Microgrid Modeling with Small Modular Reactors

Decarbonizing University Campus Microgrids through Optimal Deployment of Nuclear Power Reactors

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Prepared by

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Scoping Study

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Abstract

This report explores the decarbonization of the University of Illinois Urbana-Champaign (UIUC) campus microgrid through the optimal deployment of Small Modular Reactors (SMRs). The primary objective is to assess the technical and economic feasibility of integrating SMRs, Battery Energy Storage Systems (BESS), and thermal storage into the existing campus microgrid. The study evaluates various scenarios, including the impact of heat storage, carbon tax, SMR ramp rates, installation costs, and preheating and precooling strategies on the microgrid's performance. The findings demonstrate that SMR integration significantly reduces carbon emissions while maintaining a reliable and cost-effective energy supply. Key results show that under high carbon tax scenarios, SMRs can contribute to up to a 63.5% reduction in CO_2 emissions compared to the baseline configuration. The Levelized Cost of Energy (LCOE) analysis suggests that although the initial costs are higher with SMRs, the long-term benefits in terms of decarbonization and energy resilience make them a viable option for the UIUC microgrid. The report concludes with recommendations for future work to enhance the deployment and optimization of advanced nuclear technologies within campus microgrids.

Executive Summary

Historically, the approach to nuclear energy has been to deploy in gigawatt-scale stations to provide baseload power generation for millions of customers. However, newer designs feature an array of sizes including small modular reactors (SMRs) and microreactors, which may be better suited to the needs of the decentralized future smart grids and microgrids. Microgrids aggregate and integrate renewable generation, storage, and flexible loads within a defined electrical boundary. These systems can operate either connected to the grid or in islanded mode. When grid connected, frequency is synchronized to the macrogrid. When islanded, the microgrid ensures stability from controller (microgrid energy management system). The near simultaneous emergence of microgrids and SMRs offers significant potential advantages to future energy systems.

This scoping study develops insight into deploying SMRs and other advanced nuclear technologies to anchor reliable local grids and, in particular, microgrids. This study uses high quality data from operating generators and actual loads served to perform realistic assessments that demonstrate advanced nuclear as an ideal option for current and future energy needs. The campuses of research universities offer an opportunity to demonstrate the viability of the integration of SMR in the grid. Such deployments are ideal for small units with compressed construction and licensing timeframes.

The University of Illinois Urbana-Champaign (UIUC) campus was used as the demonstration site to analyze micro-reactor systems with actual real-time and historical data for the entire campus generation and loads. The UIUC campus microgrid is a uniquely representative model for distributed energy resources in distribution systems and a true microcosm of the macro-grid. It was chosen as the pilot microgrid for this scoping study due to its diverse power generation sources, existing combined heat and power infrastructure, significant variability in electrical and thermal demand, and detailed real-time and historical power utilization data. Of the total electricity and steam energy used on campus, on average 82% is generated at Abbott Power Plant through the burning of coal, natural gas, and fuel oil. Introducing SMR in the generation mix will considerably reduce emissions, moving towards a net-zero carbon footprint for the campus.

The UIUC campus was modelled on the Xendee microgrid platform - a comprehensive planning and decision-making tool, based on mixed integer linearized optimization with capabilities for modeling over twenty-five generation, storage and load management technologies along with financial and utility tariff criteria. The SMR model inherits features of conventional generation technologies such as unit install costs, minimum loading, and ramp rate limits which are important for baseline comparisons. Uniquely, it integrates a component for modeling nuclear reactors as one of its core capabilities with added features for fuel cost every refueling period, decommissioning cost after the SMR lifetime, option for baseload operation of the electricity generators, electricity and heat output trade-offs and cycling limits.

UIUC Microgrid

Currently, UIUC's energy infrastructure is anchored by Abbott Power Plant which is fueled by oil, coal, and natural gas. This Combined Heat and Power (CHP) facility has the primary goal of providing steam for the campus district heating system. Electricity is also generated to improve energy efficiency. The campus electricity portfolio includes substantial contingents of solar and wind. Generally, any gap in electrical demand between CHP and renewables is filled though engagement with the local macrogrid. However, the UIUC campus has demonstrated the ability to operate in islanded mode when necessary, as a true microgrid.

The UIUC campus energy ecosystem averages approximately 55 MW electricity demand and 50 MW steam demand with daily and seasonal fluctuations. In addition to many residence halls, instructional facilities, experimental laboratories, office buildings, and athletics facilities, UIUC also hosted the Blue Waters supercomputer. This facility regularly drew over 10 MW of electrical power and was cooled by a specialized chilled water system. This project includes high quality data, resolved at least hourly, of energy demand of both standard campus buildings and specialized assets like Blue Waters.

UIUC is also uniquely positioned to optimize the deployment of advanced nuclear on campus. Members of the project teams are actively engaged in licensing activities for a next-generation nuclear reactor sited on campus. Importantly, this unit is intended for integration into the existing campus energy ecosystem. The experience gained – and regulatory outcomes achieved thus far – through this project directly impact the study presented here.

Scoping Study

In this scoping study, the existing UIUC campus microgrid, with its state-of-the-art CHP equipment, was successfully replicated within the Xendee modelling framework. Following this, optimizations of various cases with various implementations of a SMR on the UIUC campus were analyzed. When the SMR was installed, it was observed that a CO_2 reduction could be achieved, albeit with a large increase in capital cost compared to incumbent fossil fuel technologies. However, reaching zero CO_2 emissions without nuclear required disproportionately large investment into new solar photovoltaic to become fully independent of the local.

The scoping study discussed below was developed in two phases. In Phase I, a model of the UIUC grid was built in the Xendee platform. This enabled computation of optimal generation mixes and hour-by-hour dispatch from these sources to meet various campus demands. Data input into the model included aggregated campus energy and steam demand as well as generation from coal, natural gas, wind, solar, and regional grid sources. Crucially, the data used to drive the model was taken from a full year of historical UIUC data and included many scales of fluctuations.

Phase II work targeted optimization and refinement of the model demonstration of the ability to efficiently model a wide range of scenarios. Optimal energy dispatch was computed over a year for various scenarios based on objectives that include economics and decarbonization. The scenarios include a baseline case of UIUC campus as it operates today for comparison. Energy portfolios including a range of SMR power ratings were evaluated, ranging from 10MW to sufficiently large to meet the full steam demand.

A significant portion of the motivation of this effort is the idea that decarbonization is continually growing in priority for energy system operators. Along these lines, it is not unreasonable to expect policy interventions to increase the cost of carbon emissions. Therefore, this study also includes investigation of the level of carbon tax that would render nuclear cost competitive with incumbent fossil fuel technologies.

To summarize, the capability for conducting techno-economic analysis in the Xendee platform was demonstrated in Phase I and used to analyze preliminary scenarios representative of decarbonization options for the UIUC campus. In Phase II, more sophisticated scenarios were developed. New features of the model, in particular improved ability to capture thermodynamics effects, were applied to analyze options for integrating of SMR into campus energy mix and operations.

Key Findings

This scoping study established a framework and analytical basis for a campus microgrid with a microreactor.

Among the results of this work, the primary findings reinforce that advanced nuclear is a legitimate option for integrating into campus energy systems with aggressive decarbonization goals. SMRs fill a key gap by providing dispatchable carbon free energy in the form of both electricity and usable heat. The new nuclear paradigm of right-sized reactor for a given application suggests in the near term, commercial nuclear technology may be readily available to achieve this integration. Deploying a reactor in a CHP configuration was found to be an effective method for decarbonizing existing district heating infrastructure. It was also found that scaling to fully carbon-free electricity without nuclear required a massive overbuild of renewable generation.

Since advanced nuclear remains in the demonstration phase, it was expected to be more costly than incumbent fossil fuel technologies over the short term. When the UIUC CHP plant was replaced in a scenario by a 158 MWth/42 MWe SMR with heat storage there was a significant CO_2 reduction of 85%, but a corresponding large cost increase of 587% due to the SMR installation costs. Findings from a scenario where the objective was to have no utility imports, more solar photovoltaic and battery technology was needed to accomplish the goal to drive CO_2 emissions to zero. However, as expected the cost increase was 759.5%. To fully eliminate electrical imports, significant solar is required for when the steam demand is near maximum, but when the steam demand is minimized, there was significant unused electricity as the SMR exports it to the grid.

At the same time, one of the primary benefits of nuclear is its ability to densely produce energy without carbon emissions. The scoping study demonstrated that placing a reasonable value on carbon emissions made nuclear energy directly competitive with incumbent energy sources. Another vector for reducing the cost of a nuclear integration project was to identify methods in which the rating of the reactor could be reduced without sacrificing reliability or resiliency. On-sight thermal energy storage was found to be very effective (charging during low demand/high renewable production; discharge during high demand). This enabled the reactor to be sized against average demand rather than peak demand. In this case, the reactor size reduction was on the order of 20%. Such reduction translates directly to reduced costs. Flexible loads were found to have this positive impact as well. The study found that pre-heating and pre-cooling lead to a tangible reduction in required reactor rating.

The study demonstrated the use of a powerful tool to explore market-driven carbon reduction strategies that are compatible with reasonable deployment vectors for candidate microgrids. Specific applications included the transition of coal to nuclear for microgrids such as UIUC’s, supplementing communities with high renewable penetration, and others which require flexible nuclear operation for reaching zero carbon goals.

Future Work

The effort documented here demonstrated a capability comprised of expertise in nuclear energy and microgrid operations, high quality data, and the Xendee modeling platform that is uniquely positioned to approach integration of advanced nuclear into modern energy systems. These capabilities call upon data sets of load profiles, generation and storage, financial incentives, and emission levels and can be used for scenarios for microgrid planning with advanced nuclear and optimization for economics, decarbonization, resiliency, and other crucial metrics.

The preliminary results reported here represent a solid foundation for future efforts. For example, the developed microgrid model can directly be used to analyze the replacement of coal-fired plants with an SMR without significant disruption and loss of generation capability in generalized settings. In another study, the microgrid model could be used to test the replacement of the fossil fueled plant with multiple small SMRs to ensure resiliency requirements are met.

The modeling and analytics demonstrated can be used for planning the energy transition of the UIUC campus, and others, to a net-zero microgrid over time, as SMR is included in the generation mix with renewables, storage and flexible loads. Further, adding SMR in the microgrid offers opportunity to learn about its capabilities and operational performance interactively as part of a real grid.

The calculations and analytical framework generated from this study are intended to serve as a cross-cutting platform for researching, designing, and optimizing operational strategies for nuclear power as part of aggregated systems of diverse energy sources, applications and users. The platform and methodology are transferable to planning of the deployment of advanced nuclear in the macro-grid.

HIGHLIGHTS

- This project simulated the UIUC campus microgrid including aggregated loads from hundreds of buildings and diverse power generation including coal, natural gas, fuel oil, solar, and wind.
- The study established the feasibility of deploying advanced nuclear reactors on campuses to meet diverse energy needs including both electricity and steam in a combined heat and power configuration.
- Advanced nuclear is a serious option for campuses, and other microgrids, planners to consider to meet decarbonization goals without sacrificing reliability.
- The long lifetimes of nuclear reactors serve to significantly enhance the value proposition of nuclear.
- Sensitivity to uncertain costs of advanced nuclear explored.
- Carbon taxes of reasonable magnitude were found to make advanced nuclear directly competitive with grid energy prices.
- Co-deployed energy storage was found to significantly reduce the required sizing of a nuclear reactor, and commensurately reduce the cost of deployment
- Pre-heating and pre-cooling buildings was further found to reduced required reactor rating.
- This study produced and demonstrated first-of-its-kind ability to model wide ranging scenarios of advanced nuclear reactor deployment on campuses and other microgrids.

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1 Introduction

All aspects of electricity generation, transmission, and distribution are currently undergoing intense innovation cycles. Technology breakthroughs are amplified by increasing public demand to reduce carbon emissions and maintain energy reliability. Renewables are increasingly being deployed both behind the meter and in grid-scale installations. While this is driving a marked decrease on the rate of accumulation of atmospheric carbon, there are potential negative impacts to grid reliability which are not yet resolved. The intermittency of renewables is well-documented and drives a need to overbuild the infrastructure and supplement it with large amounts of energy storage. Additionally, the reliability of the electrical grid has traditionally benefitted from the inertia of spinning turbines which provides time to respond to contingencies.

These challenges can be considerably mitigated through the introduction of carbon-free dispatchable energy sources: nuclear power. Historically, nuclear energy has been generated in gigawatt-scale stations to provide baseload power for millions of customers. However, newer designs feature an array of sizes including Small Modular Reactors (SMRs) and microreactors, which may be better suited to the needs of the decentralized emerging smart grids. The work documented here outlines a study to understand how SMRs can be deployed to anchor reliable local grids, and particularly microgrids. We leverage high quality data from true generators and loads to perform realistic assessments to demonstrate that advanced nuclear is an ideal option for current and future energy needs.

University campus microgrids serve as uniquely capable models of the future of electricity transmission and distribution. The University of Illinois Urbana-Champaign (UIUC) is an unmatched example of campus-level energy innovation combined with a highly instrumented integrated energy framework. This report leverages the convergence of UIUC's rich availability of data with a sector-leading advanced nuclear demonstration project to advance the state of carbon free microgrids.

1.1 Approaching the challenge of decarbonizing microgrids

As the realities of climate change are increasingly apparent, the reduction of carbon dioxide emissions is growing as a priority for energy producers and consumers alike. This is perhaps uniquely salient on a university campus. Many campuses feature centralized energy systems with well-established infrastructure. Often, as is the case with UIUC, district heating is deployed through stream distribution systems that serve many buildings. While these configurations are very energy efficient, especially at meeting heating needs, they present a great deal of inertia. In particular, steam-based district heating systems are difficult to electrify. While modern hot water systems can provide electrified heating, fully replacing an existing steam system is likely to be prohibitively expensive.

At the same time, campuses are motivated to lead charge in decarbonization. The university community is environmentally conscious, and universities are highly visible energy systems. As such, campus leadership is motivated to pledge aggressive carbon reduction. As discussed throughout this report, the convergence of these factors is leading to nuclear energy being investigated with renewed vigor for its ability to supply carbon-free energy resources to campus (and other microgrid) energy systems with minimal disruption to existing distribution infrastructure., transitioning to a net-zero campus and eventually to a zero-carbon campus.

The learnings from this study are transferable and can be adopted to many campuses. The capabilities developed are available to academia, industry, and government to further advance decarbonization goals. Further, these learnings on SMR in microgrids are helpful to the utility industry as it prepares for the integration of advanced nuclear technology in the generation mix of regional grids and markets.

1.2 Unique UIUC environment

The UIUC owns and operates the Abbott Power Plant which provides approximately 75% of the electricity for the campus and 100% of the thermal needs for the steam-driven district heating system that serves over 500 buildings. In several instances, Abbott has demonstrated the ability to operate in islanded mode as a true microgrid. The UIUC energy system is summarized in Figure 1. Energy sources are shown on the left of the figure, alongside actual high-resolution data. Energy users are summarized on the right side of the figure. In addition to the large number of buildings typically expected on a campus, UIUC also hosted a world-leading supercomputer through the end of 2021. The detailed energy use of this facility is also availability include both electricity demand and cooling demand via chilled water.

- Electrical
    - 55 MW_e average demand (Peak 80 MW_e)
    - Blue Waters Supercomputer up to 15 MW_e
    - Wind: ~25,000 MWhr/yr
    - Solar: ~7,200 MWhr/yr (20,000 MWhr/yr new installation)
    - Chillers: ~20 MW_e peak
- Thermal
    - 50 MW_{th} average demand
    - High P steam constant, Low P steam varies with T
    - 6 Chilled water plants (2 steam, 21 electric)
    - Energy storage (6.5 million gallons chilled water)
- Transportation
    - Campus fleet ~ 800 gallons/day
    - Campus bus system: up to 3,400 gallons/day
    - Bus system already investing in 10 new H_2 busses

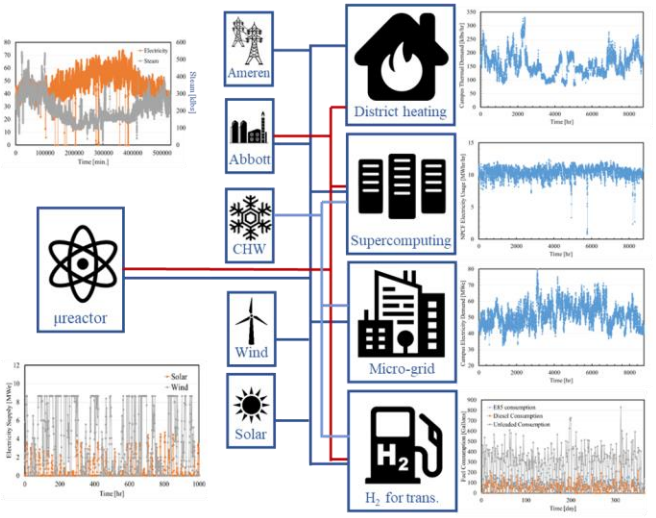

Figure 1: Graphical summary of UIUC microgrid, showing real demand and generation data as well as the role of a potential future integrated advanced nuclear reactor.

