District Heating Plant Sustainability Upgrade

April 2022

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1. Executive Summary

This project will upgrade the district heating plant to address greenhouse gas, air quality and resiliency goals. Boiler #3 will be replaced with two ultra-low NOx boilers as the first phase of an ultimate conversion to a combined heating and cooling systems (CHC) for main campus. Structural modifications and relocation of the control room will be required to accommodate the new boilers in the District Heating Plant.

The University has arrived at a decision point where investments in the district energy systems will carry us decades into the future. A culmination of equipment reaching end of life (boilers and distribution system steam piping) and improvements in alternate technology choices mean that the time to decide about the future of the district energy system is now. These critical decisions points include:

- Boiler #3 is past normal end of life (>60 years old)
- Miles of steam and condensate piping is aging and will need significant refurbishment/replacement
- Chillers at plant #1 are approaching end of life

Based on a detailed life cycle cost analysis, the recommended district energy system moving forward is a combined heating and cooling system (CHC). The system includes a hot and chilled water distribution system fueled by heat recovery chillers (HRC) and backed up/supplemented by new ultra-low NOx natural gas boilers. The recommended system also includes building airside energy recovery (BAER), a low-cost modification to building operation using control sequences that will complement the campus CHC system. The heating and cooling loops will be connected to large (multi-story) insulated tanks that will store the energy for use to serve peak loads and to avoid running equipment during times of high electricity costs.

The estimated project budget range for the District Heating Plant Sustainability Upgrade is $20-22M. Funding is requested from the State Capital Construction fund with a 17% cash match from CSU.

Once necessary approvals and funding are in place it is estimated that the project will take approximately four years to complete.

2. Justification

2.1 Physical Condition/functionality of Existing Space

The district heating plant on campus is nearly as old as the campus itself. The first district coal fired boilers were installed at the beginning of the last century (1915). In the 1960s, the plant was "modernized", and new boilers were installed to burn natural gas.

The district cooling system is much newer. Build out began in ~2000, out of the need to phase out old refrigerants in chiller equipment across Main Campus. Chillers are not as long lived as district heating equipment, however. As a result, district cooling plant #1 will reach end of life (EOL) in ~2030 and district cooling plant #2 will reach EOL in ~2040.

2.2 New Equipment list

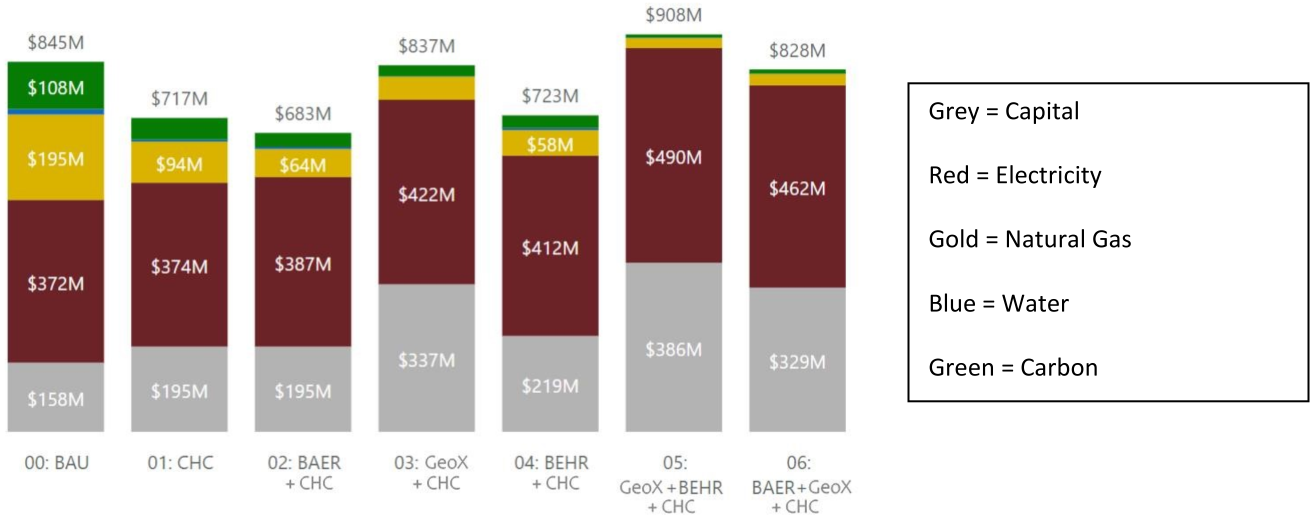
Item	Number	Total Cost
80kpph,9pmNOx, D-type Boiler	2	$6.7M
Controls		$1.54M

