Evaluating Advanced Nuclear Fission Technologies for Future Decarbonized Power Grids

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Abstract

In the coming decades, the United States aims to undergo an energy transition away from fossil fuels and toward a fully decarbonized power grid. There are many pathways that the US could pursue toward this objective, each of which relies on different types of generating technologies to provide clean and reliable electricity. One potential contributor to these pathways is advanced nuclear fission, which encompasses various innovative nuclear reactor designs. However, little is known about how cost-competitive these reactors would be compared to other technologies, or about which aspects of their designs offer the most value to a decarbonized power grid. We employ an electricity system optimization model and a case study of a decarbonized U.S. Eastern Interconnection circa 2050 to generate initial indicators of future economic value for advanced reactors and the sensitivity of future value to various design parameters, the availability of competing technologies, and the underlying policy environment. These results can inform long-term cost targets and guide near-term innovation priorities, investments, and reactor design decisions. We find that advanced reactors should cost \$5.1/W–\$6.6/W to gain an initial market share (assuming 30 year asset life and 3.5 %–6.5 % real weighted average cost of capital), while those that include thermal storage in their designs can cost up to \$5.5/W–\$7.0/W (not including cost of storage). Since the marginal value of advanced fission reactors declines as market penetration increases, break-even costs fall ∼19% at 100 GW of cumulative capacity and ∼40% at 300 GW. Additionally, policies that provide investment tax credits for nuclear energy create the most favorable environment for advanced nuclear fission. Stakeholders and investors should consider these findings when deciding which technologies to consider for decarbonizing the US power grid.

Keywords: nuclear fission, macro-energy systems, capacity expansion, technology assessment, decarbonization

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1. Introduction

The United States has set ambitious goals to fully decarbonize its electricity sector by 2035, and its entire economy by 2050 [1]. However, fossil fuel sources currently supply more than half of the country's power, so the US must rapidly transition towards clean electricity capacity if it is to achieve its decarbonization goals [2]. There exist several "pathways" toward these goals that the US may pursue, each of which includes different mixes of clean technologies. There is general consensus in the literature that these pathways will all likely include large shares of solar and wind energy complemented by short-duration battery storage (e.g. Lithium-ion batteries) and some level of demand-side flexibility, but there is no consensus about what other resource can be used to balance out the limitations of weather-dependent, variable renewable energy sources and energy-constrained storage [3, 4, 5, 6, 7]. This other resource must be firm (that is, able to generate power whenever needed, for as long as needed) and must have net-zero emissions to allow the US to reach full decarbonization. Firm, zero-carbon resources include nuclear, geothermal, natural gas with full carbon capture and storage, and combustion or oxidation of hydrogen or other zero-carbon or carbon-neutral fuels [3], and they may be complemented by (and partially substituted with) certain energy storage technologies with very low-cost of storage capacity that are techno-economically suitable for multi-day discharge periods [6].

Of these resources, nuclear energy has historically been the most widespread in the US, providing about 20% of the country's total generation [8]. However, investment into new nuclear projects has been stagnant, and the Energy Information Administration (EIA) expects this to remain the case in the future because new nuclear power plants are not currently cost-competitive with other zero-carbon sources of energy [9]. Nuclear innovation companies are seeking to overcome this reduced investment by producing newer, so-called "advanced" reactor designs that are potentially less costly and/or offer greater value by bringing improvements in reactor safety, efficiency, and flexibility over traditional designs [10]. In this paper, we perform an economic analysis of these advanced nuclear fission technologies to evaluate whether they can serve as cost-competitive alternatives to other firm, zero-carbon resources in a decarbonizing electricity system. Specifically, we employ an electricity system optimization model and a case study of a decarbonized U.S. Eastern Interconnection circa 2050 to generate initial indicators of future economic value for advanced reactors and the sensitivity of future value to various design parameters, the availability of competing technologies, and the underlying policy environment. These results can inform long-term cost targets and guide near-term innovation priorities, investments, and reactor design decisions.

1.1. *Advanced nuclear fission*

We focus on advanced nuclear fission reactors which bring potential improvements over traditional designs in four main categories: cost, size, flexibility, and efficiency. Table 1 summarizes the different types of advanced nuclear reactor designs currently under development.

1.1.1. *Cost*

For the reasons outlined previously, any advanced reactor that wishes to be competitive must prioritize lowering its costs in order to incentivize investment. This cost reduction can be achieved primarily through innovations in design (discussed in this section) or reductions in reactor size (discussed in the following section).

The BWRX-300, an advanced reactor by GE Hitachi, exemplifies a simplified nuclear reactor design focused centrally on reducing costs. The BWRX-300 is a simplified version of the tried-and-tested boiling water reactor (BWR), thereby bypassing many of the regulatory obstacles of approving a nuclear reactor [11]. Compared to traditional BWRs, the simplified design of the BWRX-300 aims to reduce material and land area costs [11].

Improvements in the safety design of advanced reactors have the potential to reduce costs as well. Passive safety mechanisms make it physically impossible for reactors to reach the temperatures necessary for a nuclear meltdown by implementing cooling through natural processes such as convection [12] and gravity [10]. Additionally, some reactors, like the NuScale VOYGR small modular pressurised-water reactor, are designed to be contained underground to reduce exposure risk. These passive safety mechanisms can reduce costs because they may require less redundancy in design, less frequent and intense monitoring by safety staff, and easier licensing and approval [13, 14].

Finally, innovations in the design of the complete nuclear plant (reactor and turbine) are being pursued to reduce costs as well. As coal plants shut down across the United States due to poor economics, their steam turbine infrastructure can be re-purposed to pair with advanced reactors, eliminating the need to finance a new turbine alongside a new reactor. The Department of Energy estimates that over 80% of coal power plants in the US could be re-used for advanced reactors, totaling 263 GWe of capacity — more than double the nuclear capacity that exists today [15]. In addition, reactors built at retired coal plants would qualify as sited in "energy communities" which have traditionally relied on fossil fuels and where additional federal subsidies can be obtained for new clean energy projects [15]. TerraPower, developer of the Natrium sodium-cooled fast reactor, is currently planning to construct its first plant at the site of a coal power plant in Wyoming [16].

1.1.2. *Size*

In addition to design improvements, reductions in size can also help lower the cost of new reactors. The typical nuclear reactor in the US has about 1000 MW of capacity [8]. The costs and timelines for constructing a power plant of this

Reactor Type	Description	Value
Microreactors	Reactors with capacities smaller than 10 MWe.	Decarbonization of remote communities and natural disaster response.
Small modular reactors	Reactors with capacities between 10 MWe and 300 MWe.	Streamlined reactor construction pipeline with potentially lower costs, faster timelines, and less construction finance risk.
Fast reactors	Reactors with no moderator that have faster moving neutrons.	Higher fuel efficiency and longer refueling cycles leading to lower operational costs.
Non-water-cooled reactors	Reactors with metal or gas coolants instead of water.	Higher operating temperatures leading to greater turbine efficiency and co-generation opportunities.

Table 1: Advanced nuclear reactor designs and the value they would bring to a decarbonized power grid [10, 21, 22, 12].

size are much larger than for smaller generators and are often subject to great uncertainty when the project begins. For example, the recent construction of two AP1000 reactors at Plant Vogtle in Georgia exceeded the predicted timeline by seven years, and construction costs more than doubled initial estimates [17]. Similar excessive delays and cost overruns have also been experienced at recent large-scale reactor projects in Europe. These uncertainties around construction cost and timelines raise the cost of capital for nuclear projects and have contributed to the reduced investment into new gigawatt-scale nuclear reactors in the United States [18]. Small modular reactors (SMRs), the name given to advanced designs with capacities of approximately 300 MW or smaller, offer compact and standardized designs that may allow for factory construction of many of their important components, leaving only the task of assembly to be performed on site [10]. This ultimately allows for more streamlined and simplified construction, potentially reducing risk and increasing predictability and thus lowering capital costs and their associated financing. Furthermore, their standardized and modular designs allow for serial production and deployment of multiple individual small units at single sites to form larger capacity generators (e.g. at many 100s or 1000s of MW scale) while facilitating local learning-by-doing (e.g. cumulative experience of local engineering and construction labor and supply chains). Design standardization and repeated construction at multi-unit plants appear to have been critical factors behind lower historical nuclear construction costs experienced in certain countries and time periods [19, 20].

1.1.3. Flexibility

To better integrate into power grids with high variable renewable energy (VRE) penetration, many advanced fission reactors are being developed with increased flexibility as a primary goal. Some designs incorporate this flexibility by allowing for faster ramp rates: the speeds at which power output can be increased or decreased in the core of the nuclear reactor [10]. Faster ramping would allow advanced reactors to better respond to quick and unpredictable fluctuations in VRE generation and potentially contribute to important ancillary services like frequency regulation and operating reserves [23].

Other advanced reactor designs are instead pursuing flexibility by coupling their reactors with thermal storage, allowing heat from the nuclear core to be diverted to storage as necessary. This allows the nuclear core to operate at a steady state, while providing flexibility in electrical production by controlling how much heat goes to the storage and the turbine. For example, at times when VRE generation is high, more heat can flow to the thermal storage medium and less to the turbine, reducing total electrical output, while the opposite can be done to increase power generation. Molten salts have already been used to store thermal energy and increase flexibility for other resources such as concentrated solar power [24], and they have also been proposed for some reactor designs, such as the TerraPower Natrium reactor. Ceramic 'firebrick' [25], crushed rock [26], and other thermally conductive materials can also be used to store heat from nuclear power plants.

1.1.4. Efficiency

The overall efficiency of a nuclear power plant is defined as the amount of electricity produced for every unit of fuel consumed. For nuclear energy, this overall efficiency depends on the efficiencies of both the core and the turbine.

The efficiency of the core is defined by the amount of heat that can be extracted per unit of fuel. Some advanced reactors run on High-Assay Low-Enriched Uranium (HALEU) fuel, which allows them to reach higher core efficiencies than traditional reactors running on Low-Enriched Uranium (LEU) fuel [12].

On the other hand, the efficiency of the turbine is defined by the amount of electricity generated for every unit of heat consumed. For thermodynamic reasons, this value is largely dependent on the temperature of the fluid used to power the turbine. Traditional reactors use water as a coolant and produce power using super-heated steam at temperatures of 300 °C–400 °C, corresponding to an efficiency of about 30% [18]. However, advanced reactors are being designed with different coolants and working fluids that can reach higher temperatures than water/steam. For example, molten salt or metal cooled reactors can achieve operating temperatures of 600 °C–700 °C, corresponding to around 40% efficiency. Even higher temperatures can be achieved using coolants such as helium gas, with so-called high-temperature gas-cooled reactors capable of reaching 850 °C. At these temperatures, conversion efficiency reaches 45 %–48 % [12, 27]. These high efficiencies are beneficial because they reduce the amount of fuel necessary to produce electricity, lowering the variable costs of the reactor. They can also lower the capital costs of a nuclear power plant by reducing the reactor capacity necessary to generate the same amount of electric power.

1.2. Contribution of this work

Although the potential benefits of advanced nuclear reactors are well-understood, few studies have assessed whether this added value improves their cost competitiveness against other firm, zero-carbon resources. Previous studies that have considered the economics of advanced reactors have focused exclusively on SMRs, and they have simply estimated the isolated costs of these reactors, without considering how their value changes as they interact with other resources at a systems level [12, 21, 22].

