Utah State University

Decarbonization Master Plan

November 9, 2022

WILLDAN

Engineering & Planning | Energy Efficiency | Sustainability

Prepared by:

Willdan Energy Solutions

2401 E. Katella Avenue,
Suite 300
Anaheim, CA 92806

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1. Executive Summary

1.1 Purpose

The purpose of this report is to document and compare the different decarbonization pathways for the Utah State University (USU) Central Energy Plant (CEP) on the Logan campus. There are many potential solutions to this complex problem. This report describes a number of "least regret" decarbonization measures that the campus can begin to adopt today while continuing to gather the key information needed to implement the best strategy among the solutions.

This report and roadmap identify the most feasible and cost-effective solutions, which are better described as paths or pathways because they are a series of interventions which take different routes, yet all start with the existing state of the CEP and end with a future decarbonized state of the CEP.

This roadmap provides the flexibility to jump from one path to another in the early years of implementation, prior to 2026. This flexibility allows for the roadmap to adapt to market forces, new information, and technological developments.

1.2 Solutions

Four solutions, or pathways, were identified during this study and are documented in this report. Each path represents a series of operational changes, energy system retrofit projects, or energy source procurement changes, which together achieve decarbonization of the CEP.

1.2.1 Path #1

Path #1 achieves decarbonization solely through procuring decarbonized energy sources to feed the CEP's existing mechanical equipment. These sources of decarbonized energy would come in two forms:

GHG *Renewable natural gas (RNG) to feed the CEP's natural gas-powered equipment*	GHG *"Clean" electricity from renewable sources to drive the CEP's electric equipment*

This solution would not include any retrofit projects at the CEP or campus buildings. Additionally, the existing cogeneration system would continue operating, fully loaded throughout the entire year.

1.2.2 Path #2

Path #2 achieves decarbonization through a combination of:

GHG *Procuring decarbonized energy sources, as in Path #1*	+	*Deep HVAC energy efficiency projects*	*Domestic hot water (DHW) electrification across all the campus buildings.*

This solution would not include any major retrofit projects at the CEP buildings. The existing cogeneration system would not operate after 2040.

1.2.3 Path #3

Path #3 achieves decarbonization through a combination of:

- *Procuring decarbonized energy sources, as in Path #1*
- *Deep HVAC energy efficiency projects, as in Path #2*
- *DHW electrification, as in Path #2*

+

Significant electrification of the campus HVAC heating systems

This solution would include significant retrofit of both the CEP and building-level systems. The existing cogeneration system would not operate after 2040.

1.2.4 Path #4

Path #4 achieves decarbonization through a combination of:

- *Procuring decarbonized energy sources, as in Path #1*
- *Deep HVAC energy efficiency projects, as in Path #2*
- *DHW electrification, as in Path #2*
- *Significant electrification of the campus HVAC heating systems, as in Path #3*

+

Installation of on-site PV solar

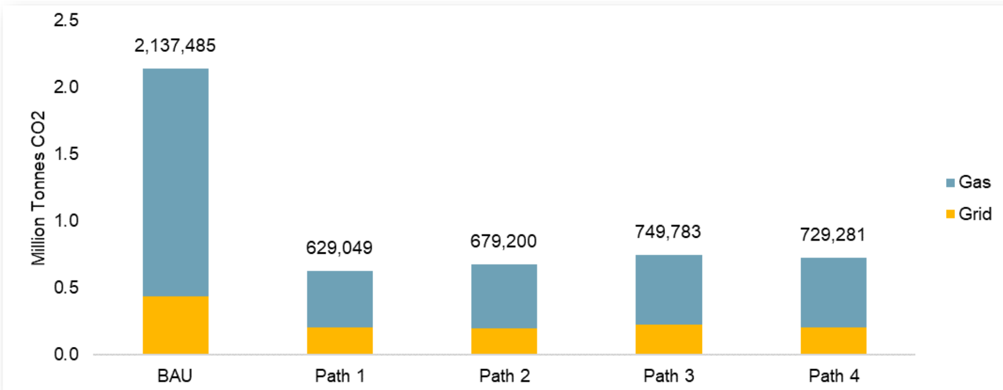
This solution would include significant expansion and retrofit at the CEP buildings. The existing cogeneration system would not operate after 2040.

1.3 Results

The results of these paths are best compared based on the lifecycle emissions reductions, and related cost impacts alongside the business-as-usual (BAU) scenario.

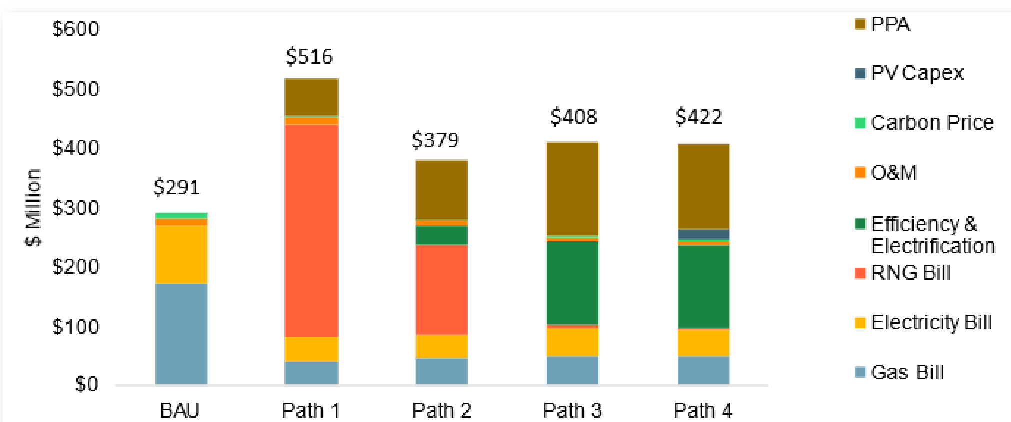
Depending on the pathway ultimately taken, the lifetime (~40 year period, 2022-2060) campus emissions are dramatically reduced by 1.4 to 1.5 million metric tons (MT) of CO_2 from the current campus trajectory. Path #1 has the lowest lifetime emissions, and Path #3 has the highest lifetime emissions, but they are all consistent with campus decarbonization targets. This comparison is shown in **Figure 1**.

Figure 1 - Comparison of Lifetime Campus Emissions for All Paths



The lifetime (~40 year period, 2022-2060) campus costs for all paths increase from the current campus trajectory. This increase ranges from $88 million (Path #2) to $225 million (Path #1). There is a substantial difference in relative lifetime costs between Path #1 and the other three paths, as shown in **Figure 2** below. It should be noted that the largest cost component of Paths #1 and #2 is tied to the price of RNG, which represents a significant source of risk. Costs as presented are adjusted for inflation but not discounted for net present value.

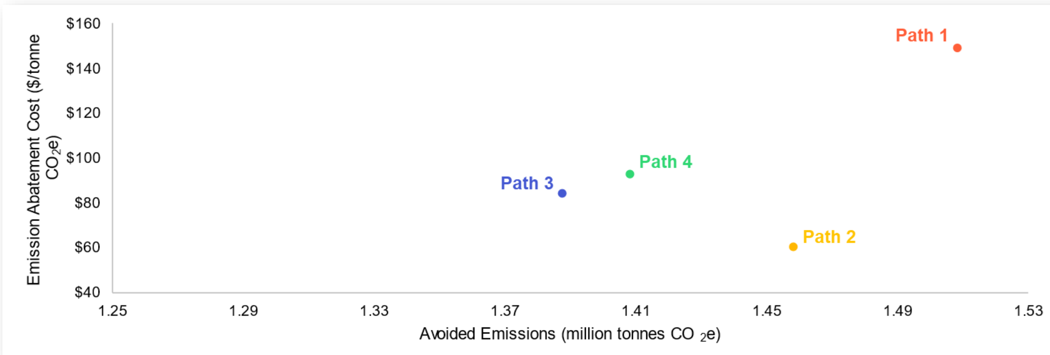
Figure 2 - Comparison of Lifetime Campus Costs for All Paths



Campus costs can also be assessed in conjunction with the associated reduction in lifetime emissions by comparing the emissions abatement costs of each path. **Figure 3** displays these abatement costs for each path relative to the business-as-usual. Avoided emissions for each path are very similar. Path #2 provides the lowest cost per unit of abatement, though again with a high degree of uncertainty due to reliance on RNG availability and pricing. Paths #3 and #4 are the next lowest cost, at approximately $84 and $93 per avoided metric ton of emissions.

Carbon abatement costs can be either compared with recommended carbon prices or the societal cost of carbon. The former is recommended by the International Monetary Fund to have a price floor of $75 by 2030,[1] while climate economists typically assess social costs of carbon to be in the $100-$200 range.[2]

Figure 3 - Emissions Abatement Costs by Path



Net present values for carbon accounting are shown in Section 8.2 of this report.

1.4 Recommendations

1.4.5 Renewable Natural Gas

Both the viability and costs of successful decarbonization through Paths #1 and #2 depend heavily on the future renewable natural gas market. The renewable natural gas market is specifically referred to as a future marketplace in this document; although renewable natural gas is available today, it is both expensive and in very limited supply, unlike more traditional energy commodities.

The fact that the RNG market does not exist at current day (2022) is reflected by the fact that RNG is not a traded commodity and neither prices nor volumes are forecasted by the U.S. Energy Information Administration (EIA). This lack of an existing RNG market creates uncertainty, which in turn translates back into scarcity and pricing volatility for the foreseeable future.

As a result, Paths #3 and #4, which both nearly eliminate the CEP's dependence on RNG, provide lower risk and greater confidence in hitting the 2040 decarbonization target than Paths #1 and #2. Each of these

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[1] *Proposal for an International Carbon Price Floor Among Large Emitters*, Ian Parry, Simon Black, James Roaf, Staff Climate Notes, International Monetary Fund, June 2021.

[2] Rennert, K., Errickson, F., Prest, B.C. *et al.* Comprehensive evidence implies a higher social cost of CO_2. *Nature* (2022). https://doi.org/10.1038/s41586-022-05224-9

two electrification pathways have only slightly higher costs than the RNG dependent Path #2, and far lower costs than Path #1.

1.4.6 Recommendations for the Five-Year Horizon (2022-2026)

There is not sufficient information available to make a final decision today on the best path, but there is sufficient information to get started. This information points to heading down the shared direction of Paths #2 and #3 until 2025/2026. During this timeframe, we recommend that USU establish three multi-disciplinary teams to accomplish the following tasks:

- **Team #1- Project Implementation**
  - Implement the energy efficiency projects in Path #2
  - Implement DHW electrification project in Path #2
- **Team #2- Utility Procurement**
  - Solicit proposals for off-site clean electricity PPAs
  - Begin the lengthy process of negotiating clean electricity rates, and or transmission of wholesale delivered electricity, with the local electric utility or other qualified providers
  - Solicit proposals for RNG resource development
- **Team #3- Finance**
  - Solicit pricing proposals for CEP electrification projects, as described in Path #3
  - Solicit pricing proposals for on-site PV solar projects, as described in Path #4
  - Submit a loan application to the DOE, which has funding available via the recently enacted the Inflation Recovery Act (IRA), that can provide supplemental low-cost, long-term financing beyond what might be available to USU. Direct pay credits are also available for procurement of renewable resources and subsidies for some energy efficiency measures.

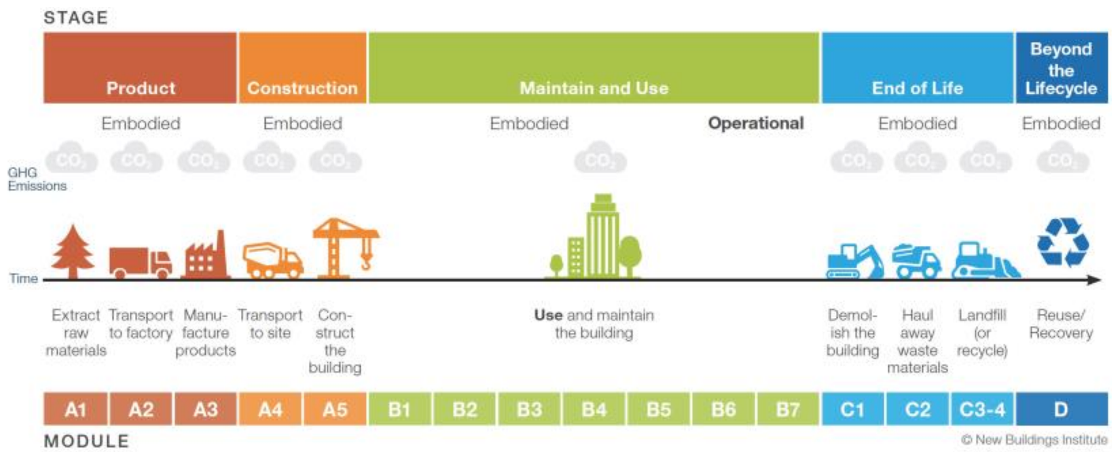
Completing these team-based tasks within the next two years will allow USU to objectively assess the RNG market and ultimately decide whether Path #2, #3, or #4 makes sense.

1.4.7 Implications for New Construction

As Utah State University continues to expand, Willdan recommends designing all new hydronic heating equipment (hot water coils, piping, etc.) to accommodate 140°F heating hot water. Decreasing the heating hot water temperature required at the equipment allows for more flexibility when selecting source equipment during the implementation of the roadmap. The equipment sizes shown in this report are designed to meet the projected loads in 2040 that account for campus expansion. As the heating hot water loop is being constructed, as recommended in paths #3 and #4, it may be possible that new buildings will not be able to immediately tie into the heating hot water loop. In this event, it is still recommended that the hydronic systems are sized for the lower heating water temperature, but the new building can be temporally tied into the existing steam distribution system until the new heating hot water loop reaches the building.

For new construction, renovations, additions, or equipment replacements it is important to look at the entire carbon lifecycle of the material used in the construction process. Accounting for carbon costs and selecting materials with lower embodied carbon reduces the carbon offsets that are required to achieve and maintain carbon neutrality. It has been estimated that 11% of global CO2 emissions are associated with building materials and construction. A whole building lifecycle carbon cost approach should be adopted during the design process for new facilities and renovations.

Figure 4 - Carbon Lifecycle Stages



2. Project Background

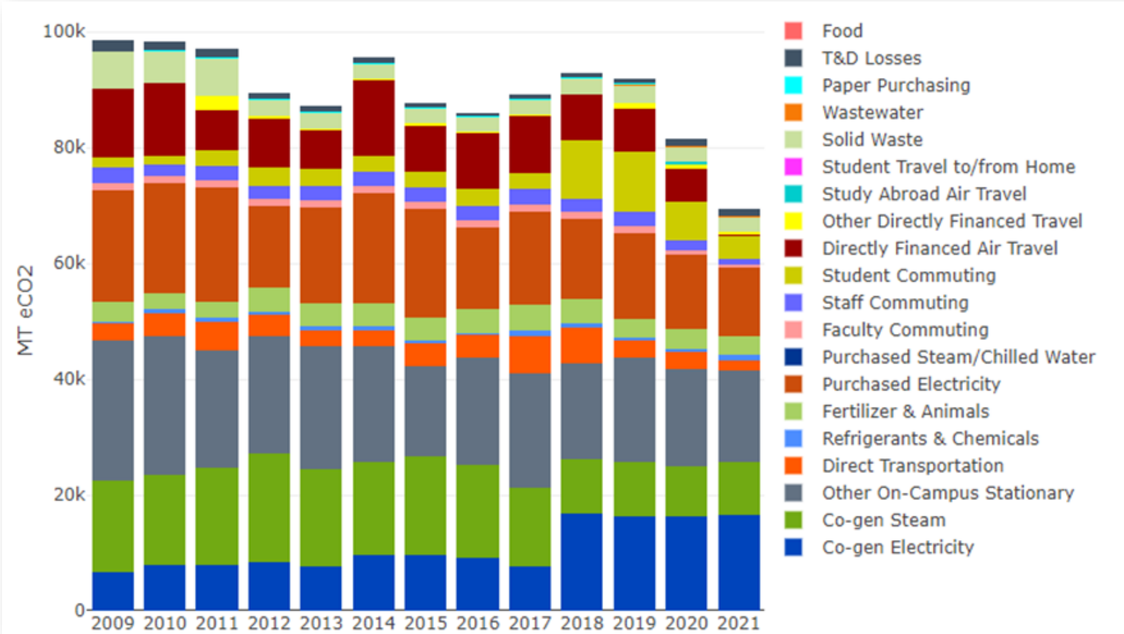
2.1 Climate Commitments

The genesis of this CEP decarbonization effort began with USU's climate commitments. USU signed the American College and University Presidents' Climate Commitment (ACUPCC) in 2007, setting the goal to achieve carbon neutrality by 2050. Following the ACUPCC signing, the USU Faculty Senate passed a resolution to accelerate this process and achieve carbon neutrality by 2040.

2.2 Baseline CO_2 Emissions

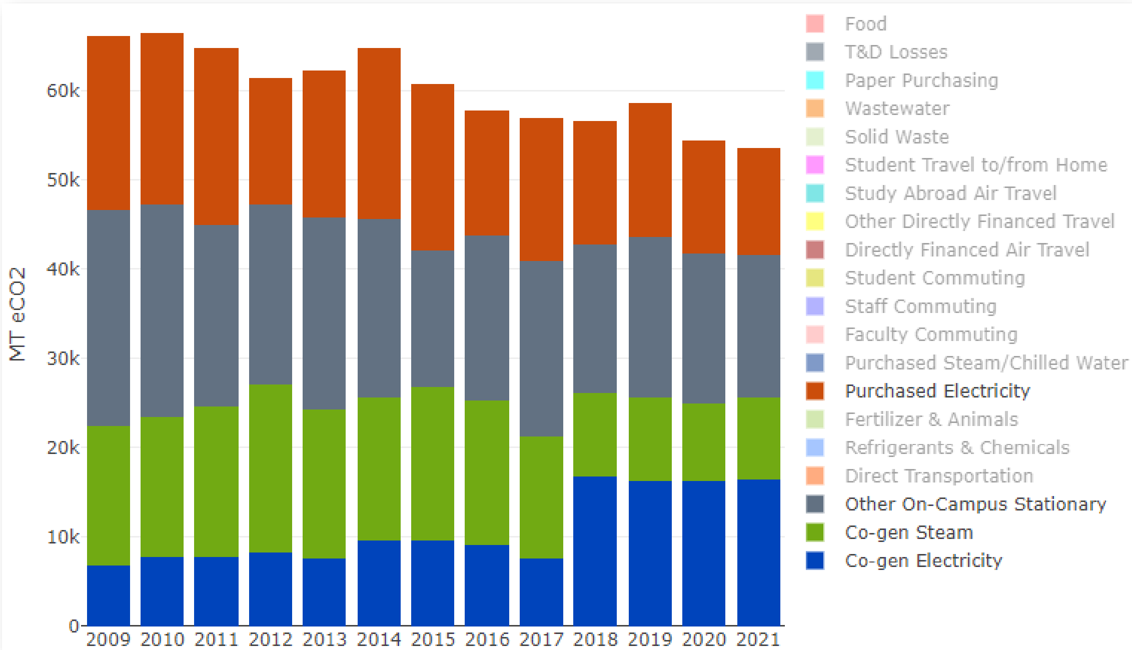
The decarbonization process for USU started with a total inventory of campus emission sources, as shown in **Figure 5** below. The total baseline emissions for 2009 are approximately 100,000 MT CO_2.

Figure 5 - Total USU Emissions Inventory



In 2009, approximately 65 MT CO_2 emissions, representing 65% of the total campus emissions, could be directly attributed to the CEP operations and purchased electricity (**Figure 6**). This means that the CEP and purchased electricity emissions are the most significant category for reduction efforts to achieve total decarbonization. Additionally, the purchased electricity emissions are intrinsically tied to the CEP emissions because the CEP generates a significant percentage of the total electricity used across the Logan campus.

Figure 6 - USU CEP and Purchased Electricity Emissions Inventory



2.3 Roadmap Development

In recognition of the decarbonization work that needs to be accomplished for the CEP, USU's Department of Utility Systems and Energy Management released an RFP for developing a CEP decarbonization roadmap. Willdan won this RFP process and was hired by USU to develop this decarbonization roadmap and produce a roadmap report as the final deliverable in this scope of work.

3. Guiding Principles & Goals

To highlight the intention of this roadmap and its focus, the team created a set of guiding principles for the project. The listed areas of focus were determined based off the scope of work in the original RFP.

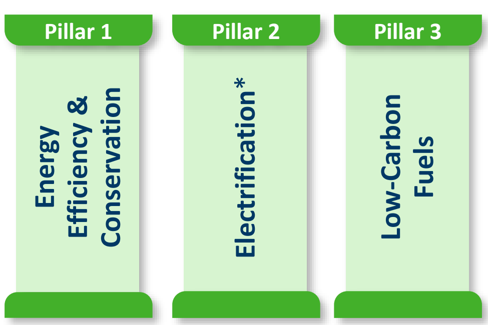
3.1 Guiding Principles

The Decarbonization Master Plan aims to:

- Utilize long-term university energy and sustainability plans and agreements.
- Provide multiple paths to decarbonization which can include optimizing campus energy consumption via energy efficiency, energy conservation, and demand management.
- Identify the resources necessary to optimize the ongoing operation and maintenance of the campus energy systems.
- Evaluate campus electrical, mechanical, and building automation infrastructure.
- Identify the best energy source or combination of sources to meet the university's needs and goals.
- Include a detailed schedule and plan for implementation.
- Delineate a plan for achieving the decarbonization goal.
- Include an analysis of the greenhouse gas (GHG) emission reductions that will be achieved with the roadmap.
- Identify financial cost/benefit analysis of the proposed paths to decarbonization.
- Identify additional environmental benefits aside from GHG emission reductions.

3.2 Pillars - Willdan's Approach to Decarbonization

A common finding across the deep decarbonization studies completed in the U.S. and globally is the use of three broad emissions reduction strategies to achieve deep decarbonization. These strategies, or "pillars," include:



** Switching fossil fuel-powered infrastructure to electricity*

Any successful mitigation scenario will include reductions from each of these pillars, but not every scenario must include every measure. Scenario analysis offers the opportunity to consider how different strategies within, and emphasis between, these pillars affect the plausibility and cost of deep decarbonization. Willdan's approach suggests that no pillar should be solely relied upon for decarbonization, but rather a more comprehensive approach should be taken to achieve greater overall reduction, leveraging components from each pillar. Moreover, maximizing a single variable while ignoring other potential variables for decarbonization is never the optimal solution.

Pillar 1

Energy Efficiency & Conservation

3.2.0.1 Pillar 1 - Energy Efficiency and Conservation

Energy efficiency means providing the same energy service (e.g., hot water, mobility, lighting) with less input energy required. Energy efficiency is an important measure from the perspective of both emissions reductions and cost. Less energy efficiency means that a larger quantity of more expensive measures will be needed, increasing the societal cost of deep decarbonization. Conservation is a change in behavior to reduce energy demands; for example, bicycling or walking rather than driving, or turning off lights and resetting temperature setpoints when spaces are unoccupied. The scenarios and recommendations in this analysis include both energy efficiency and conservation. Limiting buildings' use of electricity and natural gas makes developing infrastructure for clean energy more practical and cost effective, as smaller solar photovoltaic (PV) systems, for example, can be used to serve a building's electrical load after energy efficiency projects have been implemented. Projects in this category also tend to be "low-hanging fruit" projects with quicker financial payback, which can help support the deeper renovation and retrofit projects required to achieve 2040 sustainability goals.

Pillar 2

Electrification

3.2.0.2 Pillar 2 - Electrification

Electrification strategies shift energy usage from on-site combustion of fossil fuels in the CEP to power from electrical sources. Electrification can be an effective emissions reduction strategy because of the relatively high efficiency of electric end-use and the synergy that exists with efforts to decarbonize the electric sector. However, some electrification measures are more cost effective than others, therefore electrification must be used strategically. An important consideration when evaluating the costs of electrification are the potential impacts to the electric system's peak demand and associated infrastructure costs. It is also critical to consider that while electrification can eliminate on-site combustion of fossil fuels, some grid power is still generated with CO_2 emitting processes. As grid power inevitably shifts to more renewable sources and away from CO_2-emitting plants, Utah State's positive impact to the environment via building electrification will continue to expand. Utah State can use PPAs or on-site solar to fully decarbonize the electricity consumed. Converting existing CEP infrastructure at Utah State University will require a variety of solutions. Buildings rely on the steam and chilled water produced at the CEP to deliver conditioned air to classrooms, offices, and other spaces. In this case, changing the heating source from steam to hot water is the primary objective, eliminating reliance on steam from gas-fired boilers and a cogeneration unit in the central plant in favor of water-to-water heat pumps and electric boilers.

Pillar 3

No-Carbon Energy

3.2.0.3 Pillar 3 - No-Carbon Energy

No-carbon energy strategies substitute fossil fuels like gasoline, diesel, coal, and natural gas with low -emission alternatives like renewable electricity and renewable natural gas. The advantage of no-carbon energy is that it can be formulated as a "drop-in" fuel and used in existing equipment with little modification. However, the available supply of sustainable renewable natural gas is limited, falling far short of existing demands for liquid and gaseous fossil fuels, and the costs are higher than the fossil fuel they replace. Therefore, the limited supply of resources must be used strategically, targeted to where they provide the highest value.

4. Utility Usage Baselines and Existing Systems

This section provides a description of current campus-level conditions and details a methodology for determining USU's baseline energy expenditures and carbon footprint for which the recommendations of the Decarbonization Master Plan can be compared against.

4.1 Utility Usage Baseline

4.1.1 Natural Gas & Electricity

Table 1 - 2022 CEP Natural Gas and Electricity Baseline Consumption

Variable	Value
Non-CEP Electricity Usage (kWh)	64,040,797
CHW Existing Plant Energy (kWh)	6,456,847
Cogeneration Electricity Generation (kWh)	41,555,603
Non-CEP Gas Usage (dth)	3,486
Cogeneration Gas Usage (dth)	516,336
Steam Boiler Gas Usage (dth)	196,236
Total Electricity Usage (kWh)	**70,497,644**
Total Gas Usage (dth)	**716,058**

4.2 Existing Central Energy Plant Systems

USU operates and maintains a CEP consisting of a combined steam, chilled water, and cogeneration plant. The following subsections document the existing utility system assets within the CEP production and distribution system. For a more detailed account of existing utility systems, reference the 2017 USU Utility Master Plan by Burns & McDonnell.

Chilled Water System

Campus chilled water is supplied by four (4) electrically driven chillers located in the CEP. The chillers supply chilled water to campus and the stratified Thermal Energy Storage (TES) tank through a network of piping primarily located in tunnels with some direct buried lines.

The chilled water system uses a primary-secondary pumping scheme. The primary chiller pumps are constant-speed electrical driven pumps that supply chilled water to the chillers that supply chilled water to the TES tank, or the system as needed. The secondary TES pumps are variable-speed electrical driven pumps that supply chilled water to the campus from the tank.

The condenser water system is served by a total of six (6) cooling towers and uses a variable primary pumping scheme.

Steam System

There are four (4) steam generators in the CEP, three (3) steam boilers and a Heat Recovery Steam Generator (HRSG). All steam generators supply the campus distribution system with 90 psig saturated steam.

Cogeneration

USU owns and operates a Solar Turbines Taurus 60 (T60) combustion turbine generator (CTG) in conjunction with the three boilers. The T60 has a nominal electric generating capacity of 5.7 MW.

4.3 Utility Distribution Systems

Thermal Distribution

USU distributes steam and chilled water from the CEP to the campus buildings. The steam and chilled water distribution systems have similar routing through campus.

Chilled water is supplied to the main campus via the CEP chillers and supplemented with the TES tank. Building level shell and tube heat exchangers are used to convert the steam supplied by the CEP to heating hot water and domestic hot water.

Electrical Distribution

The USU campus is served from two locations by Logan City Light & Power at 44 kV. The North Substation has two 14 MVA peak rated transformers that step down the voltage from 44 kV to 12.47 kV. The South Substation has two transformers that step down the voltage from 44 kV to 12.47 kV, one 14 MVA peak rated, the other 9,375 kVA peak rated. The North and South substations distribute power to campus at 12.47 kV in a looped distribution network to the campus buildings. The looped distribution allows distribution switches and buildings to be served by multiple sources providing the campus with high reliability of electrical service. The distribution system is regularly switched depending on campus needs and does not have a “normal” configuration.

5. Paths to Decarbonization

5.1 Path #1

5.1.1 Overall Description

Path #1 to decarbonization proposes continuing the current operation at the CEP and all campus buildings. Decarbonization is achieved solely through the procurement of renewable natural gas and decarbonized electricity.

Table 2 - Path #1, Energy Consumption

Path #1						
Year	Total Electricity Usage (kWh)	Cogeneration Electricity Generation (kWh)	Net Electricity Usage (kWh)	Peak Demand (kW)	Total Gas Usage (dth)	CEP Water Consumption (gal)
2022	70,497,644	41,555,603	28,942,041	11,333	716,058	17,085,878
2025	76,513,529	41,555,603	34,957,926	11,966	748,102	19,157,905
2030	79,331,498	41,555,603	37,775,895	12,087	764,186	20,001,182
2035	82,149,466	41,555,603	40,593,863	12,208	781,157	20,850,010
2040	84,967,435	41,555,603	43,411,832	12,329	799,178	21,705,414

5.1.2 Retrofit Project Scope Descriptions

Path #1 proposes no projects or changes to the campus or CEP operation.

5.1.3 Plant Operations Explanations

The CEP would continue its historical operations.