2.3 Alternative analysis

Facilities Management staff secured a consultant and conducted an analysis of the district energy system during FY22. This work included studying what other universities were doing, researching new technology options, and staying abreast of the ever-changing regulatory environment.

- Combined Heating and Cooling (CHC) is a system configuration including a hot water and chilled water distribution system serving buildings, tied together at a Heat Recovery Chiller (HRC) plant. A HRC is a piece of equipment that provides both cooling and heating. Traditional chillers create chilled water using the refrigeration cycle, but heat is rejected to the atmosphere via cooling towers. In an HRC, the waste heat is captured and used for process heating, hot water loads, or can be stored in the system tank for later use. By generating both heating and cooling in a HRC, efficiencies are dramatically improved. Most importantly, heating generated is electric and displaces natural gas combustion as the primary source. A very important factor, and the most impactful part of the overall plan in both cost and construction, is the need to convert campus heating from steam to hot water. The HRC plant can only bridge two hydronic systems, it does not produce steam.
- Building Airside Energy Recovery (BAER) utilizes equipment and controls already in our buildings. These modified control sequences will allow more captured energy to be carried back to the HRC plant to be either directly used for campus heating and cooling or sent to the storage tanks for use later. Note that BAER is an enhancement of CHC, and cannot be implemented alone.
- Business As Usual (BAU) is the option where we retain the existing steam system and traditional chilled water plants. Both utilities will require their expected replacements and refurbishments over the 60-year study period, however, no efficiencies can be leveraged from the separated systems and campus heating will continue to be served through 100% natural gas combustion.

Based on a 60-year Life Cycle Analysis (LCA), BAU is the most expensive option. Installing CHC with heat recovery chillers and BAER is the least expensive option. While this is the lowest life cycle cost it does require significant capital investments in the near term, especially during the next decade to initiate the transition. Significant capital investment is also required for BAU, but is more distributed over time. Note that while the Heating Plant Sustainability Upgrade is being planned to permit all necessary heating plant configuration to support CHC, the project scope is identical to both CHC and BAU. Over time, CHC and BAU diverge considerably.



2.4 Benefits of the Project

There are tangible benefits as well life cycle cost savings; however, these are very hard to quantify and are therefore not included in the LCA.

Air Quality Issues: The Front Range EPA Air Quality assessment is anticipated to be elevated to "Severe" because of very poor air quality in recent summers. The impacts of this designation are very low limits on NO_x emissions for new sources such as boilers. If any new sources (e.g., boilers at residence halls) installed within a three-year period exceed the threshold, the University will be subject to New Source Review (NSR) permitting. This permitting will require the University to install air pollution controls on other people's equipment in this region in order to install new combustion equipment on our campus.