1.3 Optimization with Xendee

Xendee is a Microgrid Design and Planning platform based on Mixed Integer Linearized Optimization originating from Department of Energy (DOE) research work over the last 20 years. Xendee efficiently integrates a comprehensive number of economic and technical design factors. The Xendee platform includes components for the cost and performance for most generation and storage technologies (e.g., solar PV, wind, electric storage, CHP, SMR).

The modeling of nuclear reactors was added to Xendee's core capabilities in a DOE funded project with Idaho National Lab (INL). The new SMR model in Xendee inherits features of conventional generation technologies such as unit install costs, minimum loading, and ramp rate limits. These unique features are added:

- fuel cost every refueling period,
- decommissioning cost after the SMR lifetime,
- option for baseload operation of the electricity generators,
- electricity and heat output can be traded off,
- reactor power maneuvering – cycling limits [1].

In this report, the results of the preliminary study on microreactor introduction into the existing UIUC microgrid framework are presented, and opportunities for further work are discussed.

1.4 Synergy with UIUC nuclear initiatives

UIUC is currently aggressively pursuing the licensing, construction, and operation of an advanced micro-nuclear reactor to fulfill a first-of-a-kind mission of demonstrating and performing the critical operations research needed to support the nation's goal of carbon-free resilient energy. In this preliminary study, the UIUC campus with existing fossil-fueled generation was modeled with Xendee's microgrid design software and tested in various hypothetical scenarios involving the introduction of a nuclear microreactor, in some cases with full replacement of fossil fueled generation, with analysis of impacts on economics and carbon reduction. The calculations and framework generated from this study will serve as a cross-cutting platform for researching, designing, and optimizing operational strategies for nuclear power as part of aggregated systems of diverse energy sources, applications, and users. This project also leverages prior work at UIUC toward integrating advanced nuclear reactors into microgrids [2], [3], [4].

1.5 Summary of Progress

In this study, the UIUC campus with existing fossil-fueled generation was modeled with Xendee's microgrid design software and tested in various hypothetical scenarios involving the introduction of a nuclear microreactor, in some cases with full replacement of fossil fueled generation, with analysis of impacts on economics and carbon reduction. The calculations and framework generated from this study will serve as a cross-cutting platform for researching, designing, and optimizing operational strategies for nuclear power as part of aggregated systems of diverse energy sources, applications, and users. The effort documented in this report occurred in two phases. Phase I was executed as a feasibility phase to integrate basic data into the optimization platform and demonstrate the ability to simulate an energy system like that of UIUC.

1.5.1 Phase I

The primary goal of the first phase of this effort was to integrate UIUC into the Xendee microgrid model and demonstrate feasibility of the optimization approach. For this work, both the electricity and steam components of the UIUC energy systems were considered. As discussed in greater detail in Section 2, the UIUC grid consists of a CHP plant, solar farms, wind farms, and a utility connection. The model was also adjusted to include several sizes of SMRs using best available pricing data. The work showed the ability to optimize dispatch on an hourly basis for an entire representative year. The optimal dispatch for a typical July weekday computed in Phase I is shown in Figure 2. In this case, solar and wind renewables are given dispatch priority. For this feasibility phase, a microreactor was also added, typically operating at full power. Figure 3 shows the optimized steam dispatch for the same 24-hour period. This optimization was performed under the constraint that the UIUC energy assets must provide 100% of the campus steam needs at all times. Electricity dispatch then depended on economic factor; hence, the presence of utility-source electricity.

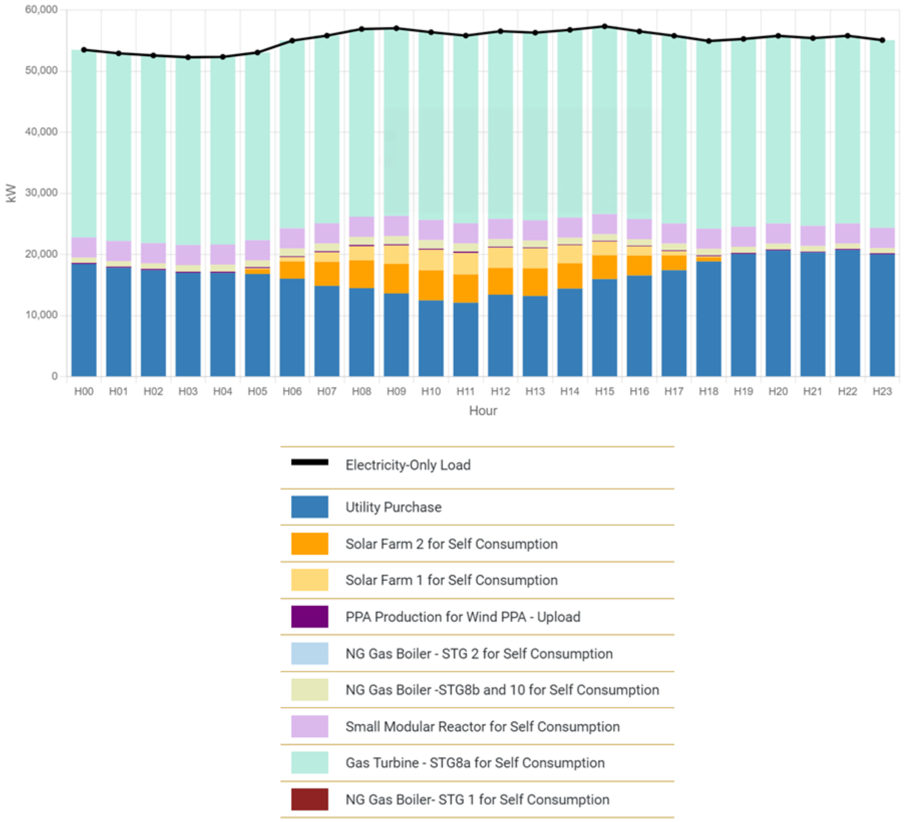

Figure 2: Feasibility phase optimized electricity dispatch for July weekday.

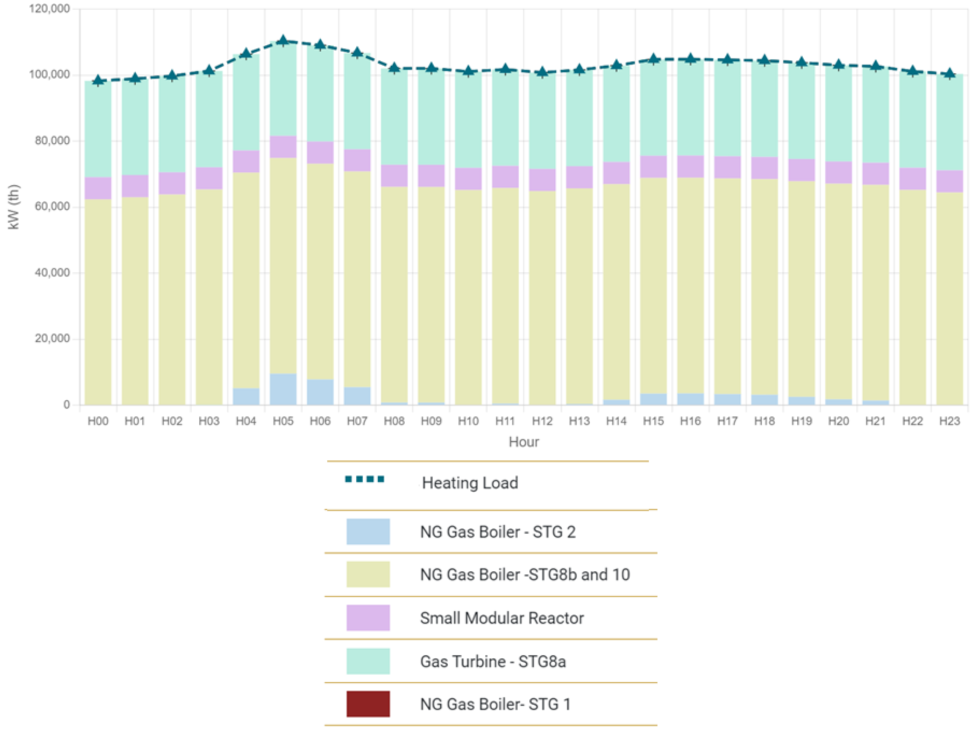

Figure 3: Feasibility phase combined steam energy dispatch for July weekday.

The optimization framework was used to analyze the ability of various energy generation mixes to achieve decarbonization. Here, the “Base Case” was the campus as-is for a representative year. Cases 2 and 3 explored adding SMR to match the required steam demand. Finally, Case 4 was a total decarbonization case in which all remaining electricity needs were filled with solar and battery storage. A key result here is that going from 85% carbon reduction to 100% required a massive buildout of solar such that total capacity of the hypothetical energy portfolio is 3-4 times the actual campus demand. The Phase II effort was focused on continuing to refine these and other deployment analyses.

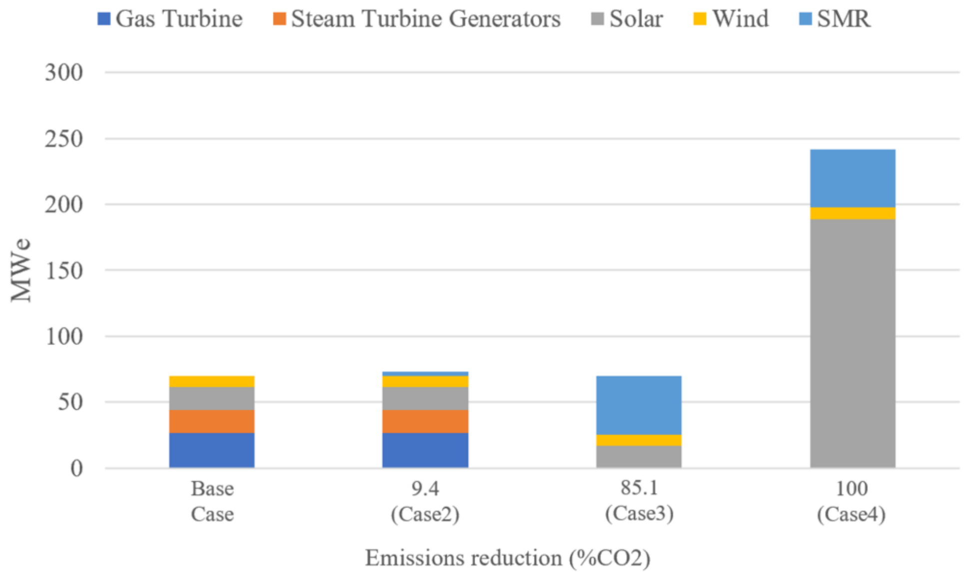

Figure 4: Feasibility phase decarbonization scenarios.

1.5.2 Phase II

The second phase of this project built on the platform developed during Phase I to optimize the deployment of an advanced reactor on a campus microgrid. The explicit goals of Phase II are discussed below.

1.5.2.1 Refining modeling of energy storage

Effective deployment of nuclear power in microgrids is streamlined through co-deployment of energy storage. Both battery and thermal energy storage options are viable depending on the application. Because steam for district heat is a primary energy product, focus was on thermal energy options (e.g., molten salt storage) for the hypothetical UIUC deployment. In a dynamic energy environment, particularly one that include variable renewable energy sources, energy storage enables matching of peak loads without oversizing the nuclear system. Optimizing this aspect of deployment, as is discussed in detail in Section 5.1, can significantly increase the economic viability of SMR integration.

1.5.2.2 Analyze effects of carbon pricing

Many current trends in energy are driven by a desire to reduce emissions of atmospheric carbon dioxide. While there is significant social pressure to take action, economic incentives lag. In particular, there are no centralizing carbon pricing schemes implemented in the US. A common approach for addressing the market externality of climate change is the imposition of carbon tax. In Section 5.2, the effects of such a policy are examined.

1.5.2.3 Refine SMR model implementation

In Section 5.3, the effects SMR characteristics such as operation and cost are examined in the context of optimal deployment. While best-available cost data are used, significant uncertainty will remain until advanced nuclear matures of the current demonstration phase. For references on the range of nuclear costs consider Refs. [5], [6], [7].

1.5.2.4 Extend modeling to multiple buildings

Phase I modeling was restricted to treating the UIUC campus as fully aggregated loads. While fully resolving campus to the building level was beyond the scope of this study, Phase II took steps toward this by separating the demand profiles of several selected buildings. The effects of pre-heating and pre-cooling these buildings are discussed in Section 5.4.

1.5.2.5 Update technoeconomic model

Finally, the collected optimization of the technoeconomic model is given in Section 5.5. This section lays out various scenarios for decarbonizing the UIUC campus through integration of SMRs with renewables. This case study provides an example of how the developed capability can be utilized for campus (and more generalized) microgrid operators to make informed decisions about technology procurement and deployment.

1.6 Layout of Report

The overall layout of the report is as follows. Section 2 describes the UIUC microgrid, including energy services provided and what types of data are available. Section 3 describes the modeling approach taken. Baseline results are given in Section 4. Section 5 details optimization studies undertaken to determine the tradeoffs used to plan for a decarbonized campus. Section 6 summarizes the report. Finally, Section 7 discusses the capabilities developed through this effort and discusses future efforts that have been enabled.

2 Description of UIUC Microgrid

The UIUC energy system provides the model for a campus microgrid to be used in this study. The research team utilized actual historical high temporal-resolution data from both energy generators and energy users to simulate the performance of candidate portfolio mixes over a representative year. As currently deployed, the centerpiece of the UIUC energy system is Abbott Power Plant (APP), which is a campus owned and operated combined heat and power (CHP) plant. APP has a primary directive of fulfilling campus's steam need is fueled by natural gas, coal, and fuel oil. Electricity is additionally provided by on-site solar farms and a real-time wind power purchase agreement (PPA). APP also powers a chilled water system that was used to provide supercomputer cooling and other chilled water needs.

2.1 Description of Generating Equipment

The primary utilities on provided by the campus energy system are electricity and steam for district heat. The UIUC campus requires 150 psi steam (high pressure) and 50 psi steam (low pressure), both of which are cogenerated by several steam turbine generators (STGs) at APP. The STGs generate non-dispatchable electricity as a byproduct of fulfilling the steam demand and can create dispatchable electricity if their remaining capacity is used. This is usually not done unless the utility import prices are high enough to make this mode of operation economically favorable. Additionally, the plant has dispatchable natural gas turbines, usually operated as a baseload source, that creates steam for the turbine generators. Natural gas and coal boilers supplement the steam production as needed.

In addition to 8 STGs, APP includes two Solar Titan 130 natural gas turbines outputting 13,500 kW_e each. STGs 1,2,3,6, and 7 each produce 50 psi steam, while STG 9 produces 150 psi steam. STGs 8 and 10 produce both high and low pressure steam. The performance of this equipment is shown in Table 1.

Table 1: Rated Performance of STGs [8].

