VEOLIA

State of Connecticut DAS

CAS Decarbonization Study
Phase 2
Deliverable 8: Feasibility Study

March 12, 2024

PREPARED FOR:

CONNECTICUT DEPARTMENT OF ADMINISTRATIVE SERVICES

PREPARED BY:
Veolia North America

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Appendices

GLOSSARY OF TERMS

Capital Expenditure (CapEx) - Funds used to acquire, upgrade, and maintain physical assets.

Carbon Offsets - Carbon offsets are a trading mechanism that allows entities to compensate for (i.e. “offset”) their greenhouse gas emissions by supporting projects that reduce, avoid, or remove emissions elsewhere.

Heating, Ventilation, and Air Conditioning (HVAC) - Collective term for all the different types of cooling and heating systems and components.

Independent System Operator (ISO) - Independent, non-profit created to operate regional power systems, implement wholesale markets, ensure open access to transmission lines.

Investment Tax Credit (ITC) - Provides a tax credit for investment in renewable energy projects as part of the Inflation Reduction Act (IRA) of 2022. For tax years beginning after December 31, 2022, most tax-exempt organizations, government entities, Indian tribal governments, and rural electric cooperatives may elect to treat certain credits as direct federal tax payments.

Net Present Cost (NPC) - The net present cost (or life-cycle cost) is an economic tool used to equate the total cost of a project over a specified time period to the total cost today, taking into account the time value of money.

Operating Expense (OpEx) - Expense incurred through normal business operations (fuel, payroll, repairs, etc).

Power Purchase Agreement (PPA) - Long-term contract between an electricity generator and a customer, during which time the power purchaser buys energy at a pre-negotiated price.

Renewable Energy Credits (RECs) - Market-based instrument that certifies the bearer owns one megawatt-hour (MWh) of electricity generated from a renewable energy resource. REC values in this report are based in the ISO New England region.

Renewable Portfolio Standard (RPS) - Policies that require that a specified minimum percentage of the electricity utilities sell comes from eligible renewable resources.

Renewable Natural Gas (RNG) - Biogas from a variety of sources that has been upgraded for use in place of fossil natural gas.

Social Cost of Carbon (SC-CO2) - Per the US EPA, The SC-CO2 is an estimate of the economic damages associated with a small increase in carbon dioxide (CO2) emissions, conventionally one metric ton, in a given year. (https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf) Note that SCC, Social Cost of Carbon, is a more encompassing term inclusive of other greenhouse gas emissions. This report references SC-C02 as defined here.

Time of Use (TOU) Rates - Time-of-use rates are utility rate structures that adjust the rate you pay for electricity over the course of the day. Typically, when both the cost of generating electricity and the electricity demand are low (i.e., in the middle of the night), the rate paid to use electricity is lower. However, when both the cost of generation and demand for electricity are high (i.e., on the afternoon of a hot summer day), the electricity rate is higher.

Virtual Net Metering (VNM) - Allows a renewable energy system's owner to share the billing credits that are generated when the system produces more power than the owner uses.

Weighted Average Cost of Capital (WACC) - Average rate to finance capital projects, also considered to be the discount rate in the NPC calculation .

Executive Summary

The Capitol Area System (CAS) Decarbonization Study provides findings regarding heating and cooling options for the existing capital district energy center (Capital District Energy Center Cogeneration Association, or CDECCA), its distribution system, and the buildings it feeds, in consideration of Executive Orders 1 and 21-3. Twenty-two (22) distinct options were conceptually reviewed and, based upon research and calculations during the study, three (3) were selected for further review based upon the following metrics:

- An option that most reduces carbon emissions;
- An option that most reduces capital and operational costs;
- An option that balances the first two, a compromise of sorts.

This CAS Decarbonization Study does not provide a recommendation of which option to select but rather presents how much each of these three (3) options is likely to cost in dollars and in carbon emissions, noting as well the Social Cost of Carbon (see "Glossary of Terms'' on the previous page). Results are represented in the following table.

TABLE 1: Key Performance Figures for Selected Scenarios

Notes:

1. All costs are in millions of dollars, except variables with asterisks (*).
2. MTCO2e - metric tons of carbon dioxide equivalent
3. Unit Cost of Carbon Reduction based on 30-Year NPC divided by carbon reduction compared to baseline carbon emissions.
4. All costs presented in this table are commensurate with the level of project definition and have an expected range of accuracy between -30% to 50%. Low temperature and geothermal scenarios likely will have the highest CapEx uncertainty and require the most additional study to determine feasibility.
5. NPC figures include CapEx with ITC.
6. Escalation of key performance figures for 5, 10, and 15 years are shown in Appendix M.
7. Based on current operating conditions without Improvement to low delta T syndrome described in Section 11.4 .

Scenario	Baseline	A.2.L	C.2.L	E.1.H
Description	**Operational Year 2020**	**Condenser & Ground Source HP w/ Electric Boilers**	**Ground Source HP**	**Natural Gas Boilers**
Capital Expenditure (CapEx)	$9.4	$78.4	$97.5	$20.0
CapEx w/ ITC	$9.4	$72.2	$85.3	$20.0
Year 1 OpEx (w/ SC-CO2)	$10.4	$7.2	$7.5	$7.9
Year 1 OpEx (w/ RECs & Carbon Offsets)	$11.6	$7.0	$7.3	$8.7
Year 1 OpEx (w/o SC-CO2, RECs or Carbon Offsets)	$5.8	$6.7	$7.0	$4.7
NPC (30-Year w/ SC-CO2 & ITC)	$236	$243	$262	$194
NPC (30-Year w/ RECs, Carbon Offsets & ITC)	$298	$241	$261	$236
NPC (30-Year w/o SC-CO2, RECs or Carbon Offsets) & w/ ITC)	$155	$238	$258	$137
Lifetime Carbon (30-Year MTCO2e)	400,557	16,001	15,095	276,673
Carbon Reduction from Baseline (30-Year MTCO2e)	-	384,556	385,462	123,884

1.0 Process and Supporting Details

1.1. Background

In April 2023, the Department of Administrative Services (DAS) retained Veolia to perform a Capitol Area System (CAS) Decarbonization Study as part of its On-Call Contract (No. OC-DCS-ENGY-0030, Task No. 3, Project No. BI-2B-414). The purpose of the CAS Decarbonization Study is to define, develop, and assess options for modifying CAS operations to meet Executive Orders 1 and 21-3 ("EO 1") and ("EO 21-3"). Incorporated into EO 1 is GreenerGov CT, a "Lead by Example" initiative with a mission of advancing environmental leadership, reducing operating costs and environmental impacts of State government operations, and generating savings for taxpayers. EO 21-3 calls for executive branch state agencies to take significant actions within their authority to reduce carbon emissions and "by 2030, all electricity purchased and generated by the Executive Branch will be 100% zero carbon".

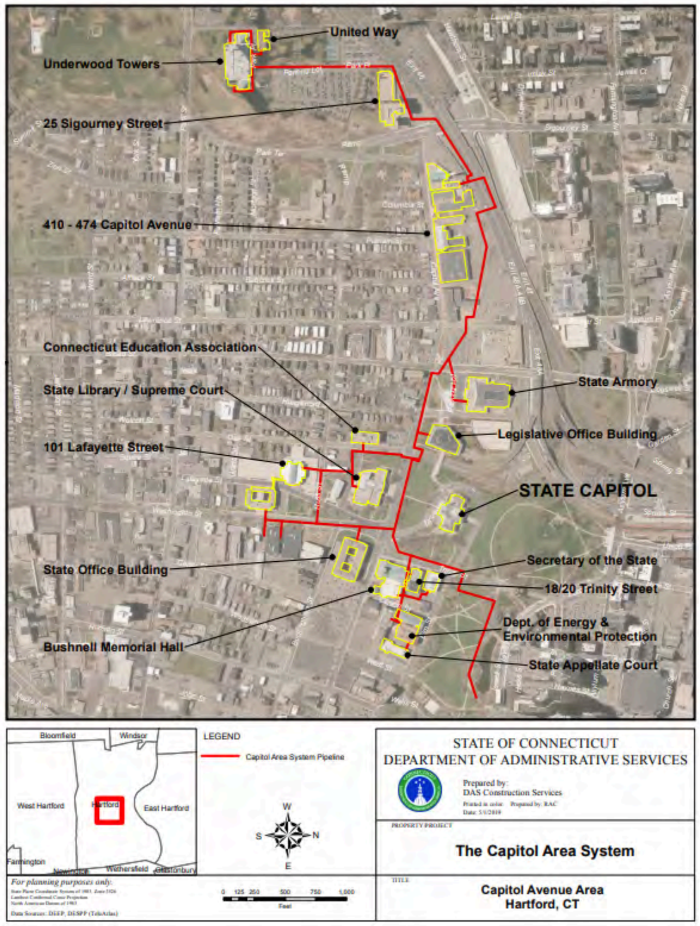
Decarbonization of the CAS, as it relates to Scope 2 emissions[1], can impact the entire supply and demand chain of energy source, generation, distribution and end use. The study was proposed to evaluate the use of various mechanisms to achieve a decarbonized CAS, chief among them include:

- Combination of State and Private demand side modifications to accept highly efficient, low to no carbon thermal supply sources
- Utility and Non-Utility supply options such as renewable electricity in the form of Power Purchase Agreements (PPAs), renewable supply contracts and/or carbon offsets[2]
- State-owned supply-side options such as geothermal and PV systems

Total energy requirements and design basis are detailed in Deliverable 2 (Appendix C) and Figure 1 below depicts the CAS thermal distribution system loop.

[1] https://ghgprotocol.org/scope-2-guidance
[2] Carbon offsets for natural gas consumption, otherwise carbon free electricity sources via Eversource, RECs, power purchase agreements,special case utility programs or owned assets

FIGURE 1: CAS Thermal Distribution System Loop



1.2. Summary of Approach

Decarbonization of CAS energy systems is complex and multifaceted and solutions must find a balance among technical, economic, regulatory and policy constraints and criteria. A simple decarbonization approach can keep conditions the same while offsetting natural gas and electric consumption with carbon offsets and renewable electricity credits (further described in Section 4.5). However, this study expands on this approach by looking at supply side options for electrification of natural gas (i.e. fuel switching from natural gas to electricity) with a range of technologies. Some of these technologies require significant changes to offtaker HVAC systems to enable lower temperature supply conditions, which can only be found through field testing and trial and error methods. During initial workshops and through subsequent deliverables, stakeholders concluded the market for "renewable" fuel sources such as hydrogen (H2), Renewable Natural Gas (RNG) or other green fuels were not adequate to serve the thermal loads of the CAS and therefore were removed from further analysis, leaving only carbon free electricity as an option for "renewable" fuel.

Given electricity as the option for decarbonization, efforts turn towards securing the minimum amount of carbon free electricity at the best price while maintaining reliability of thermal supply. This requires optimization of both supply and demand side systems, that is, efficiency first then right size supply systems. By considering CT's existing renewable portfolio standard (CT RPS) alongside EO 21-3, we have determined the volume of renewable electricity needed for decarbonization to be the amount above that supplied by Eversource[3] through RPS compliance. In other words, since current RPS standards don't require Eversource to supply 100% carbon free electricity, additional carbon free sources would be required to make up the difference in order to achieve a 100% renewable electricity supply.

1.3. Summary of Findings

TheCAS Decarbonization Study was divided into two (2) phases: a Phase 1 Initial Screening Assessment that consisted of seven (7) tasks and associated deliverables. The deliverable provided data to support a rank and score process intended to narrow an initial twenty-two (22) scenarios (i.e. ground-source heat pumps, electric or gas boilers, etc.) down to (3) for further evaluation. Veolia assisted the State in reviewing potential scoring criteria and metrics to apply. Ultimately the State issued its scoring criteria[4] to Veolia with values for each of the following three (3) scenarios for additional assessment:

1. A.2.L- Hybrid of Ground Source (GS) Heat Pumps & Electric Boilers
2. C.2.L- 100% Ground Source (GS) Heat Pumps
3. E.1.H- 100% Natural Gas Condensing Boilers

For ease of use and reference purpose we have developed a naming convention for the scenarios as follows: Scenario X.#.Y where:

- X - General configuration/class of heating technologies with values of A, B, C, D or E
- # - Unique combination of heating technologies with values of 1, 2 or 3
- Y- Either high or low temperature/enthalpy application, designated with 'H' for high temp/enthalpy and 'L' for low temperature/enthalpy

Descriptions of convention scenario designations are provided in the following table. Evaluated results for all scenarios in Phase 1 (not including four (4) which were determined to be technologically infeasible: C.1.H, C.1.L, C.3.H and C.3.L) are provided in Appendix A.

[3] See Section 6. Utility Supply Options for further details on carbon free electricity procurement options
[4] See APPENDIX J - FIGURE D1: Selection Criteria by State

TABLE 2: Scenario Description

General Configuration / Class of Heating Technologies		Technology & Fuel
A	Hybrid of Heat Pumps & Electric Boilers	Air, water and ground source (GS) heat pumps, electric boilers all supplied with renewable, zero carbon electricity or Class I REC's claiming the same.
B	100% Electric Boilers	
C	100% Heat Pumps	
D	Hybrid of Heat Pumps & Natural Gas Condensing Boilers	Heat pumps supplied with renewable, zero carbon electricity or Class I REC's claiming the same. Boilers supplied with natural gas with equivalent carbon offsets to claim decarbonization.
E	100% Natural Gas Condensing Boilers	

Phase 2 further evaluated these (3) scenarios, equipment recommendations and equipment cost projections to refine concepts established in Phase 1. The table below presents the three (3) scenarios and their key performance figures for each technology option. Baseline is defined as continued operation under existing conditions at future projected loads as defined in Deliverable 2 (Appendix C). The NPC includes initial capital costs (CapEx) and 30 year operating costs (OpEx) (fuel, operation and maintenance (O&M), repairs, etc.). Performance figures without carbon costs (social cost of carbon (SC-CO2), renewable energy credits (RECs), and carbon offsets) were selected by the State for ranking the scenarios; however, figures with these factors included are included in Table 1 . The full list of performance figures with and without carbon costs included are presented in Appendix A. Revenues from sales to the offtakers have not been calculated as part of NPC but are expected to be the same across all scenarios. Capital and operating cost estimates are commensurate with the level of project definition and have an expected range of accuracy between -30 to 50 percent.

TABLE 1: Key Performance Figures for Selected Scenarios

Notes:

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5. NPC figures include CapEx with ITC.
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7. Based on current operating conditions without Improvement to low delta T syndrome described in Section 11.4 .

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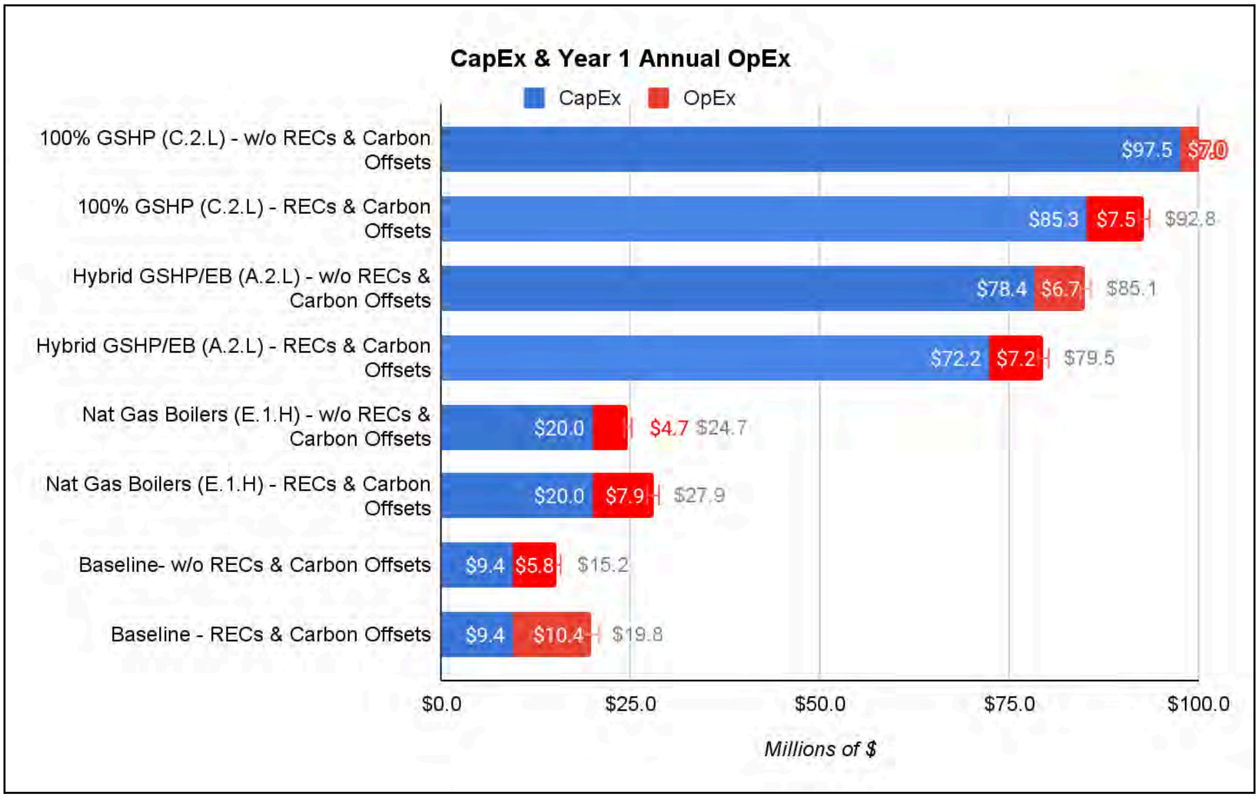
Lifetime Carbon (30-Year MTCO2e)	400,557	16,001	15,095	276,673
Carbon Reduction from Baseline (30-Year MTCO2e)	-	384,556	385,462	123,884
Unit Cost of Carbon Reduction ($/MTCO2e w/ SC-CO2)3 *	-	$632	$680	$1,566
Unit Cost of Carbon Reduction ($/MTCO2e w/ RECs & Carbon Offsets)3 *	-	$627	$677	$1,905
Unit Cost of Carbon Reduction ($/MTCO2e w/o Carbon Costs)3 *	-	$619	$669	$1,106

FIGURE 2: CapEx & Year 1 Annual OpEx



1.4 Selection Criteria

Veolia provided recommendations for scoring criteria; however, the State was ultimately responsible for incorporating criteria into a scoring matrix to narrow the twenty-two (22) distinctive scenarios Veolia developed in Deliverable 7 down to three (3) for an additional evaluation (Appendix J). The State devised the following selection criteria, with the best performing scenario from each category being selected for further evaluation:

1. **Decarbonization:** Lifetime carbon emissions are the only consideration in this criterion, and C.2.L—100% Ground Source (GS) Heat Pumps—scored the highest in this category.
2. **Cost:** This criterion prioritizes operating expenses and capital expenses, with a lower priority given to the remaining factors. E.1.H-100% Natural Gas Condensing Boilers was the least expensive option.
3. **Balanced:** This criterion assigns effectively equal weight to decarbonization and cost impacts to the scenarios. The scenario which scored highest when balancing these criteria was A.2.L-Hybrid of Ground Source (GS) Heat Pumps and Electric Boilers.

