State of Connecticut DAS

CDECCA Due Diligence Final Report

PREPARED FOR:

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1. Executive Summary

In response to the State of Connecticut's (the "State") request for support with the acquisition of the Capitol District Energy Center Cogeneration Associates (CDECCA) plant from Hull Street Energy (HSE) and in accordance with On-Call Task Assignment No.: OC-DCS-ENGY-0030, Task No. 1 we are pleased to provide the following deliverables as described in the following program summary[1] table.

Program Acquisition & Optimization Phase	Focus	Deliverable Description/Title
Purchase & Sale Agreement	Technical due diligence and support leading to financial close	Interim Due Diligence Report Final Due Diligence Report
Capital Renewal and Performance Improvements	Management of plant upgrades, automation and performance optimization	Preliminary option for pumphouse relocation

For the deliverables contained herein Veolia has partnered with Waldron Engineering. Collectively, our team has provided guidance on the State's thermal contracts and operations related to the CDECCA plant for over a decade. We possess a deep understanding of the plant and the operational intentions of the State.

The due diligence effort established a robust RFI and data room structure resulting in the receipt and indexing of over 300 critical documents. Findings based on document reviews, site inspections and owner/operator interviews have been allocated into a framework separating impacts on offer price from those related to plant optimization post financial close. Due diligence efforts were guided by the contractual premise that the State is responsible for all major capital renewal, regardless of plant ownership. The defined categories outlined below will serve as a guide for the State as they approach financial close, transition operational responsibility and work towards upgrading and optimizing the facility.

[1] Program includes four phases: 1) Acquisition Due Diligence, 2) Operational Transition Services, 3) Capital Renewal and Performance Improvements and 4) Performance Management. Task Letter 1 authorized 1) Acquisition Due Diligence and partial scope for 3) Capital Renewal and Performance Improvements.

- Category 1: Material impact on the current purchase price and terms outlined in the PSA.
- Category 2: Material impact on the State's ability to operate the plant and deliver thermal products to its offtakers, post financial close.
- Category 3: Optimization and capital renewal concerns to be addressed with subsequent diligence and design efforts, post financial close.

Ultimately, the due diligence efforts did not uncover any fatal flaw findings that would prevent the State from purchasing the facility. The State should be aware of the significant capital renewal ahead of them due to a combination of end of life equipment, lack of adequate maintenance records, deferred maintenance practices and the desire to repurpose and optimize the plant from its core design as an electric generating facility in order to meet Governor's executive order #1.

A summary of the estimated costs and associated timeframes with our key findings are outlined the following table:

Category	Description	Probable Opinion of Cost	Timeframe
1	A) Full decommissioning and removal of non-critical systems (i.e. power generation systems)	$1-$5.5 MM $1 MM needed immediately to enable pumphouse relocation. Full demolition of $5.5 MM not required.	Immediate
	B) Structural / roof deferred maintenance	$2.4 MM	Within 3 years for roof replacement, within 5 years for all other recommended repairs
2	A) Thermal equipment deferred maintenance & lack of maintenance history	Testing program results will inform least cost options.	Depends on testing program results and programming of steam to hot water conversion and pumphouse relocation.
	B) Pumphouse Relocation	Current temporary pumphouse solution costs $1.3MM/YR. Performing min. demolition ($1MM) in the CDECCA facility will enable relocation of pumphouse systems ($5.1MM)	Immediate

Category	Description	Probable Opinion of Cost	Timeframe
	C) Commodity Supply & Delivery: Infrastructure changes for electricity delivery Commodity strategy for electricity and natural gas supply	Infrastructure cost pending Eversource proposal ~ $2 MM of commodity at risk (OpEx)	0-6 Months - Perform cost benefit analysis of options as made available by Eversource, including retaining existing 115 kV service. Commodity strategy should be reviewed immediately to ensure least cost options are executed.
	D) Meter reading & billing process improvements are needed Overview of existing process to be provided by Seller	Scoping effort required to determine solution to modify billing process from field metering to invoicing (meter to cash)	Immediately, as ownership change has direct impact on current billing and revenue recovery methods.
3	A) Optimization and capital renewal	New, permanent hot water boilers and associated demo ($9.7 MM) capable of serving thermal loop and Cap Ave Complex, following a hot water conversion project ($4MM). Subsequent diligence and design efforts, post financial close will identify additional optimization and associated costs	Will require conversion of Capitol Ave. from steam to hot water Consultation with DEEP on policy and applicable incentives.

Total identified capital requirements and their associated probable opinions of cost are summarized as follows:

Capital Requirement	Cost Opinion
CDECCA Plant Purchase	$7,250,000
CDECCA Plant Equipment/System Demo	$935,464
Pumphouse Relocation	$5,125,254
Convert Cap Ave Complex (Steam-to-HW)	$4,000,000

New Hot Water Boiler System	$9,707,448
Structural/Roof Repairs	$2,400,000
Total	**$29,418,166**

Additional details on the categorical findings from our due diligence are presented in an abbreviated manner as follows:

1.1. Category 1: Impact on Purchase Price

1.1.1. Structural Related

The structural analysis by the State's third party structural firm identified approximately $2,400,000 in deferred maintenance repairs that they recommended be addressed. These included replacement of five (5) roof areas identified as being at the end of their usable life, façade restoration, cooling tower repairs, asbestos abatement, chimney repairs, miscellaneous exterior steel repairs and painting, and foundation maintenance.

1.1.2. Plant Repurposing

The cost for full demolition and removal of all equipment is no longer required for operation of the plant as a thermal only facility has been estimated at $5,470,000. This includes demolition and removal of the HRSG, steam turbine, turbine generator pedestal, steam turbine auxiliaries, condenser, pumps, and associated small tanks. While full demolition is not required for all future operating scenarios presented in this report, some degree of equipment demolition and removal will be required if the State decides to proceed with facility efficiency upgrades.

1.2. Category 2: Impact on Operations

1.2.1. Deferred maintenance

Deferred maintenance and lack of service records suggest equipment has a run to fail history. This is supported by the contractual agreement which implies 1) State of CT responsible for all capital repair and renewal and 2) weak key performance indicators with limited financial penalty. Historically, there has been limited incentive for the asset owner and operator to implement proactive O&M services and efficient dispatch protocols.

Of particular concern is the lack of response to the State's inquiry of O&M budgets, staffing levels, and maintenance costs, as requested in S1-RFI-017. A testing and inspection program has been proposed for critical systems, the results of which will inform the immediacy of capital renewal.

1.2.2. Commodity Supply & Delivery

The State faces two areas which will require immediate attention in order to secure long term least cost service from Eversource and Connecticut Natural Gas (CNG).

1. Infrastructure changes for electricity delivery
2. Commodity strategy for electricity and natural gas supply

The basis for this is the plant is repurposing from a combined cycle electric generating facility with large natural gas imports and high voltage electricity exports to one initially focused solely on thermal generation.

As Eversource continues to develop alternate electric supply configurations the State should focus its efforts on preparing for a cost benefit analysis of potential options as they are presented by Eversource. Among new infrastructure ownership, one of the options should include keeping the existing 115 kV service active to support future changes to the plant.

Separately, the State should commence a commodity supply strategy for both electricity and natural gas as current market pricing will have a material impact on this year's heating costs.

1.2.3. Meter Reading & Billing Process

Hull Street has not provided an adequate response to the critical process of metering reading and billing, as requested in RFI-007. On June 22, 2022 - HSE, State of CT, and Veolia discussed the nature of RFI-007 and it was determined that, although the State receives detailed invoices, the current process of producing invoices actions from both IHI and HSE, details of which need to be transferred to the State. On August 31, 2022 the State informed Veolia of discussions with HSE and IHI resulting in a verbal agreement for HSE and IHI to assist the State with review of the meter reading and billing process.

Given the lack of transparency of the billing and invoicing process, the State should conduct a metering assessment to establish proper protocols and adjust its revenue recovery and meter reading and billing system accordingly. Veoila recommends the following specific actions related to meter reading and billing process as the State begins its O&M transition activities:

1. Document via flow chart, the HSE/IHI process from field instrumentation to customer invoice.
2. Remove use of efficiency curves to determine variable cost of energy and replace them with direct metered consumption.
3. Update State's billing process with real time metered demand to ensure adequate contribution from end users to the total cost of capacity, i.e. demand charges.

1.3. Category 3: Optimization and Capital Renewal Concerns

In general much of the major equipment in the plant is past its expected useful life but still operational, however, oversized for thermal heating operations. Additionally, several systems were recommended for additional testing/inspection based on their age, observed condition and/or critical role in maintaining plant operation, which may reveal additional concerns. Higher than average O&M costs to maintain these older systems can be expected, as well as capital expenditures for equipment replacement as these systems fail.

1.3.1. Pumphouse Relocation

Due to the 2021 Pumphouse tank explosion, a relocation/repowering analysis was performed to provide a preliminary review of options, opinions of probable cost, and a comparative 20 year financial analysis to determine a recommended path forward. A total of six options were identified, three of which were considered worthy of further evaluation and cost benefit analysis. To support the ultimate goal of delivering reliable and least cost thermal supply, the State should pursue 'Option 3' outlined in the table below. This option requires a minimum demolition of $1MM within the CDECCA facility to procure and install new pumphouse systems for $5.1MM. Steam production in CDECCA would be completely retired in this option and will be removed and replaced with a new, permanent hot water boiler system for an additional $9.7 MM. This option also requires an enabling project of converting the Cap Ave Complex from steam to hot water for an estimated $4MM. Excluding the cost of the CDECCA plant, total capital costs for this option are $19.8MM. This option is estimated to take approximately 3 years to complete. Net present costs shown in the following table include the cost of the purchase of the CDECCA plant ($7.3MM), annual costs for pumphouse solution, and HSE payments which are carried in years 1-3, as appropriate until such services no longer are needed.

All values provided for probable opinions of cost are based solely on concept levels of design, capacity factored estimates and experience.

Option	Description	Total Cap Ex	Op Ex (Avg 20 yr)	Net Present Cost ($2022)
Status Quo (Not a feasible option, must address pumphouse)	Status Quo Hot water to the thermal loop will continue to be supplied by the temporary hot water boilers that were installed following the damage that occurred at the Pumphouse. The existing steam boilers in CDECCA would be utilized for supply of steam to the Cap Ave Complex.	$0	$8,323,008	$123,556,818
1 - Purchase, Pumphouse Relocation & Replace Boiler(s) w/ Existing Steam and New Hot Water	Minimum demolition in the CDECCA facility is included, to minimize project costs. The temporary hot water boilers that were installed will be removed and replaced with new, permanent hot water boilers in CDECCA. The existing steam boilers in CDECCA will continue to supply steam directly to the Cap Ave Complex.	$24,742,465	$3,935,196	$83,270,316
2 - Purchase, Pumphouse Relocation & Replace Boiler(s) w/ New Steam and New Hot Water	Minimum demolition in the CDECCA facility is included, to minimize project costs. The temporary hot water boilers that were installed will be removed and replaced with new, permanent hot water boilers in CDECCA. The existing steam boilers in CDECCA will be replaced with new, smaller steam boilers that are more appropriately sized for the Cap Ave Complex loads.	$28,372,713	$3,888,079	$86,113,151

3 - Purchase, Pumphouse Relocation & Replace Boiler(s) w/ Hot Water	Minimum demolition in the CDECCA facility is included, to minimize project costs. Steam production in CDECCA would be completely retired in this option, and the temporary hot water boilers that were installed will be removed and replaced with new, permanent hot water boilers in CDECCA that are capable of serving not only the thermal loop but the Cap Ave Complex (following a hot water conversion project) as well.	$27,018,166	$3,644,411	$81,177,388

Refer to section 7 for additional details on pumphouse evaluation.

2. Facility Description

The CDECCA facility, located at 490 Capitol Avenue, Hartford, Connecticut, was constructed in 1988 as a natural gas-fired, dual fuel capable, combined-cycle cogeneration merchant plant with a generation nameplate capacity of 62.1 MW. Until late 2019, CDECCA had provided peaking energy to the ISO New England power market and is presently providing steam and chilled water to the Hartford Capitol district heating network, through a Pumphouse, owned by the State.

The facility consists of a General Electric model PG 6531 (Frame 6) gas combustion turbine generator (CTG) with an in-line three (3) pressure Heat Recovery Steam Generator (HRSG) with duct-firing capabilities, and a 22.5 MW Alstom condensing/extraction steam turbine generator (STG). Thermal energy supply equipment also consists of one (1) 900-ton two-stage steam absorption chiller (de-rated), two (2) 1,800-ton centrifugal chillers, one (1) 900-ton variable speed centrifugal chiller, and two (2) package boilers (27,600 lbs/hr and 150,000 lbs/hr) which support the chilled and hot water supplies to the CAS loop and Capitol Ave Complex.

2.1. Ownership Boundaries

Based on current CDECCA (a subsidiary of Hull Street Energy LLC (HSE)) ownership and projected State ownership, a general schematic arrangement was developed (refer to Figure 2 and Figure 3). The general arrangement shows the major equipment at the thermal energy plant owned by CDECCA and the State. The State owns the pumphouse and purchased Chiller 4 in 2018. After the CDECCA plant purchase, the State will own all the equipment as depicted below.

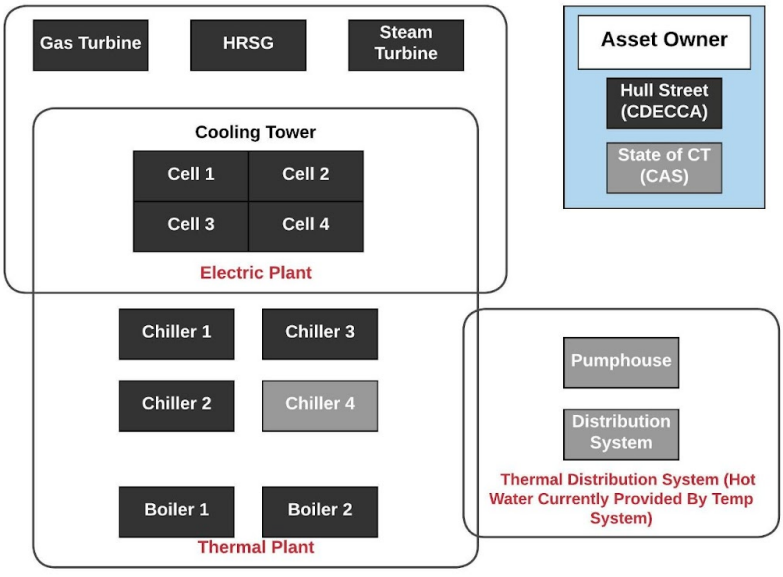

Figure 2: Before Purchase

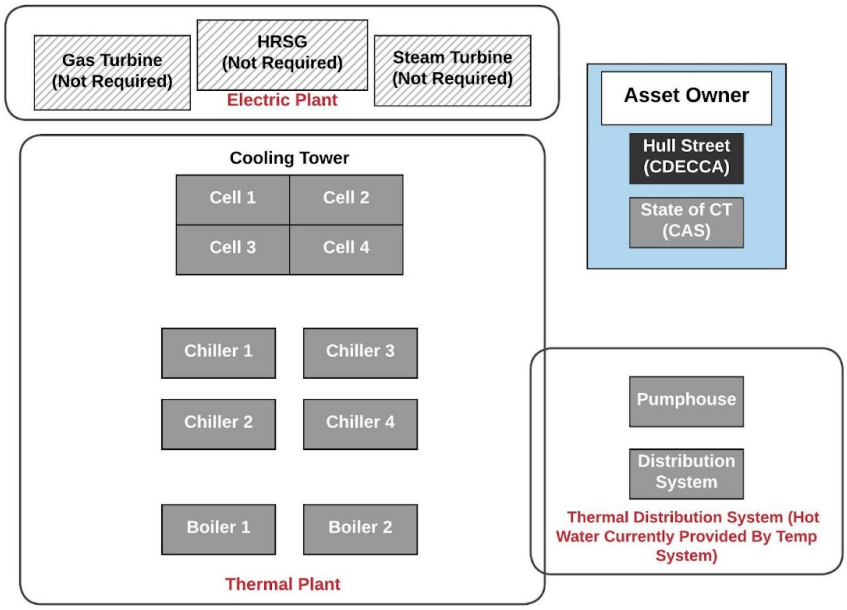

Figure 3: After Purchase - Day 1

Refer to Appendix A for a detailed general arrangement delineating thermal and electrical generation equipment as well as point of utility connections.

3. Due Diligence Approach & Methodology

SourceOne understands the level of due diligence requested by the State of CT was limited based on the States position of being responsible for asset replacement both pre and post acquisition. SourceOne initially provided an exhaustive due diligence process for consideration and based on feedback from the State removed considerable scope to align with the States desired level of due diligence.

3.1. Methodology

Engineers from Veolia and Waldron conducted multiple site visits to observe facility conditions and obtain information relating to all mechanical, electrical, and structural systems within the facility. These observations were coupled with the data received from Requests For Information (RFIs) submitted to HSE and the State to form the basis of our understanding of the condition of the facility, and to identify certain risks or costs the State will incur as a result of the acquisition.

It should be noted that the scope of our effort did not include evaluation of the facility for the presence of hazardous materials. The State retained GZA GeoEnvironmental, Inc. to provide an updated Phase I Environmental Site Assessment, Air Permit Review, and Preliminary Hazardous Building Materials (HBM) Assessment of the property (Section 4.6).

3.2. RFI Process and Turnover Document Register

3.2.1. Submitted RFIs

SourceOne provided formal Requests For Information (RFI's) pertaining to the State of Connecticut "Task Order No. 1 CDECCA Plant Acquisition Due Diligence & other services" dated April 12, 2022. SourceOne has maintained a log of all requests made including dates submitted, response dates, hyperlinks to each RFI on a shared drive as well as RFI Status. SourceOne, Hull Street, and the State of Connecticut all have access to this shared Google Drive Folder which contains the requests. These RFI's were submitted to Hull Street via email in an effort to ensure the successful acquisition of the Energy Asset from Hull Street and the future operation of the Capital Area District Energy System.

A copy of the existing RFI Summary Sheet is provided in Appendix B Each of the RFI's submitted by SourceOne to date are also included along with this report. A total of 17 RFI's have been presented on this project. Each RFI can also be also referenced in Appendix B.

