LUCID CATALYST

Cost & Performance Requirements for Flexible Advanced Nuclear Plants in Future U.S. Power Markets

Acknowledgements

Cost and Performance Requirements for Flexible Advanced Nuclear Plants in Future U.S. Power Markets

Report for the ORNL Resource team supporting ARPA-E's MEITNER Program
July 2020

Authors: Eric Ingersoll, Kirsty Gogan, John Herter, Andrew Foss

With assistance from: Jane Pickering and Romana Vysatova

We are grateful to our reviewers and advisors:

Steve Brick, Senior Fellow, The Chicago Council on Global Affairs

Charles Forsberg, Principal Research Scientist and Executive Director, MIT Nuclear Fuel Cycle Project

Jesse Jenkins, Assistant Professor, Princeton University

Abram Klein, Managing Partner, Appian Way Energy Partners

Mike Middleton, Practice Manager Nuclear, UK Energy Systems Catapult

David Mohler, Former CTO and SVP, Duke Energy; Former Deputy Assistant Secretary for Clean Coal and Carbon Management, Office of Fossil Energy, U.S. Department of Energy

Bruce Phillips, Director, The NorthBridge Group

Dave Rogers, Former Head of Global Project Development & Finance Practice, Latham & Watkins LLP

LUCID CATALYST

lucidcatalyst.com

Contents

Tables

Figures

List of Abbreviations & Acronyms

ARPA-E	Advanced Research Projects Agency–Energy (U.S. Dept of Energy)
CAISO	California Independent System Operator
CapEx	Capital Expenditures
CCGT	Combined Cycle Natural Gas Plant
CP	Capacity Performance
DAM	Day-Ahead Market
DER	Distributed Energy Resources
DR	Demand Response
ESIG	Energy Systems Integration Group (Berkeley National Laboratory)
ESS	Energy Storage System
FRAC-MOO	Flexible Resource Adequacy Criteria and Must-Offer Obligation
FRP	Flexible Ramping Product
HALU	High-Assay Low-Enriched Uranium
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
LC	LucidCatalyst L.L.C.
LEU	Low-Enriched Uranium
LSE	Load Serving Entity
MEITNER	Modeling-Enhanced Innovations Trailblazing Nuclear Energy Reinvigoration (a program of ARPA-E)
MISO	Midcontinent Independent System Operator
NGCC	Natural Gas Combined Cycle power plant
NOPR	Notice of Proposed Rule Making
NREL	National Renewable Energy Laboratory (U.S. Dept of Energy)
O&M	Operations and Maintenance
PAI	Performance Assessment Interval
PAH	Performance Assessment Hours
PFP	Pay for Performance
PJM	Pennsylvania-Jersey-Maryland Power Pool (now larger area ISO)
PPA	Power Purchase Agreement
RCP	Ramp Capability Product
ReEDS	Regional Energy Deployment System (NREL model)
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standard
RTM	Real-Time Market
RTO	Regional Transmission Operator
TRISO	Tristructural-Isotropic nuclear fuel pellets
UCM	Unit Control Mode
VRE	Variable Renewable Energy
WACC	Weighted Average Cost of Capital

Executive Summary

1

Executive Summary

Advanced reactor developers are at various stages of commercializing new products and must design for future market environments that will exist when their plants are available. It is therefore critical to have a clear understanding about what plants will need to cost to be attractive investments, and what performance characteristics will create the most value for plant owners.

This study is among the first to model the substantial contribution that flexible advanced reactors can make towards reliable, responsive, affordable, and clean future energy systems by supplying clean dispatchable generating capacity.

Advanced reactor technologies could make a major contribution to lowering the overall system cost while reducing emissions and improving the performance of future energy systems. Depending on specific market conditions, it may also be beneficial to co-locate thermal energy storage systems (ESS).

This is an unusual time. Competitive power markets are experiencing extended periods of very low power prices, driven primarily by large supplies of low-cost natural gas. At the same, growth in demand for electricity has stagnated in many areas of the U.S, driven by deindustrialization and efficiency improvements. These power market conditions would normally discourage new entrants. However, federal incentives, state policies, and corporate purchases of renewable energy are driving significant deployment of wind and solar, further depressing wholesale power prices. Remarkably, in spite of these conditions, there are now more companies developing advanced reactors than at any other time in history. However, reactor developers today must design for very different future market conditions, as described in this report, than nuclear plants have seen in the past.

In this new environment, it is critical for advanced reactor design teams to have clear signals from the market about what plants need to cost to be attractive investments, and what performance characteristics will create the most value for plant owners. Many advanced reactor designs are still in the conceptual design stage and therefore have large scope for reducing capital expenditures (CapEx) through design choices and applying target cost design methods. Designers face critical questions such as: How flexible should the reactor be? How much is that flexibility worth? How much effort and/or cost should be expended to deliver flexible performance and how much value can that create for the plant owner?

This report summarizes a modeling effort to estimate the highest allowable CapEx for advanced nuclear plants in future power market environments while still achieving a market rate of return for their owners. The goal is to define target cost and performance parameters determined by future market conditions to guide design choices and tradeoffs in the early stage of the reactor and power plant development process.

This work was funded by the U.S. Department of Energy's (DoE) Advanced Research Projects Agency-Energy's (ARPA-E) Modeling-Enhanced Innovations Trailblazing Nuclear Energy Reinvigoration (MEITNER) program thorough a Work Authorization to DoE's Oak Ridge National Laboratory. The intent was to provide guidance to Design Teams developing advanced reactors.

LucidCatalyst performed the grid modeling and underlying financial analyses summarized in this report. We used PLEXOS® electricity production cost modeling software to estimate the revenues earned by a generic high-temperature advanced nuclear plant in deregulated power markets in the mid-2030s. These revenues were then analyzed in a power plant financial model to determine the maximum allowable CapEx for which a plant must be delivered to achieve a market rate of return.

LucidCatalyst modeled two different future scenarios, each containing different resource mixes. The first was a baseline, 'low renewables' (Low RE) scenario, which presumes a continuation (and eventual expiration) of existing renewables policy. The second was a 'high renewables' (High RE) scenario that has the same resource mix as an NREL[1] Regional Energy Deployment System (ReEDS) scenario. The ReEDS scenario assumes low renewables costs and low natural gas prices (and thus high penetration of both resource types).[2] Both scenarios were modeled across the four principal deregulated U.S. power markets for the year 2034: (1) ISO-New England (ISO-NE); (2) the Pennsylvania, Jersey, Maryland Power Pool (PJM);[3] (3) the Midcontinent Independent System Operator (MISO); and (4) the California ISO (CAISO).

Assuming capacity payments seen in today's capacity markets, the PLEXOS modeling revealed that the average maximum allowable CapEx across all scenarios is $3,234/kW. This reflects a range: from a minimum of $1,965/kW to a maximum of $4,503/kW, depending on the power market, resource mix, and capacity payment amount. Each modeled scenario also includes a run with a 12-hour, integrated thermal energy storage system (ESS). The additional revenues from the 'nuclear + storage' plant justified extra allowable CapEx, ranging from $613/kW to $1,891/kW across the modeled scenarios and ISOs. The table below provides the maximum allowable CapEx for each modeled scenario and power market.

Executive Summary Table 1. **Maximum Allowable CapEx by ISO and Scenario ($/kW)**

		Low Renewables		**High Renewables**	
		w/o ESS	with ESS	w/o ESS	with ESS
ISO-NE	Low Capacity Price Case ($50/kW-yr)	$2,289	$2,962	$1,965	$2,788
	Mid Capacity Price Case ($75/kW-yr)	$2,566	$3,515	$2,242	$3,341
	High Capacity Price Case ($100/kW-yr)	$2,843	$4,068	$2,519	$3,894
PJM	Low Capacity Price Case ($50/kW-yr)	$2,358	$2,988	$2,186	$3,038
	Mid Capacity Price Case ($75/kW-yr)	$2,634	$3,541	$2,462	$3,591
	High Capacity Price Case ($100/kW-yr)	$2,911	$4,095	$2,739	$4,144
MISO	Low Capacity Price Case ($50/kW-yr)	$2,244	$2,857	$2,000	$2,654
	Mid Capacity Price Case ($75/kW-yr)	$2,521	$3,410	$2,276	$3,207
	High Capacity Price Case ($100/kW-yr)	$2,797	$3,963	$2,553	$3,760

		Low Renewables w/o ESS	Low Renewables with ESS	High Renewables w/o ESS	High Renewables with ESS
CAISO	Low Capacity Price Case ($50/kW-yr)	$2,187	$3,397	$1,968	$3,306
	Mid Capacity Price Case ($75/kW-yr)	$2,464	$3,950	$2,244	$3,859
	High Capacity Price Case ($100/kW-yr)	$2,740	$4,503	$2,521	$4,412

LucidCatalyst performed additional sensitivity analyses to assess the impact of other factors on maximum allowable CapEx. One scenario included a large fleet of advanced nuclear plants with ESS. Due to relatively low operating costs, advanced nuclear plants set lower energy clearing prices and thus decreased the allowable CapEx thresholds. Importantly, the lower average energy prices led to a small decrease in the total cost of energy delivery for the ISO, as shown in the following table.

Executive Summary Table 2. **Annual Average Market Prices for ISO-NE, PJM, MISO, and CAISO**

		Average Annual Energy Price
ISO-NE	High RE Future (Without Flexible Adv. Nuclear)	$26.32/MWh
	Fleet Deployment of Flexible Adv. Nuclear	$22.64/MWh
PJM	High RE Future (Without Flexible Adv. Nuclear)	$27.03/MWh
	Fleet Deployment of Flexible Adv. Nuclear	$22.67/MWh
MISO	High RE Future (Without Flexible Adv. Nuclear)	$26.13/MWh
	Fleet Deployment of Flexible Adv. Nuclear	$24.70/MWh
CAISO	High RE Future (Without Flexible Adv. Nuclear)	$38.06/MWh
	Fleet Deployment of Flexible Adv. Nuclear	$29.61/MWh

A second scenario explored the influence of operations and maintenance (O&M) costs on maximum allowable CapEx. Each $1/kW-year in O&M cost reduction resulted in an increase in the allowable CapEx of approximately $11/kW. The difference between the low O&M case and the high case ($61/kW-year) is $337/kW of CapEx. To put this in perspective, for plants without the ESS, this has more impact on CapEx than a reduction of $25/kW-year in capacity payments—for no additional value (energy or capacity) delivered to the market.

The generic high-temperature reactor modeled in this study potentially enables cost-effective thermal ESS. Conceptually, this operates by diverting heat from making steam for the turbine to a thermal store. In the same way that LucidCatalyst did not model a specific reactor technology, the modeling did not reflect any specific thermal storage technology.[4] Rather, it was intended to determine the allowable cost of, and value created by, the thermal energy storage system.

The integrated thermal energy storage system always increased the allowable CapEx; however, the PLEXOS modeling revealed that the scale of such an improvement depended on several factors. The plant with ESS stops making steam for the primary turbine during the lowest priced hours, storing heat from the reactor in the thermal storage facility, and then sells from both the primary and the storage facility turbine during the highest priced hours. This allows the 500 MW plant to sell no electricity for 12 hours and produce at 1,000 MWe for the other 12 hours, while the nuclear island operates continuously at full power. The amount of CapEx that can be budgeted for thermal storage depends on the grid resource mix (e.g., Low RE vs. High RE scenario), and importantly, the prevailing capacity payment.

The PLEXOS modeling revealed that co-locating a thermal energy storage system makes economic sense if the system can be built for less than $1,126/kW on average.[5] This finding should motivate further research and development in innovative, cost-effective thermal energy storage systems for integration with advanced reactors. It is also important to note that without the thermal ESS (or an alternative revenue source such as hydrogen production, process heat for industry, etc.), the modeled plants' capacity factors suffer significantly in areas with high renewable penetration.

Most market mechanisms designed to compensate flexible and dispatchable generators are still too early-stage to be able to gauge their significance in the mid-2030s. The grid will undoubtedly demand large amounts of flexible resources by that time; however, it is currently unclear how much energy will be transacted through these new products. Nonetheless, developers should track how these products evolve. Further, they should track the development of competitive technologies such as energy storage, distributed energy resources (DERs), demand-side solutions like flexible loads (e.g., EVs, electric hot water heaters, smart thermostats, etc.), and demand response programs. These resources help 'time shift' demand, smooth power flows across the grid, and enhance grid flexibility overall. They are less effective, however, in serving increases in overall electricity demand (absent DER generators). With the electrification of the transportation sector (as well as other sectors) expected to increase overall demand, advanced nuclear plants with thermal energy storage are uniquely suited to meet that demand—particularly in markets with high penetration of renewables, where ramping is needed.

Although regulated electricity markets were outside the modeling scope, advanced nuclear developers may find it favorable to focus on these markets for their initial sales efforts. Regulated utilities can utilize all the benefits of highly rampable and dispatchable output without requiring complex, often contested, and relatively slow-moving market reforms to reveal the value of certain grid services. For these reasons, regulated markets have been, in practical terms, the first markets for Gen III and III+ nuclear plants as well as other innovative power projects (see NuScale Power's current development efforts in Utah or the Kemper carbon capture and sequestration project in Mississippi).

Considering advanced nuclear plants can operate as baseload resources as well as following load, they can supply a large fraction of firm power without raising the overall cost of electricity. This conclusion should motivate ISO operators, public utility commissioners, policymakers, utilities, and other stakeholders to investigate the role that these products could play in the grids of the future and to continue supporting advanced nuclear commercialization efforts. This should also motivate organizations responsible for national and international energy modeling to include flexible, advanced nuclear with thermal energy storage in their projections for future energy systems.

The CapEx thresholds highlighted in this report are relatively low compared to conventional nuclear new-build plants in North America and Europe. However, they are well within the range of those reported by third-party cost studies[6] and advanced nuclear developers themselves. This range is also well within the costs being achieved in countries with continuous new build nuclear programs.[7] Designers should integrate these cost requirements into their plant designs and consider whether adding thermal storage makes sense in their target markets.

Main Report

2 Introduction

Several advanced nuclear plants are being designed to have similar ramping and load-following capabilities as combined-cycle natural gas plants (CCGTs). Because they also provide 24/7 emissions-free, baseload generation, the U.S. Department of Energy's Advanced Research Projects Agency-Energy (ARPA-E) approached a variety of stakeholders to better understand the factors that could potentially increase their procurement appeal.

ARPA-E arranged several meetings with utilities, policymakers, and other organizations involved in the commercialization process for advanced nuclear technology. The goal was to solicit input on the conditions that would lead to increased support. Discussions covered a range of topics and high-level feedback largely fell into the following criteria:

- Low overnight construction cost
- Fast ramp rate without steam bypass (power capacity/min)
- Short onsite construction time
- Reduced staffing levels (onsite and offsite)
- Smaller emergency planning zone limited to site boundary
- Longer time before human response required for an accident
- Reliable onsite backup power
- High process heat temperature

These criteria offer useful guiding principles for advanced reactor designers as they derive from organizations that influence, oversee, and ultimately make power plant investment decisions. They also formed the basis for eligibility requirements for ARPA-E's MEITNER (Modeling-Enhanced Innovations Trailblazing Nuclear Energy Reinvigoration) program. The MEITNER program supports a collection of projects that "seek to identify and develop innovative technologies that can enable designs for lower cost, safer advanced nuclear reactors… [and] establish the basis for a modern, domestic supply chain supporting nuclear technology."[8]

This report focuses on the first two criteria from the list above and examines the potential for advanced nuclear plants to meet the growing need for grid flexibility. Specifically, it uses PLEXOS® production cost modeling software to estimate revenues earned by a generic advanced nuclear plant in deregulated power markets with low-renewables or high-renewables scenarios in the mid-2030s. Revenues are used to estimate the maximum allowable CapEx, or the maximum cost for which a plant must be delivered. The intent is to provide advanced reactor developers, including the MEITNER program's Design Teams, with information regarding the value of 'flexible' operation (i.e., highly-rampable and capable of load following) and the CapEx targets they need to achieve by the time their reactors are commercially available. This information also allows developers to assess design trade-offs, inform interim technical targets, evaluate projected system performance, and articulate the need and impact of further investments to public and private funders.

This analysis was conducted with funding provided through an ARPA-E Work Authorization to DoE's Oak Ridge National Laboratory, which subcontracted to LucidCatalyst.

2.1 Estimating Maximum Allowable Capex in Future Markets Using Plexos Software

LucidCatalyst modeled flexible (i.e., highly-rampable), advanced nuclear plants in the four principal deregulated U.S. power markets: (1) ISO-New England (ISO-NE); (2) Pennsylvania, Jersey, Maryland Power Pool (PJM); (3) Midcontinent Independent System Operator (MISO); and (4) California ISO (CAISO). The modeling runs were set in the year 2034,[9] under the assumption that advanced nuclear plants will be commercially available by then. LucidCatalyst modeled two potential 2034 scenarios, based on different variable renewable energy[10] (VRE) penetration assumptions:

- **Baseline Renewables Future:** This conservative renewables case reflects built-in values in the PLEXOS software, which are the result of a capacity expansion/optimization model run performed by Energy Exemplar (makers of PLEXOS) for 2034 and beyond. This assumes that all current state Renewable Portfolio Standard (RPS) targets, tax credits, and other existing legislation that supports renewables deployment—current as of January 1, 2019—take effect. It does not include any non-binding targets or assume any future policy that could stimulate further renewables deployment.
- **Higher Renewables Future:** This scenario is based on the 'Low Natural Gas Price/Low Renewables Cost' scenario included in NREL's Regional Energy Deployment System (ReEDS) model (described in Section 5.2.2).[11] This assumes a higher renewables build-out and that natural gas prices do not significantly differ from today's prices (~$3/MMBtu). This implies that advanced nuclear plants need to compete with highly flexible, new-build combined-cycle gas plants in a low-cost natural gas environment.

Assuming the current spectrum of capacity payments seen in today's capacity markets, LucidCatalyst concluded that flexible advanced nuclear plants have an allowable CapEx threshold of between $1,965/kW and $4,503/kW, depending on ISO, VRE scenario, and assumptions related to capacity payments (see Section 7). LucidCatalyst also modeled a parallel scenario that includes a 12-hour, co-located energy storage system (ESS). The additional revenues from the 'nuclear + ESS' plant justified extra allowable CapEx ranging from $613/kW to $1,891/kW. This range is also driven by different scenario assumptions, but the key finding is that higher renewables penetration leads to higher ESS revenues.

LucidCatalyst modeled three additional 2034 scenarios. Each examined the impact on maximum allowable CapEx from (1) a hypothetical range of CO_2 prices, (2) a large fleet of advanced reactors operating in the same market, and (3) an alternative assumption for annual fixed O&M cost.

2.2 Report Structure

This report is primarily intended for advanced reactor developers with relatively little knowledge and/or experience with wholesale electricity markets. The report is divided into the following sections:

1 **Executive Summary**

2 **Introduction**

3 **Revenue Generation in Deregulated and Regulated Power Markets**
This section provides advanced reactor developers with a brief, high-level overview of how energy prices are set in wholesale power markets in the U.S. and highlights the most relevant revenue streams for advanced nuclear plants. It is not an exhaustive review of all aspects of market operations and settlements; rather, it focuses on the basics of price formation in deregulated markets and procurement in regulated markets.

4 **Current Revenue Potential and VRE Effects on Nuclear Projects**
Flexible, dispatchable resources are increasingly important as VRE deployment continues to rise. This section explains how VREs depress average wholesale energy prices and present fundamental challenges to grid management and current power market design. It also describes how increasing

quantities of VRE pose an existential threat to the economic viability of 'must-run' baseload assets, such as conventional nuclear plants. The goal is to provide a brief survey of the U.S. energy landscape such that advanced reactor developers have a baseline understanding from which to view the 2034 scenarios.

5 **PLEXOS and Financial Modeling Methodology and Assumptions**
LucidCatalyst developed an illustrative, advanced nuclear plant for PLEXOS modeling runs. This section includes the cost and performance assumptions for this illustrative plant and describes the methodology for preparing the 2034 low- and high-renewables scenarios in PLEXOS.

6 **Illustrative Cash Flow Analysis**
With the report's focus on allowable CapEx, it is important to walk through how this figure is calculated. This section describes the sequence of steps taken to arrive at this figure, under a set of prescribed market conditions. This provides the basis for understanding the PLEXOS modeling results.

7 **PLEXOS Modeling Results for 2034**
All 2034 modeling results are presented in this section. Specifically, it highlights the maximum allowable CapEx for flexible advanced nuclear plants in four deregulated power markets (ISO-NE, PJM, MISO, and CAISO), in the baseline- and high-renewable environments, and under a range of related input assumptions.

8 **Additional Modeling Analyses**
Several factors can influence a plant's maximum allowable CapEx. This section presents the CapEx implications of CO_2 pricing and market penetration potential. Additional modeling scenarios in this section examine the impact of a CO_2 price on CapEx, the potential to deploy significant quantity of advanced nuclear capacity without affecting energy prices (and therefore allowable CapEx), and the relationship between expected fixed O&M costs and allowable CapEx.

9 **Conclusions**
The PLEXOS modeling reveals several takeaways for MEITNER participants as they consider their plant designs. This section summarizes the findings from the modeling analysis and provides commentary on how flexible advanced nuclear plants can be delivered for less than the maximum allowable CapEx such that they can play a vital role in delivering a clean, reliable, flexible, and low-cost electric power system.

10 **Appendices**
This report also contains useful reference information for advanced reactor developers, including the MEITNER Design Teams, in the following appendices:

A. Historical revenues by market product in select ISOs

B. New market mechanisms that capture the value of resource flexibility

C. Desirable performance attributes and market participation requirements

D. Alternative ways of providing system flexibility

E. High-level cost analysis of energy storage system

F. High-level estimate of non-nuclear island costs

3 Revenue Generation in Deregulated and Regulated Power Markets

It is important that advanced reactor developers have a basic understanding of the relevant revenue streams, how energy prices are set, and relative advantages and disadvantages of deploying in deregulated and regulated power markets.

Price data included in this section are from the ISOs modeled in this analysis (ISO-NE, PJM, MISO, and CAISO).

3.1 Available Revenue Streams for Advanced Nuclear Plants in Deregulated Markets

The majority of electricity bought and sold on the electric power grid is transacted through bilateral Power Purchase Agreements (PPAs). PPAs involve two parties agreeing to a price, quantity of electricity to be supplied, and period over which that electricity is to be delivered. In deregulated markets, while most energy sales are still transacted through PPAs, there is a competitive marketplace where energy, capacity, and ancillary services (used to balance the grid) are bought and sold. Table 1 below lists the various revenue opportunities for flexible advanced nuclear power plants and qualifies their relevance.

Table 1. **Relevance of Available Revenue Streams for Flexible Advanced Reactors**

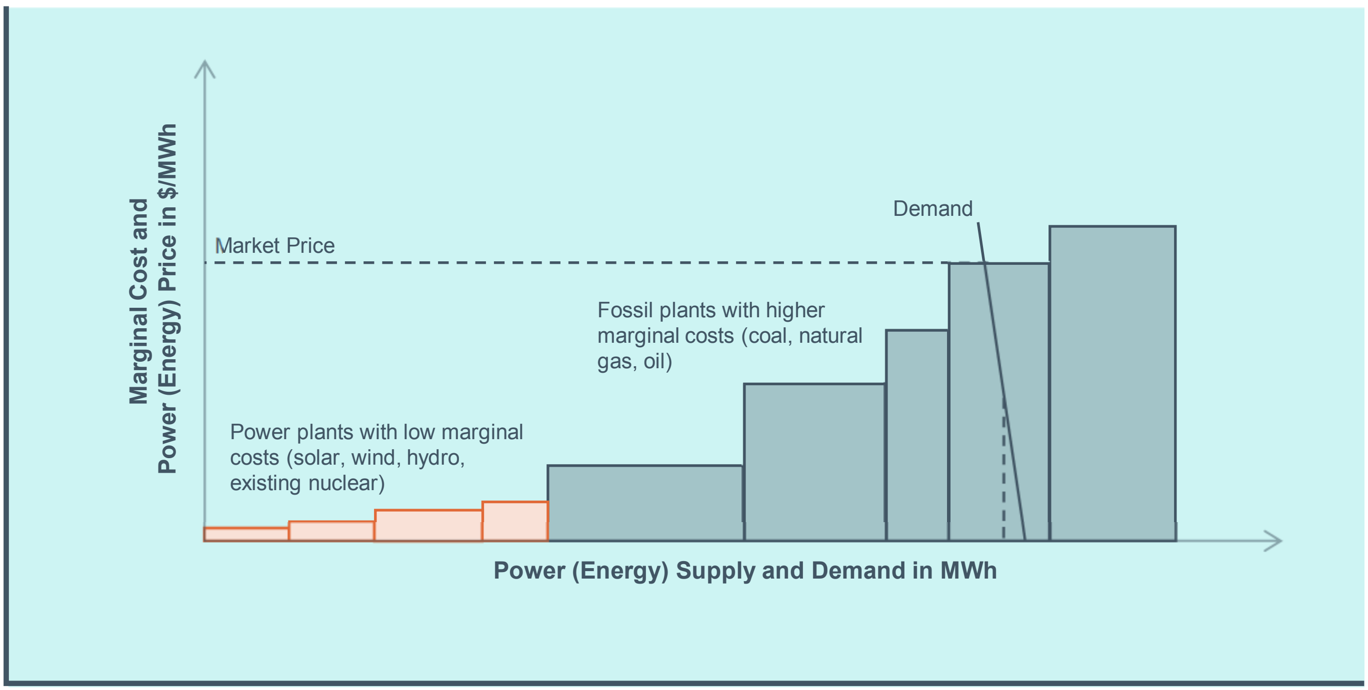
Market / Revenue Mechanism	Description	Relevance
Energy		
Day-Ahead Market	The Day-Ahead Market (DAM) allows supply and demand bids to be set a day before electricity is actually generated or consumed. It allows power plants to prepare to deliver their commitment and provides the Regional Transmission Operator (RTO) an understanding of which units will be operating to meet the following day's demand on an hourly basis. Most energy sales are still transacted through Power Purchase Agreements; however, the vast majority of electricity transacted through power markets is through the DAM. Relevance: Revenues from the Day-Ahead Market will constitute the majority of advanced nuclear plant revenues (>60%).	Very High
Real-Time Market	The Real-Time Market (RTM) is primarily used to resolve deviations between forecasted supply and demand and address other contingences (e.g., unplanned/unforeseen availability and or operational issues at power plants). Relevance: An advanced nuclear plant will sell far less energy in the Real Time market (and prices do not differ significantly from DA market).	Medium

