization of the transportation sector is being researched in a companion SA&I study (Kim et al. 2021b). Other non-electricity applications (such as hybrid energy systems) are actively being researched under the DOE-NE Integrated Energy Systems Campaign for decarbonizing other parts of the economy. Future work should consider including such systems in this type of long-term market projection.
- The A-LEAF software modeling tools used in this study employ *global cost-of-service optimization methods*, a widely-used approach to electricity market modeling which nevertheless has limitations. *Global* means that the system considers all generation assets to belong to a single, monolithic “superutility.” This actor is effectively as diversified as possible, and has the maximum degree of financial resources to bring to bear when making decisions, while having perfect global information and lacking any local incentives (i.e., profit motive) that compete with the “best interest” of the system as a whole. *Cost-of-service optimization* means that the code finds the lowest-cost-of-service solution for providing power to the modeled system, but it ignores factors that are highly relevant in the real world, e.g., whether individual units are profitable and whether utilities in the system can afford to build or retire units in the “optimal” way. Work is under way to develop a companion module for A-LEAF which will provide agent based capacity expansion (ABCE) capabilities [Biegel et al. 2021]. The ABCE tool models the decision-making processes of various independently acting utilities that coexist in a shared market system. Employing the ABCE tool for modeling CE will augment the considerable strengths of the A-LEAF code, while accounting for the market factors mentioned above. Such an approach can be used to model the trade-offs for a utility between a lower-risk small reactor and a potentially more cost-efficient larger reactor (as discussed in Section 3.1.2). While the current A-LEAF model focuses on long-term projections assuming NOAK cost estimates for different energy technologies, the new ABCE model will also enable modeling the transition from the current grid mix.

- Reliability assessment of the optimum portfolio mix is a critical aspect of grid modeling, and an active area of research, especially with respect to deep-decarbonization grids. Portfolios optimized with A-LEAF in this report meet current "reliability" metrics by ensuring sufficient ancillary services to the grid throughout the year (assuming current ERCOT reserve requirements). The study also looked at the variation of the baseline results based on a different year of data (2011 as an alternative to 2019, when severe hot- and cold-weather events occurred in Texas), as discussed in **Appendix 4**. Future work could include consideration of reliability and adequacy metrics that would assess the capability of an electrical system made of large shares of nuclear or VRE to support large weather or failure events such as the one observed in the ERCOT region in 2021 [Mann et al. 2021]. Such future work would be important for properly valuing the benefits brought about by nuclear energy in a future deep-decarbonization market analysis.
- The current capacity-expansion simulations with A-LEAF can be improved by including transmission modeling and long-term storage modeling to improve modeling of a high-VRE-deployment scenarios. The absence of transmission modeling will underestimate total system costs that will be associated with some of the optimum grid portfolios identified (especially those with lots of VRE or new large nuclear units). New modeling of transmission in A-LEAF will enable inclusion of transmission cost in future analyses for fair comparison of the transition cost of different decarbonization strategies. The current storage model in A-LEAF is well suited to modeling a few hours of storage; it can consider storing excess electricity from solar panels in the middle of the day to balance peak generation in late afternoon. However, the A-LEAF code is currently unable to model long-term storage that could theoretically be considered to balance seasonal mismatch associated with demand and variable renewable generation. This model improvement will be critical to more accurately model scenarios that consider very high levels of VRE penetration.

To conclude, the electricity grid market modeling studies completed in FY 2021 show that SMR deployment will be economically feasible under certain conditions with a carbon tax policy, moderate cost reductions of battery and VRE, and the assumption that the capital, O&M, and fuel costs of these nuclear units are below a certain threshold. Small reactors and MRs will provide attractive options if they are designed under these cost constraints, and higher levels of operating flexibility could also provide an important deployment incentive under deep-decarbonization scenarios.

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1. APPENDIX 1: A-LEAF Methods Description

The Argonne Low-carbon Energy Analysis Framework is an electricity market model that can simulate unit commitment and economic dispatch (UC/ED) and find least-cost solutions to future capacity expansion (CE) problems. Its development is being supported under various DOE-EERE and DOE-NE programs. In FY 2021, A-LEAF was rewritten in programming languages Julia [Bezanson et al. 2017] and JuMP [Dunning et al. 2017] to aid in programming flexibility and computational scalability.

A-LEAF is structured for a single region without transmission (i.e., copper plate, no power flow model). An existing fleet of generators is defined along with a set of desired conditions for a single future year. These include time series for load, solar PV generation, wind generation, frequency regulation requirement, spinning reserve requirement, and non-spinning reserve requirement; physical and cost parameters for generators (see **Appendix 2**); and fuel prices. Curtailment of solar PV and wind can be allowed. Generators can be represented as individual units or aggregated by technology.

The default A-LEAF objective function seeks to minimize the total system cost for the defined future year's conditions, subject to constraints. System costs included variable costs (including fuel and O&M), fixed costs (including no-load, O&M startup, and shutdown), new investment costs, retirement costs, reserves costs, and emissions costs. Credits can also be defined for capacity, production [$/MWh], and investment [$/kW].

The default temporal horizon for a simulation is one user-selected future year. Individual days within that future year are optimized simultaneously but independently of one another. The number of days can be reduced, with a minimal impact on results, using a scenario reduction algorithm. The number of time periods per day is 24 by default (hourly time resolution), but it can be increased to 288 (five-minute time resolution). For this report, 48 representative days with hourly resolution was found to produce very similar results to simulations with more representative days. Five-minute resolution simulations were not used in this work.

Unserved energy demand was allowed as a variable, and a value of lost load ($9,000/MWh) was multiplied by the total and added to the objective function, which corresponds to the current system-wide offer cap in ERCOT Variables for spinning and non-spinning reserve scarcity were also included with scarcity prices $1,100/MWh and $100/MWh, respectively. Simulation constraints included binary unit commitment, system balance, energy storage balance, ramping, and a planning reserve margin of 13.75%. Various other policies can be modeled with A-LEAF, such as carbon tax, capacity payments, investment tax credits, renewable portfolio standard, etc.

To find feasible and near-optimal solutions to the least-system-cost problem, A-LEAF creates a mixed integer linear program (MIP) via JuMP. JuMP sends the MIP to an optimization solver. A-LEAF has been tested with open-source solvers Cbc and GLPK as well as commercial solvers Gurobi and CPLEX. Gurobi was used for this report. A MIP gap (the ratio of the best known solution to the best dual bound solution during search tree exploration) of 0.0003 was used. Unlike a linear program, it is often computationally infeasible to prove optimality for a best-known MIP solution. Therefore, using a very small MIP gap finds the least-suboptimal feasible solution for a given computational time.

2. APPENDIX 2: Electric Reliability Council of Texas (ERCOT) System Model

The Electric Reliability Council of Texas (ERCOT) wholesale electricity market was selected for this study based on its diverse mix of generator types, its physical scope, and its publicly available operating data. 2019 was selected as the base year for the generation capacity mix, load data [ERCOT 2020a], solar PV generation data [EIA 2021b], and wind generation data [EIA 2021c]. The load, solar PV generation, and wind generation time series were normalized so they could be easily scaled within the simulations. All costs and prices were inflated or deflated to 2019 U.S. dollars.

For 2050 load and demand, the 2019 base year data was scaled up. The ERCOT load time series data for 2019 had a total demand of 384 TWh and a peak load of 74,666 MW. The MARKAL results for ERCOT total demand in 2050 were 537 TWh. The ERCOT 2019 load time series was scaled up to 537 TWh of total demand by adding a constant 17,480 MWh to each hourly data point. The new scaled-up peak load was 92,146 MW.

Prices for coal and natural gas in the Baseline scenario were 1.76 and 3.86 $/MMBtu, respectively, from the Annual Energy Outlook Reference scenario (prices as delivered to the electric power sector). [EIA 2021a] The price for low-enriched uranium fuel (LEU) was 0.50 $/MMBtu after conversion from $/MWh. [OPEN100 N.D.]

The fleet of generators operating in ERCOT by the end of 2019 was grouped into 11 types, with each type representing a typical unit of that technology class by averaging parameters. For example, the Coal unit type used the average heat rate of all coal units. The 11 existing technology types and capacities were batteries (126 MW), coal steam turbines (13,566 MW), natural gas combined cycle (28,991 MW), natural gas combined cycle co-gen/CHP (4,920 MW), natural gas combustion turbines (5,310 MW), natural gas combustion turbines co-gen/CHP (889 MW), natural gas internal combustion engines (880 MW), natural gas steam turbines (11,446 MW), nuclear steam turbines (4,972 MW), solar photovoltaic (PV) (2,268 MW), and wind turbines (23,760 MW). Four minor unit types were excluded: biomass steam turbines (105 MW), DC ties (1,220 MW), hydroelectric turbines (558 MW), and landfill gas internal combustion engines (64 MW). Unit physical parameters included power capacity [MW], energy capacity (batteries only) [MWh], maximum power rating [MW], minimum power rating [MW], heat rate (except batteries, solar PV, and wind) [MMBtu/MWh], round-trip efficiency (batteries only) [%], ramp-up rate [MW/min.], ramp-down rate [MW/min.], maximum frequency regulation reserve allocation [MW], maximum spinning reserve allocation [MW], maximum non-spinning reserve allocation [MW], and CO_2 emissions factor (coal and natural gas only) [kg CO_2/MMBtu]. Unit operating cost parameters included variable O&M cost [$/MWh] and fuel cost [$/MMBtu]. A CO_2 emissions cost was added in scenarios with a CO_2 price [$/t CO_2]: *generation* [MWh] × *heat rate* [MMBtu/MWh] × *CO_2 emissions factor* [(kg CO_2)/MMBtu] × *0.001* [metric ton/kg] × *CO_2 emissions cost* [$/(metric ton of CO_2)]. Unit fixed cost parameters included fixed O&M cost [$/MW·yr], no-load cost [$/hr·MW], startup cost [$/start·MW], and shutdown cost [$/shutdown·MW]. In some scenarios, a capacity credit was assigned based on expected availability at peak load [MW]. Table A2-1, Table A2-2, and Table A2-3 show all parameter values, while Table A2-4 and Table A2-5 show the data sources for all values.

New generator candidates were set up distinctly from existing unit types (i.e., existing unit types could not be expanded). These candidates included batteries, coal steam turbines with 90% CCS, natural gas combined cycle with 90% CCS, natural gas combustion turbines (no CCS), advanced nuclear, solar PV, and wind turbines (land-based only). Although most of the underlying technologies were the same as existing units, the generator candidates used different values for their physical and cost parameters. For 2050 solar PV and wind generation, the 2019 base year normalized time series data were used. New solar PV and wind capacity used the same normalized time series as existing units.

Candidate units were assigned annual investment costs [$/MW·yr] that the model used in expansion calculations. In the Baseline scenario, the annual investment costs were calculated with fixed overnight capital costs (OCC) through 2050 (i.e., no learning-based cost reductions). OCC were escalated via construction finance factors, project finance factors, and capital recovery factors to yield the annualized investment costs.

Unit retirements are based only on economic decisions (i.e., no age-based retirements). The current nuclear reactors in ERCOT (South Texas Project 1 and 2, Comanche Peak 1 and 2) started operation 1988–1993, so they were available in 2050 model, thus assuming 80-year lifetime operating license extensions (NRC subsequent license renewals).

Generation portfolio

Table A2-1. ERCOT generator parameters: capacity and rating.

Technology	Unit Power Capacity [MW]	Unit Storage Capacity [MWh]	Units in 2019 [N/A]	Total Power Capacity in 2019 [MW]	Max Units in 2050 [N/A]	Min Units in 2050 [N/A]	Max Power Rating [%]	Minimum Power Rating [%]
Battery (2019)	9	9	14	126	14	0	100%	0%
Battery (new)	50	200	0	0	10,000	0	100%	0%
Coal (2019)	646	0	21	13,566	21	0	79%	33%
Coal++CCS (new)	650	0	0	0	10,000	0	79%	50%
NGCC (2019)	547	0	53	28,991	53	0	85%	47%
NGCC++CCS (new)	377	0	0	0	10,000	0	85%	50%
NGCC-CHP (2019)	246	0	20	4,920	20	20	85%	45%
NGCT (2019)	59	0	90	5,310	90	0	85%	45%
NGCT (new)	237	0	0	0	10,000	0	85%	45%
NGCT-CHP (2019)	127	0	7	889	7	7	85%	59%
NGIC (2019)	44	0	20	880	20	0	90%	39%
NGST (2019)	273	0	42	11,466	42	0	75%	21%
Nuclear (2019)	1,243	0	4	4,972	4	0	91%	91%
Nuclear (new)	1,000	0	0	0	10,000	0	91%	20%

Solar PV (2019)	36	0	63	2,268	63	0	100%	0%
Solar PV (new)	150	0	0	0	10,000	0	100%	0%
Wind (2019)	110	0	216	23,760	216	0	100%	0%
Wind (new)	200	0	0	0	10,000	0	100%	0%

Table A2-2. ERCOT generator parameters: costs and finance.

Technology	Overnight Capital Cost [$/kW]	Construction Finance Factor [N/A]	CapEx [$/kW]	Fixed Charge Rate [%]	Annualized Investment Cost [$/MW]	Fixed O&M Cost [$/MW]	Variable O&M Cost [$/MWh]	Fuel Cost [$/MMBtu]	No-Load Heat [MMBtu/hr-MW]	Startup Cost [$/MW]	Shutdown Cost [$/MW]
Battery (2019)	N/A	N/A	N/A	N/A	N/A	41,565	0	0	0	0	0
Battery (new)	N/A	N/A	1,663	5.00%	83,129	41,565	0	0	0	0	0
Coal (2019)	N/A	N/A	N/A	N/A	N/A	28,983	5.68	1.76	0.579	31.28	31.28
Coal+CCS (new)	5,876	1.152	6,769	5.93%	401,275	59,540	10.98	1.76	0.579	31.28	31.28
NGCC (2019)	N/A	N/A	N/A	N/A	N/A	13,639	3.30	3.86	0.230	37.75	37.75
NGCC+CCS (new)	2,481	1.042	2,585	5.55%	143,479	27,600	5.84	3.86	0.230	37.75	37.75
NGCC-CHP (2019)	N/A	N/A	N/A	N/A	N/A	13,639	3.30	3.86	0.230	37.75	37.75
NGCT (2019)	N/A	N/A	N/A	N/A	N/A	5,683	4.55	3.86	0.248	37.75	37.75
NGCT (new)	713	1.042	743	5.55%	41,234	7,000	4.50	3.86	0.248	37.75	37.75

Technology	Overnight Capital Cost [$/kW]	Construction Finance Factor [N/A]	CapEx [$/kW]	Fixed Charge Rate [%]	Annualized Investment Cost [$/MW]	Fixed O&M Cost [$/MW]	Variable O&M Cost [$/MWh]	Fuel Cost [$/MMBtu]	No-Load Heat [MMBtu/hr-MW]	Startup Cost [$/MW]	Shutdown Cost [$/MW]
NGCT-CHP (2019)	N/A	N/A	N/A	N/A	N/A	5,683	4.55	3.86	0.248	37.75	37.75
NGIC (2019)	N/A	N/A	N/A	N/A	N/A	13,071	3.98	3.86	0.073	21.57	21.57
NGST (2019)	N/A	N/A	N/A	N/A	N/A	15,050	9.09	3.86	0.500	51.77	51.77
Nuclear (2019)	N/A	N/A	N/A	N/A	N/A	82,970	4.55	0.5	0.579	107.86	107.86
Nuclear (new)	4,416	1.130	4,989	5.20%	259,428	76,139	1.88	0.49	0.579	107.86	107.86
Solar PV (2019)	N/A	N/A	N/A	N/A	N/A	19,100	0	0	0	0	0
Solar PV (new)	1,594	1.022	1,629	4.46%	72,659	19,100	0	0	0	0	0
Wind (2019)	N/A	N/A	N/A	N/A	N/A	33,245	0	0	0	0	0
Wind (new)	1,908	1.044	1,992	4.90%	97,645	43,993	0	0	0	0	0

Table A2-3. ERCOT generator parameters: physical operations.

Technology	Heat Rate [MMBtu/MWh]	Storage Round-Trip Efficiency [%]	Ramp Up Rate [%/min]	Ramp Down Rate [%/min]	Max Regulation Reserve [%]	Max Spinning Reserve [%]	Max Non-Spinning Reserve [%]	Power Capacity Credit [%]	CO_2 Emissions Factor [kg CO_2/MMBtu]
Battery (2019)	3.412	85%	100.0%	100.0%	100.00%	20%	100%	0%	0

Technology	Heat Rate [MMBtu/MWh]	Storage Round-Trip Efficiency [%]	Ramp Up Rate [%/min]	Ramp Down Rate [%/min]	Max Regulation Reserve [%]	Max Spinning Reserve [%]	Max Non-Spinning Reserve [%]	Power Capacity Credit [%]	CO_2 Emissions Factor [kg CO_2/MMBtu]
Battery (new)	3.412	85%	100.0%	100.0%	100.00%	20%	100%	0%	0
Coal (2019)	10.758	N/A	0.7%	0.7%	0.06%	7%	21%	79%	97.10
Coal++CCS (new)	12.507	N/A	6.0%	6.0%	0.50%	20%	100%	79%	9.57
NGCC (2019)	8.243	N/A	0.8%	0.8%	0.07%	8%	24%	85%	53.46
NGCC++ CCS (new)	7.124	N/A	11.0%	11.0%	0.92%	20%	100%	85%	5.32
NGCC-CHP (2019)	6.066	N/A	0.8%	0.8%	0.07%	8%	24%	85%	53.46
NGCT (2019)	12.266	N/A	8.0%	8.0%	0.67%	20%	100%	85%	53.46
NGCT (new)	9.905	N/A	14.0%	14.0%	1.17%	20%	100%	85%	53.46
NGCT-CHP (2019)	9.592	N/A	8.0%	8.0%	0.67%	20%	100%	85%	53.46
NGIC (2019)	9.259	N/A	100.0%	100.0%	8.33%	20%	100%	90%	53.46

Technology	Heat Rate [MMBtu/MWh]	Storage Round-Trip Efficiency [%]	Ramp Up Rate [%/min]	Ramp Down Rate [%/min]	Max Regulation Reserve [%]	Max Spinning Reserve [%]	Max Non-Spinning Reserve [%]	Power Capacity Credit [%]	CO_2 Emissions Factor [kg CO_2/MMBtu]
NGST (2019)	11.539	N/A	1.0%	1.0%	0.08%	10%	30%	75%	53.46
Nuclear (2019)	10.442	N/A	0.00%	0.00%	0.00%	0%	0%	91%	0
Nuclear (new)	10.608	N/A	5.0%	5.0%	0.42%	20%	100%	91%	0
Solar PV (2019)	3.412	N/A	100.0%	100.0%	0.00%	0%	0%	76%	0
Solar PV (new)	3.412	N/A	100.0%	100.0%	0.00%	0%	0%	76%	0
Wind (2019)	3.412	N/A	100.0%	100.0%	0.00%	0%	0%	25%	0
Wind (new)	3.412	N/A	100.0%	100.0%	0.00%	0%	0%	25%	0

Table A2-4. Data sources for units existing in 2019.

Variable	Description	Units	Sources	Comments
	Unit aggregation	int	Power only: [ERCOT 2019a] CHP/Private Use Network: [USEPA 2020]	Unit counts
CAP	Unit capacity	MW	Power only, except CC: [ERCOT 2019a] Power only, CC only: [EIA 2020b] CHP/Private Use Network: [USEPA 2020]	Unit type capacity [MW] = total summer capacity of type/# of units

				CHP/private use network units used the units at or above the 5th percentile (i.e., top 95%) of summer capacity derated by 2019 capacity factor (cutoff was 100 MW) Each CC unit capacity was sum of all component (CA, CT) capacities (used EIA 860, Sch 3, Unit Code)
EXUNITS	Existing units	int	Power only: [ERCOT 2019a] CHP/Private Use Network: [USEPA 2020]	
MAXUNITS	Maximum units	int	N/A	Equal to EXUNITS
MINUNITS	Minimum units	int	N/A	Zero except CHP/private use network which were not allowed to retire
PMAX	Maximum power per CAP	%	[NERC 2020]	Used equivalent availability factor (EAF) to include deratings Assumed 100% for wind and solar; studies suggest wind >95%, solar >98%
PMIN	Minimum power per CAP	%	[EIA 2020b]	Average by technology, units had equal weight
INVC	Annual investment cost	$/MW-yr	N/A	Not used for existing units Separate unit types were used for new candidates
FOM	Fixed O&M cost	$/MW-yr	All except Battery and PV: [ERCOT 2013] Battery and PV: [NREL 2020]	
VOM	Variable O&M cost	$/MWh	All except Battery and PV: [ERCOT 2013] Battery and PV: [NREL 2020]	
FC	Fuel cost	$/MMBtu	Coal and natural gas: [EIA 2021a] Nuclear: [OPEN100 N.D., Allen et al. 1986]	Annual Energy Outlook fuel cost scenarios were used for different scenarios in this study: Reference, Low Oil & Gas Supply, High Oil & Gas

				Supply. Reference scenario prices shown in Table A2-2. Prices used were as delivered to the electric power sector. Nuclear fuel cost was converted from $/MWh to $/MMBtu using the heat rate.
NLC	No-load cost	$/hr-MW	[USEPA 2021b]	Average by technology. No-load heat [MMBtu/hr-MW] was estimated by taking the average heat input [MMBtu] for hours when a unit was operating but whose gross load [MW] was zero, then dividing by capacity [MW]. No-load heat for nuclear was assumed to be equal to coal. NLC [$/hr-MW] = no-load heat [MMBtu/hr-MW] × FC [$/MMBtu]
SUC	Startup cost	$/MW-start	[Mann et al. 2017]	
SDC	Shutdown cost	$/MW-stop	[Mann et al. 2017]	Assume equal to startup cost.
HR	Heat rate	Btu/kWh	All except nuclear: [USEPA 2020] Nuclear: [EIA 2020c]	Units listed as OP (operational) and SB (standby) only.
RUL	Ramp up limit	%/min.	Battery: [Mongird et al. 2019] Coal, NGCC, NGCC-CHP, NGST: [USEPA 2021b] NGCT, NGCT-CHP, NGIC: [IRENA 2019] Nuclear: [USNRC 2020], [EIA 2021d]	Unit types with ramp rates less than 100%/hr (Coal, NGCC, NGCC-CHP, NGST, Nuclear) had ramp rates estimated from available hourly operating data. Nuclear ramp rate was estimated from hourly generation data by fuel type and from unit availability. Unit types with ramp rates faster than 100%/hr (Battery, NGCT, NGCT-CHP, NGIC) used ramp rate estimates from literature sources. This was necessary to improve the accuracy of reserves calculations. Solar PV and Wind ramp rates were inherent to their input time series data and were not directly specified.
RDL	Ramp down limit	%/min.	Battery: [Mongird et al. 2019]	Assume equal to ramp up limit

			Coal, NGCC, NGCC-CHP, NGST: [USEPA 2021b] NGCT, NGCT-CHP, NGIC: [IRENA 2019] Nuclear: [USNRC 2020], [EIA 2021d]	
MAXR	Max freq reg per CAP	%	[ERCOT 2019b, Section 6]	Calculated from the ramping response within five seconds: (%/sec) × 5 sec. ERCOT does not explicitly define a response time for their RegUp and RegDown services, so five seconds was assumed, more akin to fast frequency response.
MAXSR	Max spin res per CAP	%	[ERCOT 2019b, Section 6]	Calculated from the ramping response within 10 minutes: (%/min) × 10 min.
MAXNSR	Max non-spin per CAP	%	[ERCOT 2019b, Section 6]	Calculated from the ramping response within 30 minutes: (%/min) × 30 min.
CAPCRED	Capacity credit	%	[ERCOT 2019a]	Sensitivity study only. Equal to PMAX except Battery, Wind and Solar PV.
EMSFAC	Emissions factor	kg/MMBtu	[USEPA 2020]	CO_2 emissions for coal and natural gas only. For natural gas, the two most-reported values were averaged (116.89 and 118.86 lbs/MMBtu) Subbituminous and lignite coal values are capacity-weighted averages, excluding W.A. Parish (dual fuel NG and SUB).
STOCAP	Energy storage cap	MWh	[EIA 2020b]	Battery only.
BATEFF	Energy storage eff	%	[NREL 2020]	Battery only.