Unit	Operation	Throttle Conditions			Extraction		Exhaust		Electric Output (MW)
		Steam (kPPH)	Press (psig)	Temp (°F)	Steam (kPPH)	Press (psig)	Steam (kPPH)	Press (psi)	
STG 1	Max Extract	124	300	625	120	70	4	1.5a	3
	Max Condense	38.8	300	625	-	70	38.8	1.5a	3
STG 2	Max Exhaust	103.2	300	625	-	-	103.2	70.0g	3
STG 3	Max Extract	115	300	700	110	70	5	1.5a	3
	Max Condense	34.2	300	700	-	70	34.2	1.5a	3
STG 6, STG 7	Max Extract	144	850	750	120	70	24	1.5a	7.5
	Max Condense	75	850	750	-	70	75	1.5a	7.5
STG 8, STG 10	Max Extract	136	850	750	100	160	36	50.0g	5
	Max Exhaust	136	850	750	-	160	136	50.0g	7
STG 9	Max Extract	128	850	750	100	160	28	2.0a	5.6
	Max Condense	128	850	750	-	160	128	2.0a	12.5

Fulfillment of the steam demand occurs by using the most efficient equipment first. This means that the high-pressure demand is first fulfilled by STGs 8 and 10, followed by STG 9 in the "Max Extract" mode.

The low-pressure demand is fulfilled first by the cogeneration with high-pressure steam from STG 8 and 10 in "Max Extract" mode, followed by using their remaining capacity for low-pressure steam production only in the "Max Exhaust" mode. Following this, STG 2 is used, and any remaining demand is sent to STGs 1 and 3, then to 6 and 7 if needed. Any extra capacity can be used for dispatchable power production if desired by running in “Max Condense” modes, but this is only done if economically favorable.

Electrical demand is fulfilled first by renewables, then by the natural gas turbines, then by steam generators, and any remaining demand is imported from the utility, Ameren. The UIUC microgrid contains two solar farms and a PPA for wind generation. Solar Farm 1 is a 4,680-kW farm with a 43,585 m^2 install space; the farm has existed for 8 years [9]. Solar Farm 2 is a 12,320-kW farm with a 99,313 m^2 install space; the farm has existed for 1 year and the per unit install cost is $1,631.50/kW [10]. Additionally, wind power generated from 67 1,500 kW_e General Electric GE 1.5sle wind turbines (hub height = 80 m) at the Railsplitter wind farm is purchased using a power purchase agreement for 8.6% of the farm’s output.

Heat recovery steam generators (HRSG) and duct burners in the gas turbines produce steam, along with boilers. Steam production occurs at an assumed 85% efficiency for the HRSGs and duct burners. The HRSGs produce 84 kPPh of 750°F steam, followed by the duct burners producing 116 kPPh. 3 natural gas boilers are used next, with each outputting 140 kPPh of 700°F steam at 81.5% efficiency. If required, 3 coal boilers are used, together outputting 425 kPPh of 760°F steam at 86.3% efficiency. All steam is produced at high pressure but can be put through pressure-reducing valves for those STGs operating on low-pressure steam [8]

2.2 Overall Demand Profiles

The UIUC microgrid’s electrical demand is shown below in Figure 1. From the figure generally the load centers vary between 40 and 60 MW_e. The electrical capacity of Abbott Power Plant at maximum power is about 69 MW_e, so most of the load can be fulfilled by UIUC’s current generational assets. However, significant imports from the local grid supplier still occur as electrical generation from the STGs can be inefficient and not cost effective when compared to the cost of importing electricity. Additionally, there are significant spikes and drops in the demand profile. These can be already difficult to load follow, more so when intermittent renewable generation is introduced. One of the uses of an SMR could be to use the reactor in a baseload configuration (most effective for nuclear assets) with thermal storage, storing energy during the drops to aid in addressing the spikes. In this way, the demand profile can be conditioned to make it easier for downstream components to load follow. It is observed in Figure 5 that the largest electrical demand occurs in the early summer months, with the lowest demand in the winter months. This makes sense, as heating is generally handled by the thermal load, while a heavy summer load is observed due to electricity use by cooling units.

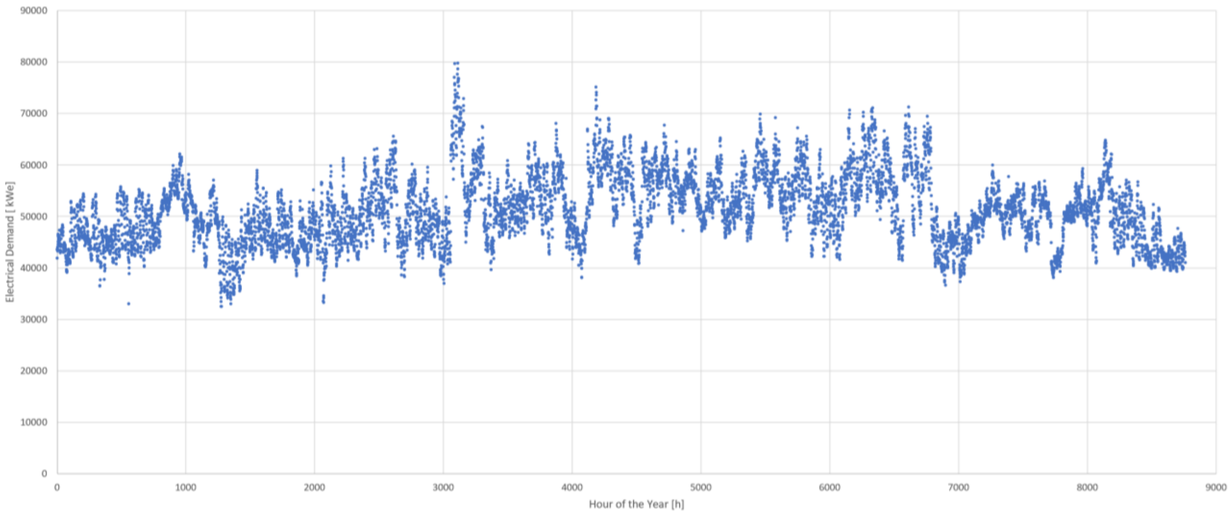

Figure 5: UIUC Electrical Demand Profile.

The UIUC steam load profile is shown in Figure 6. From the data, it can be observed that the high-pressure steam demand remains relatively constant throughout the year. However, the much more demanded low-pressure steam is heavily seasonal, peaking in the winter months and decreasing significantly in the summer months. This is due to the use of steam for heating, meaning that it is heavily demanded in winter and less so in summer. This has the additional effect of increasing Abbott's output in winter due to more cogenerated electricity and decreasing it in the summer months when electricity is generally more in demand. At present, Abbott Power Plant is able to fulfill the steam demand completely and does so on a regular basis.

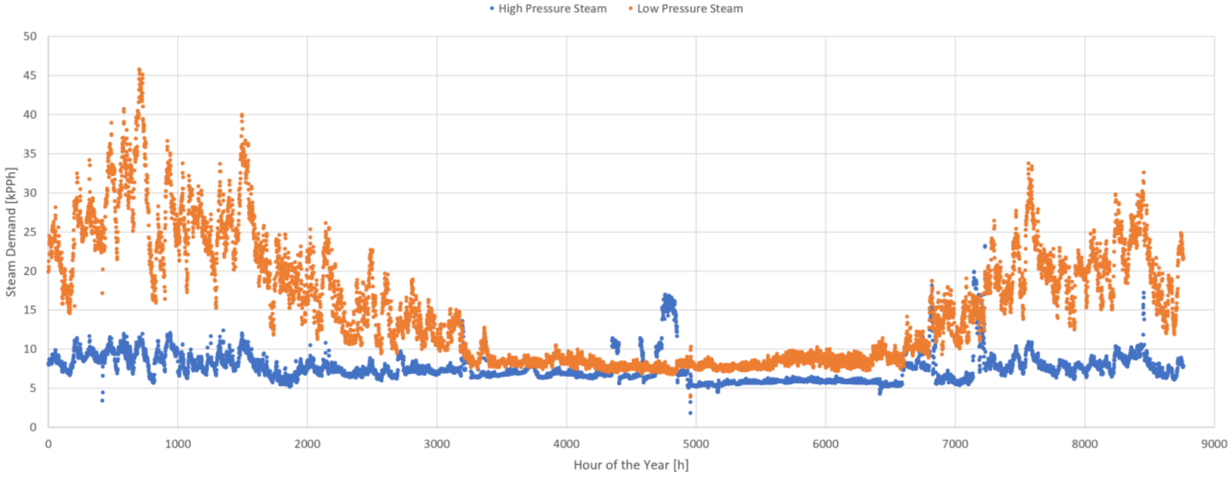

Figure 6: UIUC Steam Demand Profile.

Specific building level data also exists, and samples are presented in Figure 7 - Figure 10. The sample building in Figure 7 has a baseload demand of about 20-25 kW_e but can spike to more than double that. This is in contrast to the buildings in Figure 8 and Figure 9 which show a relatively predictable and periodic electrical demand. In Figure 10, it is observed that the building's electrical demand can drop very quickly and does so on a regular basis; this can complicate load-following measures if the demand changes so quickly. This illustrates the advantage of looking at specific buildings, as opportunities for load shedding of non-critical energy usage can be identified to reduce the imports needed, as the capacity increase to eliminate the last fraction of imports is impractically large, as is shown in later sections of this report. Buildings such as Figure 7 and Figure 10 can be identified as the buildings that cause problems for the load-following operation of the microgrid and storage solutions can be redirected to those buildings to mitigate those issues, rather than addressing the microgrid as a whole.

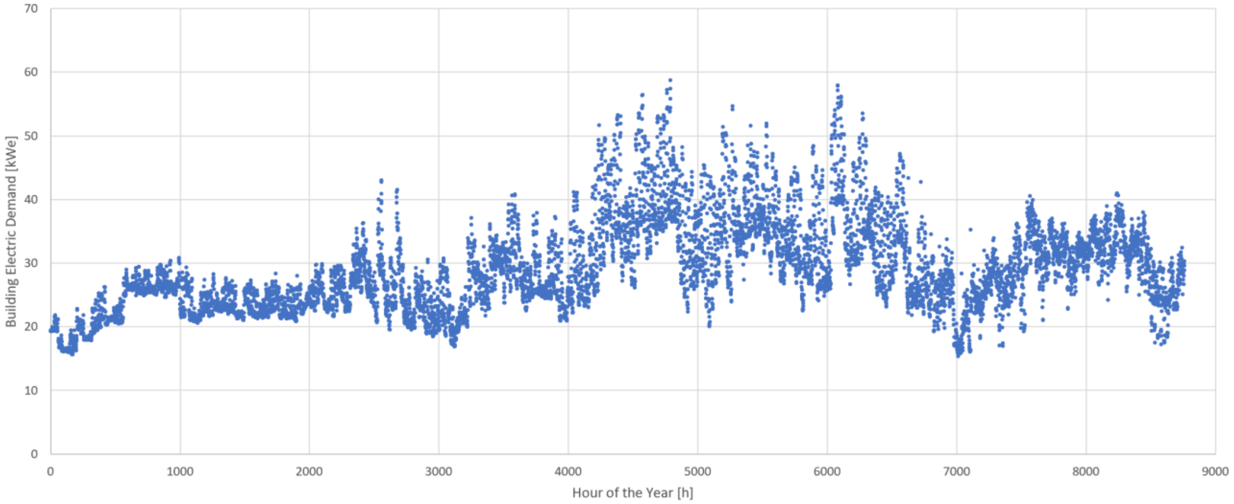

Figure 7: Building Level Electrical Demand Data.

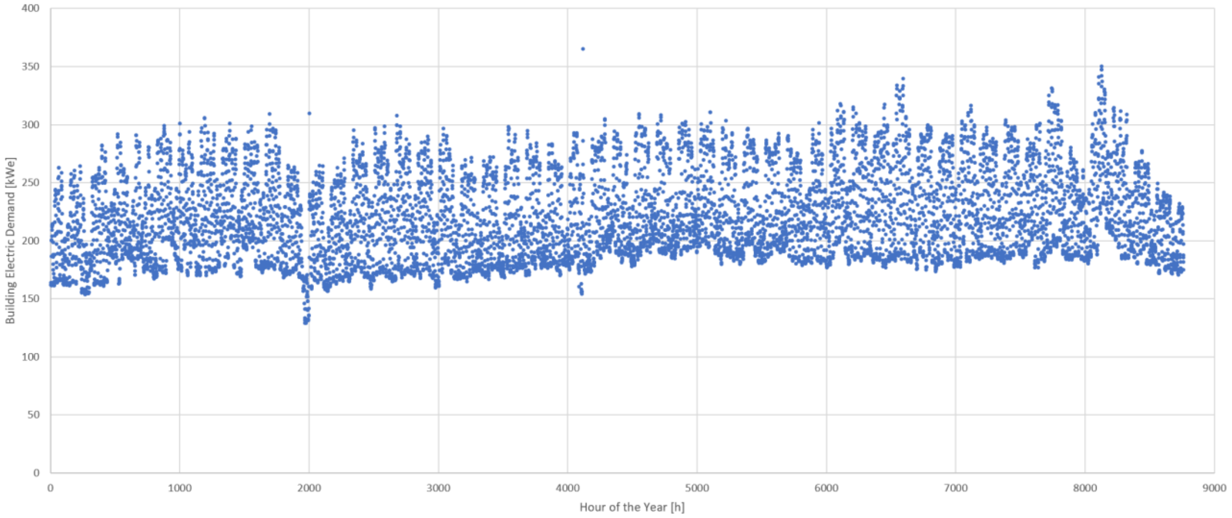

Figure 8: Building Level Electrical Demand Data.

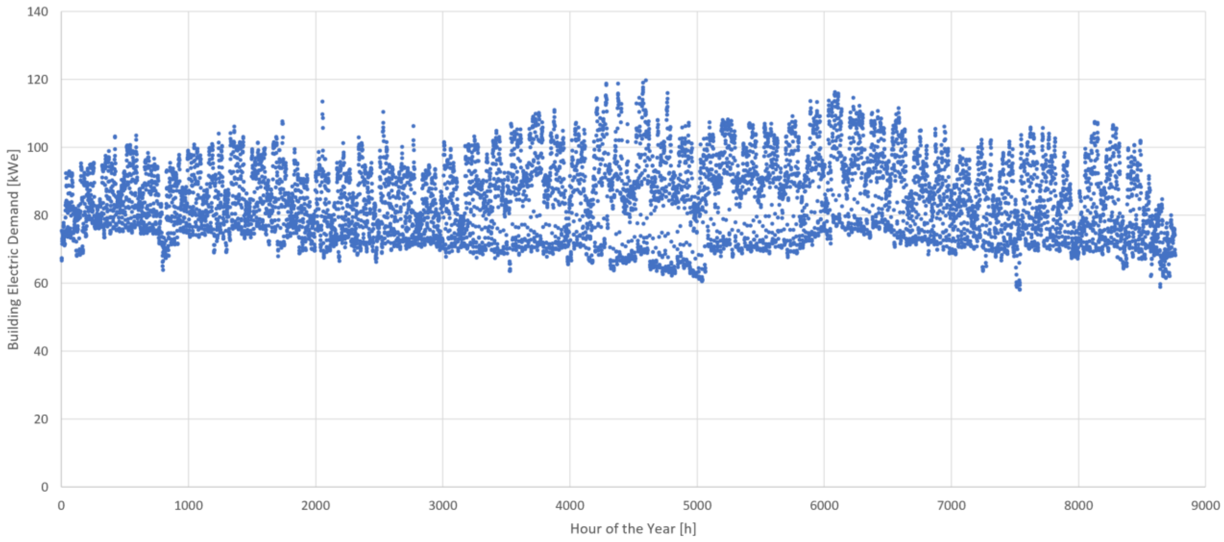

Figure 9: Building Level Electrical Demand Data.