Market / Revenue Mechanism	Description	Relevance
Capacity		
Capacity	Vertically integrated utilities and load-serving entities (LSEs or local utility companies) in deregulated markets provide capacity payments to resources that help ensure sufficient capacity to meet mandated reliability requirements or meet extraordinarily high electricity demands. These payments are designed to replace gaps in revenue resulting from energy sales that are insufficient to maintain the plants' financial viability. Relevance: This price will be negotiated with the LSE and represent a substantial percentage of annual revenues for advanced nuclear plants (~20 – 30%).	Very High
Forward Capacity	Forward capacity markets are used to incentivize the deployment of new energy resources. Developing large energy resources takes time and capital, and this market helps ensure that these resources are constructed and synchronized to the grid in time to adequately meet forecasted, future demand. Relevance: Based on a historical analysis of capacity auction results, capacity payments make up 20 – 30% of advanced nuclear revenues.	Very High
Ancillary Services		
Frequency Regulation	Resources participating in frequency regulation markets adjust their output or consumption in response to an automated signal from grid operators. These adjustments help correct short-term changes in energy demand that affect system stability and keeps the grid frequency at (or very close to) 60 Hertz. Relevance: Relatively small market and probably best suited for grid-tied, electrochemical storage (e.g., batteries) by the mid-2030s.	Very Low
Spinning Reserves	The spinning reserve market compensates grid-synchronized resources that have available capacity to inject into the grid when called upon. Resources must inject this capacity within a relatively short time, usually less than 10 minutes. While these reserves have conventionally been used to respond to unexpected contingencies, such as a generator unexpectedly falling offline, it is likely that more spinning reserves will be needed as more VREs are deployed. Relevance: Grid operators will need more synchronized resources to help maintain stability when large amounts of VRE go offline. While this market is likely to grow in size, increased participation will likely mitigate an increase in profitability. Therefore, while this may be a revenue source for advanced nuclear plants, it is not expected to be significant.	Low
Non-Spinning Reserves	The non-spinning reserve market compensates resources that are not synchronized to the grid, but can be within a short period (usually within 10 – 30 minutes). As with spinning reserves, these resources are called upon during unexpected losses in generation. Relevance: Relatively small market with little revenue.	Very Low
Voltage Control	Generating resources can be compensated for providing reactive power to compensate for drops in system voltage. Relevance: Insignificant revenue opportunities for advanced nuclear.	Very Low
Black Start	If the grid loses power, Black Start designated generators are committed to restoring electricity to the grid and do not require an outside electrical supply to do so. Relevance: Insignificant revenue opportunities for advanced nuclear.	Very Low
Other		
Flexible Ramping Product	Flexible ramping products are relatively new and currently only available in CAISO and MISO. They reward resources that can quickly adjust output—beyond what has been obligated—within a certain time period to correct forecasting uncertainties and other anomalies. It is possible that these flexible ramping products will transact more energy as VRE deployment rises. Relevance: These products are very new and currently do not transact significant quantities of energy. These may (or may not) become significant revenue opportunities for advanced nuclear plants going forward.	Low

3.2 Energy Market Price Formation in Deregulated Markets

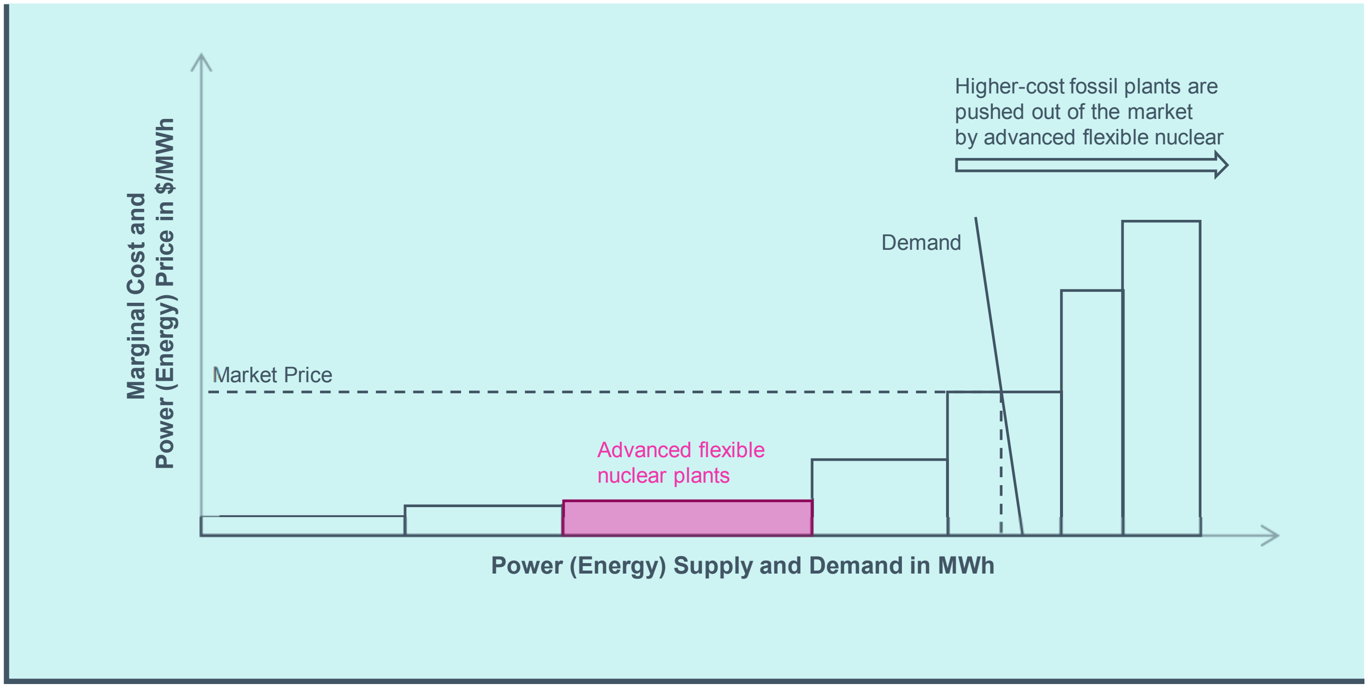
As in other competitive markets, energy prices in power markets are set by the ‘marginal costs’ of the marginal energy producer, as shown in Figure 1 below. The ‘marginal cost’ typically reflects a resource’s cost of producing each MWh of electricity, which includes fuel costs, the efficiency with which they are converted to electricity, and any other costs associated with operating, such as labor and maintenance. The marginal cost guides what a resource will bid into the energy market for a given time period. The grid operator will then arrange all energy supply bids in ascending order of price (often called the ‘merit order) for each moment in time. This supply stack (or ‘bid stack’) begins with plants with lowest marginal costs (e.g., solar, wind, hydro, and nuclear) and proceeds upward to those with higher marginal costs in (e.g., coal, natural gas, and oil plants). The supply stack is then compared to electricity demand for a given moment in time and the highest bid that intersects with the demand curve sets the clearing price for all ‘infra-marginal’ plants (i.e., with bids lower than the marginal producer).

Figure 1. **Stylized Supply Stack, Demand Curve, and Price**



For illustrative purposes, Figure 2 below shows the stylized electricity market with the addition of flexible advanced nuclear plants. Their assumed low marginal costs have the effect of pushing plants with higher marginal costs beyond the intersection of the supply and demand curve. As a result, fossil plants, which would otherwise set the market price, no longer operate as much. Displacement of high-marginal-cost plants lowers overall clearing prices.

Figure 2. **Stylized Power Market Supply, Demand, and Price with Flexible Advanced Nuclear Plants**



3.3 New Efforts to Compensate and Promote Flexible Resources

Rewarding resources that can be available and quickly ramp up and down during periods of grid stress (either on an hourly, minute, second, or sub-second basis) has been the focus of several recent regulatory initiatives relating to market design.[12] Creating new revenue 'products' often takes years to formalize and implement, however. They require several rounds of stakeholder input and are often implemented on a trial basis with subsequent revisions. In MISO, for example, it typically takes 5 – 7 years between opening a new docket and market implementation.[13]

Upon surveying the markets included in this study (ISO-NE, PJM, MISO, and CAISO), mechanisms designed to reward resource flexibility are relatively nascent and do not transact large quantities of power or capital throughout the year. None currently provide the compensation necessary to stimulate investment in new nuclear capacity. While these revenue streams will likely become more relevant, it is unclear whether they will ever be a material source of revenue for flexible nuclear plants. Developers should therefore track the evolution of these products, but not consider them as material revenue sources until they prove themselves as such. Appendix B provides a longer description of these products and their relevance to advanced nuclear developers.

3.4 Regulated Market Overview

Regulated markets offer an alternative development pathway for advanced nuclear developers. In U.S. regulated electricity markets, vertically integrated utilities own, control, and/or manage the generation, delivery, and customer-sited infrastructure for electricity delivery. They are monopolies with the obligation to serve retail customers within their service territories and follow rules[14] set forth by federal, state, and local agencies. These utilities are overseen by a public regulator, usually a state public utilities commission. Regulated utilities supply electricity at cost plus an approved rate of return on their investments for delivering electricity (including generation, transmission, and other grid resources). This structure replaces competitive markets in determining prices set for energy generation, capacity, ancillary services (and other services).

Regulated markets are largely dominant in the Southeast, Northwest, and much of the West outside California. Under this arrangement, consumers are limited in their choice of electricity provider; however, prices are generally more stable and certain over time than in deregulated markets.

3.4.1 Resource Procurement

Regulated utilities typically conduct open and competitive solicitations to procure new resources. These are either mandated or strongly encouraged by regulators to assure the lowest-cost supply for retail customers. Utilities are often allowed to participate in the bidding process; however, they are forced to accept the lowest-cost option where equivalent products and services are offered.[15] Some regulatory commissions will direct utilities to procure certain types of resources, like renewables, to meet state mandates or Renewable Portfolio Standard (RPS) goals.

Resource procurement begins with the utility typically issuing a public Request for Proposal (RFP) that describes the type of resources it seeks to procure. Based on the bid's content (including price, technology maturity/bankability, O&M contract terms, project financing terms, developer's reputation, etc.) and oversight and approval from the overseeing regulatory authority, a winner is selected. Typically, these contract terms are not made public.

3.4.2 Benefits and Drawbacks of Developing Flexible Advanced Nuclear Plants in a Regulated Market

The regulated environment is less transparent than a deregulated market environment, resulting in advantages and disadvantages for flexible advanced nuclear projects. The primary advantage is that developers are not limited to a defined suite of revenue streams, which may or may not be well designed to compensate for the values a flexible nuclear plant can provide. Developers also get the opportunity to make the case for flexibility directly to the utility, or articulate the benefits of flexibility through their RFP response. Further, when a plant becomes 'merchant' (after a PPA expires, for example) in a deregulated market, it is subject to market conditions, which are more dynamic, less predictable, and more competitive (generally lowering overall revenue potential). Two recent nuclear plant projects in the United States—V.C. Summer in South Carolina and Vogtle in Georgia—are located in regulated markets. The only current advanced nuclear development effort (NuScale Power in Utah Associated Municipal Power Systems) is taking place in a regulated market as well.

The primary disadvantage of a regulated market is the lack of price transparency and the reduced freedom of participating without necessarily winning an RFP. Furthermore, revenue is fixed and power projects are not able to access high price conditions during scarcity events. Deregulated markets have less barriers to entry; however, even in such markets the capital intensity of nuclear plants will undoubtedly require developers to sign a long-term PPA with a credit-worthy utility or a long-term capacity contract before the project can be financed (or the nuclear plant may be owned directly by the utility).

4 Current Revenue Potential and VRE Effects on Nuclear Projects

While it is difficult to predict what the 2030s power markets will look like, it will inevitably be influenced by the policy, technology, and cost trends of today. As such, it is useful to characterize current market conditions and highlight the relevant issues and developments that advanced reactor developers should track. This section highlights the current revenue potential for advanced nuclear plants as well as some of the key challenges for participation in future markets.

4.1 Wholesale Market Clearing Prices Have Been in Decline

Average clearing prices in most ISOs have been in decline over the past ten years, mostly due to falling natural gas prices. Low-cost gas reduces the marginal cost of running natural gas plants, which typically operate ‘on the margin’ and therefore set energy prices.

Table 2 provides the average Day-Ahead energy, capacity, and ancillary services prices in four ISOs over the past decade (Appendix A presents additional detail on these prices).

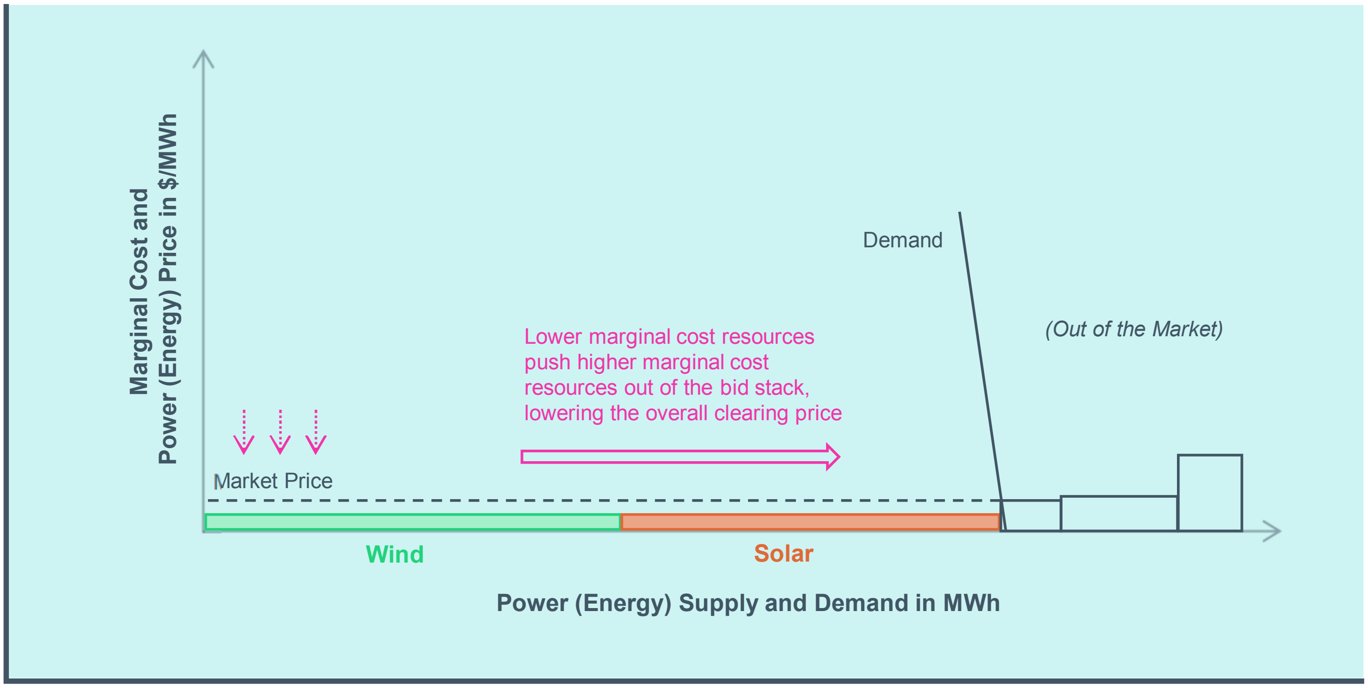
Table 2. **Average Wholesale Prices by Revenue Stream in Select ISOs (2009 – 2018)**

	ISO-NE	PJM	MISO	CAISO
Average Energy Price ($/MWh)	$44.98	$39.50	$31.34	$38.86
(Trendline growth over 10 years)	(-2.1%)	(-2.7%)	(-0.9%)	(1.1%)
Average Capacity Price ($/MWh)	$13.01	$10.30	$0.67[1]	$0.18[1]
(Trendline growth over 10 years)	(6.7%)	(1.7%)	(15.2%)	(18.0%)
Average Ancillary Service Price ($/MWh)	$1.46	$0.89	$0.14	$0.46

1 MISO and CAISO have a Resource Adequacy Construct where capacity is procured via bilateral contracts, which are not made public. These figures represent the voluntary capacity market where utilities can procure remaining capacity needed to fulfill their capacity obligations. These prices should not be used as a proxy for capacity payments. Also, most new-build energy projects require multi-year capacity contracts.

While low natural gas prices have largely driven the decline in energy prices, other factors are also at work. Research at the Lawrence Berkeley National Laboratory's Energy Systems Integration Group (ESIG) has shown that while solar PV and wind have historically had relatively little impact on energy price, they "have [now] begun to meaningfully influence temporal and geographic pricing trends."[16] Periods of exceptional sun and wind are now driving a higher frequency in the number of hours where market clearing prices are negative.[17]

Figure 3. **Market Price Declines When Renewables Dominate the Supply Stack**



The increase in VRE deployment and, more importantly, the anticipation of continued VRE deployment is forcing the power grid to become more flexible and resilient. Falling energy prices are a threat to advanced nuclear's economics. However, the need for more flexible, dispatchable resources may be an opportunity.

4.2 The Rise of Variable Renewable Energy and Need for Grid Flexibility

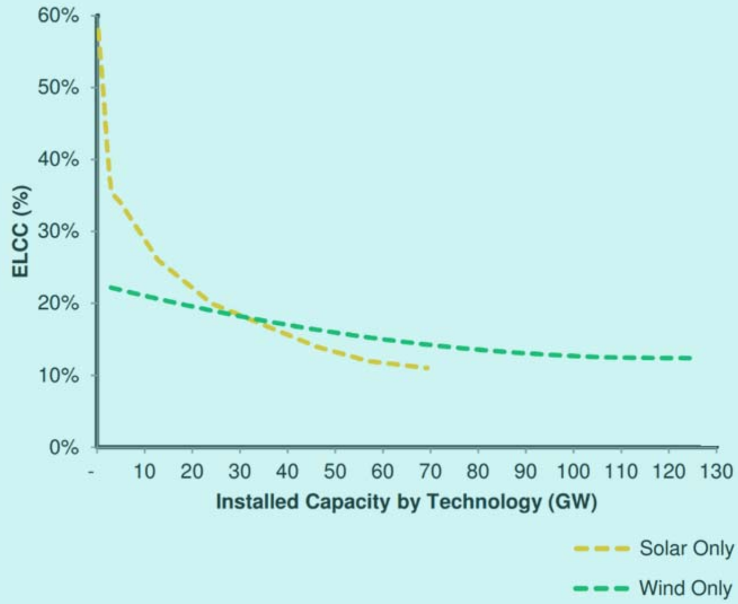
To ensure a reliable supply of electricity in uncertain conditions, system operators dynamically alter generation and/or load to keep the grid at a stable frequency of 60 Hz. Maintaining this frequency was historically furnished by large, centralized generators. In fact, the entire electric power grid was initially designed and built around large, centralized generators (e.g., coal, nuclear, and hydroelectric plants).[18] They were the basis for all grid planning decisions and their startup times, fuel availability, and operating characteristics informed the design of competitive power markets.[19] However, maintaining a balanced grid frequency has become a growing concern as more VREs are deployed. They are also disrupting the way power markets are currently designed.

Largely driven by rapidly falling costs and supportive policies, wind and solar PV deployment has increased 500% in the last 10 years.[20] Between 2009 – 2017, costs dropped 76% for solar PV and 34% for wind, and it is expected that deployment rates will continue to rise.[21] To continue accommodating these resources, power systems must maintain sufficient operating reserves and have generators that can quickly inject power when VRE—either expectedly or unexpectedly—goes offline. Beyond backfilling when the wind and sun are unavailable, the grid needs resources that can ramp down as VRE generation comes online in the morning and ramp up as the sun goes down in the evening. Figure 4 below presents the net load curve[22] for a spring day in California in 2017. As more VRE is built, the net load curve's 'belly' will drop even further, making it more difficult to meet demand during morning and evening ramps. This provides a useful reference case for other markets that will ultimately encounter steepening net load curves.

Figure 4. **Net Load Curve in CAISO for April 9, 2017**[23]

Increasing VRE not only requires increasing grid flexibility, it also triggers more renewables curtailment and transmission congestion (affecting locational marginal prices). Further, VRE's capacity to reduce expected reliability problems or outage events (measured by their Effective Load Carrying Capability, or ELCC) diminishes as more VRE is deployed (see Figure 5). This helps explain why most 'high renewables' scenarios in the mid-2030s still include a large amount of fossil generation—particularly natural gas.[24]

Figure 5. **Wind and Solar ELCC Curves as a Function of Installed Capacity in MISO**[25]



In summary, the grid was not designed around the irregular and unscheduled generation inherent to VREs. More 'flexible resources,' such as energy storage, fast ramping gas plants, and demand side resources will be needed to accommodate more VRE while maintaining a high level of grid stability. Advanced nuclear reactors, if designed to be flexible, could play a meaningful role in enabling more VRE deployment. To do so, they will need to be compensated for the inherent value of being flexible and dispatchable. Current market mechanisms do not incentivize nuclear plants to operate flexibly, nor reward them for supporting grid stability. This has created extremely challenging conditions and made it difficult for conventional nuclear projects to be profitable.

4.3 Conventional Nuclear Plants Face Fundamental Headwinds

Conventional nuclear plants typically operate as 'must-run' baseload resources. While they are capable of a moderate degree of ramping, the economics of doing so, in most cases, are poor.

Conventional nuclear plants were initially designed to ramp (up and down), load follow, and provide several ancillary services products.[26] Current reactor designs with best-in-class ramping capabilities, such as EDF's EPR and Westinghouse's AP1000, can safely ramp to a maximum of approximately 5%/minute.[27,28] However, due to high capital costs and low marginal costs of nuclear plants—particularly in deregulated markets—they seek to operate at their maximum rated capacity for as long as possible.

When market prices fall below a nuclear plant's operating costs, the plant operates at a financial loss. While they may forgo energy sales and provide operating reserves under these conditions, it is only economical to do so in highly specific scenarios.[29] Operating at a loss, or at declining profit margins—especially over a long period of time—can materially impact a plant's economics.

In markets with significant VRE penetration (e.g., CAISO), clearing prices can approach zero or below[30] during periods of exceptional sun or wind and relatively low demand. These pricing events force nuclear and other 'must-run' resources to operate at a loss or go offline. Low natural gas prices and the anticipation that VRE will continue to push prices downward has motivated several utilities to retire nuclear plants or not renew their operating licenses.[31] In fact, these difficult economic conditions have forced six nuclear plants to close in the past five years, with nine more planning to retire in the next 10 years (representing more than 18 GW of generation capacity).[32] Further, the average age of U.S. nuclear plants is approximately 37 years. Plants become more expensive to operate as they age.[33] Absent significant changes to nuclear's CapEx, operating profile, or revenue opportunities (particularly capacity payments), it is difficult to see how conventional nuclear will successfully navigate a market environment with low energy prices going forward.

It is important to note that nuclear plants are not the only generators experiencing difficult economics due to low energy prices. Natural gas plants are seeing a higher percentage of their revenues coming from non-energy sales (mostly capacity and reserve payments). Low energy price environments affect all resources.

4.3.1 Non-Market Payments Keep Some Conventional Nuclear Plants Operational

Several states have been passing legislation to provide nuclear plants with payments to ensure they continue to run, even as power market conditions worsen. Illinois, New Jersey, Connecticut, New York, and Ohio have all authorized payments to keep nuclear plants online. Pennsylvania has proposed legislation to do the same.[34] Maryland is currently analyzing whether nuclear should be eligible for clean-energy credits.[35] Proponents of legislative measures see preserving existing nuclear plants as a cost-effective means (on a $/MWh basis) of achieving their emissions-reduction goals.

While some form of 'non-market payments' may be available to advanced nuclear developers in the mid-2030s, it is neither likely nor clear how they would be structured. Therefore, the possibility of such payments should not influence design decisions being made today.

If markets begin to offer compensation to dispatchable resources that provide grid stability and dependability, or for emissions-free generation, these out-of-market payments will become less important, or entirely unnecessary. Several plant owners are also looking into potential non-power market revenue streams, such as hydrogen production,[36] to improve economic performance. Until these changes occur, low natural gas prices (which, according to natural gas price futures, are not expected to rise substantially in the coming years) and increasing VRE deployment will challenge nuclear plant economics in several markets.

5 PLEXOS and Financial Modeling Methodology and Assumptions

LucidCatalyst used PLEXOS® electricity market modeling software from Energy Exemplar to model the revenue potential of flexible advanced nuclear technology (and thus an implied maximum CapEx) in four U.S. future power markets: ISO-NE, PJM, MISO, and CAISO. The modeling exercise examines a hypothetical plant's annual revenue profile as it responds to fluctuations in demand–either through ramping up and down, or through a combination of ramping and co-located energy storage systems. PLEXOS provides empirical precision for a project's annual capacity factor and the optimal output in response to changing market conditions. LucidCatalyst also ran additional modeling scenarios to observe the effect of CO_2 prices and the aggregate impact of multiple flexible advanced nuclear plants on market prices.

To calculate the maximum allowable CapEx, LucidCatalyst transferred PLEXOS outputs—which included energy revenues and plant output/capacity factors for both the plant and, if necessary, the ESS system—into a 'post-PLEXOS' financial model. Here, capacity payments and various financial assumptions are applied to determine the final allowable CapEx. Figure 6 on the following page provides a high-level diagram of the methodology, which is described in detail in this section.

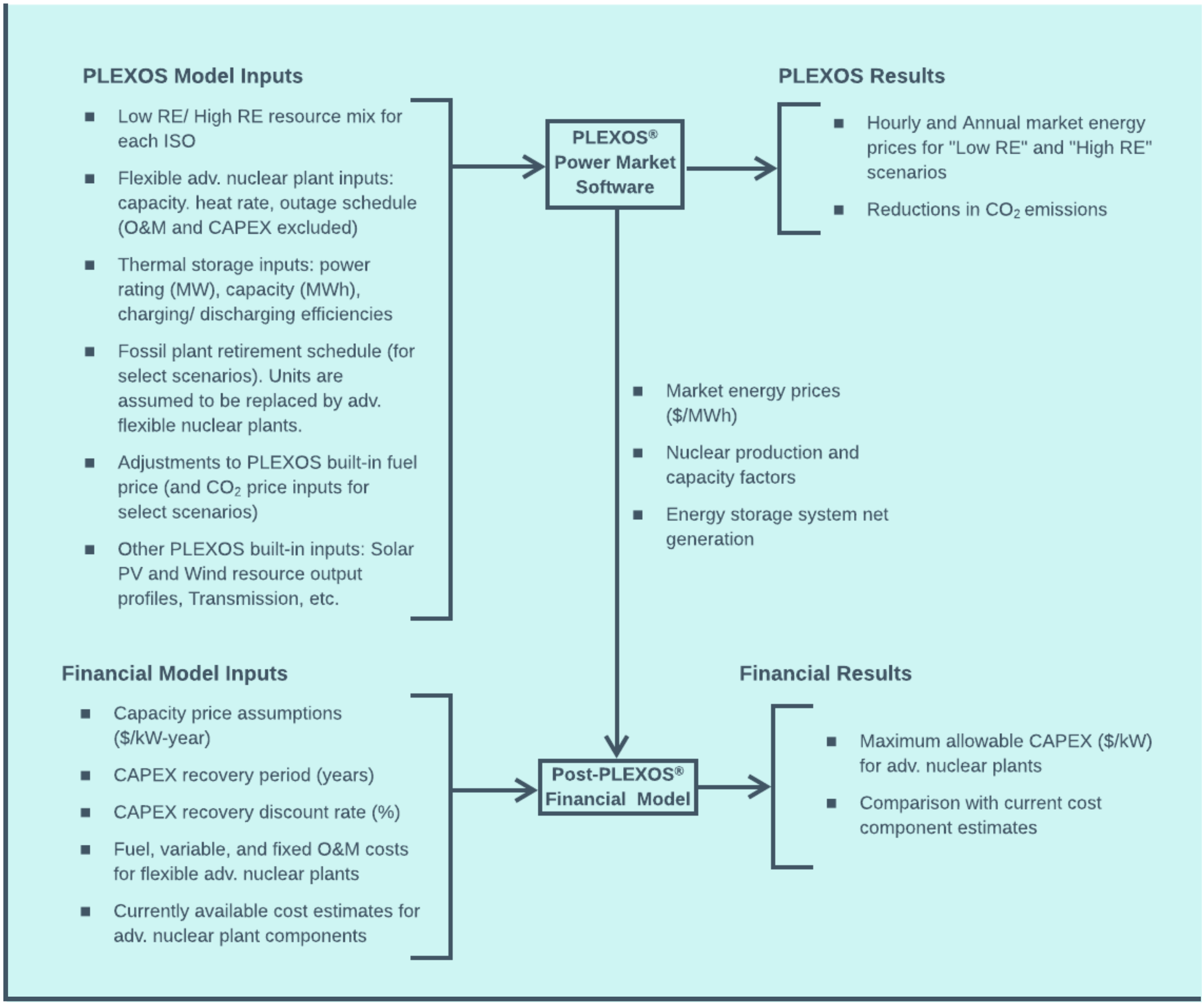
5.1 Overview of PLEXOS Electricity Market Modeling Software

PLEXOS is a production cost model for electricity markets in the U.S. (with other international versions available) that can simulate future market conditions. Production cost models predict the economic dispatch of power plants in a given service territory or market and across a defined timeframe. PLEXOS has been widely used since 1999 by grid operators, utilities, and electricity market analysts.