The following RFIs were sent to Hull ST / IHI on the corresponding dates:

Request for Information Log		
RFI No.:	**Subject / Question**	**Date Submitted**
S1-001	General RFI request for site specific information - Powerhouse	4-May-2022
S1-002	General RFI request for site specific information - Pumphouse	6-May-2022
S1-003	General RFI Request for drawings 401-417 and 601-610	12-May-2022
S1-004	CDECCA Cooling Tower	20-May-2022
S1-005	Waldron Questions - Elect, Mech, Controls	20-May-2022
S1-006	Request for Appendix B "Operations Services Documentation"	10-Jun-2022
S1-007	Billing Process Details, R-114 plan	24-Jun-2022
S1-008	GZA request for site safety equip and chemical documentation	27-Jun-2022
S1-009	Request for Appendix C Requirements - "Owner Responsibilities"	30-Jun-2022
S1-010	Powerhouse Roof Info	5-Jul-2022
S1-011	Pumphouse Loads	6-Jul-2022
S1-012	Cooling Tower Repair Recommendations	18-Jul-2022
S1-013	Turbine Run Hours	19-Jul-2022
S1-014	Operator Training Manuals	19-Jul-2022
S1-015	GZA Environmental Permit Request	26-Jul-2022
S1-016	Request for Appendix G, H and I "Operations Services Documentation"	29-Jul-2022
S1-017	O&M Agreement Info	2-Aug-2022

3.3. Site Walk and Data Collection

Engineers from Veolia and Waldron were on site to observe the CDECCA facility and perform on-site data collection on May 11, May 17, and July 18, 2022. During the initial site visit on May 11 Veolia and Waldron met with stakeholders from the State, the facility owner and the facility operator to survey the property and establish the scope and physical bounds of the due diligence investigation. The State's specialty subconsultants for environmental, property survey and structural analysis due diligence were also present.

During this phase, our observations and the data collected were used to develop a high level understanding of the existing facility for each major engineering discipline (Mechanical, Electrical, Structural and Controls). Points of demarcation between Buyer, Seller and essential utility services such as natural gas, electricity, water and sewer were also established. Based on information collected during the first two (2) site walks on May 11 and 17 an Interim Report of initial findings indicating any systems requiring further detailed inspection or investigation necessary within the due diligence period was prepared for and presented to the State on June 15, 2022.

Please refer to Appendix C to view a report of visual observations of existing conditions and recommendations to remedy and identify anomalies, by system/area of plant.

3.4. Recommended Testing Program

In the initial phase of due diligence and RFI response review it was determined that a combination of field conditions and lack of inspection / testing records required further testing on critical systems. The due diligence team put forth the following proposed testing program:

1. Development of testing specifications and request for proposals
2. Issue, review and award testing subcontract based on total value
3. Manage subcontractor and coordinate site testing
4. Review findings and incorporate into final Due Diligence deliverables as specified in Task Letter 1

3.4.1. Summary of Testing to be Conducted

Cooling Tower System

Cooling tower inspection inclusive of assessment of the cantilevered slabs that have shown discoloration on the underside is important. The cooling tower was manufactured in 1988 and is assumed to be the original system that was installed when the plant was constructed. The existing wood-framed tower consists of four (4) cells with a common basin and a plume abatement system. The towers were inspected in 2017 by International Cooling Tower and a list of deficiencies and recommendations were

provided (Appendix D). It is unclear whether or not the repairs identified in the report were implemented. In either case, based on the conditions of the tower observed in the walkthrough a current inspection is merited. During the site trip deterioration and/or damage to the existing cooling tower of the following types was noted. Note that the walkthrough was not equivalent to a comprehensive tower inspection.

- Interior partition walls were damaged or missing altogether.
- Wood panels, braces and columns throughout the tower showed visible evidence of deterioration. This does not necessarily mean immediate replacement is required but the extent of repairs that are required for structural integrity should be accomplished by a knowledgeable tower inspec
- Metal panels showed extensive corrosion in places.
- Possible damage to fill was observed, including flow-channeling that seemed to reflect improper distribution and nozzle performance in the hot water boxes.

The proposed inspection includes a structural assessment of the existing wood-framed towers to evaluate remaining life and replacement cost. The wood framing shows signs of degradation in some areas and the intent is to identify a magnitude and timeframe for the replacement/repair costs the State will inherit via the plant purchase. As the tower is significantly over-sized for the future needs of the system, if it is found to be in a state of disrepair, consideration may be given to repairing or replacing only a portion of cells. If required, full replacement cost of the cooling tower would be expected to be in the order of magnitude of millions of dollars.

Condenser Water Piping

Although not included in the visual inspection due to its scale and location, testing to understand its condition is important. Condenser water piping is required for chiller operation and not easily replaced due to the large volume of piping and the fact that it generally is not easily accessible, leading to extended outages to make repairs. Therefore, condenser water piping wall thickness testing is recommended. Similar facilities of the same vintage as CDECCA have experienced more than 80% metal loss with pinhole leaks that developed in certain areas.

Motor Control Centers

The MCCs have shown, through thermal imaging in 2020, various hot spots (refer to Traver IDC Infrared Inspection Report, Appendix E). It is recommended to determine whether or not CDECCA has made any repairs to alleviate this condition or not, as continued service with elevated temperatures will lead to fires and faults on an unpredictable and short timeline. If CDECCA has not made the repairs recommended by the previous assessment, the State could use this for negotiation, but also, it is important to validate the condition and be sure these issues have been resolved. As of the date of this report, CEDECCA has not provided documentation of recommended repairs.

Risk of failure includes loss of the plant in the event of a catastrophic event. Lead time on electrical gear is currently extended to upwards of 52 weeks due to current market conditions. MCC's are assumed to be original equipment, installed circa 1988.

TRANSFORMERS

The 13.2kV:5kV transformers should be inspected including their neutral grounding resistors. The 115kV transformer is not being prioritized as it has more recent test data than the 13.2 kV transformers, and also it is the only oil-filled unit. Oil-filled transformers are more resistant to the elements while the 13.2 kV transformers are dry type and old and could fail within a year of one another if the failure mechanisms are related to progressive, time-based degradation mechanisms. There are little recent reports on these units so we prioritize them over the 115 kV unit.3

Risk of failure includes loss of the plant in the event of a catastrophic event. Lead time on electrical gear is currently extended to upwards of 52 weeks due to current market conditions. The transformers are assumed to be original equipment, installed circa 1988.

4. System and Operating Conditions Assessments

4.1. Summary & Background

The CDECCA facility was originally constructed as a power generation facility with a nominal rating of 70 MW. The State is in the process of purchasing the facility with the intent of meeting its thermal utility needs, and as such the facility will not be operated in electrical power generation mode. Equipment and systems exclusively needed for electrical power generation will not be required and may be abandoned-in-place or demolished in accordance with the State's requirements. A key objective of this study is to define those systems and equipment that fall into this category versus those that must remain in service to meet the future thermal energy supply goals of the system.

Additionally, the long-term intention of the State is to convert all remaining steam customers on the thermal distribution loop to hot water, which will allow the repowered/future version of the CDECCA facility to export two utility products: hot water and chilled water. It is expected that for some period of time after taking ownership of the facility, the State will still require three (3) utility products to meet the thermal needs of all thermal loop customers: steam, hot water, and chilled water.

4.1.1. Expected Equipment Life and Remaining Useful Life

For the major thermal equipment at the site, expected equipment life estimates were determined based on the 'Equipment Life Expectancy Chart' authored by American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE)[2]. The purpose of this chart is to provide information on service life of similar equipment. The actual useful life of any piece of equipment is dependent upon many factors such as run hours, maintenance schedule, and other factors. In the following table, the number of years

[2] ASHRAE sets the standards and guidelines for most HVAC-R equipment.

in service were deducted from the expected equipment life to determine the remaining life of the equipment. Installation dates for most major equipment have been provided.

Table 1: Major Mechanical Asset Estimated Remaining Life

Asset List	Installation Year	Expected Equipment Life (Years)	Remaining Life (Years)
Absorption Chiller/Centrifugal Chiller #1 [900 Tons][3]	1988	23	0
Centrifugal Chiller #2 [900 Tons]	2013	23	14
Centrifugal Chiller #3 [1800 Tons][2]	1988	23	0
Centrifugal Chiller #4 [1800 Tons]	2019	23	20
Cooling Tower #1 [2 x 3,750 Tons]	1988	30	0
Cooling Tower #2 [2 x 3,750 Tons]	1988	30	0
Boiler #2 [27,600 lbs/hr]	2005	30	13
Boiler #1 [150,000 lbs/hr]	1988	30	0
Deaerator feed pump [250 HP]	1988	17	0
Condensate pump [40 HP]	1988	17	0
Centrifugal chiller condensate pump [125 HP]	1988	17	0
Auxiliary fuel oil forwarding pump [100 HP]	1988	17	0
Auxiliary boiler feed pump [100 HP]	1988	17	0
Main circulating water pump [250 HP]	1988	17	0
Auxiliary cooling water pump [250 HP]	1988	17	0
Makeup pump [15 HP]	1988	17	0
Feedwater pump #1 (1250 hp)	1988	17	0
Sump pump	1988	17	0

4.1.2. Summary Matrix of Findings

A summary matrix of major systems/equipment along with a brief narrative on identified risks and recommendations regarding future configuration and operation of the plant is included as Appendix C . In general much of the equipment is past its expected useful life but still operational, if oversized for expected future operations in some cases. However, several systems were recommended for additional

[3] Chillers #1 and #3 are original to the plant and are likely derated from the nameplate capacities listed in the table.

testing/inspection based on their age, observed condition and/or critical role in maintaining plant operation.

4.2. Mechanical

4.2.1. Condenser Water System

Historically, the condenser water system has had three key functions within the CDECCA facility:

- to supply condenser water to the steam turbine surface condenser in support of electrical power generation;
- to supply cooling to the plant auxiliary cooling system that cools various bearing and seal cooler loads; and,
- to supply condenser water to the chillers for chilled water production for the thermal loop.

The support of chilled water production will become the primary system function for future operations of the facility by the State.

4.2.1.1. Major Equipment

Cooling Tower

The existing wood-framed tower consists of four cells with a common basin and a plume abatement system. The plume abatement system is necessary because of the proximity of the tower to Interstate Highway 84. Cells 1 and 3 have VFD driven fans, while Cells 2 and 4 have two speed fans. The tower is significantly over-sized for the future needs of the system: operation of the fans in cells 2 and 4 is typically not required to support chilled water production, and for shoulder season operation fans are sometimes not required at all.

Although cooling tower data sheets and/or system flow diagrams were not available to confirm the design basis cooling tower performance, it is estimated based on high level calculations that peak chilled water production requires approximately 20% of the tower's design rated cooling capacity.

The towers were inspected in 2017 by International Cooling Tower and a list of deficiencies and recommendations were provided. It is unclear whether or not the repairs identified in the report were implemented. In either case, based on the conditions of the tower observed in the walkthrough a current inspection is merited.

Steam Turbine Condenser and Primary Pumps

The steam turbine condenser is only required for power generation and thus will not be utilized in the future. Condenser water is fed to the condenser from the cooling tower by two large primary pumps that will also not be required in the future.

Auxiliary Cooling / Chiller Plant Pumps

No flow diagram of the condenser water to the chillers was provided; however it was noted during the walkdown that the chillers are supplied with condenser water from a separate riser than the steam turbine condensing system. Both risers drop down through the building from the cooling towers.

The auxiliary cooling system has dedicated pumps, as does each chiller. All pumps are constant speed.

4.2.1.2. System Operation

Because the facility is no longer generating power, the condenser water system is operated solely to support chilled water production. It is possible a few auxiliary loads are still cooled as well but the major auxiliary loads may be retired, abandoned, or demolished, including specifically the auxiliary cooling for the combustion turbine, the steam turbine, and gas compression. (Based on a review of the auxiliary cooling water system flow diagram provided by Hull Street, the auxiliary system may be retired; however, this should be confirmed as it is possible loads have been added to the system that are not reflected on the diagram.)

Presently the condenser water supply temperature to the cooling systems and chillers is controlled manually by the operators, by staging water flow over the various towers and manually placing tower fans into service. Based on discussion with the CDECCA plant personnel a constant return water setpoint of approximately 85°F is maintained. This value could be "reset" throughout the year to potentially improve chiller plant performance.

4.2.1.3. Existing Conditions

Cooling Tower

During the site trip, deterioration and/or damage to the existing cooling tower was observed of the following types. Note that the walkthrough was not equivalent to a comprehensive tower inspection.

- Interior partition walls were damaged or missing altogether.
- Wood panels, braces and columns throughout the tower showed visible evidence of deterioration. This does not necessarily mean immediate replacement is required but the extent of repairs that are required for structural integrity should be accomplished by a knowledgeable tower inspector.
- Metal panels showed extensive corrosion in places.
- Possible damage to fill was observed, including flow-channeling that seemed to reflect improper distribution and nozzle performance in the hot water boxes.

Condenser Water Piping

Much of the piping system is significantly oversized for the needs of the chilled water production alone. The primary return header from the plant to the tower hot water basins for instance, is at least 36" diameter piping. To support a peak chilled water production load of approximately 4,000 tons, only 18" or 20" diameter headers would be required. Additionally, significant portions of the existing piping are not required to be in-service to support the future chilled water production. This is a concern for the following reasons:

- Portions of the system that do not have any flow but are filled with water due to valve locations will experience pitting corrosion and develop leaks over time; and,
- The cost of repairing or replacing 36" or 42" valves is significantly higher than dealing with 18" or 20" stock.

4.2.1.4. Recommendations

Evaluations and/or Upgrades Recommended

Abandon portions of the condenser water piping that will no longer be operated in order to avoid the issues associated with long-term corrosion and system leakage, and modify the system such that piping that is not regularly utilized is separated from the working system.

Implement a control scheme for the tower that allows for reset of the tower exit temperature to lower values during shoulder months to improve chiller plant performance.

Inspections & Tests

It is recommended that the following items be inspected further as part of the due diligence process:

1. A comprehensive inspection of the existing cooling tower should be conducted that includes the towers as well as the walkways, platforms and concrete basin. Recommendations for repair and/or replacement should be made along with an order-of-magnitude cost to complete the work. Consideration of the fact that full tower capacity is not required should be made when evaluating essential vs non-essential repairs.
2. Wall thickness testing of the condenser water risers to/from the cooling tower should be conducted as future chilled water generation will be dependent on the integrity of this piping. It will be relevant for the State to understand the wall thickness and remaining life of the existing piping.

4.2.2. Chilled Water System

The primary use for the chilled water system has been, and will remain, the supply of chilled water to the CAS thermal loop.

4.2.2.1. Major Equipment

The chilled water system contains four (4) chillers as noted below.

Chiller 1 (Steam Absorption)

Chiller 1 is a 900-ton rated steam absorption chiller that is largely inoperable. CDECCA plant operations indicated during the walkthrough that it is rarely run, and that in recent periods of use the machine has struggled during part-load operations. Based on the information supplied, this chiller should not be relied upon in the future as a primary chilled water source, and if retained, may be operated as a last resort. Motive steam must be provided from the larger auxiliary boiler as the smaller boiler is not able to carry the plant 15-psi steam load and power the chiller.

Chiller 2 (Electric Centrifugal)

Chiller 2 is a Trane CVHF 900-ton rated electric centrifugal chiller that was installed in 2012. The unit is a constant speed chiller, 460V, and was in-service during the walkthrough. The chiller appeared to be in good working condition.

The refrigerant used is R-123 according to the chiller nameplate.

Chiller 3 (Electric Centrifugal)

Chiller 3 is a Carrier 1,800-ton rated electric centrifugal chiller. The unit is a constant speed chiller, 4,160V, that was installed with the original plant. This is the oldest of the working chillers.

The nameplate refrigerant for this chiller is R-114, which is no longer manufactured because of its relatively high Global Warming Potential (GWP). (R-114 has a GWP ~130x higher than R-123, for instance.) The current refrigerant in service should be verified as it could have been replaced at some point in the past. If not, finding replacement refrigerant in the event of a leak requires access to reclaimed refrigerant from other retired units or applications. Also, as noted the greenhouse gas emissions associated with refrigerant leakage on this unit would be quite high in comparison to the other units.

Chiller 4 (Electric Centrifugal)

Chiller 4 is a Trane 1,800-ton rated electric centrifugal chiller. The unit is a variable speed chiller, 4,160V, that was installed in 2019. The unit appears to be in good working condition.

The refrigerant used is R-123 according to the chiller nameplate.

Capacity Analysis[4]

If the steam driven chiller is left out of the equation, the capacity of the facility on an N+1 basis is approximately 2,500 tons. This is the capacity with the largest unit out-of-service, and includes a modest derate on the nameplate of Chiller 3, which is the oldest chiller in the plant and unlikely to produce nameplate capacity at this time.

The State's design chilled water load for the thermal loop is unknown and is an RFI that is open as of the writing of this report. Based on operating data supplied by CDECCA, the nominal system peak demand realized in the last year of operation is 4,000 tons[1]. It will be important for the State to understand the true redundancy level of the plant for chilled water production relative to their peak load, and to understand if this redundancy level is adequate for their needs.

4.2.2.2. System Operation

The steam driven chiller was primarily used when the facility still produced electrical power, and steam from the heat recovery system was available to power the unit. Since the facility is no longer utilized for power generation the only means of operating the steam driven chiller is with a fired boiler. This could potentially be cost-effective if high demand charges from the utility are avoided, but given the facility's high voltage interconnection it may not be cost-effective at this time. Also, the greenhouse gas emissions associated with firing a boiler to produce chilled water are typically much higher than running efficient electric centrifugal machines with grid power.

It appears the smaller electric chiller is likely operated during low load periods and that the larger unit(s) are dispatched during the warmest months of the year.

4.2.2.3. Existing Conditions

The plant overall appears to be well-maintained and reports on the chillers do not contain references to plugged tubes, bearing issues, seal issues, or significant refrigerant leaks. There is no obvious indication of vibration concerns in any of the maintenance reports. The chiller plant appears to be in good condition for its age, and the load on the plant is not excessive.

The one concern, noted above, is whether or not the N+1 capacity—(the "firm" capacity, meaning the capacity with the largest single unit out of service)—meets the State's requirements going forward.

[4] The data supplied by CDECCA did not contain units and the assumption was made that the data was provided in tons. However, if the data is in gpm, this would give a significantly lower value. In work performed previously for the State, reported chilled water system peak loads were approximately 3,750 tons, so this data appears to be in-line with previous work, but it will be important to clarify.

4.2.2.4. Recommendations

Evaluations and/or Upgrades Recommended

In the future the merits of installing VFDs on chilled water and/or condenser water pumps could be evaluated for efficiency improvements.

The State should confirm the type of refrigerant in Chiller 3. If the original R-114 is still in use, consider the implications of continued use of refrigerant R-114 in Chiller 3, and its impacts on the State's greenhouse gas emissions inventories.

As noted in the condenser water section, condenser water temperature reset controls on the cooling towers could improve chiller performance; however, given the range in age of the units this would need to be studied as not all units may be capable of operating with lower pressure differentials across the compressors without controls upgrades.