2.0 Financial Assumptions

2.1. Discount Rate

A discount rate is the rate of return used to discount future cash flows back to their present value. This rate is often a Weighted Average Cost of Capital (WACC), required rate of return, or the cost of debt (e.g. bond rate). For the financial analyses conducted as part of this study the State bond rate of 3.77% has been used as the discount rate.

2.2. Potential Incentives

An updated review of available federal and state incentives as described in Deliverable 3 (Appendix D) did not find any changes or new incentives that could be relevant to the selected scenarios described in Section 1. Eversource was still unable to provide, at a minimum, a range of utility incentive values, based on the level of design and definition produced through the study. Based on this evaluation, only the Investment Tax Credit (ITC), as modified under the Inflation Reduction Act (IRA) of 2022, is applicable to the financial analysis in this deliverable. Additionally, only scenarios A.2.L and C.2.L with a geothermal heat pump system would be eligible for the ITC. A geothermal heat pump system includes any equipment that uses the ground or ground water as a thermal energy source to heat a structure or as a thermal energy sink to cool a structure. Only the portion of equipment used to produce, distribute, or use energy derived from a geothermal deposit is eligible for the credit. For the purposes of this study it is assumed that the project will meet the prevailing wage requirements and therefore a 30% ITC would be applicable. Construction of a qualified geothermal heat pump system must begin before January 1, 2035.

2.3. Social Cost of Carbon (SC-CO2)

As defined by the US EPA, the SC-CO2 is a measure, in dollars, of the long-term damage done by a ton of carbon dioxide (CO2) emissions in a given year. This dollar figure also represents the value of damages avoided for a small emission reduction (i.e., the benefit of a CO2 reduction). During discussion with the State it was determined that the State's SC-CO2 is still being developed. As such, it was agreed that until a State specific SC-CO2 has been provided, Veolia would use the following EPA SC-CO2 value for 2022 as a placeholder in its calculations. These values were obtained from Table A.5.1 of the EPA's November 2023 *"Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances"* https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf using a discount rate of 1.5%.

TABLE 3: Social Cost of Carbon

	SC-CO2 (2020 dollars per metric ton of CO2)
Emission Year	(Discount Rate: 1.5%)
2022	$346

All financial analyses are presented both with and without the SC-CO2 as a financial consideration.

2.4. Escalation Factors

An annual escalation factor of 2.5% is used for all commodities and expenses over the 30-year term, including but not limited to the following:

- Electricity cost
- Natural gas cost
- Water cost
- Labor costs
- Equipment costs
- O&M costs

This is roughly equivalent to the US Treasury 20-year Breakeven Inflation Rate of 2.48% (https://fred.stlouisfed.org/series/T20YIEM).

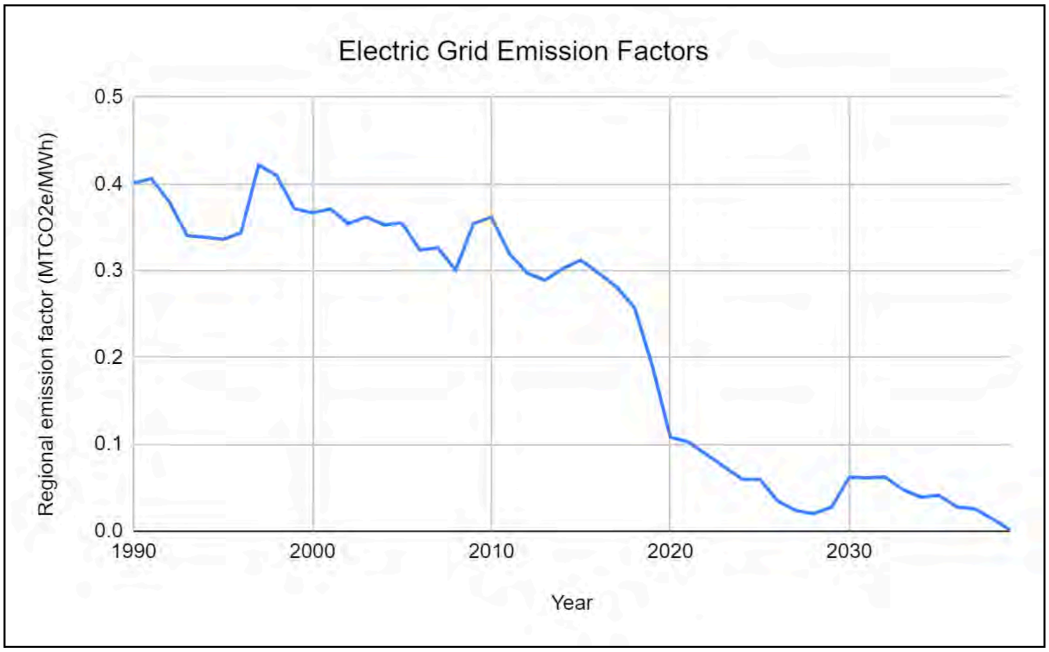
3.0 Carbon Emission Factors

The following emissions factors provided by the State have be used to calculate the potential emissions for various fuels that have been used in the past or may be used in the future by CAS:

TABLE 4: Electric Grid Emission Factors

Year	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Regional emission factor (MTCO2e/MWh)	0.4010502	0.4061386	0.3795461	0.3404675	0.3388742	0.3361012	0.3437698	0.4220527	0.4095980	0.3715102
Year	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
Regional emission factor (MTCO2e/MWh)	0.3668755	0.3712683	0.3545979	0.3621470	0.3530752	0.3551884	0.3239771	0.3264649	0.3010504	0.3545080
Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Regional emission factor (MTCO2e/MWh)	0.3617302	0.3201608	0.2973487	0.2891816	0.3027548	0.3124441	0.2971545	0.2812257	0.2576408	0.1898702
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Regional emission factor (MTCO2e/MWh)	0.1084224	0.1030013	0.0886471	0.0742929	0.0599387	0.0597731	0.0348407	0.0238254	0.0201063	0.0275437
Year	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
Regional emission factor (MTCO2e/MWh)	0.0622150	0.0616437	0.0623892	0.0477784	0.0392287	0.0414464	0.0279418	0.0257219	0.0144276	0.0009504

FIGURE 3: Electric Grid Emission Factors



Based on discussions during Workshop #1 it was agreed that CAS plant electricity purchases will conform with Executive Order No. 21-3; specifically, Section 3B which states that "By 2030, all electricity purchased and generated by the Executive Branch will be 100% zero carbon". As such, it will be assumed that starting in 2030 all electricity purchased by the plant will be 100% zero carbon. This assumption implies that dedicated zero carbon electric supply contracts will need to be procured in lieu of grid supplied power, which in accordance with Table 4 above, contains carbon in 2030 and beyond.

TABLE 5: Natural Gas Emission Factors

Natural Gas		
kg CO2/scf	kg CH4/scf	kg N2O/scf
0.054440	0.00000103	0.0000001

TABLE 6: RNG and H2 Emission Factors

	RNG (Landfill Gas)			RNG (Other Biomass Gases)			Green Hydrogen
Emission Type	kg CO2 /scf	kg CH4/scf	kg N2O/scf	kg CO2/scf	kg CH4/scf	kg N2O/scf	kg CO2e/kg
Combustion	0.00	1.55×10^{-6}	0.306×10^{-6}	0.00	2.10×10^{-6}	0.413×10^{-6}	2.00
Biogenic	0.02530	-	-	0.034100	-	-	2.00

Note: For RNG, where applicable, accounting for biogenic CO2 will be calculated on the basis of the above factors and noted as a sidebar.

Since the State requires that the future availability of any alternative fuels must also be considered, renewable natural gas (RNG) and green hydrogen (H2) are not considered viable options at this time due to the uncertainty surrounding their long term availability.

4.0 Utility Supply Options

This section provides an overview of market options for utility services required by the CAS including a summary of procurement methods for carbon free electricity, originally provided separately as part of Deliverable 6: Supply Side Evaluation Memo Report

4.1. Power Market Forecast

Our market price forecast is used to estimate the future cost of various decarbonization strategies under consideration. There are two components to the forecast:

- Base Supply: our 17 year forecast of grid power supply from either the utility or a 3rd party supplier.
- Renewable Energy Premium: the estimated incremental cost to completely offset the site's scope 2 carbon emissions using Class I Renewable Energy Credits (RECs).

The Base Supply forecast is derived from prevailing forward market rates for wholesale power in Connecticut, capacity, ancillaries and Connecticut's Renewable Portfolio Standard (RPS). Many of these subcomponents are highly susceptible to change based on underlying market conditions. The forecast extends to Year 17, based on available market projections. After Year 17, an annual escalation of 3% is assumed.

We assume Class I RECs are the most likely instrument the State would use to offset its scope 2 emissions. This is an acceptable compliance instrument under CT PURA regulations and it is consistent with state regulatory policy. We have considered an out-of-region "national green-e" REC option with a lower price point, but suspect there could be sensitivity around using RECs from markets outside of New England or that are not otherwise used for Connecticut RPS compliance purposes. We also considered power purchase agreements (ie., new project RECs and energy), however we determined that consumption at the site was too low to garner any commercial options at a reasonable price point. It's also worth noting that PPAs tend to require a fixed level of output for a longer term tenor (e.g., > 10 years), which doesn't fit well with the grid's declining emissions trend.[5]

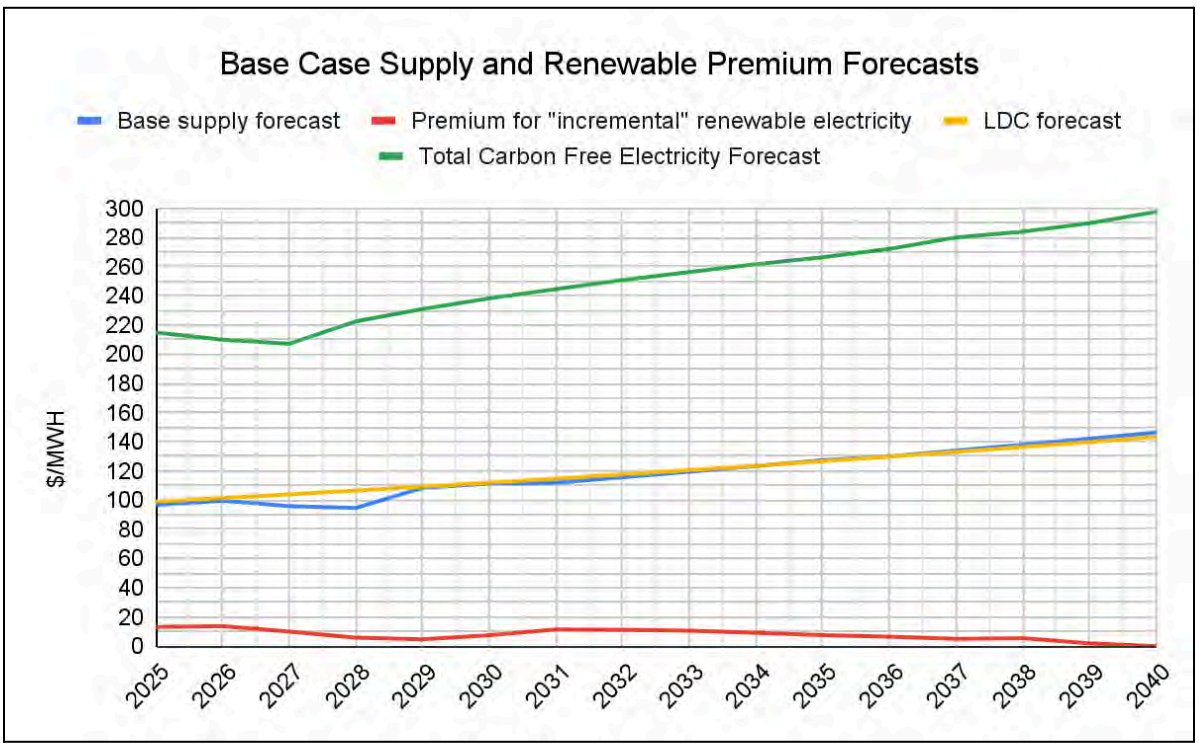
[5] A power purchase agreement is a mechanism that provides fixed revenue certainty to developers of renewable energy assets, which is often critical to financing and overall project viability. This fixed price period is typically over 10 years in duration. While there may be solutions for smaller buyers, such as through aggregation, the minimum acknowledged purchase quantity of most offsite PPAs is 5-10 MW, and Veolia's experience over the past few years indicates it may be 2-3x larger than this threshold due to limited projects in the region.
https://betterbuildingssolutioncenter.energy.gov/financing-navigator/option/power-purchase-agreement

https://www.bostonplans.org/documents/planning/policy-planning/zero-net-carbon-building-zoning-initiative/znc-bldg-zoning-renewable-energy-procurement-tag-r

For the calculation of the Renewable Energy Premium, we first quantified the carbon balance, in metric tons, that the site would need to offset from 2030 to 2040, the assumption being that the green purchases are superfluous thereafter as the electric supply must be carbon free under state law (see e.g, Public Act 22-5 (Senate Bill 10)[6]. To calculate the carbon balance, we used a CT power supply emissions factor forecast provided by DEEP. We also verified this using an alternative approach, which is to calculate the difference between the 100% offset goal and the projected state RPS % each year. The two approaches yielded fairly consistent results with respect to cost impact. It's worth noting that Connecticut's Tier 1 REC requirement under the RPS tops out at 40% in 2030 under current regulations, however Connecticut statute requires 100% carbon-free power by 2040. In the absence of regulation, we've therefore made a conservative assumption that the RPS will increase by 6% percent per year from 2030 to 2040. This ignores potential contracts with other carbon free resources such as nuclear and is therefore probably a conservative assumption. Finally, our forecast of the renewable energy premium, as well as our base case supply forecast, is heavily influenced by our forecast of the Class I RECs. There is limited liquidity in this market, however it is generally anticipated that prices will decline rapidly in the next 5 years–from $40 to roughly $20 per REC–as large offshore wind projects reach commercial operation.

The following plot shows base case and renewable energy premium forecasts including supply, delivery and premium for "incremental" renewable electricity:

FIGURE 4: Base Case Supply and Renewable Premium Forecasts



[6] https://www.cga.ct.gov/2022/act/pa/pdf/2022PA-00005-R00SB-00010-PA.pdf

- The blue curve ('Base supply forecast') represents the price forecast for electricity supply, whether that is through Eversource or a third party supplier. This electricity is generated from a mix of resources.
- The yellow curve ('LDC forecast') represents the local distribution company (LDC - Eversource) price forecast for delivery electrical supply to the CAS.
- The red curve ('Premium for "incremental" renewable electricity') represents the price forecast for obtaining the balance of carbon free electricity (the volume required beyond that which is supplied by Eversource through the RPS as described above.
- The green curve is the sum of all curves (i.e. the total cost of electricity) and is the forecast that is used in the study model to represent the price of electricity for the CAS

For scenario E.1.H- 100% Natural Gas Condensing Boilers the CAS Plant will continue to rely on natural gas boilers. For this scenario, we have also provided carbon mitigation options that assume the use of carbon offsets. Carbon offsets can be acquired from a large diversity of technologies, projects, and regions. There can also be a wide price range for these products. In our carbon offset price assumptions, we have used a midpoint of pricing received from various projects within the North American Improved Forestry Management category. Offsets should be secured from one of the leading certification and standards organizations, such as Gold Standard, Verra, or American Carbon Registry – which together are responsible for qualifying the majority of carbon credits generated in North America.[7] If carbon offsets are pursued as a financial offset tool, we highly recommend additional due diligence to ensure their source and overall use is consistent with state policy goals.

Per discussions with the State regarding the options for accounting for the potential purchase of offsets for carbon emissions at the CAS plant as capital costs rather than operating costs, it is likely that both the Class I REC and the carbon offset market structures would allow for that. Class I RECs applied to the carbon emissions associated with electricity are more typically delivered on an annual basis but they can be committed and purchased for multi-year terms. We see no reason why they could not be secured and accounted for as an annual capital expense. Carbon offsets applied to the carbon emissions associated with natural gas use at the CAS plant are generally longer term contracts (1 to 10 years) and could similarly be included as a capital expense with adjustments made as contracts expire and new ones are negotiated. A major risk to upfront commitments is that there will undoubtedly be deviations between estimated and actual quantities needed, however this can typically be addressed by remarketing excess or making spot market purchases for shortages. The remarketing of Class I RECs would be relatively straightforward as there is a reliable secondary market, however sales less than $10,000 per year would likely incur a modest trade premium. The remarketing of carbon offsets is less certain. Although possible, it is far less common as the market for any particular offset category is less stable and sell-side premiums could be significant.

4.2. Electricity Rate

According to Eversource, when the existing high tension service is decommissioned and a new lower tension service is established, the Large Time-of-Day (Rate 58) tariff will apply. From the plot above, the

[7] The World Bank. State and Trends of Carbon Pricing 2023.

green forecast line represents the sum of Eversource supply, their distribution costs and the premium the State can expect to pay to decarbonize the balance of electricity supplied by Eversorce.

This forecast can then be compared to other supply options such as renewable PPA's, on or offsite solar or utility based programs. Section 4.5 below provides an overview of such procurement options.

4.3. Natural Gas Utility Rate

The existing local utility's (Connecticut Natural Gas) applicable tariff structure for natural gas is the Large General Service (LGS) Customer rate, which is defined as a customer whose anticipated consumption is greater than 30,000 CCF per year. An estimated blended rate of $8.25 per MMBTU was used for this study.