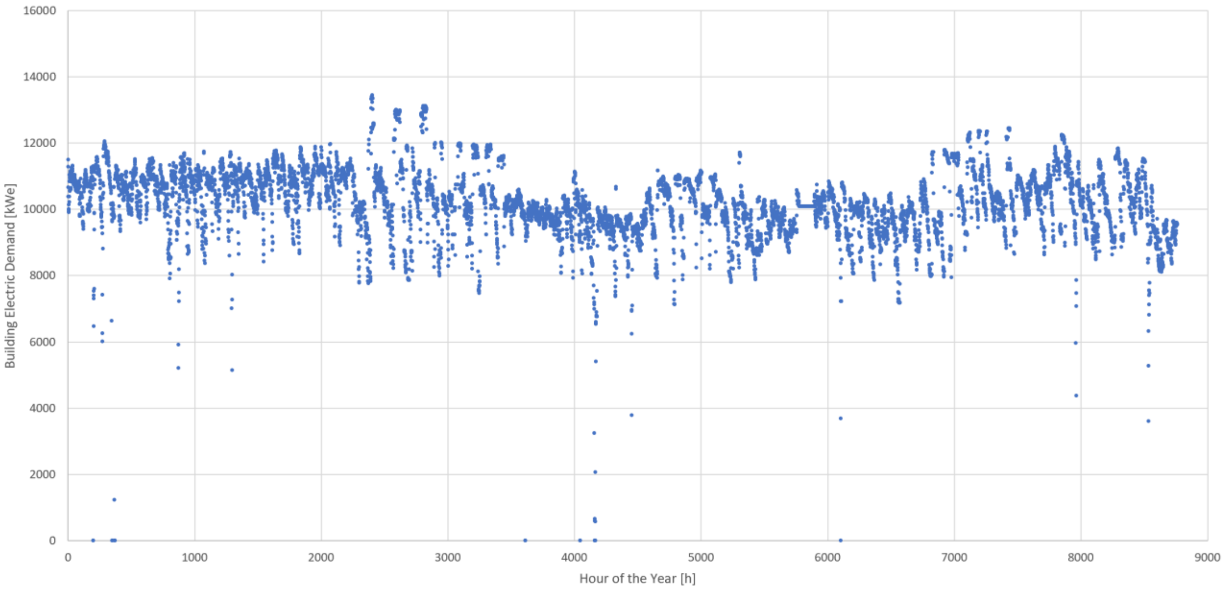

Figure 10: Building Level Electrical Demand Data.

3 Model Development

3.1 Optimization Approach with Xendee

Xendee is a powerful techno-economic analysis tool designed to address complex energy systems challenges by modeling and streamlining intricate technological interactions, particularly with advanced technologies like SMRs and hydrogen systems. It effectively models the complex interactions between various technologies, ensuring seamless integration within the broader energy ecosystem, and facilitating optimized performance and efficiency. The platform excels at optimizing the sizing of energy systems, ensuring that each component is appropriately scaled to meet specific project needs, and enhancing real-time operations by continuously adjusting to changing conditions and demands. This dynamic optimization ensures peak efficiency, minimizing waste and maximizing output.

A flowchart (Figure 11) explains how a Xendee model works and what are inputs required such as existing technologies, utility tariffs, weather profile, and loads. All this data is re-fed into the model by specifying the general conditions which include financing methodology, power systems constraints, and other regulatory measures. Xendee also streamlines the integration of technologies like SMRs with other DERs which itself is complex in nature. Again, all these scenarios are analyzed with Xendee specifying the objective function based on the needs of clients whether a cost minimization is needed reduction of CO_2 emission is a priority. All these inputs are analyzed by Xendee using mathematical optimization to provide optimal technology portfolio, planned operation, and appropriate location.

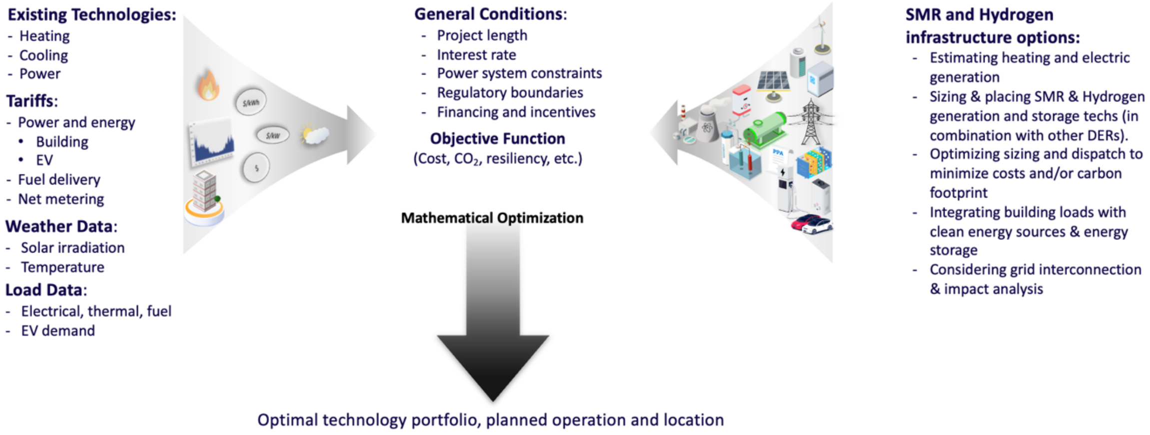

Figure 11: Flowchart illustrating operation of Xendee code.

Additionally, Xendee provides users with the tools needed to make informed technical and financial decisions by delivering comprehensive data and insights. This enables stakeholders to evaluate the feasibility and profitability of different energy solutions, ensuring decisions are both technically sound and financially viable, aligning with both short-term objectives and long-term sustainability goals.

3.2 Model Assumptions

The UIUC grid may operate in connected mode or in islanded mode. In the former case, UIUC interacts with the local grid supplier, Ameren. The STGs are operated based on meeting steam demand. Electricity is derived from renewables and cogenerated through the STGs, but operations are not required to match demand. Any deficit or surplus in electricity is resolved through engagement with the grid. In islanded mode, Abbott is required to match both steam and electricity. As in connected mode, the STGs will meet steam demand. The remaining electricity demand is then met through the operation of other STGs, with excess heat rejected to the ultimate heat sink.

It is assumed that electricity tariffs are the same for either buying or selling electricity in connected mode, but a delivery charge must be accounted for when electricity is supplied to UIUC. This charge is \$0.025/kWh$_e$ in delivery fees when importing electricity, but this fee does not appear in the price of electricity when it is sold to the market. This delivery charge is also imposed on the price of power from the wind power purchase agreement, along with a typical price of \$0.04/kWh$_e$.

Abbott Power Plant is a multifuel plant that can use natural gas, coal, and fuel oil. For this analysis, it is assumed that natural gas is the primary fuel. Based on the regional grid, imported electricity is mainly generated from coal. Since this is a non-negligible emissions contribution, the local grid supplier's emissions mix was used to calculate the CO_2 emissions. A natural gas price of \$2.87/MMBtu was used in this study, obtained from an analysis of historical pricing [11].

To calculate fuel usage, the amount of steam that must be produced from the boilers is first calculated. First, the amount of steam consumed (inlet steam) by every (STG) is calculated. From this total is subtracted the amount produced by the heat recovery steam generators (HRSGs):

$$Boiler\ steam = Steam\ required - 84\ \text{kpph} \tag{1}$$

It is assumed that the 750°F steam that enters each STG has a specific enthalpy of 3180 kJ/kg.

To find the natural gas usage, the fuel usage from running the combustion gas turbines and from running the natural gas boilers/duct burners is calculated. If the boiler steam is below 536 kpph, then the boiler steam is supplied from natural gas only (536 is 116kpph from the duct burners and 3×140kpph natural gas boilers). The equation for Btu/s of natural gas is as follows:

$$Natural\ gas = \frac{\frac{(3180-105)\,\text{kJ}}{\text{kg}}}{1.05506\,\frac{\text{kJ}}{\text{Btu}}} \times \left(\frac{Boiler\ Steam}{0.85}\right) + 12{,}000\,\frac{\text{Btu}}{\text{kWh}} \times Gas\ turbine\ power\ \# \tag{2}$$

Where 0.85 is the assumed efficiency of the natural gas boilers, and the 12,000 Btu/kWh is the heat rate of the two gas turbines and the gas turbine power is 27,000 MW$_e$ when operating as a baseload source [8]. Additionally, it is assumed that for the 150-psi steam outlet, the enthalpy is 2781.9 kJ/kg and the temperature is 366°F, while for the 50 psi steam outlet, the enthalpy is 2743.2 kJ/kg and the temperature is 298°F.

3.3 Abbot Power Plant Model

Steam turbine generators are still under development within Xendee, so the modeling of Abbott Power Plant was done using four natural gas boilers and one gas turbine component. To do this, the operation of Abbott Power Plant was simplified as follows:

First, the assumed steam enthalpies were multiplied by the steam mass flow rates for each STG to obtain steam power in kW$_{th}$. Using the electrical power and outlet steam power, as well as the inlet steam power, the efficiency of each STG could be found in each operating mode. For simplification, it is assumed that STGs with the "Max Condense" mode are not operated in this way since this represents using the STG purely for power production that is highly inefficient and typically not cost effective compared to grid imports. For STG 8 and 10 that operate in two modes, the efficiency is the average of these two modes. These results are presented in Table 2 below.

Table 2: Calculated Efficiencies of STGs in Various Operating Modes.

STG	Operation	Input Steam		Output High Pressure Steam		Output Low Pressure Steam		Total Steam Output	Electricity	Overall Efficiency
		Mass Flow [kPPH]	Power [kW_{th}]	Mass Flow [kPPH]	Power [kW_{th}]	Mass Flow [kPPH]	Power [kW_{th}]	Power [kW_{th}]	Power [kW_e]	
8	Max Extract	136	54492	100	35053	36	12442	47495	5000	96%
	Max Exhaust	136	54492	0	0	136	47003	47003	7000	99%
	Average	136	54492					47249	6000	98%
10	Max Extract	136	54492	100	35053	36	12442	47495	5000	96%
	Max Exhaust	136	54492	0	0	136	47003	47003	7000	99%
	Average	136	54492					47249	6000	98%
9	Max Extract	128	51286	100	35053	0	0	35053	5600	79%
	Max Condense	128	51286	0	0	0	0	0	12500	24%
2	Max Exhaust	103.2	41349	0	0	103.2	35667	35667	3000	94%
1	Max Extract	124	49683	0	0	120	41473	41473	3000	90%
3	Max Extract	115	46077	0	0	110	38017	38017	3000	89%
	Max Condense	34.2	13703	0	0	0	0	0	3000	22%
6	Max Extract	144	57697	0	0	120	41473	41473	7500	85%
	Max Condense	75	30050	0	0	0	0	0	7500	25%
7	Max Extract	144	57697	0	0	120	41473	41473	7500	85%
	Max Condense	75	30050	0	0	0	0	0	7500	25%

Once the efficiency of each STG is found, the Abbott Power Plant historical generation data is analyzed to further simplify the model. It was found that the maximum high pressure steam demand was 184.4 kPPH and the maximum low pressure steam demand was 363.6 kPPH. The high-pressure demand can be fulfilled by STGs 8 and 10, meaning that STG 9 does not feature in the model. Meanwhile, the other low pressure STGs will fulfill the demand after STGs 8 and 10 based on the efficiency of the STG. Furthermore, since the two steam outlet pressures have similar enthalpies, the two separate steam demands can be lumped into one combined steam energy flow demand. To model the Abbott Power Plant, each STG is paired with either a boiler or gas turbines. This creates multiple components outputting both electricity and heat that together reproduce the output of the whole plant. The diagram showing how this split occurs is shown in Figure 12 below.

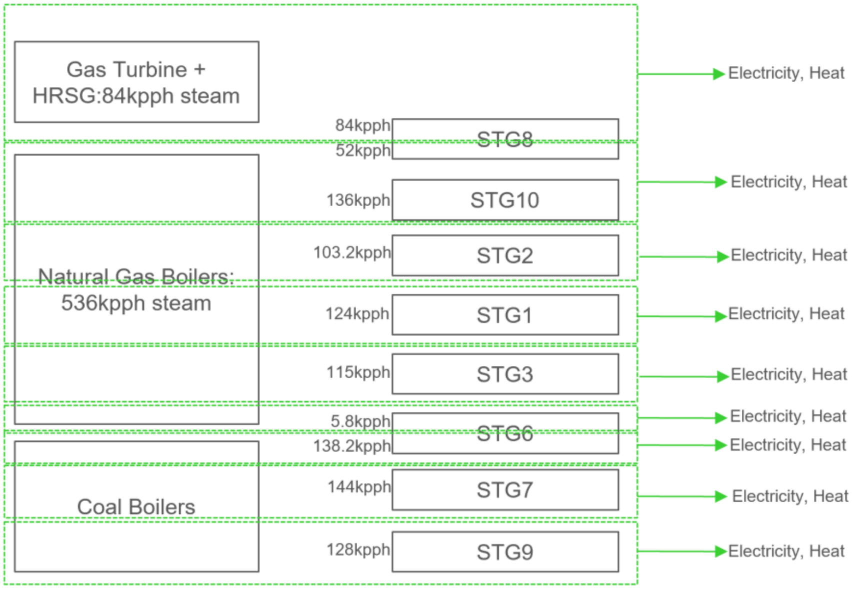

Figure 12: Separation of Abbott Power Plant into components to be implemented within Xendee.

Further analysis of the UIUC microgrid data allows for the elimination of a number of these components. From the analysis of the combined steam energy flow demand and the electricity generation, it is found that the maximum values are 158 MW$_{th}$ and 44.2 MW$_{e}$ respectively. The cumulative output of the components arranged according to efficiency and priority in operation is tallied in Table 3. The determined maximum values serve as a cutoff indicating the bare minimum of components of Abbott Power Plant that can be included. This is done to eliminate the electricity generating STGs, as they are rarely used as discussed above.

Table 3: Cumulative Steam and Electricity Capacity Output from Abbott Power Plant.

Gas Turbine/Boiler - STG		**Input Steam Mass Flow [kPPH]**	**Output Steam Energy Flow Capacity [kW$_{th}$]**	**Cumulative Steam Energy Flow Capacity [MW$_{th}$]**	**Electricity [kW$_{e}$]**	**Cumulative Electricity Capacity [MW$_{e}$]**
Gas Turbine	8a	84	29183	29	30706	30.7
Gas Boiler	8b	52	18066	47	2294	33
Gas Boiler	10	136	47249	94	6000	39
Gas Boiler	2	103.2	35667	130	3000	42
Gas Boiler	1	124	41473	172	3000	45
Gas Boiler	3	115	38017	210	3000	48
Gas Boiler	6a	5.8	1670	211	302	48.3
Coal Boiler	6b	138.2	39803	251	7198	55.5
Coal Boiler	7	144	41473	293	7500	63
Coal Boiler	9	128	35053	328	5600	68.6

From Table 3, it is seen that only STGs 8, 10, 2, and 1 are needed to fulfill the steam energy demand. This also fulfills the maximum plant electrical output, and as such all remaining components can be cut. Thus, the Xendee model excludes STGs 3, 6, 7, 9, and the coal boilers, as shown in Figure 13. Figure 14 also contains the SMR and heat storage technologies that are discussed in the succeeding section.

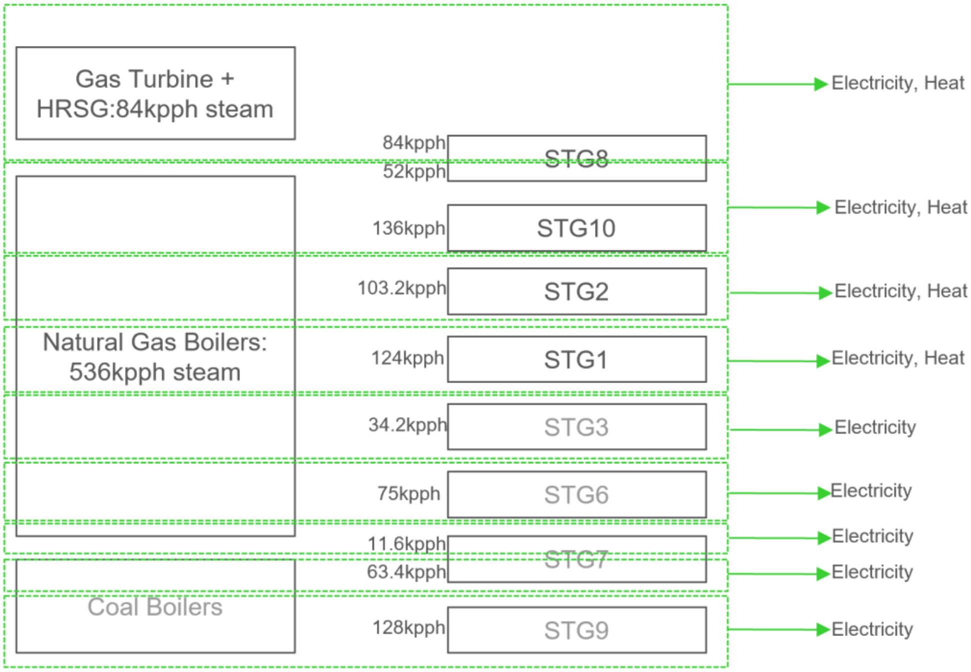

Figure 13: Separation of Abbott Power Plant into components to be implemented within Xendee.