Inspections & Tests

It is recommended that the following items be inspected further as part of the due diligence process:

1. Eddy current testing of chiller tubes to evaluate their wall thickness and condition is recommended as a best practice prior to ownership transfer of existing chillers. Given the issues with Chiller 1, testing on this unit is not considered relevant.
2. No data has been available to date that provides information on the chiller performance. If possible, it is recommended that chiller operating data be obtained during the next 60 – 90 days to benchmark chiller performance in terms of COP or kW/ton, etc.

4.2.3. Steam System

The primary use for the steam system is two-fold:

- Historically, to provide heating steam to the pumphouse, where it was converted to hot water prior to installation of the temporary hot water boilers currently in service;
- to supply heating steam to the State campus buildings that still require steam; and,
- to supply motive steam to Chiller 1.

Going forward, there is expected to be a limited time period in which heating steam is still required to heat the State campus before those buildings are converted to hot water, and if Chiller 1 is retired then steam will no longer be required.

4.2.3.1. Major Equipment

Steam is generated by two auxiliary boilers. Both boilers fire natural gas only.

Boiler 1

Boiler 1, the Zurn boiler, is the larger of the two boilers and has a nominal capacity of approximately 160,000 lbs/hr of steam production.

Boiler 2

Boiler 2, the Cleaver Brooks boiler, has a nominal capacity of approximately 25,000 lbs/hr of steam production.

Capacity Analysis

Assuming the temporary hot water boilers installed by the State are retained until new hot water boilers are installed in the CDECCA facility, it appears there is plenty of boiler capacity to meet the State's interim needs. The challenge is that the boilers are over-sized for the loads being served. During the site visit on 5/11/2022, for instance, Boiler 2 was in operation at approximately 3% firing rate to provide heating steam to the State. Boiler 1 was not operating on 5/11/2022 and has not operated since 8/26/2021. Winter loads are surely higher than those observed in early May; however the boilers likely operate well below ideal efficiencies given their mismatch in size to the loads being served.

4.2.3.2. System Operation

As noted above the steam generation equipment (as well as the auxiliary systems in the plant that are required to operate to support steam generation) are not well-matched to the loads that will be served in the short-term. If the time period during which steam will still be required is relatively short, the inefficiencies of this equipment are a burden that should be endured until new, high-efficiency hot water boilers may be installed on a permanent basis. Long-term operation with the present equipment configuration is not recommended.

At the present time, due to the damage suffered at the Pumphouse, condensate is not being returned to the CDECCA facility. This condition further exacerbates the efficiency challenges, but as with the boilers themselves, the capital cost of making efficiency upgrades is not likely to be recovered through the subsequent efficiency gains if the duration in which steam production must be maintained is short.

4.2.4. Existing Conditions

As noted above the sizing of the steam generation systems are not well-matched to the loads, but this should be a short-term issue for the State after taking ownership of the facility.

Boiler 1

CDECCA has provided emissions testing and jurisdictional inspection reports on Boiler 1, however the jurisdictional inspection reports only indicate Pass-Fail. It is recommended that the

State have a third-party boiler inspection agency provide a more detailed report on the boiler that documents the existing conditions and includes spot-checks of tube / shell thicknesses.

Regarding emissions, the air permit limit for NOx emissions on Boiler 1 is 37 ppm at 15% O_2. (This is approximately 0.13-0.14 lbs/MMBtu.) Several test reports supplied by CDECCA document compliance with this limit; however, there are also reports that show values as high as 85 ppm (units in the report are not given, but it is presumed they are in ppm). An excerpt of the report supplied by CDECCA is shown below:

BURNER TEST DATA

FIRING RATE					COMBUSTION READINGS						
Quadrant	Hi/Lo/V control out %	Steam Flow LB/H	Gas %	Air %	O2	CO	CO2	NOX	Stack Temp.	Ambient Temp.	Efficiency
	63%	65,000	60	64	4.99	4	8.91	85.9	304.3	77.7	84.2
	54%	56,000	55	53	6.26	3	8.19	68.1	299.1	79.0	84.0
	45%	47,000	44	43	6.93	21	7.82	45.3	293.0	79.7	84.0
	38%	40,000	39	38	6.51	22	8.06	39.0	288.3	80.4	84.3
	33%	34,000	33	32	6.26	12	8.19	29.5	282.7	81.0	84.5
	30%	30,000	29	30	6.04	9	8.32	24.3	280.6	81.5	84.7
	28%	26,000	29	30	7.11	12	7.72	32.3	277.9	81.9	84.4
	24%	21,000	24	30	9.52	15	6.37	23.1	279.1	82.0	83.4

Note that the air permit also describes possible revised, lower limits of 0.10 lbs/MMBtu will take effect in June, 2023. The language is complicated and also suggests that it may not be applicable to this boiler. The implications of this should be reviewed with an environmental permitting consultant to determine whether or not the boiler will be out of compliance in June, 2023.

Note from HSE: *We assume this is referring to the RCSA 22a-174, Section 22e Phase II NOx limitations that take effect on 6/1/2023. Since the CDECCA facility is operating under the RCSA 3-22a-174-33a Limit on Premises-Wide Emissions, it is no longer a major stationary source of NOx and is, therefore, not subject to the Section 22e emission limits unless AB #1 emits ≥ 274 pounds of NOx in any ozone season day in the future.*

3. NOx – RCSA §22a-174-22e (Phase 1 & Phase 2 Requirements)

a. *Limitation or Restriction*

i. The Permittee shall not cause or allow emissions of NOx to exceed the following emission limitations, based on a daily block average for an emission unit with a NOx CEM system: [RCSA §§22a-174-22e(d)(3)(A) and (C)]

Note: Pursuant to RCSA §22a-174-22e(a)(1)(B), the package boiler is not considered an "affected unit" because the package boiler's maximum heat input capacity is less than 250 MMBtu/hr

(A) Phase 1 (Beginning June 1, 2018 and ending May 31, 2023)

(1) Natural Gas: 0.20 lb/MMBtu

(2) ULSD Fuel Oil: 0.20 lb/MMBtu

(B) Phase 2 (Beginning June 1, 2023 and continuing thereafter)

(1) Natural Gas: 0.10 lb/MMBtu

(2) ULSD Fuel Oil: 0.15 lb/MMBtu

ii. The Permittee of an emission unit may cause or allow an emission unit to exceed the applicable emissions limitations specified in Section III.B.3.a.i of this Title V permit, provided the Permittee undertakes one of the following actions: [RCSA §22a-174-22e(d)(1)]

(A) Implements an alternative compliance mechanism in accordance with RCSA §22a-174-22e(g);

(B) Operates under a case-by-case RACT determination in accordance with RCSA §22a-174-22e(h); or

(C) Ceases operation in accordance with RCSA §22a-174-22e(f).

Excerpt from CDECCA Air Permit Indicting Future Constraints to NO_x Emissions for Boiler 1
(Note the potential exclusion in the second paragraph)

Boiler 2

CDECCA has not provided any jurisdictional inspection reports on Boiler 2. It is recommended that the State have a third-party boiler inspection agency provide a more detailed report on the boiler that documents the existing conditions and includes spot-checks of tube / shell thicknesses.

Regarding NOx emissions, the air permit supplied by CDECCA indicates that the current limit of 0.20 lbs/MMBtu for this boiler will be modified to 0.05 lbs/MMBtu on June 1, 2023. (Reference the excerpt inserted into this report below this paragraph.) This language is similar to the constraints described above for Boiler 1 but is more restricted (the future value is lower than the value for Boiler 1) and the possible exclusion for Boiler 1 is not noted for Boiler 2. Based on the data reports provided, it appears the boiler is presently operating at about 0.11 – 0.13 lbs/MMBtu on NOx. This means it has demonstrated compliance with the current permit limits

but that modifications could be required to operate the boiler next year. However, the applicability of this should be confirmed with an environmental permitting consultant.

2. NOx – RCSA §22a-174-22e (Phase 1 & Phase 2 Requirements)

a. Limitation or Restriction

i. Prior to June 1, 2023 the Permittee shall not cause or allow emissions of NOx as determined by NOx emission testing pursuant to RCSA §22a-174-22e(l) for the package boiler to exceed the following: [RCSA §22a-174-22e(d)(3)(A) and (C)]

(A) Phase 1 (Beginning June 1, 2018 and ending May 31, 2023)

(1) Natural Gas: 0.20 lb/MMBtu

(2) No. 2 Fuel Oil: 0.20 lb/MMBtu

(B) Phase 2 (Beginning June 1, 2023 and continuing thereafter)

(1) Natural Gas: 0.05 lb/MMBtu

(2) No. 2 Fuel Oil: 0.10 lb/MMBtu

ii. The Permittee of an emission unit shall not cause or allow an emission unit to exceed the applicable emissions limitations specified in Section III.E.2.a.i in this Title V permit unless the Permittee undertakes one of the following actions: [RCSA §§22a-174-22e(d)(1)(A), (B) and (C)]

(A) Implements an alternative compliance mechanism as provided in RCSA §22a-174-22e(g);

(B) Operates under a case-by-case RACT determination as provided in RCSA §22a-174-22e(h);

(C) Ceases operation as provided in RCSA §22a-174-22e(f)

Excerpt from CDECCA Air Permit Indicting Future Constraints to NO_x Emissions for Boiler 2
(Note there is no potential exemption paragraph as there is for Boiler 1)

4.2.4.1. Recommendations

Evaluations and/or Upgrades Recommended

1. The air permit language regarding new NOx emissions limits for Boilers 1 and 2 that will take effect in June, 2023 requires attention with regards to the timeline for boiler modifications that would be required for the State to achieve compliance. Neither boiler appears capable of passing the revised limits based on the historical emissions results provided, but as noted previously the applicability of the limits is unclear. It is recommended that the State retain the services of an environmental permitting consultant to evaluate the permit language and clarify requirements. If modifications are required to continue operating the boilers in the 2023-2024 heating season then time is of the essence.

2. It is important for the State to establish the timeline for full conversion of the thermal loop to hot water, as this will have implications for evaluation of the boilers as well.

Inspections & Tests

It is recommended that the following items be inspected further as part of the due diligence process:

1. Seek clarification from CDECCA on the high emissions values included in the reports for Boiler 1.
2. Retain the services of a third-party boiler inspector to provide the State with an independent report on the general boiler conditions for the auxiliary boilers. Boiler 1 information provided by CDECCA documents annual inspections but these were roughly 5 years ago. No such reports were provided for Boiler 2. Since the State will continue to be reliant on these boilers for heating the State facilities for some period of time, their condition should be verified.

4.2.5. Plant Auxiliary Equipment

This section focuses on the auxiliary equipment or systems in the CDECCA facility that are required to operate in order to support steam, hot water and/or chilled water production.

4.2.5.1. Major Equipment

Key auxiliary equipment are identified below:

Aux Steam System Deaerator and Feedwater Pumps

The auxiliary boilers are provided with deaerated feedwater from a dedicated deaerator and feedwater pump set.

Condensate Storage Tank

A field-erected condensate storage tank historically received condensate returns from the thermal loop and the steam condenser and forwarded this to the plant deaerators, including the auxiliary steam system deaerator noted above. The forwarding pumps are rated 850 gpm and are 250 hp, which is significantly oversized for the future steam production needs of the facility.

Air Compressors

Two Sullair compressors and a single dryer were noted during the site visit. One is enclosed and one is not. The units were both serviced in February, 2022. Based on plant flow diagrams provided the units are interconnected to an expansive air system that feeds numerous devices in support of combustion turbine and steam turbine operation. Capacity on the units should thus not be a problem for the future operating mode of the facility.

4.2.5.3. Existing Conditions

The auxiliary systems, like the steam system in general, are oversized for future operations. With the exception of the air compressors, all of the equipment noted above is required to support continued steam production and may be retired when the conversion to hot water is complete.

4.2.5.4. Recommendations

Inspections & Tests

1. Retain the services of a third-party inspector to provide the State with an independent report on the condition of the auxiliary steam system deaerator. Within a power plant, deaerators are one of the pressure vessels most prone to cracking and premature failure due to the ongoing mixture of hot and cold fluids. Loss of the deaerator would have a detrimental effect on boiler operations and the condition of the deaerator should be understood.
2. At present there is no condensate return but if the State's intent is to reinstitute condensate returns, the existing condensate storage tank should also be inspected by a third-party.

4.3. Electrical

4.3.1. Introduction

The purpose of the Existing Systems Review is to evaluate the current condition of the electrical system components and equipment., including review the maintenance program and make recommendations that include level of risk and cost:

- The Electrical system walk-down will document all the existing equipment essential to support the operation of the plant. The capabilities and limitations will be discussed with the operations staff. Maintenance records will be evaluated, and recommendations made as to the suitability of the equipment to continue operation into the future.
- Prioritize major electrical equipment testing and maintenance in terms of continued efficient operation of the plant.

4.3.2. Main Utility Transformer T1 [115kV/13.2kV] rated 42/55.9/70 MVA

The 115kV Step up transformer is the point of interconnection with the local utility Northeast Utilities System (Eversource). It is manufactured by TRANSELECTRIX TECHNOLOGY INC and has been in service for over 35 years.

The transformer is a three-winding, oil-filled transformer with one 115kV winding and two 13.2kV windings. The transformer is OA/FA/FA and has a rating of 42/55.9/70MVA is supported by the cooling fans that allow the transformer to operate at higher MVA rating with 42MVA being the base non-fan rating.

4.3.2.1. System Operation

The 115kV Step up transformer is the point of interconnection with the local utility Northeast Utilities System (Eversource). The transformer is a three-winding transformer with the 13.2kV side consisting of two windings, each connected to the gas turbine (GT) and the steam turbine (ST) side of the 13.2kV switchgear.

In normal operation the transformer steps up the generated power from the gas turbine and the steam turbine and then export it to the utility 115kV system through a utility owned switch-disconnect (1722-51L-5) and revenue meter rated 600A at 115kV. With the generators offline, the transformer is lightly loaded and powers the plant auxiliary loads and chillers.

4.3.2.2. Existing Conditions

Visual inspection of the transformer shows the unit is in good condition given that it's been in service for more than 35 years.

The results of oil testing and auxiliary protection equipment testing performed in 2016 by 3C Electrical Company did not show any major issues and are satisfactory considering the equipment age. The infrared testing of the transformer performed in 2016 by 3C Electrical Company shows minor overheating in the lightning arresters.

Figure 1: 115kV main utility transformer

Figure 2: 13.2kV cables on Transformer 51L-1X secondary

4.3.2.3. System Recommendations

Evaluations and/or Upgrades Recommended

The transformer has been in service for 35 years and even though it's in good condition it's approaching the maximum lifetime expectancy of 50 years. This means the transformer will need to be replaced within the next 15 years.

Another factor to consider is the transformer losses ~400kW which is going to be costly considering the transformer future load is only 8-10MVA compared to 42MVA when the generators were in service.

Inspections & Tests

1. Oil testing.
2. Winding Insulation test.
3. Thermographic survey to detect possible failure points/overheating issues.

4.3.3. Step-Down Transformers T2 & T3 [13.2kV/4.16kV] rated 7.5/10 MVA

The two 13.2kV transformers step down the voltage from 13.2kV to 4.16kV and feed the plant auxiliaries. They are dry-type transformer originally provided by ABB and have in service for 29 years since 1993

The transformers are equipped with neutral grounding resistors (NGR) on the 4.16kV side that limits ground fault contribution to 200A. The NGR appear to be the original units installed when the transformers were initially energized.

4.3.3.1. System Operation

The transformers steps down the 13.2kV utility power to 4.16kV and feed the various 5kV loads. The two transformers can operate in a main-backup scheme where one transformer is servicing the plant load while the second is on standby.

4.3.3.2. Existing Conditions

Visual inspection of the transformers shows the two units are in good condition despite the service time of 29 years.

The transformer infrared testing wasn't performed on the two transformers as part of the 2016 Thermographic testing by 3C Electrical Company.

Figure 3: Neutral Grounding Resistor NGR

Figure 4: Transformers 51L-1S & 51L-2S

4.3.3.3. System Recommendations

Evaluations and/or Upgrades Recommended

The transformers have been in service for 29 years and are approaching the maximum lifetime expectancy of 50 years. Even though the two transformers are in good condition, they will need to be replaced within the next 20 years.

The transformers can also be used as the main utility interconnect point if a new 13.2kV Eversource service is made available. This will achieve considerable savings by retiring the existing 115kV transformer.

Inspections & Tests

1. Transformer windings Insulation test.
2. Neutral Grounding transformer testing and physical inspection.
3. Thermographic survey to detect possible failure points.
4. Internal inspection of the transformer to verify insulators and other components are still intact.

4.3.4. Transformers T4, T5, and T6 [4.16kV/480V] rated 1000KVA

The three 4.16kV transformers step down the voltage from 4.16kV to 480V and feed the plant MCCs and low voltage 480V auxiliaries. All transformers are dry-type transformers originally provided by National

Industri Transformers, INC and have been in service for over 35 years since 1988 except transformer T6 that was replaced by an ABB transformer in 2012.

4.3.4.1. System Operation

The transformers are all energized from the 4.16kV switchgear. The transformer T4, T5 and T6 are utilized to step the voltage down from 4.16kV to 480V to power motor control centers MCC-C, MCC-D and MCC-E in addition to MCC-GT.

4.3.4.2. Existing Conditions

Figure 5: Transformer T4, T5 and T6

Visual inspection of the transformers T4 and T5 shows the two units are in good condition despite the service time of 35+ years. Transformer T6 is relatively new and was installed in 2012.

4.3.4.3. System Recommendations

Evaluations and/or Upgrades Recommended

The two transformers T4 and T5 have been in service for more than 35 years and are approaching the maximum lifetime expectancy of 50 years. Even though the two transformers are in good condition, they will need to be replaced within the next 15 years. The third transformer T6 was replaced in 2012 and thus with proper maintenance it can remain operational for the next 30 years.

Inspections & Tests

1. Transformer windings Insulation test.
2. Thermographic survey to detect possible failure points.
3. Internal inspection of the transformer to verify insulators and other components are still intact.

4.3.5. Medium Voltage Switchgear [13.8kV] (GTG-BUS & STG-BUS)

The medium voltage switchgear is manufactured by General Electric and has been in service for more than 30 years. The switchgear consists of two buses GTG-Bus and STG-Bus each dedicated to the gas turbine and steam turbine power output. It also provides power to plant service transformers T4, T5, T6 in addition to Farmington Ave Substation.

The medium voltage switchgear is rated 3,000A and 1,000MVA short circuit capability while equipped with General Electric protection relays that offer differential protection, phase overcurrent protection and ground overcurrent protection in addition to breaker failure relays and lockout relays. Control power for the switchgear is provided by GNB 125VDC lead calcium batteries and chargers. A new addition of two Discrete Programmable Automation Controller SEL-2440 and shark meters that were added but not captured in the provided existing drawings.