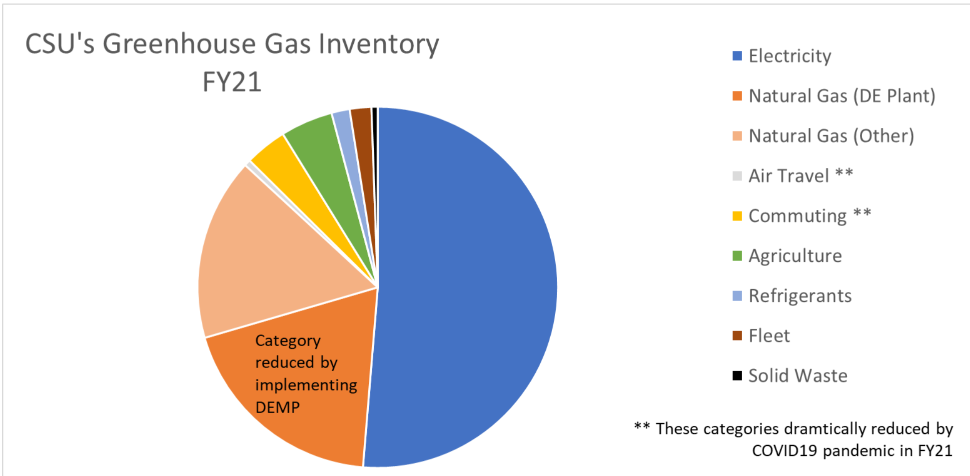
For larger boilers, regulations will require expensive and time consuming (1 year or longer) studies to install new equipment. Currently, existing boilers are being operated at 20% of total input capacity on an annual basis so that continuous emission monitoring systems (CEMS) are not required. If we operate above that level, CEMS would have to be installed. CEMS is very expensive to install and operate (cost is in the millions of dollars) and might show that the existing boilers do not meet applicable emission limits.

Of note, although current regulation poses the most risk to new and replacement equipment, regulation can become tighter at any time, and impact existing equipment. This has already happened in the recent past, placing operational restrictions on our district plant.

Regulatory issues have the potential to add a great deal of complication and cost to the Business As Usual (BAU) case. The resulting risk includes at minimum millions of dollars of additional boiler monitoring. The worst-case scenario is that we would not be able to operate at a sufficient capacity to heat campus under BAU.

Climate impacts: Currently emissions from natural gas combustion university-wide account for 35% of CSU's total Greenhouse Gas (GHG) emissions. The district energy plant alone burns ~575,000 million BTUs (MMBTUs) of natural gas every year, which results in nearly 30,000 metric tons of carbon dioxide emitted ($MTCO_2e$) in GHG emissions (out of a university total of ~160,000 $MTCO_2e$ in FY21) making up the majority of CSU's natural gas related GHG emissions.

Electricity is currently the largest GHG emissions at 51%. However, CSU and the regional utilities have all made the commitment to 100% renewable electricity by 2030. This means that by 2030 CSU's emissions related to electricity use are expected to be zero – cutting the University's total emissions in half. However, at that time (if no changes are made), natural gas is estimated to be nearly 75% of GHG emissions. Implementing this District Energy Master Plan (DEMP) will shift significant heating and hot water energy use from natural gas to electricity – substantially reducing the GHG emissions related with building heating and cooling.



3. Design Criteria

3.1 Site Constraints

The footprint of the existing heating plant will not be modified.

3.2 Flood Mitigation Analysis

Flood mitigation has been accomplished at the heating plant through previous projects.

3.3 LEED Goal

This project is not eligible for LEED certification; however, the Main Campus District Energy Master Plan transitions the campus over time from steam to hot water for heating purposes. This addresses the university's greenhouse gas, sustainability and air quality goals. Additionally, every new or renovation building project connected to the district utility will use the increased efficiency of CHC and BAER in their own LEED calculations.

3.4 Utility Incentive Programs

Utility incentive programs will be investigated during design. Discussions with utility providers have already begun, but due to the scale, complexity and unique nature of this project, rebate potential is uncertain.

3.5 Architectural/Mechanical Narrative

Structural Assessment

The two new package boilers will be located on the north (Boiler 5) and south (Boiler 4) ends of the existing operating floor in the original 1915 construction. The floor consists of an elevated concrete slab supported by steel beams and columns. Over the years the floor has gone through several modifications to accommodate installation and removal of boilers. Additional beams and columns have been added to infill floor openings and support new boilers. The existing conditions of the concrete and steel framing appear to be in good repair.

All the previous boilers in this building have been supported independently from the building via foundations in the basement. The operating floor serves as means of access and maintenance but not support.