5.1.3.1 2022-2040 CEP Operations

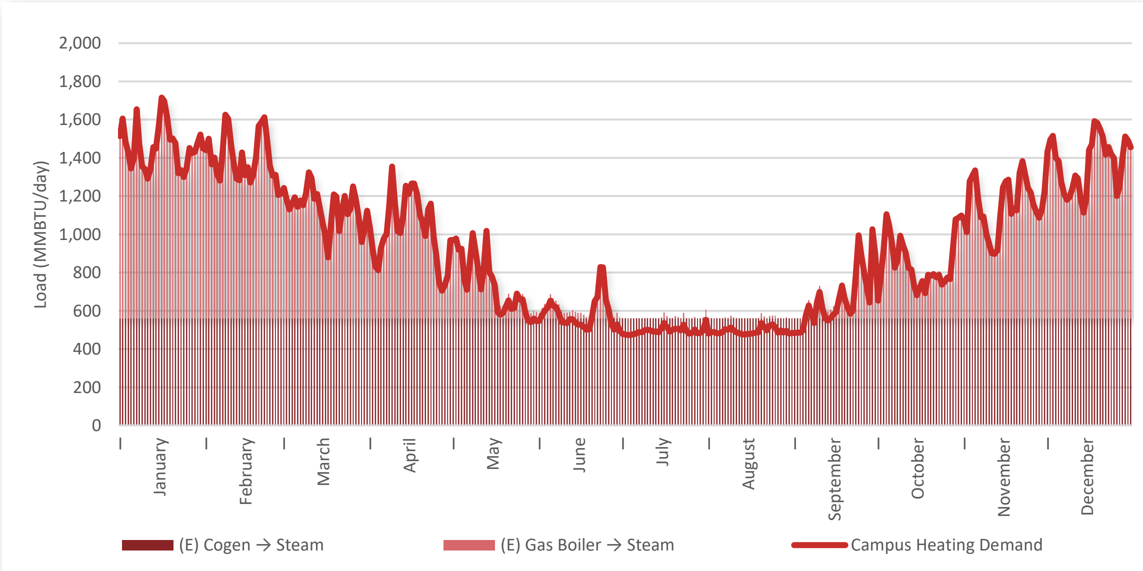


Figure 7 - Path #1, Year 2022, Daily Heating Loads

Campus heating loads are met with a combination of steam produced from the existing cogeneration heat recovery steam generator and existing gas boilers.

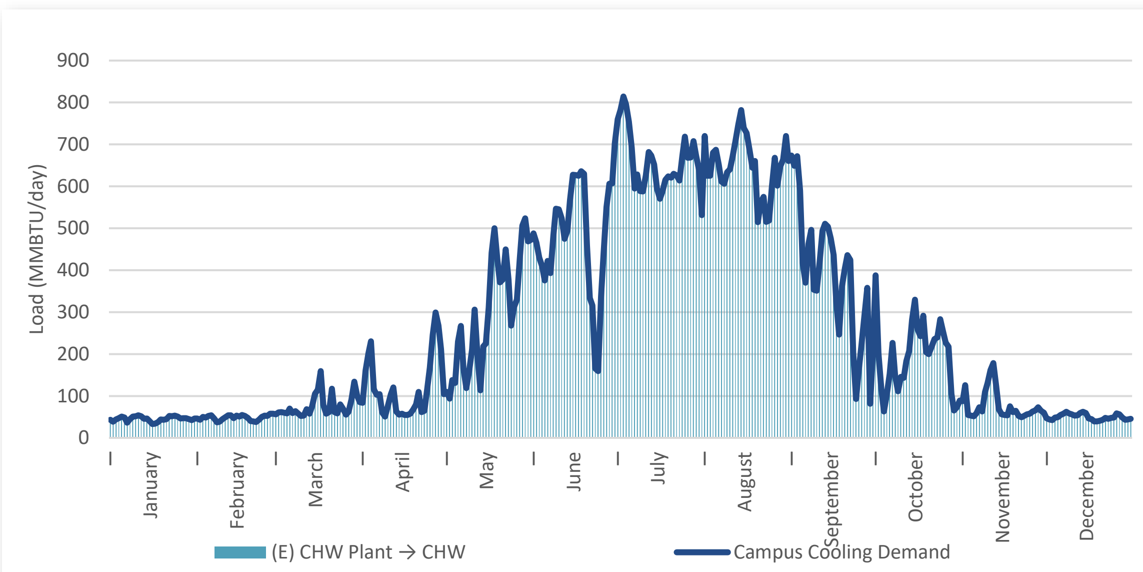
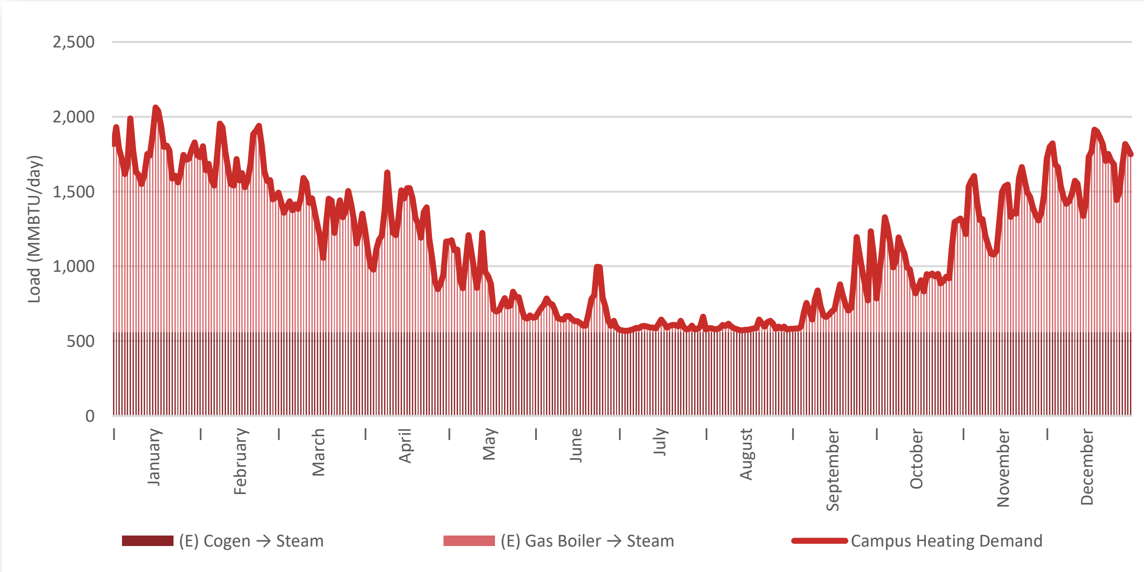


Figure 8 - Path #1, Year 2022, Daily Cooling Loads

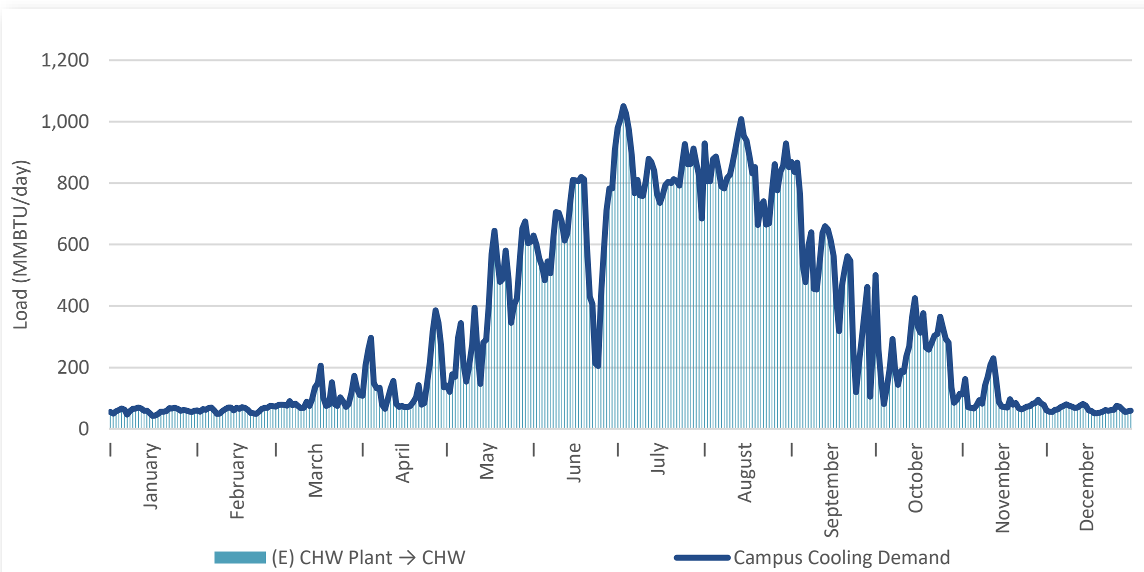
Campus cooling loads are met with the existing chilled water plant.

Figure 9 - Path #1, Year 2040, Daily Heating Loads



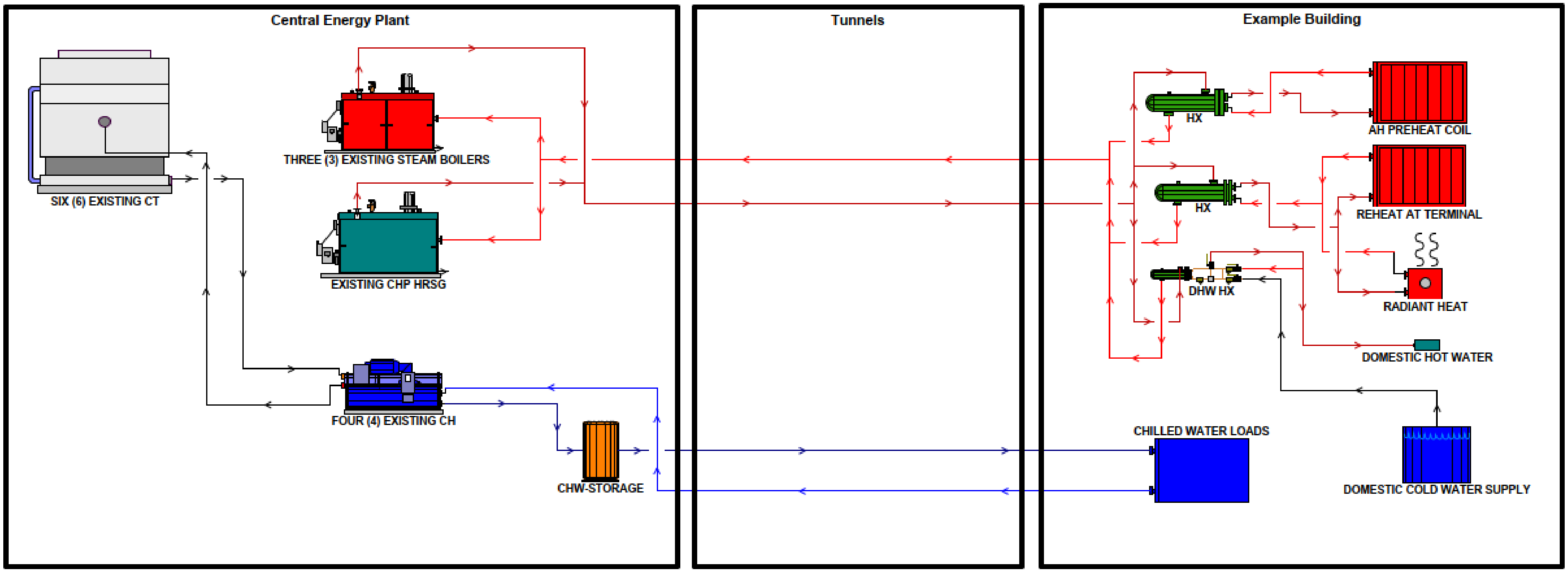
Campus heating loads are met with a combination of steam produced from the existing cogeneration heat recovery steam generator and existing gas boilers. The increase in the campus heating load in year 2040 is due to campus growth.

Figure 10 - Path #1, Year 2040, Daily Cooling Loads



Campus cooling loads are met with the existing chilled water plant. The increase in the campus cooling load in year 2040 is due to campus growth.

Figure 11 - Path #1, Year 2022-2040, CEP Equipment



5.2 Path #2

5.2.4 Overall Description

Path #2 to decarbonization proposes continuing the current operation at the CEP but slowly tapering off the use of cogeneration. Reducing cogeneration operation reduces the amount of natural gas required for heating. The cogeneration unit uses approximately twice the amount of gas per pound of steam produced than the gas boilers. Therefore, based on the forecasted price of renewable natural gas, it will no longer make financial sense to generate electricity and heating with cogeneration running on renewable natural gas. To reduce the steam demand at the CEP, building level domestic hot water heat pumps would be installed in all the buildings that currently use steam for domestic hot water. Additionally, deep energy efficiency recommissioning (RCx) improvements would be implemented throughout the campus. The deep energy efficiency RCx reduces the campus's electricity and gas consumption. Decarbonization is achieved by reducing the CEP's energy consumption coupled with the procurement of renewable natural gas and decarbonized electricity.

Table 3 - Path #2, Energy Consumption

Path #2						
Year	Total Electricity Usage (kWh)	Cogeneration Electricity Generation (kWh)	Net Electricity Usage (kWh)	Peak Demand (kW)	Total Gas Usage (dth)	CEP Water Consumption (gal)
2022	70,497,644	41,555,603	28,942,041	11,333	716,058	17,085,878
2025	65,938,883	41,555,603	24,383,280	11,621	614,952	16,201,864
2030	68,367,835	33,312,793	35,055,042	11,725	541,711	16,689,788
2035	70,796,787	20,948,578	49,848,209	11,830	481,308	17,409,316
2040	73,225,739	0	73,225,739	11,935	371,056	18,131,685

5.2.5 Retrofit Project Scope Descriptions

5.2.5.2 2022-2025 Project Scope

Domestic Hot Water Heat Pumps Throughout the Entire Campus

The existing steam distribution loop provides many of the campus facilities with domestic hot water (DHW) as well as heating hot water (HHW). This is accomplished through steam to domestic hot water heat exchangers located in the facility mechanical rooms. As part of this project, new air source domestic hot water heat pumps would be installed in the 75 campus buildings on the steam loop. The obsolete steam to domestic hot water heat exchangers would then be demolished or abandoned. The new air source heat pumps would reduce the steam demand at the central plant, lowering its GHG emissions and natural gas consumption.

Figure 12 - Example Air Source Domestic Hot Water Heat Pump

Building Level Energy Efficiency Retrofits Throughout the Entire Campus

At approximately 4.9 million sqft, the campus has a tremendous amount of conditioned space. As summarized below, there are many strategies for reducing the campus' energy demand. Implementing these efficiency retrofits as soon as possible is a logical first step in many of the paths to decarbonization. The measures would significantly reduce the energy demand of the campus to cut GHG emissions at the central plant and make it more cost effective to implement further de-carbonization strategies in future years.

Table 4 - Energy Efficiency Measure Table

ENERGY EFFICIENCY RETROFIT MEASURES TABLE
Variable Air Volume Air Handling Unit Optimization
1. Static Pressure Reset This control strategy would involve implementing a static pressure reset control strategy for the VAV air handling units throughout the campus. The existing air handling units currently operate under an industry-standard, constant static pressure setpoint. The VAV zone box dampers are modulated and electric reheat coils are enabled to control space temperature. This type of sequence has been the accepted or "standard" type of sequence in the past, but as energy consumption has become more of a concern, more efficient control sequences have been developed and should be implemented. A static pressure reset control strategy will operate the fan more efficiently, while maintaining the same level of comfort control. Instead of controlling fan speed to a constant static pressure setpoint, the fan speed will be controlled by VAV box need, to ensure that at least one of the system's VAV box dampers is fully open. This will make the static pressure of the system dynamic and will allow the fan speed to decrease more during part-load conditions than under the current operation. The new sequence should control the supply fan speed off zone damper positions.
2. Discharge Air Temperature Reset The most common reset strategy is to implement a simple proportional reset based on the outside air temperature; on a hot day, the supply-air temperature (SAT) is set to its design (or original) value, and when the weather is cooler, the SAT is increased. The converse is true a cold day. This is usually specified in a table that lists two outside temperatures and the corresponding SAT. For example, at 95°F outside temperature, the SAT is set to 53°F; at 65°F outside temperature the SAT is set at 68°F. The SAT is then reset proportionally between these two points.
3. Preheat Isolation Valve Replacement While on site, the Willdan team observed that many of the valves on the air handling pre-heat coils are allowing hot water to leak when the valves should be closed. This causes wasteful simultanenous heating and cooling during the summer months. All the pre-heat valves throughout the campus will be retrocommissioned and leaking valves will be replaced.
4. Preheat Enable/Disable Install and program bubble tight steam valves at the bulding level heat exchanges. The valves will be programed to open/close based on outside air temperature.

Zone Level Optimization

1. Ventilation Scheduling, Temperature Setbacks, Setpoint Optimization, & Occupant Relocation

The controls throughout the campus will be modified to increase the cooling temperature setpoint, reduced the heating temperature setpoint, and reduce the ventilation air delivered to zones that are scheduled to be unoccupied. On a college campus, some portion of classrooms and lecture halls are vacant at any given hour during the day or days during the year. Syncing the HVAC controls with event scheduling will allow the temperature setpoints and ventilation air to better match the actual occupancy demands of the spaces day.

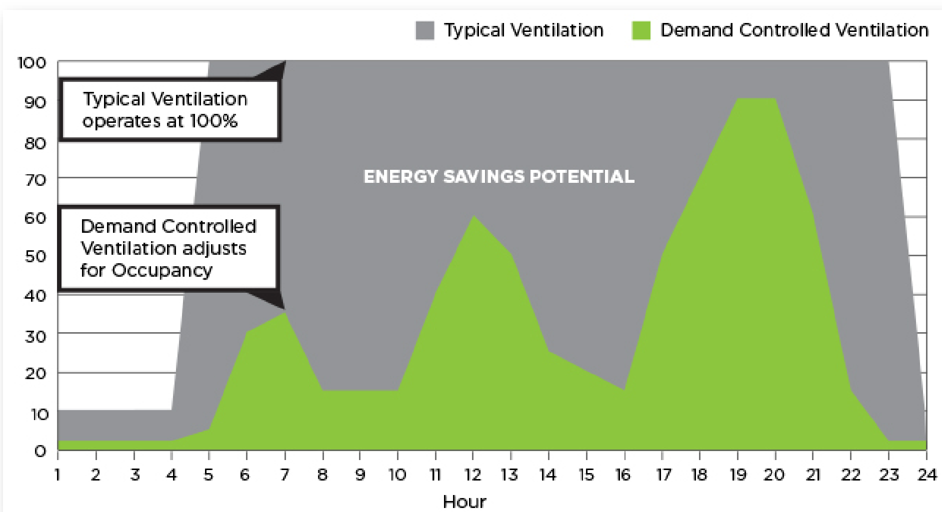
Additionally, space temperatures can be set back further during unoccupiend periods and optimized during occupied periods (lowered in heating raised in cooling) to reduce energy consumption.

Finally, building occupancy can be consolidated in summer months to ensure that excessive energy is not spent on underutilized facilities.

2. Demand Control Ventilation

This opportunity will include the installation of carbon dioxide (CO_2) sensors in spaces with high variances in occupancy, such as a lecture hall. In these spaces, large quantities of ventilation air are provided at a constant rate to satisfy the ventilation requirements at full occupancy.

Typically, these spaces are not occupied at 100% maximum capacity, thus are not required to receive the maximum ventilation rate. This control strategy will determine the minimum amount of ventilation needed to provide acceptable indoor air quality at all times. This will be accomplished through dynamically controlling the ventilation rate to each space to maintain CO_2 levels that correspond to acceptable air quality for each space. This significantly lowers the amount of energy needed to temper the outdoor air to maintain comfortable conditions in the spaces.



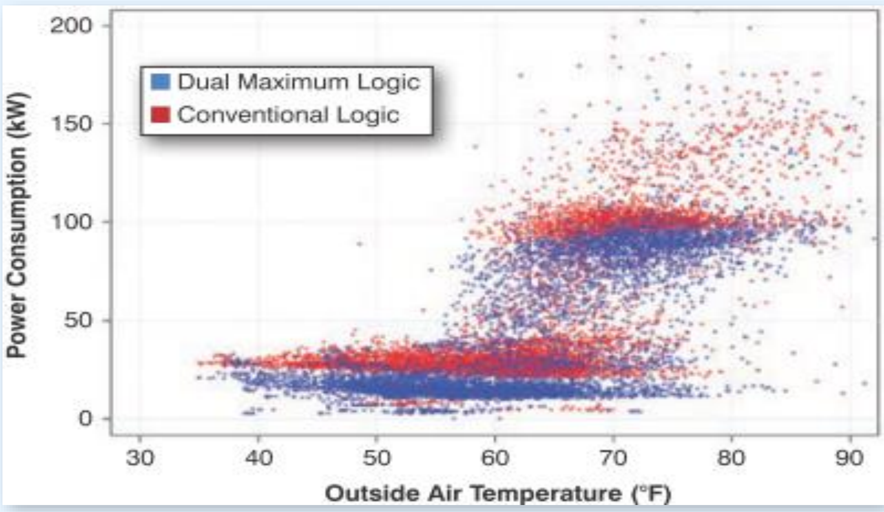
This measure will work in conjunction with better ventilation scheduling to ensure the amount of ventilation delivered to zones is optimized 24/7.

3. VAV Setpoint Optimization

VAV systems are most efficient when in the dead-band, where space temperature is allowed to float between the heating and cooling setpoints, as only the minimum ventilation air is being supplied to the space. One way to increase the amount of time systems are in the dead-band mode is to widen the temperature setpoints used to define the setpoints. This will allow space temperature to float longer before sending a signal for heating or cooling to the respective VAV box. Widening dead-bands also helps to prevent short cycling of equipment, where heating and cooling setpoints are so close together that the two modes of operation begin to compete with each other.

Modern control strategies very often use dual maximum logic, where a separate maximum heating airflow setpoint is calculated independently from the maximum cooling airflow setpoint. Heating elements are still modulated to provide adequate heating to spaces, but the lower supply airflow means less reheat is required, and can save significant fan energy at the air handling units supplying VAV boxes.

The benefits of dual maximum logic compared to traditional VAV reheat logic include lower fan energy and lower cooling energy use, improved thermal comfort by not pushing zone temperature to heating setpoints during the cooling season, and reduced stratification due to supply air temperature control. Moreover, systems which utilize dual maximum control are better able to respond to varying weather conditions, and use less power during both heating and cooling seasons. The data below demonstrates the power consumption of the same facility's HVAC system before and after implementing dual maximum control logic.



Central Energy Plant Optimization

1. Boiler Plant O_2 Trim

For fossil-fuel-powered boilers, adjusting the combustion airflow improves system performance. More air is typically supplied for combustion than is needed. Excess air helps prevent incomplete combustion which helps eliminate hazards such as smoke and carbon monoxide buildup. However, if too much air is introduced, some of the fuel is wasted in heating this excess air. A tune-up of combustion air consists of adjusting combustion air intake until measured oxygen levels in the flue gas reach a safe minimum.

2. Variable Feedwater System Optimization for Boilers

To reduce pumping energy in the heating system, VFDs can be added to the boiler condensate return and feedwater pumps. The new and existing VFDs would be optimized such that water flow more closely tracks the campus heating load reducing pumping energy at part load conditions.

3. Boiler Blowdown Heat Recovery

Heat can be recovered from boiler blowdown by using a heat exchanger to preheat boiler makeup water. Any boiler with continuous blowdown exceeding 5% of the steam rate is a good candidate for the introduction of blowdown waste heat recovery. Larger energy savings occur with high-pressure boilers.

Blowdown waste heat can be recovered with a heat exchanger, a flash tank, or flash tank in combination with a heat exchanger. Lowering the pressure in a flash tank allows a portion of the blowdown to be converted into low-pressure steam. This low-pressure steam is typically used in deaerators. Drain water from the flash tank is then routed through a heat exchanger. Cooling the blowdown has the additional advantage of helping to comply with local codes that limit the discharge of high-temperature liquids into the sewer system.

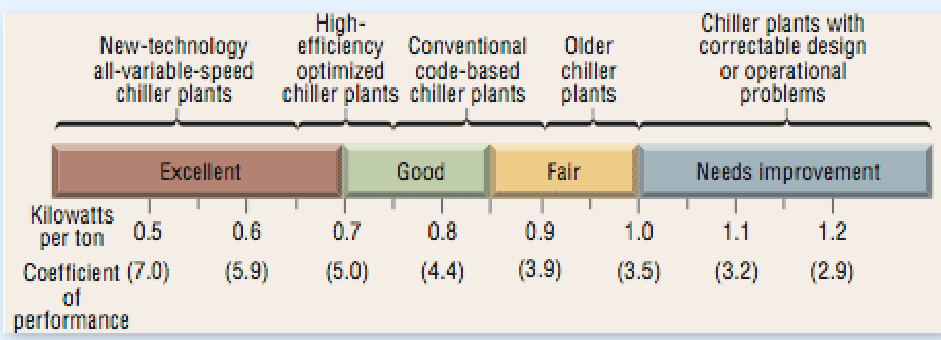
4. Reduced Hot Standby Operation of Boilers

When a boiler is firing, heat is transferred to the internal surfaces of the boiler because the combustion gases are hotter than the surfaces. Conversely, the boiler loses heat to the cold air inside the boiler when the burners are not firing. If air circulates through the boiler when firing is off, a great deal of heat is lost. This loss of heat is called “standby loss.”

Dampers that are part of burner assemblies are almost always programmed to close when the burner stops firing. On boilers without dampers, a motorized damper may be installed inside the flue to regulate flue draft. Such a damper may be controlled only in response to flue draft, not burner firing. If so, the controls can be adjusted to close the damper when firing stops. This change has major safety implications. Therefore, equip the burner controls with a low-draft interlock that stops the burner if the damper fails to open fully. The boiler should also have an easily visible draft gauge that allows the operator to verify proper damper operation.

5. Automation of Chiller Water Plant Sequences

Traditional chilled water plant design generally focuses on increasing the efficiency of individual components and controlling these components using 20-year-old strategies that result in a modest improvement in overall chiller-plant efficiency. The most efficient design of a chilled water plant incorporates variable speed drives on all plant components such as chillers, pumps and cooling towers. Additionally, a comprehensive approach is used to optimizing the dynamic variables of the entire system in response to the requirements of the load served by the plant. This approach can result in overall chiller plant efficiency improvement of 50% over traditional designs:

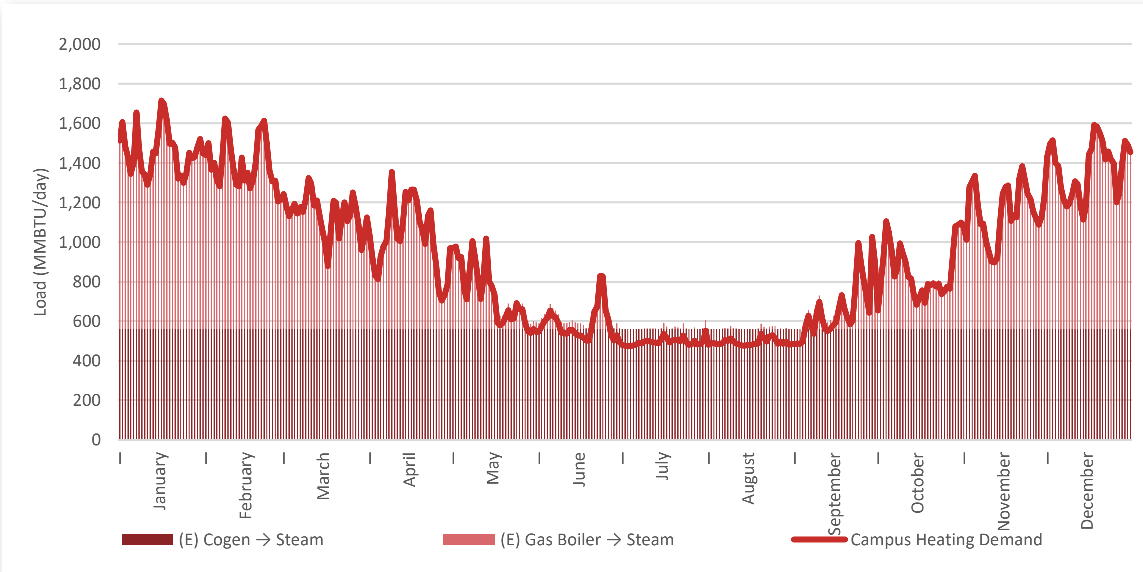


5.2.6 Plant Operations Explanations

5.2.6.1 2022-2024 CEP Operations

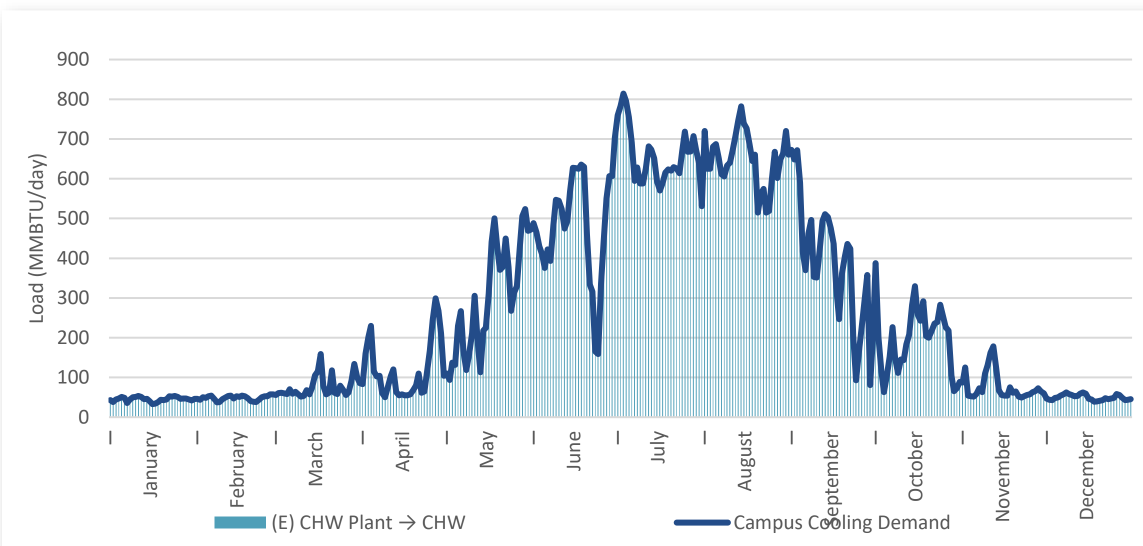
The CEP would continue its historical operations during the first phase of the project while the deep energy efficiency measures are implemented and building level DHW heat pumps are installed.