4.3.5.1. System Operation

The MV Switchgear operates normally with the tie breaker open and the two GT-Bus and the ST-BUS isolated, this allows each generator to operate independently and gives more flexibility to the operators when servicing/maintaining the generator buses.

The switchgear can operate with both generators offline in which case the switchgear is importing utility power and feeding the plant auxiliary loads through the three existing step down transformers T4, T5 and T6.

4.3.5.2. Existing Conditions

Visual inspection of the switchgear shows it's in good condition and no major defect can be detected beside some oil stain on the switchgear corner. The existing protection relays are old electromechanical type relays that are kept in good condition. The relays were last tested satisfactory by United Power Group in 2019.

The arc flash short circuit assessment performed by 3C Electrical in 2017 confirms the short circuit contribution is within the switchgear capability. The switchgear 125VDC batteries are VLA type manufactured in 2010 while the chargers are from 1988. The system was last tested and rebalanced by Power Resources, Inc in 2019, the report indicated the station battery charger and inverter were installed in 1988 but are now obsolete and should be replaced.

Bus ID	Nominal Voltage (KV)	Bus Rating Symm. KA	3 Ph Fault Symm. KA	3 Ph Fault Asymm. KA	S.C Fault Margin
BUS-GT	13.8	37	25.74	41.28	69.57
BUS-ST	13.8	37	21.36	41.28	57.72

Table 1: 3-Phase Short Circuit Fault on 13.2kV MV Switchgear

Figure 6: 13.8kV Main Switchgear

Figure 7: 125VDC Battery charger and Inverter

Figure 8: 125VDC Lead Calcium Batteries

Figure 9: SEL-2440 controllers

4.3.5.3. System Recommendations

Evaluations and/or Upgrades Recommended

The switchgear is in good condition and adequately rated to withstand available fault current. If the appropriate tests and maintenance are performed the switchgear could stay in operation for the next 20 years before requiring replacement.

The existing electromechanical protection relays are in good condition, but they're old relays that are prone to failure at any moment. The recommendation is to upgrade the existing relays with new microprocessor type relays.

The 125VDC chargers and inverters are due for replacement while batteries are 12 years old and need to be replaced within the next three years. This can also be replaced by repurposing the existing gas turbine chargers and inverters since the gas turbine is no longer in service.

Inspections & Tests

1. Visual inspection of wiring, bolted connections, insulators, and barriers.
2. Thermographic survey to detect overheating and failure points.
3. Switchgear insulation resistance and Hi-Pot test (Megger)
4. Switchgear Power factor and dielectric test

5. Circuit breaker insulation test
6. Circuit breaker functional test and open/close timing test
7. DC battery system and charger test.
8. Potential and current transformers testing
9. Protection Relays testing

4.3.6. Medium Voltage Switchgear [4.16kV] (BUS-A & BUS-B)

The existing 4.16kV voltage switchgear is manufactured by General Electric and has been in service for more than 30 years. The switchgear consists of two buses, Bus-A that feeds transformer T4 and Capital Avenue South Substation while Bus-B feeds Transformers T5 and T6.

The switchgear is rated 2,000A and 250MVA short circuit capability while equipped with General Electric protection relays that offer transformers differential protection, phase overcurrent protection and ground overcurrent protection in addition to breaker failure relays and lockout relays. Control power for the switchgear is provided by GNB 125VDC lead calcium batteries and chargers.

4.3.6.1. System Operation

The switchgear is fed through two step-down transformers T2 and T3 that step the voltage from 13.8kV to 4.16kV voltage. The switchgear then powers the gas compressor, medium voltage motor starters and multiple step-down transformers that feed the plant motor control centers.

switchgear is designed to operate with the tiebreaker normally open to isolate the Bus-A and Bus-B to make the plant more resilient to outages and faults.

4.3.6.2. Existing Conditions

Visual inspection of the switchgear shows it's in good condition. The existing protection relays are old electromechanical type relays that are kept in good condition. The electromechanical relays were last tested satisfactory by United Power Group in 2019. The arc flash short circuit assessment performed by 3C Electrical in 2017 confirms the short circuit contribution is within the switchgear capability.

The switchgear 125VDC batteries and chargers was last tested and rebalanced by Power Resources, Inc in 2019, the report indicated the station battery charger and inverter are in good condition.

Bus ID	Nominal Voltage (KV)	Bus Rating Symm. KA	3 Ph Fault Symm. KA	3 Ph Fault Asymm. KA	S.C Fault Margin
BUS-A	4.16	29	24.23	36.63	83.54
BUS-B	4.16	29	22.94	34.64	79.11

Table 2: 3-Phase Short Circuit fault on 4.16kV switchgear

Figure 10: Existing electromechanical relays

Figure 11: 4.16kV Switchgear lineup

4.3.6.3. System Recommendations

Evaluations and/or Upgrades Recommended

The switchgear is in good condition and adequately rated to withstand available fault current. If the appropriate tests and maintenance are performed the switchgear could stay in operation for the next 20 years before requiring replacement.

The existing electromechanical protection relays are in good condition, but they're old relays that are prone to failure at any moment. The recommendation is to upgrade the existing relays with new microprocessor type relays.

The 125VDC chargers and inverters are due for replacement while batteries are 12 years old and need to be replaced within the next three years.

Inspections & Tests

1. Visual inspection of wiring, bolted connections, insulators, and barriers.
2. Thermographic survey to detect overheating and failure points.
3. Switchgear insulation resistance and Hi-Pot test (Megger)
4. Switchgear Power factor and dielectric test
5. Circuit breaker insulation test
6. Circuit breaker functional test and open/close timing test
7. 5kV fuses and disconnect testing
8. DC battery system and charger test.
9. Potential and current transformers testing
10. Protection Relays testing

4.3.7. Motor Control Centers [480V] (MCC-C, MCC-D, MCC-E and MCC-GT)

The existing MCC-C, MCC-D and MCC-E are SIEMENS motor control centers supplied by Powell Electrical MFG.CO, Inc and have been in service for more than 30 years. The MCCs bus rating is 1600A at 480V with a short circuit rating of 42kA.

MCC-C provides power to water pumps, condensate water pumps, chiller condensate pumps in addition to fuel oil forwarding pump. Now that the steam turbine is retired more breakers and motor starters are made available to be repurposed for powering future loads.

4.3.7.1. System Operation

The MCCs are fed by three separate step-down transformers T4, T5 and T6 that step the voltage from 4.16kV to 480V. The MCCs are always in service to power the essential plant 480V loads and pumps.

4.3.7.2. Existing Conditions

Visual inspection of the MCC-C, MCC-D, MCC-E and MCC-GT are in good condition. The MCCs are 34 years-old and are nearing the end of their useful life. The arc flash short circuit assessment performed by 3C Electrical in 2017 confirms the MCCs are adequately rated to withstand the available short circuit contribution.

Bus ID	Nominal Voltage (KV)	Bus Rating Symm. KA	3 Ph Fault Symm. KA	3 Ph Fault Asymm. KA	S.C Fault Margin
MCC-C	0.48	42	31.48	-	74.95
MCC-D	0.48	42	32.52	-	77.44
MCC-E	0.48	30	26.89	-	89.64
MCC-GT	0.48	N/A	32.52	-	N/A

Table 3: 3-Phase Short Circuit fault on MCCs

Figure 12: motor control center MCC-D

Figure 13: 480V motor control center MCC-C

Figure 14: Motor control center MCC-D

Figure 15: Gas turbine motor control center MCC-GT

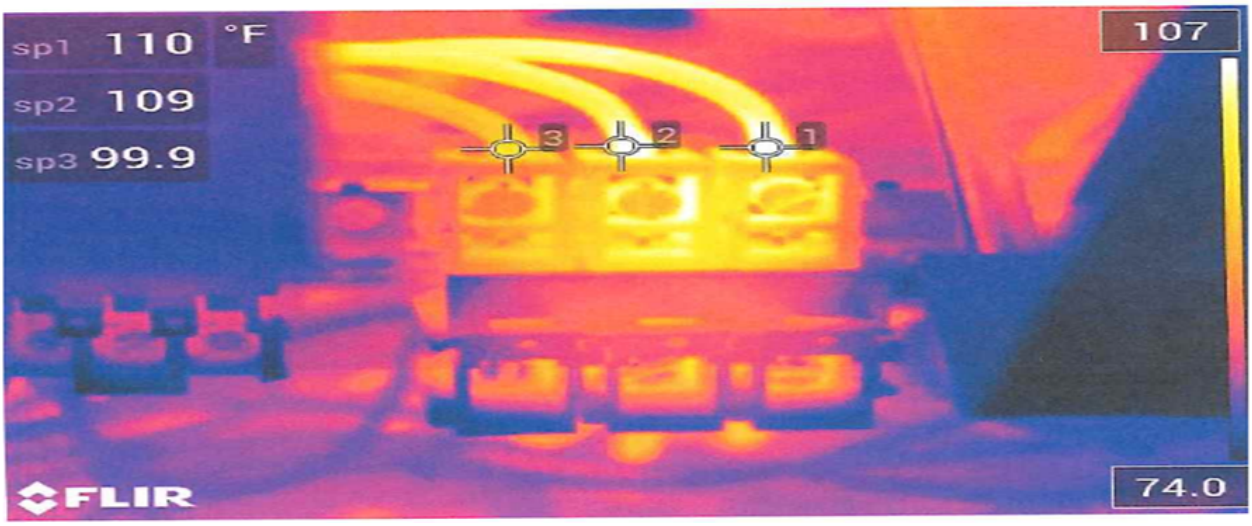

Figure 16: Example of overheating issue in MCC-D

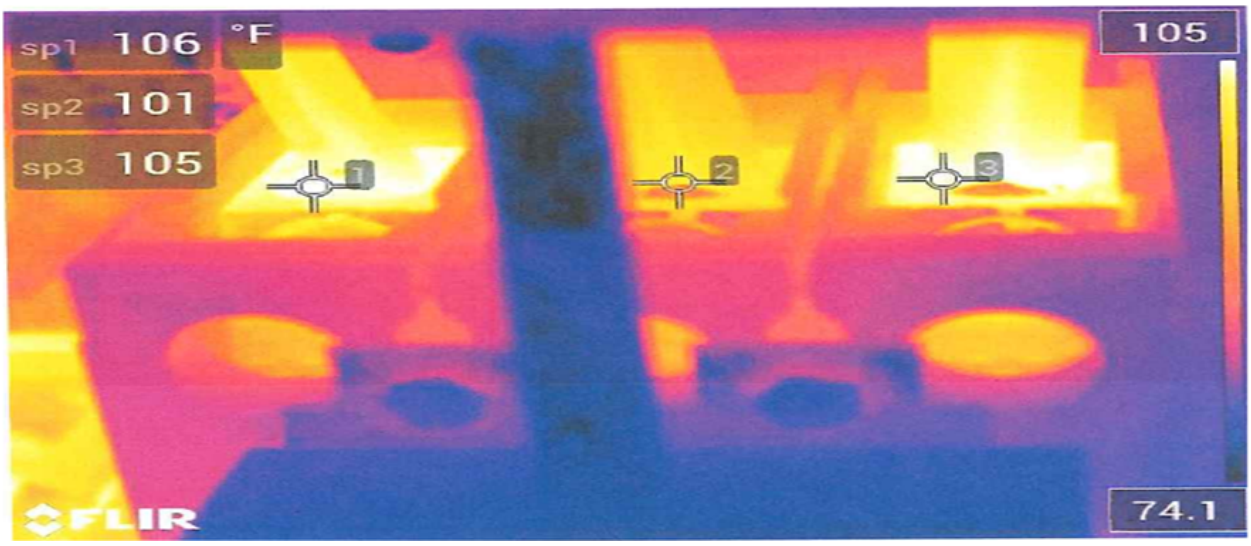

Figure 17: Example of overheating issue in MCC-C

The MCCs have shown, through thermal imaging in 2020, various hot spots (refer to Traver IDC Infrared Inspection Report, Appendix E). The photos below are examples of some of the overheating issues that were revealed by the report.

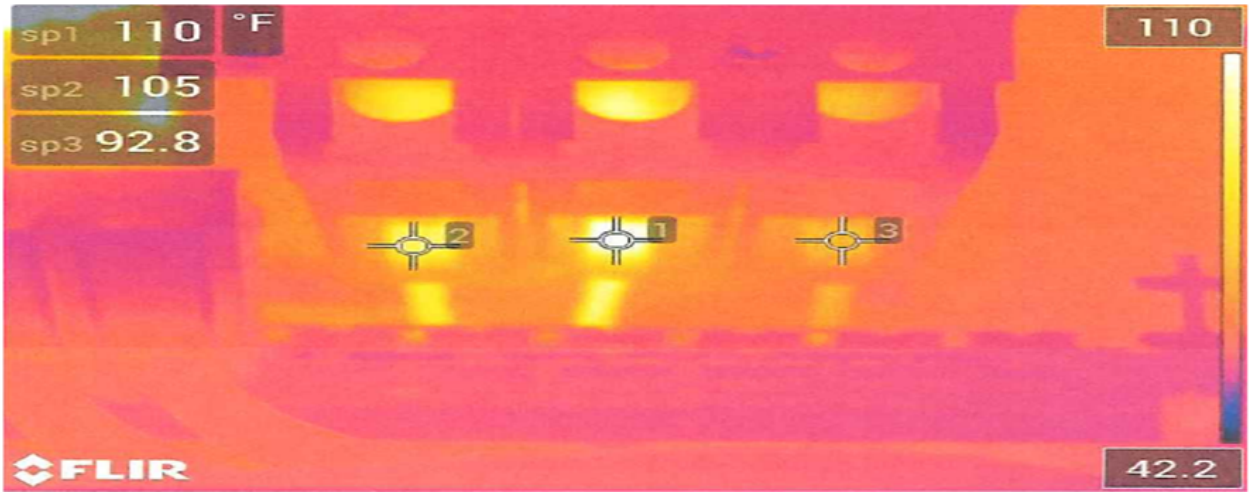

Figure 18: Example of overheating issue in MCC-E

4.3.7.3. System Recommendations

Evaluations and/or Upgrades Recommended

The MCCs are in good condition considering its age and with appropriate maintenance they could stay in operation for the next 15 years before requiring replacement. That said, the MCCs have overheating issues that need to be addressed in a timely manner, especially if the short-term plan is to power the new loads from the existing MCCs.

It is recommended to determine whether or not CDECCA has made any repairs recommended in the Traver IDC Infrared Inspection Report, as continued service with elevated temperatures will lead to fires and faults on an unpredictable and short timeline. If CDECCA has not made the repairs recommended by the previous assessment, the State could use this for negotiation, but also, it is important to validate the condition and be sure these issues have been resolved.

The individual motor starters are 35 years old and are becoming less reliable with each passing year. Finding replacement parts for these old starters will be difficult. For this reason, it is recommended that the starters be replaced within 5-10 years as the maintenance cost goes up.

Inspections & Tests

1. Visual inspection of wiring, bolted connections, insulators, and barriers.
2. Thermographic survey to detect possible failure points/overheating issues.
3. MCC insulation resistance
4. Motor starter inspection test
5. Circuit breaker inspection test

4.3.8. Steam Turbine Generator & Medium Voltage breaker

The steam turbine generator unit is a General Electric unit with rated output of 34MVA at 13.8kV, however that is limited by the extracting/condensing turbine output of 22.3MVA. The generator has been in service for more than 35 years and was recently revamped in 2017 to improve the output capability of the old generator to a maximum value of 32.4MVA. The generator is equipped with a neutral grounding resistor to limit the ground fault current and provide a grounding path on the 13.8kV system.

4.3.8.1. System Operation

The steam turbine generator was used to generate power and export power to the utility.

4.3.8.2. Existing Conditions

The steam turbine is de-commissioned and is currently offline.

Figure 19: Existing Steam turbine generator

4.3.8.3. System Recommendations

Evaluations and/or Upgrades Recommended

The steam turbine generator is old and should be demolished if the space is required for the State's future use of the facility. The MV breaker visually seems to be in good condition and upon testing can be salvaged and repurposed.

There are existing interlocks and control functions between the generator breakers, controls and the existing 13.2kV switchgear main breakers that should be investigated and safely de-commissioned before demolishing the generator.

4.3.9. Gas Turbine Generator & Medium Voltage breaker

The gas turbine generator unit is a frame 6B General Electric gas turbine capable of generating 44MVA at 13.8kV. The generator is equipped with a neutral grounding resistor to limit the ground fault current and provide a grounding path on the 13.8kV system.

4.3.9.1. System Operation

The gas turbine generator was used to generate power and export power to the utility.

4.3.9.2. Existing Conditions

The gas turbine is de-commissioned and is currently offline.

4.3.9.3. System Recommendations

Evaluations and/or Upgrades Recommended

The gas turbine generator is more than 30 years old and should be demolished if the space is required for the State's future use of the facility. The MV breaker visually seems to be in good condition and upon testing can be salvaged and repurposed.

There are existing interlocks and control functions between the generator breakers, controls and the existing 13.2kV switchgear main breakers that should be investigated and safely de-commissioned before demolishing the generator.

4.4. Civil/Structural

4.4.1. Building Structural System

4.4.1.1. Existing Conditions

The building at the Capitol Avenue location is a multi-level industrial facility that contains equipment associated with electricity and steam generation. The layout of the facility is such that the West portion is a single level which houses the primary mechanical equipment such as the Combustion Turbine Generator, Heat Recovery Steam Generator (HRSG), Steam Turbine Generator, Boilers, and more. The East side of the facility consists of a multi-level building which houses the operating room, electrical equipment, and miscellaneous support systems. Cooling towers are supported well above grade in the Northeast corner of the facility. A large exhaust stack is located outside the building footprint, just north of the turbine hall.

In general, the building framing system consists of structural steel beams and trusses supported by structural steel columns. It is laterally supported through roof and floor diaphragms and by concentrically braced frames located along the building perimeter and within the building interior. Interior equipment access platforms and access stairs consist of structural steel frames which are either structurally independent, are supported by equipment, or rely on building framing for stability. Cooling towers are supported by steel rooftop framing as well as cantilevered concrete slabs which extend beyond the building footprint. Building steel is painted to prevent corrosion. Most connections appear to consist of welded gussets, clip angles, and bolts.

All structures within the building footprint are supported by a single mat-slab foundation which is supported by large, reinforced concrete drilled piers to bedrock. Several floor slab penetrations were noted throughout the plant including large bore pipes, ventilation ductwork, and electrical conduit. In general, building framing and foundation structure are in good condition. Deficiencies and corrosion in the building structure and foundation were not observed except as noted below.