4.4. Water Utility Rate

Water supplied to the CAS plant by the MDC water was calculated at a blended rate of $8.28 per CCF.

4.5. Defining Carbon Free Electricity Options

There are several options for the mitigation of carbon emission beyond making physical changes to energy consuming equipment which may include the following categories:

4.5.1 Renewable Energy Credits

Renewable Energy Credits (RECs) are environmental attributes associated with renewable energy production, uncoupled from physical delivery of electricity. A REC indicates ownership of the environmental attributes associated with 1 MWh of renewable energy production.

Power consumers can purchase equivalent quantities of RECs to match their scope 2 emissions in order to make qualifying claims about their actions to financially mitigate their carbon emissions. This methodology is central to carbon accounting frameworks such GHG Protocol, CDP, and others. Typically, carbon accounting frameworks allow for consideration of both active and passive measures. In other words, a site that purchases power from a region or state with a low-emissions profile, as is the expectation in Connecticut, will be able to account for that lower emissions rate in its baseline carbon profile before using RECs to offset the remaining carbon imbalance.

At a high level they fall into two categories:

- National Voluntary RECs
- Regional Compliance RECs

Both have well defined auditing processes in place to verify the authenticity of the certificate and to avoid double counting. National Voluntary RECs are the lowest cost REC available and the types of energy and regions can sometimes be defined, though they are typically sourced from the Midwest and Texas. Compliance RECs may also be used for compliance with state Regional Portfolio Standards (RPS). They carry higher prices but more with specificity and restrictions around location, technology types, in-service dates, and eligible tracking platforms. RECs are prevalent in their use across North America, likely due to standardized measurement and verification, and their origin as a public policy tool for state RPS goals.

4.5.2 Carbon Offsets

A carbon offset indicates comparable ownership rights associated with the abatement of 1 metric ton of CO2, from a wide variety of qualifying actions. Carbon offsets are more nuanced than RECs because of the wider variety of potential source projects, e.g. these range from sustainable forestry management to direct carbon capture to the flaring of methane gas release at wellheads. The measurement and verification standards for carbon credits are therefore more flexible and the parties involved in this function are more distributed. Most carbon offset projects develop their own unique measurement and verification plans, and while these are subject to third party verification, they are non-uniform. Therefore, carbon offsets are seldom used in state or municipal-administered programs. There is also a wide disparity in the type and quality of carbon offsets, both in actual and perceived terms, so there may be a higher public relations risk unless buyers are deliberate about the category and messaging pertaining to the offsets they choose.

It is also worth noting more broadly that while financial offset mechanisms such as RECs and carbon offsets may be generally acceptable by major carbon accounting frameworks, the State should carefully consider whether their use is consistent with the policy goals and public statements made on the subject. While there are many interpretations of acceptable pathways towards decarbonization, there is consensus that heavy reliance on RECs and offsets is not a long-term strategy. For this simple reason, some conventional mitigation frameworks, such as the Greenhouse Gas Mitigation Hierarchy, prioritize the functions of GHG avoidance, reduction, and replacement over financial measures such as RECs and offsets. We recognize there may be any number of constraints that the state must consider while weighing the alternative approaches. Veolia is therefore not proposing any prescriptive mitigation pathway or hierarchy, however we do wish to highlight that there may be qualitative and reputational differences between the solutions, particularly with respect to those involving heavy reliance on carbon offsets and RECs.

4.5.3 Power Purchase Agreements (PPAs)

Through PPAs customers contract directly for the power off-take of a renewable energy generator and settle power transactions through the Independent System Operator (ISO). They can be set up with multiple options either within a region or in another ISO:

- Operate as a wholesale participant within the ISO and establish a PPA with a regional renewable energy asset within the ISO
- Contractual relationship where supplier carves out part of a larger renewable project
- Renewable power outside of the respective ISO can be procured but will likely be a financial Contract for Differences structure
- Behind-the-Meter PPAs offset retail consumption relieve customer from owning and operating assets

4.5.4 Special Case Utility Programs

Many utilities have voluntary renewable energy options, both in restructured and vertically integrated territories with a range of opportunities made available by state policy:

- Virtual Net Metering contracts
- REC purchase or PPA purchase with consolidated billing options
- Account aggregation, wind, or battery tariff

The incumbent utility is typically the interface in these arrangements but not always and the agreements vary by utility and state. In many cases they do NOT transfer title to the customer so they must adhere to the buyer's internal sustainability goals.

4.5.5 Owned Assets

These are renewable assets owned and operated by the end-user and require capital outlays for construction/acquisition, as well as operating costs. Depending on the operating profile, user-owned generation can provide economic benefits and flexibility of options. Such assets can be developed behind-the-meter or off-site, however the latter will typically require counterparty involvement. Additionally, the area required to provide enough generation to fully offset usage can be a significant challenge for many urban buildings.

4.6. Installed Solar PV

Solar PV could potentially be installed at state-owned offtaker buildings either as a PPA or an owned asset. While the electricity generated would not flow directly to the CAS plant its attributes could be used to offset electrical consumption at the plant. Veolia conducted a high level desktop solar PV screening of state owned offtaker buildings and determined that approximately 2,200,000 kWh of electricity could potentially be generated (Appendix I). Additional considerations such as the age and and structural integrity of the roof at each location would need to be evaluated prior to determining the feasibility of any solar installation. Additional parking lot space beyond the 410-470 Capitol Avenue parking lots may potentially be available for solar canopies depending on availability of individual properties and the State’s selection process.

5.0 Operational Costs

5.1. Operations & Maintenance

Under an Operations and Maintenance Agreement dated October 7, 2020, IHI Power Services Corp. (IHI) provides operations and maintenance (O&M) services for the CAS plant. Using 2023 labor projections, annual O&M services provided by IHI are expected to be:

- Annual Operator Fee — $200,000 per year
- Labor — $415,829 per year
- Other Reimbursable Expenses — $1,000 per month (estimated)
    - Total — $627,829 per year

All three (3) of the State selected scenarios are anticipated to require a similar magnitude of O&M as currently provided, however there are differences as to the long term maintenance and repair costs based on the specific technology deployed. Therefore, the total operating and maintenance budget for each scenario includes the annual fee as is currently provided by IHI plus technology specific repair and maintenance values. The current annual fee of approximately $150,000 for the temporary plant has not been included in annual O&M as it has been assumed that temporary operations will be relocated to the CAS plant, the cost of which has been included in CapEx assumptions.

5.2. Eversource High Tension Service

The existing annual cost for Eversource high tension service O&M is $23,034 according to Eversource. Veolia requested in July 2023 that Eversource provide a projected annual cost for future service but this cost has not yet been provided. Therefore, the existing annual cost has been carried for all scenarios. It is not expected that the difference between the current annual O&M cost and future annual O&M cost for high tension service will have a significant impact on the analysis.

5.3. Repairs & Maintenance

Based on Veolia's experience operating similar plants an annual budget for each scenario has been assumed to cover performance guarantees, spare parts and repairs.

6.0 Supply Side Design Scenario Screening Results

Appendix A presents key performance figures for eighteen (18) of the scenarios evaluated by Veolia. Total installed heating and cooling capacity was based on agreed upon parameters in Deliverable 2: Total Energy Requirements/Design Basis Memo Report.

Of the twenty-two (22) scenarios evaluated by Veolia, four (4) scenarios were determined to be technologically infeasible due to constraints of the input heat source. The condenser water heat pump only solution (C.1.H & C.1.L) was limited by the volume of condenser water available and could not generate enough heat as a stand alone solution. Similarly, an air source pump only solution (C.3.H & C.3.L) could not generate enough heat on the coldest days to meet heating demand without a supplemental heat source.

Although the low temperature solution had a lower NPC in some scenarios, the difference between the high temperature solution and the low temperature solution NPC was generally only on the order of around 5% over the assumed project term of 30 years. Since there is a greater uncertainty regarding the cost of system improvements that may be required at the offtaker buildings and/or distribution systems to implement the low temperature solution, further evaluation may indicate that the high temperature solution is the lower NPC scenario. An estimated total cost of $45M to cover system improvements at all fifteen (15) buildings has been included in the CapEx for all low temperature hot water scenarios. The estimated total cost for eight (8) state-owned buildings is $30.35 million, while the estimated total cost for seven (7) private buildings is $14.65 million.

All or partial electric solutions have a higher Year 1 OpEx compared to all natural gas solutions due to the significantly higher cost per unit of energy for electricity versus natural gas, even after factoring in expected increases in equipment efficiency. Existing annual OpEx (fuel, O&M) is approximately $3.5M. However, when based on the anticipated increased future loads which are used in all of the above scenarios OpEx would be expected to increase to approximately $4.4M under baseline 2020 operating conditions. This does not include the estimated cost of equipment repairs, which has been included in the scenario evaluations.

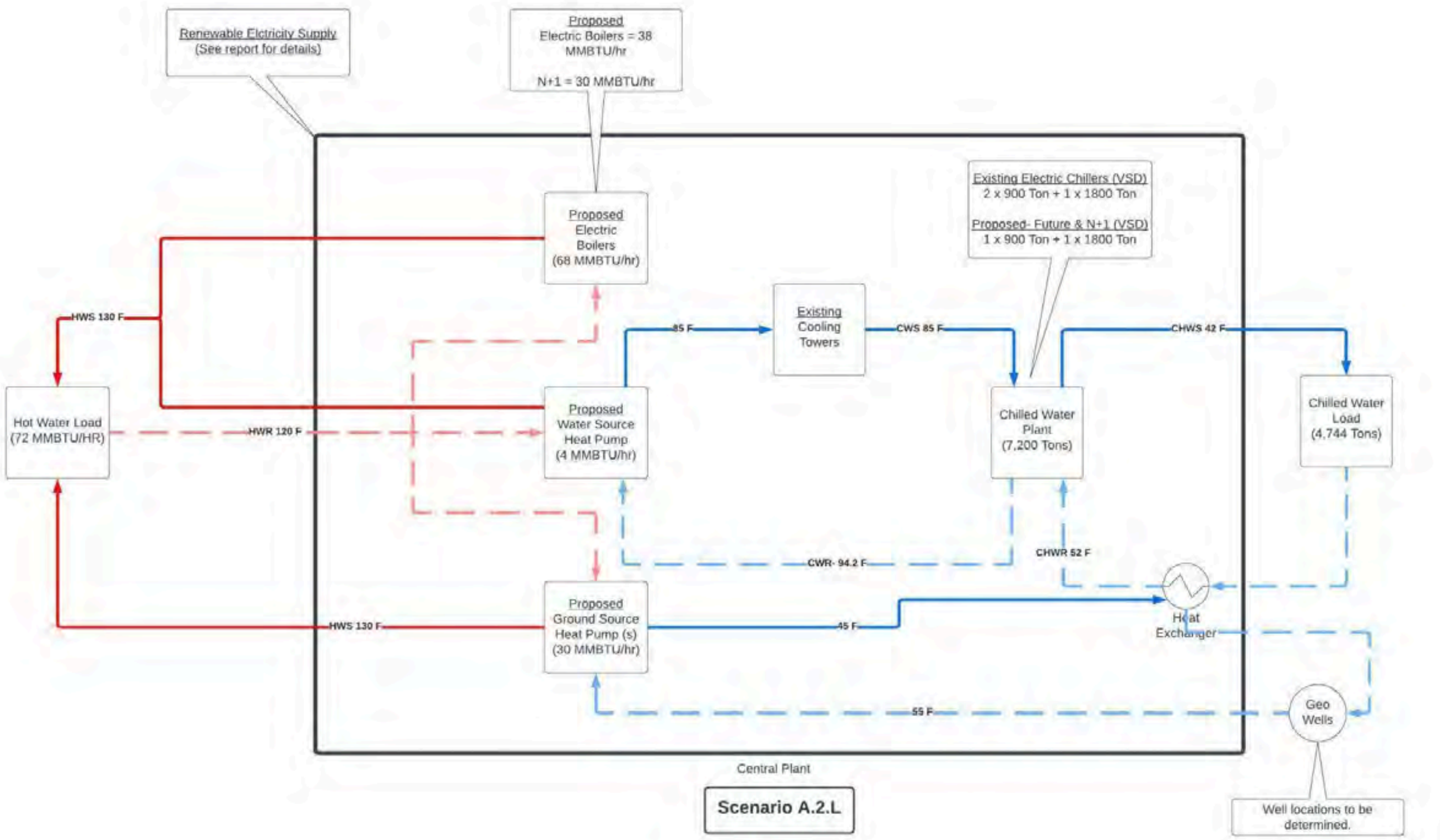
7.0 Selected Supply Side Design Scenario Definitions

The following are brief definitions of the three (3) selected CAS plant operating scenarios evaluated as part of this study and energy block diagrams for the selected scenarios are available in Appendix K. In Deliverable 7, definitions for each of the twenty-two (22) scenarios were provided.

7.1. Scenario A.2.L - Hybrid Ground Source Heat Pump & Electric Boiler (Low Temp)

Ground source heat pumps as the primary heat source, coupled with electric boilers and condenser water source heat pumps to provide hot water to the heating loop at reduced supply temperatures (approximately 130° F). The source for the ground source heat pump is geothermal wells, as showcased in Figure 5. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop. Therefore, the sizing of the water source heat pumps were limited by the condenser water leaving the water cooled chillers. While the ratio of ground source heat pumps to electric boiler capacity is adjusted to optimize financial benefit based on capital and operating expenses, the remaining heat demand will be met by these technologies.

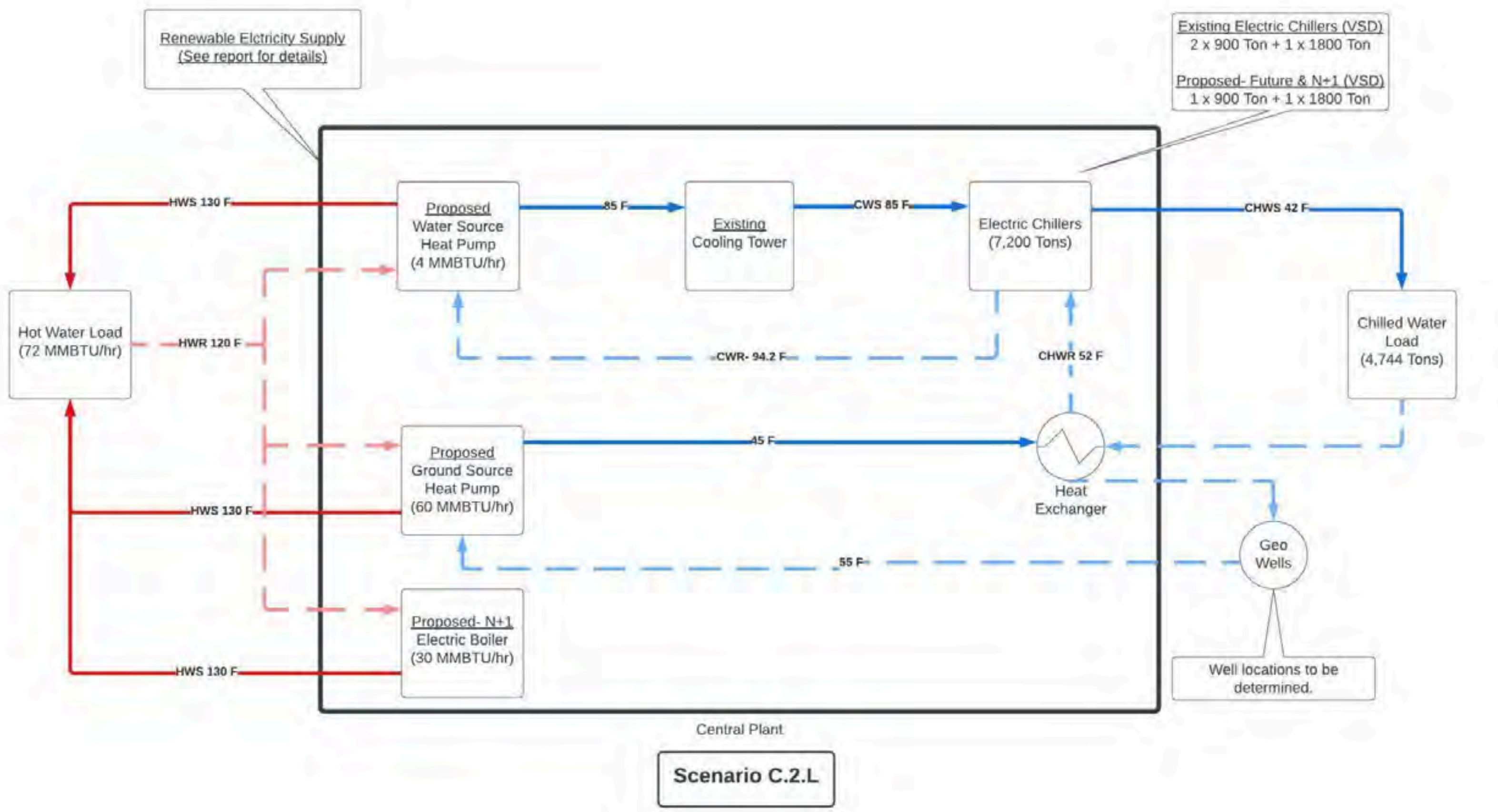
FIGURE 5: Block Diagram for A.2.L



7.2. Scenario C.2.L - Ground Source Heat Pump (Low Temp)

Ground source heat pumps as the primary heat source, coupled with condenser water source heat pumps to provide hot water to the heating loop at reduced supply temperatures (approximately 130° F). The ground source for the heat pump is geothermal wells, as showcased in Figure 6. The water source for the other heat pump is the existing condenser water loop that serves the water cooled chillers, therefore it restricts the size of the water source heat pump. The remaining heat load will be met by the ground source heat pump. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop.

FIGURE 6: Block Diagram for C.2.L



7.3. Scenario E.1.H - Natural Gas Boiler (High Temp)

Natural gas boilers provide hot water to the heating loop at existing supply temperatures (approximately 180° F to 200° F), as showcased in Figure 7. Electric chillers are used to serve the chilled water loop.

FIGURE 7: Block Diagram for E.1.H

7.4. Project Execution

Scenario E.1.H is expected to have a shorter timeframe for project execution than the other two (2) scenarios. E.1.H represents a simpler design and would likely require the least amount of additional engineering design and modifications to the existing plant to reach the project implementation stage. Scenarios A.2.L and C.2.L would be expected to have a significantly longer timeframe for project execution as application of district scale geothermal has been deployed at a limited number of locations in the U.S. Additionally, as described in Sections 9 and 10 below, additional study will be required before determining the feasibility of geothermal and converting to low temperature hot water delivery.