For this analysis, data on expected hourly demand for each service territory comes with the software package, and the program determines the optimal mix of power plants to meet demand in each hour at the lowest cost. Results include plant power operational details, market price forecasts, and CO_2 emissions from fuel consumption at fossil plants.

PLEXOS determines the optimal production patterns from power plants based on marginal cost pricing, as illustrated in the stylized power market diagrams in Section 3. PLEXOS contains detailed data on existing power plants (including their capacity, outage requirements, energy conversion efficiencies, etc.), solar and wind availability by location, demand forecasts, fuel price forecasts, transmission line limits, emissions rates, and all other necessary inputs for performing market simulations. LucidCatalyst adjusted some of the built-in data for the future baseline scenario and entered new inputs to represent flexible advanced nuclear plants with energy storage, as discussed in the next two subsections.

Figure 6. **High-Level Methodology Diagram for Calculating Maximum Allowable CapEx**



5.2 Modeling Methodology

5.2.1 Modeling Horizon

LucidCatalyst used PLEXOS to model electricity markets in 2018 (to show recent data) and 2034. The year 2034 was selected as a baseline year to model for two reasons. First, it is far enough in the future (halfway to 2050), when advanced reactors are expected to be commercially available. This is supported by several advanced nuclear companies claiming they will have a commercially available reactor in the late 2020s.[37] Second, this date also provides more time for ISOs to transition beyond what is currently being modeled in each ISO's current, forward-looking plans.

Developing credible grid scenarios for 2034 presents obvious challenges. State and regional policymakers are developing ambitious emissions-reduction targets as the cost of wind, solar, and energy storage all continue to fall. Demand-side technologies are becoming more relevant, and the electrification of transportation and heat continue to be key areas of policy focus. As these trends develop, ISOs are experimenting with new market products, as discussed in Appendix B, to reward resource flexibility (which may change the capacity mix and dispatch order of a future grid).

Modeling the operation of flexible advanced nuclear plants (with and without energy storage) in 2034 did not require making assumptions about construction time in PLEXOS. Construction is assumed to have finished by 2034 so that hypothetical plants are ready for operation in that year. Importantly, the scenarios are not being run to determine the timing of capacity additions by one or more advanced nuclear plants. The modeling largely focuses on the cost of the first advanced nuclear plant in a given ISO.

5.2.2 Modeling Scenarios

The LucidCatalyst team modeled two main scenarios in 2034: a baseline, 'low renewables' (low RE) scenario based on PLEXOS' built-in resource mix for 2034, and a 'high renewables' (high RE) scenario based on the 'Low natural gas/Low RE cost' scwenario in NREL's ReEDS model, which has a significantly higher proportion of renewables. These scenarios were selected to define the range of potential likely outcomes and allow for a comparative analysis of the impacts of flexible advanced nuclear plants on generation mix, market prices, and other modeling variables.

The 2034 'low RE' grid mix was consistent with the mix produced by Energy Exemplar (developers of the PLEXOS software). It reflects a long-term capacity expansion outlook[38] that reflects expected plant retirements, plants under construction, and plant announcements. Additionally it reflects an optimized build out of generators considering Renewable Portfolio Standards (RPS), the impacts of other emissions-based regulations, and expected resource cost curves.[39] The output assumes relatively higher penetrations of natural gas capacity, with relatively modest additions to renewable energy capacity (i.e., just enough to meet existing RPS standards).

For the higher renewables scenario, the team adopted the 2034 NREL ReEDS 'Low natural gas/ Low RE cost' scenario.[40] NREL developed their ReEDS model to forecast power plant capacity changes, generation mixes, and related electricity market impacts from a range of policy and economic assumptions. The assumptions underlying the 'Low natural gas/ Low RE cost' lead to high capacities and generation levels for natural gas plants and renewable energy facilities such as solar and wind. LucidCatalyst calibrated the 2034 baseline scenario in PLEXOS by matching the power plant type and location to the ReEDS scenario.

Under the 'low RE' and 'high RE' scenario umbrellas, a total of nine cases were modeled (see Table 3 below). The 'low RE' cases include a 2034 baseline without any advanced nuclear plants and individual runs for one plant with and without co-located energy storage system (ESS). The idea is to estimate the maximum allowable CapEx for the first plant in the marketplace. Importantly, initial modeling showed little difference between the allowable CapEx for the first and fifth plant in smaller markets like ISO-NE. In larger markets like PJM, it takes dozens of advanced nuclear plants to affect energy prices to the point that the maximum allowable CapEx is significantly different. The same cases are run for the 'high RE' scenario, with two additional cases that examine the impact of hypothetical CO_2 pricing, a large fleet of advanced nuclear plants operating in the same market, and different O&M assumptions on allowable CapEx.

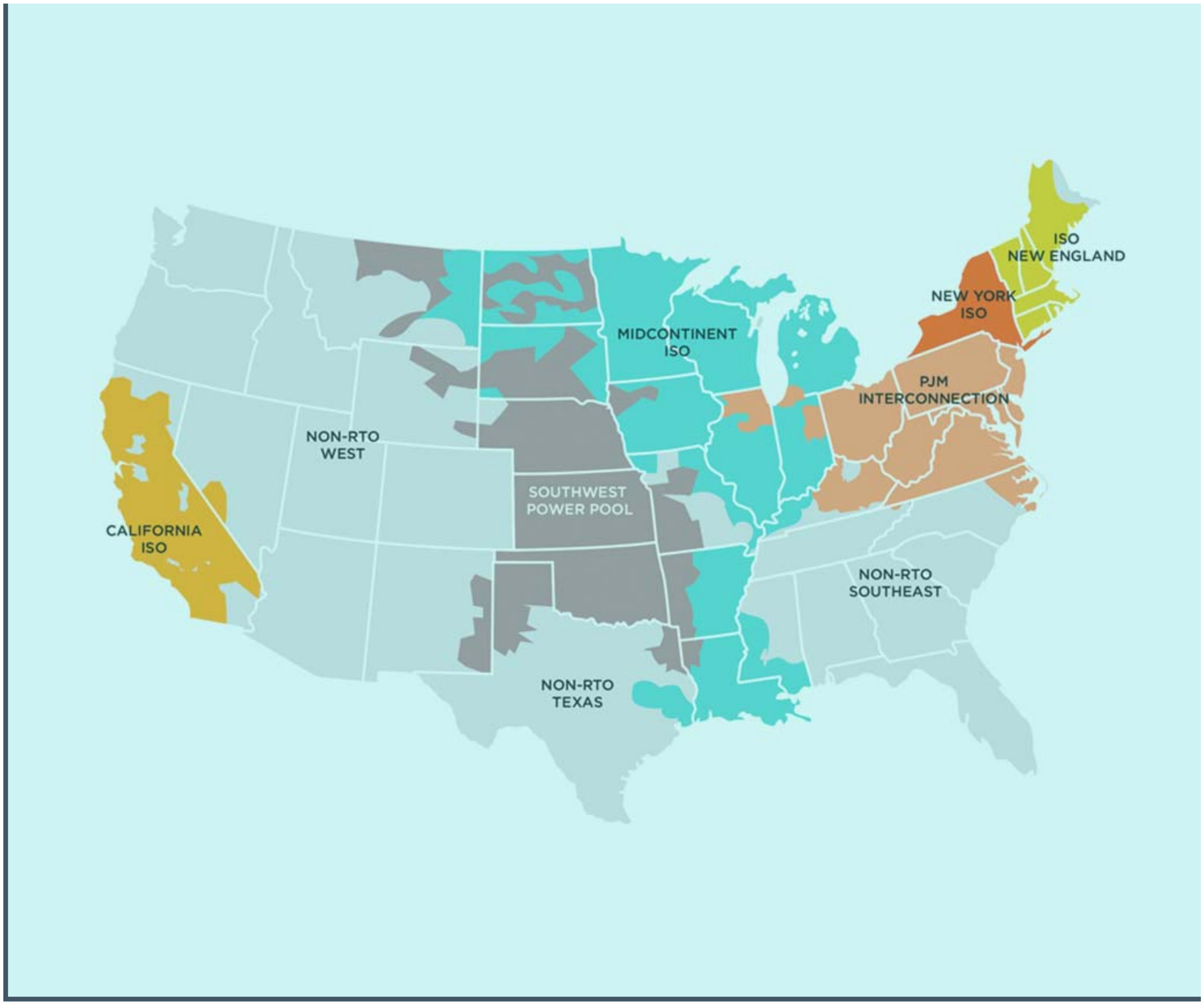
Table 3. **Modeled Scenarios in PLEXOS**

		# of Adv Nuclear Plants	ISO-NE	PJM	MISO	CAISO
2034 Low RE						
1	Low RE Baseline	0	■	■	■	■
2	Low RE w/out Thermal ES	1	■	■	■	■
3	Low RE with Thermal ES	1	■	■	■	■
2034 High RE						
4	High RE Baseline	0	■	■	■	■
5	High RE w/out Thermal ES	1	■	■	■	■
6	High RE with Thermal ES	1	■	■	■	■
7	High RE: Fleet Advanced Nuclear + ESS	varies by ISO	■	■	■	■
2034 High RE w/ Carbon Price						
8	High RE Baseline with CO_2 Price ($25, $50, $75/tonne), with and without ESS	1		■		
2034 Alternative O&M Costs (Low & High RE)						
9	Higher O&M Costs Relative to Baseline Assumption (for both Low and High RE scenarios)	1	■	■	■	■

5.2.3 Modeling Regions

Modeling four markets provides insights into the variety of contexts in which flexible advanced nuclear plants may be deployed. It leads to different results for wholesale energy prices, advanced nuclear plant operational expectations, and financial calculations such as maximum allowable CapEx. The following map and table show the geographic extents of the four competitive wholesale markets and total power plant capacity and power demand in 2018 and 2034.

Figure 7. **U.S. Regional Power Markets**



Source: Federal Energy Regulatory Commission

Table 4. **Total Capacity and Power Demand in the Four Markets in 2018 and 2034**

	Total Capacity			Total Demand	
Market	**2018**	2034 Low Renewables	2034 High Renewables[1]	2018	2034 Low or Higher RE[2]
ISO New England	35 GW	44 GW	47 GW	124 TWh	110 TWh
PJM	203 GW	239 GW	281 GW	806 TWh	869 TWh
MISO	175 GW	229 GW	243 GW	709 TWh	838 TWh
CAISO	74 GW	86 GW	88 GW	261 TWh	272 TWh

1 In the flexible advanced nuclear scenario for 2034, a fleet of flexible advanced nuclear plants with energy storage are added, while maintaining capacity between the 2034 scenarios.

2 The 2034 scenario and 2034 flexible advanced nuclear scenario have the same total demand, but net imports or exports differ between them for markets modeled with neighboring areas, leading to changes in generation between the two scenarios.

PLEXOS models these ISOs as aggregations of their component service territories (also called load zones). ISO-NE has 13 service territories, PJM has 20, MISO has 10, and CAISO has 9. Results tables for the flexible advanced nuclear scenarios shown below in Section 7 identify the service territories in which flexible nuclear plants were assumed to operate.

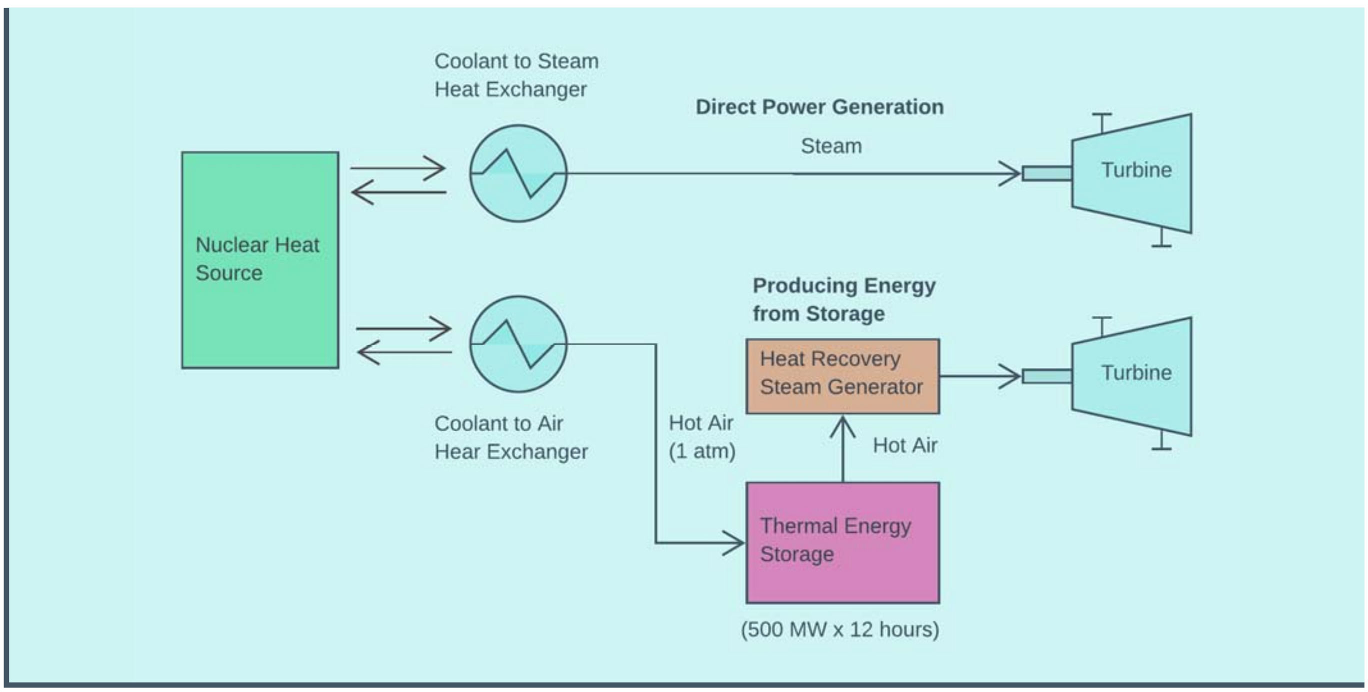
The four electricity markets differ in several key respects regarding power plant capacity and generation mix. Under 2034 baseline conditions, ISO New England has high levels of natural gas and wind (mostly offshore). PJM stands out among the regions for its higher reliance on conventional nuclear plants and coal plants. MISO has the most wind capacity and generation (onshore) among the regions and CAISO has the most solar (as well as significant amounts of wind).

Monetary inputs and outputs for the PLEXOS modeling are expressed in constant 2019 dollars. This analysis uses the PLEXOS model's built-in data for demand projections within each service territory. It also uses the model's built-in transmission constraints between service territories, parameters for the thousands of existing plants, plants under construction, and those that are expected to be built according to Energy Exemplar's capacity expansion model. The analysis uses a consistent natural gas price of $3.00/MMBtu in constant dollars for 2018 and 2034 to avoid introducing differences in market prices or plant dispatch arising from underlying fuel price differences. The PLEXOS model's built-in price projections for other fuel prices are maintained. The analysis also maintains the built-in price projections for CO_2 emission fees in the Northeast Regional Greenhouse Gas Initiative ($17/tonne in 2034) and California ($22/tonne in 2034), and there is no national CO_2 emission fee because such a program has not been enacted by Congress and the Clean Power Plan is being reconsidered. In accordance with the most recent federal energy legislation, which phases out the Production Tax Credit (PTC) for renewables, the modeling does not include these support mechanisms.

5.2.4 Modeling Inputs for Flexible Advanced Nuclear Plants with Energy Storage

The modeling software treats the nuclear plant and energy storage system as two facilities whereby the storage facility charge at a rate no greater than the amount of power being produced at the nuclear plant. Setting this model constraint (i.e., defining the relationship between the two facilities) in PLEXOS is equivalent to envisioning the energy storage system at the same site as the nuclear power plant, charging from the nuclear plant's production at certain times and discharging at other times. LucidCatalyst assumed the ESS was a thermal storage system, which stores energy as heat and subsequently uses the heat to make steam, which is sent through a dedicated steam turbine. A high-level schematic of such a thermal storage system charging and discharging is provided in Figure 8 below.

Figure 8. **Charging and Discharging Configuration of Advanced Nuclear Plant with Thermal ESS**



It is important to note that PLEXOS does not require CapEx estimates for the advanced nuclear plant, energy storage system, or any other addition to the electricity grid in order to model dispatch (such as the solar and wind additions for alignment with the NREL ReEDS scenario). It economically dispatches resources based on their marginal cost and revenue maximization opportunities. For ESS configurations, if future market prices are expected to be higher than current prices, PLEXOS assumes the operator sends energy to storage (assuming the system is not yet full).

The LucidCatalyst team entered the proceeding operating parameters for plants into PLEXOS and allowed it to determine the optimal mix of resources to meet demand based on their marginal costs, as discussed above, without reliance on CapEx estimates in the model.

5.3 Illustrative Advanced Nuclear Plant and Energy Storage System Assumptions

For modeling purposes, LucidCatalyst developed an illustrative advanced nuclear plant that assumes a uniform design and does not reflect a specific reactor technology. Physical specifications for this illustrative plant, as well as the thermal ESS, are listed in the tables below.[41, 42]

Table 5. **Assumed Capacity and Operating Specifications for Illustrative Advanced Nuclear Plant**

Advanced Nuclear Specifications	Assumption	Rationale
Net Electric Capacity (MWe)	500	This reflects the typical size of what the flexible nuclear plant would likely replace: a combined cycle gas plant (CCGT). MEITNER Design Teams are developing reactors across a broad range of scales: from 0.2 MWe to 1200 MWe. The smaller reactors are being designed for niche markets whereas this study looks at those looking to compete in power markets.
Thermal Efficiency	40%	This roughly represents the midpoint within the range of thermal efficiencies for advanced nuclear concepts[1] and includes some losses from the energy storage system.
Heat Rate (Btu/kWh)	8,530	Btu content of a kWh is 3,412 Btu.[2] This figure is divided by the thermal efficiency.
Maximum Potential Capacity Factor	92%	The advanced nuclear plants are assumed to take a four-week outage each year (8% of annual hours) for refueling and other maintenance. Their capacity factors may be lower to avoid operating at a loss during low-price periods from the PLEXOS modeling.
Outlet Temperature	600 – 700°C	While there are a range of outlet temperatures for advanced reactors (480 – 1,000°C),[3] an outlet temperature of 600 – 700°C is assumed. This is the same rated inlet temperature for most heat steam recovery generators (HSRG) used for CCGTs—allowing the application of HSRG cost assumptions for the energy storage system.
Minimum Stable Factor	0%	This implies that the plant can ramp all the way down to 0% operating capacity, which is a significant departure from conventional nuclear plants that typically have a minimum stable factor of 70%.
Maximum Ramp Rate	5%/minute (25 MW/min)	EDF's EPR and Westinghouse's AP1000 both have max ramp rates of ~5%/ minute.[4]

1 WNA, Advanced Nuclear Power Reactors, 2019.

2 U.S. Energy Information Administration (2019). What is the efficiency of different types of power plants?

3 Congressional Research Service (2019). Advanced Nuclear Reactors: Technology Overview and Current Issues.

4 OECD-NEA, Technical and Economic Aspects of Load Following with Nuclear Power Plants, 2011, p. 8.

Table 6. **Assumed Specifications for Energy Storage**

Energy Storage Specifications	Assumption	Rationale	Used in CapEx Analysis (Y/N)
Rated Output (MW)	500	Advanced reactor capacities range significantly.	Y
Hours of Storage (MWh)	12	Assumes 12 hours of 500 MW output	Y
Energy Storage Roundtrip Efficiency	90%	Assumes a charge efficiency of 90% and discharge efficiency of 100% (implying a round-trip efficiency of 90%)	Y
Outlet Temperature	600 – 700°C	This assumes that the outlet temperature is sufficiently high to be used in a 'off-the-shelf' steam turbine.	N
Assumed Energy Storage Capacity	6,000 MWh	Assumes 12 hours of storage (rated at maximum output)	Y
Maximum State of Charge	100%	The energy storage system can charge to full capacity at any point (no governor)	Y
Minimum State of Charge	0%	The energy storage system can discharge completely at any point (no governor)	Y

PLEXOS does not require CapEx inputs for the ESS, just a marginal cost of operation. The ESS' marginal cost will differ depending on system type; however, because it does not use fuel and requires extremely small amount of O&M, it is rarely, if ever, a marginal resource (and therefore never sets the energy clearing price). For these reasons, LucidCatalyst assumed $0/MWh for the ESS' marginal cost. Even if LucidCatalyst assumed a high-end marginal cost of, say, $5/MWh, the systems' dispatch would not change (nor would its revenues) as natural gas plants almost always set the clearing price and their marginal costs are 5 – 6x higher on average.[43] For the benefit of advanced reactor developers, LucidCatalyst conducted a high-level CapEx review for three types of storage systems that would be complementary to advanced nuclear plants, firebricks, molten salt, and flow batteries.[44] This review is included in Appendix E.

5.4 Revenue Assumptions

LucidCatalyst assumed that advanced nuclear plant revenues were limited to energy sales and capacity payments. While LucidCatalyst recognizes that increasing VRE deployment will likely stimulate an increase in demand for ancillary services—particularly spinning reserves—LucidCatalyst expects that the increase in demand will be met by an increase in ancillary service market participation, thus mitigating any significant increase in clearing prices. Energy revenues are calculated by the plant's output, operating hours, and clearing price. LucidCatalyst assumes a range of potential capacity payments ($50, $75, $100/kW per year). Importantly, because the energy storage system is sized for 12 hours of rated output, LucidCatalyst assumes that it also qualifies for a capacity payment.[45]

5.5 Fuel Costs and O&M Assumptions

5.5.1 Fuel Costs

In PLEXOS, fuel costs for nuclear plants depend on two inputs: (1) the price of uranium, expressed in dollars per million British thermal units (MMBtu); and (2) the heat rate of each plant, expressed in Btu per kWh, which reflects the plant's efficiency in converting fuel into electricity. Preparing the fuel cost inputs for flexible advanced nuclear plants in PLEXOS therefore involves specifying these two inputs.

The built-in dataset for PLEXOS contains a 2034 uranium price projection of $0.52/MMBtu. Analysts at Energy Exemplar (the company that licenses PLEXOS) develop price projections for uranium and other fuels to align with expectations from the U.S. Energy Information Administration and other authoritative sources.[46] The uranium price in PLEXOS represents the form of fuel currently used in U.S. nuclear plants, namely low-enriched uranium (LEU) with U-235 content between 3 to 5%.

This modeling exercise aims to remain agnostic and neutral regarding reactor technologies and fuel sources for flexible advanced nuclear plants. Some reactors would use LEU in a similar manner to current nuclear plants. Other reactor technologies would encase the uranium in a tristructural-isotropic (TRISO) fuel pellet. The use of high-assay low-enriched uranium (HALU), which rises above the typical enrichment for civil purposes toward levels for military applications, is another option for advanced nuclear concepts. The current lack of supply chains and mature markets for these novel fuels makes it difficult to forecast their prices into the modeling time horizon. For these reasons, LucidCatalyst assigned the built-in uranium price projection of $0.52/MMBtu to flexible advanced nuclear plants for this analysis.

Most current nuclear plants in the United States have conversion efficiencies between 31 and 34 percent, which equate to heat rates between 11,000 and 10,000 Btu/kWh.[47] As a result of engineering innovations and optimizations over time, most of the recently constructed plants have higher efficiencies and lower heat rates than older plants.

While this analysis refrains from specifying any particular reactor technology for the flexible advanced plants, the assumed reactor outlet temperature stated above (600 to 700°C) allows for higher efficiency than conventional designs with lower outlet temperatures (around 325°C for pressurized water reactors and 290°C for boiling water reactors). Based on the target reactor temperature range, historical improvements in efficiency, and the strong incentive among developers to minimize fuel costs, this analysis uses an efficiency of 40% and equivalent heat rate of 8,530 Btu/kWh for flexible advanced nuclear plants in the PLEXOS modeling.

By combining the uranium price projection and assumed heat rate, flexible advanced nuclear plants have a fuel cost of $0.52/MMBtu x 8,530 Btu/kWh = $4.44/kWh.

5.5.2 Operating and Maintenance Costs

Conventional nuclear plants incur high operating and maintenance (O&M) costs because of the need for large site crews and extensive upkeep requirements for complex systems. The typical headcount for a full-sized nuclear plant (around 1000 MW) is 800 people.[48] Many of the personnel positions relate to system monitoring, accident preparedness, security, and maintenance activities. The plants require frequent supplies, such as makeup materials, chemicals, and gases.

The average O&M cost for US nuclear plants in 2018 was $19.69/MWh.[49] With an average capacity factor of 93% across the nuclear fleet, this is equivalent to $160/kW per year (combining fixed and variable O&M). Another data source for nuclear plants similar to the current fleet, the U.S. Energy Information Administration uses a fixed O&M cost of $103/kW per year (equivalent to $12.46/MWh) and variable O&M cost of $2.37/MWh in the latest version of their 2019 Annual Energy Outlook.[50] The variable O&M cost equates to $19/kW after accounting for the average capacity factor, leading to a combined fixed and variable O&M estimate of $122/kW per year from this government source.

The flexible advanced nuclear plants in this modeling analysis are designed for more efficient operation than conventional nuclear plants. They reflect the goal of utilizing concepts with superior safety and streamlined processes to reduce the need for complicated backup systems and large crews for monitoring, accident preparedness, etc. Automation, robotics, and offsite control/response centers serving multiple units will also likely reduce staffing needs at advanced nuclear plants deployed in the 2030s. As an example of staffing efficiencies at a new plant concept, GE Hitachi anticipates a crew of 75 for its 300 MWe BWRX.[51]

Staffing levels at natural gas and coal plants provide useful reference points for target operations at flexible advanced nuclear plants. The U.S. Department of Energy uses baseline crew counts of 5 people per shift (20 in total with 4 shifts) for a 630 MW natural gas combined-cycle plant and 14 people per shift (56 in total) for a 550 MW coal plant.[52] These staffing levels are highly relevant to the current context because the flexible advanced nuclear plants would have their turbine-generator system on a separate fluid loop from the reactor loop (a significant simplification in terms of safety and monitoring relative to conventional nuclear plants because no fluid in the turbine building would pass through the reactor).

When Idaho National Laboratory assessed the potential costs of the Next Generation Nuclear Plant concept in 2010, the estimated crew headcount was 28 people for this High Temperature Gas Reactor with capacity of 274 MWe, based on operational similarities with natural gas and coal plants.[53] The annual cost of staff, insurance, and taxes in this study is $11 million, or $27/kW-year. After adjusting for currency inflation, this value becomes $31/kW-year in 2019 dollars (equivalent to $3.75/MWh based on the capacity factor above).

For this modeling analysis, LucidCatalyst used the O&M estimate of $31/kW-year from Idaho National Laboratory's 2010 study as the target level for flexible advanced nuclear plants in the 2030s. The energy storage system is assumed to add no O&M costs to the plant because the potential medium, such as firebrick or molten salt, would simply charge and discharge energy by movements of air or other straightforward physical processes, without the need for operators or maintenance activities. The O&M parameter for the flexible advanced plants sets a clear goal for MEITNER Design Teams in their efforts to ensure the economic viability of their advanced nuclear concepts. Subsequent sections of this report show the maximum allowable CapEx for flexible advanced nuclear plants based on this O&M parameter, among other calculation inputs. The maximum allowable CapEx would be lower (tighter constraint) in each market simulation if O&M costs were higher.

Table 7. **O&M and Fuel Assumptions**

Category	Value
O&M Cost	$31/kW-yr ($3.75 /MWh)
Fuel Expenditures	$4.44/MWh ($37 /kW-yr)

The O&M costs for the ESS system are assumed to be minimal[54] and effectively immaterial as the ESS does not require fuel or significant operational expenses.