Equipment support and access frames located at several rooftop locations are constructed using painted structural steel. Almost every rooftop frame needs new paint and is showing signs of corrosion. It should be noted that corrosion at these frames has not progressed beyond superficial corrosion. If these frames go without a new coating system corrosion will worsen and framing may become compromised in several years.

Tapered reinforced concrete slabs extend out from the building faces to provide support to the rooftop mounted cooling towers. At several locations, efflorescence and rust staining were observed at the undersides of these slabs. This is indicative of water infiltration into and through these slabs as well as reinforcement corrosion from within these slabs. Reinforcement in these slabs is the only thing supporting these slabs and the exterior portions of the cooling towers. Based on staining observed from ground level, reinforcement deterioration does not appear to be severe. At tapered reinforced concrete slabs supporting the cooling towers, further investigation is suggested to determine where water is infiltrating and the extent of reinforcement deterioration. Preserving structural integrity of the slabs is recommended. Based on findings from this investigation, repair and/or remediation could be as little as providing some sort of waterproofing system to prevent further deterioration and as much as replacement of the slabs due to advanced deterioration.

The air compressor resides in the Northeast corner of the building, below the cooling towers, on top of a concrete housekeeping slab. This pad appears to be separating from the mat-slab foundation. This is a minor issue and is easily repaired with injectable grout or replacement of the housekeeping slab.

Roofing appears to consist of different types of roofing including EPDM membrane, built-up roofing both with and without a pea-stone wear surface, and a standing seam metal roof. Where EPDM roofing was used, several patches were noted. This indicates either roofing repairs or possible equipment modifications. Several rooftop equipment systems were observed to be supported by sleepers bearing directly on roofing systems. While this is an industry standard, it can lead to premature wear and failure. Exterior cladding systems consist of masonry block and brick at ground level and metal wall panels near the roof level. Roofing and wall panel systems are showing signs of aging. Replacement or repairs of these aging systems should be considered in the near future. If exterior cladding systems are allowed to deteriorate, untold damage can and will occur to the roof decks, structural framing systems, and interior equipment.

At the Northwest, 45-degree building corner, large amounts of water infiltration and rust were noted along the interior face of the exterior wall system. It was unclear which elements are corroding and creating rust stains, but water infiltration was apparent. Deterioration at the exterior face of the masonry blocks was noted. It is recommended that this be investigated further to determine the source of water infiltration as well as a repair. While this is not a significant structural issue, it can and will lead to a larger issue with the column base and anchors located at this corner.

Many pipes, ducts, and conduits penetrated the mat-slab foundation and run underground. While this is not a current detriment, it should be considered for future maintenance and potential expansions.

Because the mat-slab foundation is a structural slab supported at specific locations by concrete piers, access to underground pipe, duct, and conduit will be difficult, expensive, and may not be feasible depending on the location.

Cooling tower structure deterioration was noted. Several exterior cover/cladding plates have rusted through. Several pieces of wood framing and plywood were noted to have deterioration significant enough to warrant replacement. It is suggested that further investigation be conducted by a cooling tower specialist be performed to assess the cooling towers.

A wood-framed stair structure above the roof level provides access to the top level of the cooling towers. While not in scope, it was noted that the stair framing structure is not structurally sound and is unsafe for use. Several loose connections and missing nuts were noted. In an abundance of caution, it is recommended that nobody be allowed to use these stairs until repairs are made.

The main exhaust stack consists of a reinforced concrete shell with an insulated, steel liner duct. The stack is supported by a concrete slab and drilled piers. While not in scope, the condition of the stack was observed from ground level. No significant signs of structural deterioration were noted. Heavy deterioration of louvers and surface mounted items was noted. An additional investigation is recommended to determine the condition above ground level.

The building layout provides multiple rigging route alternatives should equipment removal be required. The large, overhead crane can move many pieces of equipment in the southern bay to a roll-up door at the west side of the building. Additionally, curtain wall systems have been installed in the south wall and are aligned with the combustion turbine and steam turbine. Should these pieces of equipment need to be removed, the most likely path of removal is through the curtain wall systems.

4.4.1.2. Recommendations

Evaluations and/or Upgrades Recommended

The following items require evaluation and/or are anticipated future needs of the facility with regards to the existing structure(s).

- Investigate and determine source of water infiltration at tapered slabs supporting cooling towers.
- Repair stair tower that provides access to the top level of the cooling towers.
- Investigate exhaust stack structure and elements supported by the stack for deterioration.
- Consider roofing membrane replacement.
- Repair concrete deterioration at air compressor using injectable grout or through other methods of concrete repair.
- Install a method to prevent water infiltration at tapered, cantilevered concrete slabs supporting cooling towers.
    - Repair concrete and reinforcement if necessary.

    - Replace slabs if deterioration is in an advanced state.
- Repair cladding to eliminate water infiltration, particularly at the Northeast 45-degree corner.

Inspections & Tests

It is recommended that the following items be inspected further as part of the due diligence process:

1. Retain the services of a third-party to provide a structural assessment of the existing stack. Based on the walkthrough, replacement of some elements will likely be required within the next few years, especially those close to grade. Some of these items may include louvers, doors, hangers, etc.
2. Investigate condition of cooling tower structural components including wood framing members, plywood, and steel cover plates.

4.4.1.2. Third Party Structural Survey

Conlon Engineering LLC (Conlon) was retained by the State to provide technical due diligence pertaining to the acquisition of the CDECCA Plant. More specifically, Conlon was to perform a structural survey of all structures on the subject property, inclusive of the following:

- Survey of the roof, the walls, the floors, the windows and doors, any chimneys or cellars on the property, as well as outbuildings and garages.
- Document deficiencies with regard to State building codes, including seismic loads.
- Document other areas of concern such as cracks, loose masonry, damp or dry rot, insect infestations and evidence of subsidence.
- Documentation should include photographs of all deficiencies and areas of concern.
- Provide recommendations and budgetary costs to address any structural deficiencies and/or areas of concern identified as a part of the survey, and if necessary, provide calculations of current roof loading and maximum allowable loading.

Conlon noted deficiencies on the roof areas, foundation, cooling tower, facade, chimney and miscellaneous exterior steel, as well as including asbestos abatement information from GZA's report. Based on their observations and assessments Conlon identified the following recommendations for further action and provided a rough order of magnitude opinion of probable cost associated with each item, with a total estimated cost of $2,428,006. Conlon noted seven (7) distinct roof areas at the facility and identified five (5) of them as being at the end of their usable life.

Description	Rough Order of Magnitude Opinion of Probable Cost
General Requirements	**$160,255**

Asbestos Remediation	**$175,000**
Roof 1	**$130,990**
Replace Roof 1 with EPDM	*$129,640*
Paint Steel Vent Pipes & Steel Ladder at Roof 1	*$1,350*
Roof 2	**$161,679**
Replace Roof 2 with EPDM	*$157,333*
Replace Sealant & Flashing at Roof 2 Wall below Roof 3	*$2,700*
Paint Hatch at Roof 2	*$645*
Secure Air Filter Housing at Roof 2	*$1,000*
Roof 3	**$15,379**
Paint Sloped Metal Roofing at Roof 3	*$7,879*
Maintain Gutter System at Roof 3	*$1,500*
Reseal Vent Pipes Base Flashing at Roof 3	*$2,500*
Paint Steel Vent Pipes at Roof 3	*$3,500*
Roof 4	**$57,546**
Replace Roof 4 with EPDM & Tapered Insulation	*$40,116*
Paint Hatch at Roof 4	*$860*
Replace HVAC Equipment Steel Supports at Roof 4	*$16,570*
Roof 5	**$44,539**
Roof 5 Replace Roof with EPDM & Tapered Insulation	*$44,539*
Roof 6	**$40,616**
Roof 6 Replace Roof with EPDM & Tapered Insulation	*$37,116*
Replace Sealant & Flashing at Roof 6 Parapet/Wall	*$1,800*
Paint Steel Ladders at Roof 6	*$1,700*
Roof 7	**$317,895**
Replace Roof 7 with EPDM & Tapered Insulation	*$243,942*

Replace Water-damaged Ceiling Tiles Beneath Roof 7	*$36,000*
Paint Hatch at Roof 7	*$860*
Roof 7 Repair Equipment Steel Supports	*$1,505*
Screen Wall Assessment	*$3,000*
Roof 7 Screen Wall Repairs	*$7,589*
Roof 7 Stair to Cooling Tower Replacement	*$25,000*
Façade Restoration	**$102,355**
Point Up & Repair Cracks in Exterior Brick Walls	*$21,000*
Point Up & Repair Cracks in Exterior CMU Walls	*$37,000*
Waterproof CMU at Building Perimeter	*$3,370*
Seal Windows & Door Perimeters	*$1,080*
Replace Exterior Doors and Frames	*$25,661*
Scrape and Paint Steel Lintels at Exterior Wall	*$12,244*
Monitor Ext. Masonry Cracks for Differential Settlement	*$2,000*
Foundation	**$24,552**
Correct Spalled Concrete, Perimeter of Foundation Mat	*$2,680*
Correct Spalled Concrete, Surface of Foundation Mat	*$9,872*
Slope Asphalt Driveway Away from Foundation	*$12,000*
Cooling Tower	**$178,235**
Replace Wood Rails w/Code-Complaint Steel Rails	*$79,166*
Install Temporary Shoring to Support Catwalk	*$8,000*
Repair Cooling Tower Steel Fins	*$20,000*
Replace Catwalk Roof Framing and Roof Pans	*$18,000*
Correct Spalled Concrete at Cantilevered Concrete Slabs	*$9,040*
Seal the Top Surface of Cantilevered Concrete Slabs	*$9,040*

Remove Loose Material, Grout Between Deck and Steel Beam	*$4,809*
Clean Moss from Wood Cooling Tower Framing	*$10,180*
Repair Wood Cooling Tower Framing	*$20,000*
Chimney	**$18,016**
Remove Accumulated Debris from Base of Chimney	*$1,100*
Correct Spalled Concrete at Base of Chimney	*$2,416*
Scrape/Paint Deteriorated Steel at Base of Chimney	*$1,500*
Assess Condition of Chimney Catwalk Steel Framing	*$1,500*
Weld Additional Steel to Chimney Catwalk Bar Grating	*$10,000*
Assess Condition of Chimney Exterior Face for Paint Repairs	*$1,500*
Miscellaneous Exterior Steel	**$52,536**
Repair and Paint Exterior South Stair	*$11,958*
Replace Exterior Guardrail Leading to South Stair	*$30,778*
Scrape & Paint Steel Columns Supporting South Stair	*$4,000*
Assess Condition of Steel Columns Supporting South Stair	*$800*
Touch Up Paint at Architectural Faux Steel Truss	*$5,000*
Subtotal	***$1,479,591***

Design Contingency	**$295,918**
General Conditions, OH & Profit	**$390,612**
Payment and Performance Bonds	**$41,156**
Owner's Construction Contingency	**$220,728**
Total	***$2,428,006***

Additional details and assumptions can be found in Conlon's full report in Appendix F.

4.4.1.3. Third Party Property Survey

SLR International Corporation (SLR) was retained by the State to prepare a property survey locating the corners, boundary lines and/or easements for the 490 Capitol Ave parcel of land. The map was tol conform to Horizontal Accuracy Class "A-2" as defined by the "Standards and Suggested Methods and Procedures for Surveys and Maps in the State of Connecticut." The map would also depict buildings and their relationship to property lines, easements/rights-of-way, setback lines, and deed restrictions, if any. Other visible site improvements such as sidewalks, pavement areas, fences, walls, and utilities will be depicted. Any underground utility information provided will be supplemented onto the plan. The SLR property survey is included as Appendix G.

4.5. Controls Systems

4.5.1. Balance of Plant (BOP) Control System

The Balance of Plant (BOP) control system provides automation and operator interface for auxiliary systems (Fuel Oil, Feedwater, etc.) required to operate prime movers (Turbines, Boilers Chillers etc.) within the plant. Each prime mover has its own local control system that interfaces with the BOP at various levels allowing operators to satisfy electric, steam, and CHW loads. The BOP system is also responsible for recording historical data.

4.5.2. Major Equipment Control Systems

BOP Server:

The BOP server hosts PLC programing software for BOP PLCs, the SCADA software to display at operator workstations, and historian software to trend and store data. Currently there is a main and back-up server that provides redundancy for the plant. The SCADA system was upgraded within the last 5 years. This SCADA hosts Human Machine Interface (HMI) screens within the control room and remote workstation on the operating floor. The BOP uses a Pi historian system that is actively used by operators to trend and troubleshoot issues within the plant

PLC and IO Panels:

BOP PLCs and IO modules are stored in a large cabinet in the control room. These PLCs are original to the construction of the plant.

Major Equipment Control Systems:

Auxiliary Boiler 1:

Auxiliary Boiler 1 has a Texas Instrument PLC control system that is original to the installation of the boiler. Control relays are used for burner management.

Combustion control system maintains local drum pressure setpoint.

Auxiliary Boiler 2:

Auxiliary boiler 2 has a Allen-Bradley PLC control system that is original to the installation of the boiler in 2009. This control system has mostly been phased out and is mostly used as data concentration point for process monitor of the boiler A Fire-eye nexus burner management system was installed in 2012. This device controls air fuel ratio and burner safeties. A Cleaver Brooks level controller provides local drum level indication and drum level control for the boiler.

The nexus control system maintains local drum pressure setpoint once commanded online.

Chillers:

Chillers have local control systems that control internal valves and compressors to maintain leaving water temperature once commanded to run locally by operators.

Chiller 3 has a VFD driven compressor which is controlled by its local control system. All other chillers are single speed and utilize control valves to satisfy leaving chilled water temperature setpoint.

4.5.2.3. System Operation

All BOP instrumentation, control valves, and major equipment I/O is wired back to the BOP cabinet in the control room. The PLC provides data to the SCADA and historian.

The control system has limited automatic control of sub systems and requires operators to command positions of control valves and starting/stopping of pumps as required to maintain setpoints.

Operators start major equipment at local HMIs. Setpoints for chillers and boilers are commanded at local panels as well.

4.5.2.4. System Recommendations

Evaluations and/or Upgrades Recommended

The existing PLC and IO modules should be replaced as part of the installation of the hot water boilers. A large portion of the IO connected to the BOP control system is for the operation of the CTG, STG, and steam system.

A new PLC control system could be integrated into the existing SCADA and Pi historian server(s). This new control system would have a higher level of automation for remaining systems relevant to future operations, such as cooling towers.

Additionally, the new system could be integrated into the State's existing metering network to allow for trending and billing of loads to various buildings within the campus distribution system. Both the existing BOP and the campus metering system were provided by the same control system contractor.

4.6. Environmental

GZA GeoEnvironmental, Inc. (GZA) was retained by the State to provide technical due diligence pertaining to the acquisition of the CDECCA Plant and included the completion of an updated Phase I Environmental Site Assessment, Air Permit Review, Wastewater and Stormwater Compliance Analysis, and Preliminary Hazardous Building Materials (HBM) Assessment of the property. GZA's scope of work was to be conducted in general accordance with the ASTM International's Standard Practice for Phase I Environmental Site Assessments, E1527-13 (ASTM E1527-13) and with the Connecticut Department of Energy and Environmental Protection (CTDEEP) Site Characterization Guidance Document (SCGD, rev 12/2010). The ESA report was also to be generally consistent with the requirements of ASTM standard E1527-21. A summary of GZA's due diligence and recommendations is presented below and their full reports can be found in Appendicies H, I ,J and K.

4.6.1. Phase I Environmental Site Assessment

GZA's Phase I Environmental Site Assessment Report (Phase I ESA Report) presents the field observations, results, and opinions of a Phase I ESA conducted by GZA for the CT Department of Administrative Services at the target property identified as 490 Capitol Avenue, Hartford, Connecticut (Subject Property). The report also discusses the removal of several underground storage tanks (USTs) that formerly served the Subject Property and were located offsite to the northeast on property owned by the State of Connecticut. Based on the findings of GZA's Phase I ESA and on their professional judgment, GZA identified the following in connection with the Subject Property:

Areas of Concern (AOCs)/Recognized Environmental Conditions (RECs)

- In GZA's opinion, this Phase I ESA revealed evidence of the following AOCs, some of which are also RECs, in connection with the Subject Property:
    - Historical Operations at the Subject Property – The Subject Property was occupied by the Hartford Machine Screw Co. from 1885 or before through at least 1922 and structures on the Subject Property included a machine shop, a tool room, a machine work area, and a metal storage area. Soil sampling at the Subject Property in 2003 identified extractable total petroleum hydrocarbons (ETPH) in a soil sample collected from the northeastern portion of the Subject Property at a concentration above the CTDEEP Remediation Standard Regulations (RSR) criteria.
    - Current Operations at the Subject Property – Since 1988, the Subject Property has been occupied by power generation businesses and various chemicals (including sulfuric acid, sodium hypochlorite, lithium bromide, and sodium hydroxide) and petroleum products (No. 2 fuel oil and waste oil) have been and are used/stored in aboveground storage

tanks or drums within the Subject Property building. A 1,000-gallon waste oil underground storage tank (UST) is located beneath the pavement to the northwest of the building and oil/water separators are located within and adjacent to the building. In addition, a 300-gallon waste oil UST was reportedly removed from a location near the southwest corner of the Subject Property building in 2017 and a 300-gallon waste oil UST was reported to have been located to the north of the Subject Property building based on information in a 2001 Environmental Condition Assessment Form.

- Arsenic, Barium, and Lead Groundwater Contamination – According to a 2016 Phase I ESA conducted by Ramboll Environ (Ramboll), groundwater at the Subject Property contains arsenic, barium, and lead at concentrations that exceed the CTDEEP Surface Water Protection Criteria (SWPC).

Controlled Recognized Environmental Conditions (CRECs)

- In GZA's opinion, the Phase I ESA revealed the following CREC in connection with the Subject Property:
  - Previous investigations reported the presence of petroleum impacted soils related to fill materials containing coal/coal ash beneath the northeastern portion of the property. To address this condition, an Environmental Land Use Restriction (ELUR) was filed for the property on November 5, 2004. The ELUR prohibits residential activities at the Subject Property and prohibits disturbance of inaccessible soils at depths greater than two feet below the asphalt or concrete in a 2,600-square foot area on the northern portion of the Subject Property.

Historical Recognized Environmental Conditions (HRECs)

- This Phase I ESA revealed no evidence of HRECs in connection with the Subject Property.

***De Minimis* Conditions**

The Phase I ESA revealed evidence of the following de minimis condition in connection with the Site:

- GZA observed staining on the concrete floor beneath the equipment at various locations within the building.
- Regulatory records indicate that numerous small (generally <10 gallons) spills of petroleum (lube oil, turbine oil, fuel oil) and other chemicals (sulfuric acid, lithium bromide) have been reported at the Subject Property. The majority of the spills were reported to have occurred inside the building and have been classified as "closed" by the CTDEEP.