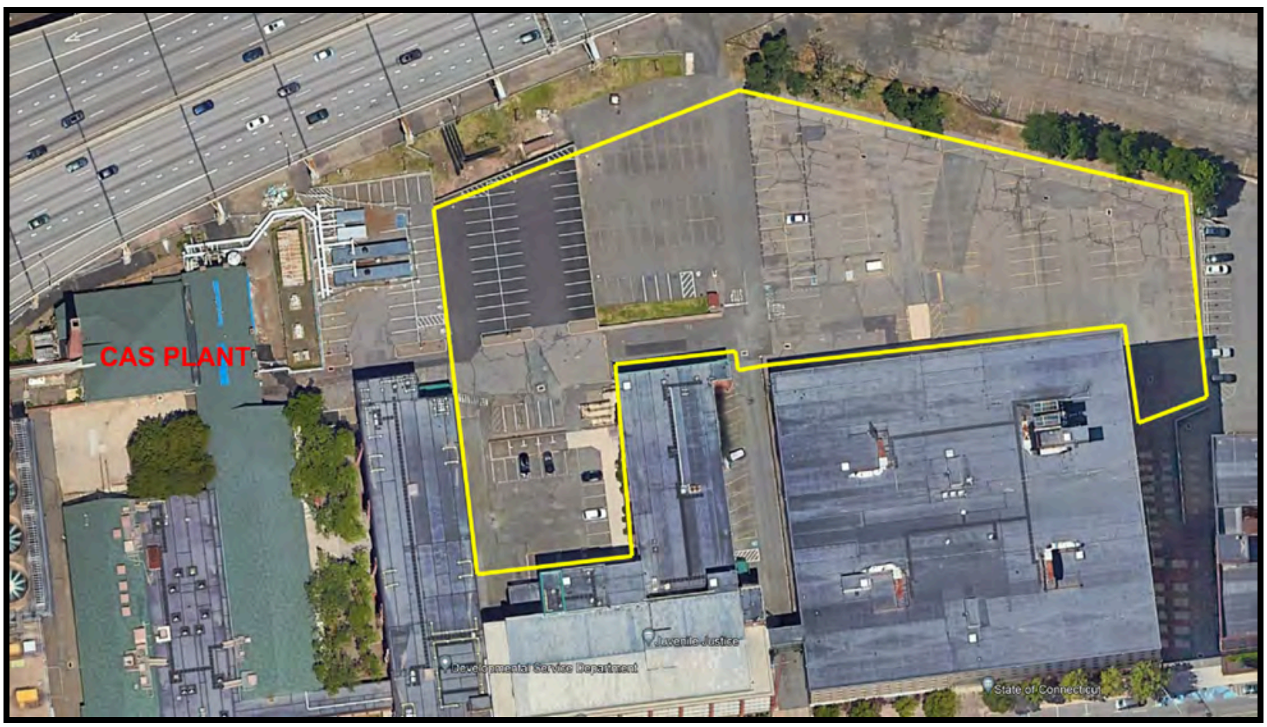
8.0 Supply Side Design Considerations

As part of Deliverable 6: Supply Side Evaluation Memo Report, a high level desktop screening was used to determine the feasibility of geothermal heat pumps. Publicly available tools such as the National Renewable Energy Laboratory (NREL) REopt® (https://reopt.nrel.gov/tool/) and Department of the Interior U. S. Geological Survey maps, as well as information from other sites where Veolia has been involved with geothermal studies and installations, was used to estimate required geothermal well layout area and depth, existing bedrock and water depths, and order of magnitude costs. Based on available information it appears that groundwater is present at approximately 10-20 feet below grade and bedrock is present at approximately 50-100 feet below grade at the site. Generally, the presence of groundwater and bedrock at relatively shallow depths such as these is conducive to geothermal installations.

Based on estimated required flow rates and peak heating demand requirements (as determined in Deliverable 2: Total Energy Requirements/Design Basis Memo Report) and using the open parking areas adjacent to the CAS plant to the east (Figure 8) it was estimated that, depending on subsurface conditions, 400-850 geothermal wells drilled to a depth of 1,500 feet could be required for the installation of a geothermal heat pump system. An installed cost for geothermal wells at the site, including drilling and piping, based on a cost per unit of energy recovery rate ($/MMBTU/Hr), was estimated based on a range of pricing from similar installations and this cost was applied to each geothermal scenario based on energy flow requirements.

In order to fully evaluate the feasibility of geothermal heat pumps at the site a detailed on-site subsurface investigation including test wells and pumping tests would be required in order to determine actual bedrock depth and composition, as well as other factors such as groundwater flow transmissivity through the bedrock. The results of this investigation would also determine the actual number, depth and cost of geothermal wells required for any geothermal heat pump installation. Should the area highlighted in Figure 8 not prove suitable for geothermal additional parking lots may potentially be available for geothermal depending on availability of individual properties and the State's selection process.

FIGURE 8: Proposed Geothermal Well Field Area



9.0 DEMAND SIDE DESIGN CONSIDERATIONS

The following demand side design considerations were originally provided as part of Deliverable 4: Demand Side Evaluation, which was intended to provide a summary of technical and financial feasibility of adopting demand side (load reduction) strategies as part of decarbonization efforts.

9.1. Low Temperature Hot Water Conversions

Based on the limited design documents provided, historic heating loop supply temperatures and discussions with site personnel it appears that the offtaker buildings' heating systems were generally designed for 180°F supply hot-water. While a lower hot-water supply (HWS) temperature (110°F -140°F) can increase the efficiency of the equipment which provides the hot water, providing the necessary heating capacity with a lower HWS temperature requires a higher fluid flow rate than a high HWS temperature. This may require additional hot-water coil rows in end-use HVAC equipment to provide the required heating capacity, as well as a higher fluid flow rate, which can affect the size of pipes, pumps, and valves, and can also increase pumping energy use. Buildings may also require weatherization to reduce heating loads and radiator redesign to meet building heating needs.

While efficiency increases at the CAS plant would not result in energy savings at the offtaker buildings themselves, and may actually increase electric use due to higher pumping rates, ensuring that the offtaker buildings could maintain heating capacity at a lower HWS temperature would be critical before deciding to lower the HWS temperature of the loop. The first step would likely be to conduct tests at each offtaker building in order to observe how its systems respond to reduced hot water temperatures and increased flow rates and determine if they are capable of meeting heating requirements under those supply conditions. Based on the age of most of the systems in the offtaker buildings and discussions with representatives from Trane, an HVAC equipment manufacturer, regarding similar low HWS temperature conversions projects it appears that the more likely outcome is that major HVAC equipment modifications and/or replacements would be required. Since 165 Capitol Avenue was the only offtaker building for which detailed HVAC design drawings were provided and it had recently undergone a major renovation of its systems using equipment from Trane, Trane was requested to provide budgetary pricing to upgrade major pieces of equipment (air handling units, variable air volume boxes, etc.) to operate at lower HWS temperatures of 130°F. Using this pricing Veolia developed an estimated $/square foot cost to upgrade major HVAC equipment at each of the offtaker buildings resulting in a total estimated cost of approximately $45M for all fifteen (15) buildings. The estimated total cost for eight (8) state-owned buildings is $30.35 million, while the estimated total cost for seven (7) private buildings is $14.65 million. This figure does not include potential costs for upgrading pumping systems or existing piping distribution networks in the buildings or the CAS loop itself and could vary significantly from actual costs developed from building testing and a full engineering study. Additional engineering studies and flow tests on the CAS loop would need to be performed before increasing flow and pressure in the system. Based on the history of documented leaks at existing flows and pressures it is possible that significant upgrades to the system could be required.

9.2. Potential Offtaker Energy Savings

In order to evaluate the opportunity within every building, the Energy Use Intensity (EUI) for each building and for each energy type was used to evaluate if the building is outside the normally accepted ranges for buildings of their type. For buildings that exceeded their expected EUI, potential savings was calculated as 50% of the difference between their current EUI and the proposed EUI average, then multiplied by their square footage to obtain the energy savings value in kBTU.

Total potential annual savings were estimated to be 12.6M kBTU of chilled water and 7.1M kBTU of hot water/steam, roughly 19% and 10% of the total chilled water and hot water/steam consumption, respectively, by all offtakers. These estimated savings are based only on comparisons relative to typical average EUIs. A more detailed investigation into individual building operating conditions may reveal higher or lower potential energy savings. Assuming that 25% of these reductions at individual buildings occur concurrently it can be estimated that a 5% reduction in existing peak chilled water peak demand (197 tons/hr) and 2.5% reduction in existing hot water/steam peak demand (1,137 MMBTU/hr) would result. However, without hourly offtaker data it is difficult to accurately estimate by how much these savings would reduce peak heating and cooling loads, and therefore the required peak capacity of the central plant.

10.0 Additional Findings

Although not included in the modeling and analyses in this report, the following subjects were reviewed as potential measures which could be further evaluated as part of future development considerations.

10.1. Thermal Storage For Selected Scenarios

Thermal storage technologies offer a comprehensive approach to meeting energy needs throughout the selected scenarios, taking into account critical elements such as capital expenditure (CapEx), operating expenditure (OpEx), and carbon emissions. In terms of CapEx, the flexibility offered by these systems to install smaller operating capacities to meet peak loads is tempered by the trade-off of potential reliability issues. When assessing thermal storage, decisions must be based on finding the ideal balance between cost-effectiveness and reliability.

OpEx can be optimized on the operational front in part due to the introduction of arbitrage by thermal storage systems. Through tactical energy storage during off-peak hours and strategic release at peak demand, users can profit from fluctuations in electricity prices, resulting in substantial cost savings over an extended period of time. In order to fully realize the financial advantages of this arbitrage technique, effective execution necessitates a deep comprehension of pricing structures, regulatory issues, and market conditions.

Thermal storage has considerable environmental advantages, one of which is its effect on carbon emissions. Since off-peak electricity is often generated from less carbon intensive energy sources, these systems help to reduce the overall carbon emission factor for the bulk power system. Furthermore, during times of increased energy usage, the capacity of thermal storage to reduce local peak demand may assist with lowering overall bulk power system demand, thereby reducing the need for higher-emission marginal generation. This dual benefit places thermal storage in line with initiatives to develop a more environmentally conscious energy landscape and positions it as a contributor to larger sustainability goals.

Aside from arbitrage on local distribution company tariffs (i.e. Eversource), there are currently no environmental / carbon market price mechanisms for contributing to the lowering of grid emission factors. Therefore, organizations must evaluate their specific operational needs and sustainability objectives when determining the appropriateness of storage. This all-encompassing strategy makes sure that thermal storage not only meets short-term energy needs but also long-term budgetary and environmental objectives.

To assess the value proposition of thermal storage, Veolia modeled a thermal energy storage system for the electric boiler scenario, A.2.L. We set the sizing of the storage to meet peak heating demand for eight hours, ensuring adequate capacity for optimal electricity arbitrage, based on expected Eversource tariff Time of Use (TOU) rate structure.

We found incorporating thermal energy storage resulted in the following benefits: peak power consumption was reduced by 5.4%, demonstrating effective peak shaving. Furthermore, annual electricity costs fell by 9%, emphasizing economic benefit in TOU arbitrage. Energy consumption increased by 5% during off-peak hours, suggesting that stored thermal energy was being used efficiently. In contrast, energy consumption significantly decreased by 38% during on-peak hours, highlighting the ability to shift loads.

Similar results are expected when thermal storage is implemented for the C.2.L scenario; however, the total savings potential will be less than the electric boiler option as the total electricity costs are lower. Conversely, an all-natural gas condensing boiler scenario E.1.H offers no benefits when thermal storage is incorporated; in fact, there is a significant increase in operating costs, therefore thermal storage is not recommended.

Veolia emphasizes the importance of thermal storage system sizing in order to achieve maximum performance and cost-effectiveness while keeping with the State's objectives.

10.2. Wastewater Heat Recovery

Wastewater heat recovery, an innovative and sustainable way to generate heat, makes use of the steady thermal energy found in wastewater. Estimates based on the U.S. Department of Energy test procedures for water heaters indicate that the equivalent of 350 billion kWh worth of hot water is discarded annually through drains.[8] Using sewage water—which is frequently obtained from municipal sewer systems—this technique captures heat and uses it to run a heat pump for a variety of heating purposes. Heat exchangers are commonly utilized in the system to facilitate the transfer of thermal energy from the sewage water to a closed-loop system. This closed-loop system then powers a heat pump to raise the temperature for heating purposes. However, there are certain hurdles to the use of wastewater heat recovery technology. The effectiveness and lifetime of heat exchange components can be affected by pollutants in sewage water, which presents a technical challenge that calls for strict maintenance procedures. In order to avoid corrosion or fouling and guarantee the smooth functioning of the system, filtration and purification methods become essential. An additional factor to take into account is the fluctuations in the temperature and flow rates of sewage water, as these can have an impact on the heat pump's efficiency. For dependable and efficient heat generation, system performance under various operating situations must be optimized, which requires careful system design. Along with technical

[8] Heat Recovery from Wastewater Using a Gravity-Film Heat Exchanger

difficulties, coordinating with sewage utilities and municipal authorities is necessary for the successful installation of sewage heat pump systems. Important procedures include working with existing infrastructure to ensure compatibility, negotiating access to sewage networks, and navigating regulatory requirements. Efficient cooperation among various stakeholders is essential for a smooth integration into the regional sewage infrastructure.

It is our understanding that a private proposal has been submitted to DEEP (and conveyed to DAS) that would apply wastewater heat recovery to the CAS loop, however Veolia has not received or reviewed this proposal.

10.3. Metering

Based on numerous metered data errors encountered during our analysis the State should conduct a thorough metering reading and billing assessment to support future design development efforts and to establish proper revenue recovery mechanisms. Veoila recommends the following specific actions related to meter reading and billing process as the State continues the redevelopment and repurposing of the CAS system:

1. Confirm calibration of the major metered energy streams into and out of the thermal generation equipment and distribution systems: Electricity, Chilled Water, Condenser Water, Hot Water and Makeup Water.
2. 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.

Accurate metered data will enable proper design basis and revenue recovery.

10.4. Low System Differential Temperatures

Metered temperature data shows extremely low differential temperatures between chilled and hot water supply and return that are causing inefficiencies and need to be addressed. According to Trane's submittal documentation for the plant's most recent 1,800 ton chilled replacement, the design chilled water supply is 42° F with a return of 52° F (10° F delta T) coupled with a condenser supply of 85° F and a return of 95° F (10° F delta T). Metered data shows an average of 3.4° F delta T for chilled water and a 4° F delta T for condenser water which is significantly lower than the design delta T of 10° F.

This situation, known as Low Delta T syndrome, results from the inefficient use of chilled and hot water at the point of consumption and leads to improper sequencing of chillers, boilers and pumps (operating more than necessary), consequently increasing energy consumption. The offtakers' secondary side of the Energy Transfer Stations (ETS) need to be better controlled to enable a higher delta T on the primary distribution system. There are several technical measures that can be implemented such as installation of pressure independent control valves (PICVs), better VFD control, correct coil sizing for the design delta T, and correct overall building management system (BMS) control.

As a supplier of thermal energy the State can implement financial measures to address low delta T in the form of penalties if return temperatures are not in line with required values, forcing end users to address the situation. Ignoring the low delta T situation can lead to an electrification basis of design that is rooted in higher than required capacities and increased long term operational costs.

11.0 Additional Assumptions

11.1. Chilled Water Production Costs

Returning the chilled water plant temperatures to chilled design conditions will improve performance and reduce operating costs. For purposes of this study, existing metered electrical consumption at each chiller is used as the status quo/business as usual/do nothing scenarios. For all future scenarios we have assumed the existing chilled water plant will be optimized (i.e. increased efficiency) and additional chilled water load will be served by a combination of new electric chillers and/or heat pumps, depending on the scenario at hand.

11.2. Hot Water Production Costs

Returning the hot water plant temperatures to design conditions will improve performance and reduce operating costs. For purposes of this study, 2020 was used as a base operating year with the assumption that, from a carbon and cost standpoint, the steam boilers provide hot water to the system. We acknowledge current hot water boilers (2021-present) as a temporary solution, therefore capturing operating and carbon costs of this configuration would not provide the State a representative comparative analysis.

APPENDIX A

Full List of Scenario Results

Notes:

1. All costs are in millions of dollars. Except variables with asterisks (*).
2. 100% Condenser water heat pump scenarios (C.1.H & C.1.L) and 100% air source heat pump scenarios (C.2.H & C.2.L) were determined to not be feasible and are not included in this table.
3. MTCO2e - metric tons of carbon dioxide equivalent
4. Baseline carbon emissions based on 2020 plant operating conditions and future projected plant loads as outlined in Deliverable 2: Total Energy Requirements/Design Basis Memo Report.
5. Unit Cost of Carbon Reduction based on 30-Year NPC divided by carbon reduction compared to baseline carbon emissions.
6. All costs presented in this table are commensurate with the level of project definition and have an expected range of accuracy between -30% to 50%. Low temperature and geothermal scenarios likely will have the highest CapEx uncertainty and require the most additional study to determine feasibility.