Table A2-5. Data sources for new candidate units.

Variable	Description	Units	Sources	Comments
	Unit aggregation	int	N/A	Unit counts
CAP	Unit capacity	MW	[EIA 2020a]	
EXUNITS	Existing units	int	N/A	
MAXUNITS	Maximum units	int	N/A	Set to 1,000 in Baseline
MINUNITS	Minimum units	int	N/A	Set to 0 in Baseline
PMAX	Maximum power per CAP	%	[NERC 2020]	Same as corresponding existing units
PMIN	Minimum power per CAP	%	All except nuclear: [NREL 2020] Nuclear: [OECD/NEA 2011]	
INVC	Annual investment cost	\$/MW-yr	OCC for Solar PV, Wind: [NREL 2020] OCC for Coal, NGCC+CCS, NGCT: [EIA 2020a] OCC for Nuclear: [Dixon et al. 2017] Construction Finance Factor: [NREL 2020] CapEx for Battery (OCC not available): [NREL 2020] Fixed Charge Rate: [NREL 2020]	Calculation method adapted from [NREL 2020] INVC [\$/MW-yr] = OCC [\$/kW] × Construction Finance Factor × Fixed Charge Rate × 1,000 [kW/MW], or INVC [\$/MW-yr] = CapEx [\$/kW] × Fixed Charge Rate × 1,000 [kW/MW]
FOM	Fixed O&M cost	\$/MW-yr	Battery, Solar PV, Wind: [NREL 2020] Coal, NGCC+CCS, NGCT: [EIA 2020a] Nuclear: [Dixon et al. 2017]	
VOM	Variable O&M cost	\$/MWh	Battery, Solar PV, Wind: [NREL 2020] Coal, NGCC+CCS, NGCT: [EIA 2020a] Nuclear: [Dixon et al. 2017]	
FC	Fuel cost	\$/MMBtu	Coal and natural gas: [EIA 2021a] Nuclear: [OPEN100 N.D., Allen et al. 1986]	Same as corresponding existing units
NLC	No-load cost	\$/hr-MW	[USEPA 2021b]	Same as corresponding existing units.

SUC	Startup cost	$/MW-start	[Mann et al. 2017]	Same as corresponding existing units
SDC	Shutdown cost	$/MW-stop	[Mann et al. 2017]	Assume equal to startup cost
HR	Heat rate	Btu/kWh	[EIA 2020a]	
RUL	Ramp up limit	%/min.	Battery: [Mongird et al. 2019] Coal, NGCC++CCS, NGCT: [IRENA 2019] Nuclear: [OECD/NEA 2011]	Solar PV and Wind ramp rates were inherent to their input time series data and were not directly specified.
RDL	Ramp down limit	%/min.	Battery: [Mongird et al. 2019] Coal, NGCC+CCS, NGCT: [IRENA 2019] Nuclear: [OECD/NEA 2011]	Assume equal to ramp up limit
MAXR	Max freq reg per CAP	%	[ERCOT 2019b, Section 6]	Calculated from the ramping response within five seconds: (%/sec)*5 sec. ERCOT does not explicitly define a response time for their RegUp and RegDown services, so five seconds was assumed, more akin to fast frequency response.
MAXSR	Max spin res per CAP	%	[ERCOT 2019b, Section 6]	Calculated from the ramping response within 10 minutes: (%/min) × 10 min.
MAXNSR	Max non-spin per CAP	%	[ERCOT 2019b, Section 6]	Calculated from the ramping response within 30 minutes: (%/min) × 30 min.
CAPCRED	Capacity credit	%	[ERCOT 2019a]	Sensitivity study only. Equal to PMAX except Battery, Wind and Solar PV.
EMSFAC	Emissions factor	kg/MMBtu	[NREL 2020]	CO_2 emissions for coal and natural gas only. Note reduction for Coal+CCS, NGCC+CCS.
STOCAP	Energy storage cap	MWh	[EIA 2020a]	Battery only.
BATEFF	Energy storage eff	%	[NREL 2020]	Battery only.

3. APPENDIX 3: Detailed MARKAL Model Description and Results

Introduction to MARKAL

The MARKet ALlocation (MARKAL) model is a data-driven, bottom-up energy systems economic optimization model. MARKAL was initially developed in the 1970s at BNL, and later adopted by the International Energy Agency (IEA). The IEA created the Energy Technology and Systems Analysis Program (ETSAP), a group of modelers and developers that meets twice a year to share knowledge, discuss model developments, extensions, and applications. The members of ETSAP ("contracting parties") can be governments, or governmental or private institutions. Currently, IEA-ETSAP has as contracting parties 18 countries, the European Commission, the ENEL Foundation and GE Global Research. The IEA-ETSAP community leads a major initiative, with the help of national teams in nearly 70 countries, for expanding and validating a common, comparable and combinable methodology, mainly based on the MARKAL/TIMES family of models, permitting the compilation of long-term energy scenarios and in-depth national, multi-country, and global energy and environmental analyses.

A MARKAL model provides a framework, based on the Reference Energy System concept (RES, depicted in Figure A3-1), to connect existing and potential energy carriers and conversion technologies from initial resource extraction to ultimate consumption by consumers. The model solution identifies the lowest cost combination of energy resources and technologies that meets energy service demands over the entire modeling time period, subject to specified constraints. Environmental emissions, resource use, capital investments and operating costs of energy technologies are all tracked. In other words, the model determines the market share of each technology, which depends not only on its individual characteristics (technical, economic, and environmental), but also on the availability and cost of the fuels (from the supply side) it uses.

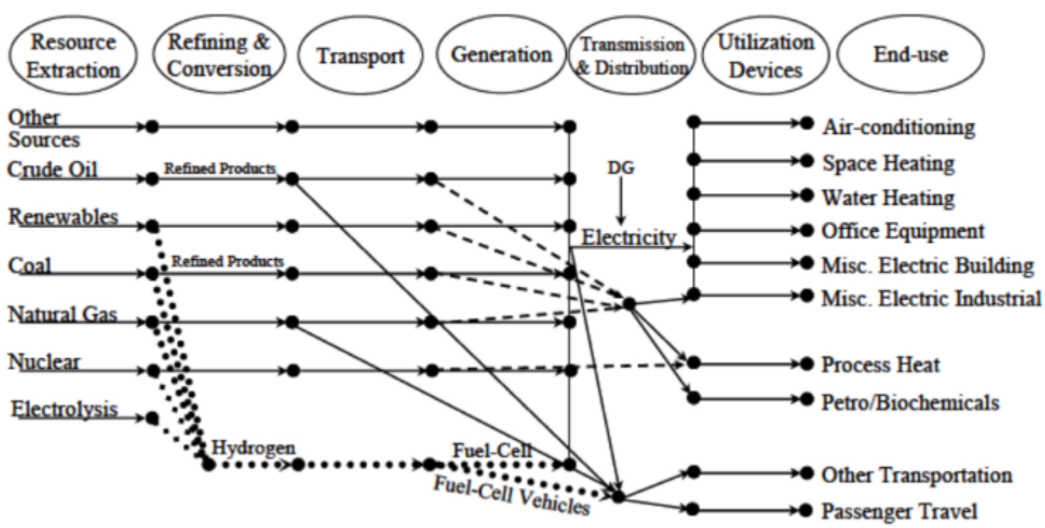


Figure A3-1 Reference energy system (portion).

The structure of MARKAL is ultimately defined by variables and equations determined from the input data provided by the user. The input database consists of both qualitative and quantitative data, broadly divided into the following categories:

- System-wide global parameters which apply to the entire model, e.g.:
    - Monetary unit for all costs (e.g. 2001 U.S. dollars in the U.S. MARKAL model)
    - Time slices that define the subdivision of the year into three seasons (winter, summer and intermediate) and four times of day (day am, day pm, night and peak).
- Time horizon: generally 40-50 years with 5-year time steps, but the user can define any time step size and run simulations of up to 60 time steps. The time step stays constant throughout the simulation. For typical applications, the runs are typically restricted to 40-50 years because the uncertainty in the input data increases for dates further in the future; the main source of data for the U.S. MARKAL model is the Annual Energy Outlook (AEO) published yearly by the Energy Information Administration (EIA), and it only provides projections through 2050. For the applications relevant to the SA&I campaign, however, the time horizon needs to stretch well beyond the anticipated initial deployment of advanced reactor technologies, in the 2040's or 2050's. The effort to update and extend BNL's U.S. energy system models to the 2100' is on-going.
- End-use energy service demands describe the specific energy services to be delivered to consumers (e.g., car, commercial truck, and heavy truck road travel, in million miles traveled per year; residential lighting, in billion lumens per year; industrial process heat in PJ): developed by the user on the basis of economic and demographic projections, for each region in a multi-region model. The load shape of the demand profiles by season/time of day is also specified for end use demands that use electricity.
- Resources are the raw commodities entering or leaving the energy system, including imports, exports, mining, and renewable energy. They are described mainly by supply curves, delivery costs and bounds on supply or growth/decay.
- Technology profiles, for the (successive) intermediate levels of the RES, between resources and end-use demands. Technologies can be process technologies, changing the form or characteristics of the energy carrier (e.g. oil refineries), or demand technologies, which are the devices used to satisfy the energy service demands (e.g. gasoline, hybrid or electric cars, satisfying the demand for passenger road travel in million miles/year). Conversion technologies are used to model electricity production, and are a sub-category of process technologies. The technologies need to be characterized by technical and cost data, such as:
    - Materials in/out (e.g. LWR fuel in, spent nuclear fuel out)
    - Capacity/availability factors
    - Capital cost
    - Fixed operating and maintenance (O&M) cost for the installed capacity
    - Variable O&M
    - Initial capacity installed
    - Bounds on total capacity and/or growth (or decay) rate
    - Year the technology becomes available

    - Discount rate

- Energy carriers are the various forms of energy (natural uranium, enriched uranium, LWR fuel, electricity, …) produced and consumed in the energy system. They link the various levels of the RES.
- Environmental emission factors can be specified for any resource or technology.
- User-defined constraints can be used to limit emissions or fix limits on the use of fuel types or technology groups.

All data above (except the system-wide parameters) are given for each time step. MARKAL computes an intertemporal partial equilibrium on energy markets, which means that the quantities and prices of the various fuels and other commodities are in equilibrium, i.e. their prices and quantities in each time period are such that at those prices the suppliers produce exactly the quantities demanded by the consumers. Further, this equilibrium has the property that the total surplus is maximized over the whole horizon. Investments made at any given period are optimal over the horizon as a whole (this is often referred to as “perfect foresight”).

The MARKAL model’s output includes the least-cost configuration of the energy system, “shadow prices” for energy carriers and environmental emissions, and reduced costs for technologies that are constrained by bounds. At equilibrium, the shadow price of electricity determines the market deployment of a specific generating technology. Its deployment starts at the point at which the marginal cost of electricity generated from that technology equals the shadow price. A new technology with a marginal cost schedule consistently higher than the shadow price will not penetrate the market competitively in MARKAL, unless some forms of economic incentives are provided to that technology in order to remove its cost barriers to enter the market. There are many econometric instruments available to use in MARKAL to reflect various forms of incentives. These include varying the technology-specific discount rate on capital, specifying a direct subsidy per unit of electricity generated, or modeling a disincentive (e.g. tax) on competing technologies.

A Graphical User Interface (GUI) named ANSWER is available for MARKAL. MARKAL-ANSWER makes it possible to easily visualize and navigate through the RES, simplifying the QA process. It is also easy to add energy technology representations at as detailed a level as the analysis requires and the data permit.

Model description

A 10-region MARKAL model of the U.S. Energy system is maintained at BNL. The regions are based on the Census bureau regions, with California broken out of the Pacific region, as can be seen in Figure A3-2, with a detailed list in Table A3-1. It can be seen that Texas is part of the West South Central region, together with Arkansas, Louisiana, and Oklahoma.

In the reference case, GDP is projected to increase at an average annual rate of 2.9 percent between 2015 and 2025, and then slow to an average annual rate of 2.2 percent from 2025 to 2050. The population growth rate is projected to decline from an average annual rate of 1 percent between 2015 and 2025 to 0.5 percent from 2025 to 2050. The reference case macroeconomic assumptions are shown in Table A3-2.

The cost assumptions for all technologies in the electricity sector are detailed in **Appendix 2**. As in previous analyses performed for the SA&I campaign, the existing LWRs are assumed to have their lives extended to 80 years. The FY21 MARKAL reference case and all sensitivities include a significant, increasing carbon tax, as shown in Figure A3-3 [Kim et al. 2021a].

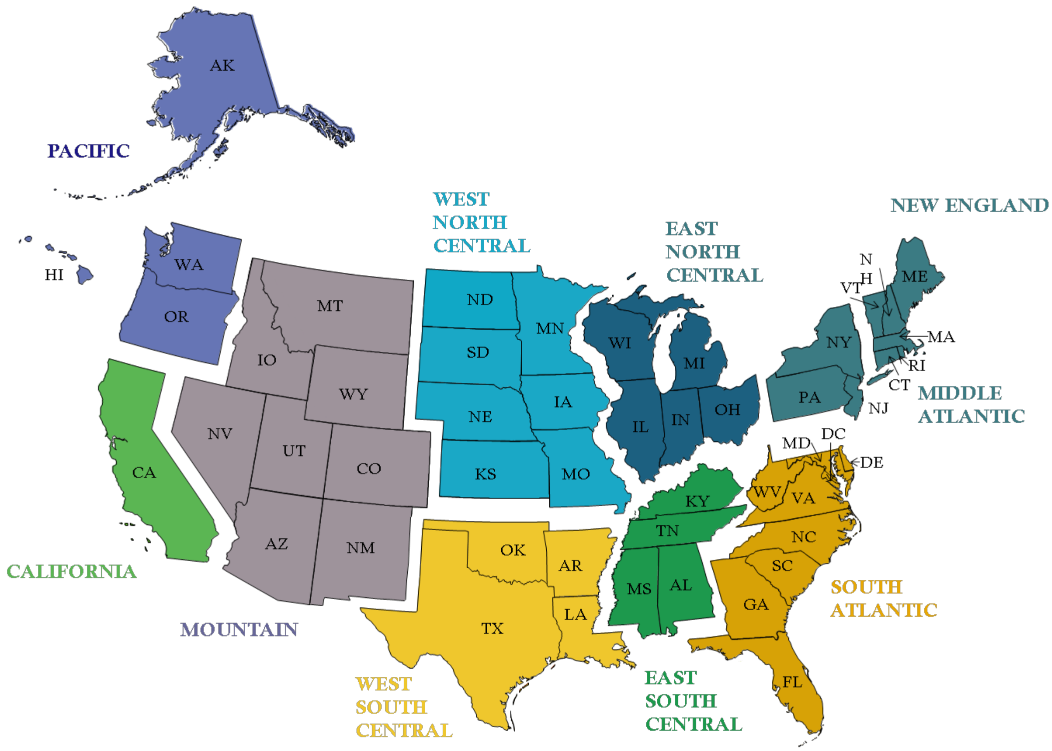


Figure A3-2. Regions in the U.S. multi-region MARKAL model.

Table A3-1. States by Region.

Region	States
New England (NEE)	Connecticut Maine Massachusetts New Hampshire Rhode Island Vermont
Mid-Atlantic (MDA)	New Jersey New York Pennsylvania
East North Central (NEC)	Illinois Indiana Michigan Ohio Wisconsin
West North Central (WNC)	Iowa Kansas Minnesota Missouri Nebraska

	North Dakota South Dakota
South Atlantic (SAT)	Delaware Florida Georgia Maryland North Carolina South Carolina Virginia District of Columbia West Virginia
East South Central (ESC)	Alabama Kentucky Mississippi Tennessee
West South Central (WSC)	Arkansas Louisiana Oklahoma Texas
Mountain (MTN)	Arizona Colorado Idaho Montana Nevada New Mexico Utah Wyoming
Pacific (PAC)	Alaska Hawaii Oregon Washington
California(CAL)	California

Table A3-2. Reference Case Macroeconomic and Demographic Assumptions.

Macroeconomic Assumptions												Annual Growth Rates		
	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'00-'25	25-'50	'00-'50
GDP (Bill. 2001$)	$10,052	$11,483	$13,390	$15,572	$18,047	$20,767	$23,611	$26,519	$29,567	$32,632	$35,940	2.9%	2.2%	2.6%
Population (Million)	275.7	296.8	310.1	323.5	337.0	350.6	362.6	373.3	381.8	387.7	393.1	1.0%	0.5%	0.7%
Total Households (Million)	105.2	115.0	122.0	129.1	135.8	142.5	145.0	149.3	152.7	155.1	157.2	1.2%	0.4%	0.8%
Commercial Floorspace (Bill. sq ft)	68.5	74.7	81.2	88.4	96.2	104.8	112.9	120.8	128.7	136.3	144.1	1.7%	1.3%	1.5%
Industrial Production (2000=100)	100	96	108	120	133	148	167	185	205	225	245	1.6%	2.0%	1.8%
Light Duty Vehicle Miles Traveled (Bill VMT)	2,355	2,667	3,017	3,354	3,680	4,053	4,377	4,680	4,929	5,106	5,272	2.2%	1.1%	1.6%

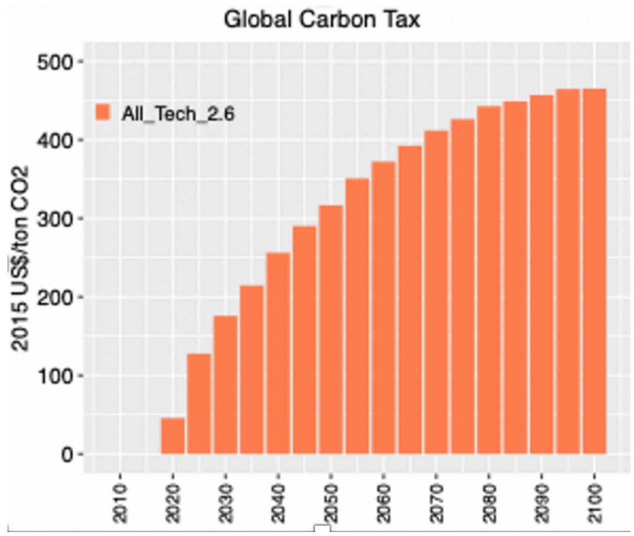


Figure A3-3. Carbon tax profile from GCAM, 2°C maximum temperature increase scenario.

Detailed results

As stated above, the FY21 reference scenario is a carbon tax case without technological learning, i.e. with fixed costs for all technologies. The demand attained in this reference case is used as boundary condition for the ALEAF analysis. Note that the demand computed by MARKAL is a combination of inputs and outputs. This is because the demands input to MARKAL are demands for services (e.g. hours of lighting per year in commercial settings or miles traveled for passenger cars). A MARKAL simulation optimizes the technologies deployed in the system to minimize the total cost, and the resulting technology mix will determine the final electricity demand. This is exemplified when comparing the FY21 reference case, with carbon tax, to a case without carbon tax, as in Figure A3-4. The demand for the carbon tax case is approximately 10% higher than the non-carbon tax case in 2050, due to an effect known as fuel switch, also seen in GCAM [Kim et al., 2021b]. In this case, due to the high carbon tax, deploying/operating gasoline light (passenger) vehicles becomes disadvantageous with respect to electric cars, thus reducing demand for gasoline and increasing demand for electricity. The installed capacities by technology type for the FY21 reference case is shown in Figure A3-5. As expected, fossil technologies (coal and natural gas) are retired and by 2050 are not in the technology mix. Note that Natural Gas with CCS is available to deploy, but is not due to cost. Instead, nuclear is deployed very aggressively, up to almost 90 GW by 2050. By contrast, the additions in solar, wind and storage technologies are relatively modest, since the cost of storage is too high in the no-learning scenario for batteries to be a viable solution to offset the variability of wind and solar. This result is consistent with the Baseline case obtained with A-LEAF under carbon tax scenario with no-learning in Section 2.3. The sensitivity calculation shown in Figure A3-6 assumes technological learning for the cost of batteries similar to the “advanced learning case” shown in Figure 2-3. In this case, there is no new nuclear and instead more than 250 GW of solar and batteries, and about 90 GW of wind, are deployed by 2050. This is also consistent with the sensitivity case obtained with A-LEAF under the carbon-tax scenario with advanced learning (shown in Figure 2-4). Note that natural gas retirements in this case lags behind the FY21 reference case, because, as stated above, MARKAL has perfect foresight and is “waiting” to deploy the replacement capacity when the cost of VRE + storage are cheaper.