Significant Data Gaps

In GZA's opinion, based on the information made available during this assessment, they did not encounter significant data gaps that affected our ability to identify RECs, CRECs, or HRECs at the Subject Property.

Non-ASTM E1527-13 Considerations

This Phase I ESA does not include an evaluation of environmental issues or conditions that ASTM E1527-13 stipulates as non-scope considerations.

Other Business Environmental Risks

The Phase I ESA revealed the following Business Environmental Risks (BERs), in addition to the BERs identified above:

- In 2021, the four approximately 60,000-gallon fuel oil USTs that formerly served the Subject Property but were located approximately 400 feet northeast of the Subject Property on land owned by the State of Connecticut were removed along with approximately 1,000 tons of petroleum-impacted soil. In addition, an oil/water separator and test manhole located adjacent to the tank farm were removed along with approximately 500 tons of petroleum-impacted soil. According to a September 2021 Tank Farm Closure Report by Zuvic Infrastructure Solutions, additional investigation is warranted to evaluate the extent and degree of contamination in overburden soil, bedrock, and groundwater, and to evaluate potential mechanisms to attain compliance with the RSRs. The former USTs, oil/water separator and test manhole were operated by Subject Property occupants.
- Future Subject Property redevelopment activities might encounter residual contamination in soil or groundwater. Impacted material must be managed either on or off the Subject Property in conformance with applicable federal, state, and local regulations.
- If dewatering is required for construction, groundwater sampling and testing in conformance with federal, state, and/or local sewer discharge permit/approval requirements may be required.

Connecticut Transfer Act Applicability

Connecticut General Statutes (CGS) Section 22a-134 as amended, commonly known as the Connecticut Transfer Act, requires the disclosure of environmental conditions when certain real properties and/or businesses, referred to in the Act as "establishments," are "transferred." Effective October 1, 2020, an "establishment" is defined as follows:

> "'Establishment' means any real property at which or any business operation from which (A) on or after November 19, 1980, there was generated more than one hundred kilograms of hazardous waste in any one month, (B) hazardous waste generated at a different location was recycled, reclaimed, reused, stored, handled, treated, transported or disposed of, (C) the

process of dry cleaning was conducted on or after May 1, 1967, (D) furniture stripping was conducted on or after May 1, 1967, or (E) a vehicle body repair facility was located on or after May 1, 1967."

GZA notes that the full definition of "establishment" in the Act contains numerous exceptions to what constitutes an "establishment" including exceptions for one-time shipments of hazardous waste, generation of universal wastes and remediation waste, among others. Similarly, there are a number of exceptions related to the definition of a qualifying "transfer." The terms "transfer of establishment" and "hazardous waste," among others, are also defined in the Act.

Based on GZA's review of information discussed in their report, the real property and/or business operation that is the subject of their report appears to be an "establishment" under the Connecticut Transfer Act because more than one hundred kilograms of hazardous waste has been generated in any one month.

Records indicate that the following Connecticut Transfer Act filings have been submitted to CTDEEP for the Subject Property:

- 10/29/2001 – Form III (Real Estate) under REM ID 4894 was filed - no verification on file
- 10/10/2006 – Two Form IIs under REM IDs 8262 & 8261 were filed for the business only, Final Verification applicable to and dated 10/1/2006
- 3/31/2017 – Form II under REM ID 13282 was filed for the business only, Final Verification applicable to and dated 3/20/2017

Because Final Verification of the 2001 Form III (Real Estate) does not appear to have occurred and over 100 kilograms of hazardous waste was generated in any one month after the 2017 Form II (Business) Verification, it is GZA's opinion that a Transfer Act filing would be required if a qualifying transfer of the Subject Property or business were to occur. Any final opinion or determination as to whether a transaction is subject to the Connecticut Transfer Act is a legal one and advice of counsel should be obtained.

GZA notes that not all of the hazardous waste manifests for the years 2009 through 2021 are available for review in the CTDEEP public files at this time; therefore, it is unknown whether additional hazardous waste was generated at the Site during these years.

Any final opinion or determination as to whether a transaction is subject to the Connecticut Transfer Act is a legal one and advice of counsel should be obtained.

GZA also noted via email that it is their understanding that the seller will remain the certifying party and will file a new Transfer Act filing, in which case they will remain responsible for resolving soil and groundwater issues related to historical and recent use of the property. The new owner will be responsible for maintaining the cap (pavement) in the area subject to the ELUR and if there is disturbance of soils in that area, or other areas at the property, as part of any construction (i.e., utility trenches or other) then a soil management plan is recommended (required in the ELUR area along with

notice to the CTDEEP). GZA did not have information regarding the age of the 1,000-gallon waste oil underground tank that is located at the property but if it's determined to be at its life expectancy (estimated 30 yrs) then it may need to be removed/replaced. At a minimum, the CTDEEP UST notification will need to be updated with new owner information.

4.6.2. Wastewater and Stormwater Compliance Analysis

Based on a review of information provided by CDECCA pertaining to stormwater and wastewater permits and plans, regulatory database information pertaining to the Facility, and available CTDEEP electronic records, GZA did not identify unresolved wastewater or stormwater permit compliance issues affecting the Facility. GZA did not perform a site visit as part of their evaluation.

GZA also reviewed requirements and the key regulations for existing wastewater and stormwater permits for the Facility in order to identify future wastewater/stormwater permitting compliance needs.

4.6.2.1. SPDES Permit

The Facility maintains a State Pollutant Discharge Elimination System (SPDES) permit (SP0002199) for which a renewal application (Application No. 201610002) is reportedly pending (awaiting review and approval by CTDEEP.

GZA recommends that the permit be transferred to the State by completing and submitting the CTDEEP License Transfer Form, with the appropriate fee, within thirty (30) days of Facility ownership transfer. The State will also need to submit a NetDMR Subscriber Agreement to allow for appropriate DAS personnel to submit electronic Discharge Monitoring Report (DMR) data in the CTDEEP NetDMR electronic reporting system.

Once the permit has been transferred, DAS will need to comply with the conditions and requirements of the SP0002199 permit, including conducting monthly discharge monitoring, submitting monthly DMRs in NetDMR and reporting any violations of permit effluent limits.

4.6.2.2. SIU General Permit

The Facility is registered under the Significant Industrial User (SIU) General Permit (CTSIU0025) for the discharge of up to 23,400 gpd of water treatment wastewaters (WTW) not subject to Categorical Pretreatment Standards into the Metropolitan District Commission (MDC) sanitary sewer system. Based on GZA's review of WTW flow rates from the Facility during 2021 and 2022, which were provided by CDECCA and indicate actual WTW flows less than 10,000 gpd, and because the Facility is no longer an electric-generating facility and, therefore, is not subject to the Categorical Pre-Treatment Standards of 40 CFR Part 423, it appears the Facility WTW discharges are eligible for coverage under the CTDEEP Miscellaneous Industrial Users (MIU) General Permit.

The CTDEEP MIU General Permit generally offers reduced compliance obligations as compared to the SIU General Permit, including reduced effluent monitoring frequency (quarterly for flows less than 10,000

gpd, as compared to the monthly discharge monitoring requirement under the SIU General Permit), no requirement to maintain SPCP or O&M Plans for the Facility, and no need to submit monitoring results in NetDMR. Should the State elect to seek WTW discharge coverage under the MIU General Permit, a DISCHARGE NOTIFICATION FORM TO POTW AUTHORITY For The General Permit For Discharges From Miscellaneous Industrial Users (DEEP WPED-REG-012) should be completed and submitted to the local POTW (MDC Hartford). Should the State elect to continue coverage for Facility WTW discharges under the existing SIU permit, transfer of the CTSIU0025 permit should be included on the CTDEEP License Transfer Form (along with the SP0002199 permit transfer, see above), with the appropriate fee, and submitted within thirty (30) days of Facility ownership transfer.

GZA also recommends that DAS evaluate whether the wastewater discharges currently covered under the SPDES and SIU General Permits, discussed above, can all be covered under the MIU-GP as GZA believes that the elimination of the power generation makes the current facility discharges eligible for coverage under MIU-GP.

4.6.2.3. Industrial Stormwater General Permit

The Facility registered under the CTDEEP General Permit for the Discharge of Stormwater Associated with Industrial Activity (Industrial Stormwater General Permit) in June 2011 (Permit No. GSI001947). The current General Permit expires on September 30, 2024.

Under the General Permit, permittees are required to prepare and implement a Stormwater Pollution Prevention Plan (SWPPP), conduct routine inspections and stormwater monitoring, and submit stormwater monitoring reports (SMRs) to CTDEEP. Based on documents provided by CDECCA, the Facility has an existing SWPPP (prepared by Berkshire Environmental Consultants Inc, and updated July 2021) which identifies three (3) drainage areas and two stormwater outfalls at the Site. The SWPPP also specifies monthly visual inspections of sensitive Facility areas including chemical unloading areas, receiving areas, ASTs, USTs, transformers, roof drains, dumpsters, exterior storage areas, facility outfalls and catch basins, quarterly visual monitoring of stormwater, comprehensive semi-annual inspections of the Facility and semi-annual stormwater sampling and analysis. The SWPPP also identifies the Facility as being subject to the additional sector-specific requirements for Sector F- Steam Electric Power Generation facilities. According to a recent SMR dated November 2020, the Facility appears to have met monitoring benchmarks for stormwater with the exception of total iron, for which the average of the four most recent monitoring results exceeds the permit benchmark of 1.0 mg/L for Sector F facilities.

In addition, a new or modified SWPPP would need to be prepared for the Facility to reference new ownership and update Facility potential pollutant sources and monitoring locations as needed. In addition, as noted above, the Facility is no longer an electric power generating facility; therefore, the SWPPP could be updated to eliminate the additional Sector F requirements. A copy of the new or updated SWPPP for the Facility would need to be submitted as an attachment to the ezFile permit registration and a $500 permit registration fee is required for state entities.

Following registration under the General Permit, DAS would need to commence the monthly, quarterly and semi-annual inspections and/or monitoring specified by the permit and SWPPP, and report semi annual monitoring results to CTDEEP via the SMR forms. Annual aquatic toxicity monitoring is also required for the first two years of the permit term for news registrants and annual employee training is required for personnel whose duties may affect stormwater quality at the Facility.

Alternatively, if all potential pollutant sources can be eliminated and/or brought inside or under cover so that no potential pollutant materials are exposed to stormwater, the Facility could submit a No Exposure

Certification to be exempted from registration, control measures, SWPPP preparation, inspection, monitoring and recordkeeping requirements of the Industrial Stormwater General Permit. There is a $250 processing fee associated with the No Exposure Certification form filing. In addition, if at any time the industrial activity is modified such that materials are exposed to stormwater, the Facility must submit a registration and comply with all pertinent sections of the Industrial Stormwater General Permit.

4.6.3. Air Compliance Analysis

The State contracted GZA to evaluate if there are any past air compliance issues that may affect future operations of the facility after acquisition and air compliance needs for the future facility.

4.6.3.1. Past Air Compliance Evaluation

To identify past air compliance issues that may affect the future operations of the Facility, GZA performed the following tasks:

- GZA searched the Connecticut Department of Energy and Environmental Protection (DEEP) files to identify air compliance related documents affecting the Facility.
- GZA reviewed the deed for the Facility at the Hartford City Hall to identify if any air compliance issues are recorded on the deed.
- GZA reviewed the United States Environmental Protection Agency (EPA) Enforcement and Compliance History Online database to identify records of any air compliance issues affecting the Facility.

GZA was not able to find records of any unresolved air compliance issues affecting the Facility during the investigation. GZA did not perform a site visit as part of this evaluation.

4.6.3.2. Future Air Compliance Evaluation

To identify future air compliance issues, GZA reviewed the air permitting requirements and the key regulations that specify equipment performance. These are discussed below.

New Source Review (NSR) Permitting

Prior to the shutdown of power generation operations in 2021, the Facility included the emission units listed in the table below that were subject to NSR permitting. The table also provides their permitting information.

Emission Unit	Permit Number	Status
General Electric Gas Turbine with John Zink Duct Burner	075-0064	Revoked effective 06/18/2021
Zurn Package Boiler	075-0065	Active
Detroit Diesel Starter Engine	075-0150	Revoked effective 06/18/2021
Dual-fuel, Cleaver-Brooks (CB) Package Package Boiler	Permit-by-rule Regulations of Connecticut State Agencies (RCSA) §22a-174-3b(c)	Active

As the permits for the equipment associated with power generation have already been revoked and as GZA understands that DAS does not intend to resume power generation, it is GZA's opinion that no further action is needed for those permits (Nos. 075-0064 and 075-0150). GZA also understands that in addition to eliminating #2 fuel oil usage at the Facility, DAS intends to either shut down the Zurn boiler and replace it with two 600 hp boilers or continue to operate it as a back-up to the CB boiler. Therefore, going forward, the Facility will utilize natural gas only and include the above listed CB boiler and the two proposed 600 hp boilers or the Zurn boiler as a back-up.

The following actions are needed to address the NSR permitting issues for this scenario:

- If the Facility does not intend to operate the Zurn boiler, DAS should request CDECCA to revoke its NSR permit (No. 075-0065).
- If the Facility intends to operate the Zurn boiler as a back-up without changing its rated capacity, the current NSR permit (No. 075-0065) must be transferred to the new owner and then modified to limit its usage to reflect its status as a back-up unit.
- If the Facility limits the Zurn boiler heat input to no greater than 50 MMBtu/hr, the boiler is eligible to operate without an NSR permit by operating under the permit-by-rule provision of RCSA §22a-174-3c. In this case, either DAS should request CDECCA to revoke its NSR permit (No. 075-0065) or revoke the permit after it is transferred.
- As the rated capacity of the Zurn boiler is greater than 50 MMBtu/hr, the boiler is not eligible to operate without an NSR permit under the permit-by-rule provision of RCSA §22a-174-3b.

- Actual performance data for the proposed 600 hp boilers are needed to determine NSR permit applicability. However, even in case the emissions are above NSR permitting thresholds, the NSR permitting can be avoided by electing to operate the proposed boilers under any of the permit-by-rule provisions of RCSA §22a-174- 3b or 3c.

- If the Facility chooses to continue to operate the CB boiler under the permit-by-rule provision of RCSA §22a-174-3b(c) or discontinue using it, it is GZA's opinion that no permitting action is needed in either case. The Facility can also elect to operate the boiler under the permit-by-rule provision of RCSA §22a-174-3c.

Even if NSR permitting is not required, the Facility will still be subject to certain recordkeeping requirements to maintain eligibility to avoid NSR permitting.

Title V Permitting

RCSA §22a-174- 33 requires that any facility with potential facility-wide emissions above the major source threshold obtain a Title V permit or comply with the permit-by-rule provisions of RCSA §22a-174-33a or 33b, which limits the emissions to fifty or eighty percent respectively of the major source thresholds. GZA's analysis of Title V permitting is based on nitrogen oxide (NOx) emissions as GZA expects it to be the limiting pollutant for determining Title V applicability and permit by rule eligibility. With the elimination of the power generation operation, the Facility has revoked its Title V Permit (No. 075-0244-TV) and has elected to operate under the permit-by-rule provisions of RCSA §22a-174- 33a, which limits facility-wide NOx emissions to 25 tons per year. With any of the operating scenarios indicated above, the Facility can continue to operate under RCSA §22a-174- 33a by noting the operating changes in the RCSA §22a-174- 33a records kept at the Facility.

Alternatively, the Facility can elect to operate all the boilers under RCSA §22a-174- 3c, which limits the Facility natural gas usage to 100 million cubic feet (mmcf)/year [RCSA §22a-174- 3c(b)(1)(A)] and maximum heat input to any of the boilers to 50 MMBtu/hr [RCSA §22a-174- 3c(b)(1)(B)]. This limits the Facility NOx emissions to 15 tons per year [RCSA §22a-174- 3c(a)(1)(A)] and therefore, the Facility would not be subject to Title V permitting and associated recordkeeping and notification requirements. The recordkeeping requirement is limited to maintaining records of natural gas purchases. As the Facility records indicate that the natural gas usage has been approximately 50 million cubic feet (mmcf) since the elimination of the power generation operation, it is GZA's opinion that this is a viable compliance option for the Facility.

RCSA §22a-174-22e and 22f – NOx Control Regulations

RCSA §22a-174-22e applies to certain fuel-burning equipment located at premises that are major stationary sources of NOx emissions. If the Facility elects operate under any of the provisions indicated above to avoid obtaining a Title V permit, it is GZA's opinion that the Facility is not considered a major source of NOx and these regulations are not applicable.

RCSA §22a-174- 22f applies to certain large fuel-burning equipment located at premises that are not major stationary sources of NOx emissions and limits the NOx emissions from each unit during May 1 through September 30 to 274 lb/day [RCSA §22a-174-22f(e)(2)(B)]. If this emission rate is exceeded, per RCSA §22a-174-22f(e)(2), the unit is subject to the stricter emission standards of RCSA §22a-174-22e. As the rated capacity of the Zurn boiler is greater than 76 MMBtu/hr, per RCSA §22a-174- 22f(b)(1)(A)(i) it is subject to RCSA §22a-174- 22f. However, as the Zurn boiler will be used as a back-up to the CB boiler, its firing rate is expected to be similar and at that firing rate its NOx emissions are expected to be well below the limit. Therefore, it is GZA's opinion that the Zurn boiler, when used as a back-up to the CB boiler, will comply with the emission limits of RCSA §22a-174-22f.

Title 40 of the Code of Federal Regulations Part 63 (40 CFR 63) Subpart JJJJJJ – Boiler Regulations

These regulations for controlling hazardous air pollutant (HAP) emissions apply to certain boilers located at area (non-major) sources of HAPs. As indicated by the recently revoked Title V Permit (No. 075-0244-TV), the Facility is not a major source of HAP and therefore, the boilers located at the Facility are potentially subject to 40 CFR 63 Subpart JJJJJJ. As long as the Facility boilers meet the 40 CFR 63.11237 definition of "gas-fired boilers", according to 40 CFR 63.11195, the boilers are not subject to these regulations. As the Facility will only burn natural gas going forward, it is GZA's opinion that the Facility is not subject to these regulations.

RECOMMENDATION

Based on the above discussions, it is GZA's opinion that the least onerous compliance option for the Facility is to revoke or arrange to revoke the Zurn boiler NSR permit (No. 075-0065) and operate all boilers under the permit-by-rule provision of RCSA §22a-174- 3c using only natural gas. The CB boiler would be used as the primary boiler. The Zurn boiler would be used to substitute or supplement the CB boiler when needed. This will allow the Facility to operate without an NSR or a Title V permit and meet the annual demand of approximately 50,000 MMBtu (50 mmcf of natural gas) and the peak demand of approximately 65 MMBtu/hr with minimal compliance requirements except for one case as described below.