Figure 13 - Path #2, Year 2022, Daily Heating Loads



Campus heating loads are met with a combination of steam produced from the existing cogeneration heat recovery steam generator and existing gas boilers.

Figure 14 - Path #2, Year 2022, Daily Cooling Loads

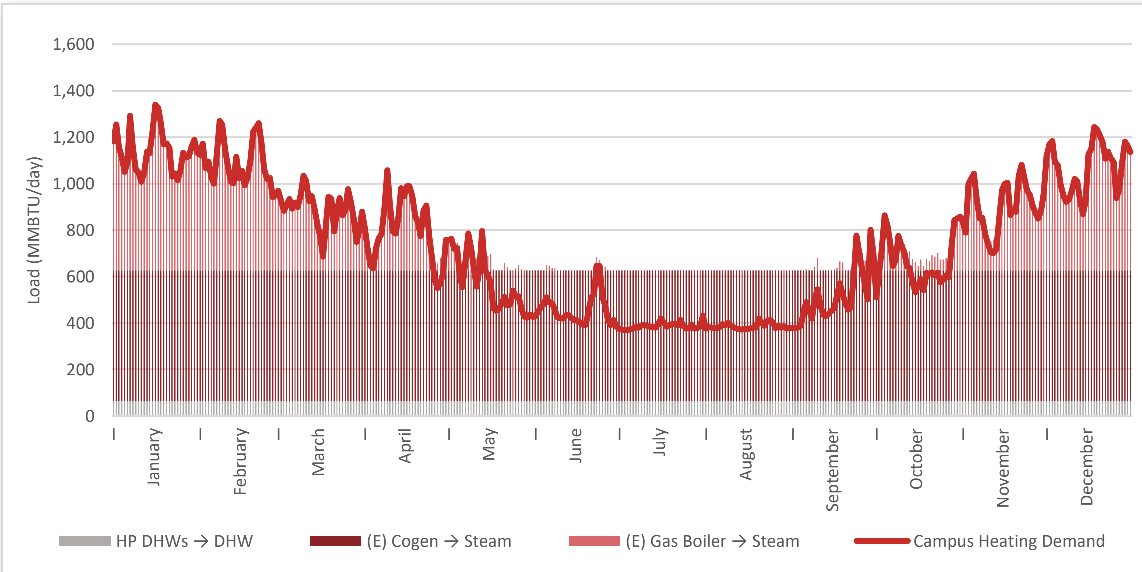


Campus cooling loads are met with the existing chilled water plant.

5.2.6.2 2025-2029 CEP Operations

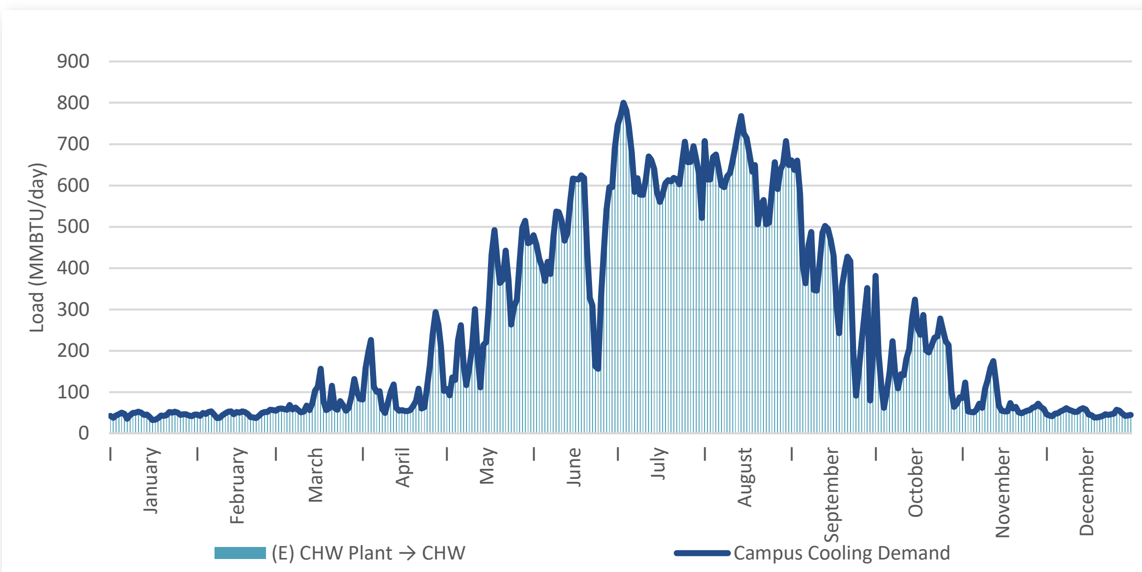
The CEP would continue its historical operations except for a reduced heating and cooling load due to the implementation of the projects described in section 5.2.5.2.

Figure 15 - Path #2, Year 2025, Daily Heating Loads



Campus heating loads are met with a combination of steam produced from the existing cogeneration heat recovery steam generator and existing gas boilers. Building level heat pumps provide domestic hot water.

Figure 16 - Path #2, Year 2025, Daily Cooling Loads

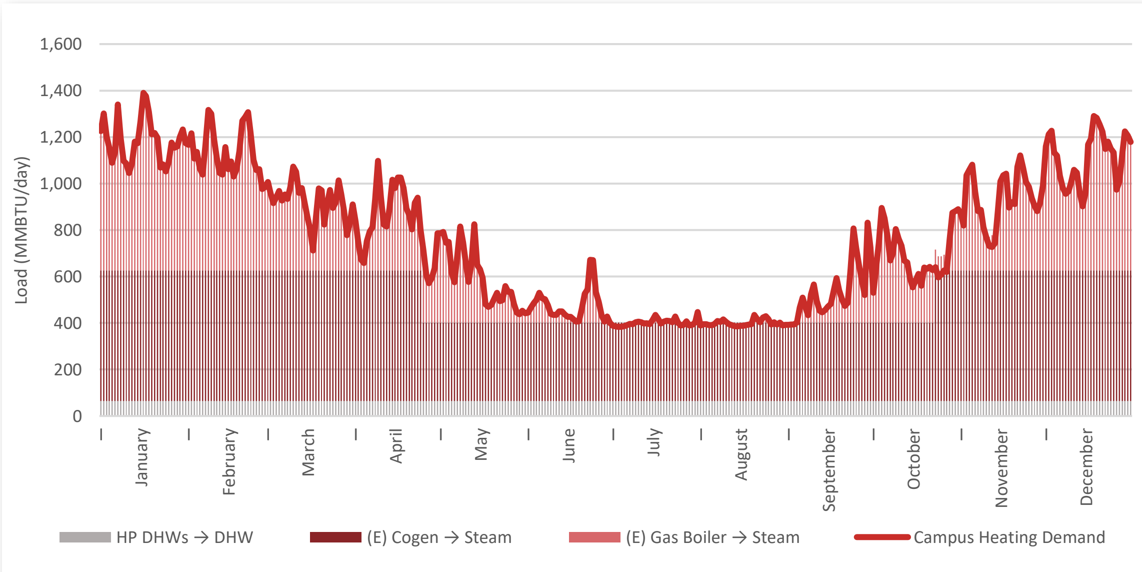


Campus cooling loads are met with the existing chilled water plant.

5.2.6.3 2030-2034 CEP Operations

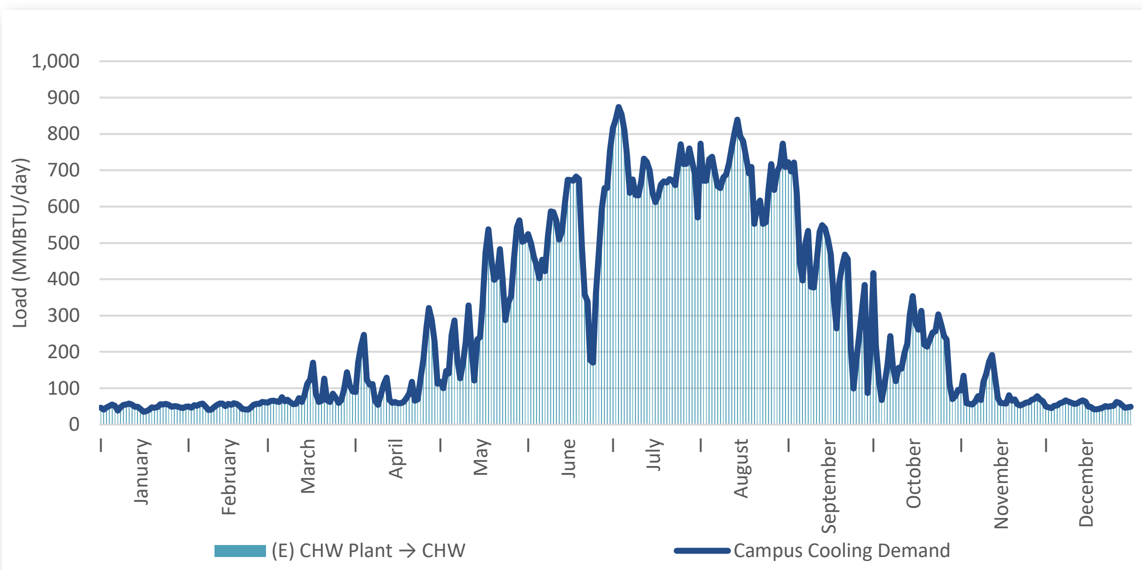
The CEP would operate similar to the operation described in section 5.2.6.2 except beginning in year 2030 cogeneration would begin to turn down to 60% capacity from mid/late April to mid/late October.

Figure 17 - Path #2, Year 2030, Daily Heating Loads



Campus heating loads are met with a combination of steam produced from the existing cogeneration heat recovery steam generator and existing gas boilers. Cogeneration reduces to 60% capacity from mid/late April to mid/late October. Building level heat pumps provide domestic hot water.

Figure 18 - Path #2, Year 2030, Daily Cooling Loads

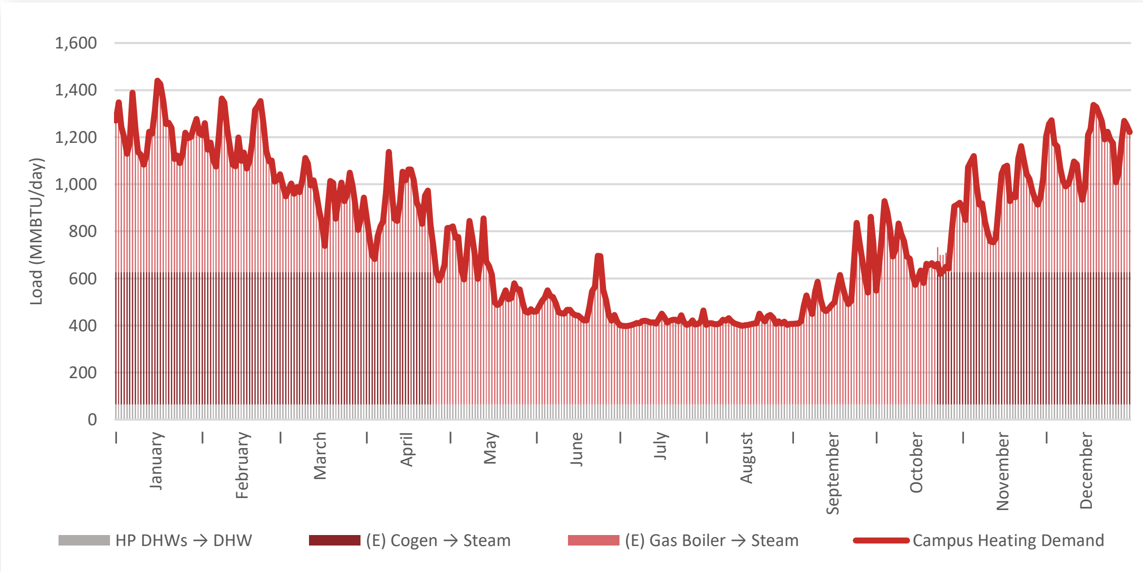


Campus cooling loads are met with the existing chilled water plant.

5.2.6.4 2035-2039 CEP Operations

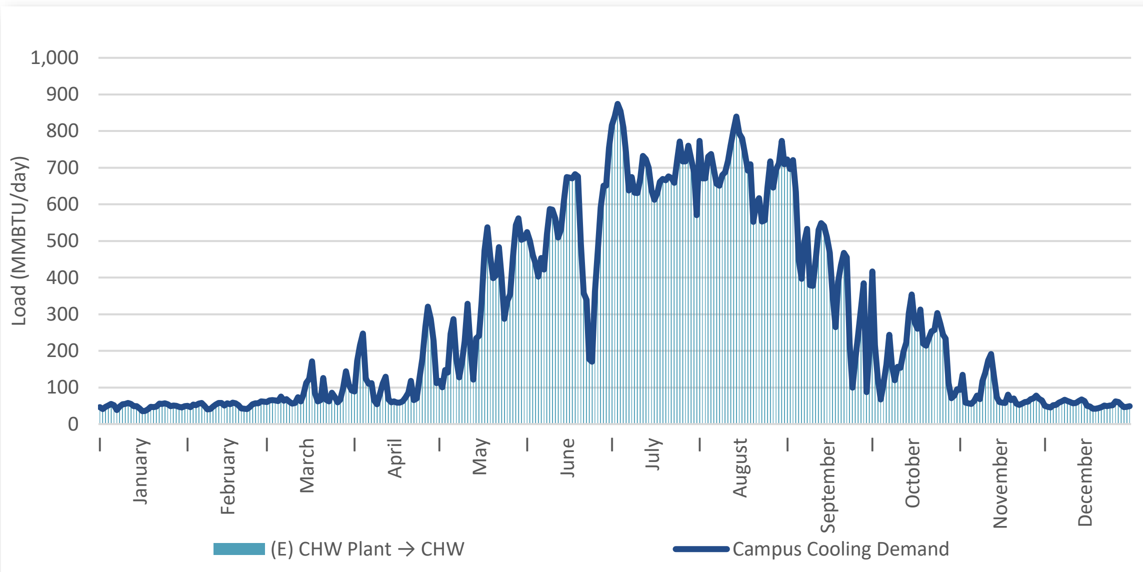
The CEP would operate similar to the operation described in section 5.2.6.3 except beginning in year 2035 cogeneration would begin to shut down from mid/late April to mid/late October.

Figure 19 - Path #2, Year 2035, Daily Heating Loads



Campus heating loads are met with a combination of steam produced from the existing cogeneration heat recovery steam generator and existing gas boilers. Cogeneration shuts off from mid/late April to mid/late October. Building level heat pumps provide domestic hot water.

Figure 20 - Path #2, Year 2035, Daily Cooling Loads

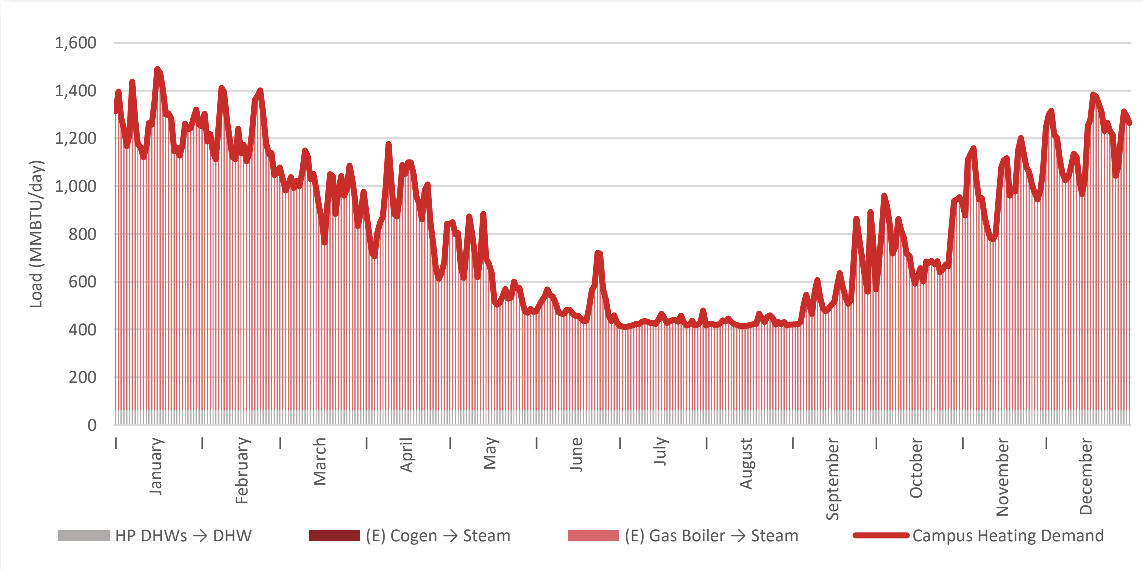


Campus cooling loads are met with the existing chilled water plant.

5.2.6.5 2040-Future CEP Operations

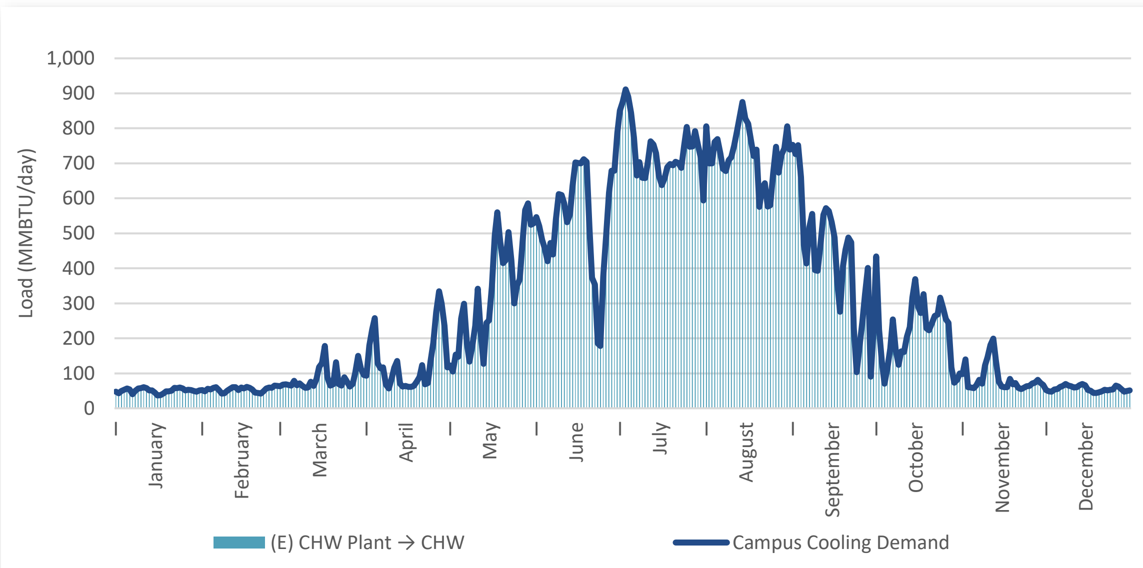
The CEP would operate similar to the operation described in section 5.2.6.4 except beginning in year 2040 cogeneration would be fully shut down.

Figure 21 - Path #2, Year 2040, Daily Heating Loads



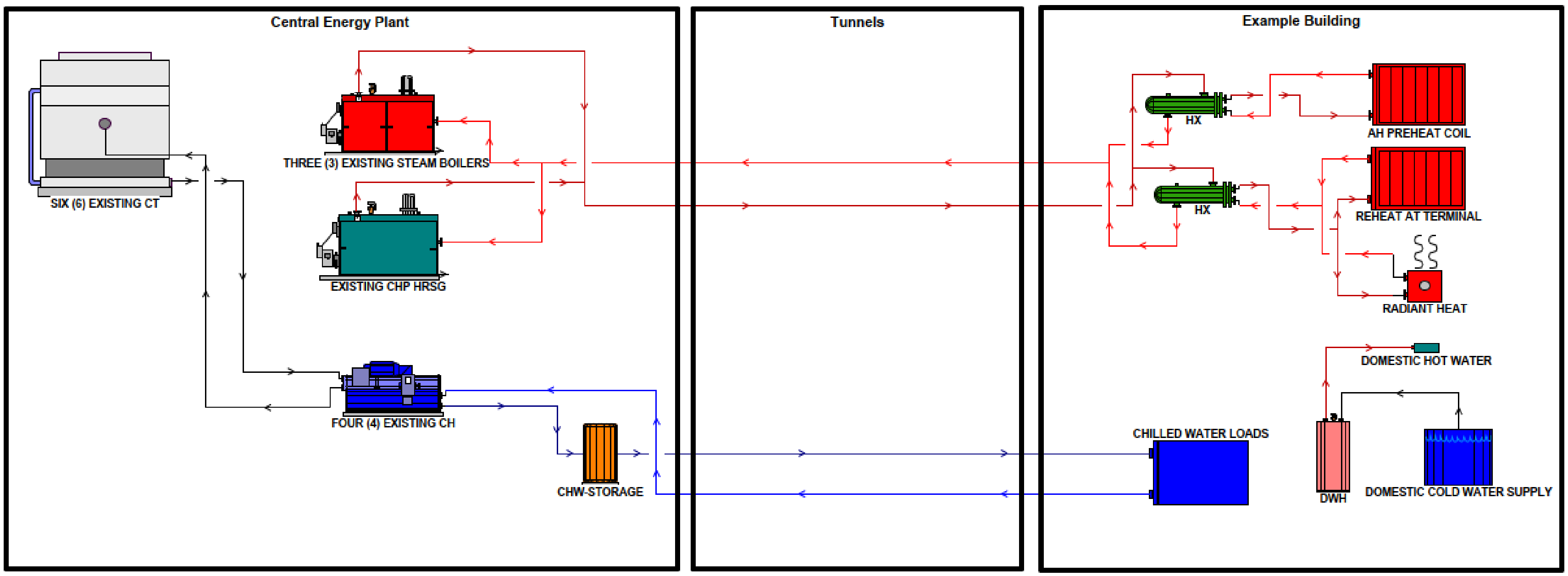
Campus heating loads are met with steam produced from the existing gas boilers and building level heat pumps provide domestic hot water.

Figure 22 - Path #2, Year 2040, Daily Cooling Loads



Campus cooling loads are met with the existing chilled water plant.

Figure 23 - Path #2, Year 2022-2040, CEP Equipment



5.3 Path #3

5.3.1 Overall Description

Path #3 to decarbonization proposes significant electrification of the central energy plant. The projects involve installing ground source heat pump chillers (HPC), electric resistance boilers, and building level domestic hot water heat pumps in addition to implementing deep energy efficiency retrofits. The projects would shift the campus from steam to a heating hot water (HHW) distribution system allowing USU reduce its reliance on natural gas for heating. In the final state, cogeneration would be shut down and heating would be provided by the ground source HPCs, electric resistance boilers, and existing gas boilers. The HPCs would provide the baseload heating while the electric resistance and existing gas boilers would provide peaking capacity. Reducing cogeneration operation reduces the amount of natural gas required for heating. The cogeneration unit uses approximately twice the amount of gas per pound of steam produced than the gas boilers. Therefore, based on the forecasted price of renewable natural gas, it will no longer make financial sense to generate electricity and provide heating with cogeneration running on renewable natural gas. Using electric boilers for peaking provides the most cost-effective solutions for electrifying the heating system. Hot water thermal energy storage would be installed to reduce peak heating demand and align the heating and cooling loads during the summer months.

The transition from steam to heating hot water requires the construction of hot water piping to serve all the buildings on the steam distribution network, as well as new AHU preheat and VAV reheat coils that can accept lower temperature heating hot water where necessary. Steam to HHW heat exchangers would also be installed in the central energy plant to convert cogeneration and gas boiler steam to HHW. Willdan proposes keeping existing steam boilers online for emergency heat, eliminating the need to increase the size of the existing emergency generator.

The HPCs would provide the campus with all the required summer heating and baseload winter cooling.

Significant electrification of the CEP increases the estimated peak electrical demand by approximately 65% but the gas usage will decrease by 98%.

Table 5 - Path #3, Energy Consumption

Path #3						
Year	Total Electricity Usage (kWh)	Cogeneration Electricity Generation (kWh)	Net Electricity Usage (kWh)	Peak Demand (kW)	Total Gas Usage (dth)	CEP Water Consumption (gal)
2022	70,497,644	41,555,603	28,942,041	11,333	716,058	17,085,878
2025	65,938,883	41,555,603	24,383,280	11,621	614,952	16,201,864
2030	79,284,147	33,312,793	45,971,354	12,650	451,489	10,306,013
2035	86,425,487	20,948,578	65,476,909	15,682	326,519	7,149,085
2040	115,738,280	0	115,738,280	18,720	13,253	3,796,417

5.3.2 Retrofit Project Scope Descriptions

5.3.2.1 2022-2025 Project Scope

Domestic Hot Water Heat Pumps Throughout the Entire Campus

Implement the same scope as described in section 5.2.5.2 of the report.

Building Level Energy Efficiency Retrofits Throughout the Entire Campus

Implement same energy efficiency retrofit scopes as described in section 5.2.5.2 of the report.

5.3.2.2 2026-2030 Project Scope

Heating Hot Water (HHW) Thermal Energy Storage Tank

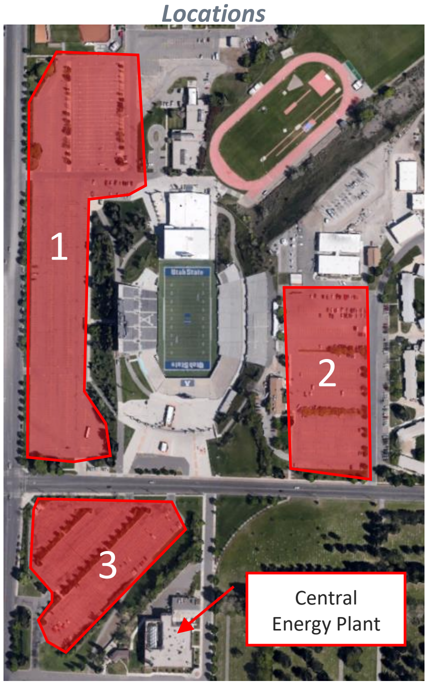
Install a new 2-million-gallon HHW thermal energy tank near the existing chilled water thermal energy storage tank. Like the existing chilled water tank, the new hot water tank would be buried underground. The thermal energy storage would flatten the daily load curve seen by the CEP heating equipment, reducing peak demand and energy consumption. It may be possible to use the existing chilled water thermal energy storage tank as a dual-purpose tank and utilize if for storing chilled water during the summer and heating hot water during the winter. Further investigation and analysis of the existing tank insulation is needed to validate this possibility.

Figure 24 - Example Thermal Energy Storage Tank

Install 500 Tons of Geothermal U-Tube Well Field Capacity

This project would involve the installation of 500 tons of geothermal U-tube well field capacity. The parking lots shown in the picture to the right have a combined area of approximately 700,000 sqft, enough space to house 1,500 tons of well field capacity. The first 500 tons of capacity would likely be built under Parking Lot Three, as that is the closet to the central plant. Then, if necessary, the well field would be expanded into Parking Lot One and/or Two in 2035 and 2040. The preliminary engineering calculations assumed each U-tube well would be 400 feet deep with twenty-five feet of spacing between wells. The actual borehole spacing requirements will be a function of soil conductivity testing to be performed in the future. The installation of the field would require tearing up the existing parking lot, drilling the wells, installing the distribution piping, re-paving the parking lots, re-striping the parking lots, and re-landscaping the parking lots. Additionally, traffic control would likely be required to install piping crossing E 1000 N Street running east to west if the well field needs to be expanded to Parking Lot One.

Figure 25 - Possible Well Field Locations



Install 500 Tons of Heat Pump Chiller Capacity in the Central Energy Plant

This project would involve the installation of a 500-ton heat pump chiller in the central energy plant. The chiller would be a key component of the new heating hot water (HHW) system as shown in the system schematics. A York CYK-HP chiller was evaluated and budgeted in the preliminary engineering process because of its ability to produce 155°F heating hot water and 42°F chilled water.

Figure 26 - York CYK-HP Chiller

Install 7.6 MMBtu/hr Electric Hot Water Boiler Capacity

Figure 27 - Example Electric Boiler

This project would involve the installation of 7.6 MMBtu/hr of electric boiler capacity, equivalent to 2,227 KW, in the central energy plant. The new electric boilers would produce 155°F heating hot water and connect to the new system as shown in the system schematics. Functionally, the boilers would help cover the peak heating demand of the campus, which would allow the heat pump chillers to be cost effectively sized for the average heating/cooling load of the campus.

Convert Air Handler Steam Heating Coils to Heating Hot Water Coils for 33% of the Campus

This project would involve replacing the steam pre-heat coils in the building air handlers with new hydronic coils sized for an entering water temperature of 140°F. The coils would be sized for a lower temperature than the 155°F design temperature of the new central plant equipment. This will allow for higher utilization of the heating hot water thermal energy storage and will account for thermal loss that may occur in the long runs of new hydronic distribution piping.