Figure 14: UIUC microgrid model within Xendee modeling platform.

The parameters used for the four components modeling the Abbott Power Plant are provided below in Table 4 and Table 5.

Table 4: Component Efficiencies in Xendee Model.

Gas Turbine/Boiler - STG		**Electrical Efficiency**	**Heat-to-Power Ratio**
Gas Turbine	8a	32.34%	0.950
Gas Boiler	8b	9.36%	7.875
Gas Boiler	10	9.36%	7.875
Gas Boiler	2	6.17%	11.889
Gas Boiler	1	5.13%	13.824

Table 5: Input Parameters for Abbott Power Plant within Xendee.

Parameters	**Value**
Installed Cost ($/kW)	1518
Lifetime (year)	50
Existing age (year)	1
Variable O&M costs ($/kWh)	0.0093
Fixed O&M costs ($/kW)	35.16

For islanded scenarios, Abbott generators 6a, 3 (gas generators), and 6b, 7, 9 (coal generators) were added to the model. These components were not modeled above as they are rarely operated and are not needed to satisfy the heating demand of the campus. However, for islanded scenarios, these generators are needed to satisfy the electrical load. The parameters of these generators are shown in Table 6. Gas turbines 6a and 3 were combined and modeled as a single generator having an output capacity of 3,302 kW_e and 39,687 (7.68% efficiency and 12.02 HPR), while the coal generators 6b, 7, 9 were combined and modeled as a single generator having an output capacity of 20,298 kW_e and 116,329 kW_th (14.86% efficiency and 5.73 HPR).

Table 6: Additional Abbott Power Plant Generators.

Turbine/Boiler - STG		Output Steam Energy Flow Capacity, kW_{th}	Electricity, kW
Gas Boiler	6a	1,670	302
Gas Boiler	3	38,017	3,000
Coal Boiler	6b	39,803	7,198
Coal Boiler	7	41,473	7,500
Coal Boiler	9	35,053	5,600

As shown in Table 7, gas boiler 6a exhibits an electrical efficiency of 15.31% and a heat-to-power ratio of 5.53. This boiler has a lifetime of 50 years and an existing age of 25 years. The installed cost for this unit is $1518 per kW, with variable operations and maintenance (O&M) costs of $0.0093 per kWh and fixed O&M costs of $35.16 per kW. Similarly, Gas Boiler 3 has a lower electrical efficiency of 7.31% and a higher heat-to-power ratio of 12.67, but it shares the same lifetime, existing age, installed cost, and O&M cost parameters as Gas Boiler 6a.

Coal boiler 6b also has an electrical efficiency of 15.31% and a heat-to-power ratio of 5.53, with a lifetime of 50 years and an existing age of 25 years. However, the installed cost for this unit is higher at $2900 per kW. The variable O&M costs for this coal boiler are $0.004 per kWh, with fixed O&M costs of $25 per kW. Coal boiler 7 shares identical efficiency, heat-to-power ratio, lifetime, existing age, installed cost, and O&M costs as Coal boiler 6b. Lastly, Coal Boiler 9 has an electrical efficiency of 13.78% and a heat-to-power ratio of 6.26. This unit also has a lifetime of 50 years and an existing age of 25 years. Like the other coal boilers, its installed cost is $2900 per kW, with variable O&M costs of $0.004 per kWh and fixed O&M costs of $25 per kW. However, all the turbines are modeled to support the electrical needs of the UIUC campus.

Table 7: Abbott Power Plant costs and operating parameters.

Equipment	ID	Electrical Efficiency (%)	Heat to Power Ratio	Lifetime (year)	Existing age (year)	Installed cost ($/kW)	Variable O&M costs ($/kWh)	Fixed O&M costs ($/kW)
Gas Boiler	6a	15.31	5.53	50	25	1518	0.0093	35.16
Gas Boiler	3	7.31	12.67	50	25	1518	0.0093	35.16
Coal Boiler	6b	15.31	5.53	50	25	2900	0.004	25
Coal Boiler	7	15.31	5.53	50	25	2900	0.004	25
Coal Boiler	9	13.78	6.26	50	25	2900	0.004	25

3.4 Advanced Reactor Model

The SMR is modeled considering that it would replace all boilers in the Abbot power plant. All turbines with similar properties are combined, obtaining a simplified three-turbine model. Each turbine is then modeled in Xendee separately. Each turbine has the following operating modes:

- Turbine 1 (steam turbine):
  - Max Extract - Production of 9,220 kW_e and 87,586 kW_{th} from 100,500 kW_{th} (96% efficiency)
  - Max Exhaust – Production of 12,910 kW_e and 86,678 kW_{th} at from 100,500 kW_{th} (99% efficiency)
- Turbine 2 (steam turbine):
  - Max exhaust – Production of 5,961 kW_e and 70,868 kW_{th} from 82,158 kW_{th} (94% efficiency)
- Turbine 3 (gas turbine)
  - Production of 27,000 kW_e and 81,000 kW_{th}

The SMR is modeled in Xendee as three separate generators, each representing a different turbine (Figure 15). The first component, representing Turbine 1 (SMR-STG1), is modeled with a CHP generator average of the two operating modes, thus with a component with a rated size of 11,065 kW_e, an electrical efficiency of 11% and Heat to Power Ratio of 7.87. The second component representing Turbine 2 (SMR-STG2) is modeled with a CHP generator with a rated size of 5,961 kW_e and an electrical efficiency 7.3% and a Heat to Power Ratio of 11.889. The third component representing the gas turbine (SMR3) is modeled with a component with a rated size of 27,000 kW_e and an electrical efficiency of 33%.

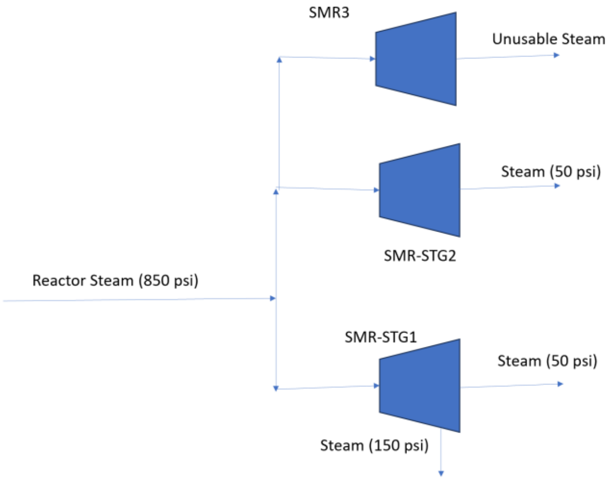

Figure 15: Abbott Power Plant Simplified Model.

In those optimizations where we seek to find the optimal configuration of the SMR, each component is modeled having a rated size of 1,000 kW_e and the corresponding efficiency and Heat to Power Ratio. The resulting optimal number of units of each component will indicate the size of each turbine.

The cost of the SMR under consideration was calculated from [1], which published capital costs of SMR as a function of size, as shown in Table 8. The specific cost per kW_{th} as a function of thermal size is fitted with a power function, and the specific cost at 200 MW_{th} (\$1,749 /kW_{th}) was used as investment cost for the three gas generators.

Table 8: SMR cost as a function of size.

Size - electrical (kW_e)	Investment Cost ($)	Specific Cost ($/$kW_e$)
100	$2,984,713	$29,847
250	$6,044,140	$24,177
500	$10,366,670	$20,733
1,000	$17,836,404	$17,836
5,000	$63,364,985	$12,673
10,000	$109,645,889	$10,965
20,000	$189,956,884	$9,498

The cost of each of the three SMRs and the operating parameters are shown in Table 9. Since the three SMRs are modeled with natural gas generators, the fuel cost per kWh and emissions were set to zero. Natural gas generators in Xendee do not include nuclear refueling costs and plant decommissioning costs, and the respective net present costs at year 0 were added to the investment cost, considering a plant life of 15 years and a refueling period of 5 years. The resulting installation cost considering fuel and decommissioning is \$3,646 /kW_{th}.

Table 9: SMR costs and operating parameters.

Particulars	Values
Per unit install cost ($/kWth)	1,749
Lifetime (years)	15
Variable maintenance cost ($/kWh)	0.003
Annual fixed maintenance cost ($/kW/year)	95
Decommissioning cost ($/kW)	7,500
Front end fuel cost ($)	230,000
Back-end fuel cost ($)	160,000
Refueling period (years)	5
Reactor capacity (kW_e)	1,000
Cycle depth (%)	10
Max cycle	6,000
Minimum load (%)	0
Max annual hours	8,760

3.5 Demand Modeling

Electric/Pre-heating- For selected building types:

Preheating and precooling allow smoothing out the heating and electric loads by shifting part of the heating and electric loads by looking six hours into the future. The microgrid heating and electric loads were modified taking, for every hour, the average load of the previous and following six hours. This approach was done considering two scenarios. In the first one, preheating and precooling can be applied to the whole load; in the second one, it can be applied only to selected buildings. The results of the first scenario aim to show the effect of the maximum theoretical amount of preheating and pre-cooling. An illustration showing the comparison between the total heating load before and after preheating is applied to the total load is shown Figure 16 (for the first week of January 2023).

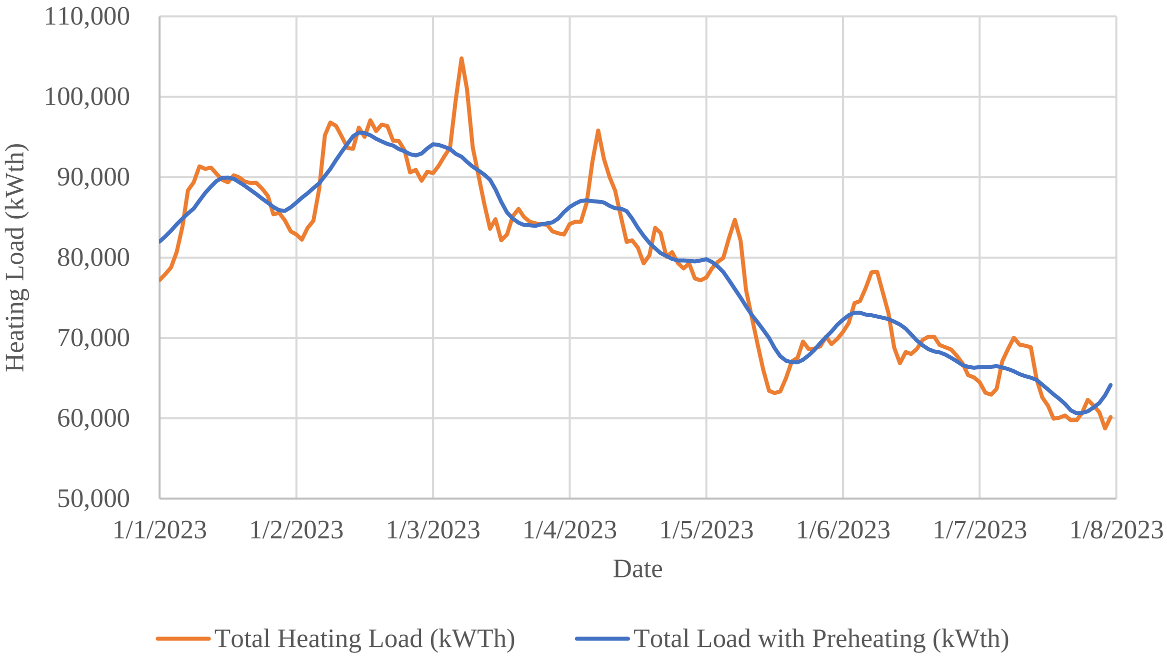

Figure 16: Heating Load with and without Preheating.

4 Baseline Results

The baseline case scenario for the UIUC SMR study involves the continuation of the existing configuration of the Abbott Power Plant, with utility electricity purchases being made as needed. In this scenario, the existing Abbott power plant being used for primarily meeting steam demand is considered, which encompasses the following components:

- Natural Gas Boiler - STG1
- Natural Gas Boiler - STG8b and 10
- Natural Gas Boiler - STG2
- Natural Gas Turbine - STG8a

These components collectively have a nameplate capacity of 39 MW. This baseline scenario is crucial as it establishes a reference point against which future configurations and improvements can be evaluated.

In this scenario, the Abbott Power Plant operates to meet the campus's steam demand, with the boilers and turbines providing the necessary thermal output. The natural gas boilers STG1, STG2, and STG8b and 10, along with the natural gas turbine STG8a, are integral in fulfilling this demand.

The baseline modeling assumptions and results are detailed in Table 10, which provides insights into the plant's performance metrics under the current configuration. This table serves as a foundation for comparing the impacts of introducing new technologies or optimizing existing systems in future scenarios. The table also summarizes the cost projections for years 2025-2040.

Table 10: Baseline results with existing Abbott Power Plant and grid-connection for future.

Parameter	**2025**	**2030**	**2035**	**2040**
Abbott Power Plant	Existing, primarily for steam demand	Existing, primarily for steam demand	Existing, primarily for steam demand	Existing, primarily for steam demand
Utility Electricity Purchase	Yes	Yes	Yes	Yes
Load	Aggregated	Aggregated	Aggregated	Aggregated
Year Projection for Utility and BESS Costs	2025	2030	2035	2040
Natural Gas Cost (cents/therm)	63.8	71.3	77.56	83.81
Average Electricity Price (cents/kWh)	5.083	5.681	6.179	6.678
Annualized Energy Cost (k$)	36,617	40,538	43,796	47,053
LCOE ($/kWh)	0.0364	0.0403	0.0435	0.0467

5 Optimization

In this section, we explore various optimization scenarios to determine the technical and financial viability of SMRs amid rising utility costs, variations in carbon tax, and the availability of financial incentives.

The primary goal of this analysis is to identify the optimal configuration of DERs for the UIUC microgrid. We focus on determining the combination of SMRs, battery energy storage systems (BESS), and heat storage that results in the lowest annual cost under different scenarios, design configurations, and policy environments.

To achieve this, we examine how the adoption of SMRs impacts the site's economics under various conditions. This involves studying the effects of:

The goal of this analysis is to identify the optimal configuration of Distributed Energy Resources (DERs), particularly SMRs, Battery Energy Storage Systems (BESS), and Heat Storage, that results in the lowest annual cost for the UIUC microgrid under different scenarios, design configurations, and policy environments.

Specifically, we aim to understand how the adoption of SMRs would impact the economics of the site under various conditions. This involves studying the effects of:

- **Heat storage**: Evaluating the integration of heat storage solutions to balance thermal loads and enhance the overall efficiency of the microgrid.
- **Carbon tax**: Analyzing the financial implications of different carbon tax rates and how they influence the cost-effectiveness of SMRs compared to traditional power generation methods.
- **SMR ramp rates, lifetime, and installation costs**: Investigating how variations in the operational characteristics and costs of SMRs affect their economic viability and competitiveness.
- **Buildings preheating and precooling:** Assessing the potential benefits of preheating and pre-cooling strategies in smoothing load peaks and reducing operational costs.
- **DERs on decarbonization planning**: Understanding the role of various DER technologies in achieving decarbonization goals and reducing the carbon footprint of the campus.

Additionally, it is crucial to compare the performance of SMRs with the existing Abbott Power Plant. This comparison includes analyzing the reliability and resilience of the microgrid with SMRs, especially in the context of an islanded operation where the microgrid operates independently from the main utility grid. All scenarios in this section assume that the 30% Investment Tax Credit (ITC) will be available for the SMR.

5.1 Impact of Heat Storage

Heat storage plays a crucial role in the operation and optimization of a microgrid, as it allows for the capture and storage of excess thermal energy produced during periods of low demand. This stored heat can be used later during peak demand periods, thereby improving overall cost. This section compares scenarios that include heat storage with scenarios without heat storage. All results assume an SMR lifetime of 15 years, an installation cost of \$4,150/kW$_{th}$., and 30% ITC.