- The Facility annual fuel demand of approximately 50 mmcf of natural gas is well below the RCSA §22a-174- 3c limit of 100 mmcf/year. Therefore, the facility should be able to operate under the limitations needed to operate under RCSA §22a-174- 3c.

- The CB boiler with a rating of 32.659 MMBtu/hr has a potential annual fuel demand of 286 mmcf, which is much greater than the annual fuel demand for the Facility. Therefore, the CB boiler by itself can meet the Facility annual fuel demand.

- As the CB boiler is rated at 32.659 MMBtu/hr, to meet the peak demand of 65 MMBtu/hr or any time the demand exceeds the CB boiler capacity, the Facility needs to operate the Zurn boiler concurrently at up to 32.241 MMBtu/hr, which is below the RCSA §22a-174- 3c maximum firing rate limit of 50 MMBtu/hr. Therefore, the facility should be able to comply with the requirements of RCSA §22a-174- 3c with both boilers when the demand exceeds 32.659

MMBtu/hr. However, there is one exception. If the Facility load demand exceeds 50 MMBtu while the CB boiler is down, the Zurn boiler by itself cannot meet the demand if limited to 50 MMBtu/hr. In that case, to operate in compliance with RCSA §22a-174- 3c, the Facility needs to either add a temporary boiler to make up the difference or request a variance from DEEP to temporarily operate the Zurn boiler above the 50 MMBtu/hr limit.

- As indicated above, the Facility operating under RCSA §22a-174- 3c is not subject to the other identified regulatory requirements.
- RCSA §22a-174- 3c requires that the Facility must maintain monthly natural gas purchase records (monthly gas bills) to demonstrate that the cumulative amount for any consecutive twelve months has not exceeded the annual limit. The records must be retained for five years.
- For any boiler rated at higher than 50 MMBtu/hr like the Zurn boiler, the Facility needs to maintain records to show that the firing rate for any such boiler has not exceeded 50 MMBtu/hr at any time.

4.6.4. Preliminary Hazardous Building Materials Evaluation

GZA performed a walkthrough of the accessible portions of the building to identify and evaluate the condition of accessible suspect asbestos-containing material (ACM), lead-containing paint (LCP), and visually observed universal wastes (UW) and hazardous materials. The work included the collection of bulk samples of observed representative suspect ACMs, LCP, and caulks/glazing/paints or sealants suspected of containing polychlorinated biphenyls (PCBs) and preliminary quantification of identified ACMs and hazardous materials.

Sampling of suspect materials at the Site was limited because the Site owner prohibited GZA from performing destructive sampling in certain areas and GZA did not sample electrical or power generation components because it was unknown if they were energized. Although reasonable effort was made to survey accessible suspect materials, additional suspect but un-sampled materials could be located in walls, voids or in other concealed areas. It was assumed that no active effort, intentional or otherwise, was made to cosmetically hide potentially salient features or conditions from GZA. Supplemental sampling to fill data gaps will need to be performed should additional materials not observed as part of this report be observed during renovation or demolition activities. Evaluation of areas that were not accessible during GZA's site visit is recommended to fill potential data gaps prior to renovation or demolition.

4.6.4.1. Asbestos Investigation

Based on results of the visual observation, bulk samples of suspect ACM were collected in general accordance with the sampling protocols outlined in USEPA Regulation 40 CFR 763 Asbestos Hazard Emergency Response Act (AHERA) and the Connecticut Department of Public Health (CTDPH) regulations. A total of 146 bulk samples were collected from 63 homogeneous areas of suspect ACM.

Laboratory analysis confirmed the presence of asbestos in caulk and a layer of tar between paper layers on polyisocyanurate insulation paper backer. GZA noted this tar layer was not observed in the other two samples from this heterogenous group (B-402 samples) and because the paper backer and tar layer are under a membrane, they cannot assess the extent of the tar on the roofs. For the purposes of their report, GZA has assumed the tar layer is present on all the roofs.

4.6.4.2. Lead Paint Sampling

The evaluation for the possible presence of lead paint included the performance of an Occupational Safety and Health Administration (OSHA) lead paint survey at the Site building. The OSHA survey was performed in compliance with the United States Department of Labor OSHA Lead Exposure in Construction Standard (29 CFR 1926.62), and US EPA Hazardous Waste Disposal Regulations (40 CFR Parts 260 through 271). The assessment was performed by collecting paint chip samples from representative accessible interior and exterior painted surfaces observed in and on the building and analyzing the samples to provide an indication of the presence of lead from testing combinations that were present to potentially create a lead hazard to workers in the course of the demolition or renovation of the building. A total of seven samples were collected and submitted for analysis.

Lead was identified to be present in three of the seven paint samples at a concentration over 5,000 mg/kg; these samples are therefore defined as lead-based paint (LBP) by the USEPA and the State of Connecticut. The lead content of three of the seven samples was less than 5,000 mg/kg and is defined as lead containing paint (LCP). Lead was not detected in one of the seven paint samples.

4.6.4.3. Universal Wastes Investigation

GZA completed a preliminary review to evaluate for the presence of quantities of chemicals or waste materials stored at the Site. GZA's assessment of waste materials included a visual inspection for stored chemical products, refrigerants, containers, fire extinguishers, smoke detectors, and ozone- depleting substances. GZA did not attempt to identify chemicals that were present in *de minimis* quantities, such as spray cans and other containers that were less than one gallon in volume. GZA did not open, stage or consolidate any containers that were cataloged. No samples were collected as part of this work. GZA also conducted a visual survey of residual UW, potential PCB-containing components and miscellaneous stored chemicals, petroleum products, and gases. UW, defined as 40 CFR Part 273 by the USEPA, includes hazardous wastes that are pesticides or electrical system components such as batteries, thermostats, and mercury-containing switches. Varying types of other hazardous materials were identified in the Site building. With the exception of the sampling of caulks/glazing/paints and sealants materials for the presence of PCBs, GZA's inventory of hazardous materials was based on a visual assessment only; therefore, no sampling or characterization of wastes was performed. In the event of building renovation or demolition, the materials identified in GZA's inventory of hazardous materials must be managed and disposed of in accordance with current state and federal hazardous waste management regulations.

During the investigation GZA visually identified building construction materials suspected of containing PCBs. The assessment was performed by analyzing the samples to provide an indication of the presence

of PCBs in the materials that were present that potentially could create a hazard to workers during the course of the demolition of the structures. GZA observed caulking and tar daubs on the roof. GZA was allowed by the owner to collect a sample for PCB analysis from the tar daubs on the roof. GZA was not allowed to collect samples of caulking for PCB analysis. PCBs were not detected in the tar daub sample.

4.6.4.4. Conclusions

Based on the results of the Preliminary Hazardous Building Materials Evaluation, GZA made the following conclusions and recommendations:

- Laboratory analysis of the samples collected during the asbestos survey confirmed the presence of ACMs, including caulk and polyisocyanurate insulation paper backer containing a tar layer. GZA notes this tar layer was not observed in the other two samples from this heterogenous group (B-402 samples) and because the paper backer and tar layer are under a membrane, GZA cannot assess the extent of the tar on the roofs. For the purposes of their report, GZA has assumed the tar layer is present on all the roofs. GZA has also assumed the electrical and power generation components contain ACM because they were not sampled;
- Laboratory analysis of the samples collected during the paint sampling identified lead based paint and lead containing paint on fire doors, transformers, and transformer brackets, cooling towers and railings;
- Laboratory analysis of the sample collected during the PCB-containing materials sampling indicated PCBs were not detected;
- Several building materials and inside wall cavities were not sampled because destructive sampling is necessary to collect the samples and we were prevented from accessing certain areas. Supplemental sampling to fill data gaps will be necessary prior to renovations or demolition of the building;
- Prior to conducting renovation or demolition activities and due to the presence of ACM, lead-containing paint, and UWs/hazardous materials identified within the Site building, GZA recommends that project-specific abatement bid specifications be developed for use in obtaining contractor pricing and developing construction sequencing. Client should retain a Connecticut-certified Asbestos Designer to develop abatement specifications for use in obtaining contractor pricing and developing construction sequencing;
- Prior to conducting renovation or demolition activities impacting confirmed or assumed ACM, Client should retain a Connecticut-licensed asbestos abatement contractor to remove ACMs;
- Prior to conducting renovation or demolition activities impacting confirmed or hazardous materials, Client should retain a qualified contractor to remove hazardous materials;

- Client should notify contractors of the potential asbestos, lead, and UW hazards per OSHA's Hazard Communication rule (29 CFR 1910.1200); and
- Universal wastes may either be removed and recycled or disposed of in accordance with applicable State and federal regulations before renovations or demolition that will disturb these materials.

4.6.4.5. Cost Estimates

GZA also prepared a Preliminary Order Of Magnitude Abatement Cost Estimate for ACMs identified at the Site (Appendix L). GZA's total cost estimate range for asbestos abatement was $150,000 to $180,000.

5. Operations & Maintenance Due Diligence

This section summarizes a review of the existing Operations and Maintenance Agreement for the CDECCA plant by and between CDECCA and IHI Power Services Corporation (IHI). This review does not take the place of a fully exhaustive O&M transition services assessment, rather highlights areas where the SOC will want to review or modify the current operating contract once it takes ownership of the plant.

On June 23, 2022, Veolia met with IHI to discuss the current operations and maintenance scope and confirmed the current operating agreement will transfer to the State of CT upon acquisition of the plant. The operating agreement in force between IHI and CDECCAat the time of this due diligence effort is titled "OPERATIONS AND MAINTENANCE AGREEMENT for the CDECCA PLANT by and between CAPITOL DISTRICT ENERGY CENTER COGENERATION ASSOCIATES and IHI POWER SERVICES CORP. " and is dated October 7, 2020. Through a series of RFI requests and discussions with the operator a comprehensive overview of the historical maintenance of the plant was not made available.

Key findings from the information made available is summarized in the sections that follow:

5.1. Annual Operating Costs

A review and adjustment of the current pricing structure of the existing contract should take priority upon acquisition of the facility. Currently there are three components for the monthly invoices, as follows and based on 2018 operating costs

- Monthly Capacity Demand Payment: ~$1.2 MM / YR
- Operating Demand Payment: ~ $1.3 MM / YR
- Variable Energy Costs: ~ 2.0 MM/YR

Going forward these three components will change as follows:

- Monthly Capacity Demand Payment will go away as the State becomes the asset owner. This payment represents the capital repayment of the original equipment at the time the plant was constructed. For the purpose of comparing this payment to the required capital renewal program the State will undertake as asset owner, a $1.2 MM/Yr payment at 2.5% interest rate for 25 years equates to a present value of $22 MM.

- Operating Demand Payment: The payment Should be reduced to reflect actual operating costs of the existing facility. Requests for details on actual operating costs and accounting history for O&M related costs were not made available by Hull Street. Future equipment choices and automation changes will help to reduce the total operating costs of the facility. It is recommended that the State rebid the operating contract for the facility and at a minimum demand a repricing of the existing agreement.

- Variable Energy Costs: The process of billing on metered consumption of thermal products multiplied by established performance (efficiency) curves will go away and in its place the State will simply pay its electricity and natural gas bill directly. The State should review its commodity procurement strategy with respect to fixed versus floating gas and electricity purchases.

  Connecticut Natural Gas and Eversource services are currently in the process of being transferred from HSE to the State. Changes to electricity service are currently being prepared by Eversource and will require detailed cost benefit evaluation and negotiations by the State. Given the plant's planned capital renewal and potential increase of electricity consumption it will be important to review options to determine least cost service from Eversource.

5.1.1. Scope Check Operational Service

Given the lack of response to RFI pertaining to specifics on the current Operation and Maintenance contract, Veolia recommends scope checking the following services provided by the Operator to make sure adequate records and operating data is being collected and prudent industry practices are being employed.

- **Operations and maintenance procedures**- Includes programs and procedures for Facilities operation.
- **Preventive/Predictive Maintenance Program -** Ensures that the preventive and predictive maintenance activities and schedules are consistent with Prudent Industry Practice. Preventive/Predictive Maintenance will minimize Corrective Maintenance.
- **Corrective Maintenance.**- Perform routine repairs on failed or malfunctioning equipment
- **Reports** - Provide periodic monthly and annual technical, incident reports, outage reports, and administrative and financial reports to the SOC.
- **Facilities Books and Records -** Maintain Facilities technical and administrative records and complete accounting books.

5.2. Computerized Maintenance Management System (CMMS)

The State should request a thorough overview of current CMMS practices and revise them accordingly. The objective of a CMMS is to ensure that it has the capability to manage maintenance activities, such as work order creation and tracking, maintenance scheduling, equipment history, parts information, inventory tracking, man-hours required for maintenance, and the Preventive Maintenance Program.

Veolia suggests transfer of the CMMS program and its previous data to the State of CT in order to determine how or if it wants to integrate this facility with the State's general asset management program.

5.3. Metering Reading & Billing

Under current operations a combination of administrative services from IHI and HSE deliver meter reading and billing processes to the State. The Due Diligence team requested details via RFI on the meter reading and billing process from field instrumentation to the final customer invoice. As of the writing of this report Hull Street has provided limited insight into this critical process.

CAS Supply Agreement Amendment 1 -2015 Exhibit D: Metering Diagrams display the physical meters and their locations in the thermal system that enable Hull Street to generate monthly invoices for the State.

The State should conduct a metering assessment to establish proper metering protocols and adjust its revenue recovery and meter reading and billing system accordingly. Veoila recommends the following specific actions related to meter reading and billing process as the State begins its O&M transition activities:

1. Document via flow chart, the process from field instrumentation to customer invoice. Assign each process/task with a responsible owner such that the State and its operator understand the roles and responsibilities of delivering accurate and timely invoices.
2. Remove use of efficiency curves to determine variable cost of energy and replace with direct metered consumption.
3. Update State's billing process with recent or real time metered demand to ensure adequate contribution from end users to the total cost of capacity.

6. Plant Repurposing & Decommissioning

6.1. Background

In 2020 HSE decided to retire the electric generators and focus solely on the production of thermal products for sale to the State. This decision triggers a number of changes, both physically and financially for the State to consider as it acquires the plant. This section provides a summary of those changes as they relate to the equipment no longer necessary for the delivery of thermal products.

6.2. Decommissioning Plan

The majority of the decommissioning of the existing power island at the CDECCA facility has already been accomplished by HSE/IHI. The combustion turbine, steam turbine, heat recovery boiler and associated auxiliaries were in a de-energized state during each of our site visits to the facility, and it is the due diligence team's understanding this equipment is no longer dispatched. For this reason, the process of de-energizing operational equipment is essentially complete.

The opinion of probable cost that has developed thus does not include an extensive decommissioning process; however, costs to remove residual fluids such as lubricants and closed cooling system media have been captured, as well as the cost to perform a detailed review of existing valve and breaker dispositions to complete the necessary lock-out/tag-out that will be required for actual demolition.

6.2.1. System and Equipment Disposition

The table below provides a high-level summary of the equipment and systems that may be abandoned-in-place or demolished (denoted as "Unnecessary") and/or will be necessary for future operations (denoted as "Necessary").

Systems and/or Equipment		Unnecessary	Necessary
Combustion Turbine		X	
Steam Turbine		X	
Heat Recovery Steam Generator		X	
Steam Turbine Condenser		X	
M/U Water Treatment System			X
	Water Softeners		x
	Demineralizers	x	
	Neutralization System	x	
HP Boiler Feedwater System		X	
Aux Boiler Feedwater System			X
Boiler Blowdown System			X

HP Steam System		X	
MP Steam System		X	
Aux Steam System			X
	Aux Boiler 1		x
	Aux Boiler 2		x
Condensate Return System			X
	Condensate Return Tank		x
	Condensate Forwarding Pumps		x
Condenser Water System			X
	Cooling Tower		x
	Primary Pumps	x	
	Aux Pumps (for Chillers)		x
Desuperheating Water System		X	
Chilled Water System			X
Compressed Air System			X
Natural Gas System			X
Wastewater System			X
115kV/13.2kV Utility Transformer			X
13.2kV System			X
	13.2/5kV Transformers		x
	13.2kV Switchgear		x
5kV System			X
480V System			X

6.2.1.1 Make Up Water Treatment System

The make-up water treatment system is required for steam production. When the steam boilers are retired, the Make-Up Water Treatment system could be retired/abandoned. Until this time, it is required for boiler water treatment; however, for low pressure steam only, without operation of the steam turbine, only water-softening is required. For this reason the high-purity treatment systems can be retired immediately.

6.2.1.2 Auxiliary Feedwater system, Auxiliary Steam System and Condensate Return System

These systems are only required for steam production. When the steam boilers are retired, these systems may also be retired.

6.2.1.3 Condenser Water

The condenser water system is required for chiller operation; however, the large primary pumps that supply condenser water to the steam turbine condenser may be retired.

6.2.1.4 Cooling Tower

The cooling tower is oversized for chilled water production and miscellaneous pump cooling. If the towers are found to be in a state of disrepair, consideration may be given to repairing or replacing only a portion of them.

6.2.1.5 Natural Gas System

With the steam boilers retiring, natural gas supply to the combustion turbine and duct burner is no longer required. Natural gas service to the auxiliary boilers is only required for steam production.

6.2.1.6 Utility Transformer

The 115kV/13.2kV transformer is only required to power the facility if electrical power continues to be imported to the facility from the 115kV transmission system. In the future, if an alternate (local distribution) service with a lower supply voltage is available to power the facility, it is recommended that a financial evaluation be conducted to compare these options.

6.3. Thermal Heating Capacity

As noted in Section 4.2.3, the steam generation equipment is oversized for the loads that are currently being served. As currently configured the boilers only supply heating steam to the State campus buildings that still require steam and no longer provide heating steam to the pumphouse, where it was historically converted to hot water prior to installation of the temporary hot water boilers currently in service. As a result the boilers are mismatched in size to the loads to be served. For instance, during the May 2022 site visit Boiler 2 was in operation at approximately 3% firing rate. This is well below the boiler's minimum turndown ratio (i.e.minimum operating load) and is therefore outside of the range where the boiler will operate at designed efficiencies. According to plant staff the boiler needed to be specially tuned to even operate at such a low load and will need to be retuned for higher winter loads. Even at these higher winter loads the boilers will likely still operate well below ideal efficiencies. While long-term operation with the present equipment configuration is not recommended, if the time period

during which steam will still be required is relatively short, the inefficiencies of this equipment are a burden that should be endured until new, high-efficiency hot water boilers may be installed on a permanent basis.