Figure 28 - Example Hot Water Coil

The estimated budget for this project also includes an allowance to replace existing hot water reheat coils at VAV boxes where necessary. It is assumed that most zones have oversized heating coils, and the lower hot water supply temperature would not prevent the zones from meeting temperature setpoint.

Install Steam to Heating Hot Water (HHW) Heat Exchangers and Hydronic Pumps in the Central Energy Plant

Electrification of the central plant would require the installation of a 140°F heating hot water hydronic system, as shown in the year 2030 and 2035 system schematics. Installing steam to heating hot water (HHW) heat exchangers would allow the existing steam boilers and cogeneration systems to contribute heat to the HHW loop as needed. Between 2025 and 2035, the steam boilers and cogeneration system would still cover 66% of the campus heat demand.

Install New Hydronic Hot Water Piping to Cover 33% of the Campus Heating Load

This project would involve the installation of hydronic hot water piping in the existing steam tunnels to cover approximately 33% of the campus heating demand. The new piping would carry approximately 3,000 gallons of hot water per minute during a design heating day. See appendix for graphics illustrating the extent of new piping to be installed.

Increase Size of Central Plant to Accommodate New Equipment

The new heat pump chillers and electric boilers to be installed in 2030, 2035, and 2040 would require more floor space in the central energy plant. This project would add approximately 2,000 sqft to the central energy plant to provide space for the new equipment. A possible area for expansion is shown in red on the picture to the right.

Figure 29 - Possible Area of Expansion for Central Energy Plant

5.3.2.3 2031-2035 Project Scope

Install New Hydronic Hot Water Piping to Cover 33% More of the Campus Heating Load (Total Coverage of 66%)

This project would involve the installation of more hydronic hot water piping in the existing steam tunnels to cover approximately 33% more of the campus heating demand. After the completion of this project, the heating hot water system would cover 66% of the campus heating demand. The new piping would carry approximately 5,000 gallons per minute of hot water during a design heating day. See the appendix for a graphic illustrating the extent of new piping to be installed.

Install 500 Tons of Geothermal U-Tube Well Field Capacity (Total Well Field Capacity of 1000 Tons)

This project would involve the installation of another 500 tons of well field capacity. After the completion of this project, the total well field capacity will be 1,000 tons.

Install 500 Tons of Heat Pump Chiller Capacity in the Central Energy Plant (Total Heat Pump Chiller Capacity of 1000 Tons)

This project would involve the installation of another 500-ton heat pump chiller in parallel with the existing chiller(s). After the completion of this project, the total heat pump chiller capacity will be 1,000 tons.

Install 7.6 MMBtu/hr Electric Hot Water Boiler Capacity (Total Electric Boiler Capacity of 15 MMBtu/hr)

This project would involve the installation of another 7.6 MMBtu/hr of electric boiler capacity in parallel with the existing boiler(s). After the completion of this project, the total electric boiler capacity will be 15.2 MMBtu/hr.

Convert Air Handler Steam Heating Coils to Heating Hot Water Coils for 33% more of the Campus (Total of 66% of Coils Converted)

This project would convert 33% more of the steam preheat coils to heating hot water. After the completion of this project, 66% of the steam preheat coils would be converted to heating hot water. Similar to the 2030 project, an allowance is included for replacing some VAV box reheat coils.

5.3.2.4 2036-2040 Project Scope

Install New Hydronic Hot Water Piping to Cover 33% More of the Campus Heating Load (Total Coverage of 100%)

This project would involve the installation of more hydronic hot water piping in the existing steam tunnels to cover approximately 33% more of the campus heating demand. After the completion of this project, the heating hot water system would cover 100% of the campus heating demand. The new piping would carry approximately 4,200 gallons of hot water per minute during a design heating day. See the appendix for a graphic illustrating the extent of new piping to be installed.

Install 500 Tons of Geothermal U-Tube Well Field Capacity (Total Well Field Capacity of 1000 Tons)

This project would involve the installation of another 500 tons of well field capacity. After the completion of this project, the total well field capacity would be 1,500 tons.

Install 500 Tons of Heat Pump Chiller Capacity in the Central Energy Plant (Total Heat Pump Chiller Capacity of 1,000 Tons)

This project would involve the installation of another 500-ton heat pump chiller in parallel with the existing chiller(s). After the completion of this project, the total heat pump chiller capacity would be 1,500 tons.

Install 7.6 MMBtu/hr Electric Hot Water Boiler Capacity (Total Electric Boiler Capacity of 15 MMBtu/hr)

This project would involve the installation of another 7.6 MMBtu/hr of electric boiler capacity in parallel with the existing boiler(s). After the completion of this project, the total electric boiler capacity would be 22.8 MMBtu/hr.

Convert Air Handler Steam Heating Coils to Heating Hot Water Coils for 33% more of the Campus (Total of 66% of Coils Converted)

This project would convert 33% more of the steam preheat coils to heating hot water. After the completion of this project, 100% of the steam preheat coils would be converted to heating hot water. Similar, to the 2030 project, an allowance is included for replacing some VAV box reheat coils.

5.3.3 Plant Operations Explanations

5.3.3.5 2022-2024 CEP Operations

Summary

The CEP would continue its historical operations during the first phase of the project while the deep energy efficiency measures are implemented, and domestic hot water heat pumps are installed.

Cogeneration

Cogeneration operates at full capacity every hour of the year similar to its historical operation.

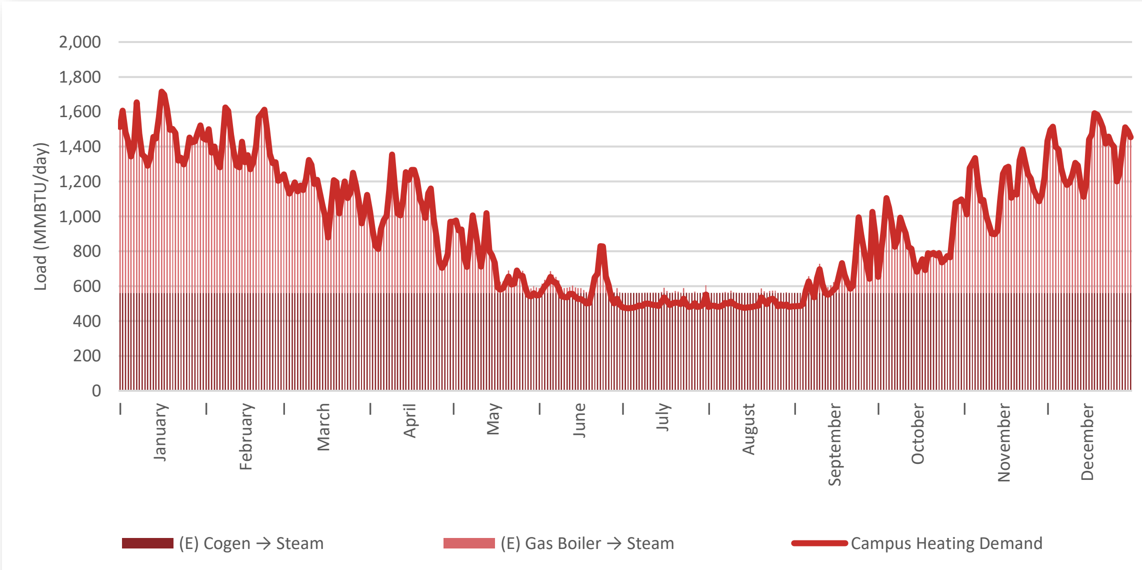
Gas Boilers

Existing gas steam boilers operate similar to their historical operation.

Chilled Water

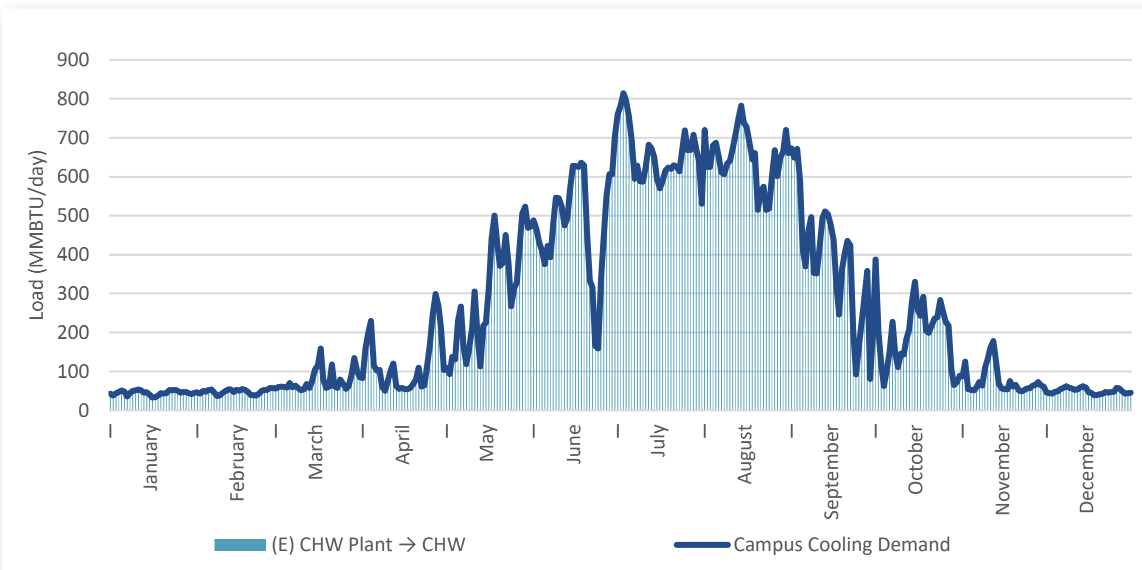
Existing chilled water plant operates similar to its historical operation.

Figure 30 – Path #3, Year 2022, Daily Heating Loads



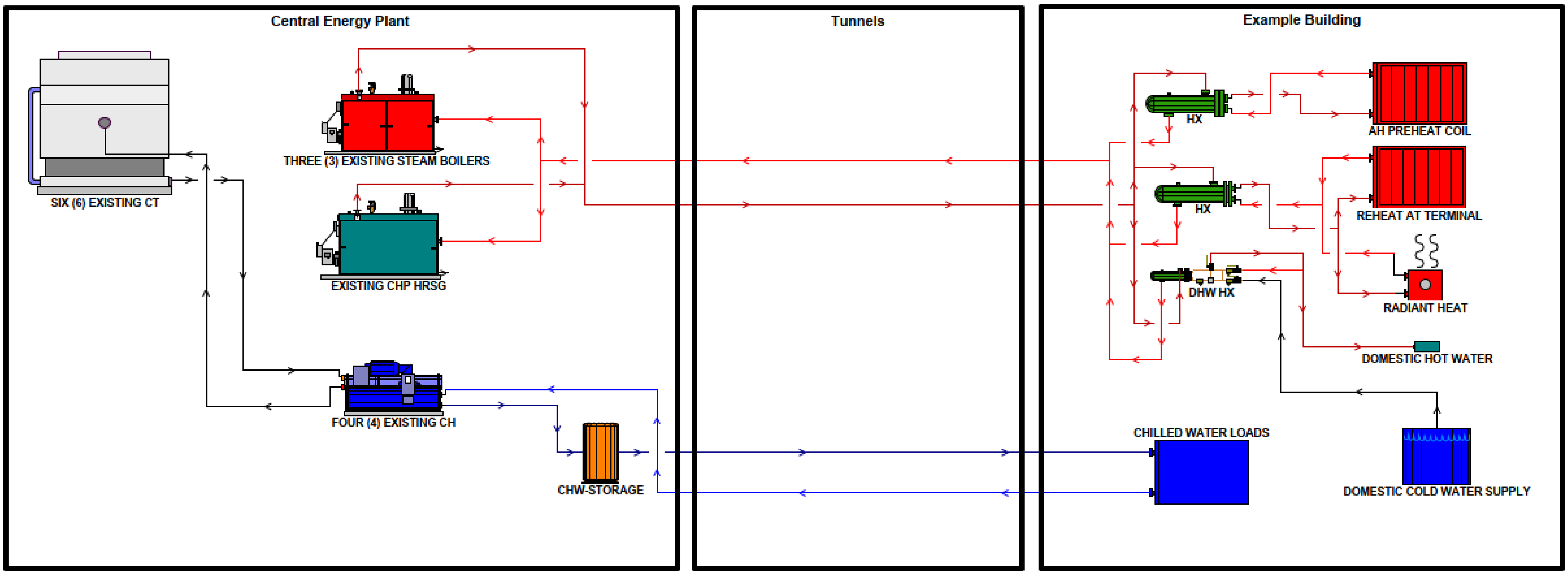
Campus heating loads are met with a combination of steam produced from the existing cogeneration heat recovery steam generator and existing gas boilers.

Figure 31 – Path #3, Year 2022, Daily Cooling Loads



Campus cooling loads are met with the existing chilled water plant.

Figure 32 - Path #3, Year 2022, CEP Equipment



5.3.3.6 2025-2029 CEP Operations

Summary

The CEP would continue its historical operations except for a reduced heating and cooling load due to the implementation of the projects described in section 5.3.2.1.

Cogeneration

Cogeneration operates at full capacity every hour of the year similar to its historical operation.

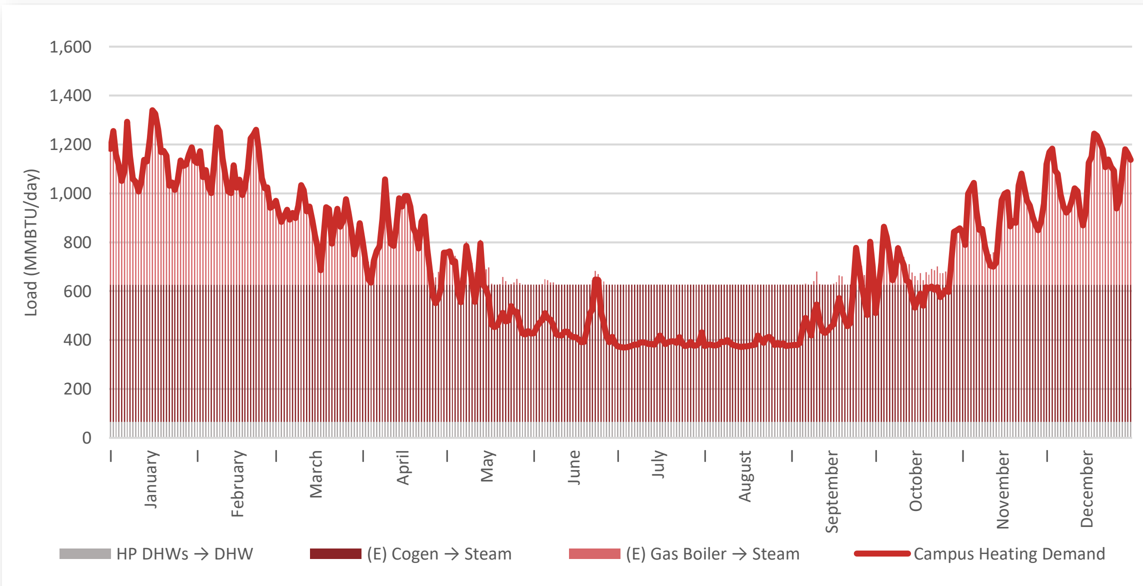
Gas Boilers

Existing gas steam boilers operates similar to their historical operation.

Chilled Water

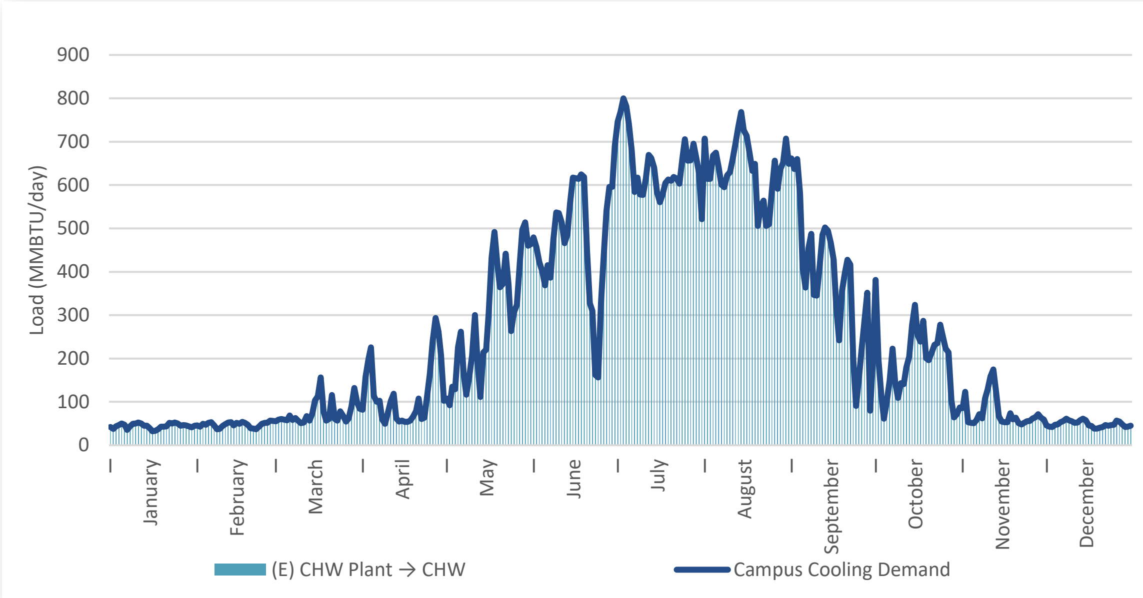
Existing chilled water plant operates similar to its historical operation.

Figure 33 - Path #3, Year 2025, Daily Heating Loads



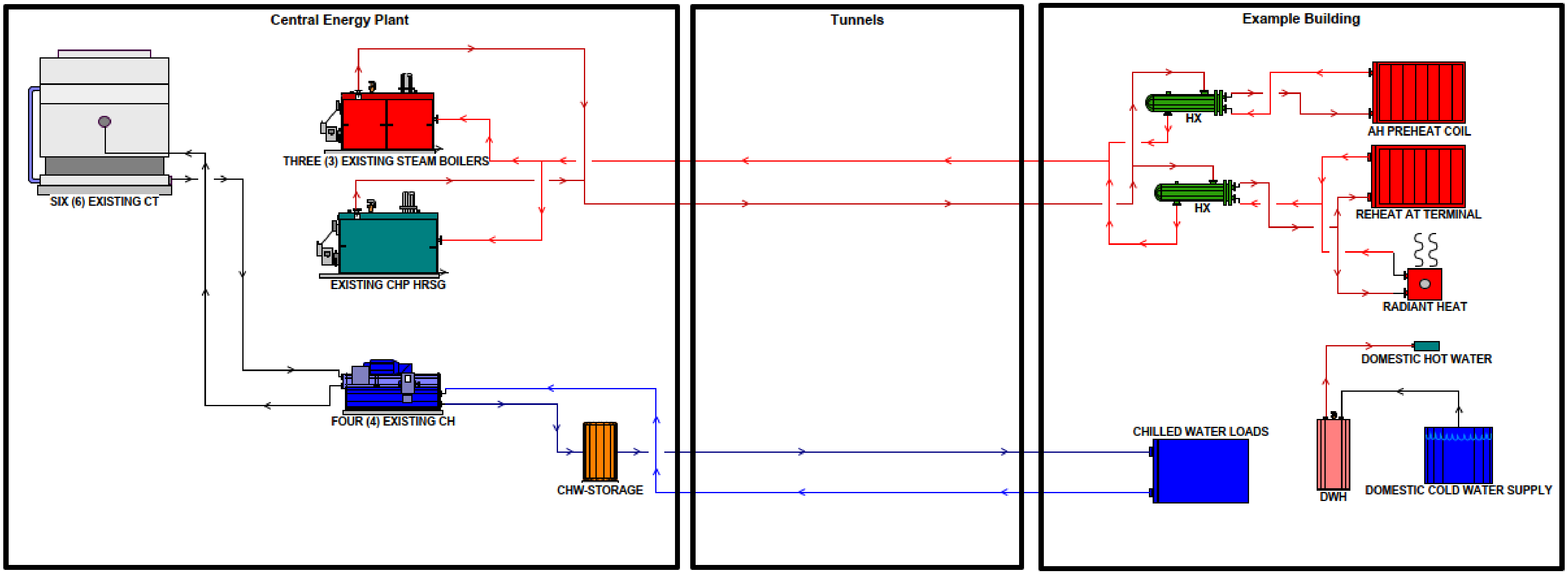
Campus heating loads are met with a combination of steam produced from the existing cogeneration heat recovery steam generator and existing gas boilers. Building level heat pumps provide domestic hot water.

Figure 34 - Path #3, Year 2025, Daily Cooling Loads



Campus cooling loads are met with the existing chilled water plant.

Figure 35 - Path #3, Year 2025, CEP Equipment



5.3.3.7 2030-2034 CEP Operations

Summary

By year 2030 the projects described in section 5.3.2.1 and 5.3.2.2 would have been implemented and 1/3 of heating loads served by the CEP would be converted to 140 °F heating hot water. Steam heating would be provided by cogeneration and steam boilers. Heating hot water would be provided by heat pump chillers and electric boilers with peak heating demand supplied by steam to HHW heat exchangers. Throughout the year cogeneration would be operating and providing steam and heating hot water to campus. The heat pump chillers, electric boilers, and steam boilers would be used to meet any additional heating hot water loads.

Cogeneration

Cogeneration would operate at 100% capacity during the winter and shoulder seasons, and then at 60% capacity from mid/late April to mid/late October. Cogeneration's heat recovery steam generator would provide steam and heating hot water to campus.

Gas Boilers

Existing gas steam boilers operate at a reduced load relative to historical operation and provide steam and heating hot water to campus.

Steam Heating

Cogeneration and existing steam boilers provide steam for heating to 2/3 of the campus.

Heating Hot Water

One 500-ton heat pump chiller, one 7.6 MMBtu/hr electric boiler, and steam to hot water heat exchangers provide heating hot water to 1/3 of the campus.

Chilled Water

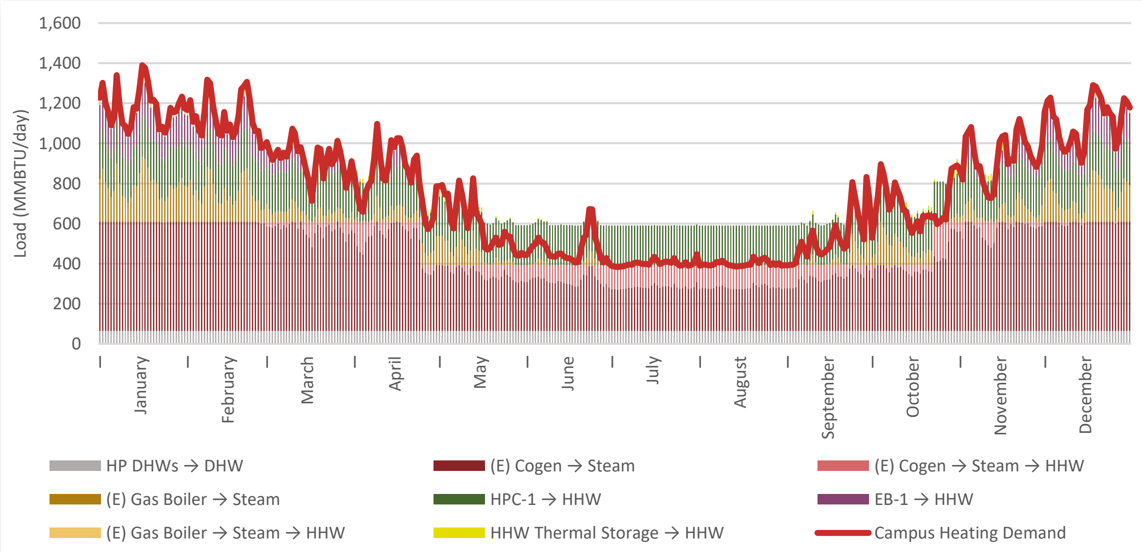
One 500-ton heat pump chiller would operate near full capacity for much of the year. Additional chilled water would be provided by the existing chilled water operating similar to its historical operation but at a reduced load.

Heat Pump Chiller Operation

The heat pump chiller would control to the campus heating or cooling load depending on which load is higher. Operating the heat pump chiller in this manner ensures a high asset utilization rate. With this operation, the heat pump chiller would be able to fully meet the summer and shoulder season HHW demand and provide CHW to the campus. During the winter, the heat pump chiller would fully meet campus CHW demand.

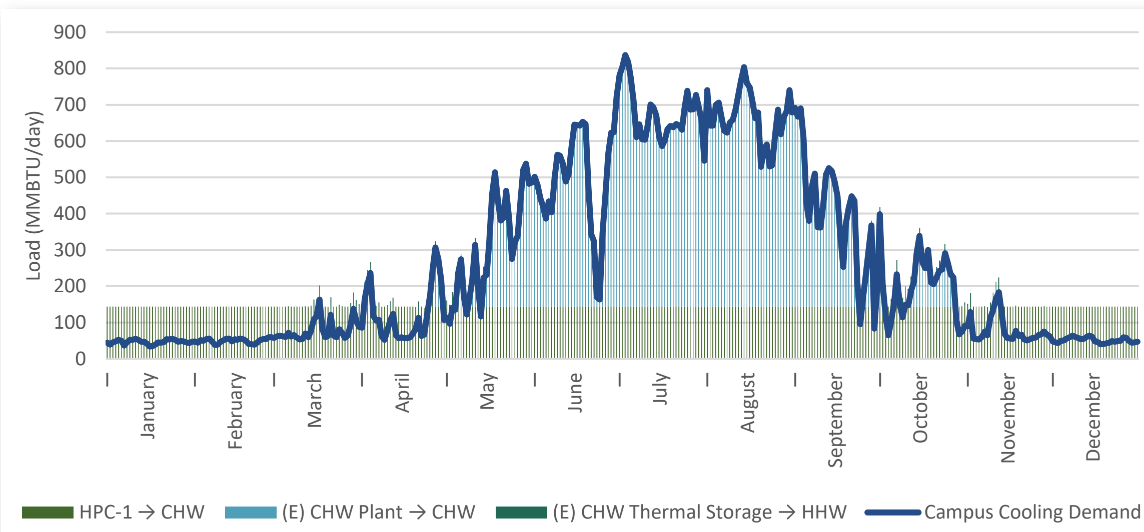
Any excess CHW or HHW produced would be directed to the geothermal U-tube bore hole loop. Due to the yearly imbalance of the heating and cooling loads at the campus, more energy would be pulled from the ground in the winter than is put into the ground in the summer. This imbalance, if left unaddressed, could lead to a depletion of energy in the ground which would reduce the effectiveness of the geothermal U-tube bore hole loop. This requires USU to monitor the ground temperature and correct the imbalance when required. Correcting the imbalance involves running the existing gas steam boilers and rejecting the heat produced into the geothermal loop.

Figure 36 - Path #3, Year 2030, Daily Heating Loads



Campus heating loads are met by several pieces of equipment. By year 2030, 1/3 of the campus would be on HHW supplied by a 500-ton heat pump chiller and a 7.6 MMBtu/hr electric boiler. At peak heating, an existing steam boiler would be used to provide HHW. The steam loads on campus would be provided by the cogeneration heat recovery steam generator and steam boilers. Excess HHW produced by the heat pump chillers would be directed into the geothermal U-tube bore hole loop. Cogeneration would operate at 60% capacity from mid/late April to mid/late October. Building level heat pumps provide domestic hot water.

Figure 37 - Path #3, Year 2030, Daily Cooling Loads



Campus cooling loads would be met with the existing chilled water plant and one heat pump chiller fully loaded throughout the year. Excess CHW produced by the heat pump chillers would be directed into the geothermal U-tube bore hole loop.