The optimal capacities of DER technologies are shown in Table 11 and reveal significant insights into the impact of varying ramp rates on capacity and Levelized Cost of Energy (LCOE). At higher ramp rates of 1.7%/min and 0.85%/min, the SMR capacities remain consistent at 520 MW_{th} and 77 MW_e, whether heat storage is included. However, the addition of heat storage at these rates reduces the required SMR capacities to 400 MW_{th} and 397 MW_{th} respectively, while maintaining competitive LCOE values of approximately $0.1711/kWh and $0.1709/kWh.

At a lower ramp rate of 0.425%/min, the SMR capacities again are 520 MW_{th} and 77 MW_e, without heat storage, while the addition of heat storage the size of the SMR decreases to 400 MW_{th} (67 MW_e). The BESS capacity sees slight variations depending on the presence of heat storage. Interestingly, the inclusion of heat storage increases the overall storage capacity to 3,200 MWh_{th}, reflecting a strategy for managing peak demand efficiently with a marginally higher LCOE of approximately $0.1714/kWh.

Table 11: Optimal DER Capacity and LCOE with SMR lifetime = 15 years and install cost = $4,150 / kW_{th}.

SMR Ramp Rate (%/min)	Results		
	Capacity/Metric	**Without Heat Storage**	**With Heat Storage**
1.7	SMR (MW_{th})	520	400
	SMR (MW_e)	77	67
	BESS (MWh)	96.6	80.5
	Heat Storage (MWh_{th})	n/a	3,100
	LCOE ($/kWh)	0.2120	0.1711
0.85	SMR (MW_{th})	520	397
	SMR (MW_e)	77	66
	BESS (MWh)	96.6	104.2
	Heat Storage (MWh_{th})	n/a	3,100
	LCOE	0.2120	0.1709
0.425	SMR (MW_{th})	520	400
	SMR (MW_e)	77	67
	BESS (MWh)	96.6	86
	Heat Storage (MWh_{th})	n/a	3,200
	LCOE	0.2120	0.1714
0.001	SMR (MW_{th})	n/a	365
	SMR (MW_e)	n/a	60
	BESS (MWh)	n/a	438.1
	Heat Storage (MWh_{th})	n/a	5,800
	LCOE ($/kWh)	n/a	0.1787

At the lowest ramp rate of 0.001%/min, the analysis with heat storage demonstrates a trade-off between capacity and flexibility, with SMR capacities decreasing to 365 MW_{th} and 60 MW_e. However, the significant deployment of BESS and extensive heat storage, reaching 438.1 MWh and 5,800 MWh$_{th}$ respectively, highlights a strategic emphasis on energy storage and load management. Despite lower SMR capacities, the LCOE remains competitive at $0.1787/kWh, underscoring the viability of this configuration for grid stability and renewable integration. However, with a 0.001% ramp rate and without heat storage the scenario becomes infeasible as the load is changing dynamically and there is no heat curtailment in the SMR model which together makes installation/consideration of heat storage imperative to become feasible.

These results underscore the critical role of ramp rates in optimizing DER configurations, and balancing capacity with operational flexibility and cost-effectiveness. Higher ramp rates support robust SMR performance while lower rates enhance storage capacity, illustrating how strategic planning can align DER investments with long-term energy goals and economic viability.

The crucial role of energy storage in optimizing deployment is further shown in Figure 17. Here the heating load is shown during a winter day with peak heating demand occurring around hour 5. In this figure, the purple and beige bars represent heat provided directly by nuclear, while the brown bar is heat provided by energy storage. The level of energy remaining in storage is shown by the line graph. Without storage, the required reactor rating would be set by the maximum demand at this single time, leading to nuclear capacity that would remain unused throughout most of the year. The co-located storage enabled the nuclear plant to operate essentially at full power with remaining capacity met by storage. This reduced required reactor size by the order of 20% without affecting the ability to meet demand.

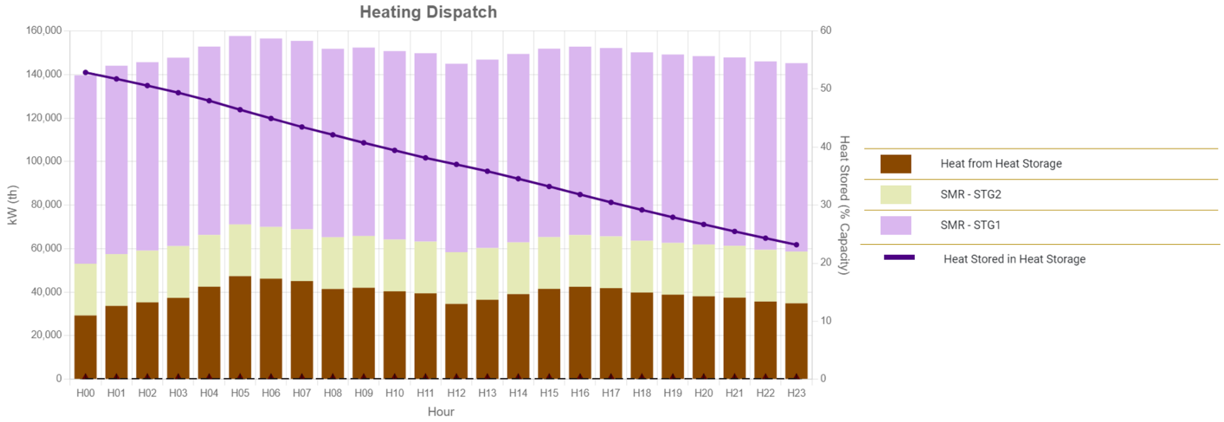

Figure 17: Effects of storage on daily dispatch on a day with peak heating demand.

5.2 Impact of Carbon Tax

Societal pressure to reduce carbon emissions is growing. However, climate change remains a market externality [12]; that is, the energy market does not have a route to price in the negative effects. As the salience of this issue grows, policy interventions grow increasingly likely. One of the candidate approaches for this is a government-imposed tax on carbon emissions in the US.

In this section, we study the impact of a carbon tax with varying values on the optimal microgrid configuration. A carbon tax imposes a fee on the carbon content of fossil fuels, thereby incentivizing reductions in greenhouse gas emissions. By incorporating different carbon tax scenarios, we aim to understand how such policies influence the adoption and configuration of DERs within a microgrid. For this purpose, we examined the following scenarios:

1. **Grid-Connected Microgrid with Both SMR and Abbott Power Plant:** This scenario evaluates a microgrid that remains connected to the utility grid while integrating both an

SMR and the existing Abbott Power Plant. The focus is on understanding how the carbon tax affects the balance between grid electricity, SMR-generated electricity, and the output from the Abbott Power Plant

2. **Grid-isolated, with both SMR and Abbot Power Plant (Abbott producing steam and electricity)**: This scenario explores a microgrid that operates independently of the utility grid, relying solely on SMRs and the Abbott Power Plant for energy production. Here, we examine the impact of a carbon tax on a self-sufficient microgrid configuration. The key considerations include:

By studying these scenarios, we aim to provide a comprehensive analysis of how a carbon tax can influence the strategic deployment of DERs in the UIUC microgrid. This includes identifying the optimal configurations that align with both economic and environmental goals. The insights gained from this analysis will inform policymakers and energy planners on the potential benefits and challenges of implementing a carbon tax in microgrid systems. All results assume an SMR ramp rate of 0.001%/minute and a 30% ITC.

5.2.1 Scenario 1: Grid-connected Microgrid

In the grid-connected scenario, the impact of carbon taxes on the optimal capacities of DERs is evident across the years 2025, 2030, 2035, and 2040 as shown in Table 12 below, highlighting how increased carbon taxes drive the deployment of SMRs and influence energy storage strategies. In 2025, at lower carbon tax levels of \$50 and \$100, there is no deployment of SMRs, Battery Energy Storage Systems (BESS), or heat storage. However, as the carbon tax increases to \$150, SMR deployment begins with a capacity of 2 MW_e, and at \$200, this capacity significantly increases to 34 MW_e. By 2030, the trend continues with no deployment at \$50 and \$100 carbon tax levels, but at \$150, the SMR capacity increases to 8 MW_e, and at \$200, it climbs to 34 MW_e.

In 2035, similar patterns emerge: no deployment at \$50 and \$100, but at \$150, the SMR capacity reaches 10 MW_e, and remains steady at 34 MW_e at \$200. By 2040, the pattern persists, with no deployment at \$50 and \$100, but at \$150, the SMR capacity reaches 13 MW_e, and stabilizes at 34 MW_e at \$200. These results highlight that higher carbon taxes significantly incentivize SMR deployment, with certain tax levels triggering substantial investments. Furthermore, at higher tax levels, the capacities stabilize, indicating a mature energy market ready for stricter carbon regulations. Overall, carbon taxes play a crucial role in shaping the future energy landscape, particularly in the adoption and optimization of SMR technology to enhance grid resilience and reduce carbon emissions.

The analysis of the impact of the carbon tax and projected utility and BESS costs on LCOE and CO_2 reduction from 2025 to 2040 provides valuable insights into the dynamics of energy economics and environmental sustainability as shown in Figure 18 below.

Beginning in 2025, the introduction of carbon taxes at different levels illustrates distinct effects on the LCOE across various scenarios. At a moderate tax rate of \$50/MT, the LCOE remains consistent with reference values, suggesting minimal immediate cost burden on consumers. This stability continues at \$100/MT, where the LCOE also aligns closely with baseline costs. However, as the carbon tax increases to \$150/MT and \$200/MT, the LCOE rises significantly, reaching \$0.0823/kWh and \$0.0916/kWh, respectively, in 2025. This escalation reflects how higher taxes drive up operational costs as utilities factor in compliance expenses associated with carbon emissions.

In 2030, similar patterns emerge with incremental increases in carbon tax leading to corresponding rises in LCOE. At \$50/MT and \$100/MT, the LCOE remains near reference levels, indicating manageable impacts on energy prices. However, at \$150/MT and \$200/MT, the LCOE climbs to \$0.0859/kWh and \$0.0947/kWh, respectively, demonstrating a more pronounced effect on consumer costs as carbon taxes intensify. These higher tax brackets also contribute to meaningful CO_2 reduction percentages, with reductions ranging from 15% to 63.5% compared to the reference scenario.

Table 12: Optimum capacities of the DERs with focus on impact of carbon tax and utility and BESS cost projection.

Year	**Carbon Tax (\$/MTon)**	**Optimum Capacities**			
		SMR (MW_{th})	**SMR (MW_e)**	**BESS (MWh)**	**Heat Storage (MWh_{th})**
2025	50	-	-	-	-
	100	-	-	-	-
	150	6	2	-	-
	200	102	34	-	-
2030	50	-	-	-	-
	100	-	-	-	-
	150	24	8	-	-
	200	102	34	-	-
2035	50	-	-	-	-
	100	-	-	-	-
	150	30	10	-	-
	200	-	34	-	-
2040	50	-	-	-	-
	100	-	-	-	-
	150	39	13	-	-
	200	102	34	-	-

Moving into 2035 and 2040, the trend continues with carbon taxes influencing LCOE and CO_2 reduction outcomes. At \$50/MT and \$100/MT, the LCOE remains stable, reflecting ongoing efforts to balance economic feasibility with environmental objectives. However, at \$150/MT and \$200/MT, the LCOE reaches \$0.0887/kWh and \$0.0973/kWh by 2035, and \$0.0915/kWh and \$0.0998/kWh by 2040, respectively. These figures underscore the increasing financial impact on electricity prices as carbon pricing policies become more stringent. Notably, the higher tax rates in 2040 also lead to significant CO_2 reductions of up to 62%, highlighting the effectiveness of such policies in driving cleaner energy transitions.

Overall, the analysis highlights the critical role of carbon pricing mechanisms in shaping energy market dynamics and environmental outcomes over the next two decades. It underscores the need for balanced policies that promote both economic efficiency and environmental sustainability, ensuring a smooth transition towards a low-carbon future while addressing the challenges of energy affordability and reliability for consumers and industries alike.

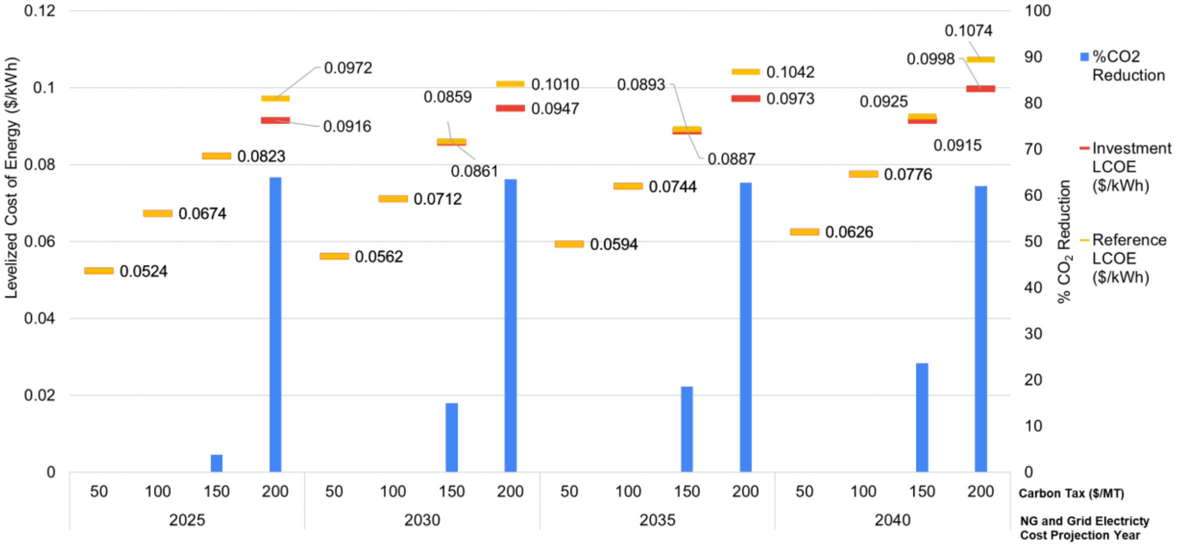

Figure 18: Impact of carbon tax, NG and electricity cost projections, and BESS costs on LCOE and CO$_2$ reduction of the cost optimum DER capacities tabulated in Table 12.

5.2.2 Scenario 2: Islanded Microgrid

As shown in Table 13 below, in 2025, the impact of varying carbon taxes on the optimum capacities of DERs is notable. With a carbon tax of $50, the optimum capacity for SMR is 8 MW$_e$. As the carbon tax increases to $100, the SMR capacity rises to 18 MW$_e$, and there is also an introduction of Battery Energy Storage Systems (BESS) with a capacity of 0.119 MWh. Further increasing the carbon tax to $150 results in an SMR capacity of 23 MW$_e$ and the addition of heat storage with a capacity of 33.3 MWh$_{th}$. At the highest carbon tax of $200, the SMR capacity reaches 26 MW$_e$, and heat storage increases to 50.3 MWh$_{th}$.

By 2030, the trends continue with similar increases in capacity in response to higher carbon taxes. At a carbon tax of $50, the optimum SMR capacity is 9 MW$_e$. With a carbon tax of $100, the SMR capacity increases to 19 MW$_e$, accompanied by 24.8 MWh$_{th}$ of heat storage. When the carbon tax reaches $150, the SMR capacity further increases to 24 MW$_e$, with heat storage reaching 28.5 MWh$_{th}$. At the highest carbon tax of $200, the SMR capacity is 27 MW$_e$, and heat storage significantly increases to 58.4 MWh$_{th}$. In 2035, the pattern of increasing capacities with higher carbon taxes remains consistent. A carbon tax of $50 results in an SMR capacity of 11 MW$_e$. As the carbon tax rises to $100, the SMR capacity increases to 21 MW$_e$. With a carbon tax of $150, the SMR capacity reaches 26 MW$_e$, and heat storage is introduced with a capacity of 33.8 MWh$_{th}$. At the highest carbon tax of $200, the SMR capacity reaches 30 MW$_e$, and heat storage further increases to 72.6 MWh$_{th}$.

By 2040, the optimum capacities reflect continued growth and the introduction of more heat storage at lower carbon tax levels. With a carbon tax of $50, the SMR capacity is 11 MW$_e$, and there is an introduction of heat storage with a capacity of 8.43 MWh$_{th}$. At a carbon tax of $100, the SMR capacity is 20 MW$_e$, and heat storage increases to 18.3 MWh$_{th}$. When the carbon tax reaches \$150, the SMR capacity is 25 MW_e, and heat storage further increases to 35.2 MWh_{th}. At the highest carbon tax of \$200, the SMR capacity is 28 MW_e, and heat storage reaches 53.4 MWh_{th}. These results highlight the significant impact that carbon taxes can have on optimizing the capacities of SMRs, BESS, and heat storage, demonstrating a clear trend of increased capacity with higher carbon taxes over time.