The operating floor in the area of the new Boiler 4 was previously infilled. The new package boiler will be supported at the operating floor level. However, this floor will need to be reinforced to support the additional load. To accomplish this a new steel frame and columns will be installed under the boiler that will be supported by new foundations. The foundations in this area are shallow spread footings but the adjacent structures and equipment are supported on deep foundations. Unless there are soft soils present in the area of the boiler it is anticipated that a shallow mat foundation will be adequate for support of the new boiler. A geotechnical investigation will be required to confirm the required foundations types. If unsuitable soils are found, then deep foundations may be required. It is likely that micro piles would be utilized due to the low head clearance of the basement.

The new Boiler 5 will be installed in the location of Boiler B-3 once removed. With the removal of Boiler B-3 there will be a large opening left in the operating floor. A new steel frame will be designed to infill the floor and support the new boiler. The existing boiler columns will be utilized in the basement with additional columns installed as required. It is anticipated that the existing boiler foundations will be adequate to support the new loads. New columns will be supported by new foundations located in the basement. The foundations in this area are shallow spread footings but the adjacent structures and equipment are supported on deep foundations. Unless there are soft soils present in the area of the boiler it is anticipated that shallow spread footings will be adequate for support of the new columns. A geotechnical investigation will be required to confirm the required foundations types. If unsuitable soils are found, then deep foundations may be required. It is likely that micro piles would be utilized due to the low head clearance of the basement.

With the removal of the existing control room located on the operating floor a new control room will be required. It is planned to construct the new control room along the east wall elevated above the operating floor. A new steel frame with a concrete floor will be constructed at the same elevation as the existing offices. Access to the area will be via the existing staircase that provides access to the existing offices.

For Boiler 4 installation, the door/window on the west side would be removed and enlarged. At this location the existing gas line and steam line inside would require rerouting/temporary removal to facilitate the boiler installation. This opening could remain open as long as the contractor determined it useful. During construction the opening would require a temporary means to close it off to keep out the exterior elements.

The center window on the north side of the building would be removed and enlarged for Boiler B-3 removal and Boiler 5 installation. At this location the existing gas line inside would require rerouting/temporary removal to facilitate the work. This opening could remain open as long as the contractor determined it useful. During construction the opening would require a temporary means to close if off to keep out the exterior elements.

Electrical Assessment

The current electrical service to the existing 1915 building was installed as part of the 1966 South Building Addition. A 750kVA transformer is located on the roof of the addition and feeds down to the ground level automatic transfer switch. From this transfer switch the electrical service feeds up to the upper-level main distribution board and MCC-1. The overall service is 1200A at 480V, 3-Phase and is fully backed up by a 750kW Caterpillar generator located to the West of the 1966 Addition. Additionally, there is an 800kW steam turbine generator (STG) located in the basement of the original 1915 building. This STG will have to be temporarily decommissioned to allow for the installation of Boiler 4.

Boiler 3 is currently served from MCC-2 located immediately East of the boiler. MCC-2 is fed from the main distribution board at the upper level of the 1966 addition. The conduit for this MCC is routed through the original plant at the same height and location as the new control room. This conduit will need to be re-routed temporarily to feed MCC-2 while the control room is built.

To install Boiler 4 a new 400A MCC (MCC-4) will be installed at the South-West corner of the original 1915 building – space that will be vacated by the relocation of the offices and control room. MCC-4 will be fed from the main distribution board at the upper level. It is critical that this MCC comes online during the summer months to avoid an overload condition on the 1200A service.

Once Boiler 3 is removed the existing MCC-2 will be demolished and replaced with a new MCC-5 to feed Boiler 5. This MCC will also be 400A and will be located adjacent to Boiler 5 in the original plant.

Electrical metered data for Summer and Winter months will help to ensure that the new load placed on the existing electrical service is within the 1200A cap.