In this paper, we address this gap by using a detailed electricity system planning model and a case study representing the U.S. Eastern Interconnection circa 2050 to determine the break-even cost of advanced reactors in future decarbonized power grids, while accounting for variations in plant design, competing technologies, and policy environment. We employ GenX, an open-source electricity system optimization model, to plan the least-cost capacity mix and capture the hourly interactions between different resources [28].[1] By minimizing the overall system cost and allowing the model to pick which resources to dispatch at hourly resolution, we can capture the break-even cost at which advanced reactors become economically competitive with other resources at different nuclear penetration levels (e.g. increasing capacity deployment). Finally, we analyze how this price changes under different policies (e.g. stringency of CO_2 emissions limits or presence of tax incentives), parametric uncertainties (e.g. competing technology, fuel, and financing costs) and reactor design decisions (e.g. operating flexibility, efficiency, and integration of thermal storage). Estimated break-even costs can be used to establish cost targets that nuclear developers must meet if they wish their reactor designs to be competitive at scale, while understanding the sensitivity of break-even costs to reactor design parameters can help inform near-term innovation priorities and design decisions. These results can also provide reference points for investors and government agencies considering investing in innovative nuclear fission concepts, projects, or companies.

2. Methods

The GenX electricity system model optimizes investment and dispatch decisions for generators, energy storage, demand-side flexibility, and inter-regional transmission in order to produce the lowest-cost system that can meet a given temporal and geographical demand profile [28]. It is highly configurable to different policy scenarios and technology mixes, allowing for thorough economic analyses of emerging clean technologies [6, 7, 29, 30].

2.1. Advanced reactor representation

To represent advanced fission reactors in GenX, we build upon an existing implementation for next-generation fusion power plants by Schwartz et al. [30].

[1] See https://github.com/GenXProject/GenX/.

Figure 1 provides a visual representation of how we treat energy flow in this implementation. Instead of considering nuclear reactors as only generators of electricity, as GenX does for other resources, we instead model the intermediate heat stage associated with nuclear electricity production; in our implementation, all fuel is first converted to heat, and then heat is converted to electricity. This allows us to model different sizes of nuclear core and turbine, core ramping rates, varying conversion efficiencies, and the integration of thermal storage and resistive heating[2]. In essence, we can independently model and co-optimize the capacity sizing and operations of each sub-component of the integrated reactor. In doing so, we can better capture the impacts of operating flexibility and the efficiency improvements associated with advanced reactors.

2.1.1. Implementation in GenX

The mathematical formulation of this advanced reactor implementation consists of added decision variables and constraints to the GenX model. The description in this section assumes a working familiarity with both constrained optimization electricity systems models as well as with the specific design of GenX. For a description of these concepts, refer to the GenX model definition [28].

First, we defined non-negative decision variables for the amount of nuclear core, thermal storage, and resistive heating capacity to be built:

$$vCoreCap_g, \;\; vStorCap_s, \;\; vRHCap_h \;\; \geq 0 \qquad \forall g \in G, s \in TS, h \in RH. \quad (1)$$

Here, G defines the set of all nuclear generators, TS defines the subset of those with coupled thermal storage, and RH defines the subset of those with resistive heating. Next, we added the costs associated with building this capacity:

$$\begin{aligned} eSystemCost \mathrel{+}= \sum_{g \in G} vCoreCap_g * cFixCoreCap_g + \\ \sum_{s \in TS} vStorCap_s * cFixStorCap_s + \sum_{h \in RH} vRHCap_h * cFixRHCap_h. \end{aligned} \quad (2)$$

Decision variables for the turbine and generator block already exist in GenX and need not be redefined. Next, we added hourly operational decision variables for the amount of heat produced in the core, the state of charge of the thermal tanks, and the amount of electricity used for resistive heating:

$$vCoreP_{g,t}, \;\; vSOC_{s,t}, \;\; vRH_{h,t} \;\; \geq 0 \qquad \forall \; t \in T, g \in G, s \in TS, h \in RH. \quad (3)$$

These operational parameters were upper bounded by the amount of capacity built for each. Upper bound constraints for the nuclear core are defined by unit

[2] Resistive heating provides the ability to consume grid electricity when power prices are low and convert it into heat for storage in thermal storage media and then dispatch heat to the plant's generator to produce electricity when prices are higher.

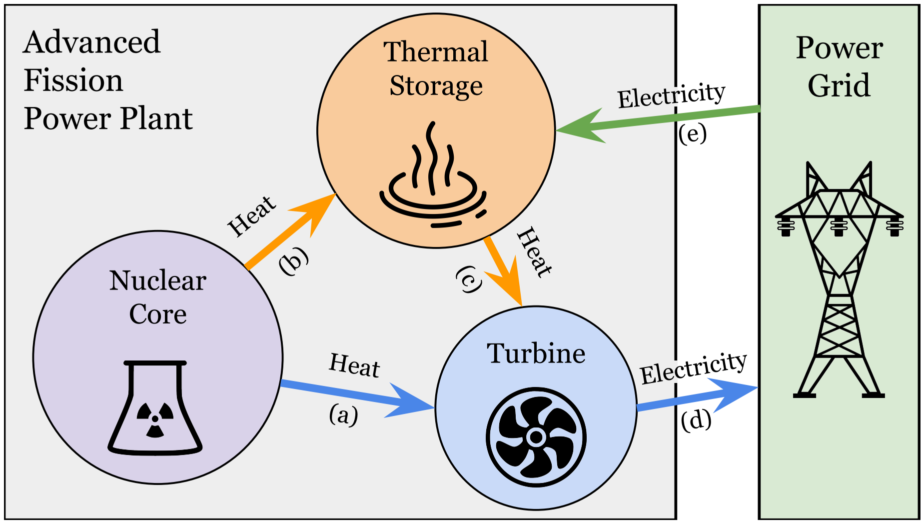

Figure 1: Schematic representation of energy flow in our advanced reactor implementation in GenX. Unlike standard nuclear reactors in GenX, this implementation separates the nuclear core from the turbine, allowing for distinct operational parameters and coupled thermal storage. Arrows labeled (a, d) represent the flow in a reactor with no thermal storage. Arrows labeled (a, b, c, d) represent the flow in a reactor coupled with thermal storage. Arrows labeled (a, b, c, d, e) represent the flow in a reactor coupled with thermal storage and resistive heating.

commitment constraints.

$$\forall t \in T: \quad vSOC_{s,t} \leq vStorCap_s \; s \in TS, \quad vRH_{h,t} \leq vRHCap_h \; h \in RH. \tag{4}$$

We linked these thermal variables to the turbine already implemented in GenX and defined how energy can flow between the separate components. For generators with no storage, energy can only flow from the core to the turbine, where it is converted to electricity:

$$vCoreP_{g,t} * pEff_g = vTurbP_{g,t} \qquad \forall t \in T, g \in G, g \notin TS. \tag{5}$$

For those with storage, we define the flow of energy by the change in state of charge between two consecutive time periods. Heat is gained via heat from the core and resistive heating and lost via thermal heat decay and generation at the turbine:

$$\begin{aligned} vSOC_{s,t} = vSOC_{s,t-1} \; &+ \; vCoreP_{s,t} \; + \; vRH_{s,t} * pEffRH_s * \mathbb{1}_{s \in RH} \\ &- \; vSOC_{s,t-1} * pDecay_s \; - \; vTurbP_{s,t} \, / \, pEff_s \qquad \forall s \in TS. \end{aligned} \tag{6}$$

In cases where resistive heating is used, we added this electrical load to the supply and demand balance at each location in the system:

$$ePowerBalance_{z,t} \mathrel{-}= \sum_{h \in RH} vRH_{h,t} * \mathbb{1}_{h.zone \in z} \qquad \forall z \in Z, t \in T. \tag{7}$$

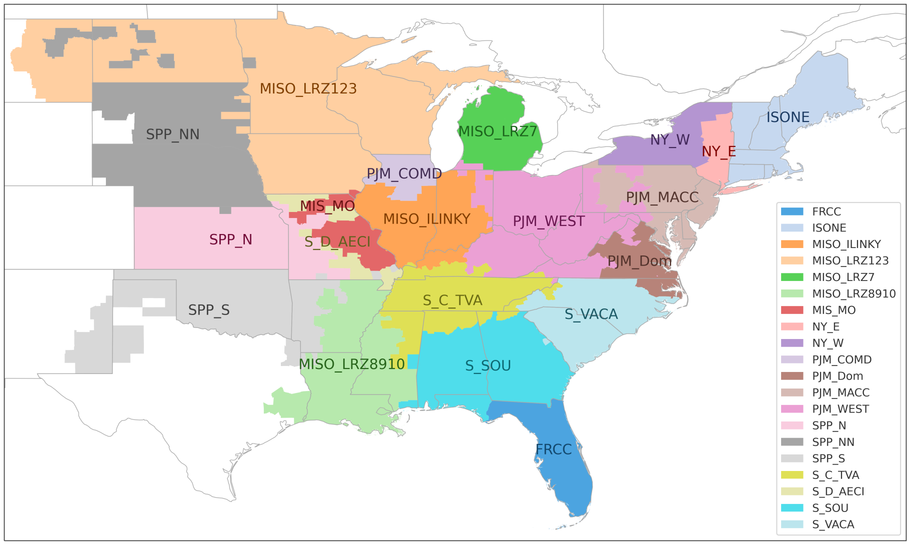

Figure 2: Eastern Interconnection of the United States divided into the 20 zones considered in this model. Adapted with permission from Schwartz et al. [30].

Finally, we added unit commitment and ramping constraints to the nuclear core in the same manner as these are applied to other generators in GenX. The mathematical definition for these constraints is available in the GenX documentation [28].

2.2. Modeling system setup

This study models the Eastern Interconnection of the United States using 20 zones (Figure 2). These zones are either identical to, or conglomerates of, those used in the Environmental Protection Agency (EPA) Integrated Planning Model (IPM) for the US power system [31]. We focus on the Eastern Interconnection because it currently includes over 90% of nuclear power capacity in the US, so it has historically been a more favorable environment for nuclear energy deployment, and it has larger potential for replacement (or re-powering) of retired reactors in the future [8].

Each of the 20 zones is modeled as a "copper plate." That is, perfect transmission is permitted within the zones, allowing for aggregation of generation and demand across the zone, although the costs of connecting different candidate renewable energy development sites to demand centers within each zone are estimated and included in the capital costs for renewable energy generators. Transmission capacity sizing and power flows between different zones are explicitly modeled with existing inter-regional transfer capacity based on EPA's IPM model (2021 edition) [31]. Where it deems economical, the model can expand transmission capacity, incurring associated transmission expansion costs sourced from the REPEAT Project [32].

We model the Eastern Interconnection system for the target year of 2050: the year by which the US has committed to decarbonizing its entire energy sector [1]. This target year of 2050 is chosen over 2035, the target year for a fully decarbonized electricity sector, to allow enough time for advanced reactors to reach commercial maturity. Many of the advanced reactor designs currently under development will not be prototyped until the late 2020s and early 2030s [10]. Thus, it is unreasonable to expect significant advanced reactor deployment by 2035, while 2050 permits sufficient time for considerable scale-up.

We model the entire 2050 year using hourly data (8760 total hours) for electricity demand in each zone, as well as capacity factor profiles for a total of 76 wind and 77 solar resource clusters spread out over the 20 zones. We compile input data using PowerGenome, an open source tool that generates GenX-specific input data for a desired model configuration [33]. PowerGenome estimates electricity demand in the following manner: First, current demand profiles and levels are taken from Federal Energy Regulatory Commission (FERC) Form 1 data; Electric space and water heating profiles are based on the National Renewable Energy Laboratory (NREL) *Electrification Futures Study* (EFS) [34]; EV charging demands are removed from FERC data and the remaining load is scaled based on 2050 projections from the U.S. Energy Information Administration (EIA) *Annual Energy Outlook 2022* Reference Case [35]; then space and water heating and EV charging loads are re-added based on equipment/vehicle stock projections from Princeton University's Net-Zero America 'high electrification' scenario [4] and the per unit profiles from the NREL EFS. Also, PowerGenome provides VRE capacity factors for each wind and solar cluster based on the 2012 sample weather year (consistent with the meteorological year used in the NREL EFS for electric heating and EV loads).