APPENDIX A (Continued) : Full List of Scenario Results

Scenario	A.1.H	A.1.L	A.2.H	A.2.L	A.3.H	A.3.L
Description	Condenser Water Source HP w/ Electric Boilers	Condenser Water Source HP w/ Electric Boilers	Condenser & Ground Source HP w/ Electric Boilers	Condenser & Ground Source HP w/ Electric Boilers	Condenser & Air Source HP w/ Electric Boilers	Condenser & Air Source HP w/ Electric Boilers
Supply Temperature	High	Low	High	Low	High	Low
CapEx	$19.9	$58.4	$43.4	$78.4	$29.0	$62.7
CapEx w/ ITC	$19.9	$58.4	$36.2	$72.2	$29.0	$62.7
Year 1 OpEx (w/ SC-CO2)	$11.7	$11.3	$10.2	$7.2	$10.8	$8.3
Year 1 OpEx (w/ RECs/Carbon Offsets)	$11.4	$10.9	$9.9	$7.0	$10.5	$8.1
Year 1 OpEx (w/o SC-CO2, RECs or Carbon Offset)	$10.7	$10.3	$9.4	$6.7	$9.9	$7.7
NPC (30-Year w/ SC-CO2 & ITC)	$298	$324	$279	$243	$286	$259
NPC (30-Year w/ RECs/Carbon Offsets & ITC)	$295	$321	$277	$241	$283	$257
NPC (30-Year w/o SC-CO2, RECs or Carbon Offsets & w/ ITC)	$290	$317	$273	$238	$279	$254
Lifetime Carbon (30-Year MTCO2e)	29,852	28,714	23,561	16,001	25,019	19,231
Baseline Carbon (30-Year MTCO2e)[4]	400,557	400,557	400,557	400,557	400,557	400,557
Carbon Reduction from Baseline (30-Year MTCO2e)	370,705	371,843	376,996	384,556	375,538	381,326
Unit Cost of Carbon Reduction ($/MTCO2e w/SC-CO2)[5] *	$804	$871	$740	$632	$762	$679
Unit Cost of Carbon Reduction ($/MTCO2e w/ RECs/Carbon Offsets)[5] *	$796	$863	$735	$627	$754	$674
Unit Cost of Carbon Reduction ($/MTCO2e w/o SC-CO2, RECs or Carbon Offset)[5] *	$782	$853	$724	$619	$743	$666

APPENDIX A (Continued) : Full List of Scenario Results

Scenario	B.1.H	B.1.L	C.2.H	C.2.L	D.1.H	D.1.L
Description	Electric Boilers	Electric Boilers	Ground Source HP	Ground Source HP	Condenser Water Source HP w/ Natural Gas Boilers	Condenser Water Source HP w/ Natural Gas Boilers
Supply Temperature	High	Low	High	Low	High	Low
CapEx	$19.1	$58.1	$54.1	$97.5	$20.7	$59.3
CapEx w/ ITC	$19.1	$58.1	$43.3	$85.3	$20.7	$59.3
Year 1 OpEx (w/ SC-CO2)	$12.9	$13.0	$10.0	$7.5	$8.2	$7.4
Year 1 OpEx (w/ RECs/Carbon Offsets)	$12.5	$12.6	$9.8	$7.3	$8.7	$7.9
Year 1 OpEx (w/o SC-CO2, RECs or Carbon Offset)	$11.8	$11.9	$9.3	$7.0	$5.7	$5.0
NPC (30-Year w/ SC-CO2 & ITC)	$325	$365	$282	$262	$205	$222
NPC (30-Year w/ RECs/Carbon Offsets & ITC)	$321	$362	$280	$261	$235	$251
NPC (30-Year w/o SC-CO2, RECs or Carbon Offsets & w/ ITC)	$316	$356	$276	$258	$164	$182
Lifetime Carbon (30-Year MTCO2e)	33,330	33,649	21,829	15,095	202,889	195,982
Baseline Carbon (30-Year MTCO2e)[4]	400,557	400,557	400,557	400,557	400,557	400,557
Carbon Reduction from Baseline (30-Year MTCO2e)	367,227	366,908	378,728	385,462	197,668	204,575
Unit Cost of Carbon Reduction ($/MTCO2e w/SC-CO2)[5] *	$885	$995	$745	$680	$1,037	$1,085
Unit Cost of Carbon Reduction ($/MTCO2e w/ RECs/Carbon Offsets)[5] *	$874	$987	$739	$677	$1,189	$1,227
Unit Cost of Carbon Reduction ($/MTCO2e w/o SC-CO2, RECs or Carbon Offset)[5] *	$861	$970	$729	$669	$830	$890

APPENDIX A (Continued) : Full List of Scenario Results

Scenario	D.2.H	D.2.L	D.3.H	D.3.L	E.1.H	E.1.L
Description	Ground Source HP w/ Natural Gas Boilers	Ground Source HP w/ Natural Gas Boilers	Air Source HP w/ Natural Gas Boilers	Air Source HP w/ Natural Gas Boilers	Natural Gas Boilers	Natural Gas Boilers
Supply Temperature	High	Low	High	Low	High	Low
CapEx	$43.3	$78.8	$33.8	$65.6	$20.0	$59.0
CapEx w/ ITC	$36.1	$72.7	$33.8	$65.6	$20.0	$59.0
Year 1 OpEx (w/ SC-CO2)	$10.3	$7.3	$10.4	$7.6	$7.9	$7.7
Year 1 OpEx (w/ RECs/Carbon Offsets)	$10.1	$7.2	$10.4	$7.7	$8.7	$8.5
Year 1 OpEx (w/o SC-CO2, RECs or Carbon Offset)	$9.3	$6.5	$8.9	$6.4	$4.7	$4.7
NPC (30-Year w/ SC-CO2 & ITC)	$280	$244	$276	$241	$194	$228
NPC (30-Year w/ RECs/Carbon Offsets & ITC)	$281	$247	$286	$251	$236	$266
NPC (30-Year w/o SC-CO2, RECs or Carbon Offsets & w/ ITC)	$269	$235	$256	$223	$137	$175
Lifetime Carbon (30-Year MTCO2e)	46,397	40,858	94,358	83,994	276,673	257,498
Baseline Carbon (30-Year MTCO2e)[4]	400,557	400,557	400,557	400,557	400,557	400,557
Carbon Reduction from Baseline (30-Year MTCO2e)	354,160	359,699	306,199	316,563	123,884	143,059
Unit Cost of Carbon Reduction ($/MTCO2e w/SC-CO2)[5] *	$791	$678	$901	$761	$1,566	$1,594
Unit Cost of Carbon Reduction ($/MTCO2e w/ RECs/Carbon Offsets)[5] *	$793	$687	$934	$793	$1,905	$1,859
Unit Cost of Carbon Reduction ($/MTCO2e w/o SC-CO2, RECs or Carbon Offset)[5] *	$760	$653	$836	$704	$1,106	$1,223

APPENDIX B

Deliverable 1: Client Kickoff Workshop #1 Memo Report

June 30, 2023

Noel Petra
Managing Director
Strategic Redevelopment
Real Estate & Construction Services
Department of Administrative Services
450 Columbus Boulevard, Suite 1301
Hartford, CT 06103
Noel.Petra@ct.gov

SUBJECT: **Contract No.: OC-DCS-ENGY-0030 Task No. 3**
Deliverable 1: Client Kickoff Workshop #1 Memo Report

Dear Noel,

Veolia has prepared the following memo report as Deliverable 1: Client Kickoff Workshop #1 for the CAS Decarbonization Project. This is the first of eight (8) deliverables under Contract No.: OC-DCS-ENGY-0030 Task No. 3. The purpose of this initial working session was to define the list of assumptions, scenarios and rank and scoring metrics to be used in the preliminary analysis to support final study selection(s). Carbon related assumptions such as the social cost of carbon, discount rate, grid emission factor forecasts, and cost effective carbon reduction definitions and others required as part of a life cycle cost analysis would be identified and defined during and following the workshop. The workshop was also an opportunity for the State of Connecticut (the "State") to convey any other scenarios or configurations to include in the study. This memo serves to memorialize agreed upon study assumptions, inputs, parameters, definitions, scenarios required for the analyses being conducted as part of the CAS Decarbonization Project.

Supply Side Design Scenarios

The following table defines the supply side scenarios and energy supply options for the generation of thermal heating and cooling products. The fuels considered to feed these supply side technologies (i.e. raw energy supply mix) include conventional natural gas, renewable natural gas, renewable fuels, geothermal, and renewable electricity.

TABLE 1: Supply Side Design Scenarios

Scenario	Description	Fuel(s)
A	Hybrid of Heat Pumps & Electric Boilers	Renewable Electricity
B	100% Electric Boilers	Renewable Electricity
C	100% Heat Pumps	Renewable Electricity
D	Hybrid of Heat Pumps & Natural Gas Condensing Boilers	Renewable Electricity, Conventional Natural Gas & Renewable Fuels/H2 ready
E	100% Natural Gas Condensing Boilers	Conventional Natural Gas & Renewable Fuels/H2 ready

The evaluation of heat pumps will include ground source, water source and air source.

Demand Side Design Scenarios

The demand side scenarios in the following table outlines the range of load requirements and potential efficiency measures for each of the end users.

TABLE 2: Demand Side Design Scenarios

Demand Side Design Scenarios	1	2	3
Description	Reduce loads via energy efficiency at public and private facilities and reduce heating supply temperature	Reduce loads via energy efficiency at public facilities and keep heating supply temperature as is	Keep loads and heating supply temperature as is
Systems Impacted	Public & Private demand side, distribution and supply side systems	Public demand side and supply side systems	Supply side systems

Social Cost of Carbon (SC-CO2)

As defined by the US EPA, the SC-CO2 is a measure, in dollars, of the long-term damage done by a ton of carbon dioxide (CO_2) emissions in a given year. This dollar figure also represents the value of damages avoided for a small emission reduction (i.e., the benefit of a CO2 reduction). During discussion with the State it was determined that the State's SC-CO2 is still being developed. As such, it was agreed that until a State specific SC-CO2 has been provided, Veolia would use the following EPA SC-CO2 value for 2022 as a placeholder in its calculations. These values were obtained from Table 4.2.1 of the EPA's September 2022 *"Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances"* (https://www.epa.gov/system/files/documents/2022-11/epa_scghg_report_draft_0.pdf) using a discount rate of 1.5%.

TABLE 3: Social Cost of Carbon

Emission Year	**SC-CO2** (2020 dollars per metric ton of CO2) (Discount Rate: 1.5%)
2022	$346

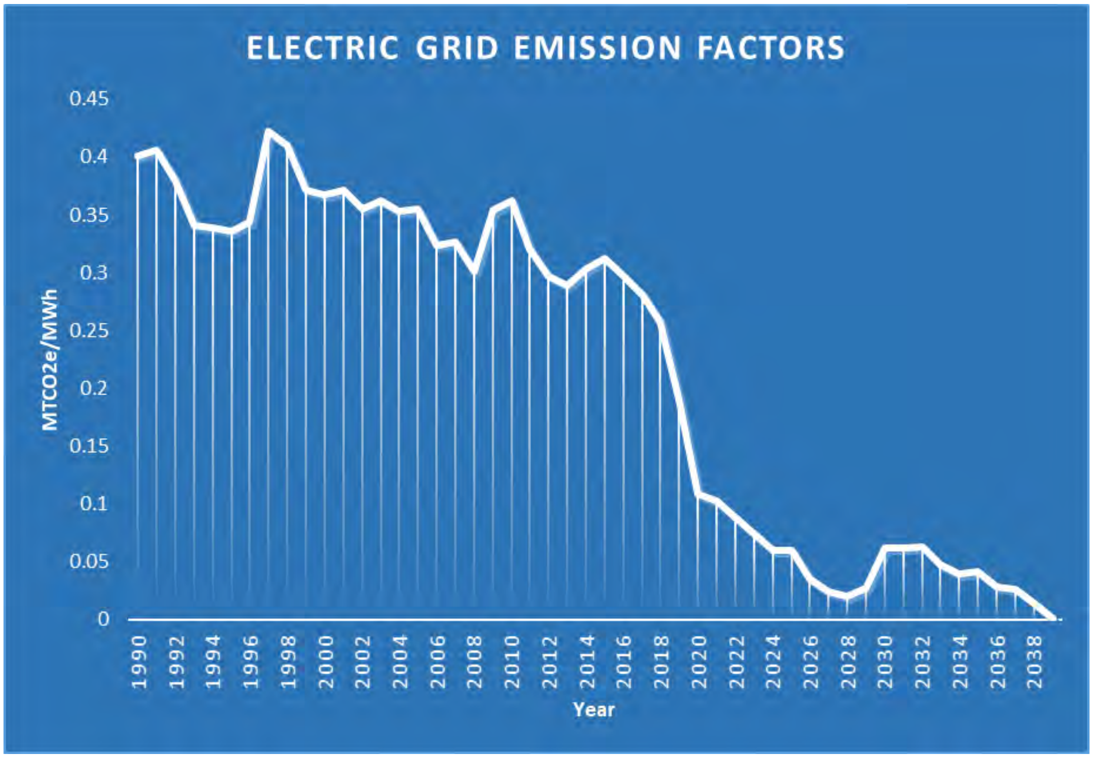
All financial analyses will be presented both with and without the SC-CO2 as a financial consideration.

Emissions Factors

The following emissions factors provided by the State will be used to calculate the potential emissions for various fuel that have been used in the past and may be used in the future by CAS:

TABLE 4: Electric Grid Emission Factors

Year	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**
Regional emission factor (MTCO2e/MWh)	0.4010502	0.4061386	0.3795461	0.3404675	0.3388742	0.3361012	0.3437698	0.4220527	0.4095980	0.3715102
Year	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
Regional emission factor (MTCO2e/MWh)	0.3668755	0.3712683	0.3545979	0.3621470	0.3530752	0.3551884	0.3239771	0.3264649	0.3010504	0.3545080951
Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Regional emission factor (MTCO2e/MWh)	0.3617302	0.3201608	0.2973487	0.2891816	0.3027548	0.3124441	0.2971545	0.2812257	0.2576408	0.1898702
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Regional emission factor (MTCO2e/MWh)	0.1084224	0.1030013	0.0886471	0.0742929	0.0599387	0.0597731	0.0348407	0.0238254	0.0201063	0.0275437
Year	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
Regional emission factor (MTCO2e/MWh)	0.0622150	0.0616437	0.0623892	0.0477784	0.0392287	0.0414464	0.0279418	0.0257219	0.0144276	0.0009504



Based on discussions during the workshop it was agreed that CAS plant electricity purchases will conform with Executive Order No. 21-3; specifically, Section 3B which states that "By 2030, all electricity purchased and generated by the Executive Branch will be 100% zero carbon". As such, it will be assumed that starting in 2030 all electricity purchased by the plant will be 100% zero carbon. This assumption implies that dedicated zero carbon electric supply contracts will need to be procured in lieu of grid supplied power, which in accordance with Table 4, contains carbon in 2030 and beyond. be

TABLE 5: Natural Gas Emission Factors

Natural Gas		
kg CO2/gal	kg CH4/gal	kg N2O/gal
0.054440	0.00000103	0.0000001

TABLE 6: RNG and H2 Emission Factors

	RNG (Landfill Gas)			RNG (Other Biomass Gases)			Green Hydrogen
Emission Type	kg CO2 /scf	kg CH4/scf	kg N2O/scf	kg CO2 /scf	kg CH4/scf	kg N2O/scf	kg CO2e/kgH2
Combustion	0.00	0.00000155	0.000000306	0.00	0.00000210	0.000000413	2.00
Biogenic	0.02530	-	-	0.034100	-	-	2.00

Note: For RNG, where applicable, accounting for biogenic CO2 will be calculated on the basis of the above factors and noted as a sidebar.

Since the State requires that the future availability of any alternative fuels must also be considered, renewable natural gas (RNG) and green hydrogen are not considered viable options at this time due to the uncertainty surrounding their long term availability. However, Veolia will evaluate natural gas burning equipment that is RNG and hydrogen “ready” and will include market outlooks, define the carbon lifecycle of RNG and green hydrogen, as well as a brief narrative on each as an option. Although a full financial analysis will not be conducted, a comparison of potential emissions should natural gas burning equipment be converted to RNG or hydrogen in the future will be included.

Discount Rate

A discount rate is the rate of return used to discount future cash flows back to their present value. This rate is often a Weighted Average Cost of Capital (WACC), required rate of return, or the cost of debt (e.g. bond rate). For the financial analyses conducted as part of this study the State bond rate of **3.77%** will be used as a placeholder for the discount rate until another rate is provided by the State.

Escalation Factor

An annual escalation factor of 2.5% will be used for all commodities, including but not limited to the following:

- Electricity cost
- Natural gas cost
- Water cost
- Labor costs
- Equipment costs

This is roughly equivalent to the US Treasury 20-year Breakeven Inflation Rate of 2.48% (https://fred.stlouisfed.org/series/T20YIEM).

APPENDIX C

Deliverable 2: Total Energy Requirements/Design Basis Memo Report

June 30, 2023

Noel Petra
Managing Director
Strategic Redevelopment
Real Estate & Construction Services
Department of Administrative Services
450 Columbus Boulevard, Suite 1301
Hartford, CT 06103
Noel.Petra@ct.gov

SUBJECT: **Contract No.: OC-DCS-ENGY-0030 Task No. 3**
Deliverable 2: Total Energy Requirements/Design Basis Memo Report

Dear Noel,

Veolia has prepared the following memo report as Deliverable 2: Total Energy Requirements/Design Basis for the CAS Decarbonization Project. This is the second of eight (8) deliverables under Contract No.: OC-DCS-ENGY-0030 Task No. 3. The purpose of this deliverable is to define the historical, existing and planned supply and demand metered thermal load data for use in the decarbonization basis of design. Data collection was conducted through conference calls, requests for information and site visits.

Historic Loads

Veolia reviewed CAS plant steam and chilled water production hourly data for the years 2019 and 2020. The data was compiled for Veolia by plant staff from the plant's PI data historian. A summary of the annual steam and chilled water produced by the plant in 2019 and 2020 for offtaker use is presented below:

TABLE 1: CAS Plant Production For Offtaker Use Data

	2019	2020
Total Steam (MMBTU)	93,819	90,817
Peak Steam Load (MMBTU/hr)	49.96	40.05
Total CHW (Ton-Hr)	4,672,724	4,903,471
Peak CHW (Ton/Hr)	3,020	3,519
Total Steam & CHW (MMBTU)	149,892	149,659

As shown in Table 1, total energy sent to the CAS offtakers was very similar in 2019 and 2020 despite the beginning of Covid-19 restrictions in 2020. Hourly load profiles and load duration curves for steam and chilled water for 2020 are depicted in Appendix A and Appendix B, respectively.

Monthly meter data for the fifteen (15) offtaker buildings was provided for the period July 2019 to April 2023. Annual chilled water and hot water usage for the offtaker buildings for 2020 is presented in the table below.