5.6 Modeling Result Categories

The following table summarizes the different PLEXOS model inputs and results.

Table 8. **PLEXOS Input and Result Categories**

Inputs	
Plant Capacities	Plant capacities are inputs to PLEXOS (with adjustments by LucidCatalyst for baseline scenario calibration and flexible advanced nuclear additions); summed by plant type (natural gas, solar, wind, etc.) for regional total.
Demand (load)	Demand in each service territory is an input to PLEXOS; summed across service territories for regional total.
Results	
Plant Operational Dispatch	PLEXOS determines the optimal combinations of plant production across the grid, including output from the advanced nuclear plants, to meet demand in each hour of the modeling period; hourly dispatch is summed over year to calculate total generation by plant in 2034.
Market Price	PLEXOS calculates market price in each hour of the modeling period in each service territory based on the marginal costs of the marginal producer to meet demand; market prices are averaged across service territories and hours in year to calculate average market price in 2034.
CO_2 Emissions	PLEXOS uses plant operational dispatch, fuel consumption per MWh, and CO_2 emission rate per unit of fuel consumption to calculate CO_2 emissions from plant operation; results are summed across plants and hours in year to calculate total CO_2 emissions in each region in 2034.
Advanced Nuclear Operational Dispatch	This is part of the broader plant dispatch results by hour described above.
Energy Storage Charging and Discharging	PLEXOS optimizes the charging and discharging by hour for each energy storage system in the modeled region, subject to the constraint limiting their hourly charging amount to the coupled nuclear plant's production in the same hour.

LucidCatalyst calculates maximum allowable CapEx by using operating profits, which derives from a combination of PLEXOS results and supplemental assumptions (e.g., annual capacity payments).

6

Illustrative Cash Flow Analysis

This section presents a high-level cash flow analysis for an advanced nuclear plant with and without ESS. This type of analysis is used to calculate maximum allowable CapEx and highlights key profitability drivers. It also lays the foundation for understanding how different future market conditions can either threaten or enhance these drivers.

As capital-intensive investments, power plants recover CapEx over time from the difference between their annual revenue and operating expenditures. In this section, operating profits are calculated in this manner and presumed to be available for CapEx recovery. Annual profits, along with industry standard assumptions regarding payback period and interest rate, are used to estimate maximum allowable CapEx, expressed in $/kW.

Calculating maximum allowable CapEx involves the following steps:

1. **Identify plant capacity and performance characteristics.** This involves specifying assumptions regarding plant capacity, annual capacity factor, and for the ESS, round-trip efficiency (the total efficiency of one charge and discharge cycle).
2. **Calculate wholesale energy revenue.** This step occurs in PLEXOS but simply includes a calculation whereby the clearing price is multiplied by the plant's output (MW) in each hour. This reflects scheduled down time for plant maintenance and other things (e.g., refueling) that might affect the plant's annual capacity factor.
3. **Add capacity payments.** In addition to wholesale energy revenue, LucidCatalyst assumes that the advanced nuclear plant receives capacity payments. This step applies a range of potential capacity prices in $/kW per year and shows the calculated payments.
4. **Calculate operating expenditures.** The three components of operating expenditures for the flexible advanced nuclear plant—fuel, variable O&M, and fixed O&M—are summed in this step.
5. **Calculate operating profit for CapEx recovery.** The difference between annual revenue (summing wholesale energy revenue with capacity payments) and annual operating expenditures (summing fuel, fixed O&M, and variable O&M) represents the operating profit per year for CapEx recovery. The implied maximum allowable CapEx is derived from the annual operating profit, which is based on additional financial parameters such as financing rates and the allowed length of time to pay back the lender.

6.1 Estimating Annual Revenue for a 500 MW Illustrative Plant

Estimating annual revenue includes only two components: energy revenue and capacity payments.

6.1.1 Energy Revenue

Energy revenue is driven by market prices and how many hours each system is operating at its maximum output. For the purposes of this illustrative cash flow analysis, the average clearing price over the year is $22/MWh, which is within the range of modeled prices in 2034. For plants with ESS, the amount of energy sent to storage will be different for each market, due to pricing conditions. However, for the purposes of this analysis, it is assumed that 25% of the nuclear plant output is to go toward charging the ESS system (which is similar to what bears out in PLEXOS). Because the ESS system is optimized to discharge when prices are at their highest, the average clearing prices at which the ESS sells power is $25/MWh (as opposed to $22/MWh). Also, because the nuclear plant charges the ESS when prices are at their lowest, the average clearing price for the rest of the energy sent to the grid is slightly higher than the annual average. For this analysis, this is assumed to be $22.50/MWh. The following table represents the energy revenue for each plant configuration.

Table 9. **Energy Revenue for Each Plant Configuration**

	Dispatch from Adv. Nuclear Plant	Total MWh	Average Clearing Price (MWh)	Total Energy Revenue
Without ESS				
500 MW Nuclear Plant	Capacity: 500 MW x Capacity Factor: 92% x 8,760 hours/year	4.03 million	$22	$88.6 million
With ESS				
500 MW Nuclear Plant	Capacity: 500 MW x Capacity Factor: 92% x 75% of output sent to grid: 6,570 hours/year	3.02 million	$22.50	$68 million
500 MW ESS System	Capacity: 500 MW x Capacity Factor: 92% x Roundtrip Efficiency: 90% x 12-hours avg. daily output: 4,380 hours/year	907,660	$25	$22.7 million
Total				$90.7 million

The difference in energy revenue between the two configurations is largely driven by the delta between the two average clearing prices and roundtrip efficiency. It is also important to note that revenues are sensitive to the input assumptions regarding capacity factor, roundtrip efficiency, and the system's power rating and discharge capacity (duration). Making significant modifications to these parameters can materially impact revenues. Other thermal storage characteristics (i.e., thermal stability, heat conductivity, response time, etc.) are excluded from the example and assumed to have immaterial consequences on the systems' operation.

6.1.2 Capacity Revenue

In addition to energy sales, nuclear plants also typically receive some form of capacity payment. Capacity programs encourage resources to be built and/or made available during periods with high demand. This analysis uses three hypothetical capacity prices: $50, $75, or $100/kW per year (the middle value of $75/kW per year reflects the approximate average of capacity prices in ISO New England recently, and a higher-end capacity price seen in recent PJM auctions). There is inherent uncertainty regarding future price levels as capacity programs continue to evolve; however, if energy prices continue to fall, one could argue that stimulating new project investment in such an environment would warrant higher capacity prices.

A $75/kW-year capacity payment translates to $37.5 million for the plant without co-located energy storage. Plants with 12 hours of energy storage can effectively supply 1,000 MW of power through two, 500 MW turbine-generators. As mentioned in the previous section, LucidCatalyst assumes that the ESS receives a full capacity payment as well. This translates to an annual capacity payment of $75 million for the plant with storage.

6.2 O&M Expenditures

The following table highlights the O&M expenses for the illustrative plant. O&M for the ESS is assumed to be *de minimis* and because the advanced nuclear plant operates at the same output under both configurations the O&M expenditures are assumed to be the same under both configurations.

Table 10. **Advanced Nuclear Plant O&M Expenditures**

Cost Category	Calculation	Estimated Value
O&M	$31/kW-yr ($3.75/MWh) X 500 MW	$15 million
Fuel	$4.44/MWh X 4,073,400 MWhs	$18 million
Total		$33 million

6.3 Maximum CapEx

Calculating maximum allowable CapEx involves calculating the total annual revenue (energy revenue and capacity payments) and subtracting the total annual operating expenditures (fixed and variable O&M). The result is the annual operating profit, which along with a capital recovery period (e.g., 22 years) and cost of capital (reflected here as the interest rate) is used to calculated maximum allowable CapEx for a breakeven profit. The table below estimates this for both plant configurations.

Table 11. **Estimated Annual Plant Revenue, Expenditures, and Operating Profits for CapEx Recovery – Without ESS and With ESS**

Illustrative Analysis	Without ESS	With ESS
Scenario Specifications		
# of Nuclear Plants	1	1
Reactor Capacity	500 MWe	500 MWe
Avg. Annual Capacity Factor	92%	92%
% of Annual Output to ESS System	–	50%
Revenue		
Nuclear Plant – Avg. Energy Price Received	$22/MWh	$22/MWh
Nuclear Plant – Direct Sales Revenue	$90 M	$45 M
Nuclear & ESS – Avg. Energy Price Received	–	$28/MWh
ESS Net Generation Revenue	–	$51 M
Total System Energy Revenue	$90 M	$96 M
Total Revenue		
Low (assumes $50/kW-yr capacity payment)	$115 M	$146 M
Mid (assumes $75/kW-yr capacity payment)	$127 M	$171 M
High (assumes $100/kW-yr capacity payment)	$140 M	$196 M
Expenditures		
Fuel Expenditures	$18 M	$18 M
Other Variable O&M Expenditures	$0 M	$0 M
Fixed O&M Expenditures	$15 M	$15 M
Total Operating Expenditures	$33 M	$33 M
Operating Profits for CapEx Recovery		
Low Capacity Price Case	$81 M	$113 M
Mid Capacity Price Case	$94 M	$138 M
High Capacity Price Case	$106 M	$163 M
Maximum Plant CapEx for Profit Breakeven		
Low Capacity Price Case	$1,798/kW	$2,496/kW
Mid Capacity Price Case	$2,075/kW	$3,049/kW
High Capacity Price Case	$2,351/kW	$3,602/kW

The following figure shows the ranges of maximum allowable CapEx with or without energy storage based on the parameter assumptions described above. Pink cells indicate unfavorable combinations of low energy and capacity prices leading to tight limits on CapEx, while green cells indicate favorable combinations of high prices leading to higher allowable CapEx. The lower pane for the case without energy storage has tighter limits on CapEx than the upper pane with energy storage because of foregone capacity payments.

Figure 9. **Ranges of Maximum Allowable CapEx ($/kW) – With ESS and Without ESS**

With ES	$50/kW-yr	$60/kW-yr	$70/kW-yr	$75/kW-yr	$80 kW-yr	$90/kW-yr	$100/kW-yr
$10/MWh	$1,225	$1,446	$1,667	$1,778	$1,888	$2,110	$2,331
$15/MWh	$1,653	$1,874	$2,095	$2,206	$2,317	$2,538	$2,759
$20/MWh	$2,081	$2,302	$2,523	$2,634	$2,745	$2,966	$3,187
$22/MWh	$2,252	$2,473	$2,695	$2,805	$2,916	$3,137	$3,358
$24/MWh	$2,423	$2,645	$2,866	$2,976	$3,087	$3,308	$3,529
$26/MWh	$2,595	$2,816	$3,037	$3,148	$3,258	$3,479	$3,701
$28/MWh	$2,766	$2,987	$3,208	$3,319	$3,429	$3,651	$3,872
$30/MWh	$2,937	$3,158	$3,379	$3,490	$3,601	$3,822	$4,043
$35/MWh	$3,365	$3,586	$3,807	$3,918	$4,029	$4,250	$4,471
$40/MWh	$3,793	$4,014	$4,235	$4,346	$4,457	$4,678	$4,899

Without ES	$50 /kW-yr	$60/kW-yr	$70/kW-yr	$75/kW-yr	$80/kW-yr	$90/kW-yr	$100/kW-yr
$10/MWh	$717	$827	$938	$993	$1,049	$1,159	$1,270
$15/MWh	$1,167	$1,278	$1,389	$1,444	$1,499	$1,610	$1,720
$20/MWh	$1,618	$1,729	$1,839	$1,894	$1,950	$2,060	$2,171
$22/MWh	$1,798	$1,909	$2,019	$2,075	$2,130	$2,241	$2,351
$24/MWh	$1,978	$2,089	$2,200	$2,255	$2,310	$2,421	$2,531
$26/MWh	$2,159	$2,269	$2,380	$2,435	$2,490	$2,601	$2,712
$28/MWh	$2,339	$2,449	$2,560	$2,615	$2,671	$2,781	$2,892
$30/MWh	$2,519	$2,630	$2,740	$2,796	$2,851	$2,962	$3,072
$35/MWh	$2,970	$3,080	$3,191	$3,246	$3,301	$3,412	$3,523
$40/MWh	$3,420	$3,531	$3,641	$3,697	$3,752	$3,863	$3,973

7

PLEXOS Modeling Results for 2034

This section presents results from modeling flexible advanced nuclear plants with and without energy storage in the four identified markets (ISO New England, PJM, MISO, and CAISO). Each subsection presents the baseline 2034 resource mix and then the CapEx for the first plant entering the market (with and without storage).

7.1 ISO New England

The table below highlights the total plant capacity by resource as well as the annual generation in all modeled scenarios in ISO-NE. Most of the capacity and generation in this market comes from natural gas. Most of the wind capacity in this market is offshore.

Table 12. **Resource Capacity and Generation in ISO-NE for the Modeled Scenarios**

Installed Capacity & Generation	Total	Coal	Nat. Gas	Oil	Existing Nuclear	Hydro	Solar	Wind	Bio/ Other	Net Imports/ Exports[1]
2018 Benchmark										
GW	**35**	1	15	6	3	4	1	1	4	–
TWh	**124**	1	67	0	25	8	1	3	10	-10
2034 Low RE Future										
GW	**44**	1	19	6	3	4	4	3	5	–
TWh	**110**	0	43	0	25	8	7	8	10	-9
2034 High RE Future										
GW	**47**	0	16	4	3	4	9	7	5	–
TWh	**110**	0	28	0	25	8	18	21	10	-2

1 Imports are negative; exports are positive.

A separate table below summarizes PLEXOS results for annual average market prices, revenue, and operating expenditures for ISO-NE in the various scenarios. It also presents the maximum allowable CapEx, which, for all four ISO modeling results, reflects the financial assumptions of a 22-year CapEx recovery period[55] and a 50-50 split of debt and equity financing with a weighted average cost of capital (WACC) of 7%.[56]

Table 13. **PLEXOS Results for ISO-NE**

	Low RE Future w/out ESS	with ESS	**High RE Future** w/out ESS	with ESS
Scenario Specifications				
# of Nuclear Plants	1	1	1	1
Reactor Capacity	500 MWe	500 MWe	500 MWe	500 MWe
Representative Load Zone	Mass Central	Mass Central	Mass Central	Mass Central
Annual Avg. Energy Market Price	$27.56/MWh	$27.57/MWh	$23.67/MWh	$23.90/MWh
Avg. Annual Capacity Factor	92%	92%	85%	86%
% of Annual Output to ESS System	–	24%	–	31%
Revenue				
Nuclear Plant – Avg. Energy Price Received	$27.73/MWh	$27.71/MWh	$25.80/MWh	$25.72/MWh
Nuclear Plant – Direct Sales Revenue	$112 M	$84 M	$96 M	$66 M
Nuclear & ESS – Avg. Energy Price Received	–	$29.76/MWh	–	$29.70/MWh
ESS Net Generation Revenue	–	$33 M	–	$42 M
Total System Energy Revenue	$112 M	$117 M	$96 M	$108 M
Total Revenue				
Low (assumes $50/kW-yr capacity payment)	$137 M	$167 M	$121 M	$158 M
Mid (assumes $75/kW-yr capacity payment)	$149 M	$192 M	$133 M	$183 M
High (assumes $100/kW-yr capacity payment)	$162 M	$217 M	$146 M	$208 M
Expenditures				
Fuel Expenditures	$18 M	$18 M	$16 M	$17 M
Other Variable O&M Expenditures	$0 M	$0 M	$0 M	$0 M
Fixed O&M Expenditures	$15 M	$15 M	$15 M	$15 M
Total Operating Expenditures	$33 M	$33 M	$32 M	$32 M
Operating Profits for CapEx Recovery				
Low Capacity Price Case	$103 M	$134 M	$89 M	$126 M
Mid Capacity Price Case	$116 M	$159 M	$101 M	$151 M
High Capacity Price Case	$128 M	$184 M	$114 M	$176 M
Maximum Plant CapEx for Profit Breakeven				
Low Capacity Price Case	$2,289/kW	$2,962/kW	$1,965/kW	$2,788/kW
Mid Capacity Price Case	$2,566/kW	$3,515/kW	$2,242/kW	$3,341/kW
High Capacity Price Case	$2,843/kW	$4,068/kW	$2,519/kW	$3,894/kW

7.2 PJM

The tables below highlight the total plant capacity by resource (including the annual generation in all modeled scenarios) as well as a summary of the PLEXOS results for PJM. This market has the most coal capacity and generation of the four markets modeled in this analysis. The High RE Future has several times more solar and wind capacity and generation than the Low RE Future. This market is modeled without neighboring zones (no imports or exports) because of its large geographic breadth.

Table 14. **Resource Capacity and Generation in PJM for the Modeled Scenarios**

Installed Capacity & Generation	Total	Coal	Nat. Gas	Oil	Existing Nuclear	Hydro	Solar	Wind	Bio/ Other	Net Imports/ Exports[1]
2018 Benchmark										
GW	**203**	57	75	6	32	9	1	7	15	–
TWh	**806**	364	140	0	247	5	2	20	28	–
2034 Low RE Future										
GW	**239**	55	111	6	25	9	7	11	15	–
TWh	**869**	253	351	0	186	5	15	32	27	–
2034 High RE Future										
GW	**281**	3	111	6	23	9	64	50	15	–
TWh	**869**	22	361	0	170	5	129	154	27	–

1 PJM is modeled without neighboring zones (no imports or exports).

Table 15. **PLEXOS Results for PJM**

	Low RE Future		**High RE Future**	
	w/out ESS	with ESS	w/out ESS	with ESS
Scenario Specifications				
# of Nuclear Plants	1	1	1	1
Reactor Capacity	500 MWe	500 MWe	500 MWe	500 MWe
Representative Load Zone	PEPCO	PEPCO	PEPCO	PEPCO
Annual Avg. Energy Market Price	$28.39/MWh	$28.47/MWh	$26.46/MWh	$26.44/MWh
Avg. Annual Capacity Factor	92%	92%	91%	92%
% of Annual Output to ESS System	–	20%	–	20%
Revenue				
Nuclear Plant – Avg. Energy Price Received	$28.34/MWh	$28.44/MWh	$26.69/MWh	$26.39/MWh
Nuclear Plant – Direct Sales Revenue	$115 M	$92 M	$107 M	$72 M
Nuclear & ESS – Avg. Energy Price Received	–	$29.81/MWh	–	$30.76/MWh
ESS Net Generation Revenue	–	$26 M	–	$48 M
Total System Energy Revenue	$115 M	$118 M	$107 M	$121 M
Total Revenue				
Low (assumes $50/kW-yr capacity payment)	$140 M	$168 M	$132 M	$171 M
Mid (assumes $75/kW-yr capacity payment)	$152 M	$193 M	$144 M	$196 M
High (assumes $100/kW-yr capacity payment)	$165 M	$218 M	$157 M	$221 M
Expenditures				
Fuel Expenditures	$18 M	$18 M	$18 M	$18 M
Other Variable O&M Expenditures	$0 M	$0 M	$0 M	$0 M
Fixed O&M Expenditures	$15 M	$15 M	$15 M	$15 M
Total Operating Expenditures	$33 M	$33 M	$33 M	$33 M
Operating Profits for CapEx Recovery				
Low Capacity Price Case	$107 M	$135 M	$99 M	$137 M
Mid Capacity Price Case	$119 M	$160 M	$111 M	$162 M
High Capacity Price Case	$132 M	$185 M	$124 M	$187 M
Maximum Plant CapEx for Profit Breakeven				
Low Capacity Price Case	$2,358/kW	$2,988/kW	$2,186/kW	$3,038/kW
Mid Capacity Price Case	$2,634/kW	$3,541/kW	$2,462/kW	$3,591/kW
High Capacity Price Case	$2,911 kW	$4,095/kW	$2,739/kW	$4,144/kW

7.3 MISO

The tables below highlight the total plant capacity by resource (including the annual generation in all modeled scenarios) as well as a summary of the PLEXOS results for MISO. The market has high wind penetration, especially in the High RE Future.

Table 16. **Resource Capacity and Generation in MISO for the Modeled Scenarios**

Installed Capacity & Generation	Total	Coal	Nat. Gas	Oil	Existing Nuclear	Hydro	Solar	Wind	Bio/ Other	Net Imports/ Exports[1]
2018 Benchmark										
GW	175	61	71	4	13	5	1	18	3	–
TWh	709	372	149	0	97	9	2	56	25	0
2034 Low RE Future										
GW	229	59	117	3	8	4	9	25	3	–
TWh	838	124	392	0	65	9	19	83	25	-122
2034 High RE Future										
GW	243	4	99	3	8	4	51	70	3	–
TWh	838	16	295	0	65	9	109	253	24	-67

1 Imports are negative; exports are positive.

Table 17. **PLEXOS Results for MISO**

	Low RE Future w/out ESS	with ESS	**High RE Future** w/out ESS	with ESS
Scenario Specifications				
# of Nuclear Plants	1	1	1	1
Reactor Capacity	500 MWe	500 MWe	500 MWe	500 MWe
Representative Load Zone	S. Illinois	S. Illinois	S. Illinois	S. Illinois
Annual Avg. Energy Market Price	$27.17/MWh	$27.17/MWh	$24.16/MWh	$24.16/MWh
Avg. Annual Capacity Factor	92%	92%	92%	92%
% of Annual Output to ESS System	–	20%	–	26%
Revenue				
Nuclear Plant – Avg. Energy Price Received	$27.21/MWh	$27.21/MWh	$24.52/MWh	$24.47/MWh
Nuclear Plant – Direct Sales Revenue	$110 M	$88 M	$98 M	$73 M
Nuclear & ESS – Avg. Energy Price Received	–	$28.44/MWh	–	$26.28/MWh
ESS Net Generation Revenue	–	$24 M	–	$30 M
Total System Energy Revenue	$110 M	$112 M	$98 M	$103 M
Total Revenue				
Low (assumes $50/kW-yr capacity payment)	$135 M	$162 M	$123 M	$153 M
Mid (assumes $75/kW-yr capacity payment)	$147 M	$187 M	$136 M	$178 M
High (assumes $100/kW-yr capacity payment)	$160 M	$212 M	$148 M	$203 M
Expenditures				
Fuel expenditures	$18 M	$18 M	$18 M	$18 M
Other Variable O&M Expenditures	$0 M	$0 M	$0 M	$0 M
Fixed O&M Expenditures	$15 M	$15 M	$15 M	$15 M
Total Operating Expenditures	$33 M	$33 M	$33 M	$33 M
Operating Profits for CapEx Recovery				
Low Capacity Price Case	$101 M	$129 M	$90 M	$120 M
Mid Capacity Price Case	$114 M	$154 M	$103 M	$145 M
High Capacity Price Case	$126 M	$179 M	$115 M	$170 M
Maximum plant CapEx for Profit Breakeven				
Low Capacity Price Case	$2,244/kW	$2,857/kW	$2,000/kW	$2,654/kW
Mid Capacity Price Case	$2,521/kW	$3,410/kW	$2,276/kW	$3,207/kW
High Capacity Price Case	$2,797/kW	$3,963/kW	$2,553/kW	$3,760/kW

7.4 CAISO

The tables below highlight the total plant capacity by resource (including the annual generation in all modeled scenarios) as well as a summary of the PLEXOS results for CAISO. This market has high solar and wind penetration, especially in the High RE Future.

Table 18. **Resource Capacity and Generation in CAISO for the Modeled Scenarios**

Installed Capacity & Generation	Total	Coal	Nat. Gas	Oil	Existing Nuclear	Hydro	Solar	Wind	Bio/ Other	Net Imports/ Exports[1]
2018 Benchmark										
GW	74	0	39	0	2	14	9	6	3	–
TWh	261	0	116	0	16	37	24	15	10	-42
2034 Low RE Future										
GW	86	0	35	0	0	14	23	10	3	–
TWh	272	0	61	0	0	37	65	28	10	-70
2034 High RE Future										
GW	88	0	30	0	0	11	34	10	3	–
TWh	272	0	49	0	0	28	97	28	10	-61

1 Imports are negative; exports are positive.

Table 19. **PLEXOS results for CAISO**

	Low RE Future w/out ESS	with ESS	**High RE Future** w/out ESS	with ESS
Scenario Specifications				
# of Nuclear Plants	1	1	1	1
Reactor Capacity	500 MWe	500 MWe	500 MWe	500 MWe
Representative Load Zone	San Diego	San Diego	San Diego	San Diego
Annual Avg. Energy Market Price	$25.79/MWh	$25.95/MWh	$22.73/MWh	$22.66/MWh
Avg. Annual Capacity Factor	79%	92%	67%	91%
% of Annual Output to ESS System	–	33%	–	34%
Revenue				
Nuclear Plant – Avg. Energy Price Received	$30.21/MWh	$26.32/MWh	$31.50/MWh	$23.26/MWh

	Low RE Future w/out ESS	with ESS	High RE Future w/out ESS	with ESS
Nuclear Plant – Direct Sales Revenue	$104 M	$71 M	$92 M	$61 M
Nuclear & ESS – Avg. Energy Price Received	–	$35.07/MWh	–	$34.48/MWh
ESS Net Generation Revenue	–	$65 M	–	$71 M
Total System Energy Revenue	$104 M	$137 M	$92 M	$132 M
Total Revenue				
Low (assumes $50/kW-yr capacity payment)	$129 M	$187 M	$117 M	$182 M
Mid (assumes $75/kW-yr capacity payment)	$142 M	$212 M	$130 M	$207 M
High (assumes $100/kW-yr capacity payment)	$154 M	$237 M	$142 M	$232 M
Expenditures				
Fuel Expenditures	$15 M	$18 M	$13 M	$18 M
Other Variable O&M Expenditures	$0 M	$0 M	$0 M	$0 M
Fixed O&M Expenditures	$15 M	$15 M	$15 M	$15 M
Total Operating Expenditures	$31 M	$33 M	$28 M	$33 M
Operating Profits for CapEx Recovery				
Low Capacity Price Case	$99 M	$154 M	$89 M	$149 M
Mid Capacity Price Case	$111 M	$179 M	$101 M	$174 M
High Capacity Price Case	$124 M	$204 M	$114 M	$199 M
Maximum plant CapEx for Profit Breakeven				
Low Capacity Price Case	$2,187/kW	$3,397/kW	$1,968/kW	$3,306/kW
Mid Capacity Price Case	$2,464/kW	$3,950/kW	$2,244/kW	$3,859/kW
High Capacity Price Case	$2,740/kW	$4,503/kW	$2,521/kW	$4,412/kW

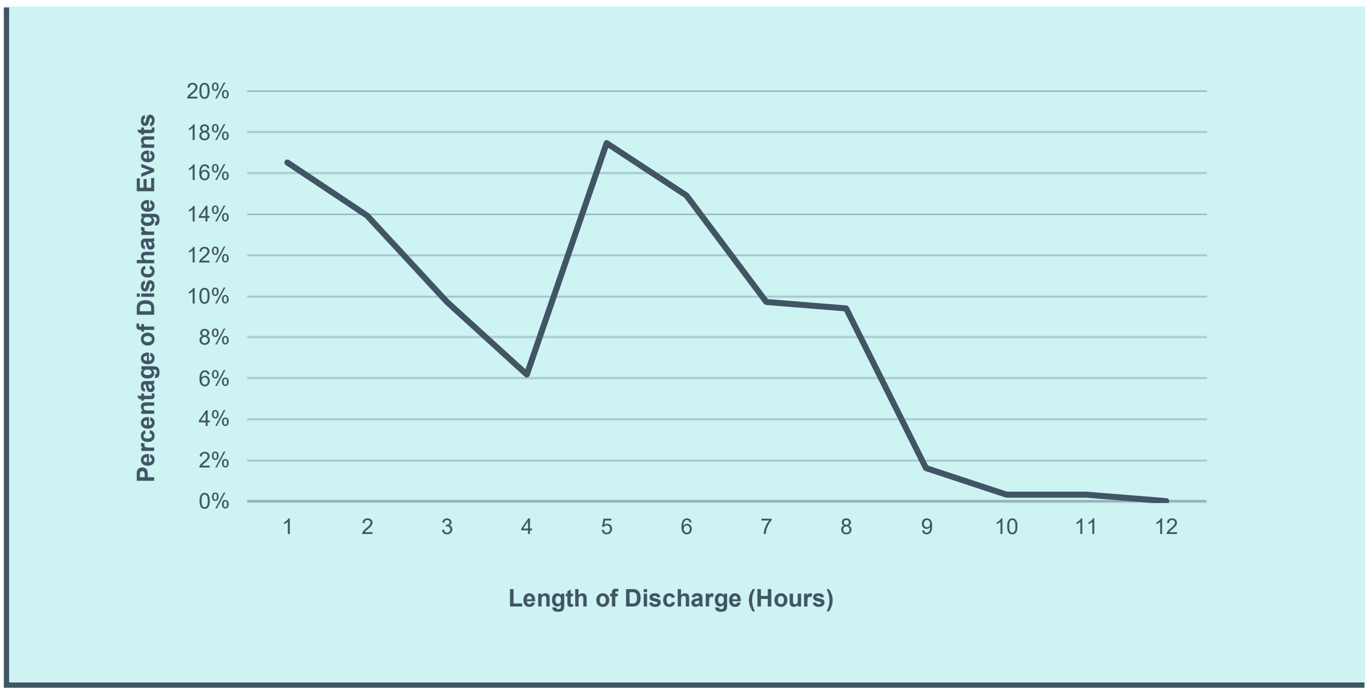
7.5 Summary and Modeling Result Implications

The PLEXOS and financial modeling results in a range of maximum allowable CapEx. As shown in the preceding tables, this range is largely driven by capacity payments, the addition of ESS, and the average energy price, which is driven by the assumption of continued low natural gas prices and the two different renewables scenarios in 2034. These highlight several implications for advanced reactor developers:

- The addition of energy storage may improve a project's economics, but this is dependent on several factors. The ESS captures higher average energy prices, as it is optimized to charge during the lowest priced hours, and sells during the highest priced hours. However, the amount of CapEx that can be budgeted for the ESS depends on the Low RE vs. High RE scenario, and importantly, the available capacity payment. For example, the CapEx threshold for ESS in MISO in the Low RE scenario and $25/kW-year capacity payment is only $613/kW. At present, there are no commercially available ESS options at this price. Conversely, assuming the High RE scenario in CAISO, and a $100/kW-year capacity payment, the allowable CapEx for the ESS is $1,891/kW. LucidCatalyst's high-level cost analysis for thermal ESS in Appendix E suggests that this is possible using today's technologies and costs, especially for reactor designs with higher outlet temperatures. It is highly likely that these will be significantly cheaper by 2034. Also, as shown in Appendix D, projections for electrochemical storage systems (i.e., batteries) are expected to be well below that cost (even for a 12-hour system) by 2034. Therefore, developers should be aware of the potential for storage to impact a project's bottom line and will want to consider it based on specific market conditions.