Mechanical Assessment

Natural gas service, fuel oil service, condensate transfer, deaeration, boiler feedwater and combustion air availability were all reviewed to confirm that there is adequate capacity for the new boilers. With the removal of Boiler B-3 (60,000 lb/hr) and the addition of two new boilers at 80,000 lb/hr each, the new firm capacity of the plant will be 310,000 lb/hr. This is derived from the loss of use of the largest boiler, leaving either Boiler B-1 or B-2 operational at 150,000 lb/hr plus the two new boilers at 80,000 lb/hr each. The projected 2022 peak steam load from the 2021 study was 160,000 lb/hr. This means that the plant must maintain a minimum of 160,000 lb/hr firm capacity to meet the combined campus and in plant steam demands. Also, per the Main Campus District Energy Master Plan, by 2045 it is anticipated that growth of the campus will require the firm capacity to be 200,000 lb/hr which is the limit of some of the auxiliary equipment.

Natural Gas

The incoming natural gas pressure at the time of the site visit was 135 psig. CSU indicates that the typical pressure is near 140 psig and does not fluctuate significantly during the year. The pilot gas for the boilers is on firm capacity while the boilers themselves can be curtailed. The pressure is reduced by two pressure reducing trains in series. Each pressure reducing station has two valves in parallel with a primary valve and secondary valve. The first train reduces the incoming gas pressure from 140 psig to 25 psig and the second train reduces the pressure from 25 psig to 20 psig. Each of the existing boilers have a pressure reducing valve at its respective fuel train which reduces the 20 psig gas pressure to approximately 11 psig to each boiler's burner.

New ultra-low NOx burners in the proposed boiler size range typically require approximately 35 psig at the burner front. This implies that the gas header pressure will be required to increase from 20 psig to approximately 45 psig. The existing boiler regulators will need to be modified (spring change out) or replaced to accommodate the increase in pressure. Modification or replacement of the existing valves will be required in the design of the installation of the new boilers. The headers capacity will increase with the increase in pressure and the existing pipe sizing is adequate to support the existing and the new boilers. The gas utility company will need to confirm the utility meter flow capability and the pressure reducing valve capabilities during design and make modifications or replacements as required.

Fuel Oil

Fuel oil is only burned when natural gas is curtailed; therefore, it is rarely used. However, it is a critical component of the system because interruptible natural gas is significantly less expensive than firm natural gas.

Assuming 85% efficient boilers for the new boilers and 75% efficient boilers for the old, the fuel oil flow required would be 43 gallons per minute with an output of 310,000 lb/hr. There are two existing fuel pumps and although the pump curves do not specifically indicate, based on the delivery pressure and motor horsepower, it appears that each pump is capable of 53 gallons per minute which is adequate for boiler consumption and recirculation to serve the two new boilers and two existing boilers while maintaining a redundant pump.

Condensate Transfer Pumps

The condensate return system consists of two surge tanks located below the offices and adjacent to the steam turbine generator in the plant basement. There are three condensate transfer pumps each sized at 250 gpm. Assuming maintaining firm capacity in the pumps, one pump would be standby while maintaining 500 gpm of firm capacity. Typical sizing of condensate transfer pumps provides 25% excess capacity above what the boilers require. The two existing pumps are able to support a firm flow capacity to the boilers of 400 gpm which equates to a firm steaming capacity from the boilers of 200,000 lb/hr.

It is customary to provide condensate pumping capacity equal to the boiler firm capacity of the plant. However, in this case the firm capacity of 310,000 lb/hr greatly exceeds the projected campus load. Per the previous study, the projected steam load does not exceed 200,000 lb/hr until 2045 at which point additional condensate transfer pump capacity will be required. As such, it is not recommended to add a fourth pump with the boiler replacement project or upsize any of the existing pumps.

Deaerator

Based on information in the boiler process and instrumentation diagram, the existing deaerator is rated at 300,000 lb/hr of capacity. The existing equipment tag was reviewed; however, the tag does not indicate the size of the tank or the capacity. It is typical to have 10 minutes of storage volume in the deaerator for the firm capacity of the plant and the deaerating capacity of the firm or above the firm capacity of the plant. That being said, most deaerator manufacturers rate the deaerator capacity at 100% makeup of cold water meaning that the operating capacity with condensate is higher. Under this assumption the DA would be sized for and be capable of handling the full 310,000 lb/hr capacity to serve the firm capacity in the plant once the two new boilers are installed. A redundant deaerator does not exist in the plant which is typical for most plants of this size.