Additionally, due to the damage suffered at the Pumphouse, condensate is not being returned to the CDECCA facility. This condition further exacerbates the efficiency challenges, but as with the boilers themselves, the capital cost of making efficiency upgrades is not likely to be recovered through the subsequent efficiency gains if the duration in which steam production must be maintained is short.

6.4. Electrical Utility Changes

On June 14, 2022 @ 2:00 PM Veolia participated in a conference call with Eversource to establish the course of action to support plant transfer from HSE to the State.

6.4.1. Future Rate Structure

The existing rate for the plant is Connecticut's Light and Power's Rate 39: Large Interruptible Service. This rate is currently closed (since February 5, 1999) and not available to new customers. According to initial discussion with Eversource this rate is not available for the State due to the fact that the plant is no longer a generating facility. Eversource indicates the facility would shift to the Connecticut Light & Power's Large Time-of-Day (Rate 58) tariff which applies to non-manufactures whose demand has previously equaled or exceeded 1,000 kW.

6.4.2. Service Transformation and Metering Configuration

Discussion with Everource revealed the potential to combine Capitol Ave complex with modified loads at CDECCA or to keep and serve them separately. Veoila recommends a further analysis of the service options once Eversource provides their initial cost estimate and project duration.

6.4.3. Future Loads

Collectively, the pumphouse and CDECCA plant loads enable the State to produce and distribute thermal heating and cooling products to the State's district energy system.

The two electrical loads are defined as follows:

1) CDECCA plant loads are those metered by Eversource at 115 kV for the physical address of 490 Capitol Ave and include the equipment owned by Hull Street Energy to produce thermal heating and cooling products, i.e. boilers, chillers, and auxiliary plant equipment.
2) Pumphouse loads are those metered by Eversource at 23 kV and are associated with further distribution and treatment of heating and cooling products for delivery to the State-owned district energy system. Eversource's current metering configuration includes not only the pumphouse but commercial office space loads of 450 and 470 Capitol Ave. Due to this metering configuration and recent impacts from Covid-19, it is difficult and best to disaggregate electrical loads in order to single out the specific pumphouse load. Therefore, total electrical load

requirements for the combined CDECCA and pumphouse, including district energy growth factors, are considered conservative.

Eversource has provided hourly interval data for 1) CDECCA plant and 2) Pumphouse for the following time periods:

Eversource Hourly Interval Data						
Not Available	**2020**		**2021**		**2022**	
Available	CDECCA Plant	Pump house	CDECCAP Plant	Pump house	CDECCA Plant	Pump house
Jan	X	X	✓	✓	✓	✓
Feb	X	X	✓	✓	✓	✓
Mar	X	X	✓	✓	✓	✓
Apr	X	X	✓	✓	✓	✓
May	X	X	✓	✓	✓	✓
Jun	X	X	✓	✓	X	X
Jul	✓	X	✓	✓	X	X
Aug	✓	✓	✓	✓	X	X
Sep	✓	✓	✓	✓	X	X
Oct	✓	✓	✓	✓	X	X
Nov	✓	✓	✓	✓	X	X
Dec	✓	✓	✓	✓	X	X

Hourly data was scrubbed of erroneous minimum and maximum data points to determine representative peaks for the combined load. Peak monthly loads were identified for each of the annual data sets provided, as seen in the following table:

Monthly Peak KW			
Month / Year	**2020**	**2021**	**2022**
Jan		1,775	1,555
Feb		2,246	1,810
Mar		1,860	1,639
Apr		2,190	2,041
May		2,839	2,455
Jun		3,423	2,316
Jul	842	3,319	
Aug	4,630	3,809	
Sep	3,570	2,331	
Oct	2,869	2,051	
Nov	2,308	1,875	

Dec	1,769	2,223	

The combined loads demonstrate a peak of 4,630 KW occurring in August. An additional load growth factor of 50% is applied to this peak to account for future loads on the district energy system resulting in a total estimated peak load of 6,945 KW.

6.4.4. Recommendations

Continued discussions with Eversource should focus on the costs and benefits of removing the 115 kV service versus the costs and benefits of a new 32 kV service, including but not limited to future options for electrification of natural gas boilers which would significantly increase the electric load and therefore the required service infrastructure.

6.5. Demolition Approach

The approach to the decommissioning and demolition assessment was to remove the equipment and systems that are not required for "Day One" operation of the facility - meaning operation immediately following the execution of the purchase and sale agreement. The scope of equipment to be demolished is shown in Appendix M, and generally consists of the power generation equipment:

1. Combustion turbine generator,
2. Heat recovery steam generator,
3. Steam turbine generator and the related auxiliaries.

For a full demolition, the contracted team will work with the facility's team to decommission the equipment, perform the necessary lock-out/tag-out procedures, and drain any equipment lubricants/fluids. As most of the equipment is presently out-of-service the decommissioning is expected to be fairly limited.

The contractor will begin the demolition by removing the storefront glass and frames from the street side of the structure to allow access into the building. The process piping lines interfering with this access point will be relocated prior to the start of demolition activities. The contractor will utilize a combination of an excavator with shear attachment as well as manual labor with manlifts to remove mechanical components including the combustion turbine located between column lines 3 & 4.

The contractor will then progress eastward, removing the silencer and larger portions of the duct system and the GACs to create additional space within the building. Material will be loaded out and removed on the street side of the structure until the turbine generator and gas turbine located between column lines 3 & 4 have been removed. Once removed, the contractor can begin loading containers and removing containers out the West access door as well as the street side of the building.

Dismantlement of the HRSG will begin as soon as reasonable access is available. The bulk of the HRSG system will be torch cut utilizing manlifts, large forklift systems, and custom-designed rigging systems.

Torch cutting emissions will be managed with smoke eaters and fans. Pieces will be lowered to the ground in sections and further processed on the ground via the excavator with shear attachment and loaded out accordingly into scrap containers. Remaining adjacent mechanical systems and unnecessary access stairs/catwalks will be removed as the HRSG is removed.

Once space within the facility has been cleared, the steam turbine will be removed through the same building opening as the combustion turbine. This avoids the need to remove the stairwell outside of the other window. The turbine generator pedestal will be removed utilizing an excavator mounted hammer. Upon removal of the steam turbine generator and pedestal, the contractor will begin working into the building taking the steam turbine auxiliaries, condenser, pumps, and associated small tanks.

There will be some control system decommissioning/modification work that the contractor will be conducting both before and after the demolition work occurs. After the demolition is complete, the storefront glass will be replaced to the condition it was in previous to the start of the demolition project. A final cleaning of the site will be conducted.

The overall duration of the demolition is expected to be approximately one year. A schedule has been developed and included in Appendix N.

6.5.1. Opinion of Probable Cost

The value is based on discussions with a local demolition contractor who visited the site and reviewed the scope of work with Waldron representatives. The cost opinion includes input from the contractor as well as internally-developed costs for various items not included in the contractor's work-up, such as the control system modifications mentioned above.

One consideration not addressed in this opinion of probable cost is the value of scrap metals. The value of scrap varies continuously with various market conditions, and because the tonnage of recovered materials for this scope is presently unknown, the assignment of a scrap value—or even a range of possible scrap values—is difficult. That said, any scrap value realized would result in roughly a dollar-for-dollar deduction from the total value indicated below. In Waldron's opinion the scrap value will obviously not be zero, but nor should it be expected to make an order of magnitude difference in the cost opinion. The value of scrap metal is likely less than the uncertainty band of this cost opinion, and thus is not a key factor in budgeting for this work.

Opinion of Probable Cost	
Engineering	$120,000
Construction Directs	$5,010,000
Construction Management	$340,000
Total	**$5,470,000**

The following clarifications apply to this cost opinion:

- All work to be accomplished by union or merit shop contractors.
- The contractor's team will have free and clear access to the site.
- All work to be accomplished on a "straight time" basis, any shift, weekend, or holiday work is excluded.
- All special insurances and bonds are excluded.
- The identification, removal, and disposal of any hazardous material is excluded.
- All state and federal permits are excluded. A demo permit is included.
- Street closure permits and police details are excluded.
- Lock-Out/Tag-Out is included.
- The potential value of scrap metals is not included.
- Cost assumes the building's existing bridge crane is available for use by the demolition contractor. Note this will require recertification by the Owner.

7. Pumphouse Relocation/Repowering

The objective of the pumphouse relocation/repowering analysis was to provide a preliminary review of options for consolidating operations within the CDECCA facility. This would allow the State to shutdown remaining equipment in the old Pumphouse Building, which was recently damaged. This evaluation is based on concept level design efforts.

Veolia identified several options and prepared a conceptual level equipment layout drawing for each option, as well as an opinion of probable cost to demolish and remove existing equipment within CDECCA—to the extent described for each option—and to design, install, and commission the new equipment. Equipment layout drawings can be found in Appendix O.

The cost opinions include engineering, construction management, equipment procurement, demolition of old equipment, demolition of walls/partitions/platforms as required, installation of new work, start-up, and commissioning. They do not include various Owner costs such as but not limited to Owner's project management, Owner's engineer, environmental permitting, any legal or accounting expenses the Owner may incur as part of this project, or project-specific insurance that may be required.

Lastly, hazardous material identification, abatement, and/or disposal has not been evaluated or included in these opinions of probable cost.

The cost opinions include bonding costs, and they are considered to be accurate to +/-25%.

7.1 Elements Common to All Options

The following basic project elements are common to all of the options that were reviewed. (A subsequent section will review the unique aspects of each option.)

- The intent for every option is to relocate utility services that are presently contained in the Pumphouse Building to the newly acquired CDECCA facility.
- All options include new secondary (distribution) chilled water pumps to replace those formerly located in the Pumphouse. The secondary (distribution) system for chilled water also includes a new expansion tank, air separator, and system controls as required to eliminate system connection to the Pumphouse.
- All options include new secondary (distribution) hot water pumps to replace those formerly located in the Pumphouse. The secondary (distribution) system for hot water also includes a new expansion tank, air separator, and system controls as required to eliminate system connection to the Pumphouse.

7.2 Elements Unique to Each Option

There are several key distinctions between the options reviewed. These distinctions include the extent of demolition of existing systems that are included/required as well as the approach to serving the Capitol Ave Complex of buildings with steam or hot water. The latter project element hinges upon the conversion of the Capitol Ave Complex from steam heating systems to hot water systems. Review of Capitol Ave Complex steam to hot water conversion was not included in this scope, however, for comparative analysis purposes we have developed an order of magnitude opinion of cost based on square footage and experience based conversion costs. The analysis assumes 400,000 SF of conversion space at $15 per square foot.

A high-level description of the unique aspects of each option that was reviewed is included in the table below. An itemized list of demolished/new equipment associated with each option is included in the table following this basic description.

Option	Description
Status Quo	Hot water to the thermal loop will continue to be supplied by the temporary hot water boilers that were installed following the damage that occurred at the Pumphouse. The existing steam boilers in CDECCA would be utilized for supply of steam to the Cap Ave Complex.
1	Minimum demolition in the CDECCA facility is included, to minimize project costs. The temporary hot water boilers that were installed will be removed and replaced with new, permanent hot water boilers in CDECCA. The existing steam boilers in CDECCA will continue to supply steam directly to the Cap Ave Complex.
2	Minimum demolition in the CDECCA facility is included, to minimize project costs. The temporary hot water boilers that were installed will be removed and replaced with new, permanent hot water boilers in CDECCA. The existing steam boilers in CDECCA will be replaced with new, smaller steam boilers that are more appropriately sized for the Cap Ave Complex loads.
2B	Same as 2, but with demolition of all equipment in CDECCA that is no longer required. This would include the combustion turbine generator, the steam turbine generator, the heat recovery steam generator and related auxiliaries
3	Minimum demolition in the CDECCA facility is included, to minimize project costs. Steam production in CDECCA would be completely retired in this option, and the temporary hot water boilers that were installed will be removed and replaced with new, permanent hot water boilers in CDECCA that are capable of serving not only the thermal loop but the Cap Ave Complex (following a hot water conversion project) as well.

3B	Same as 3, but with demolition of all equipment in CDECCA that is no longer required. This would include the combustion turbine generator, the steam turbine generator, the heat recovery steam generator and related auxiliaries. It would also include demolition of the existing steam generation equipment including the auxiliary boilers and related systems, as steam would be retired in this option.
4	Minimum demolition in the CDECCA facility is included, to minimize project costs. The temporary hot water boilers that were installed will be removed and replaced with new, permanent hot water boilers in CDECCA. The existing steam boilers in CDECCA will be replaced with new, smaller steam boilers that are more appropriately sized for the Cap Ave Complex loads.

7.3 Demolition Matrix

A table summarizing the demolition scope for each option is included below:

Demo Mechanical Equipment		1	2	2B	3	3B	4
CTG-1	Gas Turbine			X		X	
HRSG-1	Heat Recovery Steam Generator			X		X	X
STG-1	Steam Turbine			X		X	
GC-1	Gas Compressor	X	X	X	X	X	X
CW-P1	Circ Pump	X	X	X	X	X	X
CW-P2	Circ Pump	X	X	X	X	X	X
BLR-1	Aux Boiler 1					X	
BLR-2	Aux Boiler 2					X	
CND-TK-1	Condensate Receiver Tank		X	X	X	X	
DA-2	Aux Boiler DA					X	
CND-P1	Condensate Forwarding Pump		X	X	X	X	
CND-P2	Condensate Forwarding Pump		X	X	X	X	
CW-P5	Aux Cooling Water Pump		X	X	X	X	
CW-P6	Aux Cooling Water Pump		X	X	X	X	

Demo Mechanical Equipment		1	2	2B	3	3B	4
FW-P1	High Pressure Feedwater Pump		X	X	X	X	
FW-P2	High Pressure Feedwater Pump		X	X	X	X	
WTR TRTMENT	Water Treatment Skids	X	X	X		X	X
WALL ACCESS	North Wall Temporary Access		X		X		

7.4 New Equipment Matrix

A table summarizing the new equipment associated with each option is included below:

Tag	Description	1	2	2B	3	3B	4
STM-HX1	Steam to Hot Water Heat Exchanger						X
STM-HX2	Steam to Hot Water Heat Exchanger						
BLR-1	600 BHP Hot Water Boiler	X	X	X	X	X	X
BLR-2	600 BHP Hot Water Boiler	X	X	X	X	X	X
BLR-3	600 BHP Hot Water Boiler	X	X	X	X	X	X
BLR-4	90 BHP Hot Water Boiler	X	X	X	X	X	X
BLR-5	90 BHP Hot Water Boiler	X	X	X	X	X	X
BLR-6	600 BHP Steam Boiler		X	X			X
BLR-7	600 BHP Steam Boiler		X	X			X
BLR-8	600 BHP Steam Boiler		X	X			X
HW-P1A	Primary Hot Water Pump	X	X	X	X	X	X
HW-P1B	Primary Hot Water Pump	X	X	X	X	X	X
HW-P1C	Primary Hot Water Pump	X	X	X	X	X	X
HW-P2A	Secondary Hot Water Pump	X	X	X	X	X	X
HW-P2B	Secondary Hot Water Pump	X	X	X	X	X	X
HW-P2C	Secondary Hot Water Pump	X	X	X	X	X	X

Tag	Description	1	2	2B	3	3B	4
HW-TK1	Hot Water Expansion Tank	X	X	X	X	X	X
HW-TK2	Hot Water Air Separator	X	X	X	X	X	X
CHW-P5	New Secondary CHW Pump	X	X	X	X	X	X
CHW-P6	New Secondary CHW Pump	X	X	X	X	X	X
CHW-P7	New Secondary CHW Pump	X	X	X	X	X	X
CHW-TK1	Chilled Water Expansion Tank	X	X	X	X	X	X
CHW-TK2	Chilled Water Air Separator	X	X	X	X	X	X
HW-P1A VFD	Primary Hot Water Pump VFD	X	X	X	X	X	X
HW-P1B VFD	Primary Hot Water Pump VFD	X	X	X	X	X	X
HW-P1C-VFD	Primary Hot Water Pump VFD	X	X	X	X	X	X
HW-P2A VFD	Secondary Hot Water Pump VFD	X	X	X	X	X	X
HW-P2B VFD	Secondary Hot Water Pump VFD	X	X	X	X	X	X
HW-P2C-VFD	Secondary Hot Water Pump VFD	X	X	X	X	X	X
CHW-P5 VFD	New Secondary CHW Pump VFD	X	X	X	X	X	X
CHW-P6 VFD	New Secondary CHW Pump VFD	X	X	X	X	X	X
CHW-P7 VFD	New Secondary CHW Pump VFD	X	X	X	X	X	X

7.5 Cost Opinion Matrix

Of all the above options evaluated, only three (3) (Options 1, 2 and 3) were determined to be financially feasible on comparative 20 year financial analysis, as summarized in the following table. Full details of the net present cost analysis can be found in Appendix P. These tables are for relative comparison purposes only.

Option	Description	Duration to COD (yrs)	Total Cap Ex	Annual Op Ex (Avg 20 yr)	20-Year Net Present Cost ($2022)
Status Quo (Not a feasible option, must address pumphouse)	Status Quo Hot water to the thermal loop will continue to be supplied by the temporary hot water boilers that were installed following the damage that occurred at the Pumphouse. The	0	$0	$8,323,008	$123,556,818

Option	Description	Duration to COD (yrs)	Total Cap Ex	Annual Op Ex (Avg 20 yr)	20-Year Net Present Cost ($2022)
	existing steam boilers in CDECCA would be utilized for supply of steam to the Cap Ave Complex.				
1 - Purchase, Pumphouse Relocation & Replace Boiler(s) w/ Existing Steam and New Hot Water	Minimum demolition in the CDECCA facility is included, to minimize project costs. The temporary hot water boilers that were installed will be removed and replaced with new, permanent hot water boilers in CDECCA. The existing steam boilers in CDECCA will continue to supply steam directly to the Cap Ave Complex.	2.5	$24,742,465	$3,935,196	$83,270,316
2 - Purchase, Pumphouse Relocation & Replace Boiler(s) w/ New Steam and New Hot Water	Minimum demolition in the CDECCA facility is included, to minimize project costs. The temporary hot water boilers that were installed will be removed and replaced with new, permanent hot water boilers in CDECCA. The existing steam boilers in CDECCA will be replaced with new, smaller steam boilers that are more appropriately sized for the Cap Ave Complex loads.	2.5	$28,372,713	$3,888,079	$86,113,151
3 - Purchase, Pumphouse Relocation & Replace Boiler(s) w/ Hot Water	Minimum demolition in the CDECCA facility is included, to minimize project costs. Steam production in CDECCA would be completely retired in this option, and the temporary hot water boilers that were installed will be removed and replaced with new, permanent hot water boilers in CDECCA that are capable of serving not only the thermal loop but the Cap Ave Complex (following a hot water conversion project) as well.	2.5	$27,018,166	$3,644,411	$81,177,388