TABLE 2: 2020 Offtaker Use Data

Building Description	Building Address	2020	
		Annual CHW (MMBtu)	Annual HW (MMBtu)
Legislative Office Building	300 Capitol Ave (LOB)	8,313	7,408
Underwood Tower A(M24-6PP)	2 Park Place (P.P. Tower A)	4,001	8,268
Underwood Tower B (M12-24PP)	24 Park Place (P.P. Tower B)	2,390	6,606
Bushnell Theater	166 Capitol Ave (Bushnell)	722	0
United Way	30 Laurel St (United Way)	410	1,147
18/20 Trinity	18~20 Trinity St (Ethics)	974	2,685
30 Trinity	30 Trinity St (Sec. of State)	854	1,897
231 Capitol Library	231 Capitol Ave (Judicial/Supreme Court)	8,331	4,791
Armory	360 Broad St (Armory)	2,351	4,185
Capitol Place	21 Oak St (CEA)	4,524	2,121
79 Elm Street	79 Elm St (DEEP)	3,175	2,928
75 Elm Street	75 Elm St (Judicial)	927	1,238
Cap Ave Complex	410 - 470 Capitol Ave (OPM)	20,446	13,879
101 Lafayette	101 Lafayette (Judicial)	2,156	0
165 Capitol Ave (New circa 2017)	165 Capitol Ave (State Office Building)	5,159	7,692

Because of the similarity of annual plant output to the CAS offtakers in 2019 and 2020 and the lack of a full year of offtaker meter data for 2019, the year 2020 was selected as the representative CAS plant production/offtaker use period with the most complete data set. This is also the most recent full year before the pumphouse explosion in August 2021, after which a temporary hot water system was installed and plant operations were no longer representative of historic production. Hourly meter for the offtakers was requested but was unavailable for 2020. All energy production and use data used in analyses for this study will be normalized for heating degree days (HDD) and cooling degree days (CDD) to account for seasonal temperature variations.

Existing & Future Demand Loads

Existing and future total peak demand for hot water and chilled water was calculated based on schematics of existing and future loads prepared by the State[1]. A summary of these schematics is shown in the following table:

[1] State of CT provided markups to RMF's Hot Water and Chilled Water Schematic drawings to depict future and future thermal demands.

TABLE 3: Existing & Future Demand Loads

Building Description	Building Address	CHW Demand (Tons)	CHW Demand Status	HW Demand (MBH)	HW Demand Status
Legislative Office Building	300 Capitol Ave (LOB)	546	Existing	3,202	Existing
Underwood Tower A(M24-6PP)	2 Park Place (P.P. Tower A)	154	Existing	4,455	Existing
Underwood Tower B (M12-24PP)	24 Park Place (P.P. Tower B)	120	Existing	3,550	Existing
Bushnell Theater	166 Capitol Ave (Bushnell)	76	Existing	708	Future
United Way	30 Laurel St (United Way)	27	Existing	482	Existing
18/20 Trinity	18~20 Trinity St (Ethics)	38	Existing	1,858	Existing
30 Trinity	30 Trinity St (Sec. of State)	59	Existing	1,791	Existing
231 Capitol Library	231 Capitol Ave (Judicial/Supreme Court)	279	Existing	3,363	Existing
Armory	360 Broad St (Armory)	128	Existing	2,096	Existing
Capitol Place	21 Oak St (CEA)	193	Existing	928	Existing
79 Elm Street	79 Elm St (DEEP)	189	Existing	1,928	Existing
75 Elm Street	75 Elm St (Judicial)	53	Existing	1,215	Existing
Cap Ave Complex	410 - 470 Capitol Ave (OPM)	910	Existing	6,599	Existing
101 Lafayette	101 Lafayette (Judicial)	359	Existing	5,029	Future
165 Capitol Ave (New circa 2017)	165 Capitol Ave (State Office Building)	800	Existing	14,000	Existing
State Capitol	210 Capitol Ave	0	Future	10,000	Future
	80 Washington St	154	Future	2,160	Future
	90 Washington St	226	Future	3,164	Future
Supreme Court	95 Washington St (Superior Court)	368	Future	5,155	Future
	100 Washington St	65	Future	906	Future
		4,744	**Total CHW Demand**	**72,589**	**Total HW Demand**
		3,931	***Existing CHW Demand***	***45,467***	***Existing HW Demand***
		813	***Future CHW Demand***	***27,122***	***Future HW Demand***

The Total CHW Demand and Total HW Demand from Table 3 are considered to be representative of all offtaker loads which are currently or planned to be served by the CAS plant. These demand values will be used to size proposed equipment for all operational scenarios and to determine equipment requirements for N+1 redundancy to provide resilience that ensures system availability in the event of component failure. It should be noted that these values are design demand loads and may not necessarily represent actual demand at each building. While the billing meters at each building are capable of recording and exporting the hourly data needed to calculate demand, currently that data can only be accessed by connecting directly to the meters at the buildings. Once remote data logging capability is reestablished full annual hourly data for each building can be recorded and used to determine actual hourly loads and demand.

Attachments:

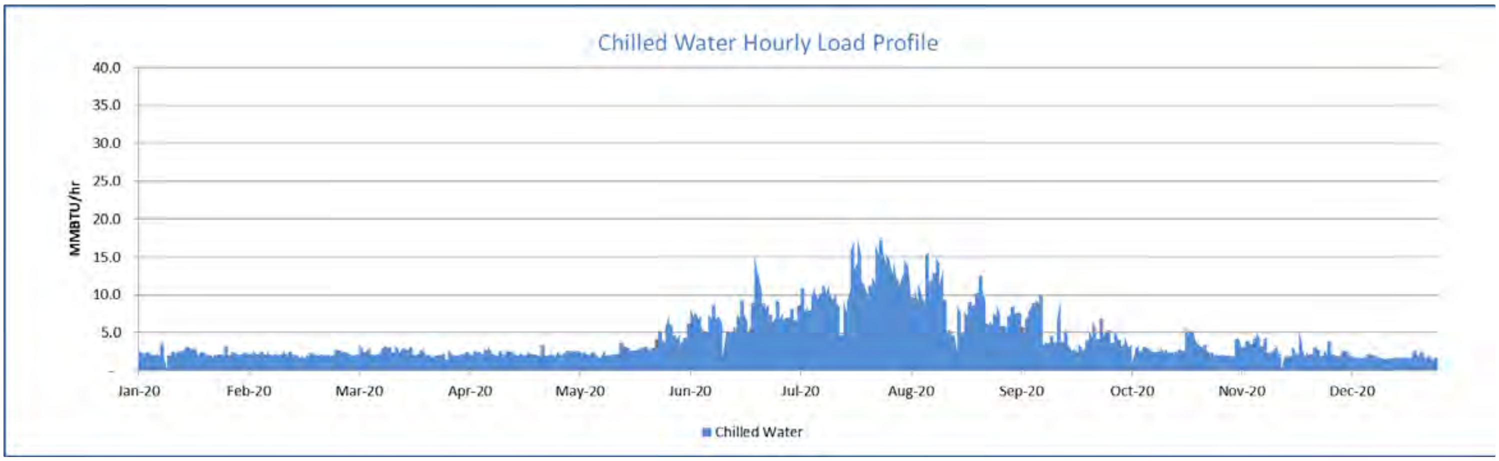
Appendix A: Hourly Load Profiles

Appendix B: Load Duration Curves

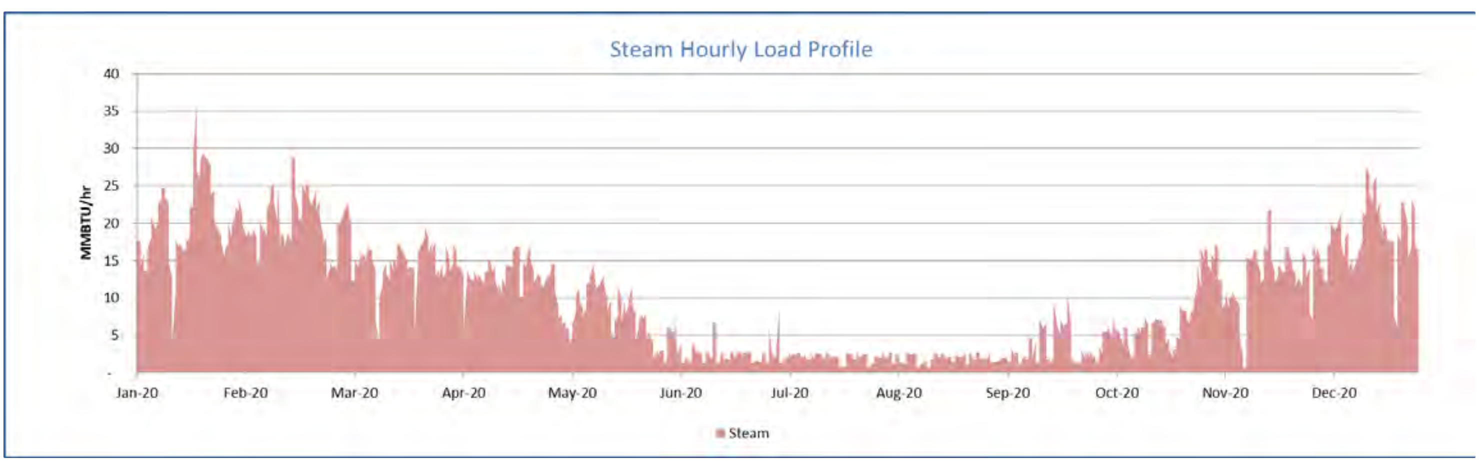
APPENDIX A

Hourly Load Profiles

2020 Chilled Water Hourly Load Profile



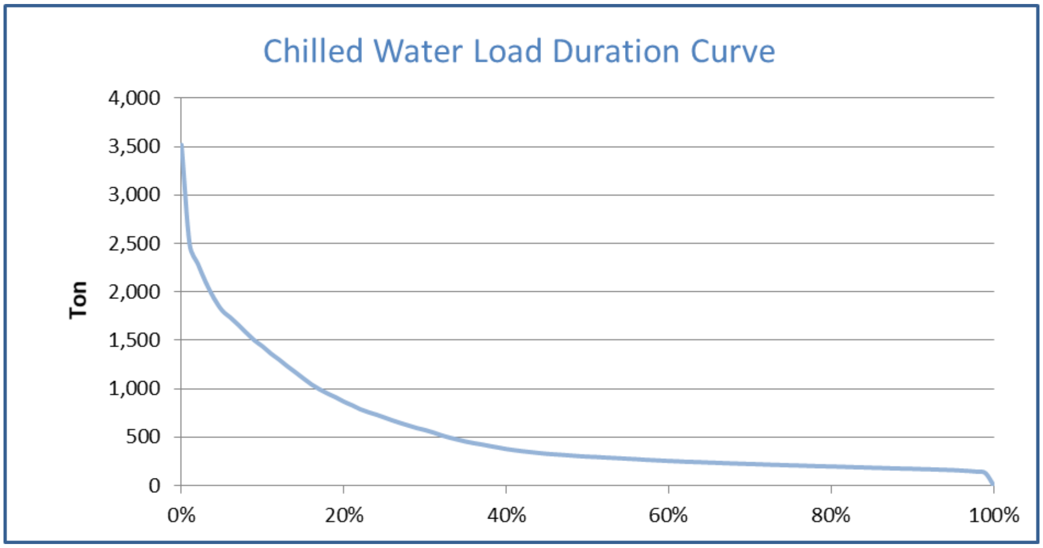
2020 Steam Hourly Load Profile



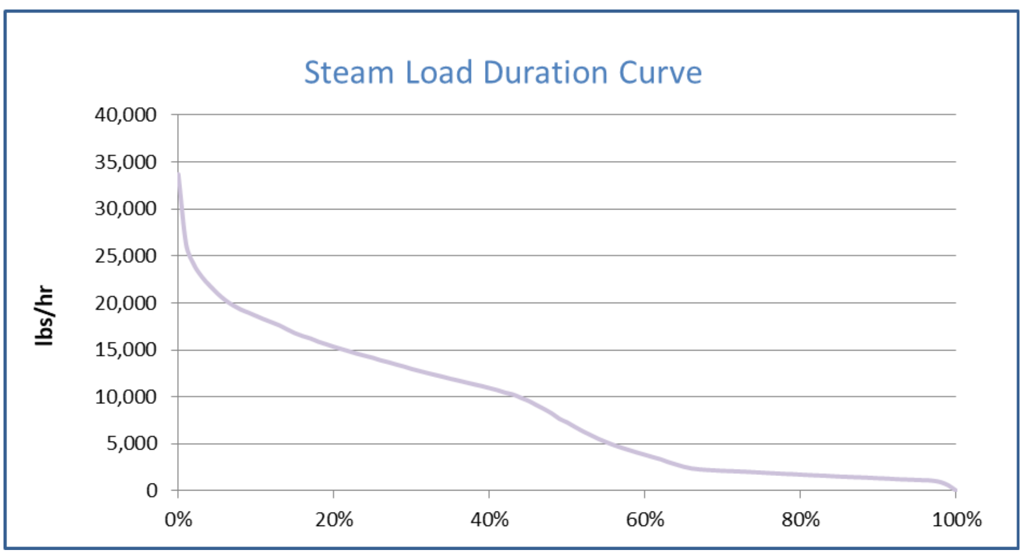
APPENDIX B

Load Duration Curves

2020 Chilled Water Load Duration Curve



2020 Steam Load Duration Curve



Note: The load duration curves are a representation of how much time the load is at or above a certain value. For example, for the steam, 20% of the time the load is ~15,000 lbs/hr or greater, 80% of the time the load is ~2,000 lbs/hr or greater, etc.

APPENDIX D

Deliverable 3: Regulatory Evaluation Memo Report

September 27, 2023

Noel Petra
Managing Director
Strategic Redevelopment
Real Estate & Construction Services
Department of Administrative Services
450 Columbus Boulevard, Suite 1301
Hartford, CT 06103
Noel.Petra@ct.gov

SUBJECT: **Contract No.: OC-DCS-ENGY-0030 Task No. 3**
Deliverable 3: Regulatory Evaluation Memo Report

Dear Noel,

Veolia has prepared the following memo report as Deliverable 3: Regulatory Evaluation for the CAS Decarbonization Project. This is the third of eight (8) deliverables under Contract No.: OC-DCS-ENGY-0030 Task No. 3. The purpose of this deliverable is to provide a summary of applicable financial incentives and to confirm applicability of such incentives, as well as timelines for incentive availability.

Investment Tax Credit

The Inflation Reduction Act (IRA) of 2022 includes new and revised tax incentives for clean energy projects, including modifications to the existing Investment Tax Credit (ITC), which provides a tax credit for investment in renewable energy projects. One major change is that many of the tax credits included in the legislation allow direct payments to be made in lieu of a reduction in tax liability ("direct pay") and/or an option to monetize the credits by transferring them to an entity with greater tax liability ("transferability"). For tax years beginning after December 31, 2022, most tax-exempt organizations, government entities, Indian tribal governments, and rural electric cooperatives may elect to treat certain credits as direct federal tax payments.

Additionally, a project can now qualify for the full 30% tax credit (versus 6%) if it ensures that all mechanics and laborers involved during the construction of the project and the maintenance of the project for five (5) years after completion are paid wages at rates not less than prevailing wages. Projects must also ensure that a percentage of total labor hours are performed by qualified apprentices. The percentage of hours will increase over time to a max of 15% in 2023 and afterwards.

The tax credit can also be increased for meeting domestic content (10%) and energy community (10%) requirements. To qualify for the domestic content bonus, all steel or iron used must be produced in the United States and a "required percentage" of the total costs of manufactured products (including components) of the facility need to be mined, produced, or manufactured in the United States. The "required percentage" of manufactured products starts at 40% for all projects beginning construction before 2025, increases to 45% for projects beginning construction in 2025, 50% for projects beginning construction in 2026, and 55% for projects beginning construction after 2026. In order to qualify for the energy community bonus the site must be:

1. A "brownfield site"
2. A "metropolitan statistical area" or "non-metropolitan statistical area" that has (or had at any time after 2009)
    a. 0.17% or greater direct employment or 25% or greater local tax revenues related to the extraction, processing, transport, or storage of coal, oil, or natural gas; and
    b. has an unemployment rate at or above the national average unemployment rate for the previous year
3. A census tract (or directly adjoining census tract)
    a. in which a coal mine has closed after 1999; or
    b. in which a coal-fired electric generating unit has been retired after 2009

Based on the DOE energy community mapping tool the CAS site would not qualify for this bonus credit. (https://energycommunities.gov/energy-community-tax-credit-bonus/). Also, in order to be conservative it has been assumed that the project will not qualify for the domestic content bonus, although this may change when the actual construction start date and equipment selections have been determined. Therefore, for the purposes of this study it is assumed that the project will only meet the prevailing wage requirements and a 30% ITC is applicable.

Under the scenarios being evaluated as part of this study, only those with a geothermal heat pump system would be eligible for the ITC. A geothermal heat pump system includes any equipment that uses the ground or ground water as a thermal energy source to heat a structure or as a thermal energy sink to cool a structure. Only the portion of equipment used to produce, distribute, or use energy derived from a geothermal deposit is eligible for the credit. The Inflation Reduction Act's new direct pay and transfer options allow organizations to utilize clean energy tax credits for equipment placed in service on or after January 1, 2023 and through December 31, 2032.
(https://www.epa.gov/green-power-markets/summary-inflation-reduction-act-provisions-related-renewable-energy#ITCPTC)

Connecticut Non-Residential Renewable Energy Solutions (NRES)

NRES is an incentive program that can help offset the cost of the electricity with the energy generated with non-residential solar or other Connecticut Class I renewable technologies. This program replaces the Low and Zero Emission Renewable Energy Credit Program (LREC/ZREC) and the Virtual Net Metering Program (VNM) with the objectives to foster the sustained, orderly development of the state's Class I renewable energy industry and to encourage the participation by customers in underserved and environmental justice communities, among others.

Sites are eligible for the NRES program if they are Eversource or United Illuminating Company (UI) customers and the proposed project is going in-service on or after the NRES request for proposals (RFP) issuance date. Currently, RFPs are issued twice annually, in February and August. Projects fall within one of the following categories, with a maximum system size of 5 MW :

- Small Zero Emission Category: ≤ 200 kW
- Medium Zero Emission Category: > 200 kW and < 1000 kW
- Large Zero Emission Category: ≤ 1000kW and ≤ 5000kW
- Low Emission Category: ≤ 5000kW

Eligible projects less than or equal to 200 kW are awarded incentive agreements on a first-come, first-served basis, and are eligible to select either the Buy-All or Netting compensation structure. Eligible projects greater than 200 kW and less than or equal to 5,000 kW are awarded incentive agreements through a competitive solicitation process subject to the price caps, and are also eligible to select either the Buy-All or Netting compensation structure.