Table 13: Impact of carbon tax and cost projection on optimum capacities of the DERs with lifetime = 15 years.

Year	**Carbon Tax**	**Optimum Capacities**			
		SMR (MW_{th})	**SMR (MW_e)**	**BESS (MWh)**	**Heat Storage (MWh_{th})**
2025	50	24	8	-	-
	100	54	18	0.119	-
	150	69	23	-	33.3
	200	78	26	-	50.3
2030	50	27	9	-	-
	100	57	19	-	24.8
	150	72	24	-	28.5
	200	81	27	-	58.4
2035	50	33	11	-	-
	100	63	21	-	-
	150	78	26	-	33.8
	200	90	30	-	72.6
2040	50	33	11	-	8.43
	100	60	20	-	18.3
	150	75	25	-	35.2
	200	84	28	-	53.4

The analysis of carbon tax impacts on LCOE and CO_2 reduction from 2025 to 2040 as shown in Figure 19 exhibits significant trends. In 2025, a carbon tax starting at \$50/MT results in a 28% CO_2 reduction with an LCOE of \$0.0628/kWh, while increasing the tax to \$200/MT achieves a 60.9% reduction with an LCOE of \$0.0974/kWh. By 2030, these figures improve, with a \$50/MT tax yielding a 31% reduction at \$0.0661/kWh, and a \$200/MT tax reaching a 61.3% reduction at \$0.1006/kWh.

In 2035, a \$50/MT tax results in a 37.8% reduction with an LCOE of \$0.0678/kWh, while a \$200/MT tax achieves a 66.8% reduction at \$0.0977/kWh. By 2040, the CO_2 reduction for a \$50/MT tax is 35.2% with an LCOE of \$0.0725/kWh, and a \$200/MT tax achieves a 62.1% reduction with an LCOE of \$0.1048/kWh.

These results highlight the strong correlation between higher carbon taxes and increased CO_2 reductions, although they also lead to higher electricity costs. This underscores the need to balance environmental goals with economic considerations in future energy policies.

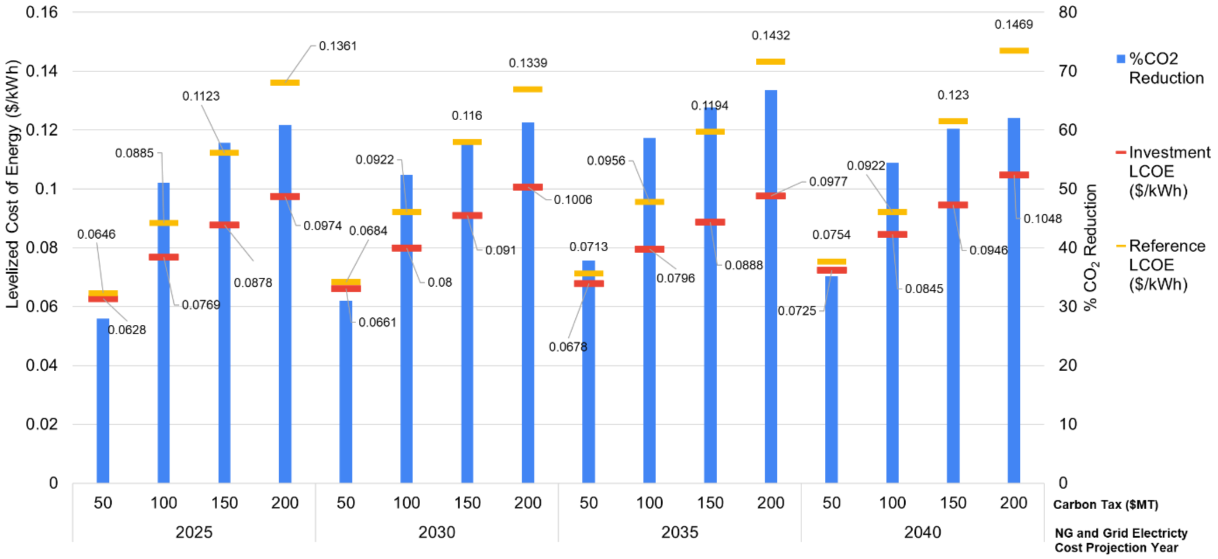

Figure 19: Impact of carbon tax, NG and electricity cost projections and BESS costs on LCOE and CO_2 reduction of the optimum DER capacities tabulated in Table 13.

5.3 Impact of SMR Ramp Rates, Lifetime, And Install Cost

In this section, we study the impact of SMR ramp rates on the optimal microgrid configuration. Ramp rate refers to the speed at which an SMR can adjust its power output in response to changes in demand. An SMR with a higher ramp rate can quickly respond to load changes, which allows for more flexible operation of the microgrid. This flexibility can reduce the need for large heat storage capacities, as the SMR can handle load fluctuations more efficiently. For this purpose, we examined the same scenarios analyzed in the previous section, as well as an additional scenario:

1. Grid-connected microgrid, with both SMR and Abbott Power Plant
2. Grid-islanded, with both SMR and Abbot Power Plant (Abbott producing steam and electricity)
3. Grid-connected microgrid, with SMR for steam only and no Abbott Power Plant

The focus of the third scenario is on understanding the economic and operational impacts of relying exclusively on SMRs for steam, while electricity is sourced from the grid and other renewable sources. All results assume a 30% ITC for the SMR.

5.3.1 Scenario 1: Grid-connected Microgrid

The analysis of the provided data highlights the significant impacts of carbon tax, utility costs, natural gas and electricity rates, and SMR installation costs and lifetime on the economic feasibility of SMRs.

Table 14: Impact of SMR cost, lifetime, and ramp rates and NG and electricity cost projections on optimum capacities of the DERs (Scenario 1).

Cost projection (Year)	**Ramp Rate (%/min)**	**Lifetime (Year)**	**Install Cost ($/kW$_{th}$)**	**Optimum Capacities**			
				SMR (MW$_{th}$)	**SMR (MW$_e$)**	**BESS (MWh)**	**Heat Storage (MWh$_{th}$)**
2030	0.001	15	1,209	-	-	-	-
			2,660	-	-	-	-
			4,150	-	-	-	-
			4,836	-	-	-	-
		60	1,209	-	-	-	-
			2,660	-	-	-	-
			4,150	-	-	-	-
			4,836	-	-	-	-
2040	1.7	60	1,209	169	33	-	-

Table 14 above presents insights into the optimal capacities of DERs, focusing on SMR and battery energy storage systems (BESS), influenced by ramp rate, lifetime, installation costs, and rising utility cost projections over the years. In 2030, scenarios with a low ramp rate of 0.001% and lifetimes of 15 and 60 years show no specific investments made in SMR, BESS, or heat storage capacities. This underscores the uncertainty and need for further evaluation under these conditions. Looking forward to 2040, a higher ramp rate of 1.7% and a 60-year SMR lifetime reveal specific thermal and electric capacities, yet BESS and heat storage remain unspecified, indicating ongoing challenges in optimizing energy storage solutions. The results highlight the significant impact of SMR costs, operational lifetimes, and ramp rates on DER feasibility, emphasizing the complexities in balancing economic viability and technological advancements amidst projected increases in utility costs.

5.3.2 Scenario 2: Islanded Microgrid

The impact of SMR cost, lifetime, and ramp rate on the optimum capacities of DERs without a carbon tax reveals notable trends. For the year 2030, at a ramp rate of 0.001% and a 15-year lifetime, no investments were made across various installation costs, except for an installation cost of $2,660, $4,150, and $4,836 per kW$_{th}$, where heat storage capacities reached 26.9 MWh$_{th}$.

For a 60-year lifetime and a ramp rate of 0.001%, the optimal capacities include 10 MW$_e$ and 12.7 MWh$_{th}$ for an install cost of $1,209/kW$_{th}$, 5 MW$_e$ and 7.4 MWh$_{th}$ for $2,660/kW$_{th}$, and 3 MW$_e$ and 14.1 MWh$_{th}$ for $4,150/kW$_{th}$. No investments were made at an install cost of $4,836/kW$_{th}$.

For a ramp rate of 1.7% and a 60-year lifetime in 2030, the optimum capacities include 10 MW$_e$ at an install cost of $1,209/kW$_{th}$, and 3 MW$_e$ with 14.1 MWh$_{th}$ at an install cost of $4,150/kW$_{th}$. These results emphasize the influence of ramp rate and SMR cost on DER capacities, with higher costs generally resulting in lower capacities, particularly when the ramp rate is low, and the lifetime is extended. However, the installation of heat storage was only an attractive investment in certain scenarios this is because of the dynamic nature of the load, coupled with a ramp rate of

0.001%, may not have been sufficient to cope with demand fluctuations, rendering SMRs as neither economically nor technically feasible in many cases.

In the year 2030 as shown in Table 16, the impact of SMR cost, lifetime, and ramp rate on the optimum capacities of DERs with a carbon tax of \$200/MTon reveals significant variations. For a ramp rate of 0.001% and a 15-year lifetime, an installation cost of \$4,150/kW$_{th}$ results in an optimum capacity of 27 MW$_{e}$ for the SMR, with 58.4 MWh$_{th}$ of heat storage, but no investments in thermal or battery energy storage. When the ramp rate increases to 1.7% with the same 15-year lifetime and installation cost, the SMR capacity remains at 27 MW$_{e}$, but the heat storage capacity reduces to 31.3 MWh$_{th}$.

For a longer SMR lifetime of 60 years and varying installation costs, the optimum capacities change significantly. At an installation cost of \$1,209/kW$_{th}$, the SMR capacity increases to 268 MW$_{th}$ (52 MW$_{e}$), with 55.3 MWh$_{th}$ of heat storage. With an installation cost of \$4,150/kW$_{th}$, the SMR capacity is slightly lower at 222 MW$_{th}$ (46 MW$_{e}$) with no heat storage. At a high installation cost of \$6,666/kW$_{th}$, the SMR capacity drops to 28 MW$_{e}$, with a further reduced heat storage capacity of 19.4 MW$_{th}$.

Table 15: Impact of SMR cost, lifetime, and ramp rates on optimum capacities of the DERs (Scenario 2 for the year 2030 with no carbon tax).

Cost projection	Ramp Rate (%/min)	Lifetime (Years)	Install Cost (\$/kWth)	Optimum Capacities				LCOE (\$/kWh)
				SMR (MW$_{th}$)	SMR (MW$_{e}$)	BESS (MWh)	Heat Storage (MWh$_{th}$)	
2030	0.001	15	1,209	-	-	-	-	0.0445
			2,660	-	-	-	26.9	0.0445
			4,150	-	-	-	26.9	0.0445
			4,836	-	-	-	26.9	0.0445
		60	1,209	30	10	-	12.7	0.0431
			2,660	15	5	-	7.4	0.0439
			4,150	9	3	-	14.1	0.0445
			4,836	-	-	-	-	0.0445
2030	1.7	60	1,209	30	10	-	-	0.0431
			4,150	9	3	-	14.1	0.0445

These results indicate that both the cost and lifetime of SMRs, along with the ramp rate, play crucial roles in determining the optimal configuration of DERs. Higher installation costs and shorter lifetimes tend to limit the capacities of both SMR and heat storage, whereas longer lifetimes and lower costs support greater capacities, highlighting the trade-offs between investment costs and operational efficiencies.

Table 16: Impact of SMR cost, lifetime, and ramp rates on optimum capacities of the DERs (Scenario 2 for the year 2030 with $200/MTon carbon tax).

Cost projection	Ramp Rate (%/min)	Carbon Tax ($/MTon)	Lifetime (Years)	Install Cost ($/kW$_{th}$)	Optimum Capacities				LCOE ($/kWh)
					SMR (MW$_{th}$)	SMR (MW$_e$)	BESS (MWh)	Heat Storage (MWh$_{th}$)	
2030	0.001	200	15	4,150	81	27	-	58.4	0.1006
2030	1.7	200	15	4,150	81	27	-	31.3	0.0996
2030	1.7	200	60	1,209	268	52	-	55.3	0.0573
2030	1.7	200	60	4,150	222	46	-	-	0.0757
2030	1.7	200	60	6,666	84	28	-	19.4	0.0979

5.3.3 Scenario 3: Grid-connected Microgrid without Abbott Power Plant

As shown in Table 17 below, in 2030, with a very low ramp rate of 0.001% and an SMR lifetime of 15 years, the impact of installation costs on the optimum capacities of DERs is notable. When the installation cost is $1,209/kW$_{th}$, the thermal capacity (SMR MW$_{th}$) is 238, the electric capacity (SMR MW$_e$) is 13, and the heat storage capacity is 3,100 MWh$_{th}$. When the installation cost increases to $2,660/kW$_{th}$, these capacities remain unchanged. However, at a higher installation cost of $4,150/kW$_{th}$, the thermal capacity slightly decreases to 229 MW$_{th}$, the electric capacity drops to 12 MW$_e$, and the heat storage capacity increases to 4,400 MWh$_{th}$.

With an SMR lifetime of 60 years, the impact of installation costs on the optimum capacities of DERs is significant. At an installation cost of $1,209/kW$_{th}$, the thermal capacity is 238 MW$_{th}$, the electric capacity is 13 MW$_e$, and the heat storage capacity is 3,600 MWh$_{th}$. When the installation cost increases to $2,660/kW$_{th}$, the SMR capacities remain unchanged, while the heat storage capacity decreases to 3100 MWh$_{th}$. However, with an installation cost of $4,150/kW$_{th}$, the SME thermal capacity increases to 246 MW$_{th}$, the electric capacity remains at 13 MW$_e$, and the heat storage capacity decreases to 2,200 MWh$_{th}$. At the highest observed installation cost of $4,836/kW$_{th}$, the thermal capacity significantly increases to 520 MW$_{th}$, the electric capacity rises to 77 MW$_e$, and the heat storage capacity adjusts to 2,500 MWh$_{th}$.

In 2030, the analysis under a consistent ramp rate of 0.001% highlights the significant influence of equipment lifespan and associated costs on Levelized Cost of Electricity (LCOE). SMR install cost varying from $1,209/kW$_{th}$ to $4,836/kW$_{th}$ results in LCOE values spanning from $0.0626/kWh to $0.157/kWh, compared to a baseline LCOE of $0.0403/kWh as shown in Figure 20 below. This variation underscores how longer equipment lifespans can lead to lower operational costs over time, as initial investments are spread across more years of service.

Additionally, the corresponding CO_2 reduction percentages, ranging from 27% to 39.6%, illustrate the direct correlation between operational efficiency and environmental sustainability objectives. Higher efficiency in energy production and utilization translates directly into greater reductions in carbon emissions, aligning with global efforts to mitigate climate change.

Table 17: Impact of SMR cost, lifetime, and ramp rates and NG and electricity cost projections on optimum capacities of the DERs (Scenario 3).