The reduction in direct emissions relative to 2015 is shown in Figure A3-7. Both the FY21 reference scenario and the technological learning case result in an approximate 80% reduction in emissions in 2035 and 100% in 2050, consistent with findings from ALEAF and GCAM [Kim et al., 2021b].

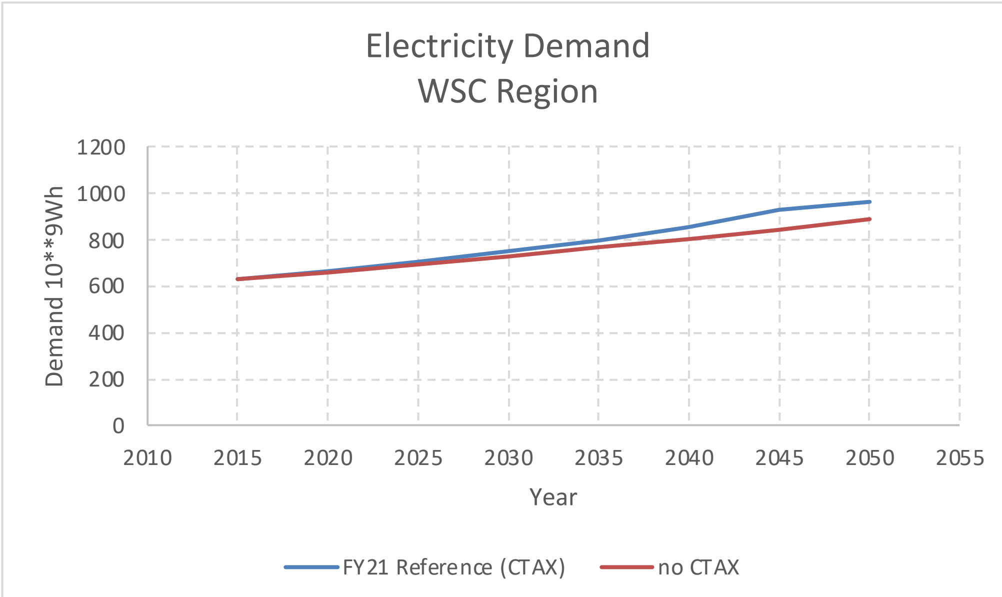


Figure A3-4. Electricity demand comparison, Carbon Tax vs. no Carbon Tax.

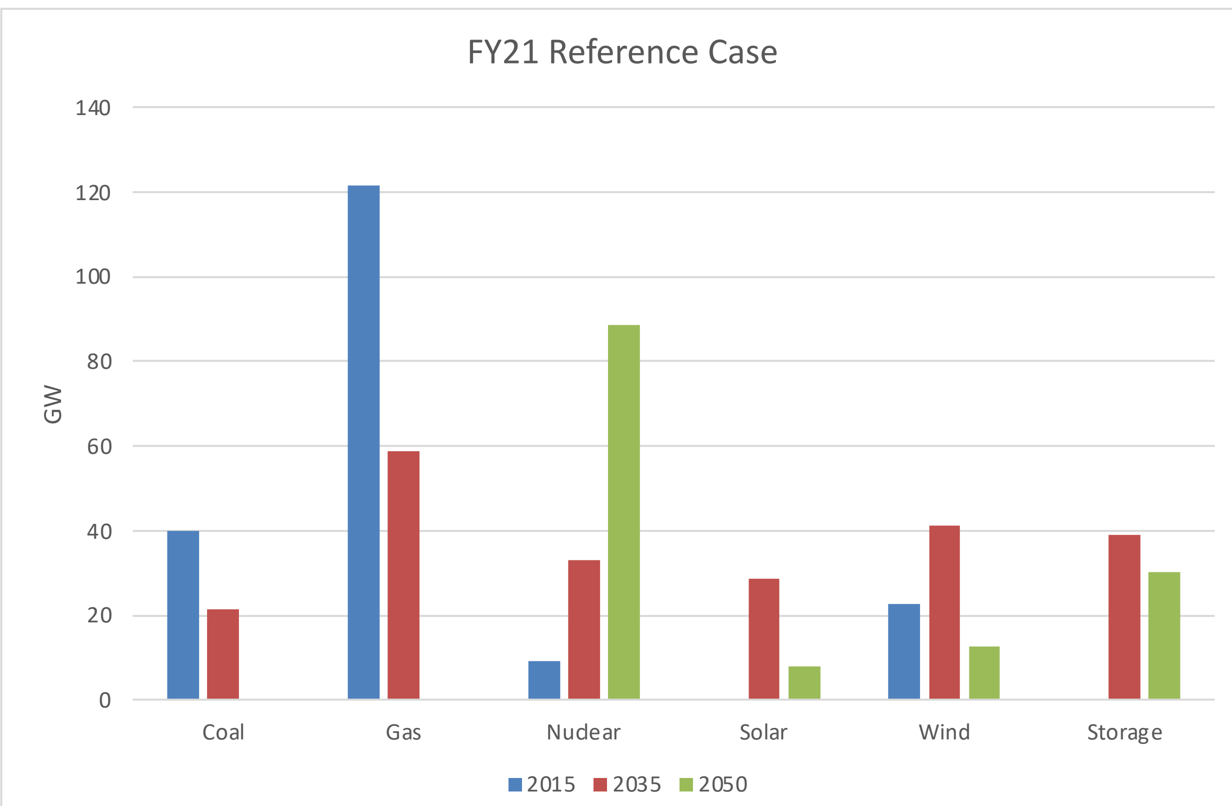


Figure A3-5. Installed capacity for the FY21 Reference Case.

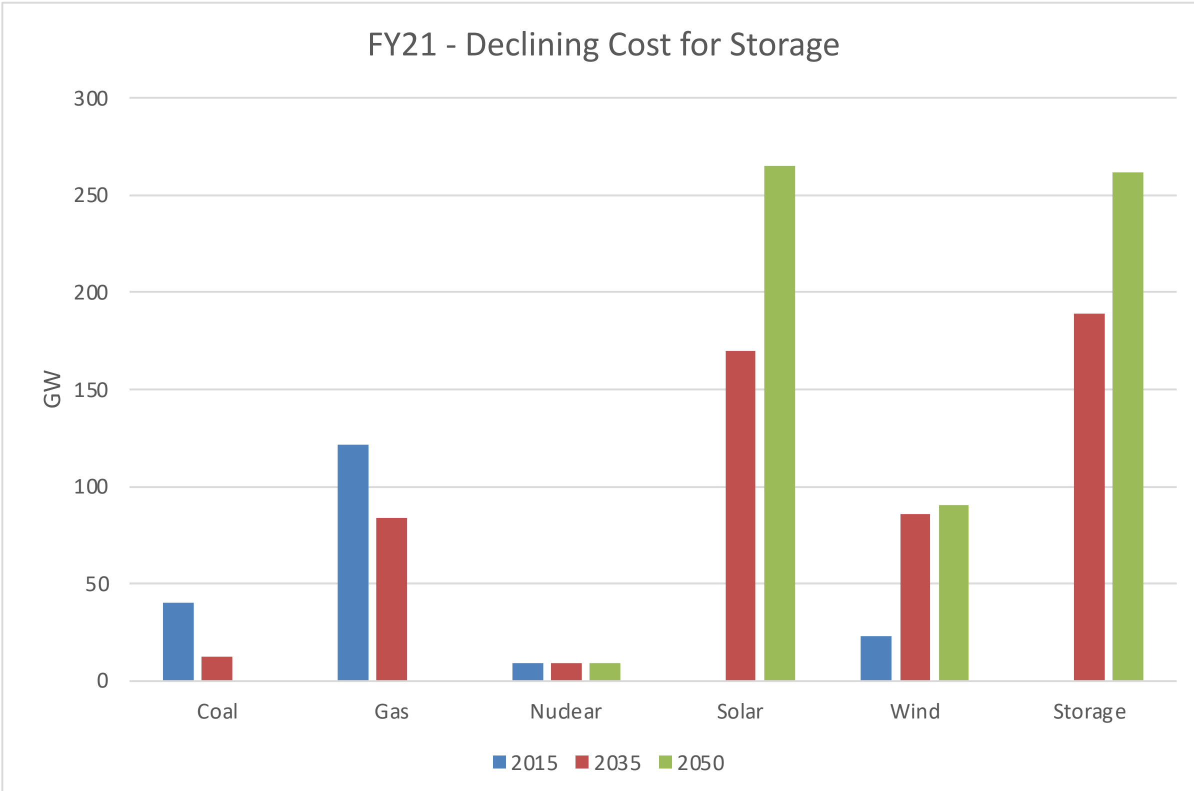


Figure A3-6. Installed capacity, technological learning for batteries.

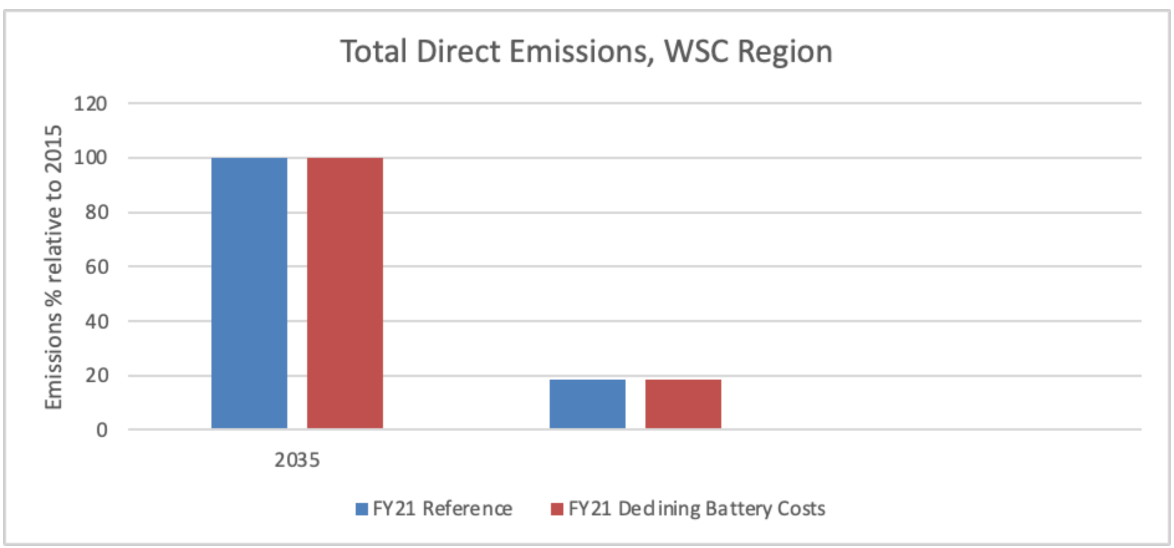


Figure A3-7. Total emissions relative to 2015, WSC Region.

4. APPENDIX 4: Sensitivity of Decarbonization Scenarios to Different Parameters

Section 2 introduced the A-LEAF model of the ERCOT market and the Baseline decarbonization scenario. In addition to the Baseline scenario, many other scenarios were simulated to show the sensitivity of the results to various parameters. These sensitivity scenarios included the following and are presented in this appendix:

1. Baseline scenario: different carbon prices
2. Different nuclear reactor power sizes and associated costs
3. Different nuclear CapEx
4. Different nuclear ramp rate
5. Different capacity payments
6. Different generator OCC and fuel prices
7. Different weather year
8. Different demand growth

Baseline scenario: different carbon prices

The Baseline scenario included midrange fuel prices (EIA AEO 2021 Reference scenario, natural gas $3.86/MMBtu), fixed costs for new generator candidates (no learning), and a carbon price of 100 $/t CO_2. The results were sensitive to the carbon price, so the Baseline scenario was re-run with carbon prices of 0, 25, 50, 75, 100 (Baseline), 200, and 342 $/t CO_2.

With no carbon price, over 20 GW of natural gas combustion turbines and over 10 GW of solar PV were built alongside a small number of batteries. The capacity and generation mix remained similar to 2019 except with much more solar PV (Figure A4-1 and Figure A4-2). Existing nuclear power plants were operating at constant output only (Figure A4-3).

With a carbon price of 25 $/t CO_2, new capacity came from nuclear, solar PV, and wind, 10–20 GW each. Generation was a diverse mix of coal, natural gas, nuclear, solar PV, and wind. At 50–100 $/t CO_2, all coal steam turbines were retired, and most new capacity came from nuclear. Most new nuclear was providing baseload, with some load following, while natural gas was mostly peaking, especially after PV dropped off in the evenings.

Starting at 200 $/t CO_2, significant amounts of natural gas combined cycle generators were retired. Some of that capacity was replaced by natural gas combined cycle with CCS. As the carbon price escalated to 342 $/t CO_2, solar PV and battery shares began increasing relative to nuclear as fossil generation dwindled. In this scenario, nuclear played a deeper load following role, while fossil peaking was needed only on the highest net load days, mostly in the summer (Figure A4-4).

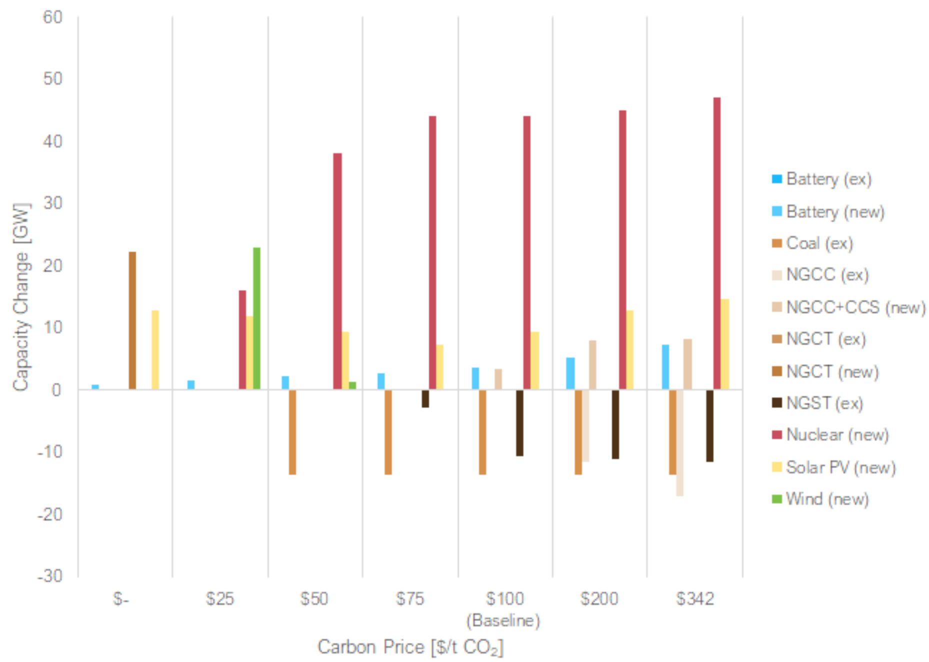


Figure A4-1. Capacity change for generator types in the Baseline scenario (No Learning, natural gas price $3.86/MMBtu) with various carbon prices.

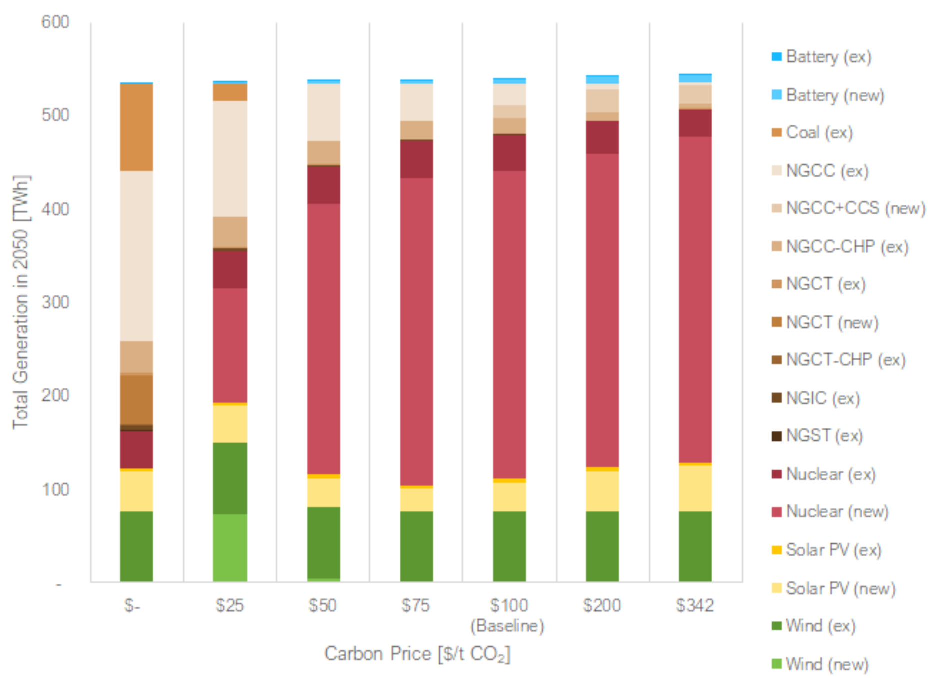


Figure A4-2. Total generation for generator types in the Baseline scenario (No Learning, natural gas price $3.86/MMBtu) with various carbon prices.

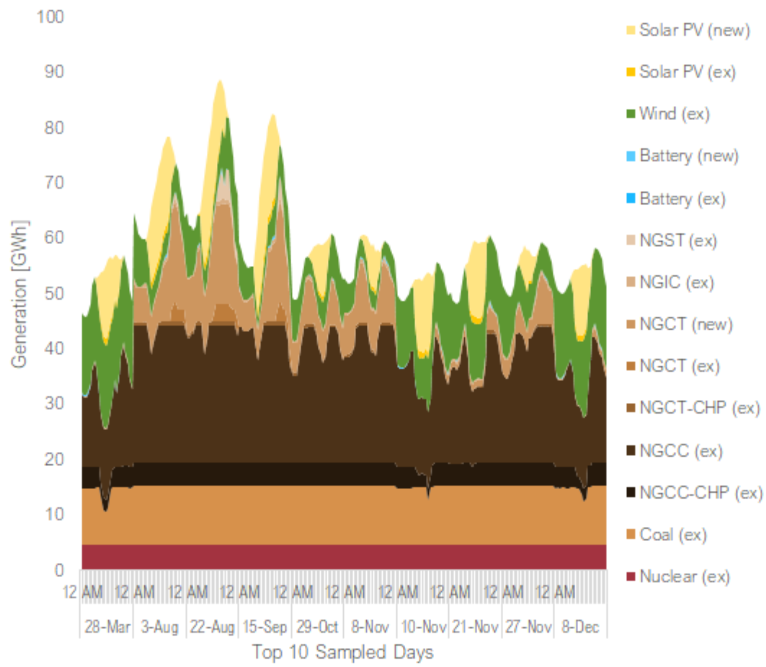


Figure A4-3. Hourly dispatch for generator types in the Baseline scenario (No Learning, natural gas price \$3.86/MMBtu) with carbon price \$0/t CO_2.

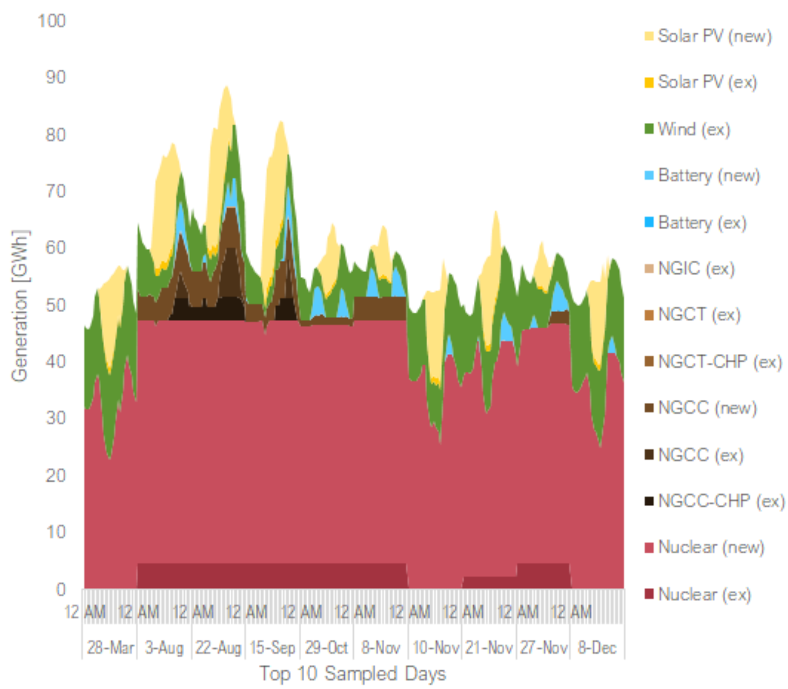


Figure A4-4. Hourly dispatch for generator types in the Baseline scenario (No Learning, natural gas price \$3.86/MMBtu) with carbon price \$342/t CO_2.

Increasing the carbon price was very effective at reducing CO_2 emissions from electricity generation. A carbon price of 100 \$/t CO_2 led to a 90% reduction in CO_2 emissions compared to 2019, while 342 \$/t CO_2

led to a 98% reduction (Figure A4-5). In ERCOT, reducing CO_2 emissions by 98% from 2019 levels would mean that only about 4 Mt CO_2 would be emitted by the entire generation fleet. This is equivalent to the CO_2 emissions of a single coal-fired unit in 2019 (e.g., Coleto Creek near Victoria, Texas [USEPA 2020]).