Furthermore, we model the build-out of capacity to meet 2050 demand in two stages (Figure 3). We first perform a capacity expansion from 2020 capacities to 2035, and we then use those 2035 capacities as starting points for the 2050 expansion. For the existing resources in 2020, we include natural gas plants, coal plants, solar, wind, traditional nuclear, biomass generators, and both hydroelectric power and storage. Values for these capacities are sourced from the EIA Form 860 [36] by PowerGenome. Out of this starting set of technologies, only some of them are eligible for new construction based on expected power system trends. These include solar PV, onshore wind, and natural gas. Notably, we do not allow new nuclear to be constructed between 2020 to 2035 under the assumption that all new nuclear construction will consist of advanced reactors in the 2035 to 2050 stage. While some first-of-a-kind reactors may be constructed prior to 2035, we omit this capacity for simplicity.

In addition to this existing technology mix, we consider new technologies for construction that do not currently have significant capacity penetration. These include lithium batteries, offshore wind, and natural gas combined cycle power plants with carbon capture and storage (NGCCS). Costs and operational parameters for these technologies come from the 2022 NREL Annual Technology Baseline (ATB) data set [37], with the NGCCS data adjusted to 100% carbon capture as in Schwartz et al. [30]. All of our input parameter values are listed

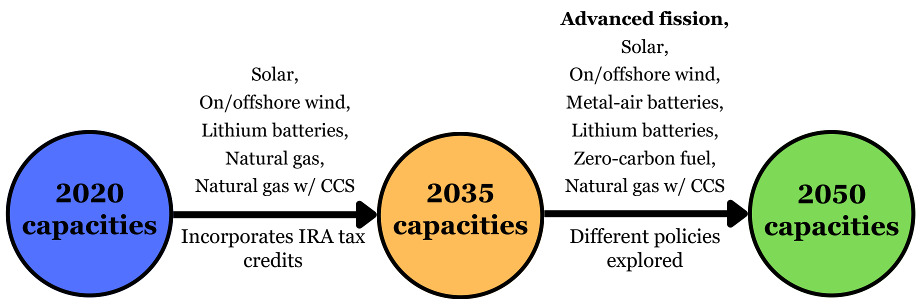

Figure 3: Two stage capacity expansion from 2020 to 2035 and from 2035 to 2050. Technologies included for each expansion are pictured, with the notable addition of advanced fission for the 2035 to 2050 expansion. From 2020 to 2035, IRA tax credits are included, and from 2035 to 2050 different policies are explored.

in Appendix C.

To model current policy incentives for decarbonized technologies, we include Production Tax Credits (PTCs) and Investment Tax Credits (ITCs) that were signed into law with the 2022 Inflation Reduction Act (IRA). All new sources of carbon-free electricity generation can elect either a PTC awarded on a per-MWh-produced basis or an ITC based on capital investment costs; both of these policies will remain active under current law for projects that commence construction before the end of 2033 or the year after U.S. electricity sector CO_2 emissions fall to 25% of 2022 levels, whichever comes later [38]. As such, we assume these credits are available for all carbon-free generators coming online before 2035. Energy storage devices are also eligible for the ITC during this period. These tax incentives are modeled by lowering technology production and investment costs respectively while adjusting for their net-present value and a transferability cost of 7.5% of the tax credit value (see Appendix D). Additionally, the 2035 expansion stage includes current state renewable portfolio standards as well as the offshore wind mandates enacted in several Atlantic states [39], but these state policies are omitted in the 2050 expansion, as full decarbonization is enforced instead. Finally, capacity reserve margins, which require available generation and storage capacity to exceed peak demand by a set planning reserve margin, are implemented to ensure system reliability (Appendix E).

Once the model determines the optimal generator and transmission capacity amounts for each technology in 2035, it uses these values as the starting capacities for the 2035 to 2050 expansion, with two exceptions. First, lithium battery capacity is reset to zero at the start of the 2035 to 2050 expansion because their lifetimes are assumed to be around 15 years, so they must be entirely replaced in the 2050 expansion [40]. Second, nuclear reactors that are set to retire before 2050 (assuming a 60 year reactor lifetime) have their capacities removed in order to model the need to replace them. Finally, compared to the 2020 to 2035 expansion, we consider three new technologies for construction. First, we include advanced nuclear reactors, the focus of this study. Second, we model low-cost metal-air batteries suitable for multi-day energy storage [41], and we source their operational and cost parameters from Baik et al. [42]. Finally, we allow natural gas plants to switch from burning natural gas to using a generic zero-carbon fuel (ZCF) as an alternative to building CCS. In practice, this ZCF could be hydrogen, biomethane (renewable natural gas), or synthetic methane, or it could continue being natural gas with fully offset emissions using direct air capture of CO_2. For the purposes of this study, we consider the ZCF to be green hydrogen (with no embodied emissions), and we source future prices from Princeton University's Net-Zero America study [4].

2.3. Experimental design

To understand the value of advanced reactors under different scenarios, we first define a reference case, calculate the break-even cost for reactors in that reference case, and then analyze how that break-even cost changes in different scenarios. We calculate the break-even cost of a reactor by modeling the reactor with zero upfront capital costs and restricting the model to build no more than a certain capacity of advanced reactors. We then examine the dual value associated with the maximum nuclear capacity constraint (also referred to as the Lagrangian multiplier or "shadow price"). For linear programming problems (as a corollary of strong duality), the dual value of any constraint represents how much the objective function — in this case overall system cost — would *lower* if we relax the right hand side of the constraint by one unit — in this case allowing the system to build one more megawatt of the free advanced reactor. As such, so long as the annualized capital cost of a reactor is less than this dual value, deployment of capacity at the level of the constraint would lower total system costs, annualized costs equal to the dual value would break even, and costs greater than the dual value would increase total system costs at this level of deployment.

Thus, we can use the dual value of the constraint on total reactor capacity to derive the break-even cost (or marginal value) of advanced reactor deployment at a given capacity penetration level. This same approach has been used in prior studies to estimate marginal value or break-even cost of different resources and is useful when the total cost of a technology is speculative [6, 30, 43, 44]. In effect, we 'solve' backwards for the break-even cost required to reach a given penetration level rather than assume a speculative cost and then identify the optimal deployment level. Note that throughout the figures in this paper, we communicate this break-even cost both as an annual cost for the lifetime of the reactor (left axes of our plots), which is the actual value derived from the dual, and an equivalent total upfront capital cost (right axes of our plots). The annual cost includes the construction investment annuity of the plant as well as its fixed operations and maintenance costs. The total capital cost represents the justifiable upfront capital cost for the nuclear plant assuming fixed O&M costs comprise 2.5% of the total capital cost, and also assuming an asset life of 30 years and a real weighted average cost of capital of 4.5% [37]. Given uncertainty about future nuclear plant financing costs, we also report in the text, where relevant, a range of capital cost targets corresponding to real WACC values of 3.5 %–6.5 %.

Table 2: The values assumed for all costs and operational parameters for the base case nuclear core.

Parameter	Value	Unit
Operational:		
Min stable power output	50	% of rated capacity
Ramp rate per hour	25	% of rated capacity
Min up commitment time	12	hours
Min down commitment time	12	hours
Costs:		
Uranium Fuel Cost	0.73	\$ / MMBtu
Variable O&M	0.16	\$ / $\mathrm{MWh_{th}}$
Startup cost	178	\$ / $\mathrm{MW_{th}}$

Table 3: The values assumed for all costs and operational parameters for the thermal storage and resistive heating.

Parameter	Value	Unit
Operational:		
Heat decay rate	2	% lost per day
Resistive heating efficiency	1	$\mathrm{MWh_{th}}/\mathrm{MWh}_e$
Costs:		
Thermal storage investment annuity	1,845	\$ / ($\mathrm{MWh_{th}}\cdot$ yr)
Resistive heating investment annuity	2,935	\$ / ($\mathrm{MW_{e}}\cdot$ yr)

Table A.5 provides a means for easily converting our reported total capital costs (at 4.5% real WACC and 30 year asset life) to any other WACC value in the range of 1 %–10 % and any asset life from 20–60 years.

Our reference case consists of an advanced reactor with ramp rates typical of a standard reactor, but also coupled with thermal storage. We assume a non-water-cooled reactor design capable of reaching 40% conversion efficiency. Regarding policy, we assume a federal decarbonization mandate by 2050. We also assume IRA tax credits are not available for marginal projects coming online in the 2035–2050 planning stage (e.g. assuming these credits expire circa 2035). Finally, for fuel and technology costs, we assume "moderate" projected values sourced from the NREL ATB 2022. Advanced reactor costs and operational assumptions, which could not be obtained from PowerGenome, are included in Tables 2–4.

From this reference case, we consider variations in the following scenarios:

a) Flexibility: We consider the effect of having unlimited ramping capabilities on reactor value compared to traditional levels of ramping. Also, we evaluate the added value from coupled thermal storage by considering reactors with

Table 4: The values assumed for all costs and operational parameters for the base case turbine. FOM represents Fixed Operation and Maintenance Costs.

Parameter	**Value**	**Unit**
Operational:		
Min stable power output	40	% of rated capacity
Up ramp rate	64	% of rated capacity
Down ramp rate	64	% of rated capacity
Min up commitment time	6	hours
Min down commitment time	6	hours
Efficiency	0.4	MWh_e / MWh_{th}
Costs:		
Investment annuity	46,123	\$ / ($MW_e\cdot$ yr)
FOM annuity	18,750	\$ / ($MW_e\cdot$ yr)
VOM	1.74	\$ / MWh_e
Startup cost	100	\$ / MW_e

no storage as well. Finally, we analyze the potential for resistive heating to increase the value of reactors with storage.

b) Efficiency: We vary from the reference salt-cooled reactor efficiency of 40% by considering traditional Light Water Reactor (LWR) efficiencies of 33% [18], as well as highly efficient gas-cooled reactor efficiencies of 50% [27].

c) Policy: We consider three different policy scenarios in addition to the reference case. Two of these scenarios cover situations where the 2050 decarbonization mandate is not fully implemented: we consider 90% and 95% reductions in emissions compared to 2005 levels, the year in which US CO_2 emissions peaked [45]. The last scenario considers the continuation of IRA policy (clean energy tax credits) for the 2035 to 2050 expansion.

d) Fuel costs: We model the advanced reactor value sensitivity to fuel costs of both natural gas as well as nuclear fuel. For natural gas, we model both high and low cost scenarios by scaling reference costs up by 75% or down by 25% respectively (equivalent to EIA's 2021 Annual Energy Outlook cost predictions for low and high oil and gas supply scenarios [46]). For nuclear fuel, only a high price variant scenario is considered, as the high price is meant to represent the price of HALEU fuel if widespread domestic HALEU fuel production capacity is not established. We implement this cost increase by increasing uranium costs by a factor of 2.5 based on the HALEU cost predictions in a Centrus report [47].

e) Technology costs: We analyze the advanced reactor value sensitivity to variations in the investment costs of other technologies. For all other technologies considered in the model, we vary their capital costs up and down by 10% and 20%, noting the resulting change in reactor value. We also consider the cost of molten salt thermal energy storage, and vary it in the same manner, to analyze its effect on the valuation of reactors with thermal storage. Finally, we consider different real WACC rates, from 1% to 5%.