Boiler Feedwater Pumps

The plant currently has three existing boiler feedwater pumps that serve all boilers in the plant from a common header. The existing pumps do not have tags indicating capacity nor are the pump curves marked for the selection. The 1984 addition of Boiler 1 added the third pump which was sized for 300 gpm. For the analysis, it is assumed that all three pumps are 300 gpm. Typical sizing of boiler feedwater pumps provides 25% excess capacity above what the boilers require. The two existing pumps are able to support a firm flow capacity to the boilers of 480 gpm which equates to a firm steaming capacity from the boilers of 240,000 lb/hr. It is customary to provide boiler feedwater pumping capacity equal to the boiler firm capacity of the plant. However, in this case the firm capacity of 310,000 lb/hr greatly exceeds the projected campus load. The projected steam load does not exceed 240,000 lb/hr until 2068 at which point additional boiler feedwater pump capacity will be required. As such, it is not recommended to add a fourth pump with the boiler replacement project or upsize any of the existing pumps.

Combustion Air

The two new boilers will be required to be supplied with code compliant combustion air from gravity fed louvers, mechanical fans or the boilers must be ducted to the exterior.

Gravity Fed Louvers: The existing building construction does not include louvers that convey air directly from the exterior into the building and current code requires 1 square inch of free louver per 4000 btu/h of fuel input into the boilers. Current code further defines that louvers must be in a high/low configuration with one louver originating 12” from the ceiling and one louver originating 12” from the floor, of which are impractical in the existing space. The size of louver required by code to accommodate the two new boilers is 670 square feet and adding this much louver to the existing structure is not practical.

Mechanical Fans: If mechanical fans are utilized, boilers must be interlocked with the fans and if a fan fails for any reason, the boilers are shut down and prevented from operating. In addition, mechanical fans would result in additional electrical loads on the plant. Due to this code requirement and the existing electrical equipment sizes for the plant, mechanical combustion air is not recommended.

Ducted to Exterior: Combustion air ducts can be ducted directly to the exterior of the building, however, temperatures below ~40 degrees F cause issues with maintaining NOx emissions control in the boilers. As such, a heating coil must be installed to maintain proper air temperature into the boilers. The existing east wall of the plant has windows high on the wall which can be converted for direct ducting the boilers to the exterior. This configuration can also be utilized for exhaust stacks from the boilers which eliminates the need for large roof penetrations in the existing concrete roof. Discharge flue gas stacks would be lighter weight double wall stainless steel construction allowing them to rest on the existing lower building roof above the proposed office and control room locations. As such, the recommendation and basis for the concept design is to direct duct combustion air through the east wall to the boilers and discharge flue gas through the east wall as well while ensuring that flue gasses are not re-entrained into the boiler's combustion air ducts.

Superior Boiler D-Type Industrial Water Tube Boiler with Ultra Low NOx Burner

3.6 CSU Standards

The CSU Building Construction Standards Manual is available at:
http://www.fm.colostate.edu/constr_standards

The CSU Standards are to be used as guidelines for design. They are divided into 3 parts for use by Architects and Engineers: the first part is administrative; the second part discusses requirements for design and deliverables at each stage of the design process; the third part consists of the technical standards arranged by CSI division. The Standards are a living document, and as such, any question about the applicability of a standard should be discussed with the project manager. The Standards should <u>never</u> be referenced or copied in Contract Documents – the design is expected to embody and conform to the Standards. Contractors are <u>not</u> to be directed to review the Standards as a contract requirement.

3.7 CSU Inclusivity Standards-not applicable to this project

3.8 List of Applicable Codes

Approved building codes and standards have been adopted by the Office of the State Architect (herein referred to as State Buildings Program (SBP)) and other state authorities, and are identified below as the minimum requirements to be applied to all construction projects at state agencies and institutions of higher education owned facilities.