- It is important to note that capacity payments are a major source of assumed revenue. For plants without ESS, each additional $50/kW-year adds $277/kW to a plant's maximum allowable CapEx. For plants with ESS, this amount is doubled to $553/kW. One a related note, while LucidCatalyst assumed a 12-hour ESS, on average, the system typically discharged for only 4 hours, exceeding an 8-hour discharge only 12% of the time (see Figure 18). Developers should therefore track if/how performance requirements for capacity payments change over time and weigh the savings of a smaller ESS with the probability of paying non-performance penalties.
- Advanced reactor developers should note that higher RE penetrations reduce average energy prices (and thus allowable CapEx). If the assumed VRE penetration is too conservative in these scenarios, the effective maximum allowable CapEx will likely be lower. Higher VRE penetration will trigger more aggressive ramping and potentially higher prices during critical peak demand periods. While this may benefit highly flexible and dispatchable resources like advanced nuclear plants, this will also lead to lower capacity factors and a likely decline in average energy prices. To the extent these factors affect revenues, maximum allowable CapEx may be lower.

Figure 10. **Frequency of Different Discharge Durations**



8 Additional Modeling Analyses

The Results section above highlights the 2034 CapEx requirements under a highly specific set of assumptions. Several different scenarios may play out and it is worth exploring other future outcomes to understand their impact on CapEx requirements.

This section examines three additional modeling analyses: 1. Effect of CO_2 Prices, 2. Market Penetration Potential, 3. Impact on Allowable CapEx from Alternative Fixed O&M Assumption.

1 **Effect of CO_2 Prices:** There are six bills in the 116th U.S. Congress that establish a CO_2 price with escalators that increase the price over time.[57] Further, seventeen states have introduced some form of carbon pricing legislation, including the California and the ten states that makes up the Regional Greenhouse Gas Initiative (RGGI), which already have a variable CO_2 price.[58] One could reasonably argue that there is a non-zero probability of a carbon pricing scheme going into effect by 2034. While current proposals differ in carbon price and rate of escalation, the most conservative proposals set a CO_2 price of around $50/tonne by 2034. This modeling analysis examines how a $50/tonne CO_2 price, with side cases of $25 and $75/tonne, would affect revenue and the maximum allowable CapEx for advanced nuclear plants.

2 **Market Penetration Potential:** Assuming the operational characteristics of a flexible advanced nuclear plant are similar to a CCGT, it is worth estimating the extent to which these resources can be deployed without significantly reducing energy prices (due to their low-price energy bids). Advanced reactor developers may want to simultaneously develop more than one project in the same ISO, and it is valuable to understand how many plants each market can accommodate and how that might affect the overall cost of electricity delivery.

3 **Impact on Allowable CapEx from Alternative Fixed O&M Assumption**: This study considers a relatively low fixed O&M assumption of $31/kW-year, which is ~70% lower than the fixed O&M assumed for today's conventional nuclear fleet (~$103/kW-year). While LucidCatalyst recognizes that this a realistic goal for advanced reactor developers to target; it is also worth exploring how higher fixed O&M might impact maximum allowable CapEx. This analysis considers a fixed O&M of $61/kW-year, a halving of today's fixed O&M cost estimate.

8.1 Effect of CO_2 Prices

To measure the impact of a CO_2 price on allowable CapEx, LucidCatalyst ran three additional scenarios for PJM: $25, $50, and $75/tonne. CO_2 prices do not cause fossil plants to retire in the PLEXOS simulations (i.e., capacity levels are the same between these simulations and the High Renewables Future described above) because this analysis uses a consistent methodology of considering plant capacity as a deterministic modeling input for each simulation. Based on their CO_2 emission rates (approximately 1 tonne per MWh for coal plants and 0.4 tonnes for combined-cycle natural gas plants), applying the CO_2 price of $50/tonne inflates fossil generators' marginal costs by approximately $50/MWh for coal plants and $20/MWh for combined-cycle natural gas plants, which significantly raises market prices and impacts the allowable CapEx for the first flexible advanced nuclear plant that wishes to enter the market. The following tables show the PLEXOS modeling results—without and with energy storage.

Table 20. **CO_2 Price Scenarios for PJM without Energy Storage**

	No CO_2 Price	$25/tonne	$50/tonne	$75/tonne
Scenario Specifications				
# of Nuclear Plants	1	1	1	1
Reactor Capacity	500 MWe	500 MWe	500 MWe	500 MWe
Representative Load Zone	PEPCO	PEPCO	PEPCO	PEPCO
Annual Avg. Energy Market Price	$26.46/MWh	$37.06/MWh	$47.57/MWh	$57.88/MWh
Nuclear & ESS Annual Capacity Factor	91%	92%	92%	92%
Total System Energy Revenue	$107 M	$150 M	$192 M	$234 M
Maximum Plant CapEx for Profit Breakeven				
Low Capacity Price Case	$2,186/kW	$3,132/kW	$4,074/kW	$4,999/kW
Mid Capacity Price Case	$2,462/kW	$3,409/kW	$4,351/kW	$5,276/kW
High Capacity Price Case	$2,739/kW	$3,685/kW	$4,627/kW	$5,552 kW

Table 21. **CO_2 Price Scenarios for PJM with Energy Storage**

	No CO_2 Price	$25/tonne	$50/tonne	$75/tonne
Scenario Specifications				
# of Nuclear Plants	1	1	1	1
Reactor Capacity	500 MWe	500 MWe	500 MWe	500 MWe
Representative Load Zone	PEPCO (DC)	PEPCO	PEPCO	PEPCO
Annual Avg. Energy Market Price	$26.44/MWh	$37.03/MWh	$47.54/MWh	$57.86/MWh
Nuclear & ESS Annual Capacity Factor	92%	92%	92%	92%

	No CO_2 Price	$25/tonne	$50/tonne	$75/tonne
Total System Energy Revenue	$121 M	$165 M	$211 M	$257 M
Maximum Plant CapEx for Profit Breakeven				
Low Capacity Price Case	$3,038/kW	$4,031/kW	$5,043/kW	$6,056/kW
Mid Capacity Price Case	$3,591/kW	$4,584/kW	$5,596/kW	$6,609/kW
High Capacity Price Case	$4,144/kW	$5,13/kW	$6,14/kW	$7,162/kW

8.2 Market Penetration Potential

Advanced nuclear plants provide the same baseload and responsive, load-following characteristics as the existing fossil fleet; yet they have much lower operating costs. By 2034, a sizeable percentage of natural gas plants will be getting close to their retirement. Absent fundamental changes to energy markets, if advanced nuclear plants ever supply the majority of firm baseload power as the primary marginal resource (setting the energy price), energy prices will begin to rapidly decline due to advanced nuclear's low price energy bids. This would significantly impact the economics of most grid resources—including advanced nuclear plants. It is therefore worth exploring the market penetration limits of advanced nuclear plants, before they begin to materially impact energy prices—and consequently their own CapEx requirements.

To highlight potential market penetration without significant impact on CapEx requirements, LucidCatalyst modeled the 2034 High RE resource mix and supplied the majority of firm baseload power with advanced nuclear plants and co-located ESS. Other power plant capacity levels remained unaffected.

Table 22 below highlights the addition of 168 GWs of flexible advanced nuclear reactors relative to the baseline scenario.

Table 22. **2034 High RE Baseline and Fleet Deployment of Advanced Nuclear Plants**

Installed Capacity & Generation	Total	Coal	Nat. Gas	Oil	Existing Nuclear	Flexible Adv. Nuclear	Hydro	Solar	Wind	Bio/ Other	Net Imports/ Exports[1]
ISO-NE											
GW	46	0	5	4	3	10	4	9	7	5	–
TWh	111	0	9	0	24	39	8	18	21	9	+17
PJM											
GW	284	3	41	6	23	72	9	64	50	15	–
TWh	872	19	96	1	165	276	5	129	154	27	–

Installed Capacity & Generation	Total	Coal	Nat. Gas	Oil	Existing Nuclear	Flexible Adv. Nuclear	Hydro	Solar	Wind	Bio/ Other	Net Imports/ Exports[1]
MISO											
GW	245	4	35	3	8	66	4	51	70	3	–
TWh	840	12	94	0	65	247	9	109	253	24	-26
CAISO											
GW	91	0	13	0	0	20	11	34	10	3	–
TWh	272	0	3	0	0	75	27	97	28	9	-33

1 Imports are negative; exports are positive.

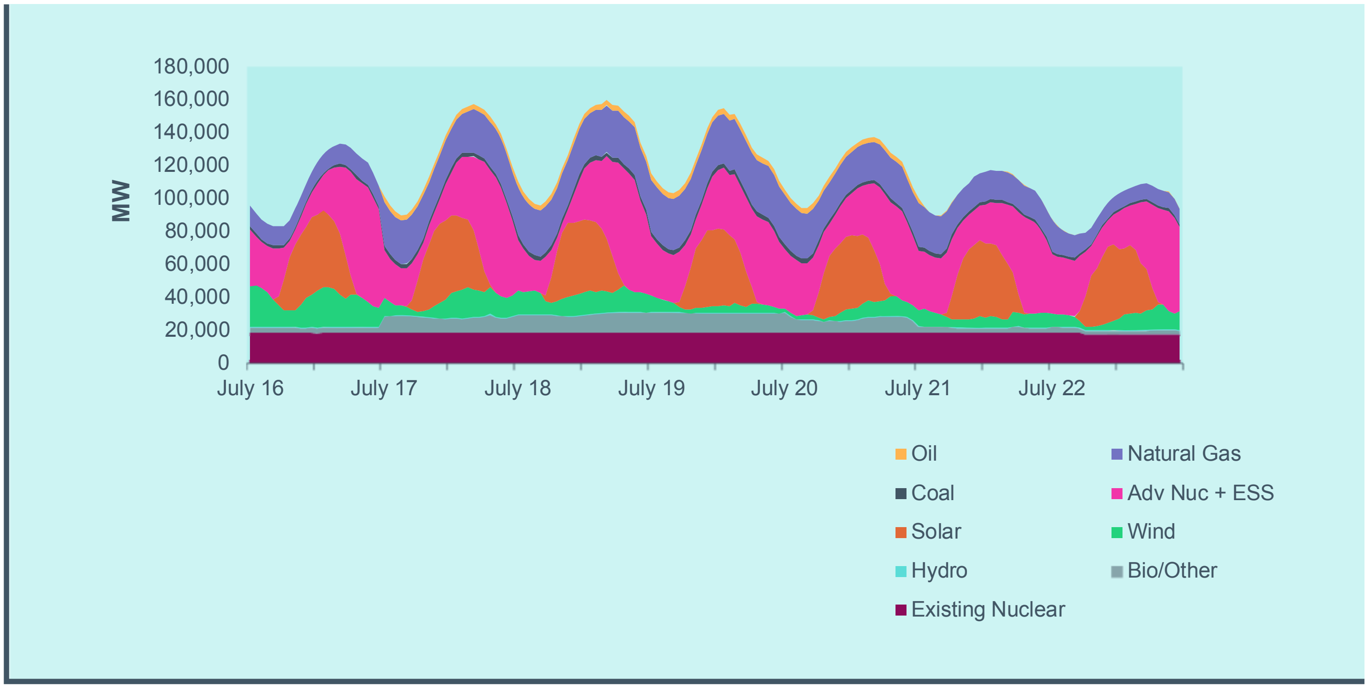
In this 'fleet deployment scenario,' annual average market prices drop in all four ISOs due to nuclear plants operating 'on the margin' for more hours, as shown in Table 23 below.

Table 23. **Annual Average Market Prices for ISO-NE, PJM, MISO, and CAISO**

	Average Annual Energy Price
ISO NE	
High RE Future (Without Flexible Adv. Nuc.)	\$26.32/MWh
Fleet Deployment of Flex. Adv. Nuc.	\$22.64/MWh
PJM	
High RE Future (Without Flexible Adv. Nuc.)	\$27.03/MWh
Fleet Deployment of Flex. Adv. Nuc.	\$22.67/MWh
MISO	
High RE Future (Without Flexible Adv. Nuc.)	\$26.13/MWh
Fleet Deployment of Flex. Adv. Nuc.	\$24.70/MWh
CAISO	
High RE Future (Without Flexible Adv. Nuc.)	\$38.06/MWh
Fleet Deployment of Flex. Adv. Nuc.	\$29.61/MWh

The flexible performance of the advanced nuclear fleet becomes apparent in reviewing hourly modeling results for a representative summer week in 2034 (July 16 – 22). In summer, cooling demand is typically high and peaks in the afternoons, between 2 to 3 pm. Because of high cooling demand during weekdays, peaks are higher during weekdays than weekends, as shown in the following figure.

Figure 11. **Dispatch Profile for PJM with Majority of Firm Power Supplied by Advanced Nuclear Plants**

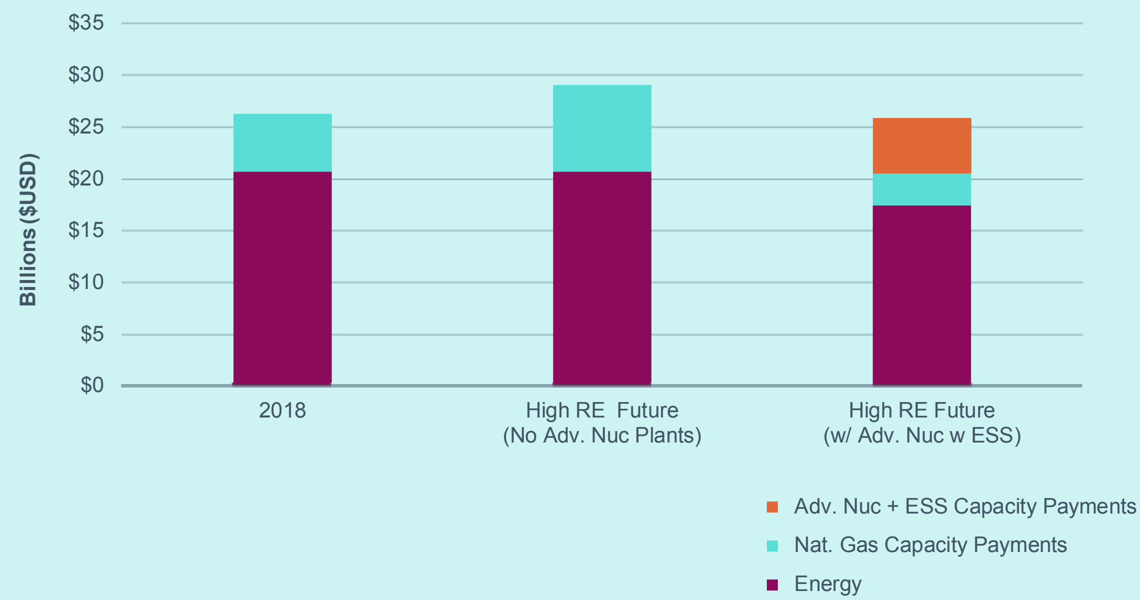


As expected, having more advanced nuclear plants reduces annual energy clearing prices and thus reduces the maximum allowable CapEx by ~$500/kW less than the CapEx requirements for the first plant.

A striking finding of this analysis is how advanced nuclear plants with ESS can actually lower the cost of serving load across the ISO.

Figure 12 below shows a subset of the total costs of serving annual load—isolating just energy costs and capacity payments to natural gas and advanced nuclear plants. Assuming all other costs (ancillary services, transmission costs, uplift payments, imports, etc.) are held constant, the amount spent on capacity for both natural gas and advanced nuclear falls slightly, and energy costs drop by over $3 billion.

Figure 12. **Total Cost of Serving Annual Load: Energy and Select Capacity Payments**



8.3 Impact on Allowable CapEx from Alternative Fixed O&M Assumption

As discussed above in Section 5.5.2, the base case calculations use $31/kW-year (equivalent to $3.75/MWh) for the combined fixed and variable O&M costs of flexible advanced nuclear plants. The base case value is a significant reduction from current O&M costs at nuclear plants and serves as an ambitious target to guide nuclear designers in their pursuit of market viability.

As a side case, the following table presents maximum allowable CapEx results assuming a less ambitious target for O&M costs. In particular, this side case posits a 50% reduction from the combined O&M cost of $122/kW-year used by the Energy Information Administration in the latest version of the Annual Energy Outlook. This alternative assumption of $61/kW-year ($7.50/MWh) for combined O&M costs is double the base case assumption cited above.

The higher O&M costs in the alternative case lead to lower maximum allowable CapEx for flexible advanced nuclear plants with or without energy storage plants, as shown in the following table. Relative to the base case results, all results of maximum allowable CapEx have tightened by $337/kW because of higher O&M costs.

Table 24. **Maximum Allowable CapEx by ISO and Scenario ($/kW) with Higher O&M Cost Input**

	Low RE w/out ESS	with ESS	**High RE** w/out ESS	with ESS
ISO-NE				
Low Capacity Price Case ($50/kW-yr)	$1,952	$2,625	$1,628	$2,450
Mid Capacity Price Case ($75/kW-yr)	$2,229	$3,178	$1,905	$3,003
High Capacity Price Case ($100/kW-yr)	$2,505	$3,731	$2,181	$3,557
Difference from Base Case ($/kW)	-$337			
PJM				
Low Capacity Price Case ($50/kW-yr)	$2,021	$2,651	$1,848	$2,701
Mid Capacity Price Case ($75/kW-yr)	$2,297	$3,204	$2,125	$3,254
High Capacity Price Case ($100/kW-yr)	$2,574	$3,757	$2,401	$3,807
Difference from Base Case ($/kW)	-$337			
MISO				
Low Capacity Price Case ($50/kW-yr)	$1,907	$2,520	$1,663	$2,316
Mid Capacity Price Case ($75/kW-yr)	$2,184	$3,073	$1,939	$2,869
High Capacity Price Case ($100/kW-yr)	$2,460	$3,626	$2,216	$3,422
Difference from Base Case ($/kW)	-$337			
CAISO				
Low Capacity Price Case ($50/kW-yr)	$1,850	$3,060	$1,630	$2,968
Mid Capacity Price Case ($75/kW-yr)	$2,127	$3,613	$1,907	$3,521
High Capacity Price Case ($100/kW-yr)	$2,403	$4,166	$2,183	$4,075
Difference from Base Case ($/kW)	-$337			

High-Level CapEx Estimation Exercise for 'Nuclear-Specific' Costs

Several advanced reactor developers are still working on their nuclear reactor designs and the other components that make up the 'nuclear-related' portion of the plant. This typically includes the 'nuclear island,' consisting of the steam supply system (i.e., nuclear reactor, reactor pressure vessel, coolants pumps, piping, controls, etc.), the containment and auxiliary building, and the fuel handling area. Other 'nuclear-related' costs include reactor licensing, nuclear permitting, fuel, commissioning and testing, related land acquisition, offsite design, and civil works. These 'nuclear-related' costs represent the majority of overall plant costs. Designers will likely find it easier to reduce costs by limiting the size and scope of the nuclear heat source design and its relationship to the rest of the plant (i.e., 'conventional island'). For example, if the design allows safety events to propagate into the steam turbine, the steam turbine must be designed to handle such events and therefore will be relatively bespoke and more expensive. If the nuclear heat source can be effectively isolated, more of the plant can be designed with commercially available, 'off-the-shelf' components, which are less expensive.

Using government cost studies for coal and natural gas power projects, LucidCatalyst derived a high-level, indicative estimate for all components downstream of the nuclear heat source. Having already estimated the maximum allowable CapEx for an entire nuclear plant, the goal was to indicatively estimate the remaining CapEx available for the nuclear-related costs. Appendix F highlights the costs included in this calculation, which should be treated as indicative, not exhaustive. Added together, non-nuclear costs are roughly $1,043/kW for a plant without energy storage and $1,453/kW with energy storage. Developers can subtract these figures from the allowable CapEx thresholds for the various ISOs.

9 Conclusions

Provided that advanced nuclear developers can design their reactors to be sufficiently low-cost, they can complement production from higher VRE penetration and lower the overall cost of serving load–all without power delivery disruptions or sharp market price swings. Providing cost-effective flexible capacity, these plants offer an emissions-free, load following option that can perform similar to CCGTs.

This study examined the maximum allowable CapEx for flexible advanced nuclear plants in 2034, in low- and high-renewable market environments. Using PLEXOS production cost modeling software, LucidCatalyst estimated the maximum allowable CapEx for flexible advanced nuclear plants in two configurations—with and without energy storage—in four deregulated power markets: ISO-NE, PJM, MISO, and CAISO. The modeling and post-modeling financial analysis revealed that the maximum allowable CapEx for the first plant entering the market is driven by energy and capacity payment revenues. The average maximum allowable CapEx across all scenarios is $3,234/kW. This reflects a minimum of $1,965/kW (High RE in ISO-NE, no ESS, and $50/kW-yr capacity payment) and $4,503/kW (Low RE in CAISO, with ESS, and $100/kW-yr capacity payment.)

Table 25. **Summary of Maximum Allowable CapEx ($/kW) by ISO, Configuration, and RE Scenario**

	Low RE w/out ESS	Low RE with ESS	High RE w/out ESS	High RE with ESS
ISO-NE				
Low Capacity Price Case ($50/kW-yr)	$2,289	$2,962	$1,965	$2,788
Mid Capacity Price Case ($75/kW-yr)	$2,566	$3,515	$2,242	$3,341
High Capacity Price Case ($100/kW-yr)	$2,843	$4,068	$2,519	$3,894
PJM				
Low Capacity Price Case ($50/kW-yr)	$2,358	$2,988	$2,186	$3,038
Mid Capacity Price Case ($75/kW-yr)	$2,634	$3,541	$2,462	$3,591
High Capacity Price Case ($100/kW-yr)	$2,911	$4,095	$2,739	$4,144
MISO				
Low Capacity Price Case ($50/kW-yr)	$2,244	$2,857	$2,000	$2,654
Mid Capacity Price Case ($75/kW-yr)	$2,521	$3,410	$2,276	$3,207
High Capacity Price Case ($100/kW-yr)	$2,797	$3,963	$2,553	$3,760
CAISO				
Low Capacity Price Case ($50/kW-yr)	$2,187	$3,397	$1,968	$3,306
Mid Capacity Price Case ($75/kW-yr)	$2,464	$3,950	$2,244	$3,859
High Capacity Price Case ($100/kW-yr)	$2,740	$4,503	$2,521	$4,412

Advanced reactor developers should be aware that while there are emerging market mechanisms to reward resources for enhancing grid flexibility and resiliency (and the operating reserve market is likely to expand), the primary revenue sources are energy sales and capacity payments. Average annual energy prices are also expected to fall due to increasing quantities of zero-marginal cost VRE. Absent a CO_2 price, or premiums paid for emissions-free generation and capacity, advanced nuclear developers will need to design their plants to an average cost of below $2,989/kW.

Advanced reactor designers should also recognize that most of the emerging market mechanisms compensating for flexible, dispatchable output are too early-stage to gauge their significance in the mid-2030s. While the grid will undoubtedly demand large amounts of flexible resources by that time, it is currently unclear how much energy will be transacted through these new products.

The decision to add a thermal energy storage system to a plant design must be informed by the specific market context in which a plant is sited. Across the four ISOs modeled, co-locating a storage system makes economic sense, on average, for less than $1,126/kW. Such a system will enable the reactor to run at its rated capacity for more hours and provide the opportunity to sell power from the ESS when prices are at their highest. Also, without an ESS (or an alternative revenue source such as hydrogen production, process heat for industry, etc.), the plant's capacity factor suffers significantly in high VRE zones. For example, in the 2034 high RE scenario, the capacity factor for nuclear plants in southern California is 67%. Given that these plants are being designed to operate for a minimum of 40 years, it is worth considering what market conditions (particularly VRE penetration) will exist beyond 2034.

A CO_2 price or capacity payment premium for emissions-free generation resources could significantly change the maximum allowable CapEx. As shown (and specific to the PEPCO load zone in PJM), a $25, $50, or $75/tonne CO_2 price significantly improves the economics for advanced nuclear plants, raising the maximum allowable CapEx by $993/kW, $2,005/kW, or $3,018/kW, respectively. Similarly, capacity markets could increase payments to stimulate deployment of emissions-free generation, which could significantly improve project economics.

Advanced nuclear developers should understand the advantages and disadvantages of developing projects in regulated markets. Depending on how deregulated markets evolve, it may be favorable to focus on regulated markets for initial development efforts. Regulated utilities can utilize all the benefits of highly rampable and dispatchable output without requiring complex and relatively slow-moving market reforms to reveal the value of certain grid services. For these reasons, regulated markets have been, in practical terms, the first markets for Gen III and III+ nuclear plants (as well as other innovative power projects like the carbon capture and sequestration project at Kemper).

The PLEXOS modeling revealed that deploying advanced nuclear power at scale can actually reduce the overall cost of serving electrical load. Nearly all national and international energy modeling efforts either do not include advanced nuclear in their projections or assume an insignificant level of capacity. Because these plants can operate as baseload resources and load follow like a combined-cycle gas turbine, they can supply a large fraction of the firm power without raising the overall cost of electricity. This conclusion should motivate policymakers, utilities, climate advocates, and other stakeholders to continue supporting advanced nuclear commercialization efforts.