As the carbon price rose and CO_2 emissions declined, total system costs increased, even if CO_2 emissions costs had been rebated to ratepayers or otherwise ignored (Figure A4-6). Low fixed-cost, high operating-cost generators were replaced by high fixed-cost, low operating-cost generators.

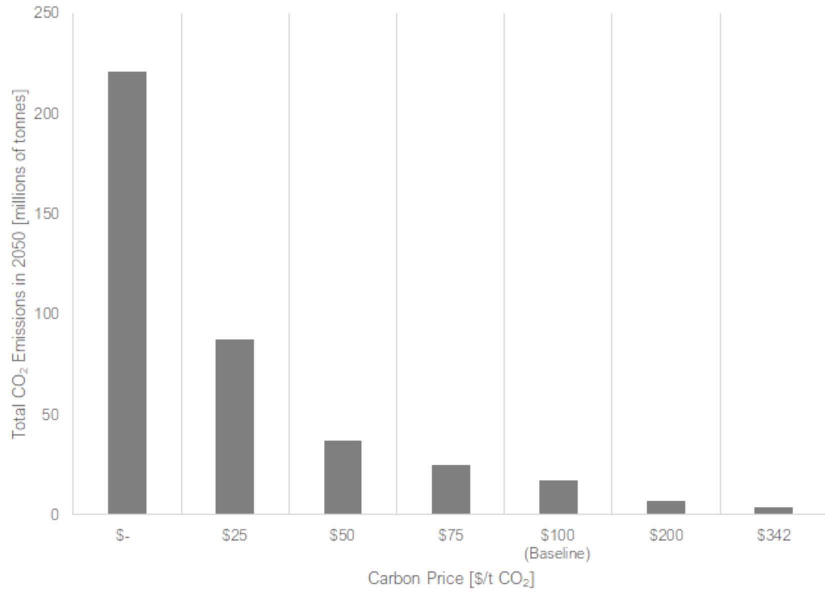


Figure A4-5. Total CO_2 emissions in the Baseline scenario (No Learning, natural gas price $3.86/MMBtu) with various carbon prices.

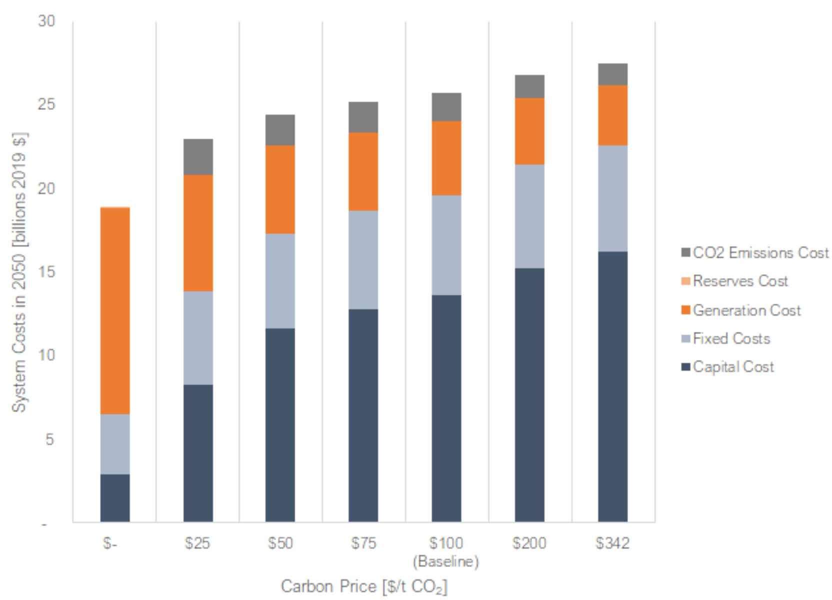


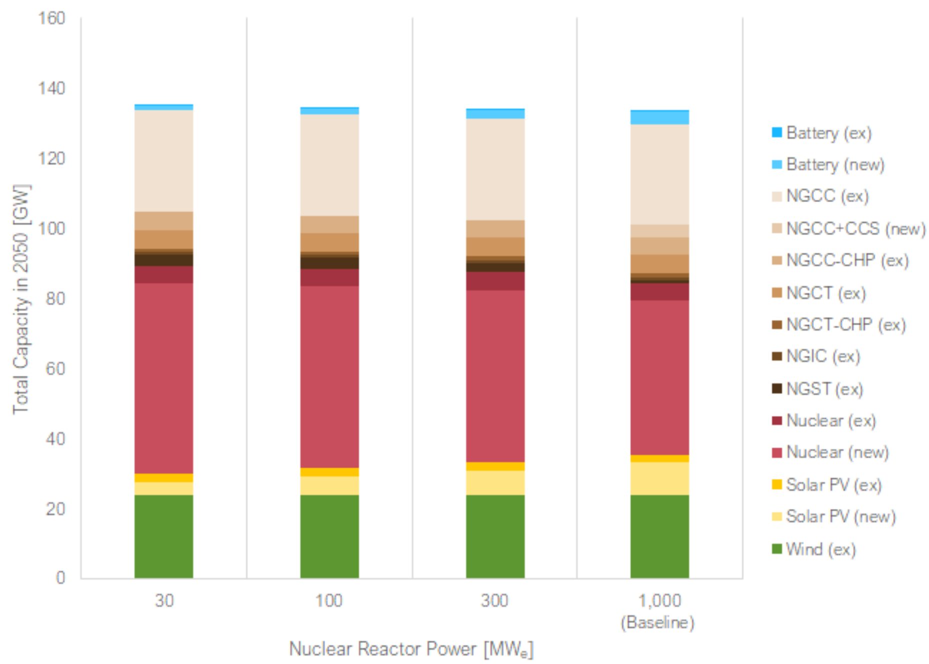
Figure A4-6. Total system costs in the Baseline scenario (No Learning, natural gas price $3.86/MMBtu) with various carbon prices.

Different nuclear reactor power sizes and associated costs

In Section 3.2, the generation results [TWh] were presented for different nuclear reactor scaling factors relative to the Baseline scenario. Additional results for these scenarios are shown below, including system capacity, CO_2 emissions, and system cost.

SMR has lower OCC: smaller is cheaper (n = 1.2), but fuel costs go up (n = 0.87)

When smaller reactors were less expensive, more nuclear capacity was built compared to the Baseline, and less solar PV and battery capacity were built (Figure A4-7). There were also fewer retirements of natural gas steam turbines. Significant amounts of natural gas combined cycle and wind remained as well. As the nuclear capacity and generation share increased, total CO_2 emissions decreased. The OCC declines for nuclear also led to lower total system costs.

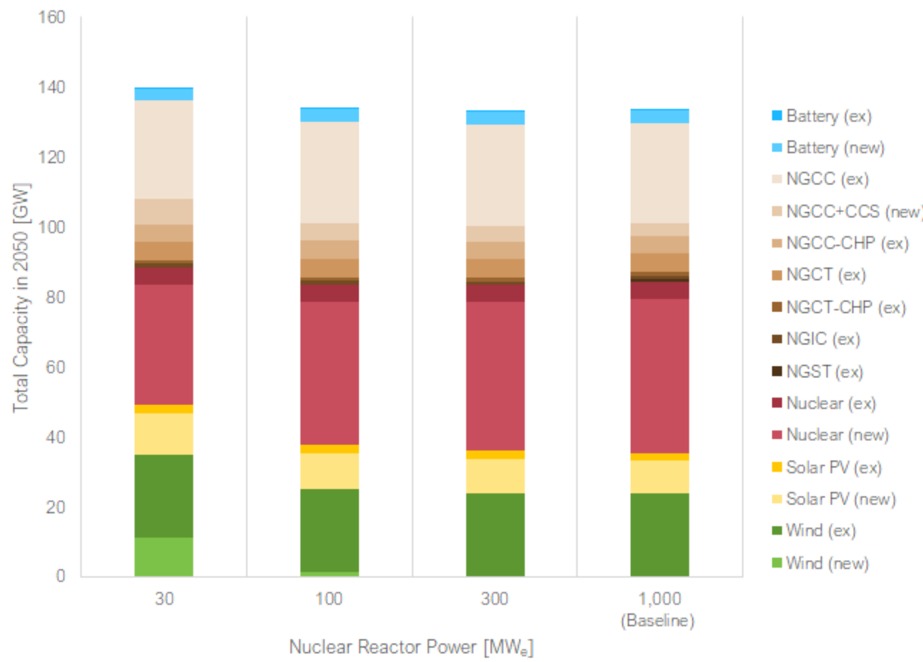


Power [MW]	30	100	300	1,000
OCC [$/kW]	2,190	2,786	3,471	4,416
CapEx [$/kW]	2,474	3,148	3,921	4,989

Figure A4-7. Total capacity mix in 2050 when considering deployment of various reactor sizes with associated capital cost, assuming smaller reactor has smaller OCC (n=1.2).

SMR has same OCC (n = 1.0), but fuel costs go up (n = 0.87)

When smaller reactors had the same OCC, the share of nuclear capacity declined as fuel costs went up (Figure A4-8). Natural gas combined cycle with CCS, solar PV, and wind were built instead. Total CO_2 emissions increased slightly due to the additional natural gas generation. Total system costs were nearly identical across scenarios.

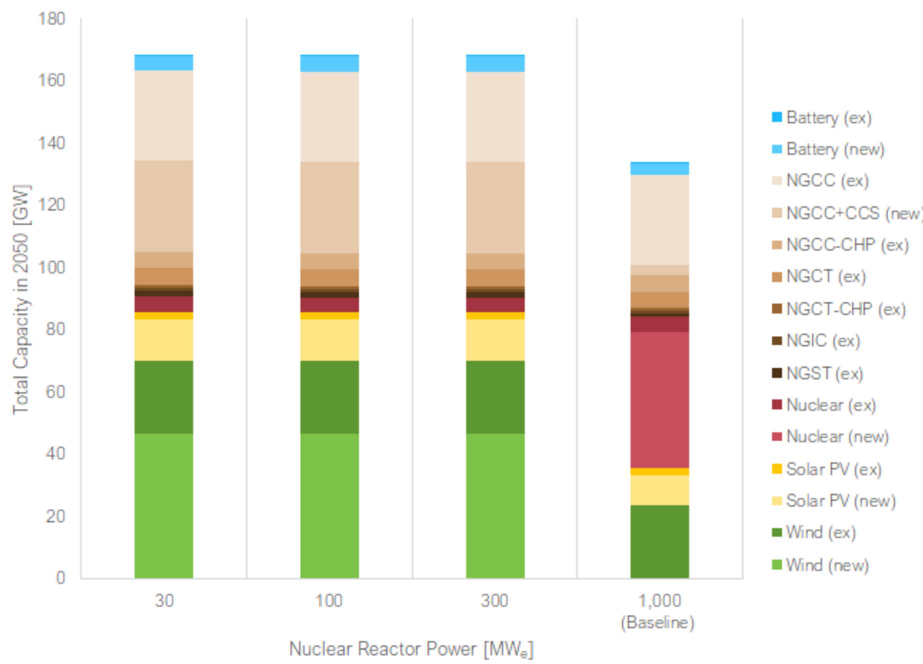


Power [MW]	30	100	300	1,000
OCC [$/kW]	4,416	4,416	4,416	4,416
Fuel Cost [$/MWh]	8.17	6.99	6.06	5.18

Figure A4-8. Total capacity mix in 2050 when considering deployment of various reactor sizes with associated capital cost, assuming smaller reactor has the same OCC (n=1.0).

SMR has higher OCC (n = 0.6), and fuel costs go up (n = 0.87)

When costs per kW increased for smaller reactors, no new nuclear capacity was deployed (Figure A4-9). Most new capacity was from natural gas combined cycle with CCS and wind, with some additional capacity from solar PV and batteries.



Power [MW]	30	100	300	1,000
OCC [$/kW]	17,955	11,092	7,148	4,416
CapEx [$/kW]	20,284	12,531	8,075	4,989

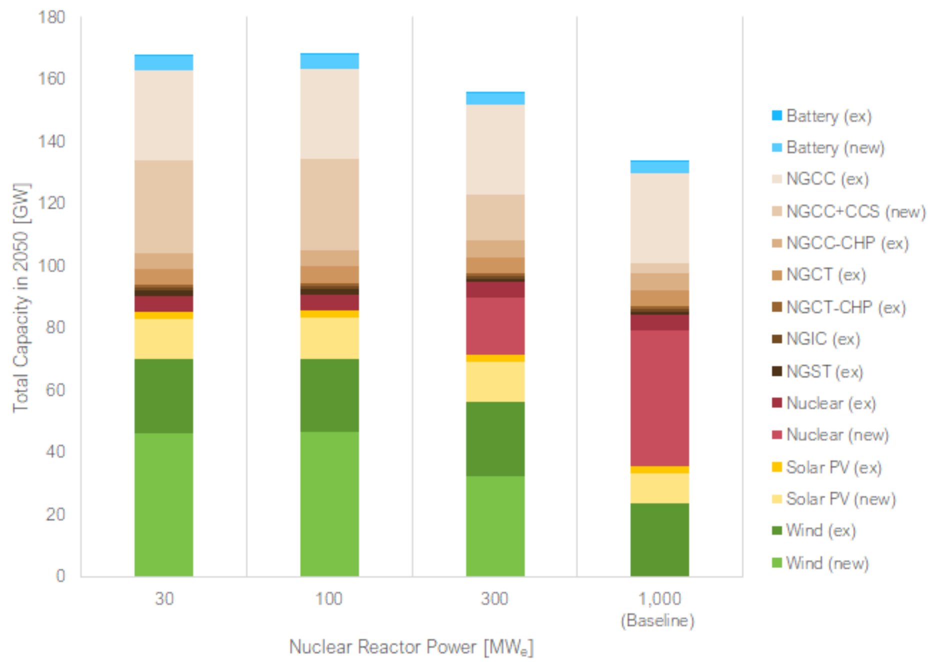
Figure A4-9. Total capacity mix in 2050 when considering deployment of various reactor sizes with associated capital cost, assuming smaller reactor has higher OCC (n=0.6).

System emissions went up compared to the baseline case with nuclear, although all scenarios were still well below the 2019 level of 180 million metric tons. Most of the additional emissions came from new natural gas combined cycle with CCS, but all other natural gas-fired generators had increased generation compared to the Baseline scenario.

Total system costs were higher than the Baseline scenario. Emissions costs increased the most, while decreased capital costs were balanced out by increased fuel costs. Fixed costs were nearly identical.

SMR has higher O&M cost (n = 0.7)

When O&M costs (especially fixed O&M) increased for smaller reactors, there was less nuclear deployment (Figure A4-10). A doubling of O&M costs led to no nuclear deployments. Natural gas combined cycle with CCS and wind primarily displaced nuclear capacity. Total system CO_2 emissions and system costs increased slightly when less nuclear capacity was deployed.



Power [MW]	30	100	300	1,000
OCC [$/kW]	4,416	4,416	4,416	4,416
Fixed O&M [$/kW·yr]	218.01	151.92	109.26	76.14
Variable O&M [$/MWh]	5.35	3.73	2.68	1.87

Figure A4-10. Total capacity mix in 2050 when considering deployment of various reactor sizes with associated O&M costs, assuming smaller reactor has higher O&M (n=0.7).

Different nuclear CapEx

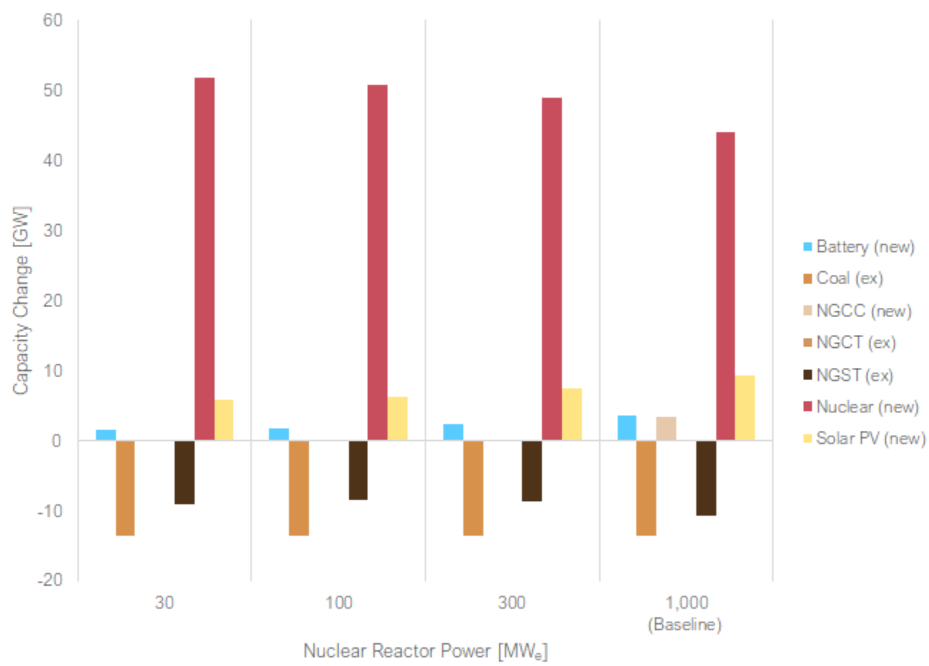
In the reactor power size scaling scenarios (Section 3.2), the overnight capital costs were varied, but the construction cost escalation leading to CapEx was the same across all reactor power sizes. However, it is possible that smaller reactors could be built more quickly and/or with better construction financing terms, as discussed in Section 3.1.

To evaluate these possibilities, the construction financing terms were modified as follows (inflation rate 2%/yr):

- 300 MW: 4 yrs, 4% nominal interest rate
- 100 MW: 3 yrs, 3% nominal interest rate
- 30 MW: 2 yrs, 2.5% nominal interest rate

All other Baseline scenario assumptions were used (No Learning, \$3.86/MMBtu natural gas price, \$100/t CO_2 price).

The reduction in CapEx for smaller reactors led to more nuclear deployment overall (Figure A4-11). This trend is similar to the scenario where smaller reactors had lower OCC but the same CapEx ratios.



Power [MW]	30	100	300	1,000
OCC [\$/kW]	4,416	4,416	4,416	4,416
CapEx [\$/kW]	4,504	4,616	4,776	4,989

Figure A4-11. Capacity change by 2050 for different nuclear CapEx scenarios.

Figure 3-5 shows the total annual generation results. Total system CO_2 emissions and system costs were lower because of the decrease in NPP CapEx.

Different nuclear ramp rate

Under the scenario where nuclear load following was prohibited (no-LF), the total nuclear capacity was less than when nuclear had some load following capability (limited-LF and adv-LF); see Figure 4-1. Instead, the generation from natural gas combined cycle with CCS and batteries was increased (Figure A4-12). Total system CO_2 emissions and total system costs were marginally higher. These simulations were done with one-hour time resolution, and using a higher resolution (5 minute) could better highlight the value of increased nuclear flexibility.

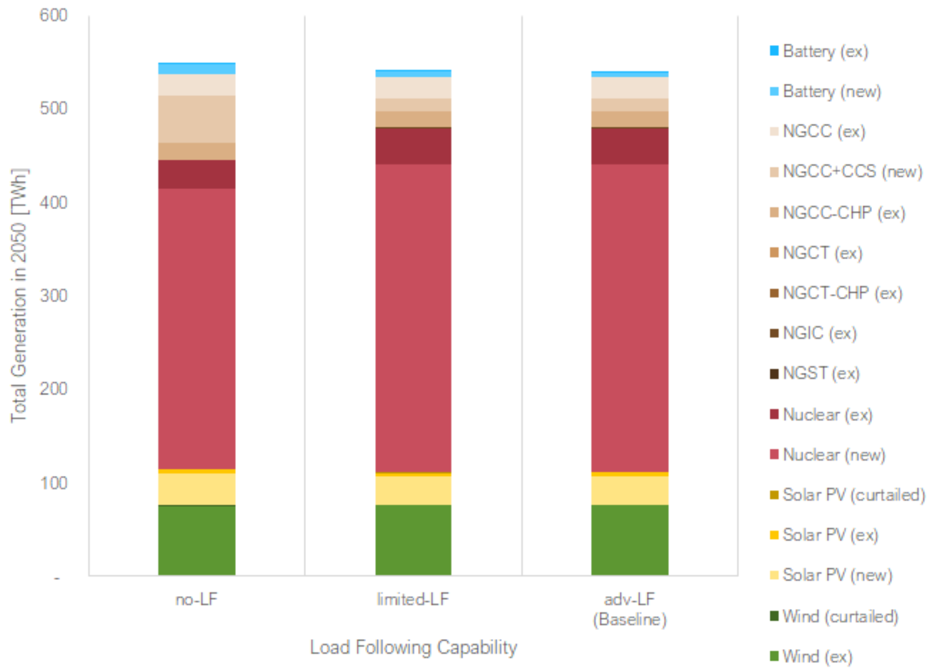


Figure A4-12. Total generation for alternatives to the Baseline scenario where nuclear load following was limited (limited-LF) or prohibited (no-LF).

Different capacity payments

Capacity payments are made to generators in some markets to incentivize their availability in future years, with the goal that grid reliability will be adequate. These payments are made outside the inter-day and intra-day offer and dispatch processes, so they can change the capacity mix by preventing unprofitable generators from retiring in some circumstances.

To evaluate the sensitivity of results to capacity payments, the Baseline scenario (No Learning, \$3.86/MMBtu natural gas price, \$100/t CO_2 price) was re-run with capacity payments of 50, 100, 150, and 200 \$/MW·day. For comparison, clearing capacity prices in PJM for delivery years 2007–2023 have ranged below 50 to over 200 \$/MW·day in various sub-areas. However, results for \$200/MW·day were discarded as unrealistic because the capacity payment exceeded the total annual cost of new natural gas combustion turbines, leading the model to build the arbitrary maximum number of those units (10,000) despite not generating any electricity.