3. Results

3.1. Substitution

The value of an advanced reactor derives from its ability to displace capacity and energy costs associated with other resources in the system and therefore reduce total system cost. As a firm resource, nuclear power exhibits significant capacity substitution value, as illustrated in Figure 4a. Each GW of nuclear capacity tends to reduce natural gas with carbon capture and storage (NGCCS) and zero-carbon fueled gas turbine (ZCF) capacity by about 0.4 GW each, substituting directly for these alternative clean firm resources. Additionally, at lower capacities (0 GW–80 GW), advanced reactors also rapidly displace battery and solar capacity. In this range, for every 1 GW of nuclear reactor built, roughly 10 GWh–11 GWh of lithium ion battery storage capacity and 2 GW of solar are displaced, with corresponding reductions in solar generation (Figure 4b). Note that our base configuration of advanced fission plant is equipped with thermal storage, which increases substitution of battery capacity (see Section 3.2 below). As nuclear penetration increases beyond 80 GW, the rate of solar and battery displacement slows while roughly 1 GW of wind is displaced per GW of nuclear capacity along with a corresponding decrease in wind generation. Finally, as nuclear penetration increases, the total quantity of energy generation displaced by nuclear decreases, indicating declining marginal utilization rates for additional nuclear capacity at high penetration levels. Declining substitution rates for NGCCS and ZCF plants with high marginal costs are also evident. Both dynamics lead to declining marginal energy substitution value for nuclear generators as installed capacity increases (even as capacity substitution value remains consistently high).

3.2. Flexibility

3.2.1. Thermal Storage

In our base configuration, advanced fission plants are equipped with thermal storage. Here we explore the added value provided by integrated thermal storage by comparing cases with and without storage capacity. We find that thermal storage adds value to advanced nuclear reactors, especially at low capacity penetrations (Figure 5a). The break-even cost of a low capacity penetration (5 GW) advanced reactor with thermal storage is about \$6.4/W (\$5.5/W–\$7.0/W over 3.5%–6.5% WACC), while that for a reactor with no thermal storage is \$6.0/W (\$5.1/W–\$6.6/W). Over an advanced reactor capacity penetration range of 0 to 100 GW, designs with thermal storage maintain about a 7–10% increase in value/break-even cost. At greater penetrations, the incremental value provided by thermal storage decreases to 0; however, given that there is about 90 GW of current installed nuclear capacity in the Eastern Interconnection [8], a roughly 7-10% increase in value is indicative of the added value that comes from coupled thermal storage across a wide range of possible advanced reactor deployment.

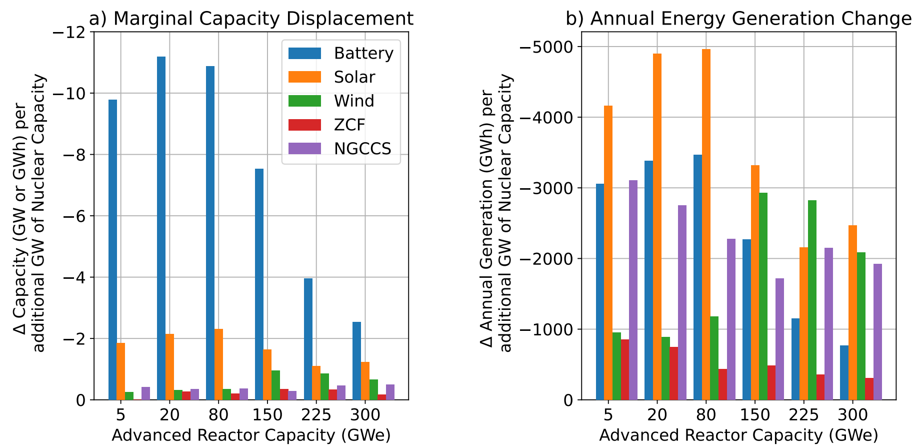

Figure 4: Marginal displacement of capacity (a) and energy generation (b) as advanced nuclear reactor capacity increases. Here, we model our base case advanced nuclear reactor.

The additional value for advanced reactors with thermal storage derives from their ability to store thermal energy during periods of low electricity prices and dispatch greater power generation during periods of higher prices, all while operating the reactor at a higher and more consistent utilization rate (Figure 6). This flexibility enables advanced reactors with integrated thermal storage to displace greater amounts of lithium battery capacity (Figure 5b) and thus deliver greater system cost reductions than reactors without thermal storage. At greater penetrations (150+ GW), the rate at which lithium batteries are displaced is equivalent for reactors with and without thermal storage, explaining the drop in marginal value at those greater capacities. No other technologies were displaced at significantly different rates between reactor-only and reactor-with-storage designs, implying the competitive advantage is primarily over lithium batteries (Figure G.13).

To analyze why reactors with thermal storage displace more lithium batteries, we consider the operational behavior of the nuclear plant. Figure 6 demonstrates the difference in nuclear power plant operational behavior for plants with (right) and without storage (left). For power plants without storage, the turbine power output (Figure 6c) is forced to match the core power output (Figure 6a), leading to high capacity factors of 90% for both. Despite the high capacity factor, the availability of zero marginal cost VRE regularly pushes net system load to zero during daytime solar production peaks (Figure 6e), requiring the nuclear core to ramp its power output significantly, while unit commitment constraints on reactor start-up and shut-down also force the turbine to continue producing even at times when system load is low (July and August, for example). This production when demand is low causes VRE generation to be curtailed and does not contribute to the revenue or marginal value of reactors as marginal electricity prices are zero during periods of renewables curtailment. On the other hand,

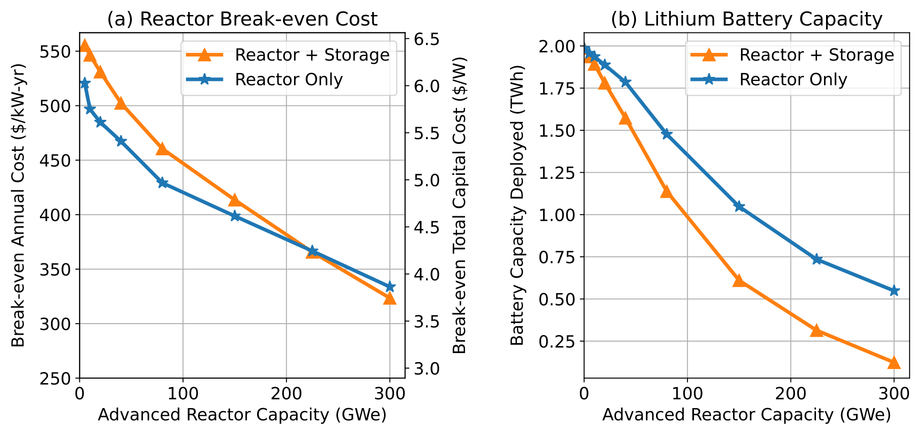

Figure 5: (a) Nuclear reactor break-even cost as a function of capacity penetration for designs with and without thermal storage. Left axis expresses break-even cost as an annuity, while right axis expresses it as a total capital cost (assuming 30 year asset life, 4.5% WACC). Break-even costs are calculated for the entire nuclear power plant, excluding costs for coupled thermal storage (Appendix A). (b) System-wide lithium battery capacity deployment as a function of advanced reactor capacity deployment. Both scenarios with and without thermal storage are presented.

nuclear power plants with thermal storage can better match the system demand profile. The turbine of a plant with storage has a much lower capacity factor of 65%, and its power production resembles the system demand profile more closely (Figure 6d). Most of the reactor's thermal energy production is shifted from periods with low or zero electricity prices (e.g. daytime hours with high solar production) to periods of higher value (when renewable energy production is insufficient to meet demand), increasing reactor revenues. The core also operates at a higher capacity factor of 96% and ramps less throughout the year, further improving reactor economics. The state of charge of the thermal tanks explains how the plant is able to achieve this (Figure 6f). In the morning hours, thermal storage is fully discharged. Throughout the day when demand is low, the thermal storage charges with heat from the nuclear core, reaching a peak in the afternoon hours. Then, thermal storage is discharged to meet the evening rise in demand. This ability to shift power generation throughout the day to match net system demand serves the same function as lithium batteries, hence why there is less battery deployment in grids with nuclear coupled with thermal storage.

Furthermore, we find that the optimal amount of thermal storage built begins at 7 MWh per MW of core thermal power for designs at low capacities, and linearly decreases to around 4 MWh per MW of core power at high penetrations (Figure G.14). Optimal turbine capacity sizing follows a similar linear trend, from 1.5 times larger than the core thermal power capacity at initial penetrations to 1.3 times larger at high penetrations (Figure G.14). These are important design parameters that advanced nuclear reactor developers can consider when

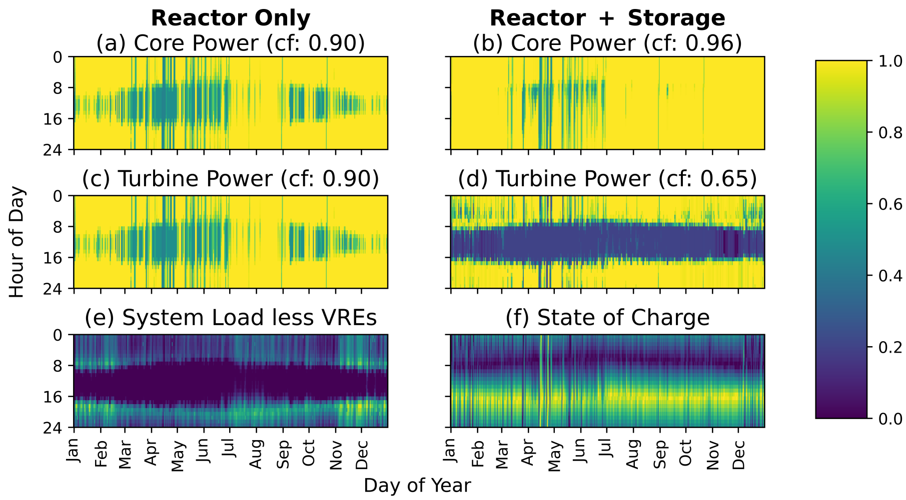

Figure 6: Heat maps illustrating advanced reactor operational profiles at 20 GW of nuclear capacity penetration. (a–b) Normalized nuclear core power output for all hours of the year, as well as capacity factors, for reactors with and without thermal storage. (c–d) Normalized turbine electrical power output for all hours of the year, as well as capacity factors, for reactors with and without thermal storage. (e) Normalized system load at all hours of the year, subtracting VRE generation. (f) Normalized state of charge for the thermal tanks at all hours of the year. For all graphs, an advanced nuclear capacity penetration of 20 GW is assumed, but similar patterns are observed at other capacities.

sizing the different components of their power plant.