In addition to tracking how markets evolve, advanced nuclear developers should also track the evolution of competitive technologies that will play an increasing role in grid flexibility and emissions-free generation. Technologies to enhance grid flexibility primarily include energy storage, Distributed Energy Resources, demand-side solutions like flexible loads (e.g., EVs, electric hot water heaters, smart thermostats, etc.), and demand response programs. These are effective in 'time shifting' demand and smoothing power flows across the grid. However, they are less effective in serving the expected increase in overall electricity demand resulting from the electrification of transportation and other sectors. Supplying emissions-free energy for multiple days or even weeks (when VREs are not generating) currently cannot be met without extremely low-cost bulk energy storage (which is not yet an economical, scalable option), or thermal generation with carbon capture, or the use of clean synthetic fuels (e.g., hydrogen, ammonia, ethanol, DME, etc.) in converted natural gas plants.

An important precondition for advanced nuclear plants to play a meaningful role in future resources mixes is their ability to be built at sufficiently low cost. While the CapEx thresholds highlighted in this report are relatively low in comparison to conventional nuclear new-build plants in North America and Europe, they are well within the range of those reported by third-party cost studies[59] and advanced nuclear developers themselves. This range is also well within the costs being achieved in countries with continuous new-build nuclear programs.[60] Designers should integrate these cost requirements into their plant designs and consider whether adding thermal storage makes sense in their target markets.

Appendices

A

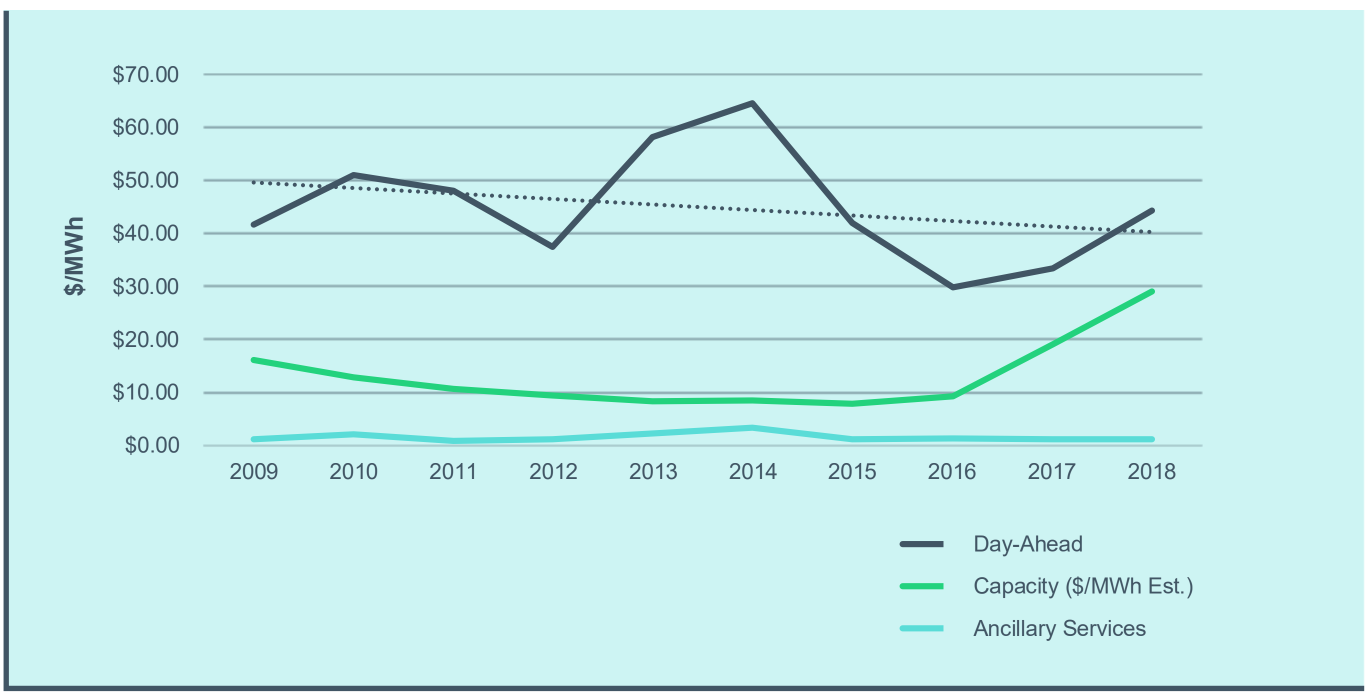
Appendix – Historical Revenues by Market Product in Select ISOs

It is useful to examine today's wholesale market prices to understand the relative revenue potential for flexible nuclear plants. By the mid-2030s, market rules and prices are bound to be different; however, revenue breakdown by product and price trends provide a useful benchmark for looking into the future.

ISO-NE (New England)

Despite the recent increase in day-ahead clearing prices in 2017 and 2018, average clearing prices for energy have been in decline for the past 10 years.[61] Overall demand for electricity ISO-NE has been in general decline year since 2013, and demand in 2017 hit an 18-year low.[62] Figure 13 presents ten years (2009 – 2018) of revenue potential for Day-Ahead energy,[63] capacity (estimated in $/MWh), and ancillary services. Energy prices were an average of $45.98/MWh across the ten-year period, the highest of the four ISOs analyzed.[64]

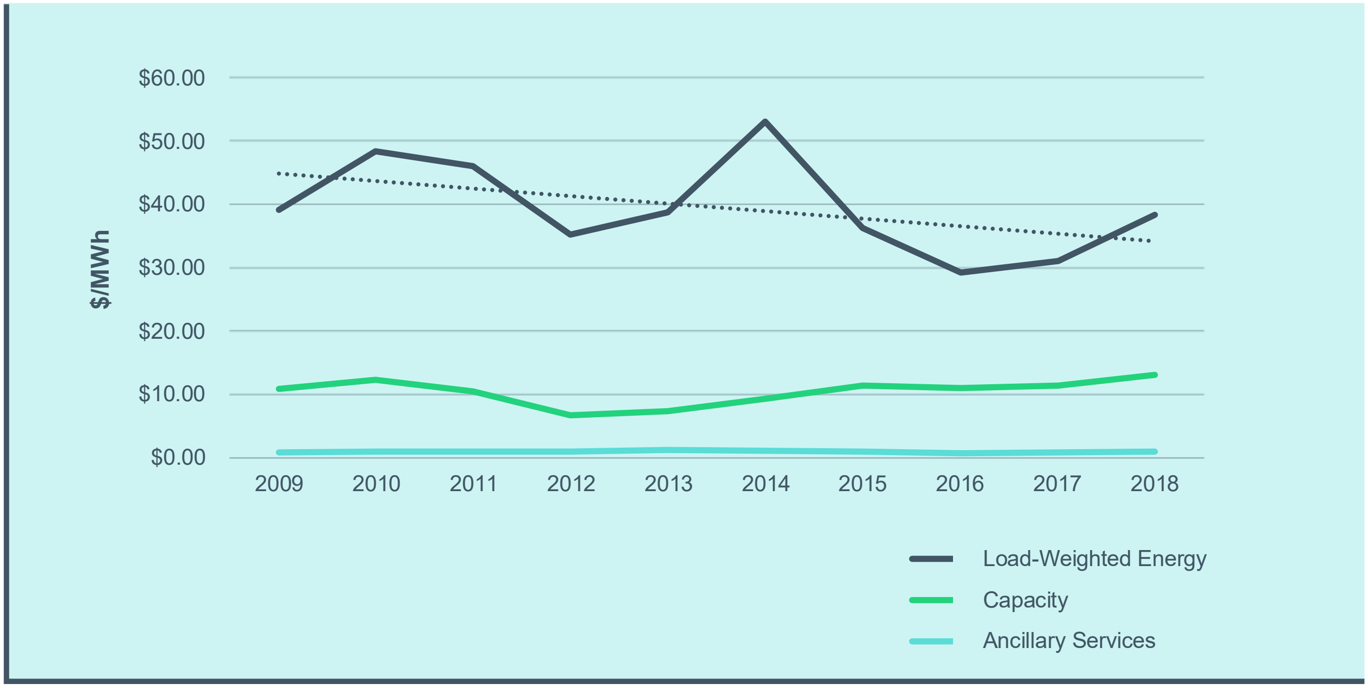
Figure 13. **Average Annual Clearing Price by Market Product in ISO-NE ($/MWh)**



PJM (Pennsylvania-Jersey-Maryland)

PJM energy prices have been declining for the past decade, on average (see Figure 14). Twelve thousand MW of coal and three nuclear plants, having filed for deactivation, may close by 2021 (Davis-Besse, Perry, and Three Mile Island). Nonetheless, projected excess capacity (based on the interconnection queue), suggests that, ignoring local reliability issues, these retirements will not affect energy prices or reliability. Most revenues come from energy (~78%), with about 20% coming from capacity revenues. Depending on capacity requirements in various PJM zones, capacity payments could be higher.[65] Ancillary services, as is the case in each power market, represent a small fraction of total potential revenue.

Figure 14. **Average Price by Component of Wholesale Power Price in PJM ($/MWh)**



MISO (Midcontinent)

MISO has the lowest average clearing price for energy of the four ISOs under consideration ($31.34/MWh from 2009 – 2018). This is partially driven by already depreciated coal and nuclear plants as well as 17GW of wind, which makes up 8% of MISO's generating portfolio.[66] Unlike ISO-NE and PJM, MISO does not have a capacity market. Instead it has a 'Resource Adequacy' construct, which places the burden on Load Serving Entities (LSEs) and Independent Power Producers (IPPs) to procure a sufficient resource capacity to provide energy during times of forecast (and unexpected) scarcity. Typically, this means either qualifying capacity through LSE-owned resources or procuring it through bilateral arrangements with other resource owners.

MISO has a 17% 'reserve margin,' which means there is 17% surplus generation capacity, on average, at any given time. There is a voluntary capacity auction where LSEs and IPPs can procure capacity that they have not already procured. Therefore, the capacity payments listed in Figure 15 only reflect the clearing prices of the voluntary capacity auctions. As with the other ISOs, MISO's ancillary service market is relatively small and would likely represent an insignificant revenue stream for advanced nuclear projects.

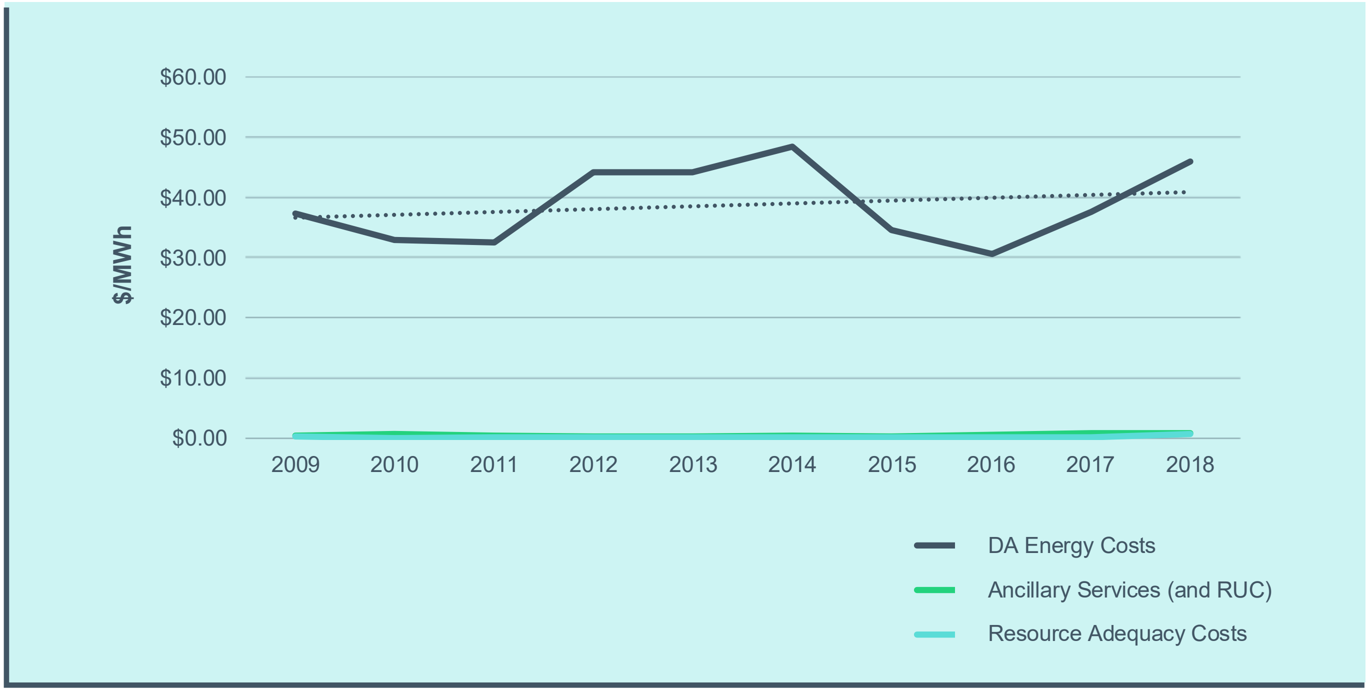
Figure 15. **Average Price by Component of Wholesale Power Price in MISO ($/MWh)**

CAISO (California)

CAISO is the only ISO that experienced a (mild) increase in energy clearing prices from 2009 – 2018, as shown in Figure 16. Day-Ahead clearing prices averaged $38.86 over this period, with prices reaching $46.06 in 2018. CAISO has more non-hydro renewables than any other ISO as a percentage of total energy generation (26% in 2018)[67] and installed capacity (23,331 MW).[68] When Governor Jerry Brown signed SB 100 into law in September 2018, California adopted a 100% RPS by 2045 (50% renewables by 2026, 60% renewables by 2030, and 100% CO_2-free energy by 2045). The increase in solar and wind will likely depress the average clearing price for energy (certainly during daylight hours), but will undoubted drive up the value for flexible, dispatchable resources. This will be especially true for the morning and evening ramp. With demand expected to grow between 1.0 and 1.5% annually until 2030,[69] this will be a revenue opportunity for flexible, dispatchable generation.

California's decision not to renew the operating licenses for the Diablo Canyon units 1 and 2, which are set to expire in 2024 and 2025 respectively, suggests that the state is perhaps not a priority market for nuclear. However, because the CAISO energy imbalance market has expanded well beyond the borders of California—to as far as Wyoming, Idaho, and Utah—there may be opportunities to supply CAISO while not being physically located within the state.

Figure 16. **Average Price by Component of Wholesale Power Price in CAISO ($/MWh)**



B

Appendix – New Market Mechanisms that Capture the Value of Resource Flexibility

Most of the new revenue streams aimed at improving grid stability by rewarding resource flexibility and dispatchability are too new and undeveloped to determine whether they will be meaningful revenues. So far, none provide the compensation necessary to stimulate investment in new capacity. However, it would serve advanced reactor developers to understand these products and track them going forward.

Ramping Products

CAISO Flexible Ramping Product

CAISO introduced its Flexible Ramping Product (FRP) in November of 2016. The FRP was designed to provide a margin of sufficient ramping capacity—available in real-time—to address uncertainty arising from load variability or intermittent renewable generation.[70] This helps maintain power balance during deviations in real-time net load,[71] reflecting potential renewable forecasting errors and other uncertainties related to ramping needs.

The FRP includes two products in the 5- and 15-minute real time markets: (1) Flexible Ramp Up, and (2) Flexible Ramp Down. FRP compensation has been extremely small, dropping from $25M in 2017 to just $7M in 2018.[72] Flexible Ramp Up was needed for 6% of the time in 2018, whereas Flexible Ramp Down was needed just 1% of the time. To participate in FRP, resources submit bids to provide the forecasted demand plus the ability to ramp upward or downward to meet a predetermined uncertainty band. They receive revenue from selling energy plus an uncertainty award (for either ramping up or down).

Currently, the ISO is working to incorporate flexible ramping capability in the Day-Ahead markets and procure FRP in smaller regions, such that transmission constraints are not a material issue to getting energy on (and off) the grid.[73]

Fast ramping advanced nuclear plants could certainly compete in this market. However, they will encounter competition from several other resources, including battery storage systems, which have exceptional charge and discharge rates. As the amount of energy transacted through this market increases, so too will the number of participating resources, which will likely mitigate revenue potential.

MISO Ramp Capability Product

MISO implemented their voluntary Ramp Capability Product in the spring of 2016. It consists of a ‘up ramp capability’ and ‘down ramp capability’ product. As with CAISO, MISO is interested in increasing ramping capacity to better respond to uncertainties in forecasted net load,[74] especially during short-term scarcity events, or other deviations from the expected dispatch horizon. Ramping resources are required to ramp up or down to meet specified uncertainty bands within ten minutes.[75] The Ramp Capability Product is co-optimized with the energy and ancillary service markets and allows resources that can ramp faster to displace slower resources. Slower resources are compensated for their forgone profit to provide such services, and faster resources get greater dispatch opportunities.

The program is completely voluntary and any dispatchable resource is eligible to participate. To date, there have been few hours where Ramp Capacity Product clearing prices are above zero (from 3 – 9% on average)[76] and the Day-Ahead and Real-Time hourly price for ramp up capability averaged $0.58/MWh and $0.21/MWh, respectively, from May 2016 to June 2019.[77] Both Day-Ahead and Real-Time ramp down capability products have been $0.00/MWh since the beginning. Given the low clearing prices, which have incidentally fallen significantly since January 2019, and the dearth of hours during which the product clears at non-zero prices, the MISO Ramp Capability project does not present a significant revenue stream for advanced nuclear plants.

ISO-NE and PJM

ISO-NE and PJM do not currently have ramping products.

Other Compensation Mechanisms for Fast, Available, and Flexible Generators

Fast Start Generation

Each of the ISOs have market pricing rules to reward resources that can more rapidly respond to dispatch instructions. Enabling a faster response is typically more costly for a resource and these rules allow them to run more often and receive compensation for their start up and fixed operating costs. In some ISOs, rules also compensate 'slower' resources that have been moved out of the merit order to make room for 'fast-start'[78] resources. It is unlikely that advanced nuclear plants will be the marginal generator very often; therefore significant revenue generation from this rule change should not be expected.

Pay-for-Performance

ISO-NE and PJM have a 'pay-for-performance' (PFP) model for capacity resources. This increases financial incentives for resources able to quickly provide additional capacity or operating reserves during periods of generation scarcity.

ISO-NE

ISO-NE's Forward Capacity Market Pay-for-Performance (FCM PFP) Project began in June 2018. Its purpose is to increase financial incentives for resources that can quickly provide additional capacity or operating reserves during periods of generation scarcity. During Capacity Scarcity Conditions (CSC),[79] resources can be eligible for additional revenue payments based on actual capacity provided (above what was already required and contracted for in the marketplace). PFP prices are cleared on a 5-minute basis until the CSC is resolved. Capacity prices are determined on how deficient the grid is in meeting its capacity and operating reserves requirements. The amount of capacity provided is multiplied by a predetermined 'performance payment rate'[80] which dictates the final payment amount. In short, if a resource can quickly provide additional grid capacity (either by ramping up or decreasing its real-time energy output to provide additional capacity or operating reserves), it is eligible for significant, above-market payments. From January 1, 2015 to August 15, 2019, there was only one CSC event declared (on September 3, 2018), and it lasted just under 3 hours.[81]

PJM

Starting in 2016, PJM began providing 'Capacity Performance' incentive payments to resources participating in its Reliability Pricing Model (RPM) capacity market. The purpose was to reward resources for being available and responsive during stressed conditions—when PJM determines they are needed to meet power system emergencies—and issuing penalties when resources do not perform. This helps ensure that the capacity offered into the RPM reflects a resource's actual performance risk (and ensures that capacity from units less likely to perform during stressed conditions are offered at higher prices to reflect their outage or non-performing risk).[82]

The number of megawatts cleared in the RPM as Capacity Performance is set to increase each year until the delivery year 2020 – 21 when all PJM resources are required to meet Capacity Performance requirements. This is to incentivize investment in resource reliability (e.g., system upgrades and fuel availability) and apply penalties to non-performance.[83] Resources that exceed performance requirements during peak system conditions collect funds from resources that underperform.

Capacity Performance increases overall capacity costs in the market; however, these are ideally offset by relatively lower pricing during extreme weather events and other conditions that stress the grid. Under Capacity Performance, resources are required to deliver their committed capacity during emergency events called Performance Assessment Intervals (PAI). System-side Performance Assessment Hours (PAH) have not been called since 2014 and zone-wide PAIs have not been called since 2015.[84] Therefore, it is unlikely to be a material source of revenue for advanced reactors. To be considered a Capacity Resource with 'unlimited energy capability,' a nuclear plant must sustain continuous operation for at least 10 hours. Capability verification testing performed by PJM requires nuclear plants to sustain their rated output for 2 hours.

Table 26. **Relevance of Emerging Market Products that Reward Resource Flexibility on Advanced Nuclear Reactor Developers**

Resource Flexibility Product	Description	Relevance to Adv. Reactor Developers	Rationale
CAISO Flexible Ramping Product (FRP)	This product provides a margin of sufficient ramping capacity—available in real-time—to address uncertainty arising from load variability or intermittent renewable generation.[85]	Very Low	FRP compensation has been extremely small, dropping from \$25M in 2017 to just \$7M in 2018.[86] The corresponding cost to CAISO for FRP ranged from \$0.00 – \$0.03/MWh from Q1 2018 to Q2 2019.[87] Flexible Ramp Up was needed 6% of the time in 2018, and Flexible Ramp Down was needed just 1% of the time.

Resource Flexibility Product	Description	Relevance to Adv. Reactor Developers	Rationale
MISO Ramp Capability Product (RCP)	The RCP is co-optimized with the energy and ancillary service markets and allows resources that can ramp faster to displace slower resources. Ramping resources are required to ramp up or down to meet specified uncertainty bands within ten minutes.[88]	Very Low	To date, there have been few hours where Ramp Capacity Product clearing prices are above zero (from 3 – 9% on average)[89] and the day-ahead and real-time hourly price for ramp up capability averaged $0.58/MWh and $0.21/MWh, respectively, from May 2016 to June 2019.[90] Both day-ahead and real-time ramp down capability products have been $0.00/MWh since the beginning.
ISO-NE Pay for Performance (PFP)	The purpose of PFP is to increase financial incentives for resources that can quickly provide additional capacity or operating reserves during periods of generation scarcity. In short, if a resource can quickly provide additional grid capacity (either by ramping up or decreasing energy output to provide additional capacity or operating reserves), it is eligible for significant, above-market payments.	Very Low	From January 1, 2015 to August 15, 2019, there was only one occasion (on September 3, 2018) when a scarcity event was declared, and it lasted just under 3 hours.[91]
PJM Capacity Performance (CP)	The purpose of CP is to reward resources for being available and responsive during stressed conditions—when PJM determines they are needed to meet power system emergencies—along with penalties when resources do not perform.	Very Low	Under Capacity Performance, resources are required to deliver their committed capacity during emergency events called Performance Assessment Intervals (PAI). System-side PAIs have not been called since 2014[92] and very rarely have zonal PAIs been called.

C

Appendix – Desirable Performance Attributes and Market Participation Requirements

In general, resource 'flexibility' includes the ability to start up and shut down over short periods of time or rapidly change generation output to support system reliability. The primary value of 'flexible' advanced reactors is their ability to load follow when renewables go offline. Currently, this is supplied by natural gas plants (both CCGTs and CTs). To be competitive with natural gas (which may have integrated, affordable carbon capture technologies by the mid-2030s), flexible advanced nuclear plants will need to have certain performance characteristics.

This appendix highlights the desired performance attributes for advanced nuclear plants, which follows the attributes of best-in-class CCGTs. For reference, generic market participation requirements for energy, capacity, and ancillary services markets are also included.

Competing with Best-In-Class Gas Turbines

Advanced nuclear plants with energy storage will primarily compete with gas turbines in a combined-cycle configuration. New, 'best-in-class' CCGTs have extremely fast start times and can achieve maximum capacity in 30 minutes from a 'hot start' (i.e., generator is running and electrically synchronized to the grid).[93] This is important for quickly meeting the morning or evening ramp, or quickly backfilling for renewables. As shown in Table 27, ramp rates are also extremely high. For example, the GE 7HA.02, can ramp up to 60 MW/minute. It can also ramp down to a minimum operating capacity of 33% (which can be reduced to 15% in a two-plant configuration).[94] Under idealized operating conditions (where ambient temperature, pressure, and humidity affects efficiency), best-in-class CCGTs are extremely flexible and valuable resources.

Table 27. **Selected Performance Criteria for 'Best-in-Class' CCGTs**

	Siemens SGT-9000HL Series	GE 7HA-Class: 7HA.02	MHPS M501J Series
Capacity (MW; 1-unit Configuration)	595	573	614
Net Efficiency	>63%	>63%	>64%
Ramp Rate (MW/min)	85*	60	42*
Turndown – Minimum Load (%)	40%	33%	50%
Startup Time to Full Load	<30 minutes**	<30 minutes	30 minutes

* Simple cycle configuration.
** Based on 8000HL series.

Sources:
Siemens SGT-9000HL | 405 MW | 60 Hz, GE Power 9HA POWER PLANTS Fact Sheet, MHPS M501J Series, GE Power gas power systems offerings I 2019

Another competitive feature of best-in-class CCGTs is minimal outage risk. Some of the major turbine manufacturers have claimed, based on field operation hours, that fleet uptime or availability (reflecting unscheduled maintenance) consistently exceeds 99%.[95] Further, manufacturers continue to push efficiency and believe combined-cycle net efficiency could reach 65% by the early 2020s.[96] This will continue to improve operating costs.

Grid operators also benefit from a CCGT's rotational inertia. During changes in demand, the inertia of the spinning turbines opposes frequency changes and thereby gives system operators more time to correct the frequency deviation (by adjusting generation or load) and maintain a 60 Hz grid frequency. While there is currently no market for inertia, there are frequency response products[97] and the service is undoubtedly valued by vertically integrated utilities.

Advanced reactor developers should consider how their reactor and energy storage system should perform to meet these performance characteristics. Notably, without storage, a reactor that can achieve these operating characteristics would be extremely valuable for grid stability, however, economics would be an issue. As previously stated, without significantly inflated capacity payments, other out-of-market payments, unprecedentedly high reserve prices, or other revenue streams, the economics are challenging.

General Market Participation Requirements

Performance Requirements for Energy Revenues

Generators participating in wholesale electricity markets must meet several, well-established technical and operating performance requirements. During project development and through operations (until retirement), the ISO's interconnection, commissioning, and on-going testing procedures and protocols ensure that resources can perform as stated once ready for commercial operations. For grid operators to effectively and efficiently carry out their responsibilities, resources need to operate as expected.

At a high level, the ISO makes exhaustive assurances that all eligible energy resources are dependable market participants. It is essential that resources be capable of receiving and responding to electronic dispatch instructions and communicate when they are (or will be) down—so system operators can balance the grid accordingly. Therefore, both wireless and 'hardline' communications equipment are setup between the ISO and energy resource. The ISO also maintains a power system model that has all the 'vital statistics' for each resource. Knowing what each resource is capable of—plus the operating condition of each resource in any given moment—allows the operators to optimize economic dispatch.

Communication Protocols

There is a suite of digital and analog channels through which generators and demand resources communicate with the ISO (and vice versa). These include a mix of telemetry solutions which include wireless technologies (e.g., cellular systems, unlicensed ration frequencies, etc.) and supervisory control and data acquisition (SCADA) technology. It also includes hard-wired fiber optic, ethernet cables, and establishing dedicated 'hard-line' telephone cables between the plant and ISO control room. All required communications equipment is tested prior to any generator being available for dispatch.