Figure 38 - Path #3, Year 2030, Heating Loads vs. OAT

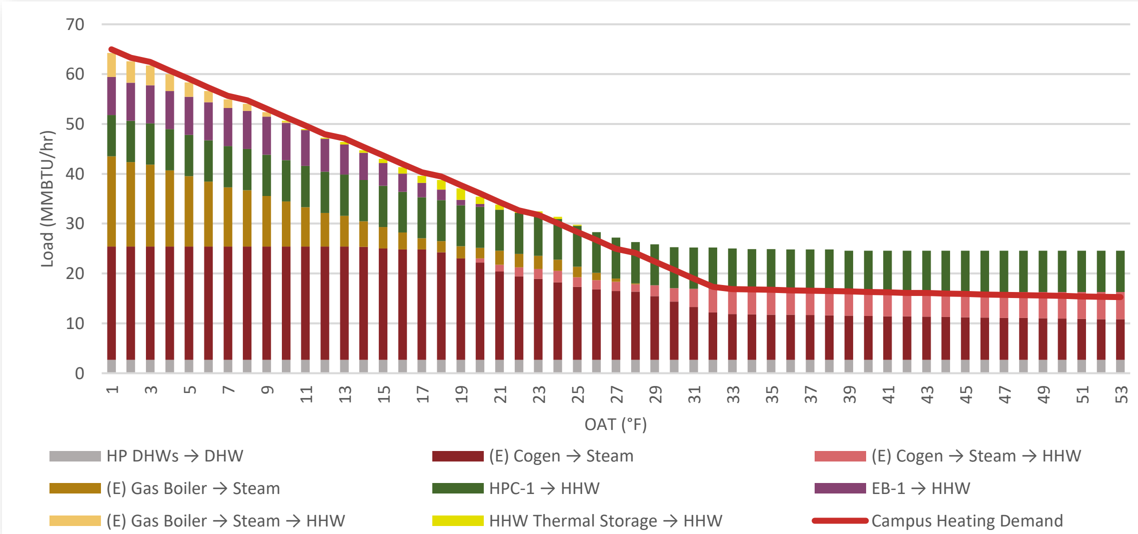


Figure 39 - Path #3, Year 2030, Cooling Loads vs. OAT

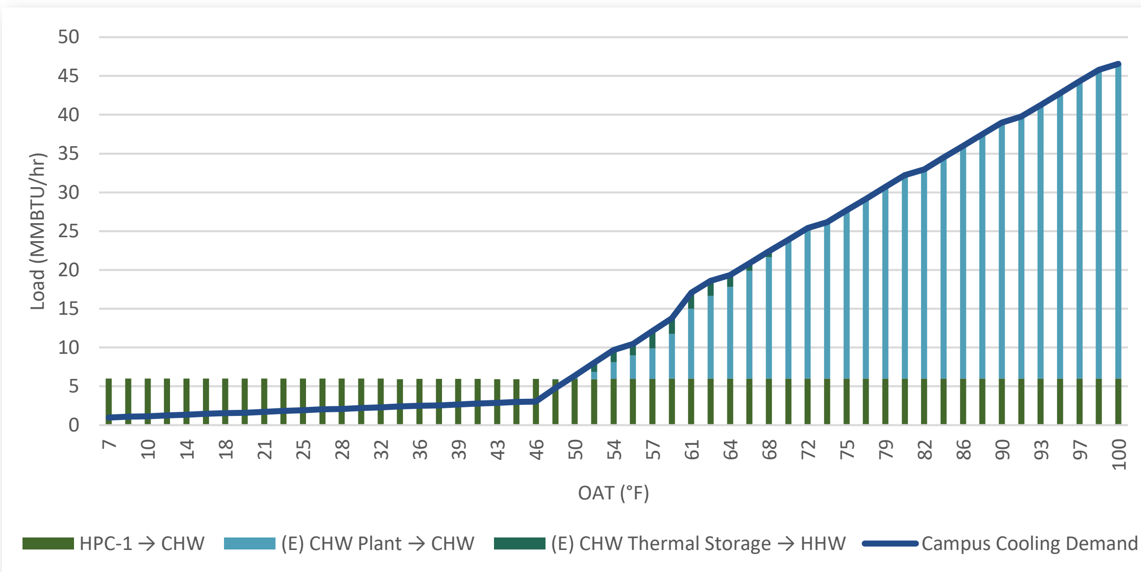
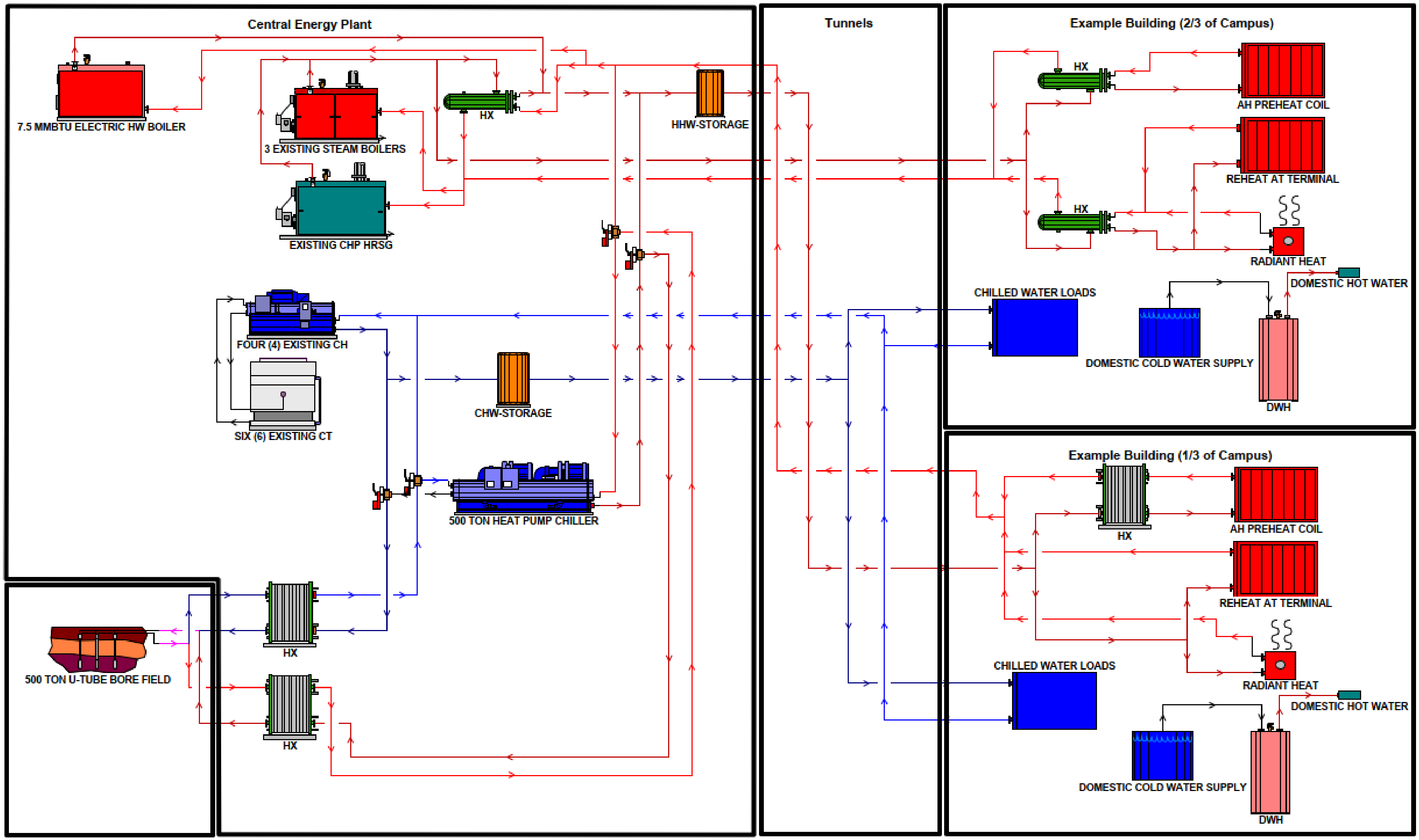


Figure 40- Path #3, Year 2030, CEP Equipment



5.3.3.8 2035-2039 CEP Operations

Summary

By year 2035 the projects described in section 5.3.2.1, 5.3.2.2, and 5.3.2.3 would have been implemented and 2/3 of heating loads served by the CEP would be converted to 140 °F heating hot water. Steam heating would be provided by cogeneration and steam boilers. Heating hot water would be provided by heat pump chillers and electric boilers with peak heating demand supplied by steam to HHW heat exchangers. Throughout the year, cogeneration would be operating and providing steam and heating hot water to campus. The heat pump chillers, electric boilers, and steam boilers would be used to meet any additional heating hot water loads.

Cogeneration

Cogeneration would operate during the winter and shoulder seasons and shut down from mid/late April to mid/late October. The cogeneration heat recovery steam generator would provide steam and heating hot water to campus when operating.

Gas Boilers

Existing gas steam boilers operate at a reduced load relative to historical operation and provide steam and heating hot water to campus.

Steam Heating

Cogeneration and existing gas steam boilers provide steam for heating to 1/3 of the campus.

Heating Hot Water

Two 500-ton heat pump chillers, two 7.6 MMBtu/hr electric boilers, and steam-to-hot-water heat exchangers supplied from cogeneration and/or gas steam boiler provide heating hot water to 2/3 of the campus.

Chilled Water

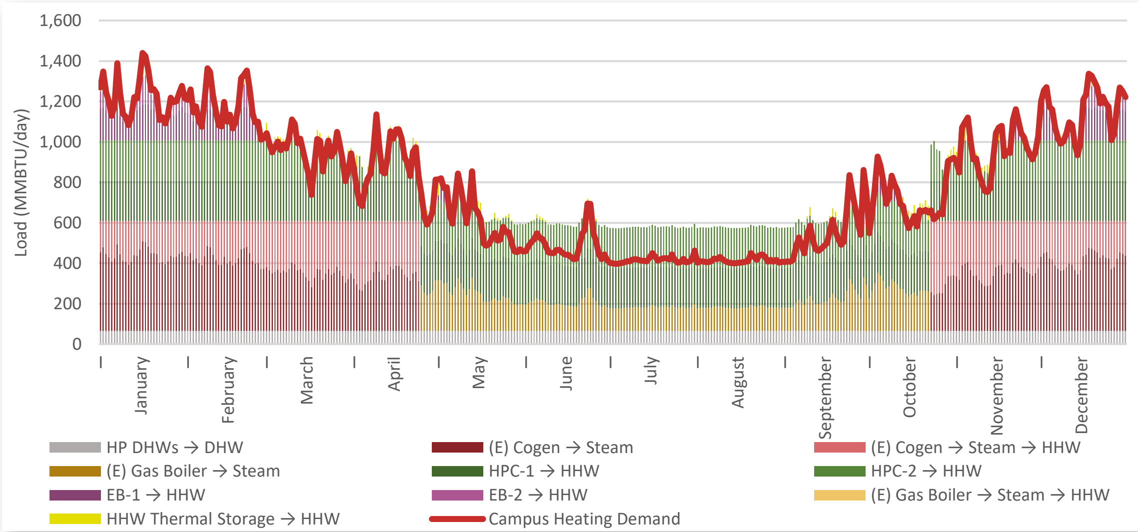
Two 500-ton heat pump chillers would operate near full capacity for much of the year. Additional chilled water would be provided by the existing chilled water operating similar to its historical operation but at a reduced load.

Heat Pump Chiller Operation

The heat pump chillers would control the campus heating or cooling load depending on which load is higher. Operating the heat pump chillers in this manner ensures a high asset utilization rate. With this operation the heat pump chiller would be able to fully meet the summer and shoulder season HHW demand and provide CHW to the campus. During the winter, the heat pump chillers would fully meet campus CHW demand.

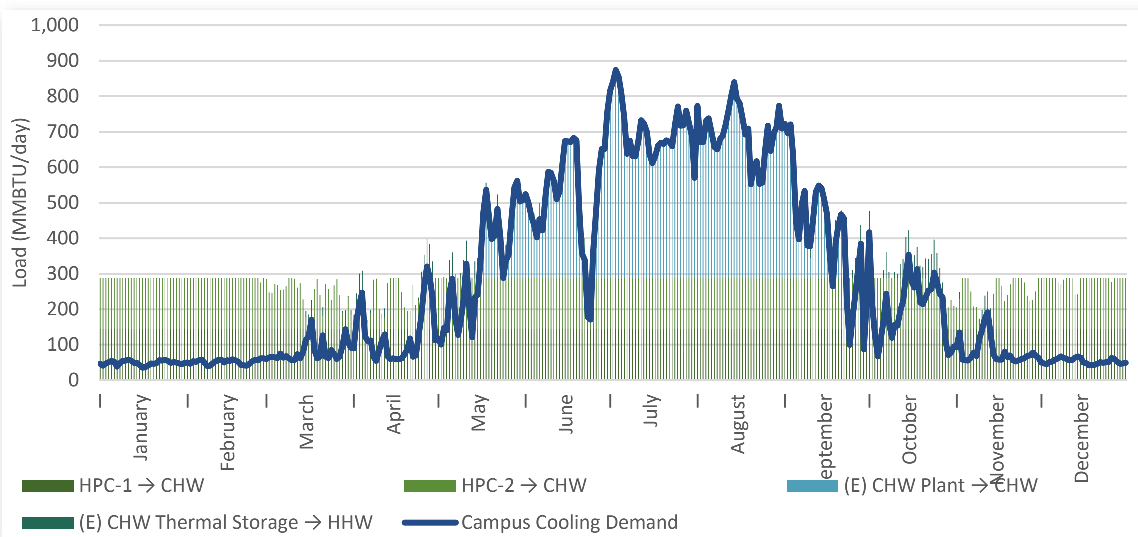
Any excess CHW or HHW produced would be directed to the geothermal U-tube bore hole loop. Due to the yearly imbalance of the heating and cooling loads at the campus, more energy would be pulled from the ground in the winter than is put into the ground in the summer. This imbalance, if left unaddressed, could lead to a depletion of energy in the ground, reducing the effectiveness of the geothermal U-tube bore hole loop. This requires USU to monitor the ground temperature and correct the imbalance when required. Correcting the imbalance involves running the existing gas steam boilers and rejecting the heat produced into the geothermal loop.

Figure 41 - Path #3, Year 2035, Daily Heating Loads



Campus heating loads are met by several pieces of equipment. By year 2030 2/3 of the campus would be on HHW and would be supplied by two 500-ton heat pump chillers, two 7.6 MMBtu/hr electric boiler, and cogeneration through a steam to HHW heat exchanger. At peak heating, an existing steam boiler would be used to provide HHW. The steam loads on campus would be provided by the cogeneration heat recovery steam generator and steam gas boilers. Excess HHW and excess CHW produced by the heat pump chillers would be directed into the geothermal U-tube bore hole loop. Cogeneration would shut down from mid/late April to mid/late October. Building level heat pumps provide domestic hot water.

Figure 42 - Path #3, Year 2035, Daily Cooling Loads



Campus cooling loads would be met with two heat pump chillers operating close to full capacity throughout the year and the existing chilled water plant. Excess CHW produced by the heat pump chillers would be directed into the geothermal U-tube bore hole loop.

Figure 43 - Path #3, Year 2035, Heating Loads vs. OAT

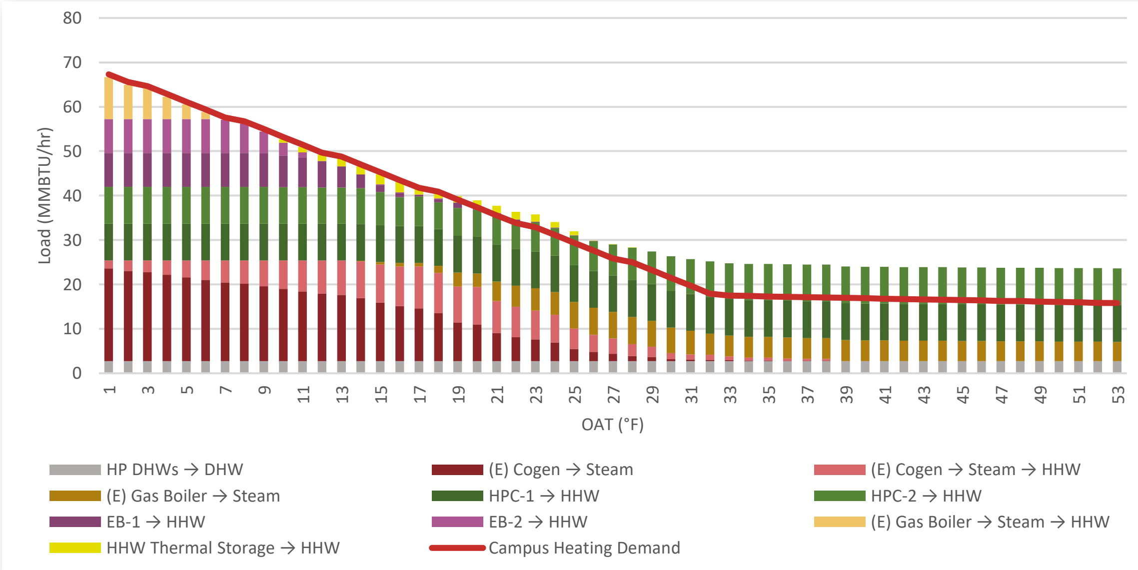


Figure 44 - Path #3, Year 2035, Cooling Loads vs. OAT

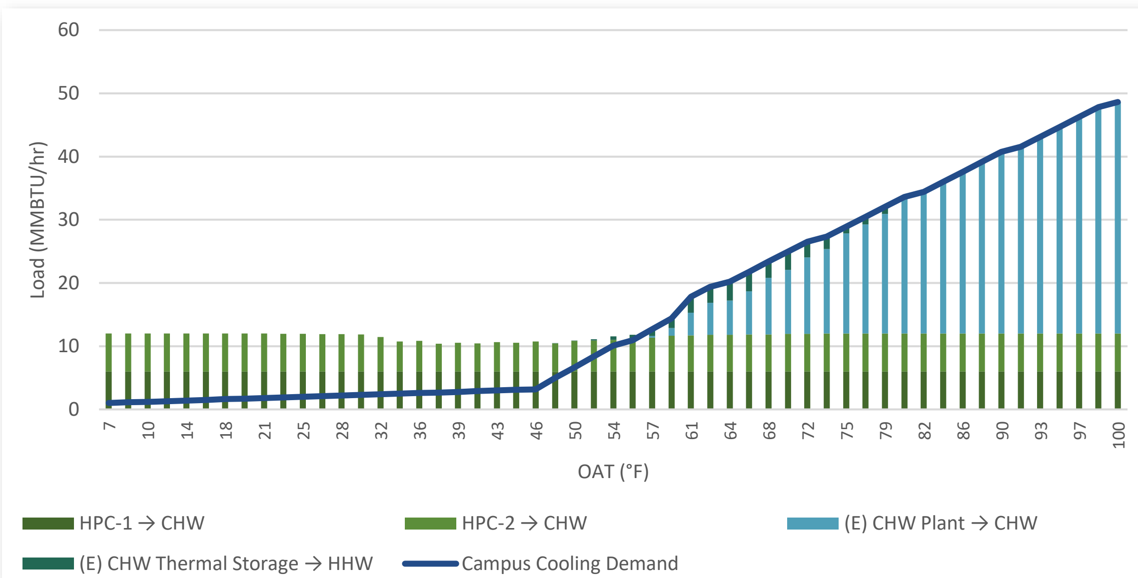
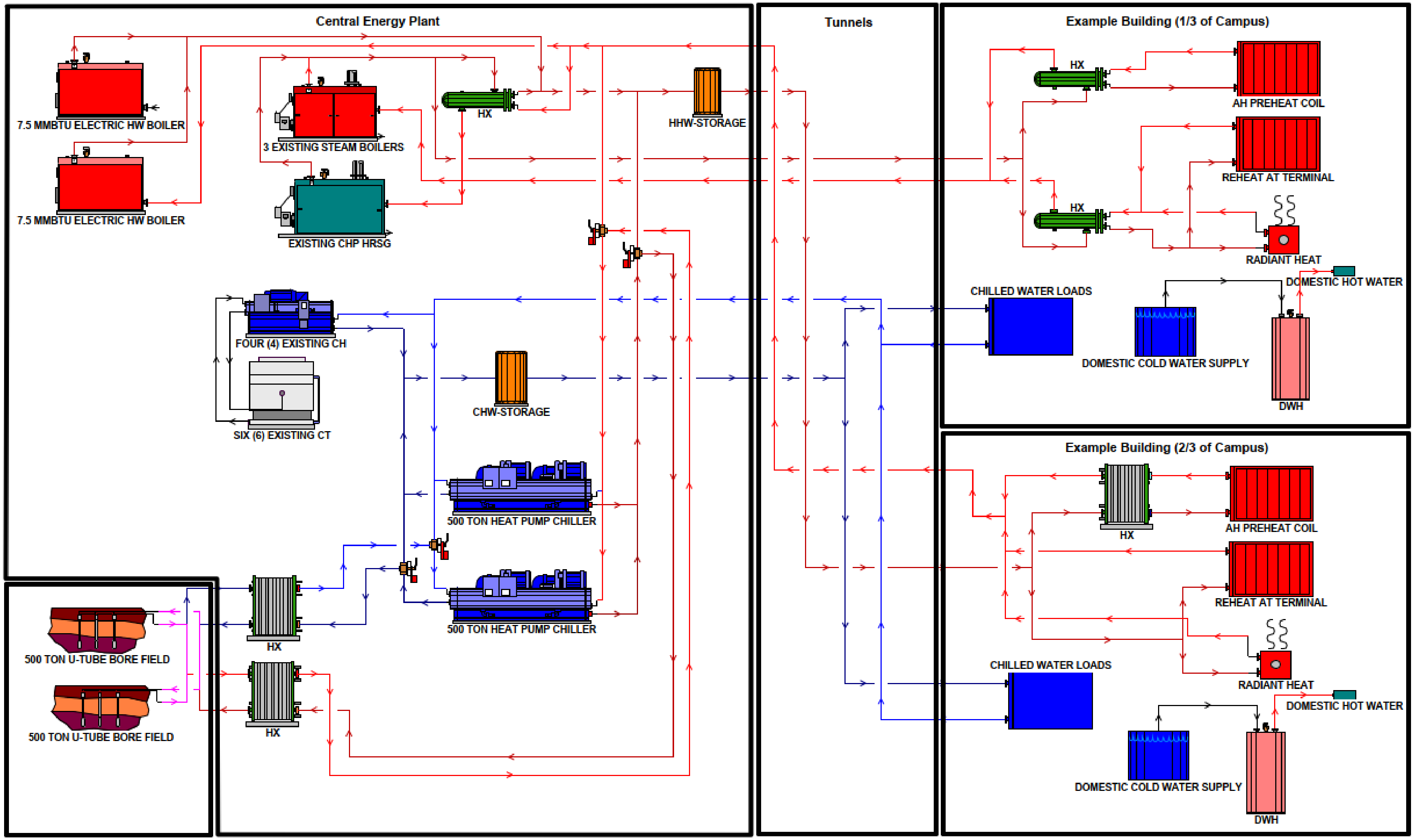


Figure 45 - Path #3, Year 2035, CEP Equipment



5.3.3.9 2040-Future CEP Operations

Summary

By year 2035, the projects described in section 5.3.2.1, 5.3.2.2, 5.3.2.3, and 5.3.2.4 would have been implemented and all the heating loads served by the CEP would be converted to 140 °F heating hot water. Heating hot water would be provided by heat pump chillers and electric boilers with peak heating demand supplied by steam to HHW heat exchangers. Cogeneration would be fully shut down.

Cogeneration

Cogeneration no longer operates and is shut down.

Gas Boilers

Existing gas steam boilers only operate to cover peak heating hot water loads.

Steam Heating

Steam would no longer be required for heating; however, the steam infrastructure would remain in place for emergency and redundancy.

Heating Hot Water

Three 500-ton heat pump chillers, three 7.6 MMBtu/hr electric boilers, and steam-to-hot-water heat exchangers supplied from gas steam boilers will provide heating hot water to campus.

Chilled Water

Three 500-ton heat pump chillers would operate near full capacity for much of the year. Additional chilled water would be provided by the existing chilled water operating similar to its historical operation but at a reduced load.

Heat Pump Chiller Operation

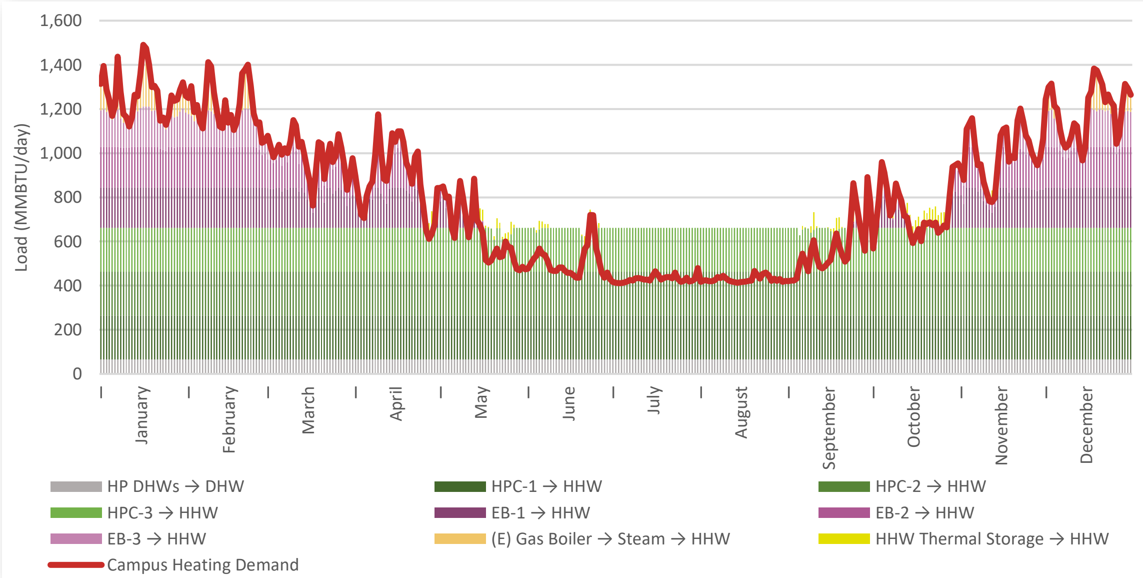
The heat pump chillers would control to the campus heating or cooling load depending on which load is higher. Operating the heat pump chillers in this manner ensures a high asset utilization rate. With this operation, the heat pump chiller would be able to fully meet the summer and shoulder season HHW demand and provide CHW to the campus. During the winter the heat pump chillers would fully meet campus CHW demand.

Any excess CHW or HHW produced would be directed to the geothermal U-tube bore hole loop. Due to the yearly imbalance of the heating and cooling loads at the campus more energy would be pulled from the ground in the winter than is put into the ground in the summer. This imbalance, if left unaddressed, could lead to a depletion of energy in the ground reducing the effectiveness of the geothermal U-tube bore hole loop. This requires USU to monitor the ground temperature and correct the imbalance when required. Correcting the imbalance involves installing and running 1,200 tons of air source heat pumps and rejecting the heat produced into the geothermal loop.

Air Source Heat Pump Operation

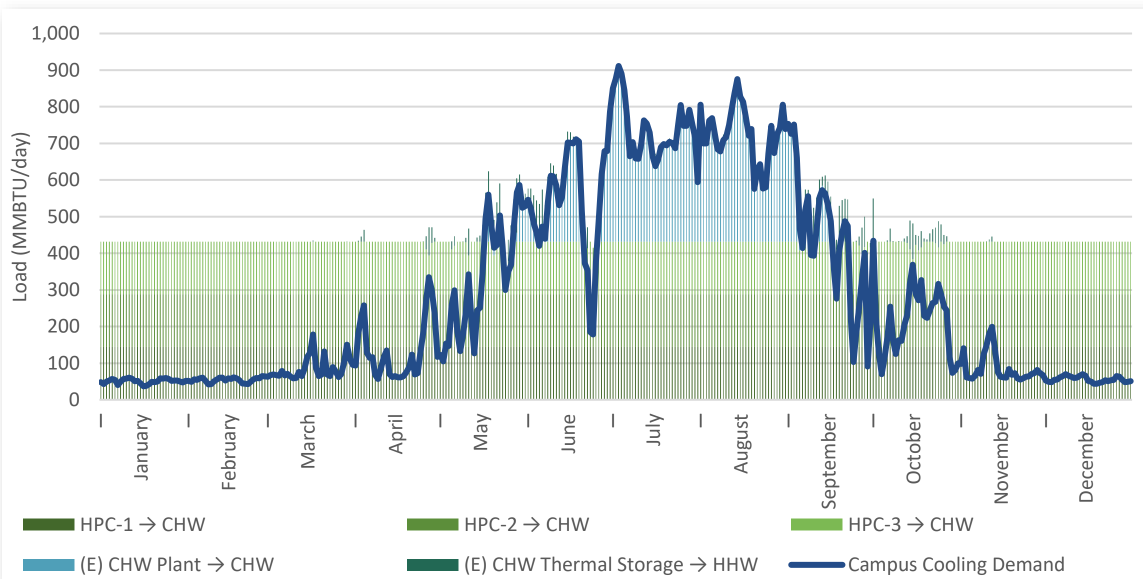
The air source heat pump system would only operate to increase the ground temperature. The air source heat pump would only operate when the outside air temperature is favorable to its efficiency (e.g., when the outside air temperature is above 55°F).

Figure 46 - Path #3, Year 2040, Daily Heating Loads



Campus heating loads are met by several pieces of equipment. By year 2040 all the campus would be on HHW and would be supplied by three 500-ton heat pump chillers, three 7.6 MMBtu/hr electric boilers, and existing steam boilers through a steam-to-HHW heat exchanger. Excess HHW and CHW produced by the heat pump chillers would be directed into the geothermal U-tube bore hole loop. Cogeneration would be fully shut down. Building level heat pumps provide domestic hot water.

Figure 47 - Path #3, Year 2040, Daily Cooling Loads



Campus cooling loads would be met with the existing chilled water plant and three heat pump chillers operating close to full capacity throughout the year. Excess CHW produced by the heat pump chillers would be directed into the geothermal U-tube bore hole loop.