3.2.2. Resistive Heating

In addition to incorporating thermal storage to decouple reactor operation from power generation, advanced reactors with integrated thermal storage could also employ resistive heating during periods of low electricity prices to 'charge' the thermal storage tank. When this option is available in the model, we find that thermal storage with resistive heating is economically attractive but does not change the relative economic value of advanced reactors (Figure 7a). Instead, the availability of resistive heating promotes the construction of additional molten salt storage and steam generator capacity — in effect, we see the installation of 'thermal batteries' that charge and discharge to the grid independently of the nuclear reactor, rather than resistive heating operating in synergy with the reactor to supply the same thermal storage and power generation capacity. As Figure 7b illustrates, even with no installed advanced reactor capacity, lithium battery capacity is lower when resistive heating is available than when it is not. Thus, it is clear that thermal batteries, which can be considered to be independent from the nuclear reactors, are economic (under these cost assumptions) and substitute for a portion of lithium battery capacity. We then note that the rate of change of battery deployment with respect to reactor core deployment is roughly equivalent for reactors with and without resistive

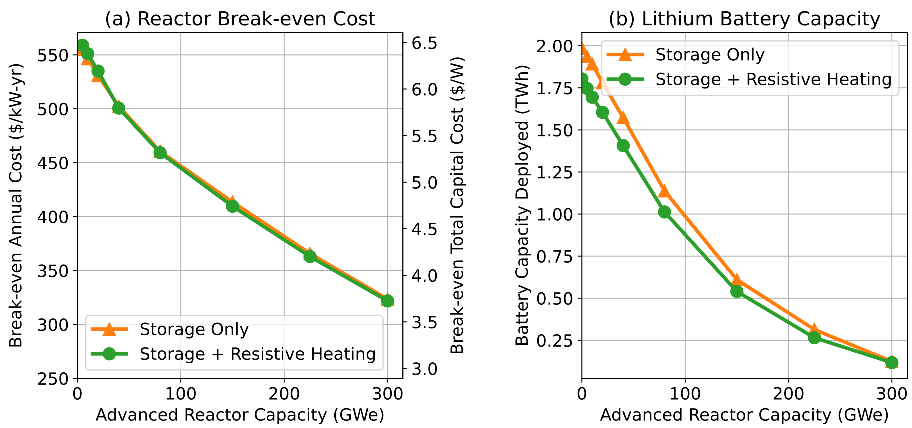

Figure 7: (a) Nuclear reactor break-even cost as a function of capacity penetration for designs with and without resistive heating. Left axis expresses break-even cost as an annuity, while right axis expresses it as a total capital cost (assuming 30 year asset life, 4.5% WACC). Break-even costs are calculated for the entire nuclear power plant, excluding costs for coupled thermal storage or resistive heating (Appendix A). (b) System-wide lithium battery capacity deployment as a function of advanced reactor capacity deployment. Both scenarios with and without resistive heating are presented.

heating (Figure 7b). Thus, the effect of an additional unit of nuclear core does not displace any additional battery when resistive heating is implemented. This explains why, although thermal batteries bring added value to the system as a whole, they do not make advanced nuclear capacity more valuable.

3.2.3. Core operational parameters

The final element of flexibility we consider is associated with improved ramping and reduced commitment times for nuclear cores. Even for designs without thermal storage, having a nuclear core that can operate freely with no ramping or commitment constraints (for the core or the turbine) increases economic value by <1% (significantly lower than the added value from thermal storage). Furthermore, for designs already incorporating thermal storage, increasing core operational flexibility for the reactor core adds near-zero value. This is consistent with our earlier results that the core operates at high capacity factors when paired with thermal storage and thus requires little flexibility. Ultimately, thermal storage is a much more valuable method for increasing flexibility than increased core ramping flexibility, as storage permits available thermal energy to be shifted to produce more electricity during the most valuable periods, while increased ramping can only reduce generation during low price periods and avoid the reactor's relatively modest variable costs (as well as any potential negative price periods). Note that this study does not consider operating reserve provision. Prior work has estimated that reactors ramping down during periods of low electricity prices could use their spare capacity to provide ancillary services (frequency regulation and operating reserves) that could modestly increase annual revenues (on the order of 2–5%), although ancillary service markets are relatively small and thus only a handful of reactors at most could benefit from these additional revenues [23].

3.3. Efficiency

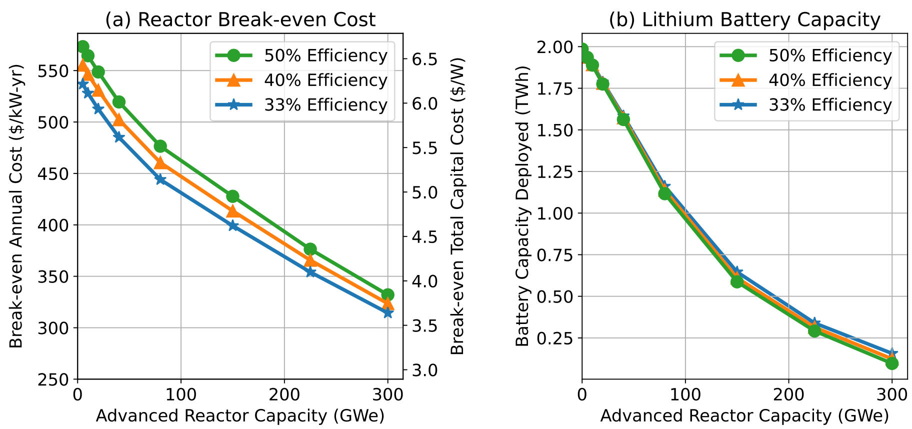

Figure 8: (a) Nuclear reactor break-even cost as a function of capacity penetration for designs with varying turbine conversion efficiencies (50% for gas-cooled, 40% for salt-cooled, and 33% for water-cooled reactors). Left axis expresses break-even cost as an annuity, while right axis expresses it as a total capital cost (assuming 30 year asset life, 4.5% WACC). Break-even costs are calculated for the entire nuclear power plant, excluding costs for coupled thermal storage (Appendix A). (b) System-wide lithium battery capacity deployment as a function of advanced reactor capacity deployment. Different lines correspond to different turbine conversion efficiencies.

Advanced reactors using non-water coolants can achieve higher input turbine temperatures and thus increased power generation efficiency. We find that improved reactor efficiency modestly increases the marginal value of advanced reactors at each level of penetration. We find that across capacity penetration levels, gas-cooled reactors with 50% conversion efficiency consistently exhibit about 3.5% higher marginal value (and thus can afford correspondingly higher break-even cost) than a salt-cooled reactor with 40% efficiency and 7% greater value than a traditional water-cooled reactor at 33% efficiency.

Unlike more flexible reactors, higher efficiency reactors do not obtain a relative competitive advantage over lithium batteries (Figure 8b). The amount of displaced battery capacity at each level of advanced reactor penetration is roughly equal regardless of reactor efficiency considered. This implies that the added value from improved efficiency does not come from out-competing other technologies, but instead from improving reactor economics. For example, more efficient reactors consume less fuel to produce the same amount of electricity and can build less turbine capacity for the same size of nuclear core. These improvements lead to the consistent observed increase in marginal economic value.

3.4. Policy

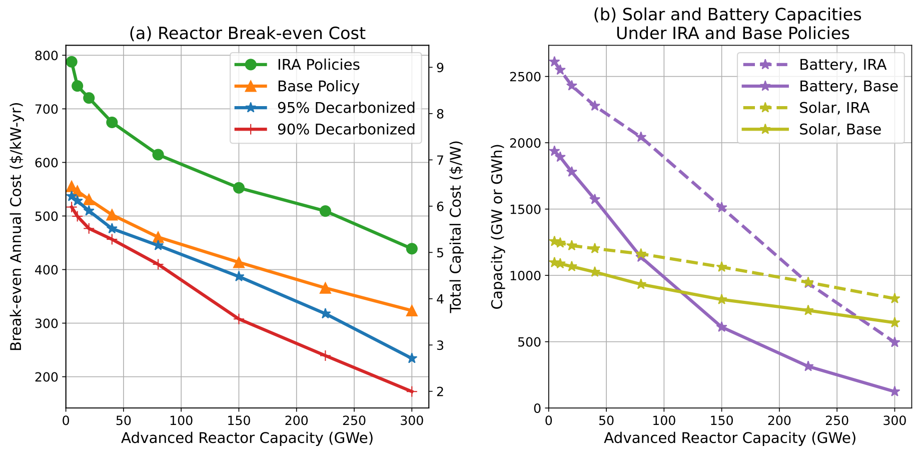

Figure 9: (a) Nuclear reactor break-even cost as a function of capacity penetration under different policy scenarios. Left axis expresses break-even cost as an annuity, while right axis expresses it as a total capital cost (assuming 30 year asset life, 4.5% WACC). Break-even costs are calculated for the entire nuclear power plant, excluding costs for coupled thermal storage (Appendix A). (b) Absolute capacities of solar and battery resources as the capacity of advanced nuclear reactors increases, under two policy scenarios: our base policy (IRA until 2035), and our extended IRA policy (IRA until 2050).

For policy scenarios, we consider the effects of continuing the tax credits established by the Inflation Reduction Act of 2022 (IRA) from 2035 to 2050 as well as different levels of decarbonization enforcement by 2050. The IRA extends the production tax credit (PTC, worth $27.5/MWh in 2022 USD) and investment tax credit (ITC, worth 30% of eligible capital costs) for all carbon-free generation sources and offers generators the choice of whichever credit is more lucrative. Additionally, bonus incentives increase the value of the PTC by 10% and the value of the ITC by 10 percentage points if projects are built in qualifying 'energy communities' or employ sufficient domestic content (these bonuses can be combined). We assume that nuclear reactors qualify for one of the two bonus incentives and elect an ITC worth 40% of capital costs (as this delivers greater net-present value than the PTC), so we calculate post-IRA reactor value by dividing the pre-IRA reactor value by the ITC (after applying a transferability cost of 7.5% of the tax credit value, see Appendix D). We find that the value of our base case reactor under this extended tax credits scenario increases by about 40% at low penetrations to over $9/W, while this increase in value declines to about 25-30% at higher penetrations (Figure 9a). This erosion in added value from the ITC occurs because the IRA also subsidizes competing clean energy resources, and the relative advantage for those resources is stronger than for advanced nuclear. We can compare the deployed capacity for two competing resources, batteries and solar, in a continued IRA scenario versus in a base policy scenario (Figure 9b). Between 0 and 150 GW of advanced nuclear penetration, batteries go from 1950 GWh–610 GWh ($\Delta - 1340$) under the base policy, and from 2610 GWh–1510 GWh ($\Delta - 1100$) under continued IRA policy. Similarly, solar goes from 1100 GW–810 GW ($\Delta - 290$) under the base policy, and from 1250 GW–1060 GW ($\Delta - 190$) under continued IRA policy. Both technologies see higher capacity deployment and slower displacement by advanced nuclear in the continued IRA policy scenario, implying that their economics benefit more strongly from the policy than those of advanced nuclear energy.

Under scenarios with a binding emissions limit, we find that the marginal value of nuclear at low penetrations declines only modestly if the US does not mandate full decarbonization of electricity supply by 2050 (Figure 9a). Until about 100 GW of capacity, the value of nuclear capacity is roughly 5% and 10% lower for the 95% and 90% decarbonization scenarios respectively, relative to the fully decarbonized case. In essence, for every 1% reduction in the US enforced decarbonization mandate, advanced fission reactors will lose about 1% of their economic value at low-to-moderate penetration levels (<100 GW). However, at greater penetrations (e.g. 225 GW–300 GW), reactors exhibit significantly lower value under incomplete decarbonization scenarios, with the marginal value/break-even cost of advanced fission declining about 25% to 50% at 95% and 90% decarbonization, respectively. To frame this another way, an advanced reactor design capable of achieving installed capital costs of around \$4/W would have an addressable market of around 300 GW under a zero emissions scenario, but this would shrink to about 210 GW under a 95% emissions reduction cap and to ∼125 GW with a 90% emissions reduction cap.

This sharp reduction in value at higher penetrations results from advanced nuclear competing with cheap natural gas. If full decarbonization is not enforced, existing natural gas plants will be allowed to remain operational, reducing the need to build more expensive NGCCS plants. We find that under 100% decarbonization, advanced nuclear never fully displaces NGCCS capacity, but it does so after ∼200 GW in the 95% scenario and after ∼20 GW in the 90% scenario (Figure G.15). These capacities directly correspond to the kinks at which advanced nuclear value begins to drop more dramatically in Figure 9a. In essence, once advanced reactors have fully displaced NGCCS plants, they must begin competing against the cheaper natural gas plants instead, thereby lowering their marginal value. Thus, if the US does not mandate full decarbonization by 2050, the addressable market for advanced reactors will be much more constrained.