For the Buy-All compensation structure, the customer exports all electricity produced by their renewable energy project to the grid directly without supplying power to their property. The Electric Distribution Company (EDC) purchases all the generated clean energy at the as-bid price (or set price for the small category). The customer purchases all the energy for their property from the grid.

For the Netting compensation structure energy generated by the renewable system is first used to offset the property's consumption. At the end of the month, if more energy was produced by the system than consumed on site, the customer receives a credit on their bill that can be used in later months. Customers may also qualify for an incentive payment calculated based on the total production of the renewable system. Bidders will indicate what their monetary on-bill credit amount (i.e., energy compensation rate), and what their direct payment to a Tariff Payment Beneficiary rate (i.e., REC payment) will be at the time of Bid submission.

This program may be applicable for solar installations at the offtaker buildings, whether paid for by the building owner or installed as part of a PPA. However, because it is a competitive bidding process and program funding may vary in the future, the benefits and eligibility would not be known until after the selection process was completed.

Connecticut Green Bank

The Connecticut Green Bank was formed to accelerate the green economy using limited public dollars to attract multiples of private capital investment and they support the Governor's and Legislature's energy strategy to achieve cleaner, less expensive, and more reliable sources of energy while creating jobs and supporting local economic development. In discussions with the Green Bank it wasn't clear how decarbonization of the CAS plant itself would fit into their financing model but they are open to discussing how they could play a role once more details on a potential project have been finalized. One path may be through the Green Bank's Open Request for Proposals, through which the Green Bank provides access by project developers to Green Bank capital that will catalyze investment which, but for the Green Bank's participation, would either not happen or be realized at a much slower pace.

The Green Bank also offers programs that may be applicable to assist with adding solar PV to the offtaker buildings. Through the Green Bank's Solar PPA solar can be installed with no money down. A power purchase agreement, or PPA, allows the building owner to purchase the electricity generated by the solar system on its building, often at a significant discount to grid power. The Green Bank and its partner oversee the development and management of the system. Private and public properties and institutions can use the Green Bank Solar PPA to add solar to their buildings. (https://www.ctgreenbank.com/building-solutions/solar-programs/solar-ppa/)

A Solar Roof Lease program is also offered by the Green Bank. Under this program the building roof's unused space is leased to the Green Bank for fixed payments. The Green Bank or its partner then install solar and own the system and are responsible for performance and maintenance. Most commercial and municipal properties are eligible for this program.
(https://www.ctgreenbank.com/building-solutions/solar-programs/solar-roof-lease/)

Department of Energy & Environmental Protection (DEEP)

Although it is possible that DEEP could play a role in financing the CAS decarbonization project, according to Jeff Howard at DEEP no discussions regarding DEEP's potential role have been conducted. These discussions would need to be initiated outside of DEEP. The completion of the CAS Decarbonization Study may be the appropriate time to initiate a discussion with DEEP regarding potential financing.

Connecticut Natural Gas (CNG)

The natural gas provider for the CAS facility, CNG, an Avangrid company, does not directly provide incentives for high efficiency boilers. All incentives are provided through Energize Connecticut, an initiative of the Energy Efficiency Fund, the Connecticut Green Bank, the State, and local electric and gas utilities. The initiative has funding support from a charge on customer energy bills. Discussions with CNG and a review of Energize Connecticut's natural gas boiler incentives (https://energizect.com/rebates-incentives/heating-cooling/commercial-natural-gas-boiler) indicated that a potential incentive of $5/input MBH may be available. This incentive is only available when replacing an inefficient non-condensing boiler with a new high efficiency condensing boiler and a verification inspection on the existing heating system must be conducted in order to qualify. Condensing boilers must have an Annual Fuel Utilization Efficiency (AFUE) or Thermal Efficiency of 95% or higher. The input capacity can not be higher than 2,500 thousands of BTUs per hour (MBH). Based on the size of the boilers required for the CAS project it does not appear that this incentive is applicable. In addition, the current incentive expires at the end of 2023 and under the current regulatory climate of disincentivizing natural gas use there is no guarantee that it will be available in the future.

Eversource

Although Eversource, the electric provider for the CAS facility, does not have an existing set of incentives for district energy scale heat pumps due to their nature as an emerging technology in the U.S., during discussions with their incentive team they indicated that Eversource is always looking at potential incentives for new technology. Veolia provided Eversource with information on proposed operating scenarios and equipment for the CAS plant. Eversource is currently reviewing this information in order to determine what if any potential incentives they may be able to provide.

As with CNG, Eversource incentives are provided through Energize Connecticut (https://energizect.com/explore-solutions/new-home-business-construction-existing-building-efficiency) for other prescriptive energy savings programs. These programs can help offset the cost of replacing or modifying inefficient, functioning equipment such as lighting, HVAC, chillers, motors, controls, water heaters, and commercial cooking equipment through financial incentives up to 40 percent of the installed costs and zero-interest or low-interest rate financing. Custom incentives are also available for Retro-Commissioning (RCx), which is a systematic process to improve how equipment and systems function together in an existing building. RCx is a cost-effective way to improve energy efficiency and reduce energy costs since it focuses primarily on optimizing existing equipment through low-cost improvements. Most of these incentives are based on a per unit of energy (e.g. kWh electricity, CCF natural gas) saved at the building. Since all of the buildings receive the vast majority of their heating and cooling energy from the CAS plant and not through the direct import of energy (i.e. electricity or natural gas) from the utility, once energy efficiency measures have been selected, additional discussions with Eversource would be required to determine how the incentives would apply in each individual situation.

National Energy Improvement Fund

As part of the Energize CT Energy Efficiency Programs, the National Energy Improvement Fund provides low-interest, electric & natural gas energy efficiency loans to commercial and industrial customers that implement energy-saving measures through a qualifying Connecticut Energy Efficiency Fund program. The first $100,000 of a loan is subsidized by the Connecticut Energy Efficiency Fund with rates available from 0.00% - 2.99% with a repayment term of 48-60 months. Anything over $100,000 can be financed at market rates. The loan must be used to upgrade or replace existing equipment with high-efficiency equipment. These loans would only be applicable to energy-saving measures already approved through a qualifying Connecticut Energy Efficiency Fund program and may be applicable to measures implemented at the offtaker buildings.

APPENDIX E

Deliverable 4: Demand Side Evaluation Memo Report

September 27, 2023

Noel Petra
Managing Director
Strategic Redevelopment
Real Estate & Construction Services
Department of Administrative Services
450 Columbus Boulevard, Suite 1301
Hartford, CT 06103
Noel.Petra@ct.gov

SUBJECT: **Contract No.: OC-DCS-ENGY-0030 Task No. 3**
Deliverable 4: Demand Side Evaluation Memo Report

Dear Noel,

Veolia has prepared the following memo report as Deliverable 4: Demand Side Evaluation for the CAS Decarbonization Project. This is the fourth of eight (8) deliverables under Contract No.: OC-DCS-ENGY-0030 Task No. 3. The purpose of this deliverable is to provide a summary of technical and financial feasibility of adopting demand side (load reduction) strategies as part of decarbonization efforts.

1. Site Visits

Veolia conducted site visits for ten (10) of the fifteen (15) CAS offtaker buildings on June 12th and 13th, 2023 for the purposes of data collection, energy assessment, and conducting interviews with site staff. Site visits were conducted at the following buildings:

- 165 Capitol Avenue (State Office Building)
- 166 Capitol Avenue (Bushnell Theater)
- 79 Elm Street (DEEP)
- 2 Park Place (Park Place Towers A)
- 24 Park Place (Park Place Tower B)
- 300 Capitol Avenue (Legislative Office Building)
- 360 Broad Street (Armory)
- 21 Oak Street (Connecticut Education Association)
- 231 Capitol Avenue (Judicial/Supreme Court)
- 75 Elm Street (Appellate Court Building)

At each location visited Veolia interviewed key staff responsible for building operations, recorded visual observations of energy loop transfer stations and major HVAC equipment and reviewed building automation system (BAS) screens for information on HVAC controls and setpoints. Of the remaining five

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(5) offtaker buildings, 18-20 Trinity Street (Ethics) and 30 Trinity Street (Sec. of State) are currently vacant and 30 Laurel Street (United Way), 101 Lafayette (Judicial) and 410 - 470 Capitol Avenue (OPM) did not have a representative available to provide access during the time of the site visits. However, Veolia was provided energy audit reports from 2020 for 18-20 Trinity Street, 30 Trinity Street, 450 - 460 Capitol Avenue and 410 Capitol Avenue which were reviewed to obtain information on building systems and operations. Veolia also requested up-to-date mechanical drawings for each building in order to compile a detailed list of existing HVAC equipment at each building. However, these drawings were only available for 165 Capitol Avenue, which recently underwent an extensive renovation.

At each location, hot water and chilled water for the building are provided through an energy transfer station connected to the CAS district utility system, with the exceptions of 166 Capitol Avenue and 101 Lafayette which receive chilled water only and 410 - 470 Capitol Avenue which receives steam instead of hot water. This system provides and meters hot water/steam and chilled water to the buildings, billing by the MMBtu (for hot water/steam) and Day-Ton (DTon) for chilled water. The energy consumption is measured by flow meters and temperature sensors in each building. Distribution systems in each building vary but generally consist of chilled water and hot water/steam piping networks which distribute energy to a mix of air handling units (AHUs), fan coil units (FCUs), variable air volume (VAV) boxes and radiators. Total metered hot water/steam and chilled water use at each building for 2020 is shown in Table 1.

TABLE 1: Offtaker Building List & 2020 Chilled Water and Hot Water/Steam Use

Building Address	Square Footage	Ownership	Annual CHW 2020 (MMBtu)	Annual HW/Steam 2020 (MMBtu)
300 Capitol Ave (LOB)	240,000	State-owned	8,313	7,408
2 Park Place (P.P. Tower A)	261,365	Private	4,001	8,268
24 Park Place (P.P. Tower B)	244,090	Private	2,390	6,606
166 Capitol Ave (Bushnell Theater)	200,000	Private	722	0
30 Laurel St (United Way)	30,000	Private	410	1,147
18-20 Trinity St (Ethics)	84,437	Private	974	2,685
30 Trinity St (Sec. of State)	61,864	Private	854	1,897
231 Capitol Ave (Judicial/Supreme Court)	200,000	State-owned	8,331	4,791
360 Broad St (Armory)	177,248	State-owned	2,351	4,185
21 Oak St (CEA)	113,582	Private	4,524	2,121
79 Elm St (DEEP)	280,300	State-owned	3,175	2,928
75 Elm St (Judicial)	47,000	State-owned	927	1,238
410 - 470 Capitol Ave (OPM)	431,066	State-owned	20,446	13,879
101 Lafayette (Judicial)	125,727	State-owned	2,156	0
165 Capitol Ave (State Office Building)	328,238	State-owned	5,159	7,692
		Total	**64,733**	**64,845**

Each building utilizes a BAS to control the distribution of heating and cooling energy. Veolia reviewed BAS control screens at each location visited to better understand how the building's systems are controlled. However, this only provided a snapshot of operations at the time of the site visit. Long term trend data of key system parameters would provide a more detailed picture of how the building's systems operate and interact but it did not appear that this functionality had been enabled at any of the locations visited. Veolia requested that data trending be enabled at each building so it could be reviewed at a future date, ideally after a full 12 months to observe how the systems through all seasons.

2. Potential Energy Efficiency Measures

This section focuses on high level Energy Efficiency Measures (EEMs) identified by Veolia which, if implemented, would lower the overall energy usage. Potentially feasible EEMs were created based on the site visits and an energy consumption review. An economic analysis was then performed on EEMs to establish an estimated cost and savings. To perform the economic analysis, quantities of materials and implementation costs have been estimated and assumptions made where required. These estimations and assumptions can be found in the individual EEM detail sections of this report. Veolia uses estimation and assumption techniques, along with corresponding tools, to provide a conservative return-on-investment. The return-on-investment calculations provide the client with the proper information to make economically beneficial improvements to their facilities. However, the capital investment figures provided are estimate-grade only and should not be considered as a contractor-supplied quote or an investment-grade estimation. Additionally, detailed work (including system sizing, equipment selection and specification) is a required next step for implementing any of the recommended measures. Veolia offers services for performing investment-grade economic calculations based on responses to RFPs. The full list of findings, EEM details, observations, and recommendations may be found in the following sections.

2.1. Retrocommissioning

Retrocommissioning (RCx) is a systematic process for optimizing energy performance in existing buildings, specifically focusing on improving the control of energy-using equipment such as HVAC systems. It can lower building operating costs by reducing energy consumption and increasing equipment life. Many studies have shown that RCx can achieve energy savings ranging from 5% to 20%, with a typical payback of two years or less. A typical RCx program may include:

- Calibration of the indoor and outdoor building sensors.
- Inspection of damper and valve controls to make sure they are functioning properly.
- Review of building automation control operating schedules.
- Review of utility rate schedules.
- Chilled-water and condenser-water temperature reset.
- Maintaining steam traps.
- Adjusting combustion airflow.
- Review of reheat system resets.
- Review air system flow rates, including supply, return, exhaust, and outside airflow.
- Review temperatures of heating and cooling delivery systems (air side and water side).
- Review of lighting controls (e.g. occupancy sensors, day-lighting)

The energy and financial savings for this EEM were carried out for each of the Offtaker buildings. The calculations assume a 5% energy savings. Actual achievable savings will likely depend on factors such as the size, age and condition of existing systems and controls. Potential project costs, savings and ROI for this EEM can be seen in the table below.

TABLE 2: Offtaker Building Estimated RCx Cost & Savings

Building	Savings (MMBTU)	Savings ($)	RCx Net Cost ($)	Simple Payback (Yrs)
Legislative Office Building	786	$36,198	$78,000	2.2
Underwood Tower A(M24-6PP)	613	$28,250	$84,944	3.0
Underwood Tower B (M12-24PP)	450	$20,714	$79,329	3.8
Bushnell Theater	36	$1,663	$65,000	39.1
United Way	78	$3,586	$9,750	2.7
18/20 Trinity	183	$8,426	$27,442	3.3
30 Trinity	138	$6,335	$20,106	3.2
231 Capitol Library	656	$30,215	$65,000	2.2
Armory	327	$15,048	$57,606	3.8
Capitol Place	332	$15,299	$36,914	2.4
79 Elm Street	305	$14,053	$91,098	6.5
75 Elm Street	108	$4,986	$15,275	3.1
410 - 470 Capitol Ave (OPM)	1,716	$79,035	$71,462	0.9
101 Lafayette	108	$4,963	$40,861	8.2
165 Capitol Ave (New circa 2017)	643	$29,589	$106,677	3.6

2.2. Solar PV

Based on the unused roof space that appears to be available at the sites roof-mounted solar photovoltaic (PV) may be a viable energy conservation measure. Using aerial photographs and solar production estimation tools, Veolia estimated the energy production and cost of energy of PV roof-mounted energy systems for each facility. The cost savings and payback period were based solely on a straightforward system purchase price using a fixed estimated cost per watt for installation and offset electrical use at an estimated blended utility rate of $0.16/kWh. Other PV procurement models such as a Power Purchase Agreement (PPA) or lease may yield different results and be more attractive financially since they do not require capital outlays. Additionally, site specific financial incentives which would lower costs and payback period are likely available but would require additional information and investigation. Other factors such as roof age and structural integrity would also need to be investigated to determine the actual area suitable for rooftop PV. Other PV options such as parking lot canopies were assumed to be viable at 410-474 Capitol Ave and may also be a viable alternative for other locations. A summary of potential project costs, savings and ROI for this EEM is presented in the table below.

TABLE 3: Offtaker Building Estimated Solar PV Cost & Savings

	Module DC Nameplate (kW)	Annual Production (MWh)	Installation Cost	Electricity Savings	Simple Payback
20 Trinity St	27.2	35.44	$88,400	$5,670	15.6
25 Sigourney St	74.6	98.23	$242,450	$15,717	15.4
30 Trinity St	30.4	39.65	$98,800	$6,344	15.6
101 Lafayette	70.7	93.77	$229,775	$15,003	15.3
165 Capitol Ave	111	146.6	$360,750	$23,456	15.4
231 Capitol Ave	65.9	87.08	$214,175	$13,933	15.4
410-474 Capitol Ave (Roof)	305.6	410.2	$993,200	$65,632	15.1
410-474 Capitol Ave (Carports)	684.5	935.9	$3,336,938	$149,744	22.3
Bushnell	68.2	90.89	$221,650	$14,542	15.2
CT Appellate Court	45.8	61.12	$148,850	$9,779	15.2
Legislative Office Building	113.9	152.7	$370,175	$24,432	15.2
State Armory	301.4	348.4	$979,550	$55,744	17.6
Total	**1899.2**	**2499.98**	**$7,284,713**	**$399,997**	

2.3. Compressed Air Leak Survey

Several offtaker buildings were observed to utilize pneumatic air systems to control valves in their HVAC systems. Leak surveys of compressed air systems often reveal significant potential savings. Leaks are a significant source of wasted energy in a compressed air system, often wasting as much as 20%-30% of the compressor's output. Compressed air leaks can also contribute to problems with system operations, including:

- Fluctuating system pressure, which can cause air tools and other air-operated equipment to function less efficiently, possibly affecting production
- Excess compressor capacity, resulting in higher than necessary costs
- Decreased service life and increased maintenance of supply equipment (including the compressor package) due to unnecessary cycling and increased run time

Although leaks can occur in any part of the system, the most common problem areas are couplings, hoses, tubes, fittings, pipe joints, quick disconnects, FRLs (filter, regulator, and lubricator), condensate traps, valves, flanges, packings, thread seal-ants, and point-of-use devices. Leakage rates are a function of the supply pressure in an uncontrolled system and increase with higher system pressures. Leakage rates identified in cubic feet per minute (cfm) are also proportional to the square of the orifice diameter. Since the air compressors are electric none of the potential savings would affect central plant operations but could reduce electrical consumption at the building itself.

2.4. Solar Hot Water

The potential for installing solar hot water on the offtaker buildings was also investigated. Based on discussions with an installer of solar hot water systems it was determined that while the potential for installing solar hot water systems exists, these systems are capable of producing only low temperature hot water, require extensive piping and storage systems to be integrated into existing thermal systems, and have a significant energy output reduction in winter months. Additionally, their estimated installation cost is roughly 5-6 times the cost of traditional solar PV per unit of energy capacity. Therefore, the more cost effective use of limited roof space at the offtaker buildings would be the installation of solar PV.