Cost projection	Ramp Rate (%/min)	Lifetime (year)	Install Cost ($/kW$_{th}$)	Optimum Capacities			
				SMR (MW$_{th}$)	SMR (MW$_{e}$)	BESS (MWh)	Heat Storage (MWh$_{th}$)
2030	0.001	15	1,209	238	13	-	3,100
			2,660	238	13	-	3,100
			4,150	229	12	-	4,400
		60	1,209	238	13	-	3,600
			2,660	238	13	-	3,100
			4,150	246	13	-	2,200
			4,836	520	77	-	2,500
2040	1.7	15	4,150	238	13	-	3,100

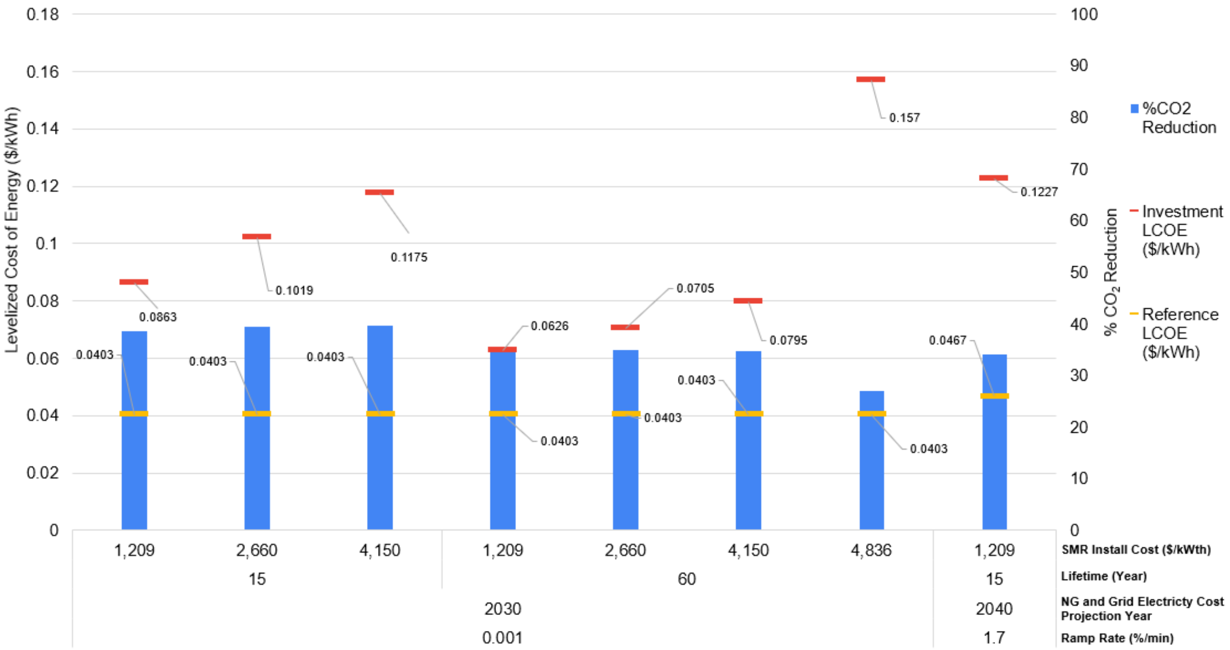

Figure 20: Impact of SMR costs, lifetime, and ramp rates and NG and electricity cost projections on LCOE and CO_2 reduction of the optimum DER capacities tabulated in Table 17 (Scenario 3).

5.4 Impact of Preheating and Precooling

In this section, we aim to analyze the impact of preheating and pre-cooling on campus buildings. These strategies involve flattening the load by pre-cooling and preheating buildings when the electric and heating loads are low, thereby smoothing load peaks. We analyze the results for the following scenarios:

1. No preheating and precooling
2. Preheating and precooling on selected buildings
3. Preheating and precooling on the whole campus

The load is modified to account for preheating and precooling according to the methodology explained in Section 3.5. We assume that the SMR has a ramp rate of 0.001%, an installation cost of \$4,150/kW$_{th}$, a 15-year lifetime, and a 30% ITC. The 2025 cost projections for utility and fuel costs are used. It is important to note that the results presented in this section are suboptimal, i.e. Xendee didn’t find an optimal solution within the maximum runtime (40 hours).

In the "No Preheating" scenario, the optimal configuration includes an SMR with a thermal capacity of 366 MW$_{th}$ and an electric capacity of 60 MW$_{e}$ as shown in Table 18. This setup also necessitates a battery energy storage system (BESS) capacity of 458 MWh and a significant heat storage capacity of 5,800 MWh$_{th}$. This configuration reflects the need for high thermal capacity and substantial storage to efficiently manage a consistent, aggregated load without additional preheating requirements.

Conversely, in the "Preheating/Precooling on Selected Buildings" scenario, the optimal capacities shift to accommodate the thermal demands of preheating. The SMR's thermal capacity is increased to 385 MW$_{th}$, while the electric capacity slightly increases to 62 MW$_{e}$. The BESS capacity slightly decreases to 426 MWh, and the heat storage capacity decreases to 3,700 MWh$_{th}$. This adjustment indicates that the system requires a lower heat storage and battery capacities to handle fluctuations in the load.

In the "Preheating/Precooling on Aggregated Load" scenario, the optimal capacities of the SMR and the Heat Storage are almost the same as in the “Preheating/Precooling on Selected Buildings” scenario, while the capacity of the BESS decreases to 421 MWh, since the system requires a lower BESS capacity to handle fluctuations in the load.

Table 18: Impact of SMR cost, ramp rate and preheating scenario on optimum DER capacities.

Cost projection	**Ramp Rate (%/min)**	**Scenario**	**Lifetime (Years)**	**Install Cost (\$/kW$_{th}$)**	**Optimum Capacities**			
					SMR (MW$_{th}$)	**SMR (MW$_{e}$)**	**BESS (MWh)**	**Heat Storage (MWh$_{th}$)**
2025	0.001	No Preheating/ Precooling	15	4,150	366	60	458	5,800
2025	0.001	Preheating/ Precooling on Selected Buildings	15	4,150	385	62	426	3,700
2025	0.001	Preheating/ Precooling on Aggregated Load	15	4,150	382	61	421	4,100

In the three cases above the carbon (CO_2) reduction is almost 100% as the steam and electricity demand is fulfilled by SMRs and storage technologies. Moreover, the LCOE is almost the same around $0.1772/kWh.

5.5 Decarbonization Scenarios

In the context of microgrid planning, it is crucial to assess the impact of various DER technologies on decarbonization goals. For this purpose, as shown in Figure 21 and Figure 22, a baseline scenario was considered where the total steam and a portion of the electricity demand are supplied the by Abbott Power Plant (APP), while the remaining electricity demand is met by utility grid, wind PPA, and solar PV. The baseline case is then compared to three cases:

A. An SMR producing electricity and steam is added to the mix with the Abbott Power Plant, in a **grid-connected** condition
B. SMR replaces the Abbott Power Plant, in a **grid-connected** condition
C. SMR replaces the Abbott Power Plant and produces electricity and steam, and its size is optimized in a **grid-islanded** condition
D. SMR replaces the Abbott Power Plant and produces steam with electricity as a byproduct with additional PV providing additional electricity, in a **grid-islanded** condition

For Case A, an investment in an SMR with an electric output of 23 MW_e (69 MW_th of thermal capacity) is made and provides a total emission reduction of 40%. In Case B, the Abbott Power Plant is replaced by an SMR with an electric output of 44 MW_e (263 MW_th of thermal capacity), which allows a carbon reduction of 79%. Islanded cases without the Abbott power plant (Cases C and D) allow the campus to be carbon-free (100% emission reductions). To achieve this, the two options are: C) investing in an SMR with a 66 MW_e electric output (286 MW_th of thermal capacity) or D) investing in an SMR with a 40 MWe electric output (208 MWth of thermal capacity) and 183 MW_e of PV (which, together with existing 17 MW_e, results in a total of 200 MWe).

Comparing Case B to Case C, it is important to note that an additional investment in an SMR of 22 MWe (23 MW_th) allows the campus to be grid independent, retire the Abbott Plant, and be carbon-free.

Note that all these cases include investments in heat storage and battery, which are not represented in the charts below.

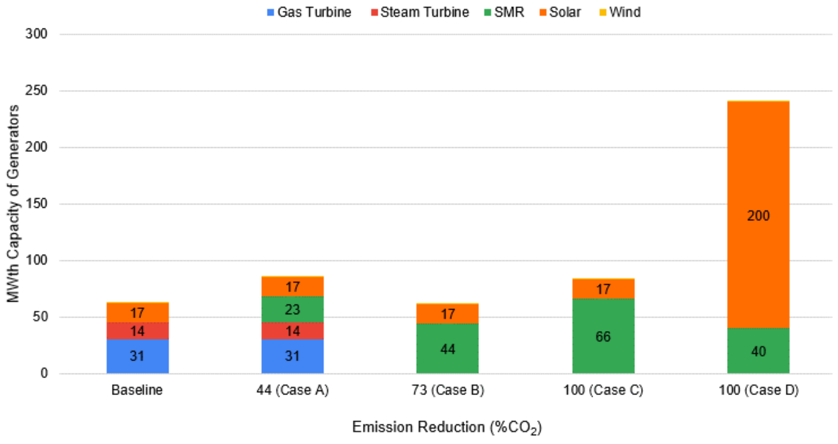

Figure 21: Decarbonization scenarios of UIUC campus considering various cases with and with utility grid, APP, and additional PV investment (thermal capacity of generators)

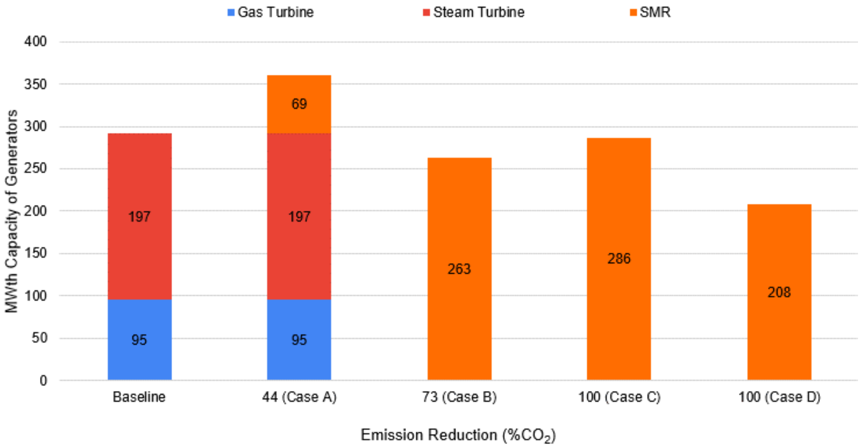

Figure 22: Decarbonization scenarios of UIUC campus considering various cases with and with utility grid, APP, and additional PV investment (thermal capacity of generators)

6 Conclusions

The work documented in this report was aimed at realistically exploring pathways for integrating advanced nuclear technologies into microgrids. The efforts were based on a foundation built by integrating actual energy system data from the UIUC campus into the Xendee microgrid modeling platform. The work progressed in two phases. Phase I demonstrated the ability to integrate the data set and model the UIUC campus with its array of energy sources and loads. Phase II demonstrated the ability to integrate an advanced reactor technology into a campus portfolio to meet energy demands in an environment where decarbonization is prioritized. The UIUC campus was chosen as the case study due to the availability of high-quality data, the diversity of energy sources, the diversity of energy uses including electricity and steam, and the leading edge research on campus aimed at commercialization of advanced nuclear.

The UIUC campus consists of hundreds of buildings with unique electricity, steam, and chilled water demand. Buildings include residence halls, athletics facilities, supercomputing facilities, office space, classrooms, and many other types. Demand data is available for all of these buildings at high temporal resolution. Existing campus generation includes owned fossil fuel power plant as well as significant solar and wind-based renewables. In this work, a full year of hourly resolved data, both generation and demand, was integrated into the Xendee modeling platform to model the entire campus. This model was used to evaluate the ability of advanced nuclear technologies to meet the needs of all energy streams while integrated into the vibrant energy ecosystem. Initially, the campus load was aggregated into a single load.

During the feasibility phase the optimal energy dispatch was computed over a year for various scenarios based on decarbonization. The scenarios included a baseline case of UIUC campus as it operates today. Additionally explored were cases of SMRs being integrated at additional levels. Deploying a reactor in a CHP configuration was found to be an effective method for decarbonizing existing district heating infrastructure. It was also found that scaling to fully carbon-free electricity without nuclear required a massive overbuild of renewable generation.

Phase II work targeted optimization and refinement of the model. Since advanced nuclear remains in the demonstration phase, it is expected to be more expensive than incumbent fossil fuel technologies over the short term. Therefore, a primary vector for reducing the cost of a nuclear integration project is to identify methods in which the rating of the reactor can be reduced without sacrificing reliability or resiliency. In an era of variable renewable energy resources and reasonably predictable demand, on-sight energy storage is shown to be very effective. In this case, energy storage is charged during low demand/high renewable production, then discharged during high demand. This enables the reactor to be sized against average demand rather than peak demand. As energy systems continually grow ‘smarter’ the ability to exploit flexible loads also grows. This study also found that pre-heating and pre-cooling lead to a tangible reduction in required reactor rating.

A significant portion of the motivation of this effort is the idea that decarbonization is continually growing in priority for energy system operators. Along these lines, it is not unreasonable to expect policy interventions to increase the cost of carbon emissions. Therefore, this study also includes investigation of the level of carbon tax that would render nuclear cost competitive.

Key findings include:

1. **Decarbonization Potential**: The integration of SMRs, especially when combined with energy storage systems like Battery Energy Storage Systems (BESS) and thermal storage, significantly reduces carbon emissions. In scenarios with high carbon taxes, SMRs contribute to up to 63.5% reduction in CO_2 emissions compared to the baseline configuration
2. **Economic Viability**: The Levelized Cost of Energy (LCOE) analysis indicates that while initial costs are higher with the introduction of SMRs, the long-term benefits of reduced fuel costs, lower maintenance, and enhanced sustainability outweigh these initial expenditures. The financial analysis also highlights the importance of incentives like the Investment Tax Credit in improving the economic feasibility of SMRs
3. **System Resilience**: SMRs provide a reliable, dispatchable power source that can operate independently of the grid, enhancing the resilience of the campus microgrid. This capability is crucial in scenarios where grid reliability is compromised due to extreme weather events or other disruptions
4. **Optimization of Energy Mix**: The study shows that a carefully optimized mix of SMRs, BESS, and other renewable energy sources can meet the campus's energy demand effectively while minimizing costs and emissions. The scenarios modeled demonstrate the importance of strategic planning and investment in diverse energy technologies to achieve optimal results.

7 Capabilities and Future Work

The effort documented here demonstrated a capability comprised of expertise in nuclear energy and microgrid operations, high quality data, and the Xendee modeling platform that is uniquely positioned to approach integration of advanced nuclear into modern energy systems. These capabilities call upon data sets of load profiles, generation and storage, financial incentives, and emission levels and can be used for scenarios for microgrid planning with advanced nuclear and optimization for economics, decarbonization, resiliency, and other crucial metrics.

The focus of this work was analysis of a university campus energy system. When considering that, from the perspective of this analysis, a campus can be considered as a collection of energy users tied to a collection of energy generators subject to organization constraints, the concept of an ‘energy campus’ extends to many applications. The approaches developed here directly scale to other universities, national laboratories, hospitals, data centers, supercomputers, and essentially any modern microgrid. During the course of this project capabilities were developed that bring breadth and depth to the methodology and analytical tools were developed that advance capabilities for the modeling and analysis of microgrids, especially as regards the integration of new technologies, e.g., SMR. These capabilities range from datasets for load profiles for all facilities, multiple generations sources, including most significantly advanced nuclear, optimization and a platform for scenario development. These represent a step advancement of capability.

This capability can be expanded by applying scaling techniques to the available data to increase applicability. For example, consider classifying UIUC loads as aggregated residence halls, athletic facilities, instructional facilities, experimental laboratories, and infrastructure. Further consider incorporating climate models (e.g., heating degree days versus district heat steam) and the range of applicability of the existing dataset expands dramatically when integrated with stochastic modeling.

7.1 Deployment Optimization

Recent trends have shown that interest in deploying nuclear power for localized applications is growing steadily. However, questions remain about the optimal deployment of nuclear. For one example, consider that one reactor sized to the full demand may require very large independent backups to meet demand during refueling or maintenance outages. Instead, a larger number of smaller reactors may provide acceptable redundancy and reduce the cost of reliability. For another example, consider that co-located energy storage (thermal, batter, or other) provides small reactors with short term peaking ability. When properly sized, this deployment choice may significantly reduce the total size of reactor need, and therefore reduce the cost.

The capability developed through this study is directly usable for follow on work to establish optimized, and decarbonized, microgrids with a previously unavailable focus on realistic deployment of advanced nuclear designs.

7.2 Planning Fossil-to-Nuclear Transition without Disruption

Although advanced nuclear technologies are being designed to be constructed much faster and cheaper than prior nuclear megaprojects, they are still anticipated to have nontrivial licensing, construction, and commissioning phases. Coupled with the sizable investment required, many entities interested in transitioning to nuclear will be faced with the task of when to make crucial decisions regarding securing financing, procuring hardware, building infrastructure, and others. The capability developed through the study can be directly used to game out procurement pathways to realize a nuclear-powered campus with a finite budget and, perhaps more importantly, without causing any disruptions to critical energy services.

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