3.5. Fuel Costs

Advanced reactor value is moderately sensitive to fluctuations in natural gas costs but highly sensitive to variations in nuclear fuel costs (Figure 10a). A 75% increase in natural gas cost (relative to the base case cost of \$3.79/MMBtu) adds about 10% in value for low-penetration designs, and that increase in value drops linearly to roughly 7% at high penetrations. On the other hand, a 25% decrease in natural gas fuel cost decreases reactor value by about 6% at all penetration levels. This observation reflects the fact that only a portion of nuclear's marginal

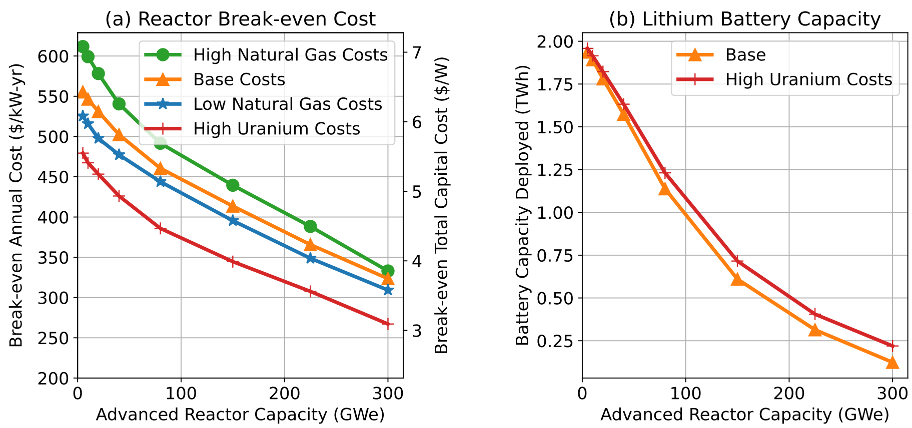

Figure 10: (a) Nuclear reactor break-even cost as a function of capacity penetration under different fuel cost scenarios. High natural gas costs are 1.75x the base costs ($6.64/MMBtu), low natural gas costs are 0.75x the base costs ($2.85/MMBtu), and high uranium costs are 2.5x the base costs ($1.83/MMBtu). Left axis expresses break-even cost as an annuity, while right axis expresses it as a total capital cost (assuming 30 year asset life, 4.5% WACC). Break-even costs are calculated for the entire nuclear power plant, excluding costs for coupled thermal storage (Appendix A). (b) System-wide lithium battery capacity deployment as a function of advanced reactor capacity deployment. Only base and high nuclear fuel cost scenarios are considered to analyze the effect of nuclear fuel on reactor competitiveness.

value comes from substitution of gas-fired generation at NGCCS plants (see Figure 4).

A high nuclear fuel cost future would reduce reactor valuation by 15% at low penetrations, and by up to 20% at high penetrations (Figure 10a). This reduction in value exhibits two components: a 15% "fixed" reduction that occurs at all penetrations, and an additional "variable" reduction that varies from zero to 5% as capacity penetration increases. The "fixed" reduction in value can be attributed to poorer reactor economics. In a "moderate" uranium cost scenario, the fuel costs for producing one unit of electricity are $\$6.27/\text{MWh}_\text{e}$, while those in a high uranium costs scenario are $\$15.7/\text{MWh}_\text{e}$. Thus, the variable costs of producing energy are higher, lowering inframarginal rents for nuclear reactors and decreasing the break-even cost. The "variable" reduction in value can be attributed to a slower decline in lithium battery deployment in a high nuclear fuel cost scenario (Figure 10b). In other words, higher nuclear fuel costs translate to less substitution of lithium battery capacity per megawatt of reactor capacity deployed.

3.6. Technology Costs

As the value of advanced fission plants derives from substitution of competing resources (see Section 3.1), we consider the sensitivity of our results to parametric uncertainties in the input costs of all technologies. At low capacity penetrations (20 GW), the break-even cost of advanced reactors is most sensitive to variations in lithium battery investment costs, followed by solar PV and

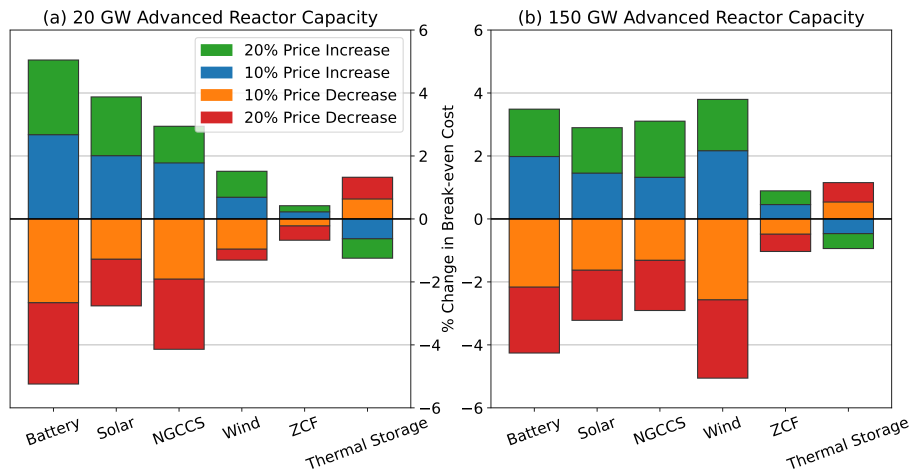

Figure 11: The effect of variations in the costs of other technologies on the break-even cost of advanced reactors. For each technology, 4 different price scenarios are considered: a 20% increase in investment costs, 10% increase, 10% decrease, and 20% decrease. From left to right, the considered technologies are lithium batteries, solar energy, natural gas with CCS, wind energy, and ZCF generators. Metal-air batteries are not considered as they do not have significant capacity deployment. Finally, the effect of cost variations for thermal storage is considered as well.

NGCCS (Figure 11a). These results are directly consistent with Figure 4 which demonstrates that at low capacity penetration, nuclear primarily competes with and displaces solar and battery capacity as well as NGCCS and ZCF capacity. With either lower substitution rate (wind) or low capital costs (ZCF), nuclear value at low penetration is much less sensitive to wind and ZCF costs. It is notable that a significant increase in battery costs of 20% only leads to a 5% increase in reactor marginal value, and vice-versa for a decrease in battery costs, while nuclear exhibits even lower sensitivity to other resource costs. At larger capacities (150 GW), the sensitivity to battery costs decreases, while that to wind costs increases significantly (Figure 11b), consistent with observed changes in marginal substitution rates at higher penetrations in Figure 4.

Figure 11 also demonstrates that advanced reactor valuation is highly resilient against variations in thermal storage investment costs. If the cost of storage rises by 20%, the reactor will only lose about 1.5% of its value, and this is true at both low and high capacity deployments. When comparing this finding to earlier results that show thermal storage adding about 7-10% in value for low-penetration designs, it becomes clear that thermal storage adds significant value even if storage costs more than anticipated in this study.

In addition to uncertainties in the capital costs of other technologies, we also analyze how sensitive our results are to uncertainties in our real weighted average cost of capital (WACC) assumptions. Figure 12 demonstrates that advanced nuclear reactors are strongly sensitive to variations in WACC. For

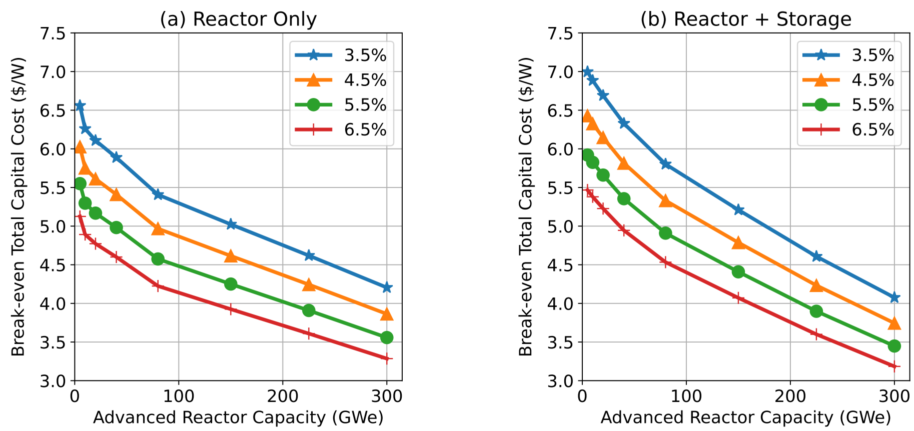

Figure 12: The effect of variations in WACC assumptions on break-even cost for (a) advanced nuclear reactors and (b) advanced reactors with coupled thermal storage. Break-even costs are expressed as a total capital cost assuming 30 year asset life and the WACC noted in the legend. Break-even costs are calculated for the entire nuclear power plant, excluding costs for coupled thermal storage (Appendix A). These results use Table A.5 to calculate variations from our base assumed WACC of 4.5%.

both scenarios with and without storage, we note that value drops by 8 to 10% for each 1% increase in WACC. Because total nuclear plant costs are dominated by their capital costs, it is reasonable to expect that their break-even costs are highly sensitive to the cost of capital to finance and build these plants. Whereas at 20 GW penetration, advanced reactors would have a break-even cost of \$5.6/MW at a real WACC of 4.5% (and 30 year asset life), the break-even cost would fall to \$4.8/MW at 6.5% and increase to \$6.1/MW at 3.5% WACC. Note that Table A.5 permits further conversion of reported break-even capital costs to equivalent break-even costs at any other WACC value in the range of 1-10% and any asset life from 20-60 years.

4. Discussion

The initial economic value of an advanced reactor with no thermal storage is \$6.0/W (\$5.1/W–\$6.6/W over 3.5%–6.5% WACC), with marginal value declining steadily as capacity penetration increases to a value of \$3.8/W at 300 GW. For the purposes of analyzing present-day investments in advanced nuclear, the low-penetration valuations are more useful, as they will indicate cost targets for the first tranche of new advanced reactors deployed at Nth-of-a-kind scale. For context, this estimated valuation is lower than the total capital cost estimated in NREL's *Annual Technology Baseline 2022* for small modular reactors in 2050, which is \$6.64/W [37]. Thus, based on the break-even costs established in this study, advanced reactors must achieve lower costs if they wish to be economically-competitive with other technologies in the future. This study identifies a long-term extension of investment tax credits (ITC) established by the Inflation Reduction Act as an effective policy instrument to improve the economics of advanced reactors; we identify their break-even cost to be beyond \$9/W if current ITC policy persists to 2050. Beyond policy, however, there are a few other avenues by which advanced reactors could increase their value or lower their construction costs in order to increase their economic competitiveness. For example, reactors that can co-generate heat, hydrogen, or other products may have two or more products to sell, which could increase the value of advanced fission plants and allow them to justify higher construction costs [48], although we do not explicitly model this possibility in this study. Furthermore, the advent of SMRs could facilitate factory fabrication of reactor components, leading to lower costs due to accelerated learning-by-doing, labor productivity, and lower construction risk [12].

In practice, however, the promise of SMRs to lower construction costs and increase predictability may prove overly optimistic. For example, in 2023, NuScale Power increased construction cost estimates for their first commercial project — a 462 MW facility featuring six 77 MW modular, factory-produced reactors — by 75%, and this cost increase would have been even more significant without the countervailing impact of IRA and DOE subsidies [49]. Based on this most recent cost estimate, we calculate that the full construction cost of NuScale's first SMR project is on the order of \$20/W, or \$11.4/W after IRA and DOE subsidies. These costs significantly exceed the \$6.0/W marginal value identified in this study. NuScale cited construction material cost increases, as well as rising interest rates, as the primary reasons behind the cost increase [49]. Later in 2023, the Utah Associated Municipal Power Systems pulled out of the project due to the cost rises, leading to its cancellation [50]. Thus, the NuScale project exemplifies how sensitive advanced reactors are to unfavorable investment environments and high interest rates, which is consistent with our results in Section 3.6.