Figure 48 - Path #3, Year 2040, Heating Loads vs. OAT

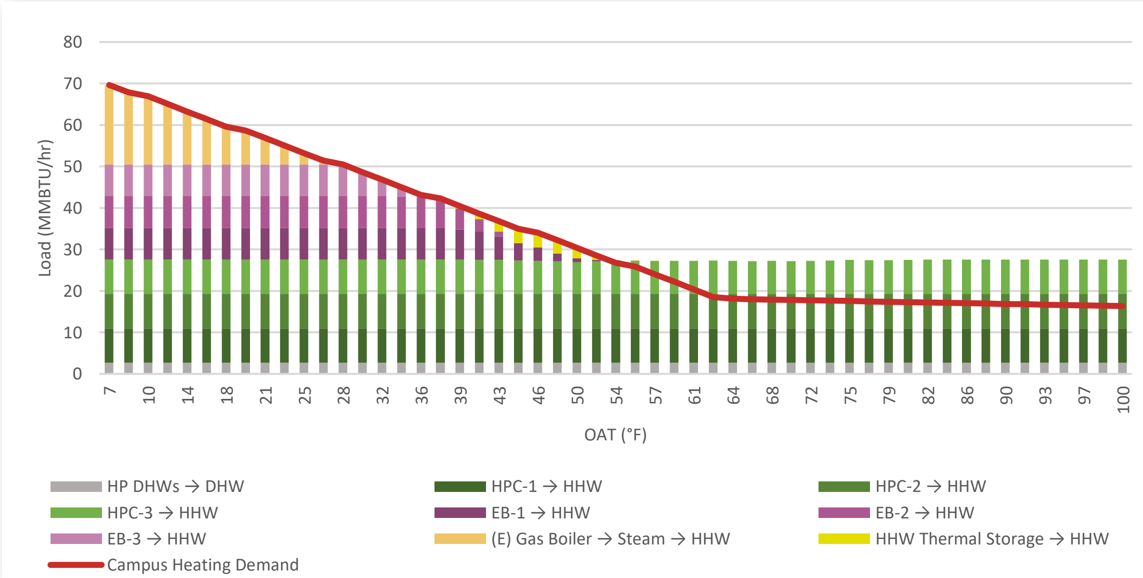


Figure 49 - Path #3, Year 2040, Cooling Loads vs. OAT

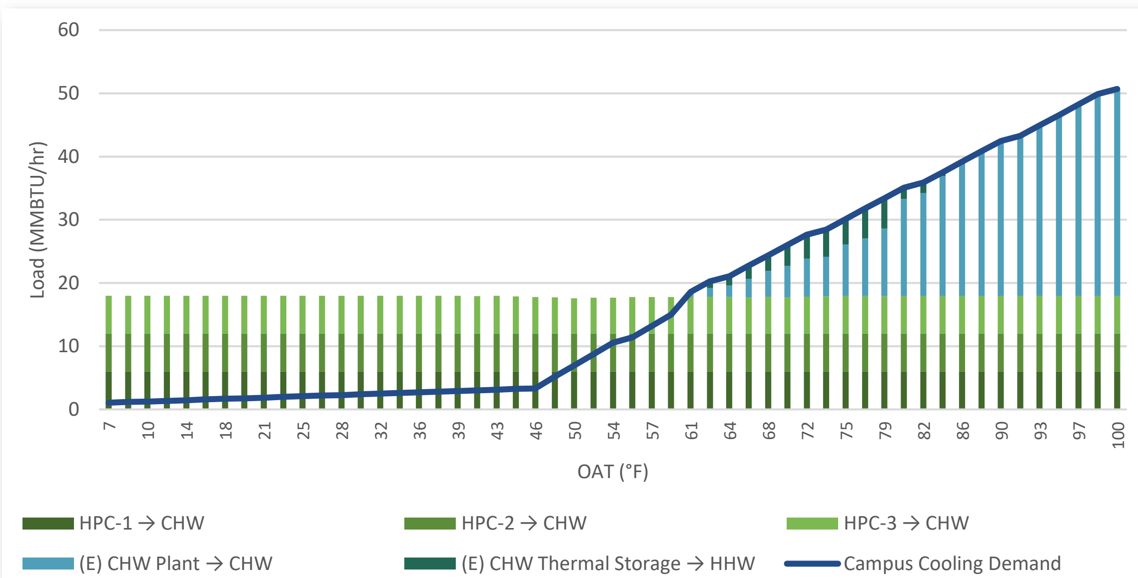
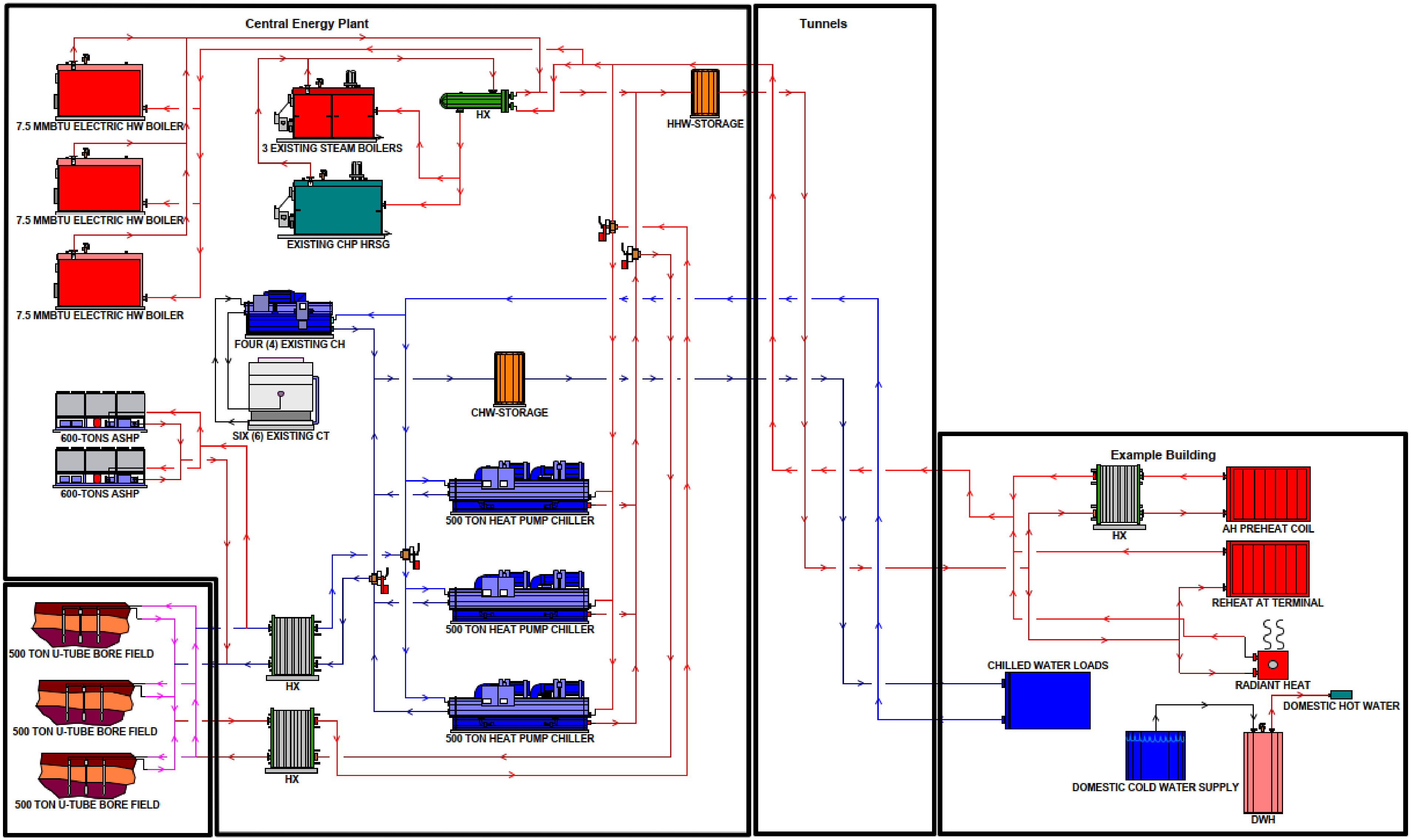


Figure 50 - Path #3, Year 2040, CEP Equipment



5.4 Path #4

5.4.1 Overall Description

Path #4 is identical to Path #3 (described in section 5.3); however, 2.1 MW of on-site solar would be installed in each 5-year period. See **Figure 51 and Figure 52** for possible areas for installing on-site solar at the campus.

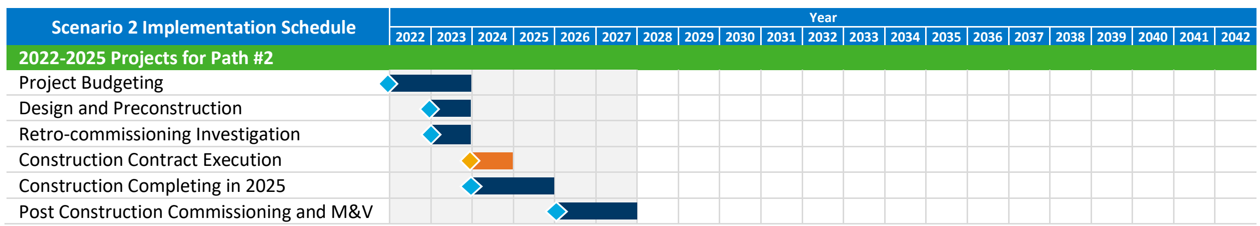
Figure 51 - Possible Parking Lot Solar Locations

Figure 52 - Possible Ground-Mount Solar Locations

6. Implementation Schedule

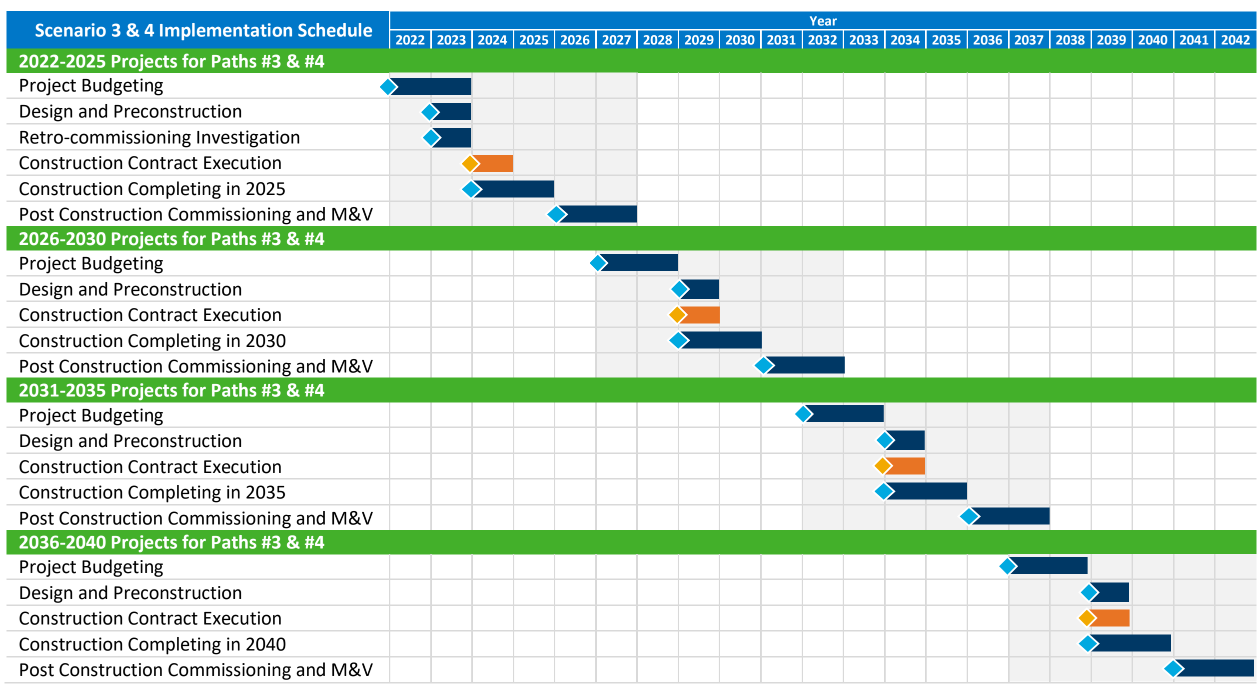
6.1 Path #2

Figure 53 - Path #2 Implementation Schedule



6.2 Paths #3 & #4

Figure 54 - Paths #3 and #4 Implementation Schedule



7. Project Costing

7.1 Estimating Process and Background

The design-build construction cost estimates were developed by Willdan's in-house pre-construction team. The Willdan team used as much information as possible to develop conceptual level estimates that can serve as the foundation for sound decision making. Our process included:

- Receiving pricing feedback from local subcontractors for the most complicated HVAC scopes.
- Referring to existing plans and utility maps to develop accurate takeoffs.
- Using the RSmeans pricing database to inform unit pricing assumptions.
- Including estimated contingency to account for project unknowns.

The design-build contract estimates are all-in costs and include anticipated soft costs to engineer and commission the projects. All costs listed below are in 2022 dollars. Additionally, the projects are considered incremental costs above and beyond required maintenance and equipment costs.

7.2 Path #1

Path #1, business as usual, does not assume any capital-intensive engineering or construction projects in the future.

7.3 Path #2

Table 6 - Path #2 Project Costs (2022$)

Estimated Engineering and Construction Costs for Path #2		
2022 - 2025 Projects for Path #2		
Deep Energy Efficiency Retrofits	$	9,541,656
Domestic Hot Water Heat Pumps	$	23,293,165
All Years Estimated Engineering and Construction Costs:	**$**	**32,834,821**

7.4 Path #3

Table 7 - Path #3 Project Costs (2022$)

Estimated Engineering and Construction Costs for Path #3		
2022 - 2025 Projects for Path #3		
Deep Energy Efficiency Retrofits	$	9,541,656
Domestic Hot Water Heat Pumps	$	23,293,165
Total:	**$**	**32,834,821**
2026 - 2030 Projects for Path #3		
Hydronic Hot Water Thermal Energy Storage	$	6,500,468
Steam to HHW Heat Exchangers and HHW Pumps	$	425,677
Extend HHW Mains in Existing Tunnels and Add Buildings to HHW Loop	$	12,036,243
Airside Hot Water Coil Replacements	$	4,855,117
500 Tons of Heat Pump/Heat Recovery Chiller Capacity	$	4,784,921
500 Tons of U-Tube Geothermal Borefield Capacity	$	12,152,627
7.6 MMBtu Electric HHW Boiler	$	2,018,072
Increase Size of Central Energy Plant to Accommodate New Equipment	$	1,560,112
Total:	**$**	**44,333,237**
2031 - 2035 Projects for Path #3		
Extend HHW Mains in Existing Tunnels and Add Buildings to HHW Loop	$	6,314,808
Airside Hot Water Coil Replacements	$	4,855,117
500 Tons of Heat Pump/Heat Recovery Chiller Capacity	$	4,784,921
500 Tons of U-Tube Geothermal Borefield Capacity	$	12,152,627
7.6 MMBtu Electric HHW Boiler	$	2,018,072
Total:	**$**	**30,125,545**
2036 - 2040 Projects for Path #3		
Extend HHW mains in Existing Tunnels and Add Buildings to HHW Loop	$	6,223,930
Airside Hot Water Coil Replacements	$	4,855,117
500 Tons of Heat Pump/Heat Recovery Chiller Capacity	$	4,784,921
500 Tons U-Tube Geothermal Borefield Capacity	$	12,152,627
7.6 MMBtu Electric HHW Boiler	$	2,018,072
Install 1,200 Tons of Air Source Heat Pump Capacity	$	3,326,522
Total:	**$**	**33,361,189**
All Years Estimated Engineering and Construction Costs:	**$**	**140,654,792**

7.5 Path #4

Table 8 - Path #4 Project Costs (2022$)

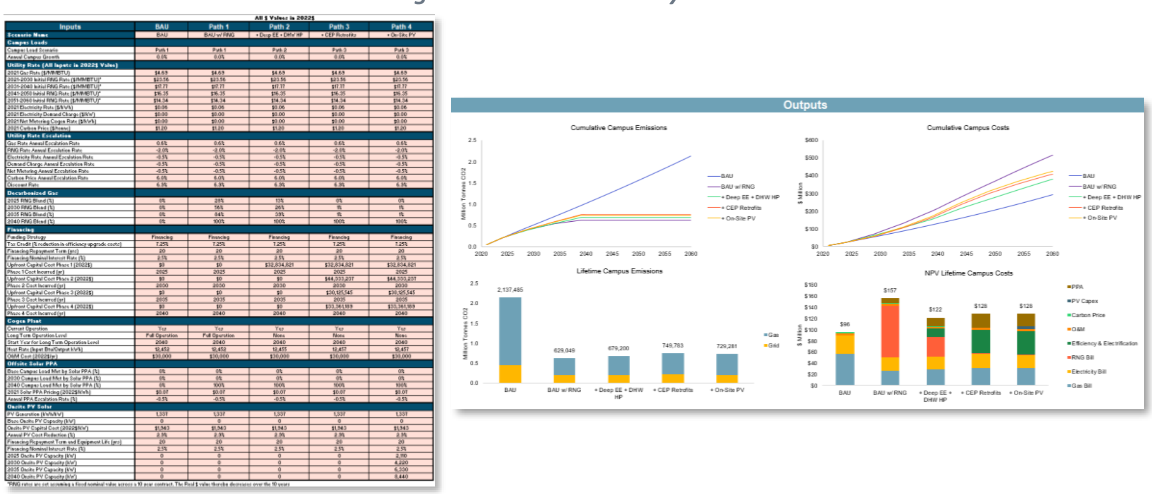
Estimated Engineering and Construction Costs for Path #4		
2022 - 2025 Projects for Path #4		
Deep Energy Efficiency Retrofits	$	9,541,656
Domestic Hot Water Heat Pumps	$	23,293,165
On-Site Solar	$	4,099,882
Total:	**$**	**36,934,703**
2026 - 2030 Projects for Path #4		
Hydronic Hot Water Thermal Energy Storage	$	6,500,468
Steam to HHW Heat Exchangers and HHW Pumps	$	425,677
Extend HHW mains in Existing Tunnels and Add Buildings to HHW Loop	$	12,036,243
Airside Hot Water Coil Replacements	$	4,855,117
500 Tons of Heat Pump/Heat Recovery Chiller Capacity	$	4,784,921
500 Tons of U-Tube Geothermal Borefield Capacity	$	12,152,627
7.6 MMBtu Electric HHW Boiler	$	2,018,072
Increase Size of Central Energy Plant to Accommodate New Equipment	$	1,560,112
On-Site Solar	$	4,099,882
Total:	**$**	**48,433,119**
2031 - 2035 Projects for Path #4		
Extend HHW mains in Existing Tunnels and Add Buildings to HHW Loop	$	6,314,808
Airside Hot Water Coil Replacements	$	4,855,117
500 Tons of Heat Pump/Heat Recovery Chiller Capacity	$	4,784,921
500 Tons of U-Tube Geothermal Borefield Capacity	$	12,152,627
7.6 MMBtu Electric HHW Boiler	$	2,018,072
On-Site Solar	$	4,099,882
Total:	**$**	**34,225,427**
2036 - 2040 Projects for Path #4		
Extend HHW mains in Existing Tunnels and Add Buildings to HHW Loop	$	6,223,930
Airside Hot Water Coil Replacements	$	4,855,117
500 Tons of Heat Pump/Heat Recovery Chiller Capacity	$	4,784,921
500 Tons U-Tube Geothermal Borefield Capacity	$	12,152,627
7.6 MMBtu Electric HHW Boiler	$	2,018,072
On-Site Solar	$	4,099,882
Install 1,200 Tons of Air Source Heat Pump Capacity	$	3,326,522
Total:	**$**	**37,461,071**
All Years Estimated Engineering and Construction Costs:	**$**	**157,054,318**

8. Carbon Accounting and Lifecycle Costing

8.1 Model Methodology

Once pathways were developed, Willdan and E3 collected the inputs required to model lifecycle costs and carbon emissions as relevant for the projects. Model inputs include details on campus operations, systems, loads, utility costs, capital project costs, and individual project timelines. Inputs were gathered or derived from campus data, internal pro-forma valuations, and publicly available sources. Using campus data, Willdan developed annual campus load profiles for business-as-usual and each decarbonization pathway. After all load profiles were established, E3 input these into a custom-built Scenario Analysis Tool (SAT). This tool is an Excel dashboard to evaluate pathways measure-by-measure. The SAT offers users the ability to adjust pathway inputs and run sensitivity analyses, ultimately outputting campus emissions and expenditure trajectories. A snapshot of the SAT can be seen in **Figure 55**. Using the scenario analysis tool, E3 and Willdan evaluated the different pathways being considered, comparing financial performance as well as the projected magnitude and speed of GHG emissions reductions achieved.

Figure 55 - Scenario Analysis Tool



8.1.1 Assumptions Across Pathways

Across all pathways, key assumptions have been made on model parameters including utility rates, campus growth rate, cogeneration plant operation, and emissions factors and pricing (**Table 9**). Additional assumptions regarding on-site PV solar, solar power purchase agreement (PPA), and renewable natural gas (RNG) costs are also held constant (**Table 10**), though they are only relevant in certain pathways. Each of these default values have been selected based on publicly available data for the Mountain/West region of the United States as a whole. Input sources labeled as E3 Assumption are either derived from previous projects, standard market assumptions, or E3's internal pro forma valuations. E3 and Willdan recognize that some of these assumptions are not definite and may merit further exploration in future analyses.

Two sets of inputs are modified from the original source data to better align with Utah State University's circumstances. The first is the grid emissions factors, which come originally from the National Renewable Energy Laboratory's Cambium Model. Cambium provides emissions factors for Utah as a whole, but it does not provide data at the utility level. The forecasted state-wide factors fall short of Logan City Light & Power's commitment to 50% renewable adoption by 2030. To address this, the 2021 and 2022 Cambium factors are preserved, but emissions reductions are accelerated so that the Cambium Utah 2050 emissions factor is instead achieved by 2030 and applied to all following years. This would reflect approximately 45% renewable energy adoption and is therefore still a slightly conservative assumption.

The second modified input is the renewable PPA price, which applies to all non-BAU pathways but most heavily impacts Paths #2-4. Here the value was determined by taking the combined average price point of solar combined with storage PPAs provided by the Berkeley Laboratory Utility Scale Solar report, selecting projects at or below 100MW in the southwestern continental United States. This resulted in a price of approximately $0.05 per kWh, which is escalated to $0.07 to meet assumptions for the location and smaller expected PPA sizing.

Table 9 - Default Inputs Across All Pathways

Category	Input	Input Source
Campus Annual Growth Rate	0.5%	E3 Assumption
Economic Parameters		
Inflation Rate	2.0%	E3 Assumption
Discount Rate	6.9% real (9.0% nominal)	E3 Assumption
Utility Rates		
2022 Electricity Rate ($/kWh)	$0.0627	Provided by USU
2022 Gas Rate ($/MMBtu)	$4.7188	Provided by USU
Electricity Annual Escalation Rate	-0.5% real (1.5% nominal)	U.S. EIA Annual Energy Outlook
Gas Annual Escalation Rate	0.6% real (2.6% nominal)	U.S. EIA Annual Energy Outlook
Cogeneration Plant Parameters		
Cogeneration Heat Rate (Btu/kWh)	12,450	Provided by USU
O&M Cost (2022$/yr)	$30,000	Determined by Willdan
Carbon Pricing		
2022 Carbon Price ($/ton CO_2e)	$1.20	2021 IEPR GHG Allowance Price Projections, Mid Case
Carbon Price Annual Escalation Rate	6.0% real (8.1% nominal)	2021 IEPR GHG Allowance Price Projections, Mid Case
Emissions Factors		
2022 Grid Emissions Factor (kg CO_2e/kWh)	0.487	NREL Cambium Model – Utah Long Run Marginal Emissions Rate
Cogeneration Non-RNG Emission Factor (kg CO_2E/MMBtu)	52.912	U.S. Energy Information Administration

Table 10 - Default Inputs Across All Applicable Pathways

Category	Input	Input Source
Renewable Natural Gas (RNG)*		
2021-2030 Initial RNG Rate (2022$/MMBtu)	$23.56	UC Davis Study[3]
2031-2040 Initial RNG Rate (2022$/MMBtu)	$17.77	UC Davis Study
2041-2050 Initial RNG Rate (2022$/MMBtu)	$16.35	UC Davis Study
2051-2060 Initial RNG Rate (2022$/MMBtu)	$14.34	UC Davis Study
Off-Site PV Solar PPA		
2022 PPA Rate ($/kWh)	$0.07	E3 Assumption from Berkeley National Laboratory data
Annual PPA Escalation Rate (%)	-0.5% real (1.5% nominal)	E3 Assumption
On-Site PV Solar*		
Lifetime Generation Rate (kWh/kW)	1,337	Determined by Willdan/E3
2022 On-Site PV Capex ($/kW)	$1,943	E3 Pro Forma Assumption
PV Capex Annual Reduction Rate	2.9% real (1.0% nominal)	E3 Pro Forma Assumption
Financing Term (yrs)	20	E3 Assumption
PV Equipment Life (yrs)	20	E3 Assumption
Financing Nominal Interest Rate (%)	2.5%	E3 Assumption

**RNG rates are modeled to be set to fixed nominal rates in the first year of a ten-year contract. The Real $ value therefore decreases each year within the ten years until the contract is renegotiated. Similar assumptions are made for on-site solar and the energy efficiency and electrification upgrades, with fixed nominal rates set in the year costs are incurred*

[3] *Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute*, A. M. Jaffe, Institute of Transportation Studies, UC Davis 2016

8.1.2 Pathway-Specific Inputs

To meet USU's commitment to decarbonization by 2040, all pathways outside of 'business-as-usual' assume that the campus will transition any gas it uses to RNG by 2040, and that any electricity demand that is not otherwise decarbonized will be met by an off-site solar PPA. The natural gas transition is assumed to be stepped in five-year increments, so that every five years the amount of RNG consumed is increased by another 25% of the projected 2040 gas load. Because the use of gas increases during the time horizon in Path #1 and decreases in Paths #2-4, the consumption of RNG as a percent of each year's total gas consumption does not directly align with 25%, 50%, and 75% in intermediate years, but does achieve 100% in 2040. The PPA is modeled for a full transition in 2040 to show the bare minimum necessary to reach the decarbonization goal. Path #1 is based solely on this RNG and PPA transition.

Each pathway modeled reflects the implementation of incremental decarbonization measures on top of the prior pathway. This means that Path #2 reflects including deep energy efficiency and domestic hot water heat pumps in addition to the RNG and PPA transition of Path #1. Path #3 incorporates all of Paths #1 and #2 measures as well as additional central energy plant retrofits. Path #4 assumes all measures from Paths #1-3 and the addition of on-site PV solar.

Implementation of measures for Paths #2 and #3 is set to occur in five-year steps until 2040. Rather than incurring the cost for each measure in the year of implementation, each set of measures is assumed to be financed individually over a longer period. To incorporate the expected life span of equipment and financing periods, modeling goes through 2060.

Path #4 models the addition of on-site solar in a similar manner, with PV capacity added linearly and costs incurred in five-year increments from 2025 to 2040, with 20-year financing for each addition of on-site solar. The cumulative total capacity is listed in **Table 11**, with representative upfront costs below. In the model itself, solar is presumed to be financed following the assumptions listed in **Table 10**. The model accounts for the lifespan of the solar with replacement costs for each tranche to maintain the 2040 capacity levels through 2060. Note that this only indicates impacts of new on-site solar, as USU's existing solar is already incorporated into the base cost and load assumptions.

Tax credit values noted in the inputs are based on anticipated availability from the Inflation Reduction Act. The Act provides for public, non-profit entities to receive the benefits of what would be tax credits through incentive measures instead. Recovery of these funds is dependent upon expected levels of efficiency improvements and emission reductions relative to USU's current performance. The impact of the $0.50/sqft incentive noted below is averaged across measures and expected areas of relevance to result in a 7.25% reduction in energy efficiency upgrade costs, as is input in the Scenario Analysis Tool.

The equipment updates and retrofits in Paths #2-4 would also result in varying levels of annual expense for water treatment/consumption and maintenance staff as compared to BAU or Path #1. These values were determined by Willdan separately from the upfront implementation costs.

Table 11 depicts the cost and financing basis for each pathway as determined by Willdan and E3, providing snapshots of the expenses in years that upgrade costs are incurred. The expenses are scaled between each step and to both ends of the model horizon, based on assumed campus growth.

Table 11 - Pathway-Specific Inputs

	Path #1 BAU w/ RNG	Path #2 + Deep EE + DHW HP	Path #3 + CEP Retrofits	Path #4 + On-Site Solar
RNG Use (% of projected 2040 gas use)				
2025 RNG Blend (%)	25%	25%	25%	25%
2030 RNG Blend (%)	50%	50%	50%	50%
2035 RNG Blend (%)	75%	75%	75%	75%
2040 RNG Blend (%)	100%	100%	100%	100%
Efficiency & Electrification Upgrades				
Financing Interest Rate (Nominal %)	-	2.5%	2.5%	2.5%
Financing Period (yrs)	-	20	20	20
Tax Credit ($/sqft)	-	$0.50	$0.50	$0.50
2025 Measures Upfront Cost	-	$32.8M	$32.8M	$32.8M
2030 Measures Upfront Cost	-	-	$44.3M	$44.3M
2035 Measures Upfront Cost	-	-	$30.1M	$30.1M
2040 Measures Upfront Cost	-	-	$30.0M	$30.0M
Equipment-Related Water + Maintenance Staff Expenses				
2025 Expense	$234,519	$200,779	$200,779	$200,779
2030 Expense	$244,379	$206,849	$165,686	$165,686
2035 Expense	$259,280	$215,280	$162,500	$162,500
2040 Expense	$264,278	$223,739	$141,555	$141,555
On-Site Solar				
2025 Cumulative Capacity (kW)	-	-	-	2,110
2030 Cumulative Capacity (kW)	-	-	-	4,220
2035 Cumulative Capacity (kW)	-	-	-	6,330
2040 Cumulative Capacity (kW)	-	-	-	8,440
2025 New Installation Cost	-	-	-	$3.8M
2030 New Installation Cost	-	-	-	$3.2M
2035 New Installation Cost	-	-	-	$2.8M
2040 New Installation Cost	-	-	-	$2.4M

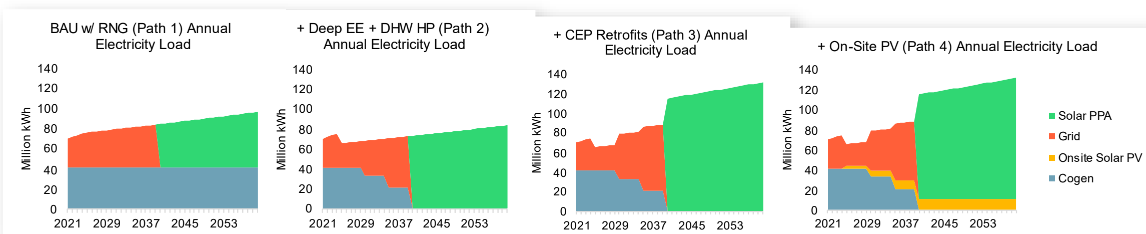
8.2 Emissions and Costing Results

8.2.3 Electricity Load

Year-by-Year Impacts

All pathways evaluated for this analysis experience some increase in electric loads due to campus growth. In 2025, Paths #2-4 experience a 12% reduction in electric load from the implementation of deep energy efficiency retrofits and installation of domestic hot water heat pumps. In 2030 and 2035, Paths #3 and #4 both experience a 17% and then 6% year-over-year increase in electric load from the implementation of central energy plant retrofits. The stepdown of the cogeneration plant further increases demand for grid-supplied electricity, mitigated partially by on-site solar in Path #4. In 2040, all grid electricity is shifted to a solar PPA to achieve full decarbonization. A breakdown of annual electricity load for each pathway can be found in **Figure 56**.