Verbal and electronic communications are performed by a registered entity (which may be the energy resource itself or a third party) responsible for scheduling, compliance, dispatching administrative functions (information requirements, market monitoring, etc.), and authorized to submit market and technical information.

Information Provided to the ISO

There are several different types of generator-specific information that is submitted to the ISO and ultimately incorporated into its power system model. This includes static information related to voltage and reactive control, the unit's one-line diagram, transmission line information and associated equipment, and certain technical data for physical components. It also includes different types of dynamic information. Using ISO-NE as an example, such information includes:

- **Desired Dispatch Point (DDP)** is the control signal, expressed in megawatts, transmitted to direct the output, consumption, or demand reduction level of each grid-tied resource dispatched by the ISO in accordance with the asset's Offer Data.
- **Actual Generation** is the actual generation being produced by the generating asset.
- **Economic Minimum Limit** is the lowest sustainable output level as specified by physical design characteristics, environmental regulations, or licensing limits.
- **Economic Maximum Limit** is the maximum available output, in MW, of a Generator Asset that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Generator Asset's Offer Data. This represents the highest MW output a Market Participant has offered for a Generator Asset for economic dispatch.
- **Emergency Minimum Limit** means the minimum output, in MWs, that a Generator Asset can deliver for a limited period of time without exceeding specified limits of equipment stability and operating permits.

- **Response Rate** is the response rate, in MW/Minute, at which a Market Participant is willing to change its output or consumption.
- **Regulation High Limit** (applicable to Frequency Regulation offers) is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.
- **Regulation Low Limit** (applicable to Frequency Regulation offers) is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.
- **Unit Control Mode**[98] describes the current operational state of an energy resource.
- **Heartbeat** describes the active digital connection between computers at the ISO and grid resource and confirms that related energy Data Acquisition and Concentration device are properly scanning and exchanging data as required.

These types of information are indicative of the information that all ISOs need in order to properly dispatch a resource. Beyond the minimum operating requirements, which are highlighted in the table below,[99] the desired operating requirements to realize energy revenue simply requires that there be consistency between the plant's scheduled output and actual output.

Table 28. **Minimum Operating Requirements for Large Generators**

Category	Description of Technical Requirement
Reactive Power	Generators must maintain a composite power delivery at continuous rated power output at the Point of Interconnection with dynamic reactive capability over the power factor range of 0.95 leading to 0.95 lagging.
Voltage Control	All generators must keep and maintain an automatic voltage regulator (AVR) in service (and keep it in automatic operation).
Governor Control	Generators over 10 MW must provide and maintain a functioning governor, which includes the hardware or software that provides autonomous frequency-responsive power control. It must have a speed droop set between 4 – 5%, a frequency response deadband of no greater than 59.964 – 60.036 Hz, and a real power response that does not override the governor's response.
Power Quality	A generator's facility shall not cause excessive voltage flicker nor introduce excessive distortion to the sinusoidal voltage or current waves

Source: ISO-NE. Appendix 6 Large Generator Interconnection Agreement.

The requirements above are sourced from ISO-NE and while PJM, MISO, and CAISO have similar requirements, they also have additional participation requirements that are important to note.

- PJM: To be considered a resource with ‘unlimited energy capability,’ a resource must sustain continuous operation “commensurate with PJM load requirements, specified as 10 hours.”[100] If there is insufficient historical operating data to pull from, PJM will verify the plants capability by testing whether it can sustain output for 2 hours.[101]
- MISO: To participate as a Resource Adequacy resource in MISO, an advanced nuclear plant will need to sustain its maximum output for a minimum of four hours across the expected peak hour for each operating day.[102]
- CAISO: To qualify for Resource Adequacy, like MISO, advanced nuclear plants must meet a ‘minimum availability threshold,’ whereby they are capable of generating for four continuous hours. To participate in ‘flexible’ Resource Adequacy, advanced nuclear plants would have to place bids in the Day-Ahead market from one of the following options:[103]
  - Base Ramping: 5am – 10pm (all days)
  - Peak Ramping: 2 – 7pm or 3 – 8pm (all days)
  - Super-Peak Ramping: 2 – 7pm or 3 – 8pm (non-holiday weekdays).

Performance Requirements for Capacity Resources

ISO-NE

ISO-NE capacity resources are compensated based on their Capacity Supply Obligation (CSO), measured in MW and associated payment rate for a given time period (Capacity Commitment Period).[104] During shortage events (or ‘Capacity Scarcity Conditions’), capacity resources with a CSO are rewarded for being available and operating until the scarcity event has passed. During these events, the ‘Pay-for-Performance’ mechanism is active and both capacity and non-capacity resources are rewarded for their availability and ability to meet system needs.

Capacity resources are required to demonstrate their ability to respond to ISO Dispatch Instructions and to maintain performance at a specified output level for a specified duration. For new nuclear and combined-cycle capacity resources, these occur within five business days of commercial operations and projects must operate for 4 continuous hours at the capacity level bid in the Forward Capacity Auction.[105] Existing resources are audited annually as a requirement of fulfilling capacity supply obligations (CSO) during summer and winter Capacity Commitment Periods and nuclear and combined-cycle plants are required to run for 2 hours continuously.[106]

PJM

In PJM, resources with capacity contracts are obligated to be available during periods of grid stress when PJM declares that emergency actions are necessary. These periods are called ‘Performance Assessment Intervals’ (PAIs) and have historically occurred during critical peak periods in the winter. The Capacity Performance construct was initiated after the 2014 polar vortex, where 22% of generation capacity was out of service, which nearly tripled the number of forced outages across the region. In fact, eight of the ten highest critical peak periods in history were experienced during January 2014.[107]

During PAIs, resources receiving capacity payments must be available to inject energy onto the grid (at the capacity for which they are receiving capacity payments). PAIs at the RTO level have not occurred since 2014; however, it is important to note that when contracted capacity resources are not available during PAIs, they are penalized. Of the 30 PAHs in 2014, the average interval was 4.3 hours and the longest was 13 hours (during the height of the polar vortex).

In addition to being available, 'performing' resources must achieve pre-defined and approved ramp rates during a scarcity event. Acceptable rates have historically been defined as being between the historic average and maximum over a defined period (up to 3 months). They ultimately require approval by PJM. Table 29 highlights the required operating parameters for eligible capacity resources. Currently, nuclear plants—presumably because they are only used as baseload resources—are not subject to capacity performance operating requirements.[108, 109]

Table 29. **Capacity Performance and Base Capacity Resource Minimum Unit-Specific Operating Parameters in PJM (Select Technologies)**

Generator Technology	Min Down Time Hrs	Min Run Time Hrs	Max Daily Starts	Max Weekly Starts	Start-up Time Hot Hrs	Warm Hrs	Cold Hrs	Not. Time[1]	Turn Down Ratio
Reciprocating ICE	0.6	1	12	84	0.1	0.1	0.1	0.1	>1
Aero CT	1.1	1	6	42	0.1	0.1	0.1	0.1	>1
Frame CT	1.25	3	4	28	0.25	0.25	0.25	0.1	>1.5
CCGT	3.5	4	3	21	0.5	0.5	0.5	1	>1.5
Storage	<1	TBD	TBD	TBD	Start Time + Notification <1				TBD

Source: Slide 14 in PJM (2016). Capacity Performance / Performance Assessment Hour Education.

1 Notification Time / Time to Start (Cold/Warm/Hot Hours).

MISO: Capacity Performance

In MISO, non-intermittent capacity resources (i.e., nuclear) must offer all its claimed capacity into the Day-Ahead market for all hours it is scheduled to be available. Intermittent capacity resources (for which co-located energy storage may be categorized) must submit bids into the Day-Ahead energy market and offer at least four continuous hours daily across the MISO forecasted daily peak.[110]

CAISO: Flexible Resource Adequacy

Each CAISO LSE must procure sufficient flexible RA resources. Flexible RA resources must submit economic bids depending on one of three Flexible Capacity Categories (listed in the table below).[111, 112]

Table 30. **Categories of Must-Offer Obligations for Flexible RA Capacity Resources in CAISO**

	Category 1	**Category 2**	**Category 3**
Must-Offer Obligation	17 Hours	5 Hours	5 Hours
	5am – 10pm Daily for the whole year	3pm – 8pm for May – September	3pm – 8pm for May – September
	5pm – 10pm Daily for the whole year	2pm – 7pm for January – April and October – December	2pm – 7pm for January – April and October – December
	Daily	Daily	Non-holiday weekdays
Energy Limitation	At least 6 Hours	At least 3 Hours	At least 3 Hours
Starts	The minimum of two starts per day or the number of starts feasible with minimum up and down time	At least one start per day	Minimum 5 starts a month

Source: California Public Utility Commission, 2019 Filing Guide for System, Local and Flexible Resource Adequacy (RA) Compliance Filings.

Start-up time is not an eligibility requirement; however, resources that can start within 90 minutes can qualify all capacity from zero up to their 'Effective Flexible Capacity'[113] (EFC).[114] If a resource requires more than 90 minutes, the capacity eligible for Flexible RA is the difference between its Pmin and EFC.

CAISO has an open docket to revise Flexible RA requirements, which include reducing start-up time to 60 minutes or less for RT (5-minute or 15-minute) products.[115]

CAISO: FRAC-MOO

The Flexible Resource Adequacy Criteria and Must-Offer Obligation (FRAC-MOO) is an initiative related to flexible resource adequacy. It requires LSEs to procure sufficient flexible resources based on each month's maximum 3-hour ramp and peak demand. Qualifying resources are obligated, through a 'Must-Offer Obligation,' to submit bids into CAISO's day-ahead markets (as opposed to self-schedule).

Some analysts view the flexible ramping product and FRAC-MOO as being less for attracting new flexible resources and more as a 'retirement prevention tool' for existing flexible capacity resources considering solar-induced decline in energy revenues.[116] It is likely that existing flexible resources in CAISO can serve as adequate flexible RA capacity until there is a 50% renewables mix (or higher).[117]

Operating Requirements for Fast-Start Generation

Resources that are relatively fast to start up and ramp are typically more expensive than other marginal resources and therefore do not set the price as often. During tight system conditions, fast-start generators may be too expensive to get dispatched. In response, fast-starting pricing regimes have been proposed to allow these resources to set the price more often. This usually requires relaxing a resource's Economic Minimum[118] to zero so it is available for dispatch and then separately compensating it for its start-up/no-load[119] costs.

FERC issued a Notice of Proposed Rule Making (NOPR) in 2016 regarding fast-start pricing, which directed the RTO/ISOs to "…apply fast-start pricing to any resource committed that can start up within 10 minutes or less, has a minimum run time of one hour or less, and submits economic energy offers to the market."[120] The RTO/ISOs are still implementing the NOPR existing operating requirements.[121, 122, 123, 124]

Table 31. **FERC's Existing Operating Requirements for RTO/ISOs to Receive 'Fast-Start' Pricing**

ISO	Description of Technical Requirements
ISO-NE[1]	Minimum Run Time does not exceed one hour Minimum Down Time does not exceed one hour Time to Start does not exceed 30 minutes after receiving a Dispatch Instruction from ISO Available for dispatch and manned or has automatic remote dispatch capability Capable of receiving and acknowledging a start-up or shut-down dispatch instruction electronically within 60 seconds
PJM[2]	<=1 hour for start-up and minimum run time
MISO[3]	Online resource: <=1 hour for starting, synchronizing and injecting energy to the grid (online resource); minimum run time of <=1 hour Offline resource: <=10 minutes for starting, synchronizing and injecting energy to the grid: minimum run time of <=1 hour
CAISO[4]	Start-up time of less than two hours

1 ISO-NE. Appendix 6 Large Generator Interconnection Agreement.

2 PJM (2019). Fast-Start Summary. August 7, 2019.

3 MISO (2013). MISO Module A—Common Tariff Provisions 30.0.0. November 19, 2013.

4 CAISO (2019). Fifth Replacement FERC Electric Tariff. Effective as of January 1, 2019.

Operating Requirements for Ancillary Services

As shown in Table 32 below, operating requirements for regulation, operating reserves, and supplemental reserves are largely similar across all four RTOs.[125]

Table 32. **Summary of Ancillary Service Operating Requirements**

Ancillary Service Product	ISO-NE	PJM	MISO	CAISO	Performance Requirements
Regulation					
Regulation	■	■	■		Must immediately increase or decrease output in response to automated signals (typically 2 – 4 seconds depending on market)
Regulation – Up				■	
Regulation – Down				■	
Regulation Mileage – Up				■	Must minimize the absolute change in output between four-second set points.
Regulation Mileage – Down				■	
Spinning Reserves					
10-minute Synchronized Reserves	■				Synchronized to the grid and must respond within 10 minutes
Synchronized or Reserves		■	■		
Spinning Reserves				■[1]	
Non-Spinning Reserves					
30-minute Operating Reserves	■				Must respond within 30 minutes
10-minute Non-Sync Reserves	■				Must respond within 10 minutes
Primary Reserves[2]		■			
Supplemental Reserves			■		
Non-Spinning Reserves				■[1]	

1 Must run for at least two hours.

2 Synchronized and non-synchronized.

Source: Summarized data collected from: Zhou et al. (2016). Survey of U.S. Ancillary Services Markets. Center for Energy, Environmental, and Economic Systems Analysis, Energy Systems Division, Argonne National Laboratory.

Other ancillary services, in addition to being minor revenue sources, require less generation modification and therefore would not influence design considerations for advanced reactor developers. Supplying voltage support typically requires having automatic voltage regulating (AVR) equipment (and telemetered communication with the ISO). Because flexible nuclear plants are motivated to run as much as possible, they will likely not supply black start services. However, if they do, they must be capable of starting without support from offsite power and operate at full capacity for 12–16 hours (depending on the ISO).[126]

D

Appendix – Alternative Ways of Providing System Flexibility

Non-generation resources are becoming increasingly relevant in the competitive landscape of 'flexible' technologies against which advanced nuclear will need to compete. This section briefly summarizes the applications and market adoption potential for energy storage and demand-side technologies and applications.

Energy Storage

Much has already been written about the grid benefits of energy storage.[127, 128] Energy storage systems take up energy, store it, and make it available for use at a later time. They are extremely useful for grid balancing and have become a cost-competitive alternative for a growing number of applications in recent years. ESS is now regularly procured by utilities and increasingly required to be co-located with new renewable projects. Table 33 below highlights the range of applications, including services that directly support integration of variable renewables.[129]

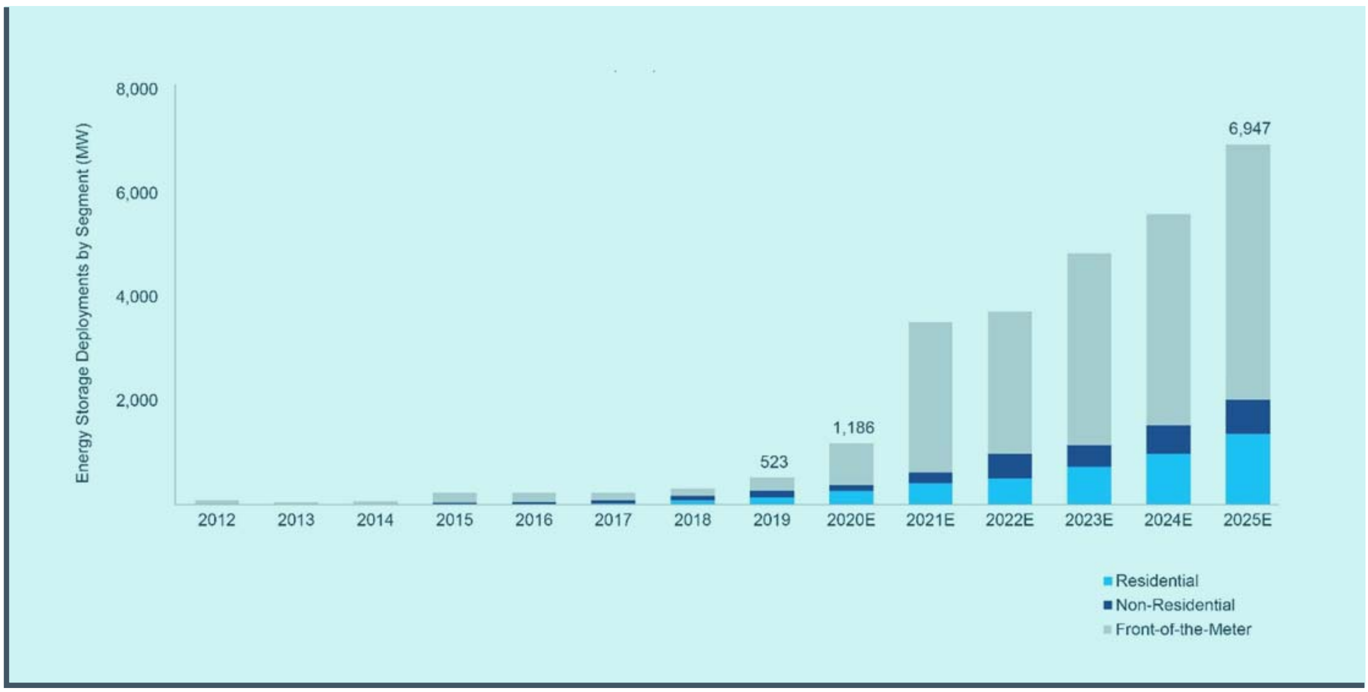
Table 33. **Select Energy Storage Applications**

Category	Storage Services	Supporting Renewable Integration
Bulk Energy Services	Electric Energy Time-Shift (Arbitrage)	■
	Electric Supply Capacity	■
Ancillary Services	Regulation	■
	Spinning, Non-Spinning, and Supplemental Reserves	■
	Voltage Support	
	Black Start	
	Other Related Uses (load following; frequency response; flexible ramping; power smoothing of renewable output)	■
Transmission Infrastructure Services	Transmission Upgrade Deferral	
	Transmission Congestion Relief	
Distribution Infrastructure Services	Distribution Upgrade Deferral	
	Voltage Support	
Customer Energy Management Services	Power Quality	
	Power Reliability	■
	Retail Electric Energy Time-Shift	■
	Demand Charge Management	
	Increased Self-Consumption of Solar PV	■

Category	Storage Services	Supporting Renewable Integration
Off-grid	Solar Home Systems	■
	Micro-Grids: System Stability Services	■
	Micro-Grids: Facilitating High Shares of VRE	■
Transportation	Electric Vehicles	■
Source: The U.S. DOE/EPRI 2015 Electricity Storage Handbook, Sandia National Laboratories.		

Figure 17 below shows the annual growth trajectory for storage, with an estimated 4.4 GWs deployed in 2024—representing a more than 14-times increase over 2018. Cumulatively, this assumes over 18 GWs of deployed capacity. At the same time, Wood Mackenzie and ESA (2019) predict that the U.S. energy storage market will be valued at approximately $4.7 billion.[130] Outside the U.S., the market is expected to keep growing at a rapid pace, which will undoubtedly drive further cost reductions.

Figure 17. **U.S. Annual Energy Storage Deployment Forecast, 2012-2024E (MW)**[131]



With electrochemical storage (inclusive of battery storage) taking up an increasingly larger share of new storage installations in the U.S., it is useful to examine cost reduction curves for battery storage over time. The price of lithium ion batteries fell 80% between 2010 and 2017 ($/kWh) and Bloomberg New Energy Finance (BNEF) believes storage costs will continue to drop by 52% between 2018 and 2030 (see Figure 18).[132] This forecast is supported by the International Renewable Energy Agency (IRENA), which predicts a of drop between 54 – 61%.[133] These predictions suggest an installed cost of $70/kWh by 2030. Significant improvements in round rip efficiency, the number of full charge-discharge cycles, and calendar life are expected to be accompany these cost declines. By 2040, BNEF expects storage will represent 7% of the total installed power capacity globally, reaching nearly 1,000 GW.[134] Other experts see more modest growth (600 GW by 2040);[135] however, a positive trajectory is clear.[136]

Figure 18. **Lithium-Ion Battery Price, Historical and Forecast**

As more projects are deployed, financiers, developers, utilities, operators, and regulators are getting more comfortable with the technology.[137] Market rules are evolving (albeit at different rates across the ISOs) to compensate storage for the values it provides.

Initially, energy storage entered the market by providing high power-short duration services (i.e., ancillary services). As costs have come down, storage is expanding to include more energy time-shifting (as opposed to power-related/balancing) values. Currently, there are no commercially available[138] bulk storage technologies (beyond pumped hydropower) that are cheap enough to store and dispatch energy on a weekly, monthly, or seasonal basis.

Demand-Side Flexibility, Demand Response, and Distributed Energy Resources

A new generation of communication and control technologies is emerging to time shift electricity use across hours of the day. Several utility-led programs are allowing utilities to control customer-sited loads that have grid-interactive hardware and software (e.g., EVs, air conditioning, electric water heaters, thermostats, smart solar inverters,[139] etc.). As more of these resources are deployed and, if possible, aggregated, they are expected to help peak shave and provide another grid-balancing tool to grid operators.

ISOs have Demand Response (DR) programs where the utility pays electricity customers to reduce their consumption relative to a measurable baseline level of consumption. The ability to reduce load on demand reduces the requirement to procure expensive peaking generation, which can be valuable during critical peak periods of demand.

Distributed energy resources (DERs) are typically small-scale physical and virtual assets are connected to and interact with the grid at the local distribution level (oftentimes located behind-the-meter). DERs encompass a range of technologies that include solar PV, energy storage, combined heat and power plants, fuel cells, energy efficiency, and controllable loads. Through various communication and control platforms, these resources can be used individually or in aggregate to provide value to customers, the local distribution network, or the larger transmission network. The orchestrated use of multiple DER technologies has given rise to the concept of the 'virtual power plant' (VPP), or the optimized use of heterogenous DERs (using control, monitoring, and management software) to provide retail or wholesale market services. VPPs can provide flexible grid services for applications such as frequency regulations, demand response, operational reserves, or peak demand management to maintain or improves the grid reliability, efficiency, and overall performance.

In aggregate, flexible loads, DR, and DERs are expected to play a material role in helping grid operators manage variable renewable integration. While they show great promise, it is important to be aware of several issues that could limit their effectiveness. Namely, leveraging flexible loads requires aggregating several thousand systems, which involve customer acquisition costs, the prospect of installing additional hardware, and potential technical challenges related to aggregation and responding to grid signals. DR programs have been in operation for over a decade but are rarely required to modify their load.[140] DER aggregation and wholesale market performance, like flexible loads, is still far from where it will ultimately be. It will be important for MEITNER Design Teams to follow how these flexible resources evolve—both technically and as they are supported by policy—as they will undoubtedly be valuable grid reliability tools.

E

Appendix – High-Level Cost Analysis of Energy Storage System

The analysis described in this report includes scenarios in which advanced nuclear plants would use co-located energy storage systems (ESS) to increase revenue by charging from the reactor's energy when market prices are low and discharging to the grid for energy sales when market prices are high. LucidCatalyst and project advisors developed the following high-level information on three potential ESS approaches to assess the financial feasibility of this concept relative to the extra allowable CapEx for advanced nuclear plants with ESS calculated from the PLEXOS results. The three potential ESS approaches in this preliminary assessment are firebricks (thermal ESS), molten salt (thermal ESS), and flow batteries

The financial feasibility assessment accounts not only for the ESS medium but also for the heat recovery steam generators (HRSG) and additional turbine-generator capacity when the reactor and ESS release energy to the grid at the same time. The assessment below indicates that the cost estimates for these approaches, based on currently available data, could be financially feasible as components of flexible advanced nuclear plants. This is because their CapEx levels are near the extra allowable CapEx values enabled by ESS from many of the PLEXOS simulations. Moreover, the cost estimates shown below are well within the CapEx thresholds for simulations with high revenue to advanced nuclear plants through high capacity payments ($100/kW case) or a CO_2 program that lifts electricity market prices.

Firebricks

Forsberg et al. describe the possible use of firebricks for storing and releasing thermal energy from nuclear plants to provide load-following services to the grid and increase nuclear plant revenue.[141] Firebrick, or refractory brick, is designed for higher temperatures than typical masonry brick. Firebrick is already produced at large scale and low cost for many applications. Forsberg et al. estimate the cost for firebrick in this application as less than $10/kWh of thermal energy. This excludes the additional equipment necessary for coupling the medium to the nuclear plant.

As a high-level assessment of firebrick configurations and costs, LucidCatalyst and project advisors performed the following calculations:

The density of brick is approximately 2,200 kg/m^3.[142] Packing brick in the system would reduce the density by approximately 25%, leading to a packed density of 1,650 kg/m^3.

The specific heat of brick is approximately 1.05 kJ/kg-K.[143] Multiplying the packed density by the specific heat leads to an effective volumetric specific heat of 1,732 kJ/m^3-K.

Assuming a temperature of 500 C (773 K) from the reactor into the storage system, the bricks store 0.866 GJ per m^3 or 0.525 GJ per metric tonne.

The maximum output for each storage system is 500 MWe, which effectively doubles the production capacity of the flexible advanced nuclear plant when added with the 500 MWe of direct power production from the reactor. The storage system can discharge at maximum output for 12 hours, implying a capacity of 6,000 MWh in terms of electric energy. Assuming a conversion efficiency of 40%, this capacity is equivalent to 15,000 MWh of thermal energy, or 54,000 GJ (using the conversion ratio of 3.6 GJ per MWth). From the energy storage parameters for brick specified above, a system at each plant to store this amount of energy would have a volume of 62,000 m^3 and weight of 103,000 metric tonnes.

The typical price for large orders of ordinary brick is approximately $300/tonne.[144] The total raw materials cost for the necessary weight of brick is $31 million. If labor costs for installation are approximately equal to the raw materials cost, then installation adds another $31 million to the system cost and the subtotal is $62 million (~$10/kW installed).

As another cost estimation approach for brick thermal energy storage, Storasol indicates the cost of its storage system as approximately $20/kWh.[145] A system for this thermal capacity with 12 hours of discharge capability would cost $300 million. The estimated cost of the HRSG is $89 million, and the supplemental steam turbine is $112 million. For the other necessary equipment, the cooling system for the steam turbine is estimated to cost $33 million, the water system $59 million, and the transformers and grid connections $54 million.[146] The estimated cost for the total package is $646 million, which equates to $1,292/kWe and $269/kWhe with 80% round-trip efficiency.

Molten Salt

NREL indicates that an oil-to-salt heat exchanger would cost approximately $30/kWh of thermal energy.[147] The cost of a salt-to-steam apparatus for the application in this analysis would presumably be similar. For a nuclear reactor with 500 MWe of electric capacity and thermal conversion efficiency of 40%, the equivalent thermal capacity is 1250 MWth. A molten salt system for this thermal capacity with 12 hours of discharge capability would cost $450 million. As discussed above, the estimated cost of the supplemental steam turbine is $112 million. For the other necessary equipment, the cooling system for the steam turbine is estimated to cost $33 million, the water system $59 million, and the transformers and grid connections $54 million. The estimated cost for the total package is $707 million, which equates to $1,414/kWe and $262/kWh with 90% round-trip efficiency.

Flow Batteries

As an indicative example of flow battery economics, StorTera has designed a single liquid flow battery with a lifetime up to 20 years that costs $150/kW.[148] The cost per unit of energy is $94/kWh. For a 12-hour system, the energy component would cost $1,125/kW, leading to a total cost of $1,275/kW.

F

Appendix – High-Level Estimate of Non-Nuclear Island Costs

The following table includes the cost estimates (with their associated sources) for all costs downstream of the nuclear heat source. This primarily consists of costs related to power conversion and balance of plant.

The estimates below are largely sourced from a 2015 U.S. DOE detailed cost study for natural gas and coal plants,[149] with other supporting data. The figures exclude contingency costs and all costs were bought to 2019 USD by using the Federal Reserve Bank of St. Louis' Producer Price Index for Electrical Machinery and Equipment.[150] Importantly, these estimates are from NGCC and coal plants that are 630 MW and 500 MW respectively (similar to the size of the 500 MW illustrative advanced nuclear plant). Costs are rounded to the nearest hundred thousand. This costing exercise assumes that the power conversion system and all other downstream components are effectively off-the-shelf components that are otherwise used by other thermal power plants. For conventional nuclear plants, these components have traditionally had higher costs due to the 'nuclear premium' for things such as steam turbines that, due to the plant design, had to meet higher nuclear-grade standards. This costing exercise assumes that advanced reactor developers are able to separate these downstream components from their nuclear heat source design.