Reactors that incorporate coupled thermal storage into their designs can increase the initial marginal value of a reactor to \$6.4/W (\$5.5/W–\$7.0/W over 3.5%–6.5% WACC), justifying a roughly 7% increase in break-even cost relative to the reactor-only design, which increases to up to 10% at low to medium nuclear capacity penetrations. This estimated marginal value/break-even cost corresponds only to the nuclear plant portion of the cost (excluding thermal storage costs), so the total cost of a plant including the cost of the thermal storage could be higher. Furthermore, this study has also demonstrated that reactor value is resilient against small variations in thermal storage capital costs. Thus, integrating thermal storage with performance characteristics comparable to (or better than) the molten salt cost assumptions used in this study is likely to be a profitable design choice for advanced reactor developers.

TerraPower is actively designing a salt-cooled fast reactor coupled with thermal storage, and their first generation cost estimates are around \$11.6/W upfront, or \$7.0/W after applying the IRA ITC [51]. This subsidized cost estimate falls above the \$6.4/W valuation for a reactor with thermal storage, implying the project is not profitable, though it is closer to being so than the NuScale project. Of course, because construction has not begun, it is impossible to know whether these estimates will be accurate, or whether TerraPower will experience the same cost overruns as NuScale. TerraPower's construction timeline has already been delayed after Russia's 2022 invasion of Ukraine halted the import of HALEU fuel used in the reactor [52]. Furthermore, molten salt thermal storage is not yet a fully mature technology, and it could present challenges to the operation of the plant as a whole. For example, a leak in the Crescent Dunes solar plant's molten salt storage halted operations in the project and eventually led to its bankruptcy [53]. Even still, if engineering challenges are met and assumed costs are achieved, thermal storage gives advanced reactors a more competitive economic starting point.

A side benefit of this study is the recognition of thermal batteries — storage tanks equipped with resistive heating — as a cost effective storage mechanism that can displace about 10% of lithium battery deployment. These thermal batteries do not directly add value to a nuclear reactor, as the two would operate largely independently of each other. However, co-locating nuclear reactors with thermal batteries could potentially decrease upfront construction costs for both technologies, as they could share the thermal storage tanks. We do not consider possible economies of scale or scope from such arrangements in this modeling. Future work can thus evaluate the potential value of co-locating these two technologies.

Increasing turbine efficiency to the highest level achievable by current proposed designs provides a 7% increase in marginal value for advanced reactors. When considering that non-water coolants such as molten salt tend to be more corrosive and thus require special construction materials, this modest increase in value may be offset by higher construction costs [12]. High-temperature gas-cooled reactors can avoid these corrosion issues and may therefore be better suited to absorb the 7% increase in marginal value.

Furthermore, improving the efficiency of advanced reactors is likely to require a switch from LEU fuel to HALEU fuel. Currently, there is no commercial source of HALEU fuel in the US, and HALEU fuel costs may be significantly higher than LEU fuel. We find that the marginal value of advanced reactors will decrease by 15 %–20 % if fuel costs are 2.5 times our base fuel assumptions ($1.83/MMBtu vs $0.73/MMBtu). Therefore, the risk of developing advanced reactors without first establishing a HALEU supply chain could easily outweigh the added value that comes from greater efficiency. Although the DOE has funded a HALEU enrichment plant in Ohio beginning to demonstrate HALEU production at the end of 2023, it is restricting its use for fueling advanced reactor prototypes only [54]. Thus, the US is still a long ways away from establishing a domestic, commercial supply of HALEU fuel for future generations of reactors. Nevertheless, the 2022 Inflation Reduction Act committed an additional $700 million in funding through 2026 to promote the development of a domestic supply chain of HALEU, indicating a promising step in the right direction [55].

4.1. Limitations

We note that GenX is an electricity-only energy systems model, which inherently limits the types of analyses that can be performed with the model. For example, we separately model heat and electricity production, but all heat is eventually converted back to electricity. We are thus unable to model reactors capable of cogeneration, such as district heating, desalination, and hydrogen production. The ultimate goal of the US is to decarbonize its entire energy system, not just electricity, so this implementation fails to capture nuclear energy's value in full. Future work could analyze advanced reactors in other models that integrate multiple energy systems beyond electricity. Similarly, our study focuses only on the value of nuclear energy for the Eastern Interconnection of the United States, but the findings could vary for countries or regions with different available resources and demand. Furthermore, we ignore broader real and perceived safety concerns related to nuclear energy, which could slow or constrain its commercial deployment. Finally, we run GenX with continuous capacity investment decisions and thus cannot capture potential economies of unit scale in nuclear costs, which may be relevant to analyze designs with different capacity size per reactor.

The one-at-a-time experimental approach in this study, where we vary parameters in specific categories while keeping all others at their reference values, is a good way to create initial indicators of value in the broad design space of advanced reactors. However, it misses capturing the full range of possible designs. For example, although we assess efficiency gains for reactors with thermal storage, we do not consider them for reactors without it. Similarly, although the effect of a 20% increase in battery prices is assessed, the results of simultaneous increases in both battery and solar prices are not. A broader, combinatoric uncertainty analysis could yield additional insights.

5. Conclusion

Decarbonizing the US electricity grid is one of the country's biggest priorities in the coming decades. Advanced nuclear reactors, which may offer greater levels of flexibility, efficiency, and safety over traditional designs, have the potential to serve important roles in the United States' transition to net-zero emissions energy systems. This study aims to quantify the economic value that advanced reactors could bring to a future decarbonized power grid in order to establish cost targets for designs currently under development. We achieve this by using the GenX electricity systems model to analyze how different advanced reactor design and policy scenarios affect their value in the Eastern Interconnection of the US circa 2050.

We find that the first tranche of advanced reactor capacity deployed will exhibit a marginal value (and thus maximum break-even capital cost) in the \$5.0/W to \$7.0/W range dependent on several factors, which is lower than recently reported costs of several designs under development today. Advanced reactor designs should thus focus centrally on achieving low capital costs to ensure economic viability. To further improve their economics, advanced reactor developers can also consider coupling their reactors with thermal storage, which increases break-even reactor value by about 7–10%. This is the best way, under the options considered in this study, for reactors to achieve higher levels of operational flexibility, which can increase their value in a power grid with high amounts of solar and wind energy capacity. Greater thermal efficiency offers a more modest opportunity for enhancing a design's value, but efficiency improvements should be considered in the context of potentially higher fuel costs for HALEU fuel as well, which reduce reactor value.

Policymakers and private sector investors can use the results of this study to guide investment decisions related to advanced reactors and other technologies. Without subsidies, recently reported costs of first generation advanced reactors will be too prohibitive for the technology to be profitable. However, continued access to investment tax credits, as implemented in the 2022 Inflation Reduction Act, has the potential to enable commercialization of advanced nuclear reactors, provided reactor vendors achieve sufficient capital costs. Furthermore, any policy that lowers or raises fossil fuel prices will lower and raise nuclear plant value accordingly. A large obstacle to widespread advanced reactor deployment, however, is the fact that most of these designs require HALEU nuclear fuel, none of which is commercially accessible in the US today. Thus, policymakers advocating for a growth in advanced reactor investment must also provide the necessary incentives to establish a domestic HALEU economy, and HALEU funding in the 2022 Inflation Reduction Act serves as a strong first step.

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Appendix A. Calculating the Break-Even Cost

Appendix A.1. Defining the Break-Even Cost

The upfront capital costs of advanced nuclear reactors are not yet well-known, so instead of using them as inputs into the GenX model, we designed this study to calculate their break-even capital costs (the threshold at which they become economically competitive with other technologies) as outputs of the model. We do this by making the nuclear reactor free in the model, such that it will build as much reactor as possible. However, we constrain the model to build no more than a certain pre-determined advanced nuclear core capacity. We take the rate of change of the cost function with respect to nuclear core capacity (i.e. the dual of the capacity constraint) as indicative of the break-even cost of the reactor core at that given capacity penetration. To evaluate how break-even cost varies at different capacity penetrations, we repeat this experiment at 5, 10, 20, 40, 80, 150, 225, and 300 GW_e capacity constraints, loosely following a geometric distribution.

Appendix A.2. Adjusting for the Cost of the Turbine

Because we only make the core of the reactor free, but not the turbine (as steam turbine construction costs are well-known), the model outputs the break-even cost of the nuclear plant without considering the cost of the turbine. However, the literature often refers to capital construction costs for a complete nuclear power plant, not just the nuclear core component. Thus, to contextualize our results, we add the cost of the turbine (assumed to be $750,000 per MW_e) to the break-even cost of the nuclear core (on a per-MW_e basis). This inherently assumes that there is a 1:1 ratio between the amount of nuclear core built and the amount of steam turbine built. This is a necessary assumption in order for us to communicate results that are consistent with those in the literature. However, this is often not the case for nuclear reactors with thermal storage, as the turbine capacity often exceeds the core capacity to accommodate periods when stored energy is dispatched in addition to produced energy; we found the core-to-turbine ratio for reactors with storage to be between 1:1.3 and 1:1.5. However, because the cost of the core is significantly larger than that of the turbine, we find these small variations in ratio to have a very small effect on the overall break-even cost.

Appendix A.3. Converting to Total Capital Costs

GenX models one year of power system operation, so it considers all construction costs for generators as annuities paid for an initial capital investment. Thus, the break-even cost calculated by the model is communicated as a break-even annual cost. This annual costs includes both the financing cost of paying back the initial investment, as well as the yearly operational costs. We assume these operational costs comprise 2.5% of the total capital costs of the reactor which is equivalent to the ratio in the NREL ATB [37]. We also assume a real Weighted Average Cost of Capital (WACC) of 4.5% and an asset lifetime of 30

	Asset life / years								
WACC	20	25	**30**	35	40	45	50	55	60
1.00%	1.07	1.23	1.36	1.46	1.56	1.64	1.71	1.77	1.83
2.00%	1.00	1.13	1.24	1.33	1.40	1.47	1.52	1.57	1.61
3.00%	0.94	1.05	1.14	1.21	1.27	1.31	1.35	1.39	1.41
4.00%	0.88	0.97	1.04	1.10	1.14	1.18	1.21	1.23	1.25
4.50%	0.85	0.93	**1.00**	1.05	1.09	1.12	1.14	1.16	1.18
5.00%	0.82	0.90	0.96	1.00	1.04	1.06	1.08	1.10	1.11
6.00%	0.77	0.84	0.88	0.92	0.94	0.96	0.98	0.99	0.99
7.00%	0.72	0.78	0.82	0.85	0.86	0.88	0.89	0.89	0.90
8.00%	0.68	0.73	0.76	0.78	0.79	0.80	0.81	0.81	0.82
9.00%	0.64	0.68	0.71	0.72	0.73	0.74	0.74	0.75	0.75
10.00%	0.61	0.64	0.66	0.67	0.68	0.68	0.69	0.69	0.69

Table A.5: Conversion table for different financial assumptions. Any total capital cost in our results can be multiplied by the relevant coefficient in this table to see what the result would look like under different asset lives and WACCs.

years, also consistent with the ATB. These assumptions yield a capital recovery factor of 6.1% per year. If we add this value to the 2.5% operational costs, we find that the annual costs are 8.6% of the total capital cost. We use this value to convert the GenX annuities into total upfront capital costs. Table A.5 provides conversion factors to calculate our total capital costs under different asset life and WACC assumptions.

Appendix B. Data Availability

All scenarios presented in this paper ran on a branch of GenX v0.2.0. The source code for this branch is available at `https://github.com/emiliocanor/GenX/tree/senior_thesis`. The standard GenX model is available at `https://github.com/GenXProject/GenX`. PowerGenome is available at `https://github.com/PowerGenome/PowerGenome`. Data will be made available upon request.