Compared to the Baseline scenario, no significant differences in capacity were seen until the capacity price was at least \$100/MW·day (Figure A4-13). At \$100/MW·day, natural gas steam turbines were no longer retired, and at \$150/MW·day, coal steam turbines were no longer retired. At and above \$100/MW·day, solar PV and battery capacity increased substantially, natural gas combined cycle with CCS increased slightly, and new nuclear capacity decreased slightly. Total capacity was also higher at and above \$100/MW·day (Figure A4-14).

Total generation results were similar across scenarios except when solar PV increased (Figure A4-15). In those cases, nuclear and natural gas generation declined. Note that when capacity prices were at least \$100/MW·day, the natural gas steam turbines and coal steam turbines were unused (i.e., they did not generate any electricity). Total system emissions decreased as the capacity price increased due to the deployment of solar PV, with a 32% emissions decrease at \$150/MW·day. Total system costs increased as the capacity price increased (Figure A4-16). These results showed that capacity payments can influence system emissions, and in some cases help to reduce them. However, the total cost of the payments can lead to high abatement costs if not used in conjunction with more direct emissions policies like carbon prices.

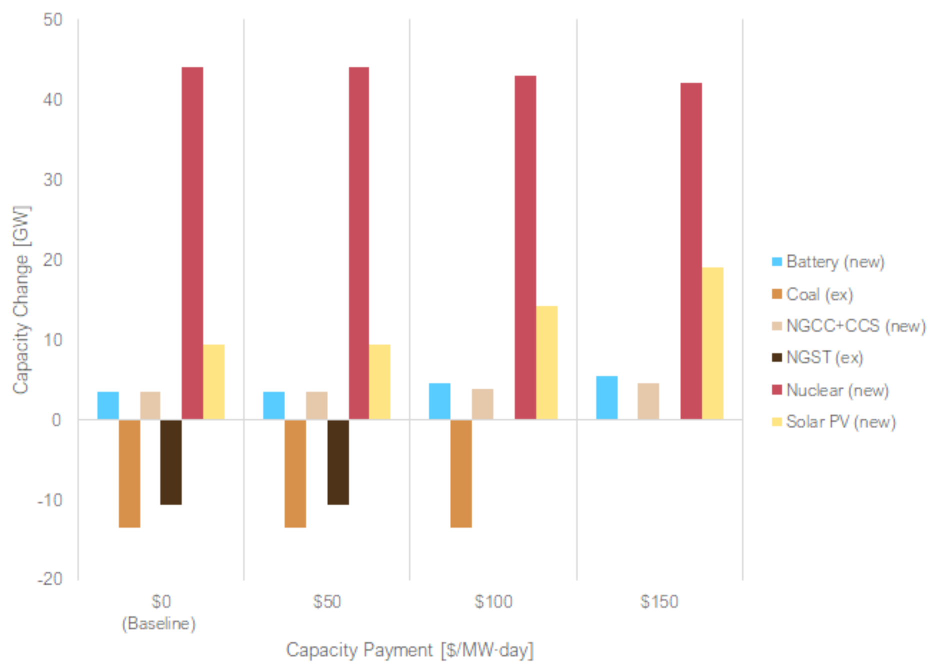


Figure A4-13. Capacity change in various capacity price scenarios, carbon price \$100/t CO_2.

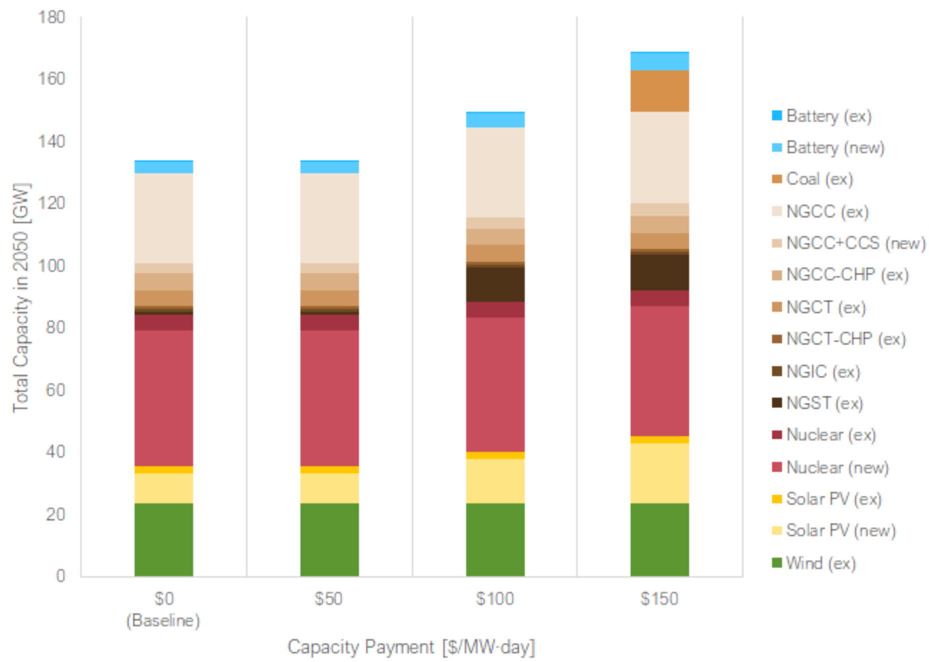


Figure A4-14. Total capacity in various capacity price scenarios, carbon price $100/t CO_2.

Figure A4-15. Total generation in various capacity price scenarios, carbon price $100/t CO_2.

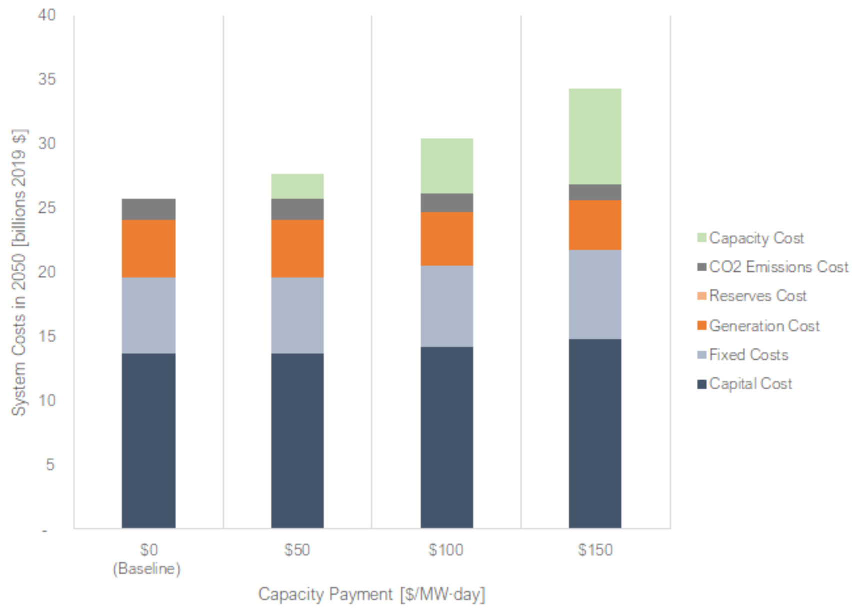


Figure A4-16. Total system costs in various capacity price scenarios, carbon price \$100/t CO_2.

Different generator OCC and fuel prices

To establish the Baseline deep decarbonization scenario, three types of parameters were identified as having the greatest impact on results: overnight capital costs for new generator types, fuel prices, and carbon prices. Figure 2-3 shows the OCC assumptions for the four different technology learning scenarios: None, Conservative, Conservative (Higher Nuc Cost), and Advanced. Three fuel price scenarios were used from the EIA's Annual Energy Outlook 2021: High Oil & Gas Supply, Reference, and Low Oil & Gas Supply [EIA 2021a]. Seven carbon prices were used: 0, 25, 50, 75 100, 200, 342 \$/t CO_2.

Three of the learning scenarios (None, Conservative, and Advanced) were simulated with the three fuel price scenarios and seven carbon prices, ultimately yielding 63 permutations. The learning scenario Conservative (Higher Nuc Cost) was run with one fuel price scenario (Reference) and seven carbon prices for seven permutations.

Table A4-1 is a directory of scenario permutations and generation results presented as figures below. Table A4-2 tgive total CO_2 emissions results across scenarios, and Table A4-3 give total system cost results across scenarios.

Table A4-1. List of generation results organized by learning scenario and fuel price scenario.

		Fuel Price Scenario		
		High Oil & Gas Supply	Reference	Low Oil & Gas Supply
Learning Scenario	None	Figure A4-17	Figure A4-18	Figure A4-19
	Conservative	Figure A4-20	Figure A4-21	Figure A4-22
	Conservative (Higher Nuc Cost)	N/A	Figure A4-23	N/A
	Advanced	Figure A4-24	Figure A4-25	Figure A4-26

No Learning scenarios

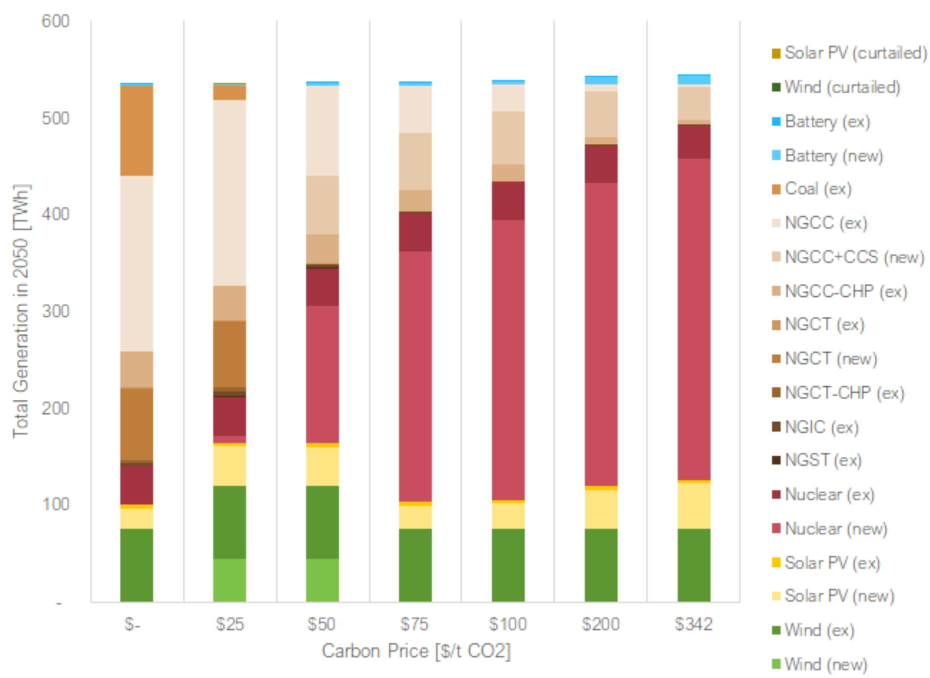


Figure A4-17. Total generation in 2050: No Learning, EIA AEO 2021 High Oil & Gas Supply (NG 2.80 $/MMBtu), various CO_2 prices.

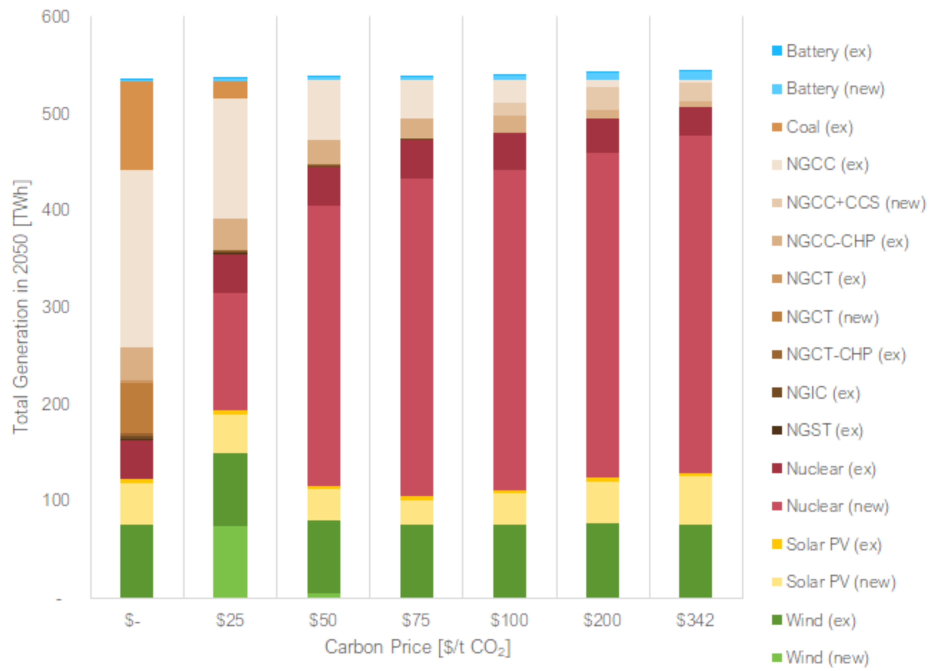


Figure A4-18. Total generation in 2050: No Learning, EIA AEO 2021 Reference (NG 3.86 $/MMBtu), various CO_2 prices.

Figure A4-19. Total generation in 2050: No Learning, EIA AEO 2021 Low Oil & Gas Supply (NG 6.75 $/MMBtu), various CO_2 prices.

Conservative Learning scenarios

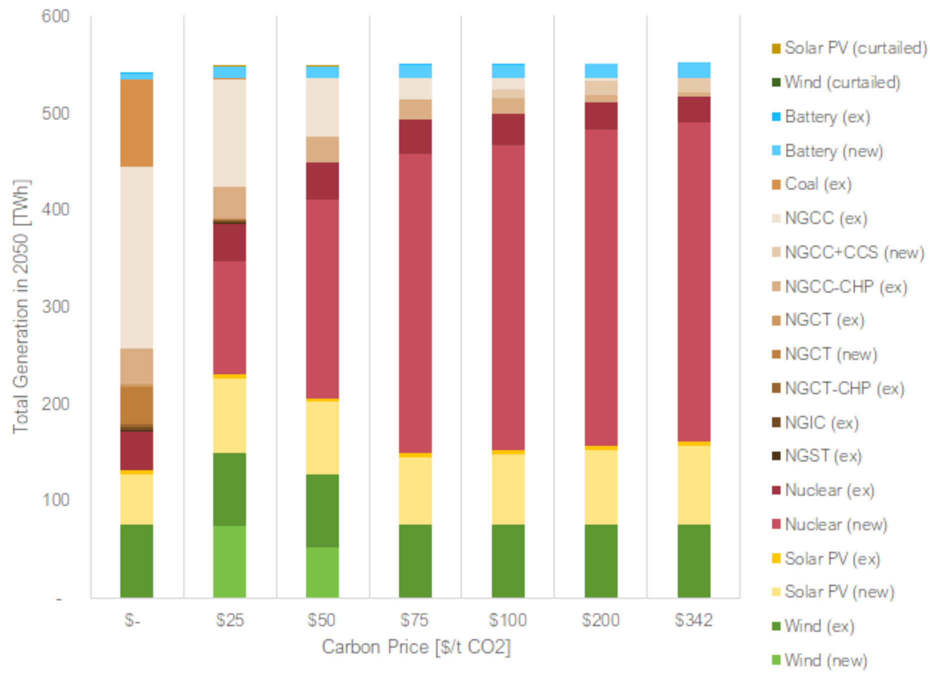


Figure A4-20. Total generation in 2050: Conservative Learning, EIA AEO 2021 High Oil & Gas Supply (NG 2.80 $/MMBtu), various CO_2 prices.

Figure A4-21. Total generation in 2050: Conservative Learning, EIA AEO 2021 Reference (NG 3.86 $/MMBtu), various CO_2 prices.

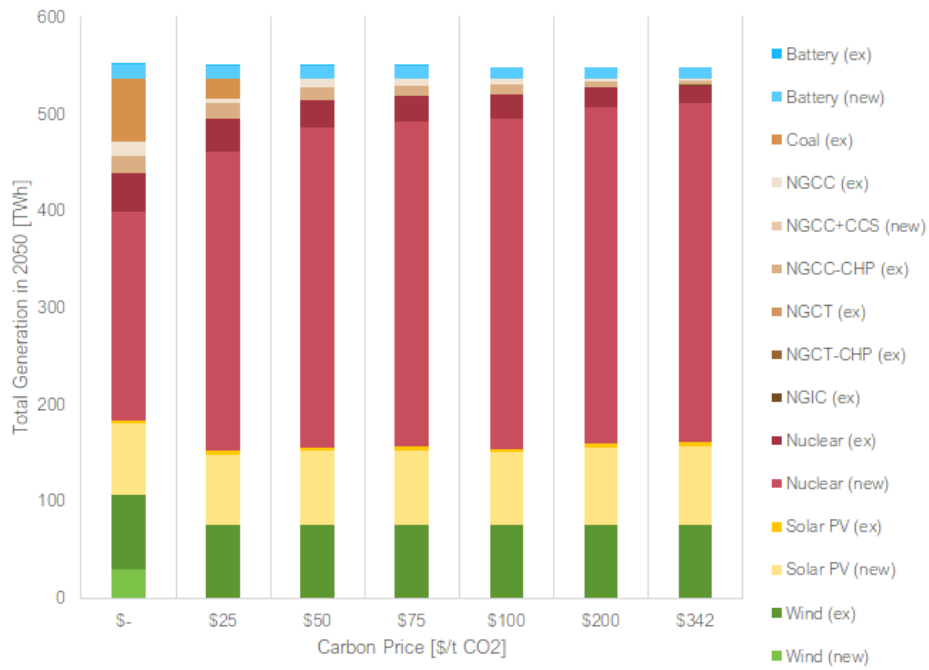


Figure A4-22. Total generation in 2050: Conservative Learning, EIA AEO 2021 Low Oil & Gas Supply (NG 6.75 $/MMBtu), various CO_2 prices.

Conservative Learning (Higher Nuc Costs) scenarios

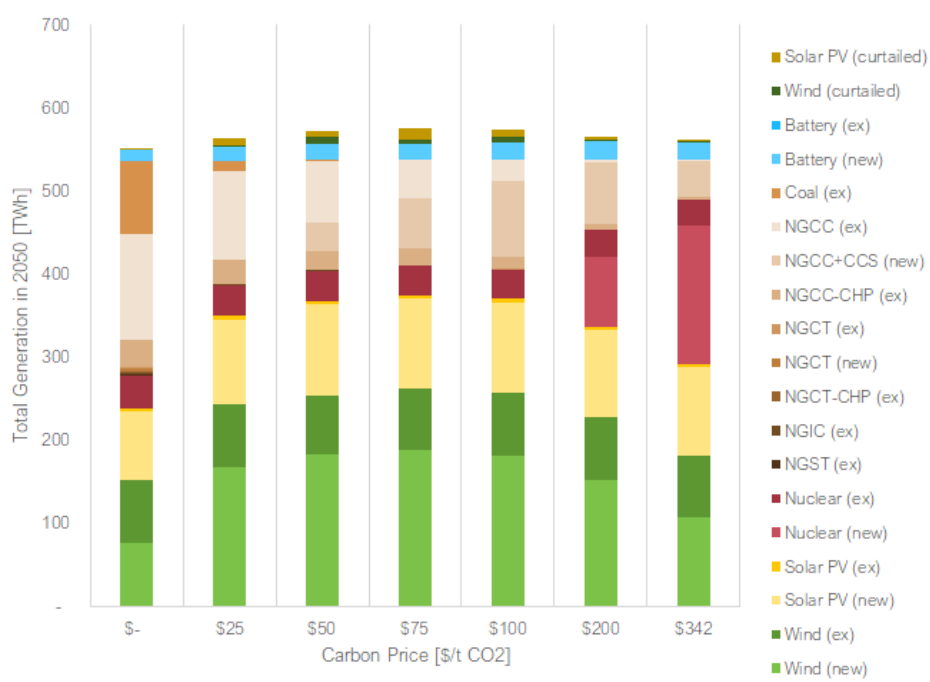


Figure A4-23. Total generation in 2050: Conservative Learning (Higher Nuc Cost), EIA AEO 2021 Reference (NG 3.86 $/MMBtu), various CO_2 prices.

Advanced Learning scenarios

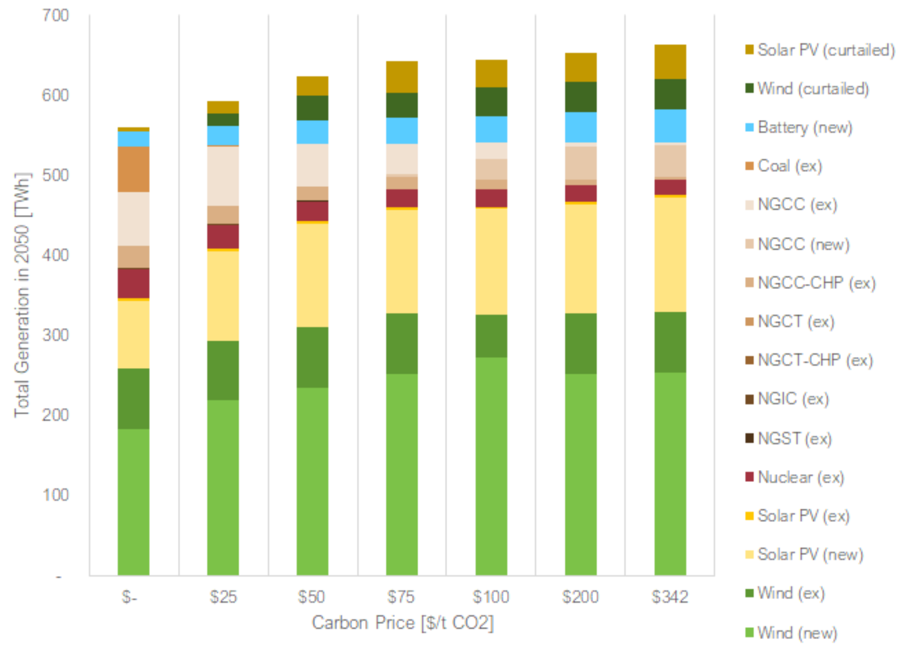


Figure A4-24. Total generation in 2050: Advanced Learning, EIA AEO 2021 High Oil & Gas Supply (NG 2.80 $/MMBtu), various CO_2 prices.