There are two tables below. The first estimates the non-nuclear costs for a plant without thermal storage, or $880/kW. The second table outlines the additional non-nuclear costs for a plant with a co-located ESS, which is $1,100/kW (or $91.67/kWh for a 12-hour system).

Table 34. **Non-Nuclear Island Costs for 500 MW Plant without ESS**

Non-nuclear Component[1]	Cost	$/kW	Cost Base Year	$/kW (2019 USD)	Relevant Assumptions	Reference Plant
Feedwater and Misc. BOP Systems (a)	$54.1 M	$108	2011	$111.26	Assumes costs (expressed in $/kW) relate only to 219 MW steam turbine (not 422 MW gas turbine)	NGCC
Coolant to Steam Hx (a)	$28.8 M	$58	2011	$59.22		NGCC
Ducting (b)	$121.4 M	$243	2019	$242.87		NGCC
Steam Turbine Generator (a)	$40 M	$80	2011	$82.33	LC received an indicative quote from Mitsubishi Heavy Industries for a 600 MW steam turbine generator of $80/kW. The turbine plant auxiliaries, condenser & auxiliaries, steam piping, and foundations are sourced from 2015 DOE study.[1]	Coal
Cooling Water System (b)	$32.2 M	$64	2011	$66.20		NGCC
Accessory Electric Plant (a)	$11.8 M	$24	2011	$24.28		NGCC
Instrumentation and Control (a)	$7.7 M	$15	2011	$15.75		NGCC
Improvements to Site (a)	$20 M	$40	2011	$41.19		NGCC
Buildings and Structures (excludes ESS or NSSS) (a)	$54.1 M	$108	2011	$111.26		NGCC
Land (c)	$0.9 M	$2	2011	$2	Assumes 300 acres	Coal
Financing Costs (d)	$26.5 M	$53	2011	$55		Coal
Owner's Costs (e)	$67.5 M	$135	2011	$139	Includes Pre-production costs, Inventory Capital, and Other Owner's Costs	NGCC
Totals	$430.9 M			$880		

1 Information labeled (a), (b), (c), (d), and (e) are respectively sourced from Exhibit 4 – 14 Case B31A, Exhibit 3 – 49 Case B31A, Exhibit 2 – 1, Exhibit 3 – 19, and Exhibit 4 – 15 from U.S. DOE (2015). Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3. National Energy Technology Laboratory; Office of Fossil Energy.

Table 35. **Additional Non-Nuclear Costs for a Plant with a 500 MW ESS**

Component[1]	Cost	$/kW	Cost Base Year	$/kW (2019 USD)	Relevant Assumptions	Reference Plant
Coolant to Air HX (a)	$28.8 M	$58	2011	$59		NGCC
Fans[2]	$14.8 M	$30	2016	$30	Calculations based on $5/MMBtu J Class gas turbine	NGCC
Thermal Energy Storage Facility	$97.8 M	$196	2019	$201	Internal LucidCatalyst Analysis	Assumes refractory brick
Cooling Water System (a)	$40 M	$80	2011	$111	Excludes contingency costs and assumes costs (expressed in $/kW) relate only to 219 MW steam turbine (not 422 MW gas turbine)	NGCC
Accessory Electric Plant (a)	$32.2 M	$64	2011	$59		NGCC
Instrumentation and Control (b)	$11.8 M	$24	2011	$41	$0	Coal
Extra HRSG (hot air to steam) (a)	$57.5 M	$115	2011	$118		NGCC
Buildings and Structures (conventional plant) (a)	$20 M	$40	2011	$41	$0	Coal
Financing Costs – prorated by CapEx basis (d)	$26.5 M	$53	2011	$55		Coal
Owner's Costs (d)	$67.5 M	$135	2011	$139		Coal
Land (c)	$0.9 M	$2	2011	$2	Assumes 300 acres	Coal
Steam Turbine Generator (a; MHI quote)	$121.4 M	$243	2019	$243	Indicative quote from Mitsubishi Heavy Industries (see Table 34 entry)	NGCC
Storage Totals	$519.2 M	$1,038		$1,100		
Cost of Storage ($/kWhe)	$91.67					

1 Source: Info in this column labeled (a), (b), (c), (d), and (e) are respectively sourced from Exhibit 4 – 14 Case B31A, Exhibit 3 – 49 Case B31A, Exhibit 2 – 1, Exhibit 3 – 19, and Exhibit 4 – 15 from U.S. DOE (2015). Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3. National Energy Technology Laboratory; Office of Fossil Energy.

2 Source: Gulen, S. Can et al. (2017). "A Cheaper HRSG with Advanced Gas Turbines." Power Engineering. Issue 3 and Volume 121.

Endnotes

Further information, references, and hyperlinks

1 National Renewable Energy Laboratory (NREL) is part of the U.S. Department of Energy's Office of Energy Efficiency & Renewable Energy.

2 This is the "Low Natural Gas Price / Low Renewables Cost" scenario included in NREL's ReEDS model, which is described in further detail in Section 5.2.2.

3 Note that the PJM ISO now covers a broader area than when it was originally named.

4 We do include, however, a conceptual cost buildup for a firebrick thermal storage facility in Appendix E, which suggests that a thermal storage system as modeled can be built for less than is allowable capital cost in most of the scenarios. The sources used for this are published reports on the cost of fossil power plants, not optimized for this application, and hence there is large scope for further cost reduction in this system.

5 This figure represents the average across the four ISOs.

6 Energy Innovations Reform Project (2017). What will advanced nuclear power plants cost? July 25, 2017.

7 Energy Technologies Institute (2018). The ETI Nuclear Cost Drivers Project: Summary Report. April 20, 2018.

8 ARPA-E's MEITNER program website.

9 Section 5 includes the complete rationale for selecting the year 2034.

10 Variable renewable energy sources are those that are non-dispatchable (i.e., intermittent), including solar PV, wind, run-of-river hydropower, tidal, and wave energy.

11 The NREL ReEDS model is a capacity planning and dispatch model for the North American electricity system.

12 Hsieh, Eric and Anderson, Robert (2017). Grid Flexibility: The Quiet Revolution. U.S. Department of Energy, Office of Scientific and Technical Information.

13 MISO (2018). Review Ranking Input from the 2018 Market Roadmap Stakeholder Prioritization Survey. August 9, 2018.

14 These rules govern everything from resource procurement, billing rates, and incentive programs to terms of service.

15 Lazar, J. (2016). Electricity Regulation in the U.S.: A Guide. Second Edition. Montpelier, VT: The Regulatory Assistance Project.

16 Wiser, Ryan (2019). The Impact of Variable Renewable Energy on Wholesale Power Prices—Implications for the Merchant Market Value of Wind and Solar. Lawrence Berkeley National Laboratory.

17 Bajwa et al. (2017). Growing Evidence of Increased Frequency of Negative Electricity Prices in U.S. Wholesale Electricity Markets. IAEE Energy Forum. Fourth Quarter 2017; Bloomberg (2018). Power Worth Less Than Zero Spreads as Green Energy Floods the Grid. August 6, 2018.

18 It was cheaper on a $/MW basis to build large, centralized power plants rather than smaller, distributed plants. Borberly, A. and Kreider, J. F. (2001). Distributed Generation: The Power Paradigm for the New Millennium. CRC Press, Boca Raton, FL.

19 Wind Solar Alliance (2018). Customer Focused and Clean: Power Markets for the Future. Nov 2018.

20 Wind Solar Alliance (2018). Outdated Electricity Market Rules Prevent Full Renewable Energy Participation.

21 International Monetary Fund (2019). Falling Costs Make Wind, Solar More Affordable. April 26, 2019.

22 'Net load' refers to the difference between forecasted demand and expected generation from variable renewables.

23 California ISO (2017). Renewables Watch—For Operating Day: Sunday, April 09, 2017.

24 See NREL ReEDS model (any scenario, including "80% National RPS"); U.S. EIA—Annual Energy Outlook, 2019 (natural gas increases in absolute and relative terms beyond 2050); and BloombergNEF New Energy Outlook (2019).

25 MISO (2018). Renewable Integration Impact Assessment (RIIA).

26 This is done by providing operating reserves and frequency regulation services when wholesale energy prices drop below marginal operating costs.

27 Patel, Sonia (2019). Flexible Operation of Nuclear Power Plant Ramps Up. Power Magazine.

28 Jenkins et al. (2018). The benefits of nuclear flexibility in power system operations with renewable energy. Applied Energy. Vol. 2222. July 15, 2018. Pgs. 872 – 884.

29 Jenkins et al. (2018) concluded that flexibly operating a nuclear plant could actually increase its gross operating margins by providing operating reserves and frequency regulation services when wholesale energy prices drop below marginal operating costs. They also concluded that it could reduce solar and wind curtailment and lower overall operating costs for the entire power system. Their analysis, however, considered only one plant in a stylized, high renewable power system. A fleet of plants would quickly depress these ancillary services revenues, leaving the fundamental economic dilemma of operating below a plant's rated output.

30 The wind production tax credit pays wind projects for each MWh of generation. Therefore, wind projects can bid negative prices and still theoretically make positive cash flow.

31 Union of Concerned Scientists (2018). The Nuclear Power Dilemma: Declining Profits, Plant Closures, and the Threat of Rising Carbon Emissions. November 2018.

32 ClimateNexus (2019). Nuclear Energy in the U.S.: Recent plant closures and policy decisions. April 4, 2019.

33 U.S. Energy Information Administration (2018). Frequently Asked Questions: How old are U.S. nuclear power plants, and when was the newest one built?

34 Reuters (2019). Pennsylvania state lawmaker offers bill to save nuclear power plants. March 11, 2019 and NEI (2019). Ohio policymakers support nuclear plants and the 2.3 million tons of CO_2 they prevent. June 13, 2019.

35 Baltimore Sun (2019). Maryland bill mandating 50% renewable energy by 2030 to become law, but without Gov. Larry Hogan's signature. May 22, 2019.

36 In August 2019, the DOE announced funding for a project with Exelon—which has the country's largest nuclear fleet—to produce, store, and use hydrogen produced from an existing nuclear plant. Shortly thereafter, ARPA-E provided funding to FirstEnergy Solutions, Xcel Energy, and Arizona Public Service to demonstrate hydrogen production from existing nuclear facilities as well.

37 Bloomberg Environment (2019). Advanced Nuclear Reactors Targets for Late 2020s, Companies Say. February 13, 2019.

38 The capacity expansion is performed by Energy Exemplar using their Aurora® software through 2046.

39 Energy Exemplar (2018). North American Datasets, Data Documentation. August 2018.

40 National Renewable Energy Laboratory (NREL). 2019. Regional Energy Deployment Systems (ReEDS) Model: Standard Scenarios Results Viewer.

41 U.S. Energy Information Administration (2019). What is the efficiency of different types of power plants? Last updated: August 8, 2019.

42 Congressional Research Service (2019). Advanced Nuclear Reactors: Technology Overview and Current Issues. April 18, 2019.

43 NREL (2019). Annual Technology Baseline: Electricity. Natural Gas Plants.

44 LucidCatalyst did not perform nor reference detailed engineering studies to confirm the claims made about thermal storage performance characteristics. It assumes that the claims made in either the published literature or by the companies themselves are true.

45 This assumption is supported by several of the project advisors as the 12-hour capacity exceeds contiguous dispatch requirements for capacity resources for all four ISOs (PJM's 10-hour contiguous dispatch being the longest).

46 U.S. Energy Information Administration (2019). Table S1b. Weighted-average price of uranium purchased by owners and operators of U.S. civilian nuclear power reactors, 1995–2018 dollars per pound U3O8 equivalent. Nuclear & Uranium.

47 With perfect energy conversion, 1 kWh could be produced from 3,412 Btu. Heat rate calculations scale up the necessary Btu per kWh by dividing 3,412 by the efficiency percentage.

48 Bowers, H. I., Fuller, L. C., and Myers, M. L, Cost Estimating Relationships for Nuclear Power Plant Operations and Maintenance, Oak Ridge National Laboratory, 1987, Web. doi:10.2172/5431729. Table 3.1.

49 Nuclear Energy Institute, Nuclear Costs in Context, September 2019, p. 2.

50 U.S. Energy Information Administration, Cost and Performance Characteristics of New Generating Technologies: Annual Energy Outlook 2019, Table 2.

51 Nuclear Energy Insider, GE Hitachi chases gas plant displacement with new 300 MW reactor, April 18, 2018.

52 U.S. Department of Energy, Cost and Performance Baseline for Fossil Energy Plants, Volume 1, Version 3, 2015, Exhibits 4–16 and 3 – 51.

53 Idaho National Laboratory, Power Cycles for the Generation of Electricity from a Next Generation Nuclear Plant, 2010, p. 33. INL and the plant designer (General Atomics) provided further estimates of staffing levels and O&M costs in 2012, but these estimates do not account for the staffing efficiencies envisioned for flexible advanced nuclear plants in the 2030s. For instance, the 2012 study includes 7 telecommunications staffers, 5 storekeepers, 89 security personnel, and 16 organizational effectiveness staffers.

54 LucidCatalyst did not have detailed information regarding ESS maintenance costs; however, peer-reviewed literature (see following references) suggests that it is ~1 – 2% of total CapEx over a year. Black & Veatch (2016). Molten Salt: Concept Definition & Capital Cost Estimate. Prepared for U.S. DOE SunShot. June 30, 2016; IEA (2010). Technology Roadmap: Concentrating Solar Power; Purohit Ishan (2010). Techno-economic evaluation of concentrating solar power generation in India. Energy Policy 2010, p.38.

55 The 22-year CapEx recovery assumption was provided under the guidance of project advisors who had brokered several large PPA negotiations for large power projects. This is on the higher end of the typical recovery periods considered by debt and equity investors.

56 Assumes a 5.5% interest rate on debt and an 8.5% return for equity investors. Naturally, the WACC is a material assumption in calculating maximum allowable CapEx. Increasing or decreasing the WACC by a percentage point changes the maximum allowable CapEx by about 8 – 9%.

57 Ye, Jason (2019). Carbon Pricing Proposal in the 116th Congress. Center for Climate and Energy Solutions.

58 Climate XChange Education and Research Inc. (2020). State Carbon Pricing Network.

59 Energy Innovations Reform Project (2017). What will advanced nuclear power plants cost?

60 Energy Technologies Institute (2018). "The ETI Nuclear Cost Drivers Project: Summary Report." April 20, 2018.

61 Per analysis of ISO-NE Annual Market Reports from 2008-2018.

62 2017 Annual Markets Report. ISO New England Inc. Internal Market Monitor. May 17, 2018.

63 Over 95% of energy is transacted in the Day-Ahead market.

64 $/MWh figures are taken directly from ISO-NE annual market reports, with the exception of $/MWh of capacity for years 2014 – 2017. These data points were estimated based on the reported total spend on fulfilling capacity contracts as a percentage of total spend on energy (which, on a proportional basis is translated to $/MWh)

65 See PJM's Capacity Market Auction Results.

66 Potomac Economics (2019). 2018 State of the Market Reports for the MISO Electricity Markets. June, 2019.

67 CAISO (2019). 2018 Annual Report on Market Issues& Performance. May 2019.

68 California ISO (2019). What are we doing to green the grid? As of October 23rd, 2019.

69 California Energy Commission (2018). The California Energy Demand 2018-2030 Revised Forecast. See Table ES-1: Comparison of CED 2017 Revised and CEDU 2016 Mid Case Demand Baseline Forecasts of Statewide Electricity Demand.... 1 – 1.5%.

70 CAISO (2018). Day-Ahead Market Enhancements: Updates to Revised Straw Proposal.

71 *Net Load* reflects the total system demand not being met by variable renewable resources like solar PV and wind.

72 CAISO (2018). 2018 Annual Report on Market Issues & Performance.

73 CAISO (2018). Day-Ahead Market Enhancements: Updates to Revised Straw Proposal.

74 As the grid resource mix includes more variable renewable generation, it becomes increasingly challenging to forecast load using historical averages.

75 Wang et al. (2016). Ramp capability Modeling in MISO Dispatch and Pricing. FERC Technical Conference on Increasing Realtime and Day-Ahead Market Efficiency through Improved Software.

76 Cavicchi, Joseph; Harvey, Scott (2018). Ramp Capability Dispatch and Uncertain Intermittent Resource Output (Table VI-7—MISO Ramp Up Shadow Prices). Advanced Workshop in Regulation and Competition, 31st Annual Western Conference. Monterey, California, June 27 – 29, 2018. Revised July 17, 2018.

77 See MISO Informational Forums (July 2019; April 2918; October 2017; and November 2016).

78 A resource must meet the following criteria to be considered a 'Fast Start Generator': (1) Minimum Run Time does not exceed one hour; (2) Minimum Down Time does not exceed one hour; (3) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; (4) available for dispatch and manned or has automatic remote dispatch capability; and (5) capable of receiving and acknowledging a start-up or shut-down dispatch instruction electronically.

79 Capacity Scarcity Conditions (CSC) are conditions when the grid cannot redispatch resources to create more operating reserves (which, at the time, will be dispatching at a capped price), to help maintain grid stability. Pay-for-Performance is triggered, and prices are cleared on a 5-minute basis, until the CSC is resolved.

80 ISO-NE's performance payment rates: 6/1/2018 – 5/31/2021 ($2,000/MWh); 6/1/2021 – 5/31/2024 ($3,500/MWh); 6/1/2024 – 5/31/2025 ($5,455/MWh). These need to get converted 5-minute rates by dividing by 12.

81 ISO-NE (2019). Capacity Scarcity Condition Report (includes ability to search historical data).

82 PJM (2018). Strengthening Reliability: An Analysis of Capacity Performance. June 20, 2018.

83 Ibid.

84 PJM (2019). Historical Emergency Procedures triggering Performance Assessment Hours, MS Excel spreadsheet.

85 CAISO (2018). Day-ahead Market Enhancements: Updates to Revised Straw Proposal.

86 CAISO (2018). 2018 Annual Report on Market Issues & Performance.

87 CAISO (2019). Q1 Report on Market Issues and Performance. June 28, 2019.

88 Wang et al. (2016). Ramp capability Modeling in MISO Dispatch and Pricing. FERC Technical Conference on Increasing Realtime and Day-Ahead Market Efficiency through Improved Software.

89 Cavicchi, Joseph; Harvey, Scott (2018). Ramp Capability Dispatch and Uncertain Intermittent Resource Output (Table VI-7—MISO Ramp Up Shadow Prices). Advanced Workshop in Regulation and Competition, 31st Annual Western Conference. Monterey, California, June 27– 29, 2018.

90 See MISO Informational Forums (July, 2019; April, 2918; October, 2017; November, 2016).

91 ISO-NE (2019). Capacity Scarcity Condition Report (includes ability to search historical data).

92 PJM (2019). Historical Emergency Procedures triggering Performance Assessment Hours.

93 Wärtsilla's Flexicycle plants can ramp to full capacity in 5 minutes in a simple cycle configuration and then convert to combined-cycle operations within the hour. Other large turbines in a simple cycle configuration can achieve maximum capacity in less than 10 minutes from a cold start.

94 GE (2017). 7HA Power Plants.

95 Siemens (2016). Siemens gas turbine portfolio.

96 General Electric (2018). Powering Forward: GE's Record Setting HA Gas Turbine Ignites a New Era of Power Generation. September 2018.

97 See ERCOT's Fast Responding Regulation Service Up and Down (FRRS) market and CAISO's stakeholder initiative.

98 The following are Unit Control Modes (UCM): UCM 1 – Off-line and unavailable for dispatch; UCM 2 – Off-line and available for dispatch; UCM 3 – Generator on-line, not dispatchable; UCM 4 – On-line and available for dispatch; UCM 5 – Posture generator to maintain reliability or provide VAR support; UCM 6 – Generator regulating.

99 ISO-NE. Appendix 6 Large Generator Interconnection Agreement.

100 PJM Manual 21 (2019). Rules and Procedures for Determination of Generating Capability. Rev. 14.

101 Ibid.

102 MISO (2018). Resource Adequacy Business Practice Manual. Manual No. 011.

103 CAISO (2019). Final Availability Assessment Hours. May 15, 2019.

104 ISO-NE (2018). Lesson 6B1: Supplier-Side Settlement—FCM Credit and Peak Energy Rent (PER).

105 ISO-NE (2014). Market Rule 1—Standard Market Design.

106 Ibid.

107 PJM Interconnection (2018). Strengthening Reliability: An Analysis of Capacity Performance.

108 PJM (2018). Capacity Performance Unit Specific Parameter Adjustment FAQs.

109 Table based on slide 14 from PJM (2016). Capacity Performance / Performance Assessment Hour Education.

110 MISO (2018). Resource Adequacy Business Practice Manual. Manual No. 011. Effective Date: Nov-01 – 2018.

111 The determination of operational need for the three Flexible RA Categories are as follows: Category 1) Based on the magnitude of the largest 3-hour secondary net load ramp; Category 2) Based on the difference between 95% of the maximum 3-hour net load ramp and the largest 3-hour secondary net load ramp; Category 3) Determined by 5% of the maximum 3-hour net load ramp of the month.

112 Table source: California Public Utility Commission (2019). 2019 Filing Guide for System, Local and Flexible Resource Adequacy (RA) Compliance Filings. Issued October 3, 2018.

113 Effective Flexible Capacity (EFC) is the capacity that is available to be used to meet a LSE's Annual Flexible Resource Adequacy requirement. EFC calculation is currently under review by CAISO.

114 Effective Flexible Capacity values are required and determined based on a resources Pmin and weighted average ramp rate. CAISO Tariff (2019). California Independent System Operator Corporation, Fifth replacement Electronic Tariff.

115 CAISO (2018). Flexible Resource Adequacy Criteria and Must Offer Obligation—Phase 2: Revised Draft Framework Proposal. Presented at February 7, 2018 Stakeholder Meeting.

116 Singleton, Chad (2017). Can California Conquer the Next Phase of Renewables Integration?

Greentech Media. June 9, 2017.

117 Ibid.

118 A resource's 'Economic Minimum' (or 'EcoMin') is the minimum amount of energy (MW) that it must be allowed to produce while under economic dispatch.

119 'No-load Cost' encompasses the fixed cost of operation. It includes the cost of starting up the plant, getting it synchronized to the grid, and standing by to increase power out. Effectively, it represents the costs outside generating energy to serve load.

120 FERC (2016). FERC Proposes Minimum Pricing Requirements for Fast-Start Resources.

121 ISO-NE. Appendix 6 Large Generator Interconnection Agreement.

122 PJM (2019). Fast-Start Summary. August 7, 2019.

123 MISO (2013). MISO Module A—Common Tariff Provisions 30.0.0. November 19, 2013.

124 CAISO (2019). Fifth Replacement FERC Electric Tariff. Effective as of January 1, 2019.

125 Table reflects summarized data collected from Zhou et al. (2016). Survey of U.S. Ancillary Services Markets. Center for Energy, Environmental, and Economic Systems Analysis, Energy Systems Division, Argonne National Laboratory. January 2016.

126 ISO-NE (2019). ISO New England Operating Procedure No. 11 Blackstart Resource Administration (OP-11); PJM (2015). Black Start Definitions & Procurement Process; MISO (2018). Business Practices Manual, Outage Operations; CAISO (2017). CAISO Fifth Replacement Tariff—Appendix D: Black Start Generating Units.

127 The U.S. DOE/EPRI 2015 Electricity Storage Handbook provides an excellent overview on energy storage technologies and grid applications: Akhil et al. (2015). DOE/EPRI Electricity Storage Handbook in collaboration with NRECA. February 2015. Prepared by Sandia National Laboratories.

128 Energy Storage Association (2019). Energy Storage Benefits; Breeze, P. (2018). An Introduction to Energy Storage Technologies. Power System Energy Storage Technologies, 1–11; Union of Concerned Scientists (2019). How Energy Storage Works.

129 Adapted from the 2015 DOE/EPRI Handbook—see footnote 128.

130 Wood MacKenzie Power & Renewables / Energy Storage Association (2019). U.S. energy storage monitor—2018 Year in review and Q1 2019 executive summary.

131 Figure source: Wood Mackenzie Power & Renewables / Energy Storage Association (2019). U.S. Energy Storage Monitor: 2018 Year in review and Q1 2019 Executive Summary. March 2019.

132 Bloomberg New Energy Finance (2018). Long-Term Energy Storage Outlook.

133 IRENA (2017), Electricity Storage and Renewables: Costs and Markets to 2030, International Renewable Energy Agency, Abu Dhabi.

134 Walton, Robert (2018). BNEF raises forecast for global battery deployment to $1.2T by 2040. Utility Dive. November 8, 2018.

135 Deign, Jason (2019). The Safety Question Persists as Energy Storage Prepares for Huge Growth. Greentech Media. July 24, 2019.

136 Figure source: Bloomberg New Energy Finance's New Energy Outlook 2018.

137 In May 2020, the company Form Energy announced a 1 MW x 150 MWh pilot project with Great River Energy. This is a major achievement for the storage industry and if costs get low enough, this could trigger a significant change in the types of applications in which energy storage can participate. This would have profound impacts on shoulder and baseload resources.

138 U.S. Energy Information Agency (2018). U.S. Battery Storage Market Trends. May 2018.

139 Smart inverters, like traditional inverters, convert DC to AC current (which can be used on the grid), but they can also support renewable integration by providing voltage regulation, ride through capabilities (helps solar stay grid connected during periods of low voltage), frequency support. They can ensure that renewables can either go offline when the grid goes down or avoid overloading local transformers or circuits.

140 PJM has not called a Load Management Events since 2013; MISO called its first emergency DR event in 10 years in 2017 and has since called 5 events. Kolo, Elta (2019). Defining System Flexibility: Supply is Only Half of the Equation.

141 Forsberg, C., Brick, S., & Haratyk, G. (2018). Coupling heat storage to nuclear reactors for variable electricity output with baseload reactor operation. The Electricity Journal, 31(3), 23–31.

142 See simetric.co.uk.

143 See the specific heat of solids at engineeringtoolbox.com.

144 See Remodeling Calculator (2019). 2020 Brick Prices—Complete Brick Buying Guide. (using approximate average price of $600 per thousand bricks and average weight of 4.5 lb per brick).

145 Epp, Baerbel (2018). Molten salt storage 33 times cheaper than lithium-ion batteries. Global Solar Thermal Energy Council.

146 Analysis of typical power plant component costs from U.S. Department of Energy, Cost and Performance Baseline for Fossil Energy Plants, Vol. 1: Bituminous Coal and Natural Gas to Electricity, July 6, 2015. Page 189.

147 National Renewable Energy Laboratory. G. Glatzmaier. Developing a Cost Model and Methodology to Estimate Capital Costs for Thermal Energy Storage. NREL/TP-5500-53066. September 2011. P. 7. See also NREL, Craig S. Turchi and Garvin A. Heath, Molten Salt Power Tower Cost Model for the System Advisor Model (SAM), NREL/TP-5500-57625, February 2013. Page 6.

148 StorTera (2019). SLIQ—The Single Liquid Flow Battery. The original cost estimates of £120/kW and £75/kWh have been converted to dollars using an exchange rate of 1.25 U.S. dollars per British pound (£).

149 U.S. DOE (2015). Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3. National Energy Technology Laboratory; Office of Fossil Energy.

150 Federal Reserve Bank of St. Louis (2019). Producer Price Index by Commodity for Machinery and Equipment: Electrical Machinery and Equipment.

LUCID
CATALYST

lucidcatalyst.com

LucidCatalyst delivers strategic thought leadership to enable rapid decarbonization and prosperity for all.