Appendix C. Input Cost Data

Table C.6 includes the cost assumptions for all technologies for which we considered construction. For a few technologies, there are changes made to the NREL ATB data set from which PowerGenome sources its cost assumptions. These changes are implemented to replicate a similar study by Schwartz et al. that models a fully decarbonized Eastern Interconnection in 2050 [30].

1. Metal-air batteries are not included in the ATB, so their cost and performance assumptions are sourced from Baik et al. [42] as done by Schwartz et al. [30].

Table C.6: The baseline values assumed for the costs of all technologies considered for construction in the model. Those for advanced fission are included separately in Tables 2 through 4. Average fuel cost is included because costs vary over time and geography. Storage technologies include two costs where applicable, first for power capacity ($/kW), then for energy capacity ($/kWh).

Technology	**Inv cost ($/kW)**	**FOM ($/kW-yr)**	**VOM ($/MWh)**	**Start Cost ($/MW)**	**Average Fuel Cost ($/MMBtu)**
Solar Energy	686	15.56	0	0	0
Onshore Wind	827	35.15	0	0	0
Offshore Wind	1920	71.79	0	0	0
Natural Gas CCS	2320	74.77	12.76	103	3.79
ZCF Generator	790	20.90	4.94	134	14.41
Lithium Battery	187 ‖ 117	4.67 ‖ 2.94	0.15	0	0
Metal-air Battery	1200 ‖ 12	30 ‖ 0.30	0	0	0

2. The ATB only includes cost assumptions for natural gas with 90% CCS, but to have these technologies be considered in a decarbonized grid, it was necessary to model natural gas with 100% CCS. Thus, costs are scaled up from the ATB assumptions, and increased CO_2 transportation costs are applied as well. For more information regarding the cost scaling and transportation cost assumptions, refer to Schwartz et al. [30].

Appendix D. IRA Tax Credits

PTCs and ITCs are included to directly model the IRA provisions. The base ITC from IRA of 30% is used, as is the base PTC of $27.5/MWh [38]. For each of these, we assumed they could benefit from at least one of the IRA's bonus credits. Bonus credits are applied to projects with a minimum percentage of manufactured products coming from the US, as well as those sited in an "energy community" — a region of the US that has historically relied on coal, oil, or gas [38]. After applying these bonus credits, the ITC rises to 40% and the PTC rises to $28.6/MWh. The tax credits are paid out as reductions in the amount of owed tax from a clean energy business over the duration of the tax credit, but these are often sold to other businesses that owe greater tax. Thus, we apply a 7.5% 'haircut' to the IRA tax credits which represents the lost value from the resale of the tax credits as done by Ricks et al. [29]. Finally, we convert the tax credits into their net present value in 2020 dollars. These were incorporated into GenX as reductions in variable operation costs (PTC) and investment costs (ITC) for each eligible technology.

Appendix E. Capacity Reserve Margins

Each zone considered in the model has its own Capacity Reserve Margin (CRM) depending on its demand uncertainty and reliability needs. The 20 zones considered can be grouped into 6 different CRM values (Table E.7A), which are obtained from PowerGenome [33]. Also, each technology has a specific amount of its unused capacity that can be contributed to the CRM policy at any time (Table E.7B). For a description of how the CRM policy is implemented, refer to the GenX documentation at `https://genxproject.github.io/GenX/`.

Table E.7: The CRM policy values for each zone, and the amount that each technology can contribute of its unused capacity towards the reserve amounts.

	A: Capacity reserve margins for each zone.
CRM Value	**Zone**
0.12	SPP_N, SPP_NN, SPP_S
0.15	NY_E, NY_W, FRCC, S_C_TVA, S_D_AECI, S_SOU, S_VACA
0.155	PJM_COMD, PJM_Dom, PJM_MACC, PJM_WEST
0.18	MISO_ILINKY, MISO_LRZ123, MISO_LR27, MISO_LRZ8910, MIS_MO
0.183	ISONE
	B: Reserve capacity for each technology.
% of Capacity	**Technology**
0.8	Solar, Wind, Hydroelectric power
0.9	Nuclear, Coal, Natural gas, ZCF generator, Biomass
0.95	Lithium battery, Metal-air battery, Hydroelectric storage

Appendix F. Advanced Reactor Costs and Parameters

This appendix defines assumptions made for the costs and operational parameters of advanced reactors. Here, we focus on the definitions for the base cases, as the values taken in other scenarios are described in Section 2.3.

Appendix F.1. Nuclear Core

Table 2 summarizes the input values assumed for base case nuclear cores. We began by defining the ramp rate to be 25% of the core's capacity every hour, and the minimum stable output power to be 50% of the rated capacity. These values are consistent with those employed for traditional reactors in other electricity system models [3, 30]. Although reactors (especially advanced ones) can theoretically ramp much faster than this, in practice, ramping rates are kept low to reduce stress on reactor components [23]. Also, the minimum stable output of a reactor varies significantly depending on the amount of time the fuel has been in operation, and 50% is close to the midpoint of this potential range [23]. Although these parameters are fairly conservative, more flexible values are explored in Section 3.2. Minimum up and down commitment times are set at 12 hours, a slight improvement from traditional times, to reflect a more flexible advanced core design; again, more and less optimistic values are analyzed in Section 3.2. Finally, the heat rate of the reactor (heat per unit of fuel) is set to be the same as that for a nuclear reactor from the ATB. This is an area of potential improvement for advanced reactors, but the possible range of values is not yet well defined, so speculating potential values would produce results without justification. Even still, efficiency gains are considered in Section 3.3.

Costs for advanced reactors follow those of reactors in the ATB closely, as there is no literature on their expected operational costs. For Variable Operation and Maintenance (VOM) costs, we take the NREL ATB values and subtract the VOM costs for the turbine. We take the same approach for startup costs. Startup fuel use is set to zero, as it is zero for reactors in the ATB as well.

Appendix F.2. Thermal Storage

Table 3 summarizes the input values assumed for the base case thermal storage. Thermal storage charge rate is limited by nuclear core and resistive heating power capacity, while discharge rate is limited by turbine capacity, so no explicit rates are modeled. Only a heat decay rate is included to simulate heat loss, and it is derived from a molten salt thermal storage study [56]. Resistive heating is widely considered to have 100% conversion efficiency [25]. As for the costs, we assume $22/kWh$_{\mathrm{th}}$ for thermal storage [56], and $35/kW$_e$ for resistive heating [25].

Appendix F.3. Turbine

Table 4 summarizes the input values assumed for the base case turbine. We assumed ramp rates, minimum stable powers, and minimum up and down commitment times consistent with a stand-alone generator for a concentrated solar power plant [57]. We set the efficiency at 40%, consistent with molten salt reactors, and a rough midpoint for the potential ranges achievable. We set the startup fuel to zero for the same reasons as the nuclear core. The investment costs are from the DOE [58], while the FOM, VOM, and startup costs are obtained from a concentrated solar power study with a stand-alone turbine [57]. Both of these costs are converted into annuities using the same financial assumptions as the nuclear core, under the assumption that the power plant (core + turbine) is financed as one lump sum.

Appendix G. Supplemental Figures

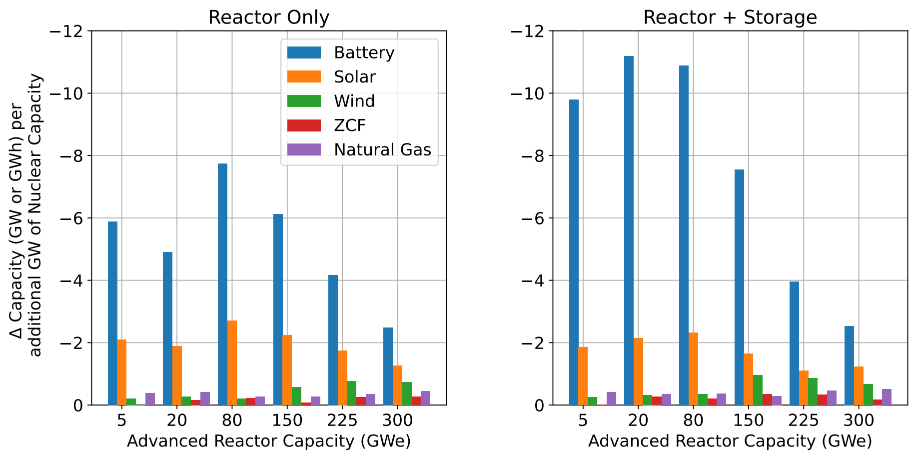

Figure G.13: Rate of change of capacity for other resources with respect to an additional MW of advanced reactor capacity in a (a) reactor only or (b) reactor + storage scenario. Rate of change is estimated using the slope between data points and assigning the value to the right-hand endpoint. Rate of change is reported in GWh/GW for batteries, and GW/GW for everything else.

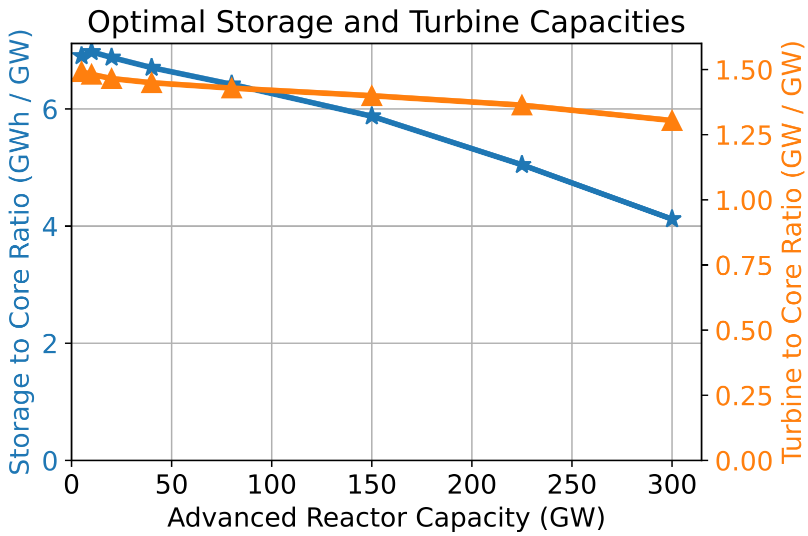

Figure G.14: (Left axis) Optimal amounts of thermal storage construction at varying amounts of thermal core construction. (Right axis) Optimal amounts of turbine construction at varying amounts of thermal core construction.

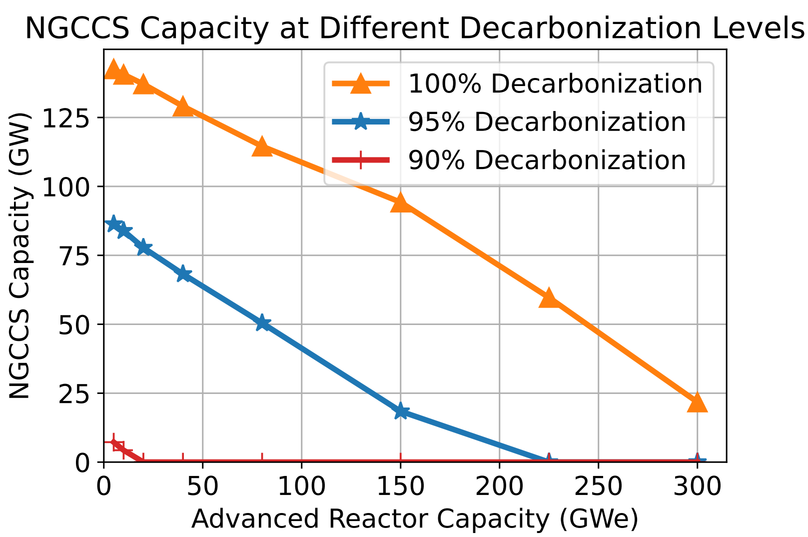

Figure G.15: Total NGCCS capacity at different levels of advanced reactor penetration, under different levels of decarbonization.

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