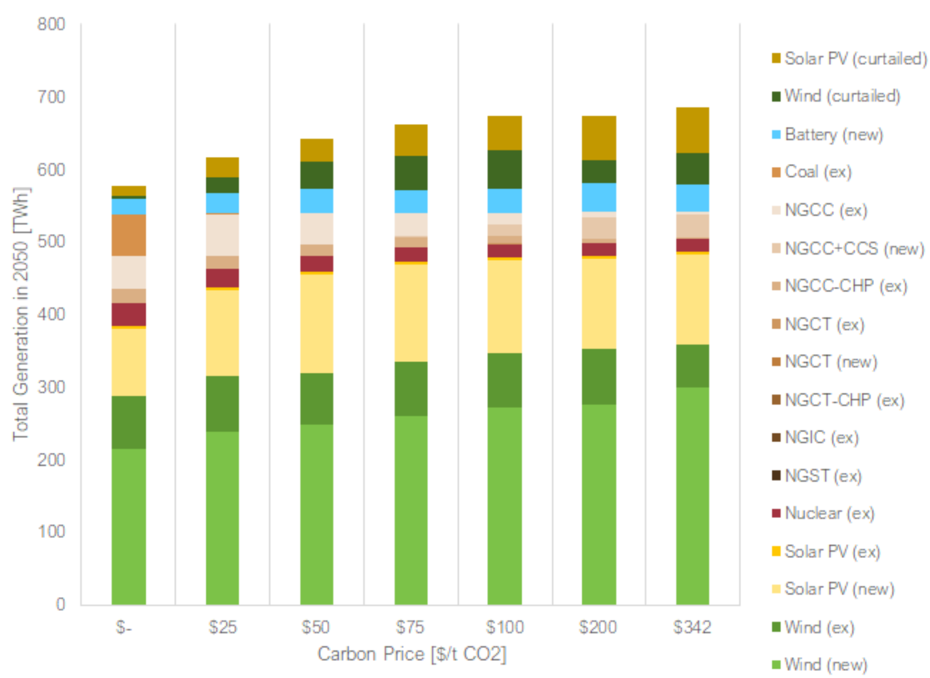


Figure A4-25. Total generation in 2050: Advanced Learning, EIA AEO 2021 Reference (NG 3.86 $/MMBtu), various CO_2 prices.

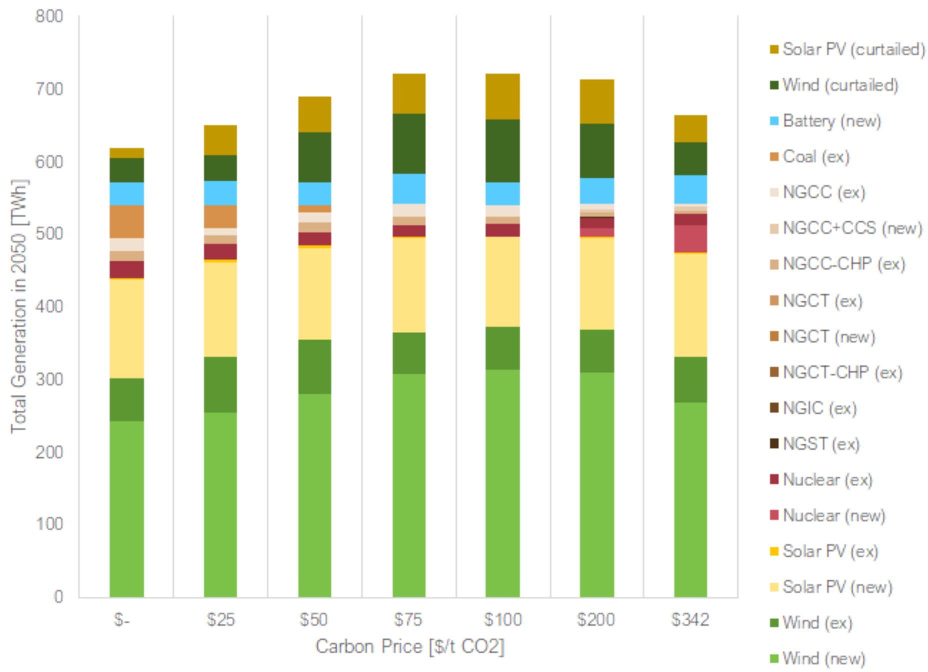


Figure A4-26. Total generation in 2050: Advanced Learning, EIA AEO 2021 Low Oil & Gas Supply (NG 6.75 $/MMBtu), various CO_2 prices.

Total CO_2 emissions across scenarios

Table A4-2. Total CO_2 emissions [millions of metric tons] across scenarios.

		Fuel Price Scenario		
		High Oil & Gas Supply	Reference	Low Oil & Gas Supply
		carbon price \$0/t CO_2		
Learning Scenario	None	233	221	115
	Conservative	215	157	81
	Conservative (Higher Nuc Cost)	N/A	164	N/A
	Advanced	99	86	59
		carbon price \$100/t CO_2		
Learning Scenario	None	21	17	11
	Conservative	11	9	6
	Conservative (Higher Nuc Cost)	N/A	19	N/A
	Advanced	14	12	10
		carbon price \$342/t CO_2		
Learning Scenario	None	4	4	3
	Conservative	2	2	2
	Conservative (Higher Nuc Cost)	N/A	4	N/A
	Advanced	4	4	3

Total system cost across scenarios

Table A4-3. Total system cost [billions 2019 $] across scenarios.

		Fuel Price Scenario		
		High Oil & Gas Supply	Reference	Low Oil & Gas Supply
		carbon price $0/t CO_2		
Learning Scenario	None	16.1	18.8	22.7
	Conservative	14.8	16.9	18.9
	Conservative (Higher Nuc Cost)	N/A	16.9	N/A
	Advanced	12.0	12.8	13.9
		carbon price $100/t CO_2		
Learning Scenario	None	25.1	25.7	26.5
	Conservative	20.5	20.7	21.1
	Conservative (Higher Nuc Cost)	N/A	22.7	N/A
	Advanced	15.5	15.9	16.6
		carbon price $342/t CO_2		
Learning Scenario	None	27.3	27.5	27.9
	Conservative	21.5	21.7	21.8
	Conservative (Higher Nuc Cost)	N/A	24.5	N/A
	Advanced	17.1	17.4	17.9

Different weather year

Weather is the primary driver for load, solar PV generation, and wind generation, so the weather year assumption has an important impact on results. This study used 2019 as the reference weather year. To test the sensitivity of the results to the weather year, the Baseline scenario was run with 2011 as the weather year. Compared to 2019, the weather in Texas in 2011 had more extreme cold in January and February and more extreme heat in the summer.

To make a straightforward comparison, the hourly load data from 2011 was scaled up to 537 TWh of total demand by adding constant baseload (the same method used for 2019 load data). Wind generation was taken from real-time, 15-minute generation data for 2011 [ERCOT 2021a]. There was no utility-scale solar PV generation in ERCOT in 2011, so modeled solar PV output for 2011 was used at the same plant sites in operation in 2019 [ERCOT 2020b].

Using 2019 as the reference for comparison, the 2011 weather year scenario led to 50% more PV capacity and 100% more battery capacity; natural gas combined cycle capacity was retired instead of being added; and essentially no change in nuclear capacity (Figure A4-27). The increase in solar PV capacity led to about 7% less nuclear generation using the 2011 weather year (Figure A4-28). Total system emissions and total system costs were nearly identical between the two scenarios.

This sensitivity analysis showed that using different weather patterns changed the capacity expansion solution, with some technologies deployed much more or much less depending on the year. However, for the primary interest of this study, the nuclear deployment rate was basically unchanged by different weather years selected.

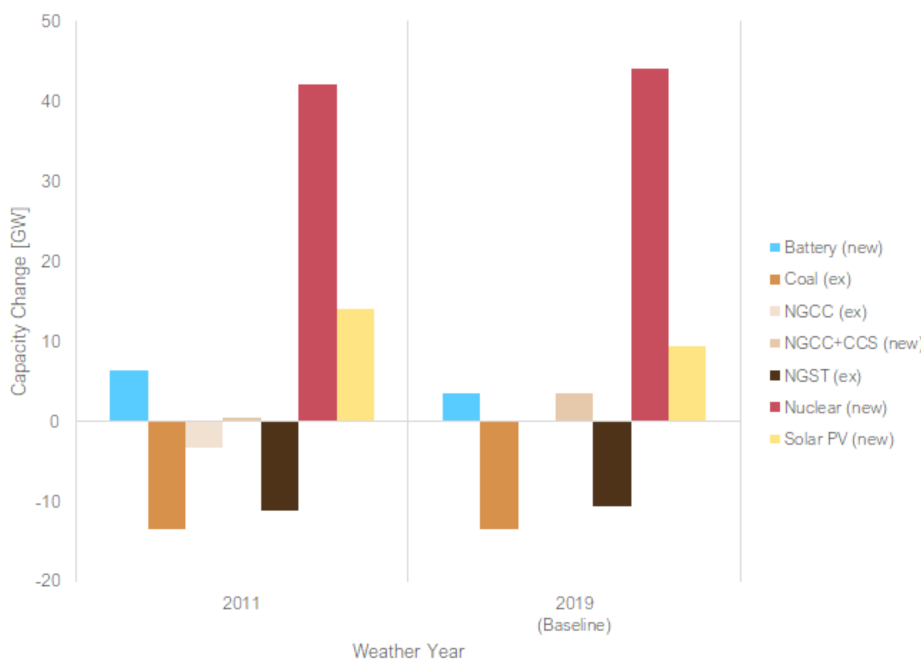


Figure A4-27. Capacity change between reference and 2050, when considering reference year as weather years 2019 (Baseline) and 2011.

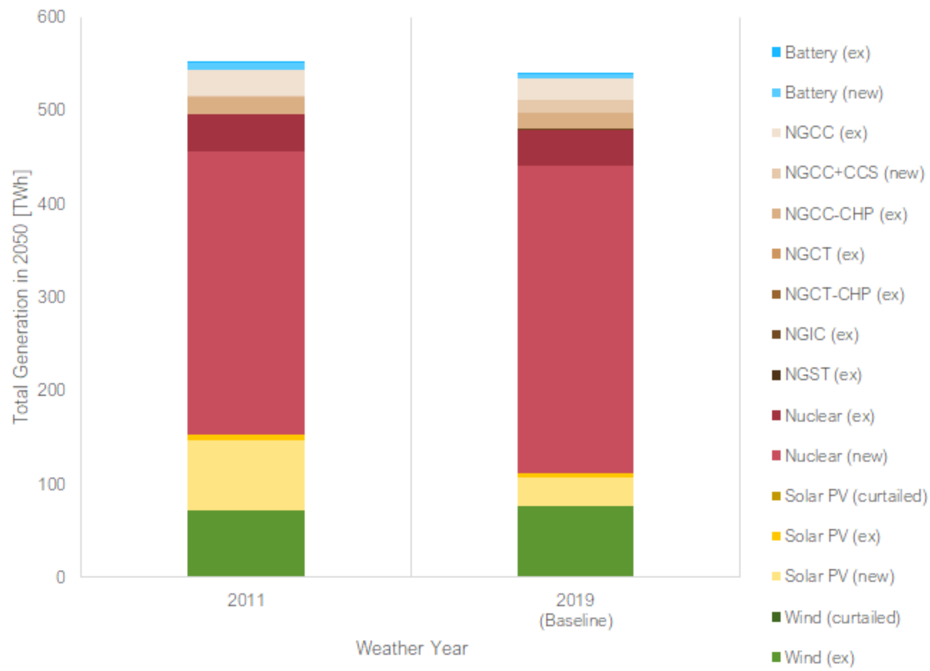


Figure A4-28. Total generation between reference and 2050, when considering reference year as weather years 2019 (Baseline) and 2011.

Different demand growth

Load and total demand are fundamental drivers of capacity mix, so two alternative total demand scenarios were evaluated against the incumbent results from MARKAL (Appendix 3). A lower-growth scenario was created with results from the Annual Energy Outlook 2021 Low Economic Growth scenario [EIA 2021a], where total demand in 2050 in ERCOT was 472 TWh. A higher-growth scenario was created by fitting an exponential curve to historical annual demand in ERCOT 2002–2020, yielding 637 TWh in 2050. This higher-growth forecast was lower than ERCOT's forecast through 2030 [ERCOT 2021b]. In all three scenarios, hourly load data from 2019 was scaled up by adding baseload. Historical and forecast data are shown in Figure A4-29.

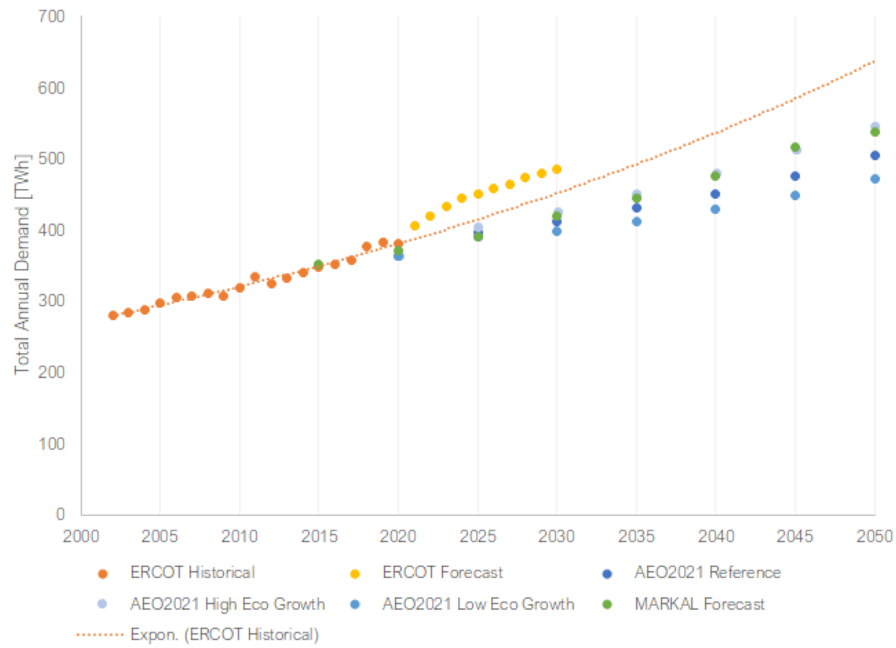


Figure A4-29. ERCOT total annual demand, historical 2002–2020 and forecasts.

The amount of nuclear capacity increased in the higher-growth scenario (ERCOT) and decreased in the lower-growth scenario (EIA) compared to the Baseline scenario (MARKAL) (Figure A4-30). Besides nuclear, only natural gas steam turbine capacity was different between scenarios, with fewer retirements in the higher-growth scenario (ERCOT) and more retirements in the lower-growth scenario (EIA).

Figure A4-30. Capacity change in 2050 for three demand growth scenarios.

Because the difference in capacity mix was almost entirely from nuclear capacity, nuclear generation increased or decreased relative to the baseline MARKAL scenario. The generation from all other technologies was essentially unchanged (Figure A4-31). This led to total CO_2 emissions being nearly identical across the three scenarios. System costs went up or down based on the change in nuclear capacity.

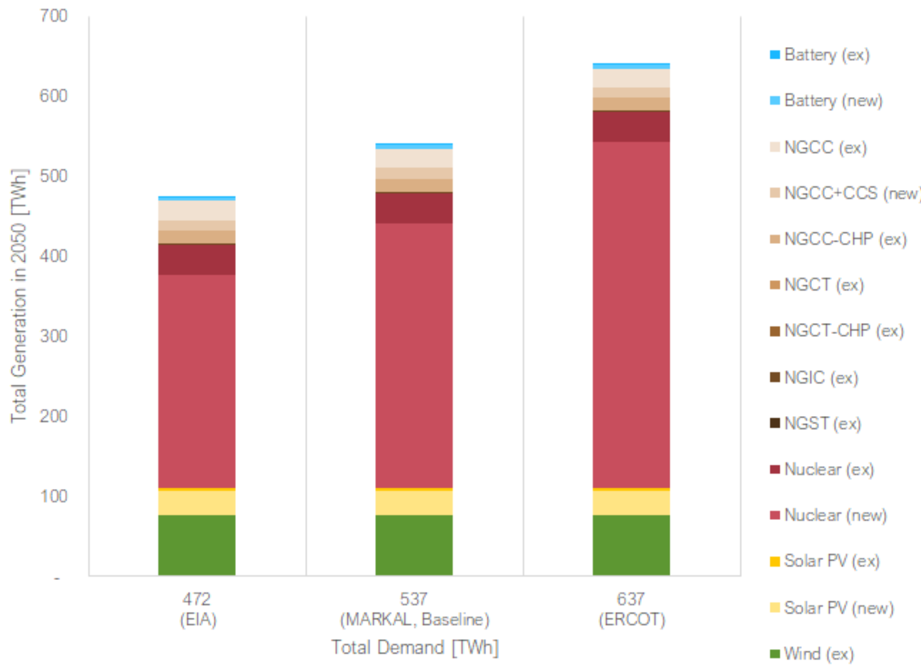


Figure A4-31. Generation mix in 2050 for three demand growth scenarios.

5. APPENDIX 5: Literature Review of Nuclear System Economics

Cost estimate of various reactor concepts and thermal energy storage

A literature review activity was undertaken to develop understanding of capital and O&M cost estimates for new nuclear builds and TES systems. The goal of the activity was to provide cost data to support the A-LEAF electricity market modeling activities described in this report. Below are given short summaries of references that were investigated. The references included specific estimates based on a particular plant or TES design and general estimates based on a class of reactor or TES technology. Ideally, the selected cost data for the nuclear unit should be for an NOAK plant and include overnight capital, fixed and variable O&M, and fuel costs. The selected cost data for the TES should include overnight capital cost and fixed and variable O&M. The TES cost data is presented as the additional cost to a co-located new nuclear build.

As shown below, there is a wide variety of information available on this subject from various sources. After briefly describing each reference and what information was found in it, a summary table with recommended values is given. This collection is far from exhaustive; however it is expected to be representative as consistent numbers are reported from various sources using different methods.

Advanced Fuel Cycle Cost Basis Report

The US DOE advanced fuel cycle cost basis report R Modules [Dixon et al. 2017] includes summary information on the capital and O&M costs for several reactor types. The results are presented as summary estimates with a suggested distribution. The estimates are based on historical precedent, when available, and assumptions based on projections of the costs of NOAK reactors. All capital cost estimates in the R Modules are overnight costs and the most recent version uses 2017$.

Light Water Reactors: Module R1

Given the significant domestic and international experience building and operating LWRs, it comes as no surprise that Module R1 is significantly based on construction and operation precedent. Module R1 includes considerable background information on the construction costs of US and French LWRs. Recommended cost distributions are provided with the mean values selected for this work.

Fast Reactors: Module R2

Compared to LWRs, there is significantly less construction and operation experience for fast reactors. Module R2 includes a summary of built fast reactors and estimates based on paper studies but eventually settles on a cost estimates very close to that of LWRs in Module R1.

Gas-Cooled Reactors: Module R3

While gas-cooled reactors have been built and operated, there has not been enough experience to make modern estimates based on precedent. Instead, Module R3 estimates NOAK capital costs above LWR and SFR in Modules R1 and R2. No O&M cost is given in Module R3 due to inexperience.

INL/NGNP

Many documents have been generated by INL and its partners as part of the NGNP project related to HTGRs. One such document [Gandrik 2012] provides OCC, O&M, and fuel cost estimates for NOAK HTGRs as a function of temperature and energy conversion technology and considering multi-unit sites. Uncertainty bands are also provided for the OCC.

The NGNP project considered process heat from HTGRs to be very important thus results are often presented in terms of thermal power. Results in the report that are provided in thermal power units are converted here to electric power units assuming a 45% efficiency.

No distinction is made in the report on the difference in variable and fixed O&M. A list of O&M cost categories is provided so one might be able to determine fixed and variable contributions to total O&M based on preferred classification of these categories. All costs in the report are given in 2009$. NOAK values for a 4-pack of 350 MWt and 600 MWt reactors are used here.

Open-100

The Open-100 design concept is an attempt at making an open-source small modular light water reactor. Included in their public design is a capital cost breakdown and an O&M estimate. The capital costs are based on a vintage DOE report [Allen et al. 1986].

The Open-100 site includes cost estimates for a large LWR (1144 MW) and the small Open-100 LWR (114 MW) in 2020$. Some costs are scaled (the Open-100 reference design is arbitrarily selected to be 1/10th the large LWR), and some costs are assumed to be reduced through some efficiency (e.g., manufacturing method changes, staffing optimization) or design change (e.g. reduction in components or system complexity).

GT-MHR

Detailed cost estimates are available for the GT-MHR, a helium-cooled reactor that was the subject of many detailed technical and economic studies [GCRA 1994, GT-MHR Staff 2003, Shenoy 2005]. As described in Module R3, these estimates are likely too dated (1994$ or 2002$) to be useful even if inflated. They are provided for completeness.

S-PRISM

Like the GT-MHR, the S-PRISM design has been circulated for several decades and has been the subject of a variety of technical and economic studies [Boardman et al. 2001]. The provided cost estimates are likely overly optimistic given their vintage (1996$) but are provided for completeness.

Lucid Catalyst

- *Reactor Cost Estimates*

As part of a study for the UK government, Lucid Catalyst developed capital and O&M cost estimates for several advanced reactor types [Boardman 2001]. They also made a cost estimate for a large PWR which was based on the same 1986 report referred to by Open-100. All estimates in the reference report were provided in 2017$.