Figure 56 - Annual Electricity Load by Generator



Lifetime Impacts

From today to 2060, deep energy efficiency retrofits and the installation of domestic hot water heat pumps (Path #2) reduce lifetime electric load by about 13% compared to 'business-as-usual.' With the further addition of the central energy plant retrofits (Path #3 or #4), lifetime electric load increases by about 37% over the Path #2, or 19% over 'business-as-usual.' As Paths #2-4 first gradually reduce reliance on the cogeneration plant until shutoff in 2040, lifetime cogeneration electric generation decreases by 61%. With the addition of on-site solar, 9% of lifetime electric generation is shifted to on-site solar PV. A breakdown of lifetime electric load for each pathway can be found in **Figure 57** and in **Table 12**.

Figure 57- Lifetime Electricity Load by Generator

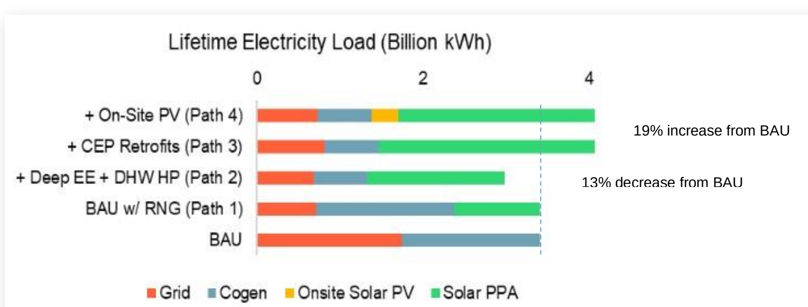


Table 12 - Lifetime Electric Load by Generator (MWh)

Generator	BAU	Path #1 BAU w/ RNG	Path #2 + Deep EE + DHW HP	Path #3 + CEP Retrofits	Path #4 + On-Site Solar
Grid	1,746,093,629	708,338,222	685,795,779	820,368,586	735,758,843
Cogeneration	1,662,224,120	1,662,224,120	645,307,281	645,307,281	645,307,281
On-Site Solar PV	-	-	-	-	321,517,022
Solar PPA	-	1,037,755,407	1,646,420,665	2,602,280,279	2,365,373,000
Total	**3,408,317,748**	**3,408,317,748**	**2,977,523,725**	**4,067,956,146**	**4,067,956,146**
Savings	**-**	**-**	**430,794**	**(659,638)**	**(659,638)**

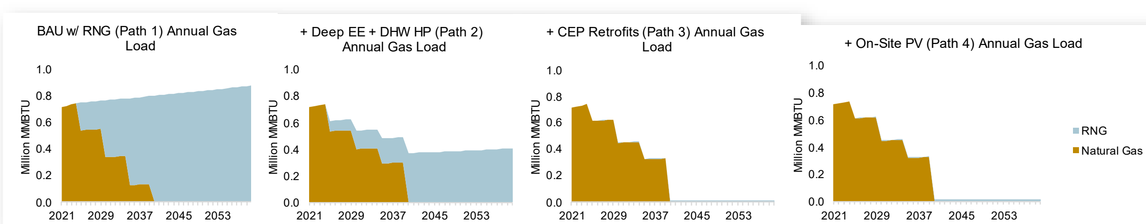
8.2.3.1 Gas Load

Year-by-Year Impacts

Like the electric load, gas load exhibits a baseline trend of increase due to campus growth. Paths #2-#4 counteract this through electrification measures and by gradually phasing out cogeneration use. In 2025, Paths #2-4 experience a 17% reduction in gas load from the combination of the cogeneration phase-out, as well as the implementation of deep energy efficiency retrofits and installation of domestic hot water heat pumps. The central energy plant retrofits in Paths #3 and #4 expand this to a 28% reduction in load in both 2030 and 2035. By 2040, the cogeneration plant shuts down completely, leaving less than 2% of the original gas use in Paths #3 and #4. In Path #2, the cogeneration must be replaced by additional boilers so significant gas use continues.

All paths see a portion of natural gas load shifted to RNG throughout the horizon, with 25% of the 2040 RNG need added every five years. Because the RNG need in 2040 is lower for Path #2 and almost nonexistent in Paths #3 and #4, less RNG is adopted in earlier years. This modeling assumes that the nature of RNG markets will require longer-term commitment for procurement, so this would avoid purchasing more than future needs. A breakdown of annual gas load for each pathway can be found in **Figure 58**.

Figure 58 - Annual Gas Load by Fuel Source



Lifetime Impacts

From today to 2060, combining the cogeneration phase-out with deep energy efficiency retrofits with the installation of domestic hot water heat pumps, lifetime gas load is reduced by 40% compared to 'business-as-usual.' With the addition of the central energy plant retrofits, lifetime gas load decreases by 68%. With a staggered RNG implementation, 75% of lifetime gas load is shifted to RNG in Path #1, though this decreases to 53% and then 3% of the lifetime gas load in Paths #2-4. A breakdown of lifetime gas load for each pathway can be found **Figure 59** and **Table 13**.

Figure 59 - Lifetime Gas Load by Fuel Source

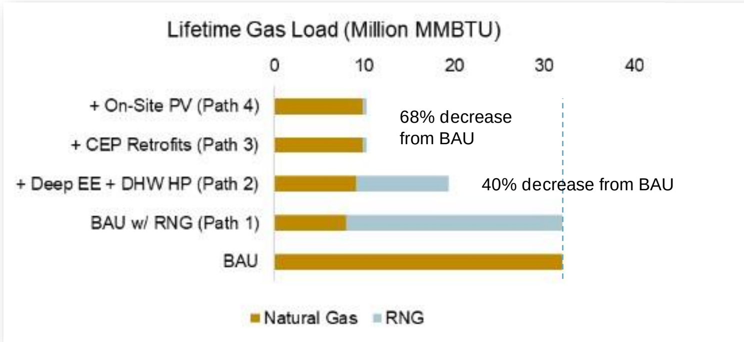


Table 13 - Lifetime Gas Load by Generator (MMBtu)

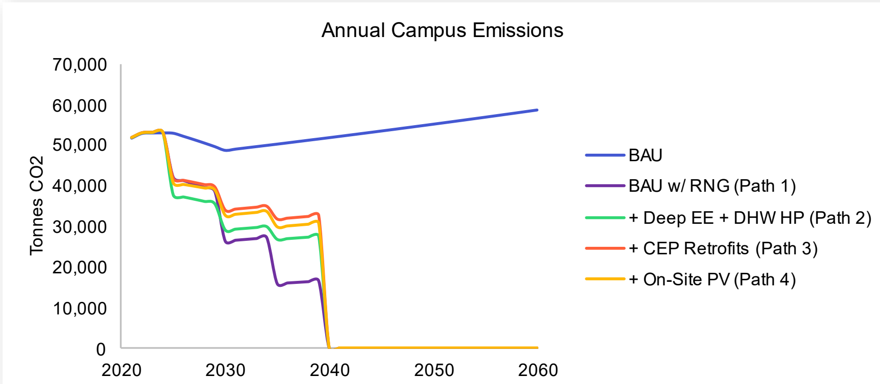
Fuel Source	BAU	Path #1 BAU w/ RNG	Path #2 + Deep EE + DHW HP	Path #3 + CEP Retrofits	Path #4 + On-Site Solar
Natural Gas	32,054,382	7,978,299	9,121,170	9,880,359	9,880,359
RNG	-	24,076,083	10,212,659	349,698	349,698
Total	**32,054,382**	**32,054,382**	**19,333,829**	**10,230,058**	**10,230,058**
Savings	**-**	**-**	**12,720,553**	**21,824,324**	**21,824,324**

8.2.4 Campus Emissions

Year-by-Year Impacts

As shown in **Figure 60**, each of the pathways evaluated in this analysis achieves zero annual emissions starting in 2040, due to 100% RNG and off-site solar PPA. Campus emissions are reduced in a staggered manner from 2025 to 2040 from the increased penetration of RNG and any energy efficiency measures.

Figure 60 - Annual Campus Emissions



Lifetime Impacts

Lifetime emissions are driven primarily by on-site gas combustion. From today to 2060, all pathways achieve lifetime emissions reduction compared to 'business-as-usual,' shown in **Figure 61** and **Table 14**.

Solely adopting RNG reduces lifetime emissions by 60%, which is increased to 70% with a solar PPA in 2040. With each energy efficiency and electrification measure, there is a small emissions penalty based on the assumption that a RNG blend of at least 50% will be cleaner than the electricity grid. The addition of deep energy efficiency retrofits and domestic hot water heat pumps would then increase lifetime emissions by 3% of the 'business-as-usual' baseline. Central energy plant retrofits would increase lifetime emissions by another 3% of the 'business-as-usual.' If RNG is not adopted as rapidly as modeled for Path #1, or if the combination of grid renewables or a PPA reaches approximately 50% by 2030, the electrification measures will instead result in emissions reduction. The addition of on-site solar PV reduces lifetime emissions by about 1% of the 'business-as-usual' scenario.

Figure 61 - Lifetime Campus Emissions by GHG Source

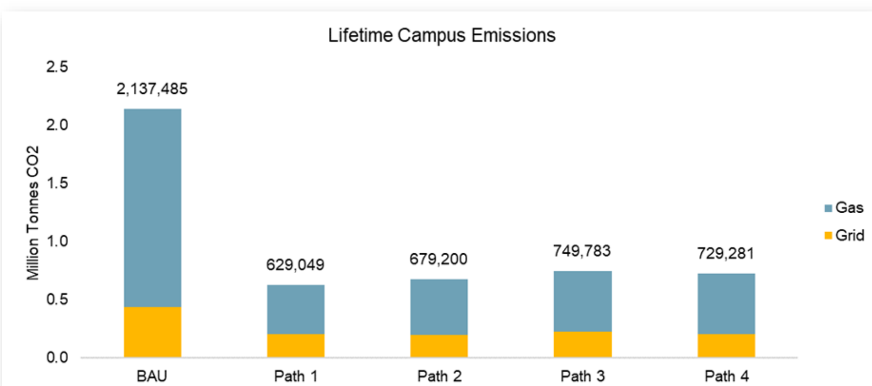


Table 14 - Lifetime Campus Emissions by GHG Source (MT CO_2e)

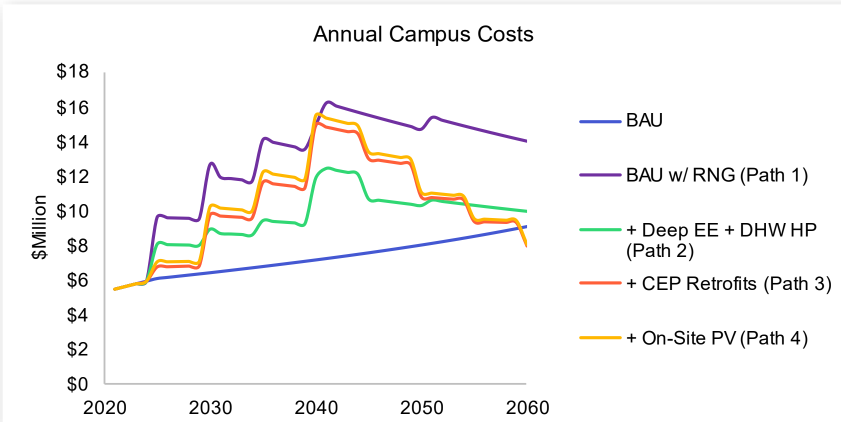
GHG Source	BAU	Path #1 BAU w/ RNG	Path #2 + Deep EE + DHW HP	Path #3 + CEP Retrofits	Path #4 + On-Site Solar
Gas	1,696,047	422,144	482,615	522,785	522,785
Grid	441,438	206,905	196,585	226,998	206,496
Total	**2,137,485**	**629,049**	**679,200**	**749,783**	**729,281**
Savings	**-**	**1,508,436**	**1,458,285**	**1,387,702**	**1,408,204**

8.2.5 Campus Costs

Year-by-Year Impacts

As shown in **Figure 62**, campus annual costs increase every 5 years from 2025 to 2040 due to increased penetration of RNG. Because all capital projects are financed over 20-year periods, the expenses for these projects are distributed over the lifetime and do not increase campus costs as drastically in any given year.

Figure 62 - Annual Campus Costs



Lifetime Impacts

Lifetime campus costs are driven by utility bills and capital project financing, with RNG bills being the largest cost driver. From today to 2060, each of the pathways evaluated in this analysis incurs incremental costs compared to 'business-as-usual,' as seen in **Figure 62** and **Table 15**. Note that **Figure 61** and **Table 15** both display the net present value (NPV) of costs based on the assumed discounting factor. Removing the discounting factor produces the same general trends, though Path #4 becomes slightly more expensive than Path #3 due to the later payments associated with replacing panels for the on-site solar PV.

Adopting RNG and a solar PPA in Path #1 increases lifetime costs by 64%. With the addition of deep energy efficiency retrofits and domestic hot water heat pumps, lifetime costs come down by 22% compared to Path #1. With the addition of central energy plant retrofits, lifetime costs rise by about 6%. The addition of on-site solar PV is cost neutral. It should be noted that RNG makes up approximately one- to two-thirds of the total costs for Paths #1 and #2. This presents a significant source of risk due to uncertainty of resource availability and price volatility.

Figure 63 - NPV Lifetime Campus Costs by Cost Component

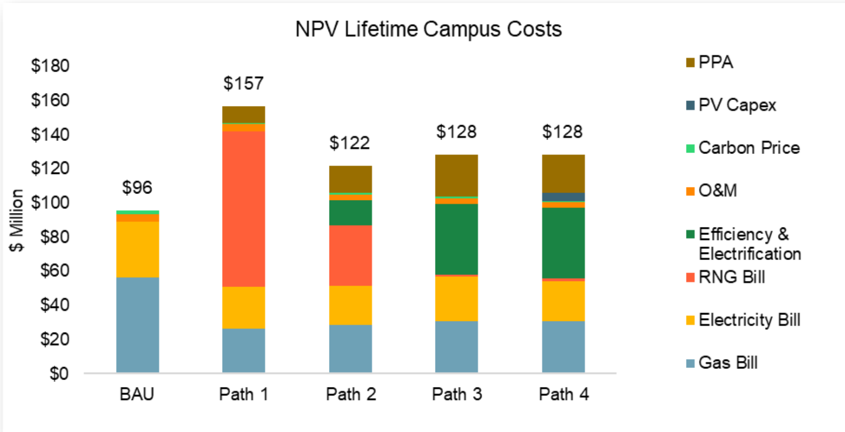


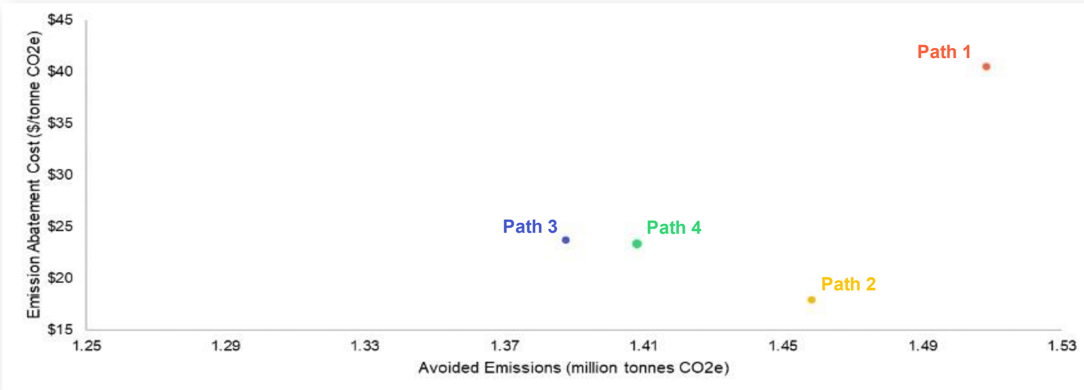
Table 15 - NPV Lifetime Campus Costs by Cost Component

Cost Component	BAU	Path #1 BAU w/ RNG	Path #2 + Deep EE + DHW HP	Path #3 + CEP Retrofits	Path #4 + On-Site Solar
Gas Bill	$56,370,235	$26,678,187	$28,896,162	$30,976,789	$30,976,789
Electricity Bill	$33,049,268	$24,292,425	$22,587,918	$25,783,482	$23,532,730
RNG Bill	-	$91,240,536	$35,408,986	$1,168,976	$1,168,976
Carbon Price	$2,191,197	$714,773	$766,562	$843,862	$821,558
O&M	$4,011,244	$4,011,244	$3,492,451	$3,008,896	$3,008,896
PV Capex	-	-	-	-	$4,548,464
PPA	-	$9,731,085	$15,665,894	$24,761,014	$22,467,915
Efficiency & Electrification	-	-	$14,865,301	$41,871,236	$41,871,236
Total	**$95,621,943**	**$156,668,248**	**$121,683,274**	**$128,414,255**	**$128,396,563**
Incremental Cost	**-**	**$61,046,305**	**$26,061,330**	**$32,792,312**	**$32,774,620**

One strategy to evaluate the performance of each pathway is to calculate the "emission abatement cost," or the incremental cost of each measure per MT of CO_2e that is avoided due to the implementation of that measure. The net present value emission abatement cost for each pathway can be seen below in Figure 60. Note that though the graph scale is adjusted to highlight the trajectory of the values, the avoided emissions values are closely clustered.

Adopting RNG and a 2040 solar PPA in Path #1 has a net present value emission abatement cost of $40.47 per MT of CO_2e. With the addition of deep energy efficiency retrofits and domestic hot water heat pumps, the emission abatement cost is reduced to $17.87 per ton. With the addition of central energy plant retrofits, emission abatement cost rises to $23.63, then falls slightly to $23.27 with the addition of on-site solar PV. This favorable shift for on-site solar is dependent on the discount rate used, because the replacement costs for panels are incurred so late in the time horizon.

Figure 64 - Emission Abatement Cost (NPV)



10. Projects considered, but not recommended

The Willdan team analyzed many ideas that were not recommended as paths to decarbonization. These ideas are detailed below.

10.1 Path #3 and #4 Alternative Pathways

Two alternative paths, similar to what is proposed in paths #3 and #4 were also explored; however, Willdan believes that path #3 as proposed in this report is the best financial investment with the lowest risk.

Path #3 alternate #1 proposes to do everything describe in path #3 but not install electric boilers and instead rely on the existing natural gas boilers running on renewable natural gas. This alternative path still allows for significant decarbonization through electrification, but USU will still be reliant on renewable natural gas for winter heating which increases the financial risk due to the uncertainty in the renewable natural gas market. It is worth noting that the decision to install electric boilers can be postponed until after year 2035. By year 2035 the renewable natural gas market will be more established and allow USU to make the best financial decision.

Table 16 - Path #3 Alternate #1 Construction Costs (2022$)

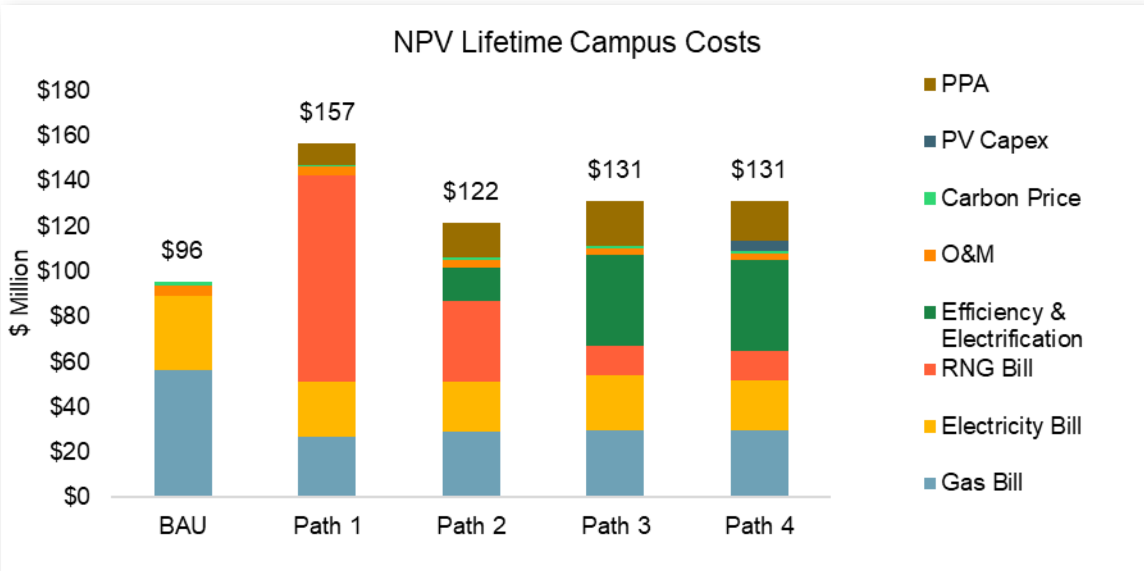
Estimated Engineering and Construction Costs for Path #3		
2022 - 2025 Projects for Path #3		
Deep Energy Efficiency Retrofits	$	9,541,656
Domestic Hot Water Heat Pumps	$	23,293,165
Total:	**$**	**32,834,821**
2026 - 2030 Projects for Path #3		
Hydronic Hot Water Thermal Energy Storage	$	6,500,468
Steam to HHW Heat Exchangers and HHW Pumps	$	425,677
Extend HHW Mains in Existing Tunnels and Add Buildings to HHW Loop	$	12,036,243
Airside Hot Water Coil Replacements	$	4,855,117
500 Tons of Heat Pump/Heat Recovery Chiller Capacity	$	4,784,921
500 Tons of U-Tube Geothermal Borefield Capacity	$	12,152,627
Increase Size of Central Energy Plant to Accommodate New Equipment	$	1,560,112
Total:	**$**	**42,315,165**
2031 - 2035 Projects for Path #3		
Extend HHW Mains in Existing Tunnels and Add Buildings to HHW Loop	$	6,314,808
Airside Hot Water Coil Replacements	$	4,855,117
500 Tons of Heat Pump/Heat Recovery Chiller Capacity	$	4,784,921
500 Tons of U-Tube Geothermal Borefield Capacity	$	12,152,627
Total:	**$**	**28,107,473**
2036 - 2040 Projects for Path #3		
Extend HHW mains in Existing Tunnels and Add Buildings to HHW Loop	$	6,223,930
Airside Hot Water Coil Replacements	$	4,855,117
500 Tons of Heat Pump/Heat Recovery Chiller Capacity	$	4,784,921

500 Tons U-Tube Geothermal Borefield Capacity	$	12,152,627
Install 1,200 Tons of Air Source Heat Pump Capacity	$	3,326,522
Total:	**$**	**31,343,117**
All Years Estimated Engineering and Construction Costs:	**$**	**134,600,576**

Table 17 - Path #3 Alternate #1 Energy Consumption

Path #3 Alternate #1 - No Electric Boilers					
Year	Total Electricity Usage (kWh)	Cogen Electricity Generation (kWh)	Peak Demand (kW)	Total Gas Usage (dth)	CEP Water Consumption (gal)
2022	70,497,644	41,555,603	11,333	716,058	17,085,878
2025	65,938,883	41,555,603	11,621	614,952	16,201,864
2030	74,230,207	33,312,793	12,455	474,912	10,452,681
2035	81,589,392	20,948,578	13,027	348,933	7,289,431
2040	92,541,965	0	13,354	114,404	4,429,778

Figure 65 - Path #3 Alternate #1 NPV Lifetime Campus Costs



Path #3 alternate #2 proposes to install ground source heat pumps to cover all the campuses heating and cooling loads. This alternative option would require the installation of 4,700 tons of ground source heat pump cooling capacity (6,500 tons heating capacity) instead of the 1,500 tons proposed in this report. This option was not explored further because of the significant financial investment required, low asset utilization rate, and constructability concerns due to the size of the required borehole field.

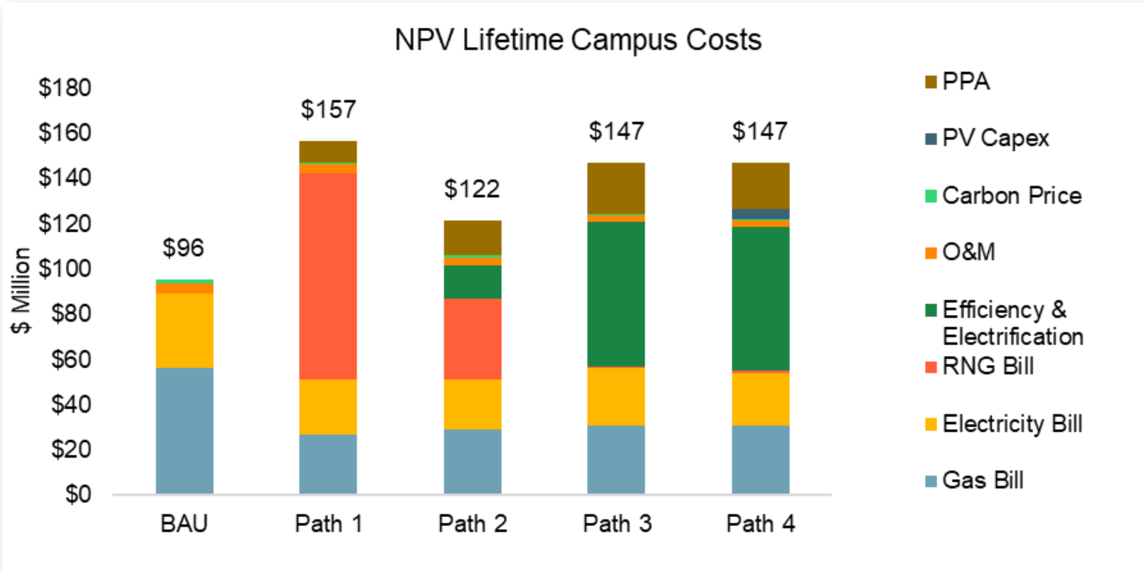
Table 18 - Path #3 Alternate #2 Construction Costs (2022$)

Estimated Engineering and Construction Costs for Path #3		
2022 - 2025 Projects for Path #3		
Deep Energy Efficiency Retrofits	$	9,541,656
Domestic Hot Water Heat Pumps	$	23,293,165
Total:	**$**	**32,834,821**
2026 - 2030 Projects for Path #3		
Hydronic Hot Water Thermal Energy Storage	$	6,500,468
Steam to HHW Heat Exchangers and HHW Pumps	$	425,677
Extend HHW Mains in Existing Tunnels and Add Buildings to HHW Loop	$	12,036,243
Airside Hot Water Coil Replacements	$	4,855,117
1600 Tons of Heat Pump/Heat Recovery Chiller Capacity	$	14,824,214
1600 Tons of U-Tube Geothermal Borefield Capacity	$	34,526,750
Increase Size of Central Energy Plant to Accommodate New Equipment	$	1,560,112
Total:	**$**	**74,728,581**
2031 - 2035 Projects for Path #3		
Extend HHW Mains in Existing Tunnels and Add Buildings to HHW Loop	$	6,314,808
Airside Hot Water Coil Replacements	$	4,855,117
1600 Tons of Heat Pump/Heat Recovery Chiller Capacity	$	14,824,214
1600 Tons of U-Tube Geothermal Borefield Capacity	$	34,526,750
Total:	**$**	**60,520,889**
2036 - 2040 Projects for Path #3		
Extend HHW mains in Existing Tunnels and Add Buildings to HHW Loop	$	6,223,930
Airside Hot Water Coil Replacements	$	4,855,117
1500 Tons of Heat Pump/Heat Recovery Chiller Capacity	$	14,824,214
1500 Tons U-Tube Geothermal Borefield Capacity	$	34,526,750
Install 1,200 Tons of Air Source Heat Pump Capacity	$	3,326,522
Total:	**$**	**63,756,533**
All Years Estimated Engineering and Construction Costs:	**$**	**231,840,824**

Table 19 - Path #3 Alternate #2 Energy Consumption

Path #3 Alternate #2 - Full Heat Pump					
Year	**Total Electricity Usage (kWh)**	**Cogen Electricity Generation (kWh)**	**Peak Demand (kW)**	**Total Gas Usage (dth)**	**CEP Water Consumption (gal)**
2022	70,497,644	41,555,603	11,333	716,058	17,085,878
2025	65,938,883	41,555,603	11,621	614,952	16,201,864
2030	79,012,505	33,312,793	13,446	450,225	4,069,729
2035	86,148,012	20,948,578	14,268	301,920	1,145,282
2040	105,069,765	0	15,803	4,171	0

Figure 66 - Path #3 Alternate #2 NPV Lifetime Campus Costs



10.2 Solar Thermal

For this solution, a centralized solar thermal array system would supply 150°F HHW to the campus. Solar thermal collectors work similarly to photovoltaic arrays – but instead of producing electricity, they use the energy from the sun to heat a fluid (either water or glycol) to high temperatures and pressures for heating applications. There are several types of solar thermal collectors, including flat plates and evacuated tubes, each with their own advantages and drawbacks. The system would need to be designed to avoid overheating in the summer and freezing in the winter as this would cause damage to the equipment. For times when the sun isn't shining, such as at night or during cloudy weather, a storage tank could be used to store extra hot water for the campus, similarly to the CHW storage tank the campus already employs.