Applicable codes:

2018	INTERNATIONAL BUILDING CODE
2018	INTERNATIONAL MECHANICAL CODE
2018	INTERNATIONAL ENERGY CONSERVATION CODE
2017	NATIONAL ELECTRICAL CODE
2018	INTERNATIONAL PLUMBING CODE
2018	INTERNATIONAL FUEL GAS CODE
2018	INTERNATIONAL FIRE CODE
2010	ADA STANDARDS FOR ACCESSIBLE DESIGN
2009	ICC/ANSI A117.1

4. Project schedule, cost estimates and financing

4.1 Project schedule/phasing

The project phasing is complicated by space limitations in the existing plant and regulatory limitations from the Colorado Department of Health and Environment (CDPHE). In addition, the project must be accomplished with no loss of heating capacity during colder months. A possible project phasing plan is shown below. Schedule is non-specific, but in general, it is anticipated that the Design and Permitting phase would take approximately two years, followed by two years of construction.

Design and Permitting

1. Initiate schematic design and generate specific boiler makes and models that satisfy requirements.

2. Boiler purchasing process as required to select boiler to be installed.

3. Begin regulatory emissions modeling.

4. Complete design and emissions modeling.

5. Obtain construction permit from CDPHE.

Construction Phase

1. Construct new offices, restrooms, locker rooms, etc. on mezzanine level.

2. Construct new control room on mezzanine between offices and existing Boiler B-3.

3. Relocate stairways as required

4. Install new control system and migrate balance of plant controls to new control system.

5. Migrate Boiler B-2 to new control system.

6. Migrate Boiler B-1 to new control system.

7. Temporarily provide firing rate control for Boiler B-3 from new control system.

8. Move storage above offices and control room to temporary storage containers exterior to the plant.

9. Demolish existing offices, control room, storage, locker rooms, etc. on the main floor level.

10. Make structural modifications to existing main level floor. This includes rerouting of any plumbing that served the offices.

11. Create temporary opening on the exterior of the building for installation of first new Boiler 4.

12. Temporarily remove steam piping and vent piping serving steam turbine generator. Steam turbine generator will be down during this time.

13. Set new Boiler 4 to the south of the control room.

14. Cover wall with temporary enclosure.

15. Reinstall steam feed to steam turbine generator as well as safety relief piping.

16. Isolate north 160psig header via main isolation valve in the header and install new tap for new Boiler 4. This will require the plant to operate on Boilers B-1 and B-2 while Boiler B-3 will be isolated.

17. Isolate boiler feedwater pump 2 and install new tap between header valves. Boiler feedwater pumps 1 and 3 will continue to operate.

18. Install breeching, combustion air duct, feedwater economizer, instruments, electrical, controls, steam, gas and other piping and make new Boiler 4 operational including tuning and testing on both gas and oil.

19. Once the new Boiler 4 is fully operational and has been run for at least two weeks without issues, shut down Boiler B-3 and demolish the boiler.

20. Demolition includes the entirety of Boiler B-3 including the forced draft fan in the basement, any associated controls, electrical equipment, platforms, etc.

21. Temporarily isolate and cap existing steam, feedwater, gas and oil connections for Boiler B-3.

22. Repair wall opening where Boiler B-3 stack is removed.

23. Following boiler demolition, make structural modifications to the floor to allow for installation of new boiler.

24. Remove temporary roof enclosure and set new Boiler 5 to the north of the control room.

25. Repair wall opening in conjunction with Boiler 5 installation.

26. Install breeching, combustion air duct, feedwater economizer, instruments, electrical, controls, steam, gas and other piping and make new Boiler 5 operational including tuning and testing on both oil and gas.

27. Finalize any remaining outstanding structural work including final placement of stairs.

28. Prepare basement for storage and move all stored materials into basement.

Once necessary approvals and funding are in place it is estimated that the project will take approximately two years to complete.

4.2 Financing

The estimated project budget range is $20-22M. Funding is requested from the State Capital Construction fund with a 17% cash match from CSU.

4.3 Cost estimate/methodology

Cost estimates were developed by a 3rd party consultant. CSU standards specify that the A/E document 20% of the construction budget in bid alternates, to cover potential volatility in the construction market as the project progresses.

Appendices

a. **Site map**
b. **Floor plans**
c. **Budget Estimate**