- *TES Cost Estimates*

Another report [Ingersoll et al. 2020] by LucidCatalyst works backwards to determine the allowable cost of a new nuclear build based on US electricity market economics. Scenarios examined include new builds with and without TES. Included in their analyses are estimates of the capital costs of several types of TES. Estimates of nuclear fuel and O&M costs are also included. This reference uses 2019$.

IEA

A recent report [IEA & OECD/NEA 2020] by the International Energy Agency (IEA) and the Nuclear Energy Agency (NEA) details the expected costs of building electricity generating plants using a variety of technologies, including new nuclear. While their conclusion is the cheapest option in terms of LCOE is life extension of currently operating plants, they also provide overnight capital, O&M, and fuel cost estimates for new builds. The report uses 2018$.

DOE Integrated Energy Systems

The DOE Integrated Energy Systems (IES) program produced a report [Ponciroli et al. 2021] that included cost models of energy storage systems. As specific O&M costs of TES systems vary with utilization, values referenced in the IES report are given as total costs based on an assumed utilization. Reporting costs according to actual utilization is not feasible using the tools in this report due to non-linear relationships. Specific O&M costs are thus reported based on the nameplate capacity.

MIT Microreactor

A study [Forsberg, 2021] by researchers at MIT developed cost requirements for a 10 MW fission battery. Similar to the report by LucidCatalyst, the costs developed were not justified based on analysis of a specific MR design but instead imposed as economic requirements following analysis of general MR characteristics. Therefore, if a reactor of this size is to be built and operated, it will likely meet these requirements or else it would not be a valid economic choice. It is another matter as to whether such a reactor can be developed.

The report does not list its assumed baseline year. Given its general nature and the uncertainty inherent in its derivation, costs are assumed to be applicable in any recent year.

TES Cost Estimates

Estimates for the costs and operational benefit of TES are often associated with studies of concentrated solar power (CSP) plants, though sometimes they are generic [Smallbone et al. 2017; McTigue et al. 2015; Jülch 2016], or specific to nuclear [Denholm et al. 2012; Li et al. 2014; Edwards et al. 2016] Though there are a number of different TES technologies, the methods suitable for direct coupling to nuclear power are limited [Denholm et al. 2012].

Capital costs of TES are primarily based on the cost of additional or augmentation of baseload power conversion equipment and the cost of storage. The power block costs scale with nameplate rating. Generally, these costs can be calculated according to traditional energy conversion equipment costs [Ingersoll et al. 2020]. Storage costs scale with storage capacity. Herrmann et al. [2004] provide an example of the breakdown of costs for a TES based on its storage size for a fixed power block.

A TES will also have O&M costs which are directly attributed as the additional costs required above nuclear O&M costs. Technically, such costs will vary based on the utilization of the TES. However, for this work, costs must be reported based on the nameplate ratings of the TES power block or storage size as utilization cannot be known beforehand. It therefore can appear that specific costs are increasing as size increases implying that the most economic TES has zero size; however, this is not the case. The overall costs are indeed increasing, however the costs are being reported per power block rating while the costs are related to the storage size. The determining factor is thus the utilization of the TES. Herrmann et al. [2004] also provide an example of how utilization of CSP tends to saturate based on the solar insolation resulting in inefficiencies when storage exceeds 12 hrs. This inefficiency is within the analysis limits of hourly storage which is the focus of this work and only applies when generation tends to vary with the time of day. Long term storage options (I.e., for months or years) are not considered. Studies of nuclear plants coupled to TES have shown the need for less storage capacity than CSP given the baseload nature of the nuclear generation [Denholm et al. 2012].

All costs are to be given in January 2019$ according to the CPI inflation calculator [BLS N.D.]. Conversion of costs from reports using different year dollars, *ReferenceCost*, are converted using the equation:

$$ReferenceCost \times Factor = 2019\$$$

Values of the correction factor, *Factor*, used in this report are given in Table A5-1.

Table A5-1. CPI factors.

Year	Factor	Year	Factor	Year	Factor	Year	Factor	Year	Factor
1980	3.235	1990	1.976	2000	1.491	2010	1.162	2020	0.976
1981	2.893	1991	1.870	2001	1.438	2011	1.143	2021	0.962
1982	2.669	1992	1.823	2002	1.421	2012	1.111		
1983	2.574	1993	1.765	2003	1.385	2013	1.093		
1984	2.470	1994	1.722	2004	1.359	2014	1.076		
1985	2.386	1995	1.675	2005	1.320	2015	1.077		
1986	2.297	1996	1.630	2006	1.269	2016	1.062		
1987	2.264	1997	1.582	2007	1.244	2017	1.037		
1988	2.176	1998	1.558	2008	1.192	2018	1.016		
1989	2.079	1999	1.532	2009	1.192	2019	1.000		

Summary and Recommendation

A summary of the previous cost estimates is given in Table A5-2. The costs are corrected to 2019$ and listed in descending order of specific OCC. In some cases, there was no distinction between O&M categories. These cases have a total O&M cost and "xxx" placed in location of unknown data. The recommended values used by other sections in this report are highlighted. Due to the level of variation in cost parameters coming from the data available in the literature, it was decided to focus this study on the impact of different reactor power output, without or with TES. The impact of different reactor technologies is not being considered due to the large uncertainty associated with their costing. Thus, one will use Large PWR cost data as reference estimates, since those are the ones with lowest uncertainty. In the following section, one will discuss relationships between reactor size and cost data, to derive some cost parameters for different sizes of reactors.

Summary cost data for TES is given in Table A5-2.

Table A5-2. Summary NOAK costs for nuclear reactors.

Source Name	Specific Overnight Capital	Fixed O&M	Variable O&M	Fuel	Multi-Unit
	[$/kW]	[$/MWh]	[$/MWh]	[$/MWh]	[#]
NGNP 4x350	7599	18.78	xxx	16.88	4
Large PWR (Lucid Catalyst)	5902	21.77	xxx	7.26	1
HTGR (Module R)	5805	xxx	xxx	xxx	xxx
LWR SMR (Lucid Catalyst)	5604	21.77	xxx	7.26	xxx
NGNP 4x600	5498	12.56	xxx	16.88	4
LWR (IEA)	5305	11.32	1.46	9.10	1
SFR (Module R)	4872	9.23	2.18	10.37	xxx
Large PWR (Open 100)	4700	6.82	16.94	5.10	1
Large PWR (Module R)	4416	8.64	1.87	5.18	1
LMR (Lucid Catalyst)	4051	21.77	xxx	18.66	xxx
HTGR (Lucid Catalyst)	3496	10.37	xxx	8.29	xxx
MSR (Lucid Catalyst)	3272	17.62	xxx	3.11	xxx
MIT	3093	9.83	0.98	9.76	1
Open 100	2588	1.34	3.39	5.10	1
S-PRISM	2326	3.24	6.76	8.15	4
GT-MHR	1386	6.01	1.00	10.52	4

Table A5-3. Summary NOAK costs for TES.

Source Name	Power Block Costs	Storage Costs	O&M Costs
	[$/kW]	[$/MWh]	[$/kW/MWh]
Lucid Catalyst	600	xxx	xxx
Herrmann	xxx	xxx	Variable
Selected or adapted from several sources	600	60	0.0545

Literature review of different scaling factors for capital costs and O&M

Given there is little recent experience building and commercially operating modern commercial reactors at sizes less than ~1,000 MW, some analysis must be performed to determine the effect of reactor size (thermal or electric power) on the capital, O&M, and fuel costs. The approach for this work is to use scaling factors applied to large LWR reactor data.

The issue of economies of scale and learning rates for nuclear power is, at best, unresolved and controversial. Discussion on these two factors on the capital and O&M costs are given in the following sections.

Learning

Given the diversity of plant designs spread across the country, there is little evidence of learning for construction of large LWRs in the US. During the 1970s, when most of the currently operating nuclear plants began construction, there was much optimism about the costs of nuclear plants and increasing electricity demand and many more reactors were planned than were ever built. Though some plants were built quickly and at or below budget, many plants were under construction for a decade or more and subject to many regulatory and design changes including those resulting from the TMI accident. These changes often resulted in schedule slip and cost overruns.

New, standardized designs of large LWRs, such as AP-1000, promised cost reductions through modularization and learning through experience, however this has not yet been observed in the US due to the limited number of units being built. The cautionary tale of the AP-1000 in the US is currently more about interest during construction and the financing and management of large projects than anything else. As reported in the AFCCB report and elsewhere, a well-managed Gen. III+ plant can be built on time and on budget, though the given examples are international (e.g., Barakah in UAE) and may not be applicable to the current US manufacturing and regulatory environment.

Smaller plants propose increased learning rates due to the necessity of building many units to achieve a required installed power level. For example, ten 100-MW electric units can be built to meet the same demand as a single 1,000-MW plant. The argument for smaller units is that during the construction of the ten units, workers and project managers will become more experienced, which will result in meaningful cost savings by the time the tenth plant is built. If construction follows a staggered schedule, a group of workers can move from unit 1 to 2 to 3 and so on and apply the lessons learned along the way. There may be additional benefits to building in this staggered manner which will be discussed in the section on financing capital costs.

For example, the GT-MHR projected learning in O&M according to the number of reactors built overall and the number of reactors at a given site [GCRA 1994]. The data from GT-MHR reports was reproduced in Figure A5-1. Note that the notation of “Target” for GT-MHR studies corresponds to NOAK for the purposes of this study. While the magnitude of the data is lost due to the use of 1994$, the trend is indicative of the past and present theoretical basis of nuclear plant O&M cost reduction: reactor operating experience and multi-unit sites reduce costs. The GT-MHR also projected learning rates for capital costs in a similar manner.

The US EIA collects and reports data on many aspects of US energy including O&M costs [EIA 2020c, Table 8.4].[1] A compilation of available data is shown in Figure A5-2. Recent O&M data for nuclear facilities[2] shows a decreasing trend in overall O&M when adjusted for inflation (Figure A5-3). The downward trend reflects price pressure on nuclear units to reduce O&M to be competitive with other electricity producers and also corresponds to increase in nuclear capacity factor (Figure A5-4).[3] As plants that are struggling to reduce O&M are retired, the decreasing O&M trend will likely continue, albeit not indefinitely.

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[1] Note that discrepancies exist in these datasets when reporting on previous, overlapping years. The discrepancies were noted to be small and do not significantly change the presented results. The tables used for the charts shown in this report are from 2019, 2010, and 2001 with preference given to the latest data when resolving discrepancies.

[2] Unfortunately, the data is sourced in aggregate from utilities who report a FERC Form 1. So, while it may be possible to get some specific plant information due to singular association of some nuclear units with a utility, it was determined that this a detailed task like that was better suited as future work.

[3] The curve was constructed from EIA data given in the same reports as the O&M data. It is based on total nuclear generation in the US and the summer generation capacity.

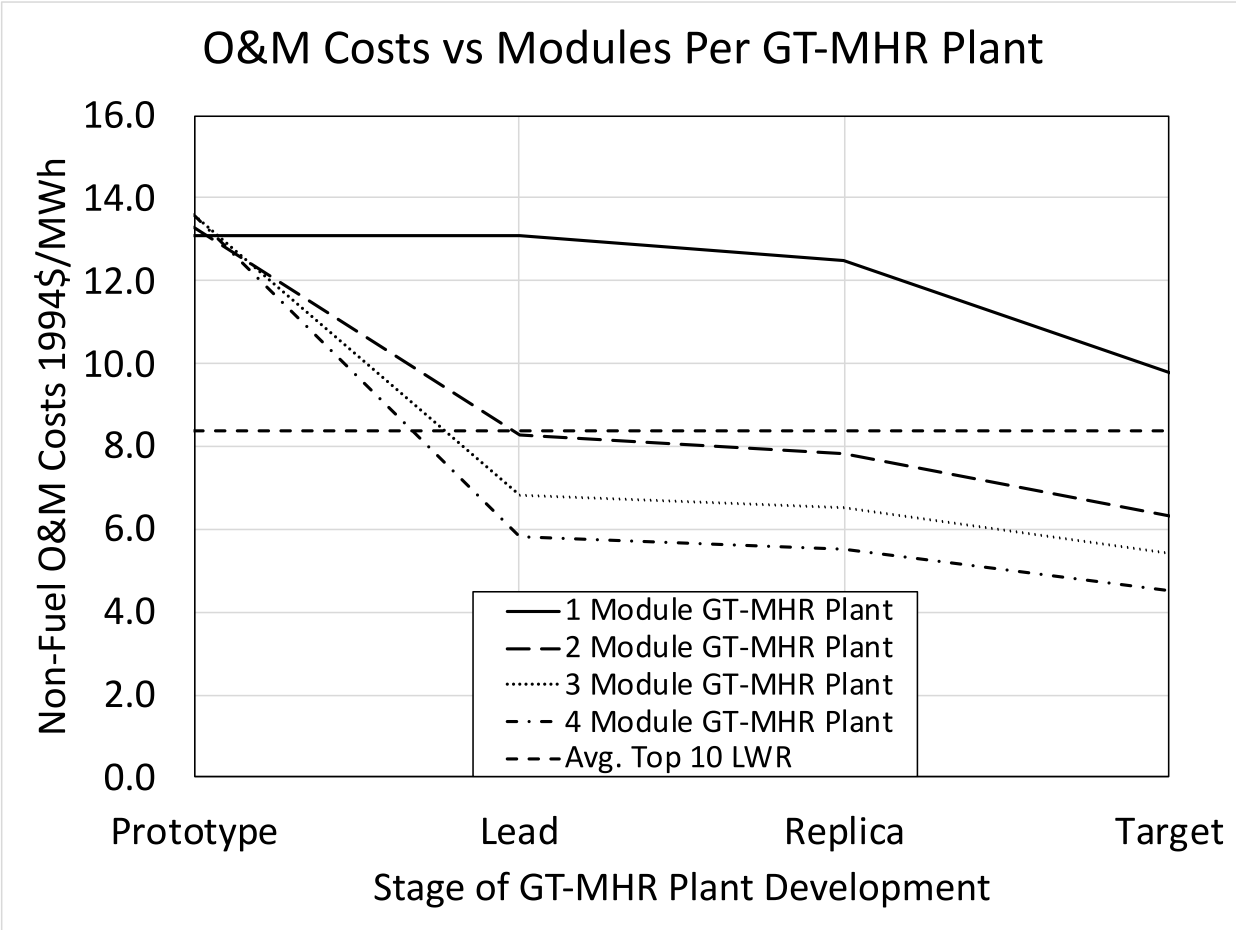

Figure A5-1. Learning projection of GT-MHR as a function of number of plants built and multi-unit site size.

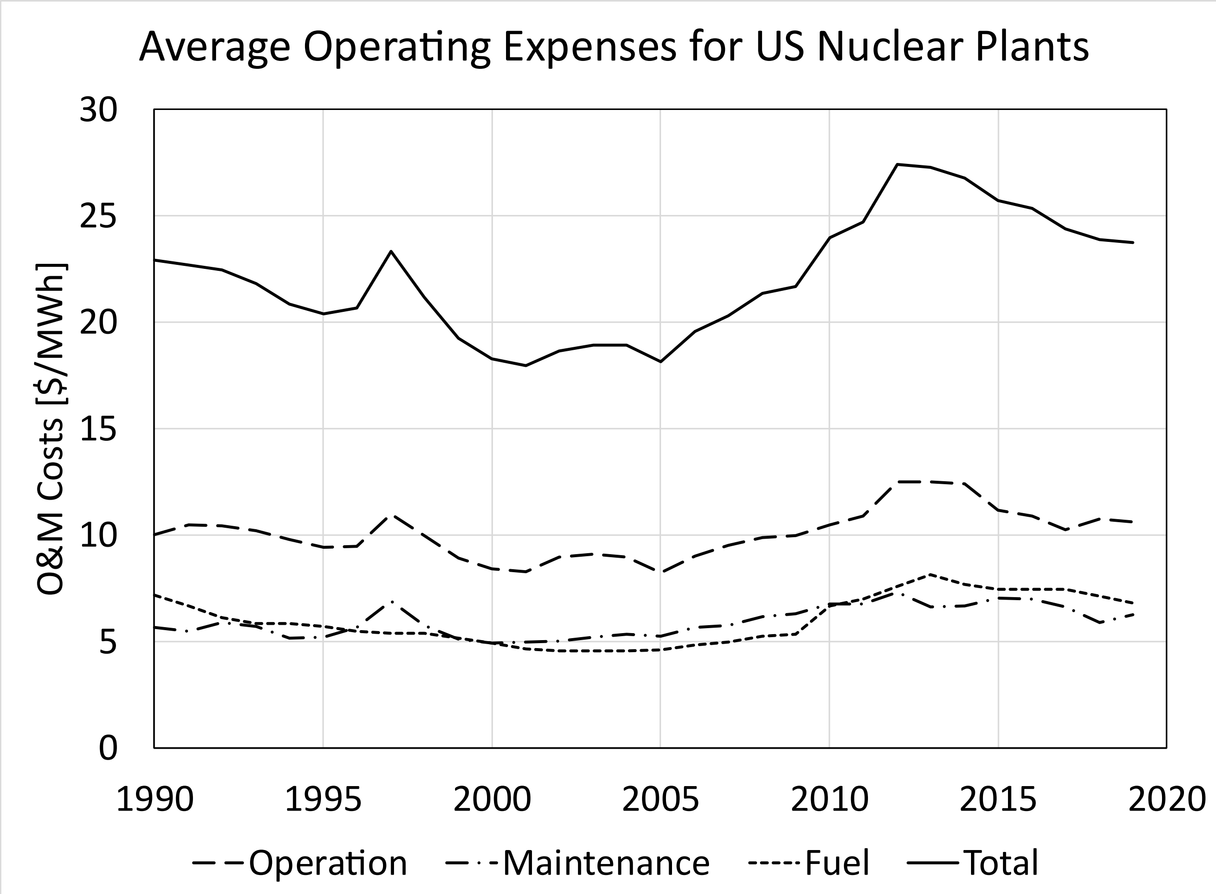

Figure A5-2. Recent O&M costs for average US nuclear plant (reported year dollars).

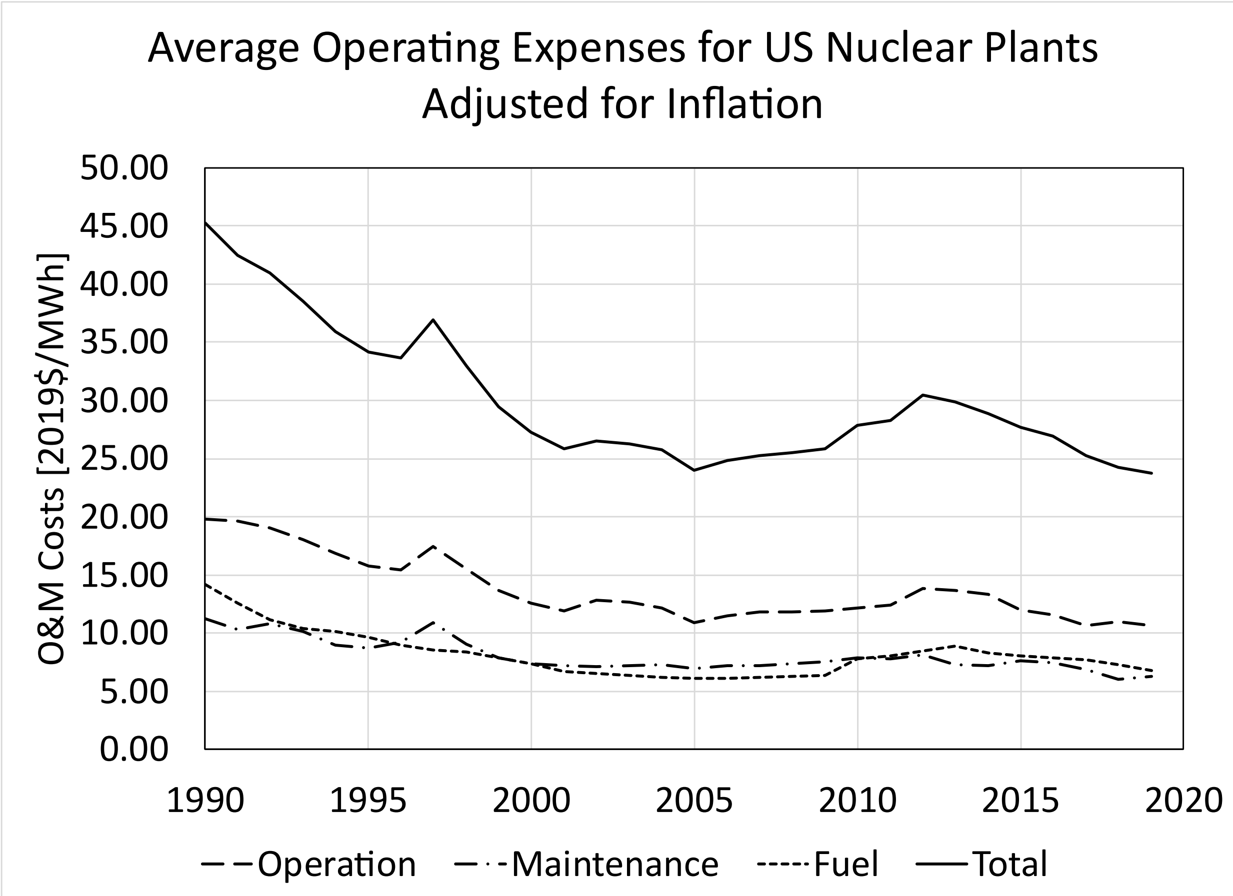

Figure A5-3. Recent O&M costs for average US nuclear plant (adjusted for inflation to 2019$).