Figure 67 - Example Solar Thermal Collector

A distribution system would be built through the tunnels for the HHW loop. New construction buildings would be designed to the 150°F supply temperature for the building reheat and pre-heat source. The existing buildings that operate on the current 190°F supply temperature would be progressively converted to use the new 150°F heating hot water supply temperature. USU already has a building renewal system where mechanical rooms are sequentially rehabilitated. The retrofits required to convert the buildings to the new temperature would be part of the existing maintenance plan. To serve domestic hot water loads, each building would have an air-source heat pump to produce the hot water. Air-source heat pumps are a simpler solution compared to configuring heat exchangers, which would bring project costs down.

Separating the domestic hot water load in this manner would also help balance out the uneven heating and cooling loads the campus experiences.

The issue with this idea is that the system would struggle to provide campus heating during the highest demand of the season. Preliminary analysis showed that in order to completely cover the peak heating demand of the campus, the solar thermal array would need to span an area greater than the existing campus itself. A more practical solution would be to install solar thermal panels wherever possible, including the unused hillside on the south side of the highway and supplement the heat as needed with another method, such as steam.

The solution does have positive aspects – it is an entirely passive method of HHW generation, the campus would be fully electrified and could run on a lower temperature and pressure, and the system would stay centralized. However, the cons outweigh the pros – the acreage required for the system to work is much larger than the campus's existing available areas, and accounting for freezing and overheating would provide design challenges. Solar thermal collectors are complicated to design and implement successfully due to their maintenance requirements. If the system is not designed and maintained well, extreme high and low temperatures can destroy the pieces of the system and cause an interruption to service as well as a massive repair bill.

10.3 100% Air Source Heat Pumps for HHW

For this solution two different options were considered. A decentralized air source heat pump system with air source heat pump located at each building or a centralized air source heat pump system installed at the central energy plant. To serve the domestic hot water loads at each building, individual domestic hot water air-source heat pumps would be installed.

During the winter, due to the low efficiency of air source heat pumps at low ambient temperatures, and the limited lift available with air source heat pumps currently available another heat source would be required to supplement the air source heat pumps. Supplementary steam boilers or an electric resistance heating system installed at the central plant could provide the supplemental heat.

This solution was mainly ruled out for the following reasons: decentralizing the heating systems greatly increases the maintenance and air source heat pumps are currently only available in relatively small sizes compared to USU's heating load requiring the installation of 20 or more units causing a maintenance and space concern. Although this solution is easy to install, the cons outweigh the pros and so this solution was not explored further.

10.4 Open Loop GSHP

Open loop ground source heat pumps function in the same way as the closed loop system, with one key difference. Rather than recirculating the same fluid through the system and a heat exchanger, these types of heat pumps take groundwater from a source nearby, extract the heat, and then expel the water to a different location. These are sometimes known as "pump and dump" systems. They are not recommended as part of this project due to maintenance and environmental concerns.

Open loop systems only work if there is a large, consistent supply of clean water to use. Considering Utah's desert climate and the ongoing effects of climate change, relying on this groundwater is not the best option long-term. Additionally, if debris like silt gets into the system, it can cause the ground source heat pumps to degrade over time and function poorly. To explore this option further, testing would need to be done on the area to make sure groundwater is present and sufficient, and an approved location for dumping the used water would need to be found. Although open loop systems are cheaper to install than closed loop systems, the maintenance requirements can be substantial. In contrast, closed loop systems require almost no maintenance once installed and have a long lifecycle.

10.5 Hydrogen

Central plant systems can be modified to run on hydrogen, a renewable resource, rather than natural gas. Switching to hydrogen for fueling the central plant would decarbonize the campus, but it would not be simple or practical. Although there are plans for a renewable hydrogen plant in the area, it will not be built until after the timeline of this Master Plan, so obtaining the hydrogen would be difficult. Additionally, using hydrogen is less efficient than other types of renewables because there are losses associated with pumping and burning it.

10.6 Carbon Offsets and RECs

The team discussed the possibility of using carbon offsets and renewable energy certificates for USU's decarbonization goals. Carbon offsets do not remove carbon from the campus systems – rather, the University would pay a company specializing in this offering the amount equivalent to their carbon use. The company then spends that money on carbon-reducing projects that aim to reduce GHG emissions. Renewable energy certificates buy attributes of electricity that is cleanly generated to reduce the buyer's emissions footprint.

These options are not recommended because they do not physically reduce the amount of carbon used by the campus. The campus would be paying more for equipment it already has that will eventually need to be replaced. Instead, this report recommends reducing emissions by fully decarbonizing the heating systems for the campus, as well as installing photovoltaic arrays to produce renewable electricity.

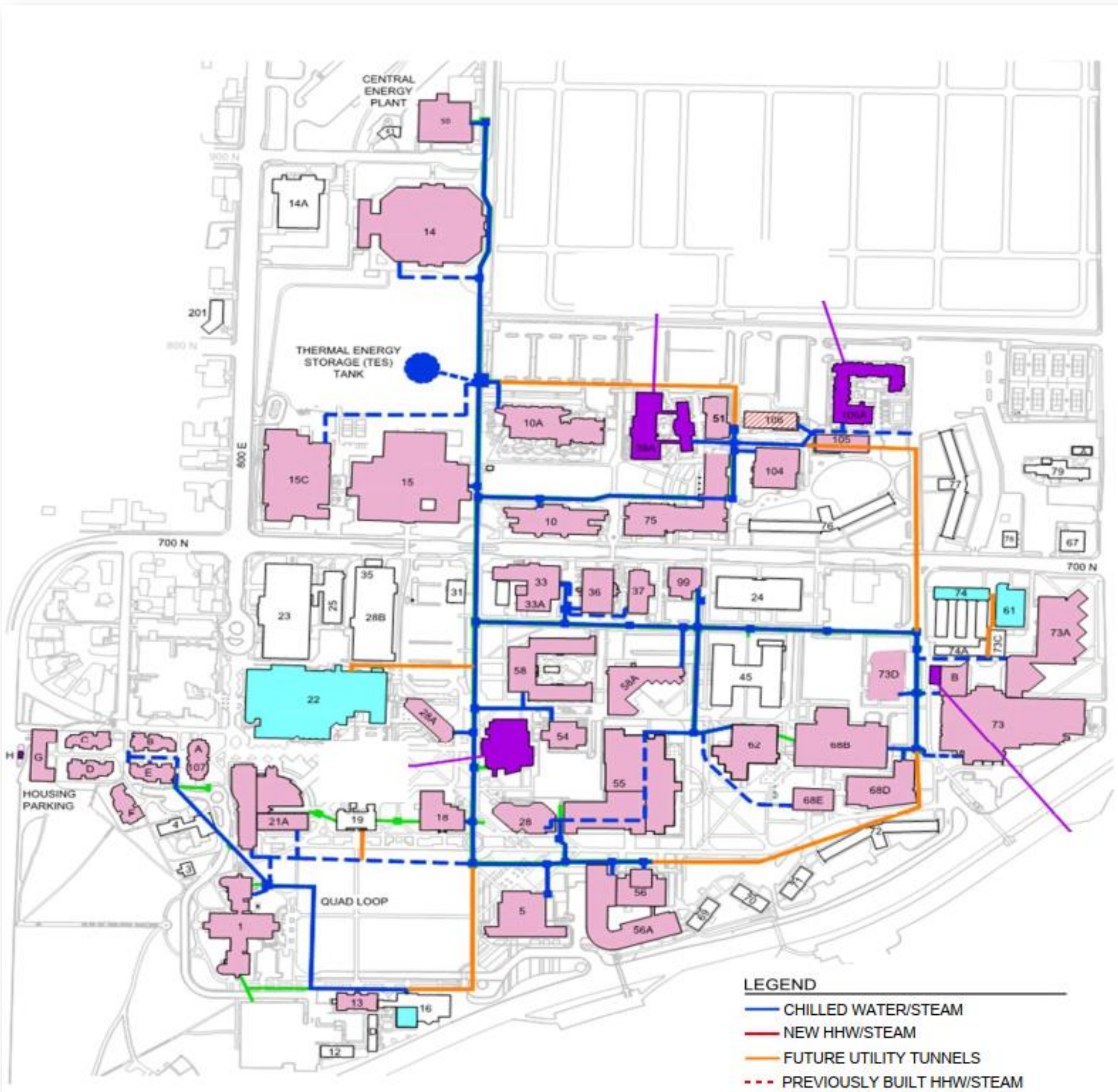
11. Appendix

11.1 Utilities' Plans

11.1.1 Existing

The existing utility tunnels are used for steam and chilled water supply and return. Most of the tunnels were designed and constructed before this report. The tunnels shown in orange are planned for future construction.

Figure 68 - Current Utility Tunnel Map and Plan



11.1.2 Future

This report details a plan to install a new heating hot water loop throughout the campus. A strategic approach installs the distribution pipe for the heating hot water system in three projects. Starting from the central energy plant, each phase of the proposed construction adds in pipe to accommodate one more third of the campus heating demand.

Figure 69 - Heating Hot Water Installed as Part of the 2026 – 2030 Projects for Paths #3 and #4

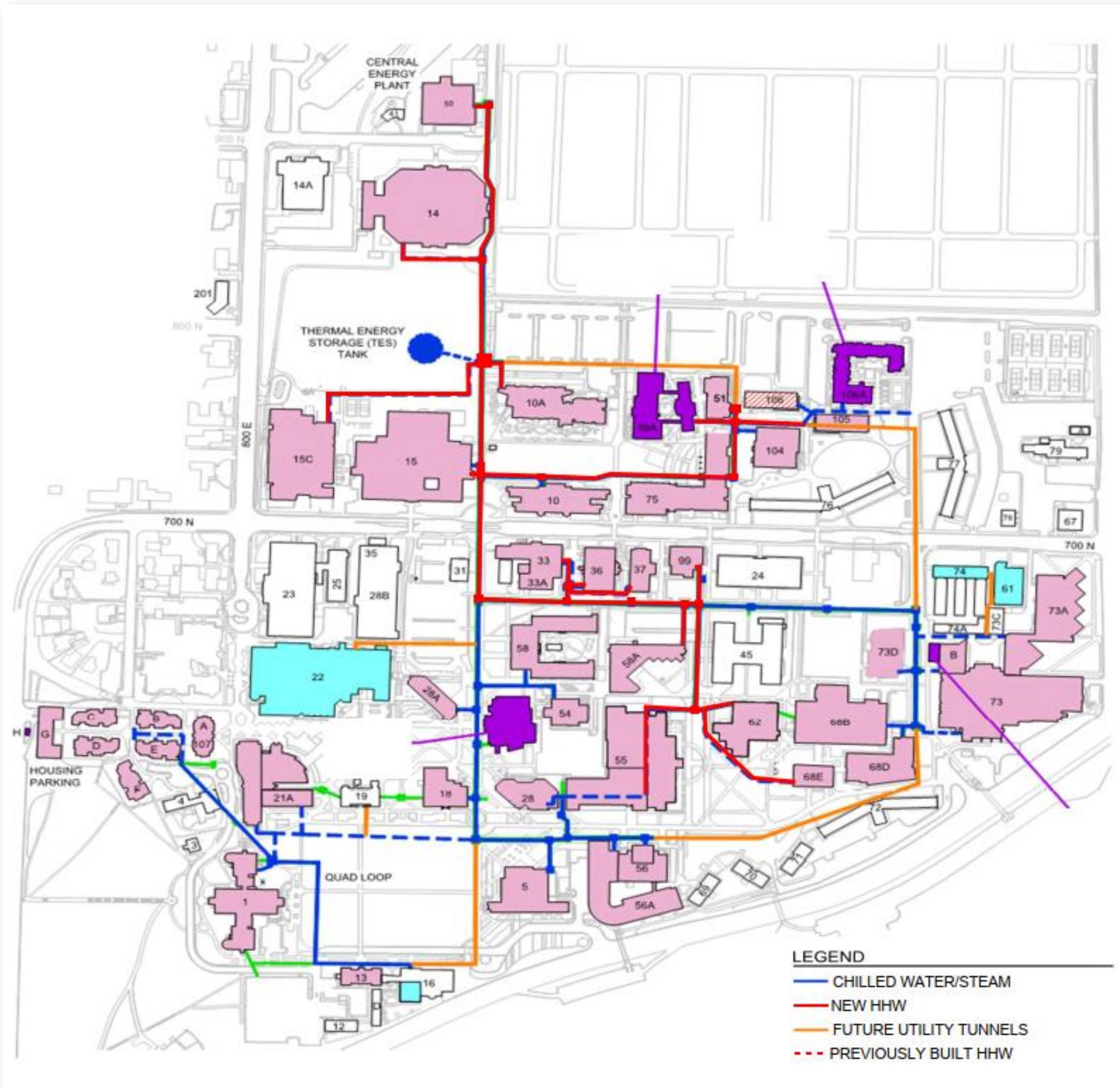


Figure 70 - Heating Hot Water Installed as Part of the 2031 – 2035 Projects for Paths #3 and #4

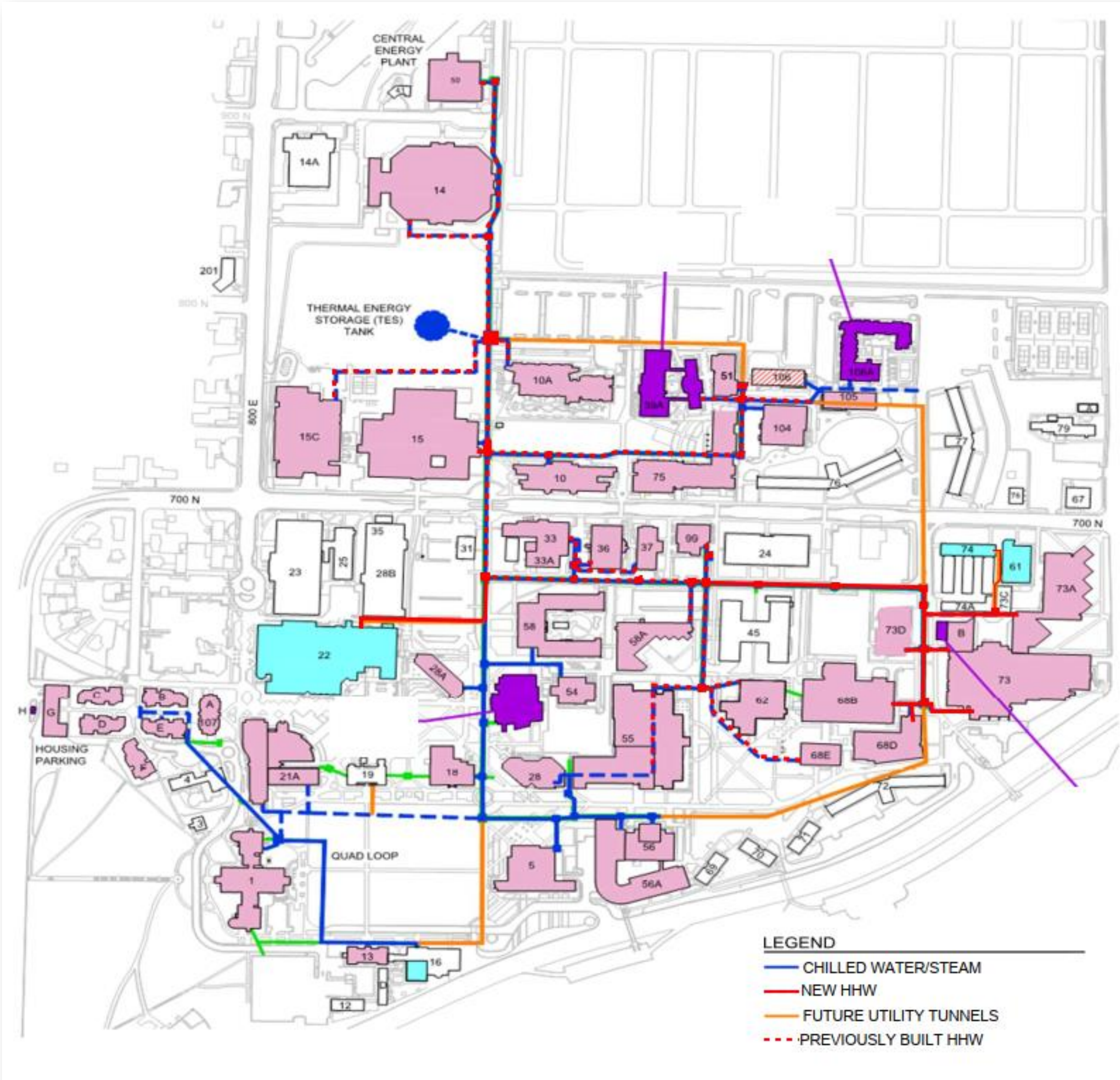
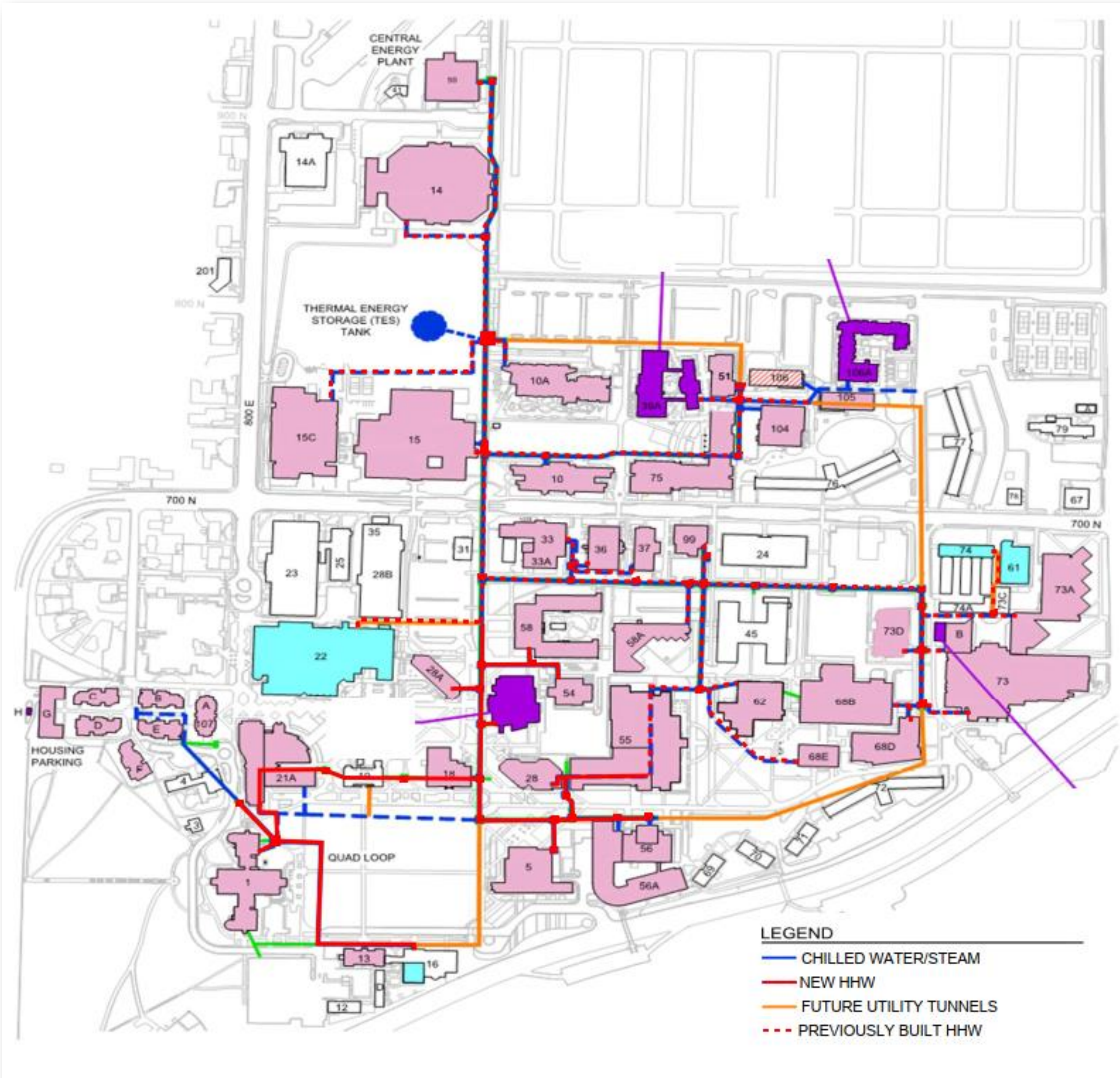


Figure 71 - Heating Hot Water Installed as Part of the 2036 – 2040 Projects for Paths #3 and #4



11.3 Modeling Summary

The baseline is developed from the monthly CEP reports provided by USU. The data provides daily values from 2012 to the beginning of 2017 for the values below:

- Make-up water usage,
- Total water usage,
- Boiler 1,2,3, 4 gas usage and steam production,
- Cogeneration gas usage
- Cogeneration electricity production,
- Electrical energy used,
- Electrical energy used for cooling,
- Cooling sent up the tunnel,
- Cooling used by the turbine,
- Average outside air temperature.

Values calculated from data:

- Chiller plant kW/ton,
- Cogeneration electricity generation efficiency, cogeneration steam efficiency,
- Steam boiler system efficiency,

Chiller plant kW/ton, total tons of cooling, and total steam production was put into 1°F outside air temperature bins. A trend line was applied to the binned data and then the binned data was then associated with TMY3 temperature data for Logan, Utah. This data provides the information needed to develop a baseline hourly heating, cooling, gas usage, and electricity usage for the CEP.

- Total tons of cooling and total steam production values were used to determine the total heating and cooling load of the campus.
- Electrical energy used for cooling was calculated from the binned kW/ton data and binned total tons of cooling.
- Gas usage was calculated from the binned total steam production (campus heating load at CEP) and the boiler and cogeneration steam efficiency.

The baseline loads were then scaled based off the forecasted campus growth, heating, and cooling loads from the 2017 Burns and McDonnell report shown in the table below.

Table 20 - Campus Growth Projections

Description	Baseline	2022	2025	2030	2035	2040
Total Campus Building Area (sqft)	4,471,660	4,914,061	5,310,087	5,500,287	5,690,486	5,880,686
Campus Heating Demand (PPH)	88,667	97,131	105,018	108,935	114,810	116,768
Campus Cooling Demand (Tons)	3,873	4,517	5,115	5,352	5,708	5,827

Table 21 - Baseline Energy Model 2012-2017

Baseline	
Variable	**Value**
Non-CEP Electricity Usage (kWh)	58,275,359
CHW Existing Plant Energy (kWh)	5,536,278
Cogeneration Electricity Generation (kWh)	35,029,123
Non-CEP Gas Usage (dth)	3,172
Cogeneration Gas Usage (dth)	435,243
Steam Boiler Gas Usage (dth)	187,977
Total Electricity Usage (kWh)	**63,811,637**
Total Gas Usage (dth)	**626,393**

Figure 72 - Baseline Campus Heating Demand

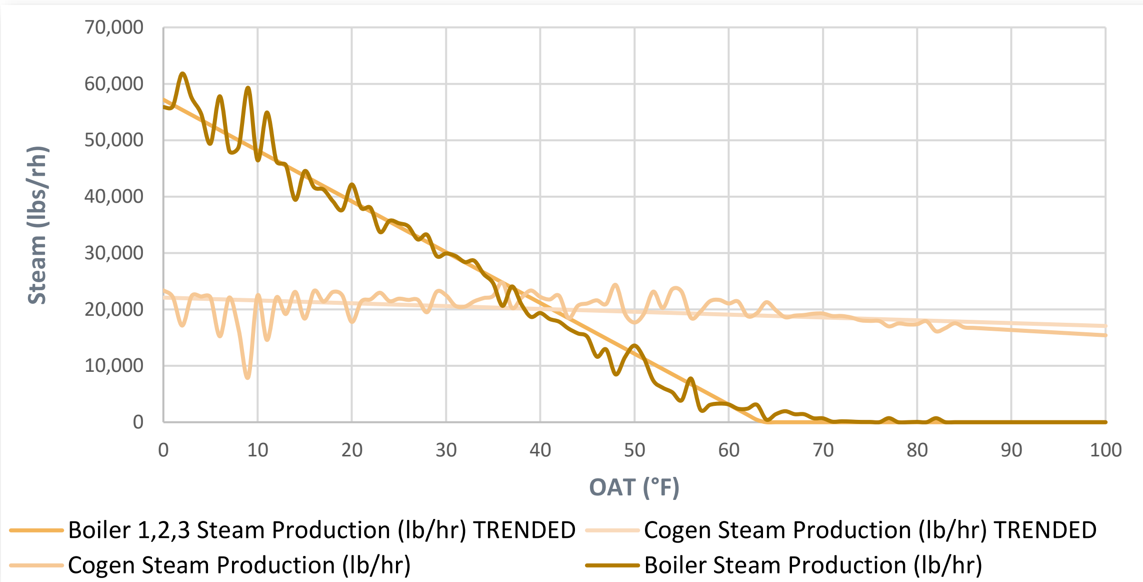


Figure 73 - Baseline Campus Cooling Demand

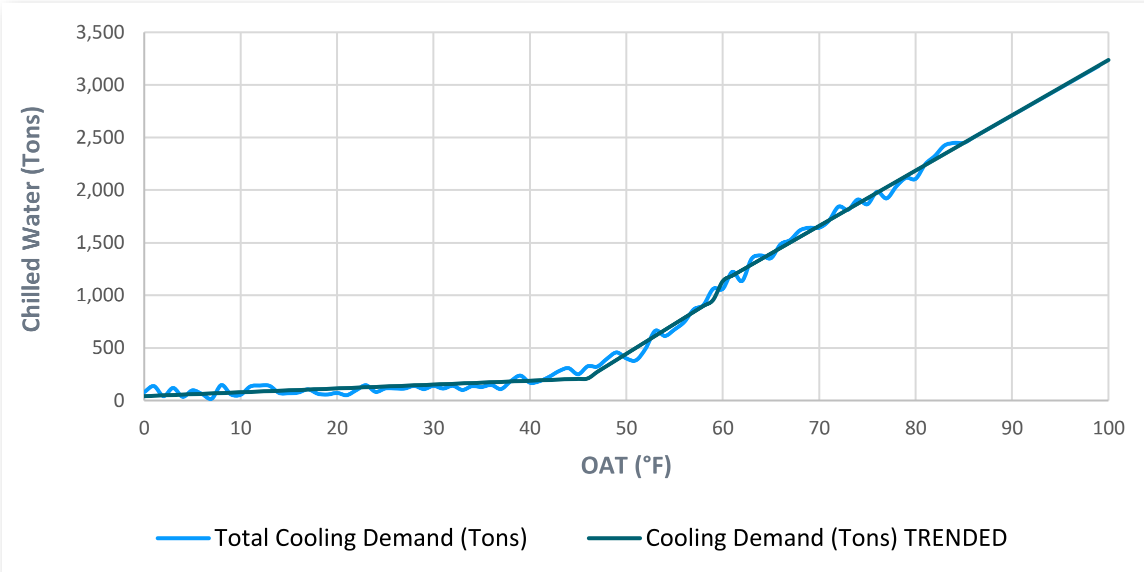


Figure 74 - Baseline Existing Chiller Plant Efficiency

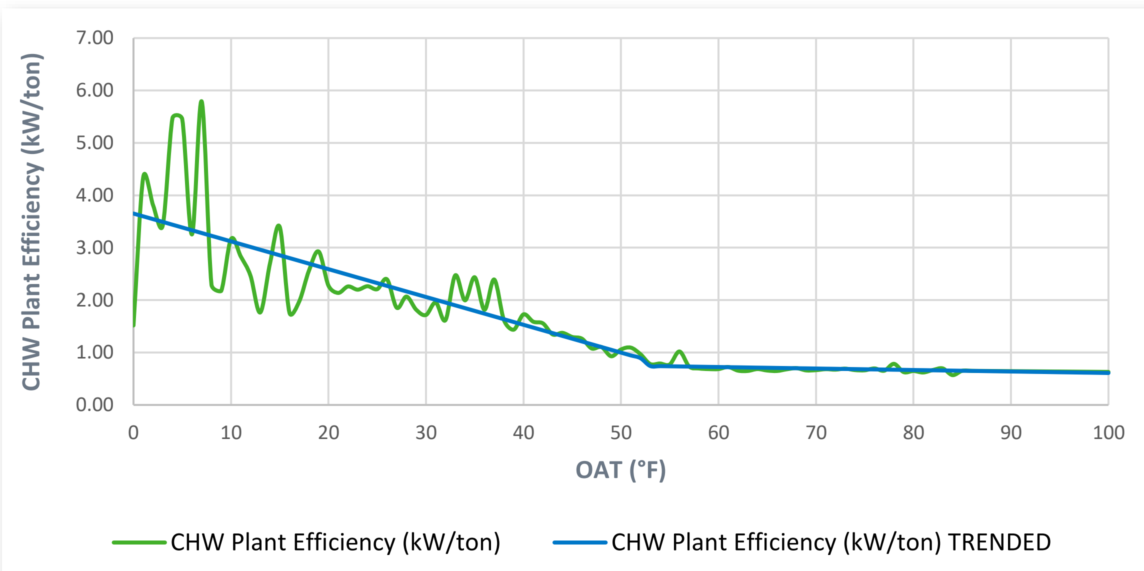


Figure 75 - Baseline CEP Water Consumption