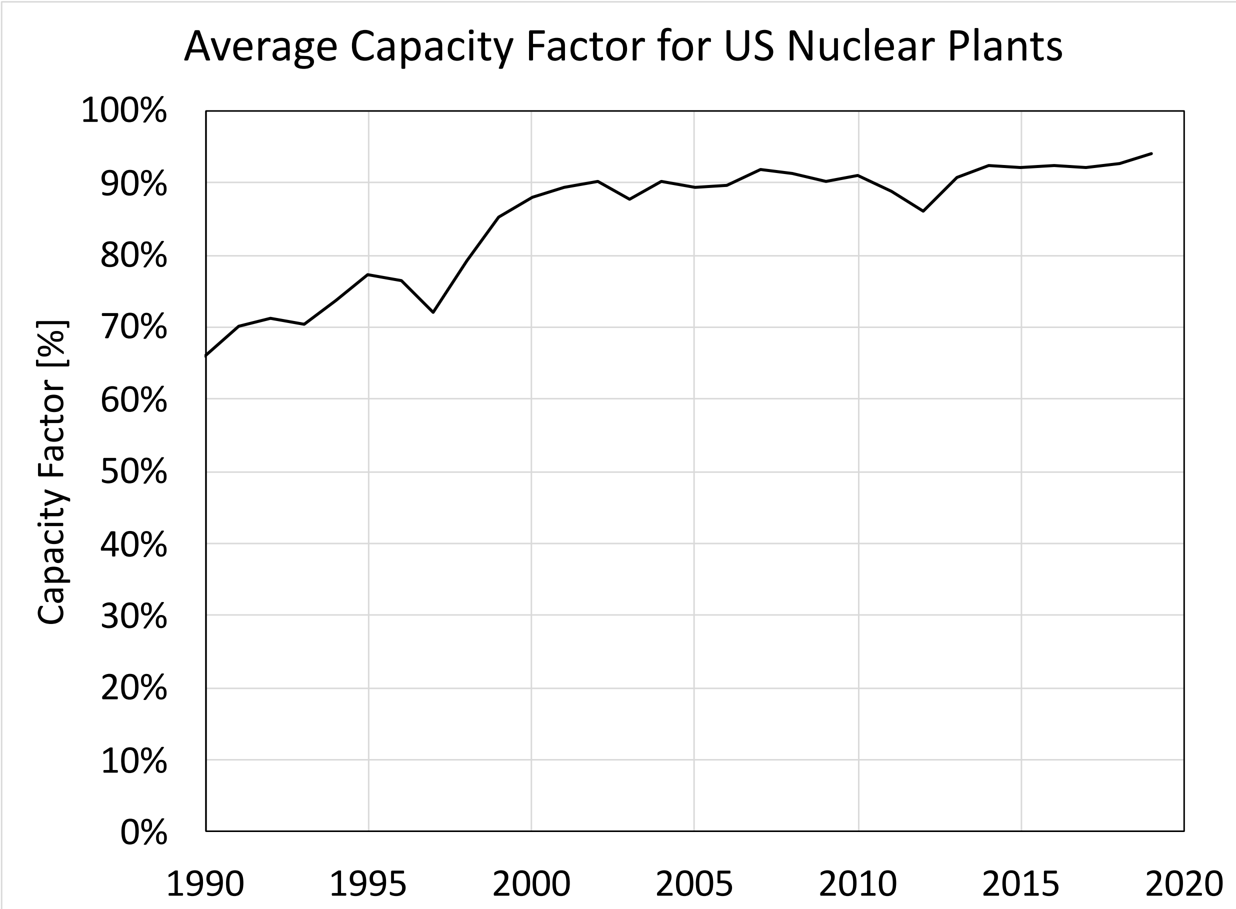

Figure A5-4. Average US nuclear capacity factor.

Scaling of OCC

This section describes scaling of overnight capital costs as a function of reactor size. It has long been suggested that scale economies might exist for large nuclear facilities under the Gen I to II technology paradigm. This may be apparent when viewing the early stages of nuclear development, however this effect may just be attributed to learning. As Phung [1987] suggests, regulatory and time-related costs compound and act to negate economies of scale, and the way to reduce costs is regulatory stability and design standardization. [Lovering and McBride 2020, OECD/NEA 2020] go further by indicating how small modular reactors seek to exploit learning, modularization/simplification, and standardization to achieve favorable economics.

Negative economies of scale may be observed for large plants due to the large radiological source term and the resulting regulatory and design burden (i.e., the need for redundant and diverse safety systems). However, the introduction and now preference for passive safety systems in Gen III+ and Gen IV plants limits the maximum size of a single reactor due to passive decay heat removal over long periods.

The argument for cost reduction via multi-unit sites is also given by Krautmann and Solow [1988]. Their work attempts to quantify economies of scale for nuclear power. Their conclusion was that any economies of scale for nuclear power are unproven for single unit sites. They suggest there likely exists favorable economics for multi-unit sites though they noted very few sites in the US that have more than two units and are therefore not large enough to benefit. The scale of the US electric grid limits the number of 1,000 MW nuclear units that can be built at a single site. It stands to reason that a large number of smaller units with equivalent electrical output to single large unit will better benefit from learning economies.

A mathematical treatment for scale economies is required with prior information as background. The exponential form used by Lovering and McBride [2020] and others is simple to use and is likely a reasonable approximation. Three scenarios are developed here.

- The first scenario is no economy of scale exists – the specific capital cost (in $/MW installed) of a large plant is the same as small plant. This scenario is possible if small plants are able to leverage learning and other advantages of being small to break-even with the cost of building a low power nuclear facility.
- The second scenario is positive economy of scale – where large plants costs less than small plants on a per kW basis.
- The third scenario is negative economy of scale – where small plants costs less than large plants on a per kW basis. This scenario is where small plants are built in sufficient number, thus taking full advantage of learning, modularization, simplification, and standardization, to actually be less (per kW) than large plants.

These scenarios are limited to being monotonic. It is possible that some intermediate power level is the cheapest. Certainly, some power level is the cheapest per kW, however a monotonic approach has been assumed by others and will be used here. The baseline size is the largest considered for this work: 1,000 MW.

The coefficients chosen for scaling are given in Table A5-4. Scaling functions take the form:

$$\frac{Cost_1}{Cost_2} = \left(\frac{Power_1}{Power_2}\right)^{n-1}$$

Where $Cost_x$ is the specific overnight capital cost of technology x, $Power_x$ is the electric power of technology x, and n is the scaling coefficient.

Table A5-4. Reactor size scaling coefficients and factors.

Power [MW]	Positive n=0.6	Equal n=1.0	Negative n=1.2
30	4.07	1.00	0.50
100	2.51	1.00	0.63
300	1.62	1.00	0.79
1,000	1.00	1.00	1.00

The data from Table A5-2 and Table A5-5 are combined and shown in Figure A5-5. Note the log-log scaling and use of relative size and cost. Plants designated as multi-unit such as GT-MHR and S-PRISM are shown with the relative power of a single unit and relative cost associated with building multiple units at a single site. Some references do not provide a specific plant size. In these instances, a relative size of 1.0 is assumed as most references are evaluating large nuclear installations. Recent commercial estimates of specific OCC are also included [Clifford 2021, Mulder 2021, NuScale 2020]. These estimates provide context for previous discussions on learning and the projected economics of small reactors. Given the proprietary nature of such estimates, there are no further details available at this time.

The selected scaling factors in Table A5-4 are based on enveloping the data and projections described above and listed in Table A5-2 and shown in Figure A5-5. This report uses NOAK costs which assume the full affect of learning. As described by Lovering, it is possible for small reactors to achieve specific OCC parity with large reactors with sufficient learning even when FOAK specific OCC estimates are significantly higher. As evidenced by the commercial projections, there are companies currently expecting to demonstrate specific OCC parity or reduction in the near term. Based on these reasons, the final values of the selected scaling factors were chosen to bound these estimates and projections.

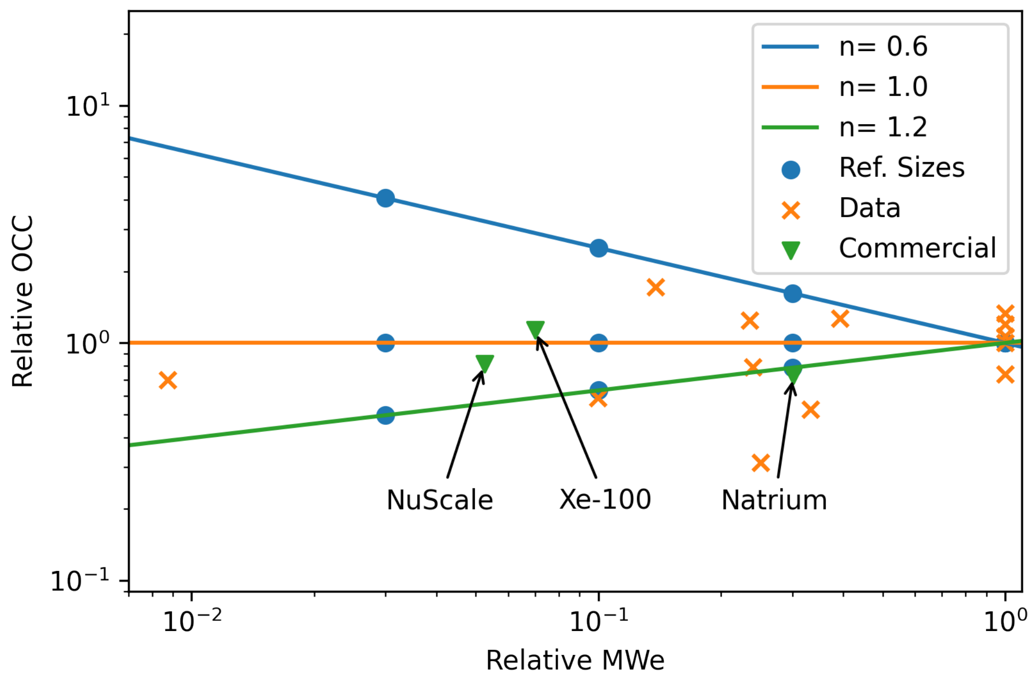

Figure A5-5. Relative OCC vs. relative reactor power.

Scaling of Non-Capital Costs

This section includes discussion of scaling methods for O&M and fuels costs as related to reactor size.

- *Scaling of Fixed O&M*

Fixed O&M costs are associated with plant staff and predictable acquisition of materials for plant O&M. Currently, several hundred full time staff are required for 1,000 MW plants. The number of staff required must correlate with reactor size for the economic viability of small reactors. Furthermore, multi-unit efficiencies must be realized, like multi-unit control rooms proposed for plants like NuScale. Other proposed cost reductions for small plants are related to the site boundaries and associated security and radiological monitoring costs. Very small plants may require remote monitoring and intermittent in-person O&M for economic viability, if technically achievable and permitted by regulator. In this instance, reductions in O&M may be achievable if small reactors are deployed in sufficient number. However, this scenario is very uncertain, and it is reasonable to assume that equal specific O&M can be achieved, at best.

Based on these considerations, scaling of fixed O&M is projected in two directions: equal or positive. Positive scaling is such that fixed O&M costs will be twice at 100 MW compared to 1,000 MW (n=0.7).

- *Scaling of Variable O&M*

Costs associated with variable O&M may be irregular or not as predictable as fixed O&M. They will undoubtably occur, so they are still included in cost projections. When it comes to reactor size, variable O&M will scale with the complexity of the power block. Power conversion technology specific O&M changes may also apply. For example, it might be expected that O&M would be higher for non-steam/water power conversion cycles at least until sufficient learning has occurred. Unexpected parts and maintenance associated with new systems may be accounted for in the variable O&M category.

Small reactors will thus likely see an increase in variable O&M costs. The same scaling assumption is used for fixed and variable O&M (n=0.7).

- *Scaling of Fuel Costs*

When considering reactor size, specific fuel costs are expected to be constant with size within the same fuel technology paradigm with consideration for possible losses in fuel efficiency due to unfavorable neutronic factors. However, many small plants propose alternate fuel forms or coolants which will affect specific fuel costs. Other factors that affect fuel cost include: level of enrichment, power balance efficiency, neutronic efficiency, discharge burnup, and fuel form.

Take for example a small HTGR reactor that has high power cycle efficiency, HALEU UCO TRISO, and high burnup. Each of these factors will increase or decrease specific fuel costs as compared to the reference LWR with Zr-clad UO_2 fuel enriched to <5%. The uncertainty of these costs for an NOAK HTGR, and the uncertainty for other small reactors of various technologies also without developed fuel cycles, necessitates a conservative approach for future cost estimates. Therefore, as specified below, fuel costs will escalate with decreasing reactor size.

The costs of LWR-type fuel are mature and well-known. Reactor size scaling within that technology envelope will mostly be affected by neutronic factors [Brown et al. 2017]. This inefficiency is approximated as 33% increase in uranium use (for a 100 MW SMR) which is assumed to directly correlated to the fuel cost- this will be represented with positive scaling factor of 0.87 as shown in Table A5-5. The literature review in previous sections indicates technology-dependent fuel costs may require specific fuel costs increases greater than 100% (e.g., NGNP), so it is possible that specific fuel costs will be even greater for small reactors

No near-term scenario has been identified for significantly reducing specific fuel costs, though with sufficient technological maturation, some advanced technologies may very well decrease specific fuel costs eventually. Since there is no general correlation of fuel technology to reactor size, and specific technology studies are outside the scope of this work, a simple approach based on the core physics arguments above is used.

Therefore, an exponential cost function of the same form used for OCC is proposed with scaling coefficients given in Table A5-5.

The cost of spent fuel disposal is $1/MWh regardless of other considerations and is internal to the fuel costs in the table.

Table A5-5. O&M and fuel scaling coefficients and factors.

Power [MW]	Fixed+Var O&M positive n=0.7	Fixed+Var O&M equal n=1	Fuel positive n=0.87
30	2.86	1.00	1.58
100	2.00	1.00	1.35
300	1.44	1.00	1.17
1,000	1.00	1.00	1.00

- *Other Costs*

The overnight cost of a nuclear plant, while significant, is multiplied by the financing costs to produce the total capital cost. Financing costs cannot usually be known at the beginning of a project. Instead, they can only be projected based on the expected construction duration and interest rates. Construction delays lead to immediate costs for wasted labor but can also lead to even more significant costs due to compounding. Once the plant is completed, costs can be paid back with revenues, so it is important for new plants to be built quickly after securing financing so they can start to pay back their debt. Financing can also be acquired "as-needed" during construction which can reduce the cost compared to acquiring all funds at the start of the project.

There are other factors that affect new nuclear plant financing. Large 1,000 MW plants require loans of several billion USD per unit. The size of the loan restricts the number of potential customers and lenders. Small nuclear units, or even multi-unit sites of small units, may need to only finance less than $1B. The lower cost to entry provides more options for customers and lenders. This competition and lower overall cost may reduce financing costs. Shorter construction durations and staggered construction schedules for small plants may lead to a more favorable economic situation that limits payments. Therefore, the financing costs may vary with reactor size.

For this study, financing costs will be reduced to two parameters: construction duration, t, and interest rate, r. The financing cost multiplier (FCM) is calculated by:

$$FCM = (1 + r)^{t/2}$$

Example calculations of the FCM are provided in Table A5-6. These factors can be applied to the OCC to estimate the additional cost to the project that comes from financing.

It is recognized that this is a simple estimation of financing costs incurred during construction. The aforementioned nuances of small reactor construction and operation are not included. A more complex accounting of these scheduled costs as a function of rector size or technology is recommended for future work.

Table A5-6. Example financing cost multipliers.

Construction duration [yr]	Interest rate [%]	FCM [-]
2	2.5	1.025
3	3	1.045
4	4	1.082
5	5	1.130
5	7	1.184

Cost Assumptions Associated with Thermal Energy Storage

Thermal energy storage is mostly an add-on cost for nuclear, even when an integral part of the reactor design (as considered in Natrium). Addition of TES to nuclear is assumed to not significantly change specific fuel costs. Additional capital and O&M costs are expected. The additional costs are associated with purchase and installation of new equipment, modification or augmentation of equipment needed for non-TES installation, and additional maintenance of equipment caused by cyclic loading[4]. For a TES to provide benefit to nuclear, these costs must be offset by additional market opportunities.

Costs scale with the size of the TES within a given technology. While certain technologies may be more cost beneficial at certain nameplate ratings, it is assumed here that a general economy of scale exists. There are many factors that might determine the selection of a TES to pair with a given nuclear plant including working fluid compatibility, heat exchanger material compatibility, desired storage size, and desired storage charge/discharge rate. For the purposes of this report, a TES is considered to be collocated with the nuclear unit and integrated with the nuclear BOP. This assumption limits the types and scale of TES.

Cost scaling for TES systems compatible with CSP are summarized by [Glatzmaier 2011]. Costs are shown to scale with operating temperature (higher is cheaper) and specific heat capacity of the storage medium (again, higher is cheaper). No size scaling was performed; however, the target size was for a 6hr storage coupled to 100 MW CSP. Scaling with temperature and working fluid is a technology specific type of scaling which is outside of scope of this work. It is recognized that small reactors with non-traditional working fluids may be more or less compatible with baseline TES systems depending on their temperature and working fluid(s).

It has been suggested that scaling of a TES may occur using standard scale laws observed for chemical equipment or heat exchangers [Jacob et al. 2017]. However, this approach has not yet been verified considering the uncertainty in large TES systems required for nuclear.

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[4] Alternatively, one might purchase different equipment that is designed for cyclic loading, however this cost would be accounted in the category of equipment augmentation. Whether augmented equipment is purchased or original equipment is maintained more often is an economic question for each operator to answer. Regardless, some additional cost is associated with addition of TES.

Due to scales associated with reactor technology (with advanced, high temperature reactors being able to leverage more efficient TES systems), TES equipment size, and TES thermal efficiency many scaling scenarios could be considered. It is recognized that specific reactor technologies may benefit from specific TES scaling synergies. Scaling occurs independently based on power block size, and energy storage size. A constant factor of $600/kW was used for TES power block scaling. A factor of $60/MWh was used for energy. The combined capital cost is then escalated using the FCM. O&M costs are derived from [Herrmann et al. 2004] as $0.0545/kW/MWh. For this study, it is assumed that a TES does not increase the O&M of a nuclear plant, but instead has its own attributable O&M costs. A TES is intended to allow the nuclear reactor to operate at maximum capacity instead of load-following. If the TES is appropriately sized for its local electricity market, then the need for reactor load-following should be minimized. Therefore, additional nuclear O&M costs are neglected under this “right-sized” assumption.

Costs Summary

There are many factors that affect the cost of nuclear plant as a function of its size. While classical economies of scale may be thought to apply within a type of technology, there are many differences between proposed, yet-to-be-built small reactors and operating LWRs which contradict scale economy assumptions. While FOAK inefficiencies are expected, the increased learning rate per MW-installed of small plants may allow for realization of cost parity or reduction for NOAK small plants when compared to large plants.

Beyond OCC projections, the fueling and operation of small plants will also be different. For fuel, size has some known detrimental neutronic effects, though they may be augmented or countered by changes to fuel form, composition, or enrichment which are less well known on the scale required for power reactor operations. O&M costs for large LWRs have been decreasing in recent decades as capacity factors have increased and competitive pressure has increased on nuclear plants to operate in markets against VRE and fossil fuel sources. While small reactors may benefit from some of these improvements to plant operations, they may require new approaches to account for changes in technology as compared to steam cycle LWRs. As was the case for OCC, cost increases should be expected before learning is realized for O&M on the way to NOAK.

To account for these uncertainties, scaling factors are proposed to take the known, well-established data of operating LWRs and quantify the costs of reactors based on size. Three types of size scaling are suggested: positive, equal, and negative.

A set of scenarios is presented in Table A5-7 and Table A5-8. These scenarios incorporate all the previous discussion on reactor size and scaling.

Table A5-7. Reactor size analysis scenarios.

Power	Construction time, loan rate	Scaling Factor OCC/O&M	Specific Overnight Capital	CAPEX	Fixed O&M	Variable O&M	Fuel
[MW]	yr, %	n/n, e/e, p/n, p/p	$/kWe	$/kWe	$/MWh	$/MWh	$/MWh
1,000	5yr , 5%	n/e	4416	4989	8.64	1.87	5.18
300	5yr , 5%	n/e	3471	3921	8.64	1.87	6.06
100	5yr , 5%	n/e	2786	3148	8.64	1.87	6.99
30	5yr , 5%	n/e	2190	2474	8.64	1.87	8.17
300	5yr , 5%	e/e	4416	4989	8.64	1.87	6.06
100	5yr , 5%	e/e	4416	4989	8.64	1.87	6.99
30	5yr , 5%	e/e	4416	4989	8.64	1.87	8.17
300	5yr , 5%	p/e	7148	8075	8.64	1.87	6.06
100	5yr , 5%	p/e	11092	12531	8.64	1.87	6.99
30	5yr , 5%	p/e	17955	20284	8.64	1.87	8.17
300	5yr , 5%	e/p	4416	4989	12.40	2.68	6.06
100	5yr , 5%	e/p	4416	4989	17.24	3.73	6.99
30	5yr , 5%	e/p	4416	4989	24.74	5.35	8.17
300	4yr , 4%	e/e	4416	4776	8.64	1.87	6.06
300	5yr , 7%	e/e	4416	5230	8.64	1.87	6.06
100	3yr , 3%	e/e	4416	4616	8.64	1.87	6.99
30	2yr , 2.5%	e/e	4416	4526	8.64	1.87	8.17

Table A5-8. Reactor flexibility with TES scenarios.

Power Baseload +TES	Construction time, loan rate	TES storage size	Specific Over-night Capital	CAPEX	Nuc. Fixed O&M	Nuc. Variable O&M	Fuel	TES O&M
[MW]	yr, %	MWh	$/kWe	$/kWe	$/MWh	$/MWh	$/MWh	$/kWe/yr
300 + 300	5yr , 5%	600	4416 + 720	4989 + 813	8.64	1.87	6.06	32.7
300 + 300	5yr , 5%	1200	4416 + 840	4989 + 949	8.64	1.87	6.06	65.4
300 + 150	5yr , 5%	300	4416 + 720	4989 + 813	8.64	1.87	6.06	16.35
300 + 150	5yr , 5%	600	4416 + 840	4989 + 949	8.64	1.87	6.06	32.7
300 + 600	5yr , 5%	1200	4416 + 720	4989 + 813	8.64	1.87	6.06	65.4
300 + 600	5yr , 5%	2400	4416 + 840	4989 + 949	8.64	1.87	6.06	130.8