3. Low Temperature Hot Water Conversions

Based on the limited design documents provided, historic heating loop supply temperatures and discussions with site personnel it appears that the offtaker buildings' heating systems were generally designed for 180°F supply hot-water. While a lower hot-water supply (HWS) temperature (110°F -140°F) can increase the efficiency of the equipment which provides the hot water, providing the necessary heating capacity with a lower HWS temperature requires a higher fluid flow rate than a high HWS temperature. This may require additional hot-water coil rows in end-use HVAC equipment to provide the required heating capacity, as well as a higher fluid flow rate, which can affect the size of pipes, pumps, and valves, and can also increase pumping energy use. Buildings may also require weatherization to reduce heating loads and radiator redesign to meet building heating needs.

While efficiency increases at the CAS plant would not result in energy savings at the offtaker buildings themselves, and may actually increase electric use due to higher pumping rates, ensuring that the offtaker buildings could maintain heating capacity at a lower HWS temperature would be critical before deciding to lower the HWS temperature of the loop. The first step would likely be to conduct tests at each offtaker building in order to observe how its systems respond to reduced hot water temperatures and increased flow rates and determine if they are capable of meeting heating requirements under those supply conditions. Based on the age of most of the systems in the offtaker buildings and discussions with representatives from Trane, an HVAC equipment manufacturer, regarding similar low HWS temperature conversions projects it appears that the more likely outcome is that major HVAC equipment modifications and/or replacements would be required. Since 165 Capitol Avenue was the only offtaker building for which detailed HVAC design drawings were provided and it had recently undergone a major renovation of its systems using equipment from Trane, Trane was requested to provide budgetary pricing to upgrade major pieces of equipment (air handling units, variable air volume boxes, etc.) to operate at low HWS temperatures. Using this pricing Veolia developed an estimated $/square foot cost to upgrade major HVAC equipment at each of the offtaker buildings resulting in a total estimated cost of approximately $45M for all fifteen (15) buildings. This figure does not include potential costs for upgrading pumping systems or existing piping distribution networks in the buildings or the CAS loop itself and could vary significantly from actual costs developed from building testing and a full engineering study. Additional engineering studies and flow tests on the CAS loop would need to be performed before increasing flow and pressure in the system. Based on the history of documented leaks at existing flows and pressures it is possible that significant upgrades to the system could be required.

4. Offtaker Overall Energy Use Analysis

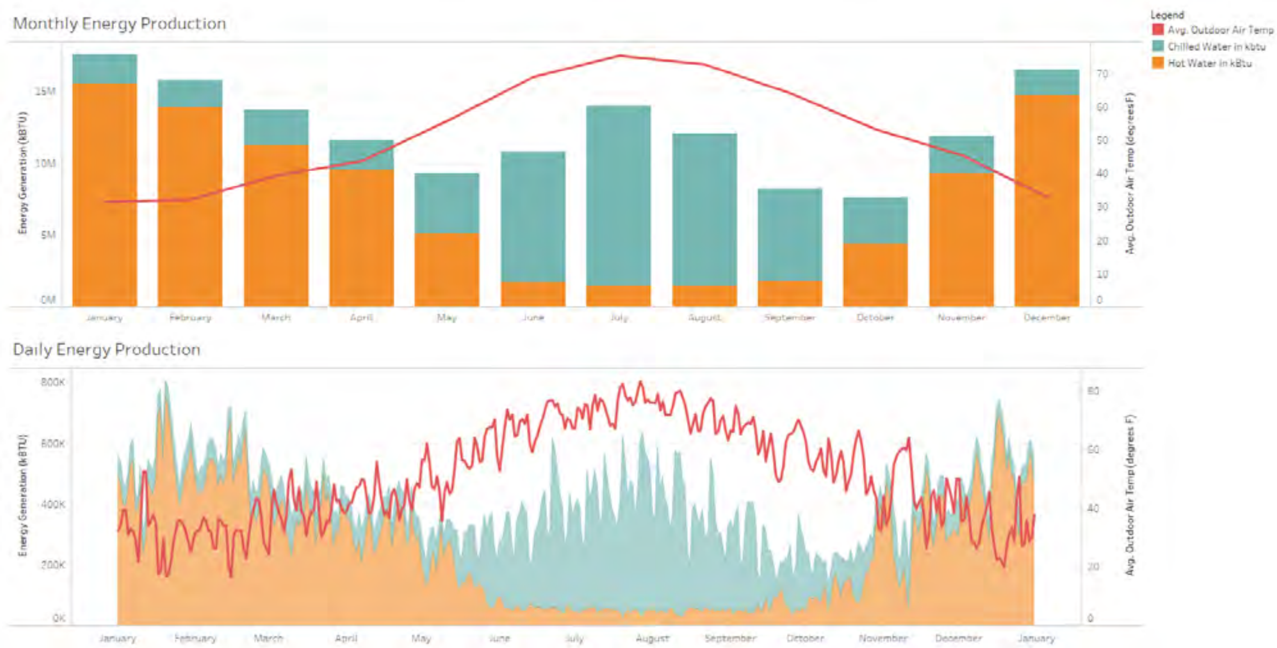
In order to analyze energy use and production, monthly chilled water and hot water/steam use for each of the offtakers and hourly data for the central plant was entered into Hubgrade, Veolia's full-service software solution for monitoring and supporting facility managers and on-site operators. While Hubgrade is generally used actively by Veolia's analysts and customers to deliver a comprehensive energy monitoring and management solution through advanced analytics, reporting, and actionable efficiency insights, in this case it was used to analyze trends and metrics in static data since real-time data is not currently available. While this provided a snapshot of offtaker energy use, real-time, or at a minimum hourly, data would be required to fully understand energy use at each building and develop actionable recommendations for reducing energy consumption. The following sections provide an analysis of energy production and consumption using Hubgrade tools and graphical outputs. The figures shown in the following sections can also be found on-line on the Hubgrade server: https://tableau.s1inc.com/#/site/S1Public/views/StateofCTEnergydata/EnergyProduction?:iid=1

4.1. Chilled Water and Hot Water Production

The following figures present the energy production of the central plant both in monthly and daily intervals for the full year 2020 with an overlay of the outdoor air temperature. As expected, it is apparent that there is a large correlation between outdoor air temperature and the amount of hot water and chilled water produced by the plant.

One observation in this chart is that the plant produces a base load of chilled water in the summer and a base load of hot water in the winter. For both energy types, a base load of approximately 50 MMBTU per day is present even when the temperature is too high or too low. For hot water, this is likely due to domestic hot water and HVAC re-heat usage in buildings on the loop. For chilled water, based on discussions with site personnel at the offtaker buildings, it is likely that some simultaneous heating and cooling is occurring during the winter months in order to maintain temperatures at some of the buildings.

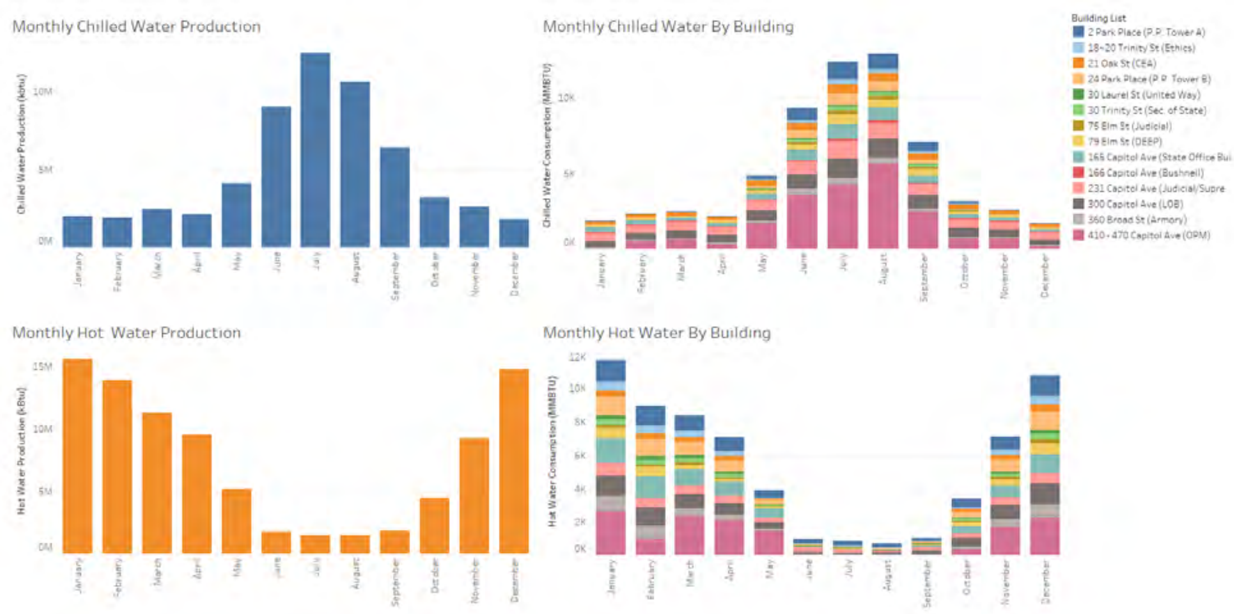
FIGURE 1: Central Plant 2020 Chilled Water and Hot Water/Steam Production



4.2. Monthly Production vs. Individual Building Usage

Plant production data closely aligns with the individual offtaker data presented separately. The charts below show a comparison between production and offtaker usage per month for each energy type. As expected, 410-470 Capitol Ave utilizes the largest amount of chilled water and hot water/steam. 231 Capitol Avenue (Judicial/Supreme Court) appears to use the most chilled water, relative to its size, during the winter months. Based on conversations with site personnel, it is likely that this is due to the environmental requirements of the State library located in this building as well as some simultaneous heating and cooling that occurs to maintain temperatures in the occupant spaces.

FIGURE 2: Monthly Production vs. Individual Building Usage

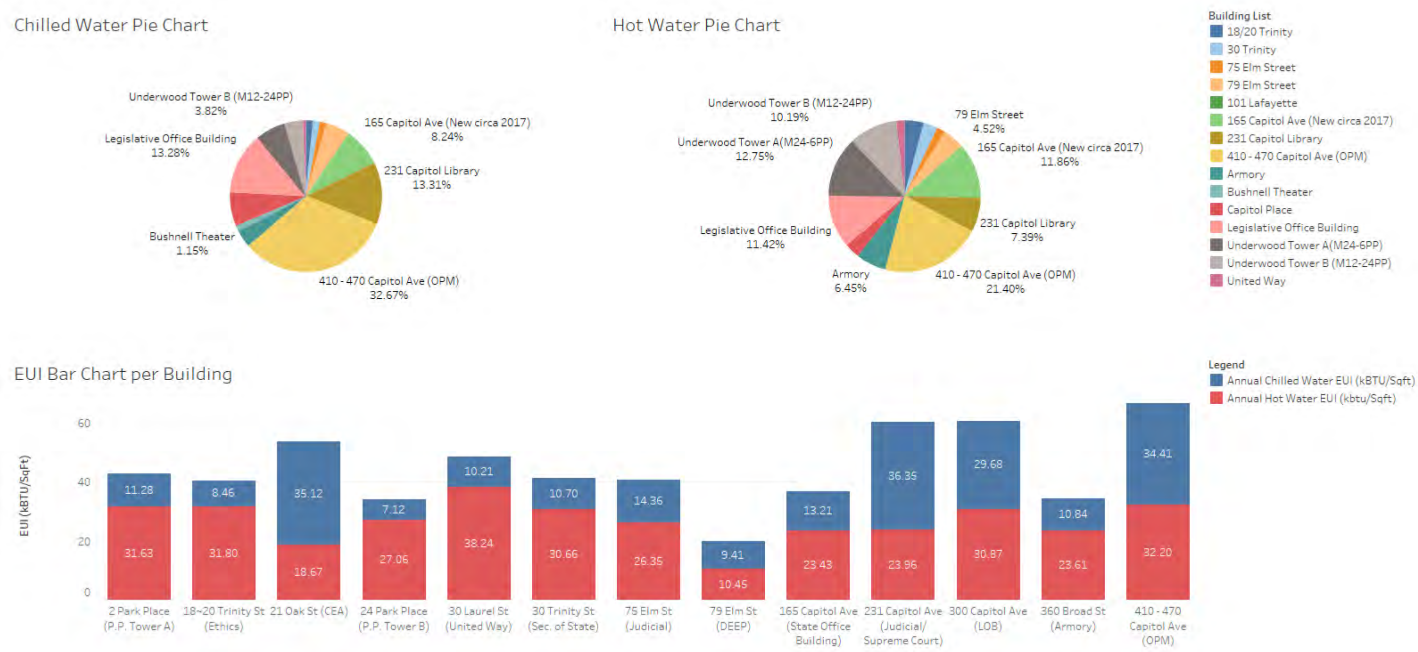


4.3. Proportional Energy Usage and EUI per Building

In the following figures, the two (2) pie charts show the total energy consumption per building for hot water and chilled water. As observed previously, 410-470 Capitol Ave utilizes the most chilled water and hot water/steam. It is closely followed by the Legislative Office Building, 165 Capitol Ave and 231 Capitol Ave.

Next, the Energy Use Intensity (EUI) of each building was calculated for chilled water and hot water consumption and stacked to compare. While some buildings appear to use approximately a similar amount of energy for chilled water and hot water per year, most buildings use significantly more hot water than chilled water. The only exception is 21 Oak St (CEA). Its EUI is approximately 65% chilled water and 35% hot water.

FIGURE 3: Proportional Energy Usage and EUI per Building



4.4. EUI and Energy Consumption Map

In this map view below, the chilled water performance is shown on the top map and the hot water performance is shown on the bottom map. The color of the circle indicates the EUI for that energy type; a darker color indicates a higher EUI. The size of the circle indicates its consumption; a larger circle represents higher energy consumption. For our analysis, we evaluated a combination of the two metrics to establish the largest opportunity for savings. For example, a building with a large circle and a shade of darker red indicates a much larger opportunity for savings when compared to a building with a smaller circle and a light red.

For chilled water, it appears that the largest opportunities for energy reduction are at 410-470 Capitol, 231 Capitol, Legislative Office Building and Capitol Place, in that order. For hot water, it appears that the largest opportunities are at 410-470 Capitol, Underwood Tower A and Legislative Office Building, in that order.

FIGURE 4: EUI and Energy Consumption Map

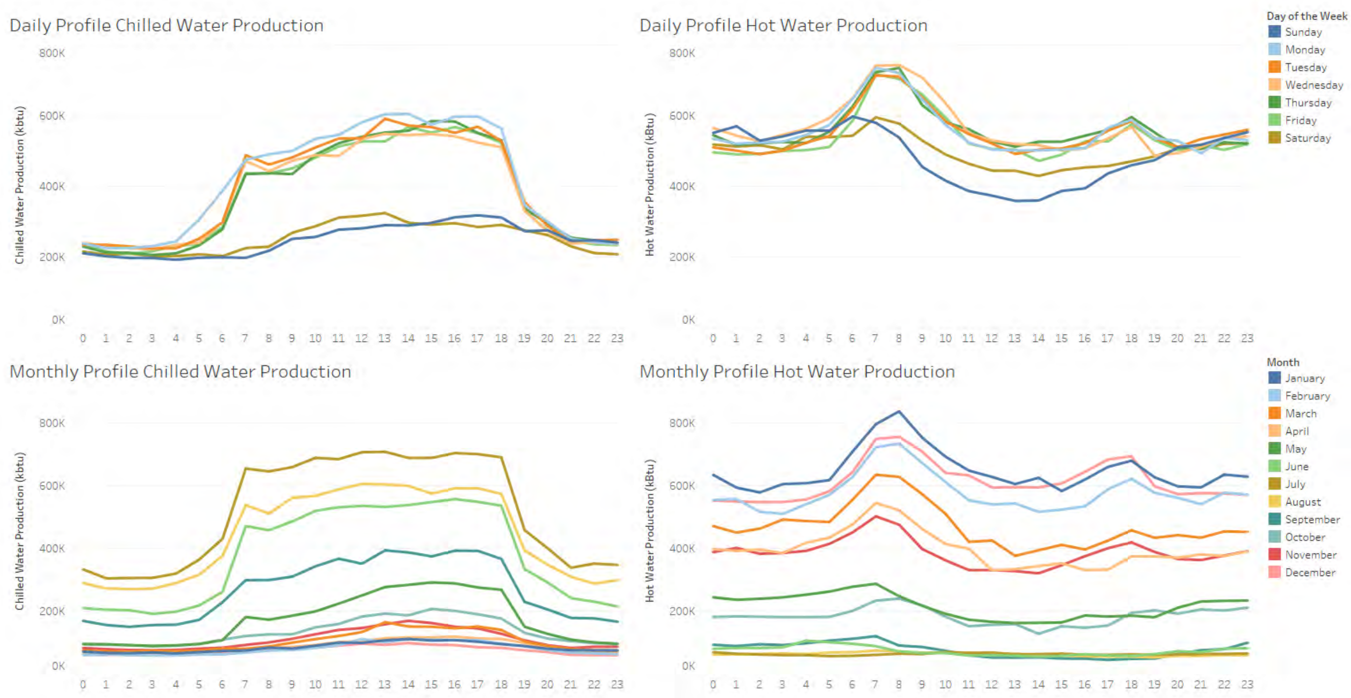
4.5. Average Day & Month Profiles

The charts below present what an average 24-hour period of chilled water and hot water production looks like for individual days of the week or months of the year. The chart in the top left shows the average daily profile for the central plant for chilled water production broken down by day of the week. It is clear that the plant operates at baseline for Saturday and Sunday as expected since most of the off-takers are only occupied Monday to Friday. All other days of the week, except for Monday, have a similar profile with equipment starting up around 6:00 am and shutting down around 6:00 pm. On Mondays, the plant starts up between 4:00 am and 5:00 am, most likely as a result of a partial shut down over the weekend.

The chart in the top right shows the average daily profile for the central plant for hot water production broken down by day of the week. This profile is not as clear cut as the chilled water profile, but it does appear that Saturday and Sunday production are slightly lower. There is a small bump around 7:00 am every morning as those are usually the coldest hours of the day. The ratio of occupied-hour production to unoccupied-hour production indicates that there could potentially be opportunities for night setbacks that are not fully realized.

The bottom two charts show the same profile broken out by individual months. As expected, June, July and August show the highest chilled water production and December, January, and February show the highest hot water production.

FIGURE 5: Average Day & Month Profiles

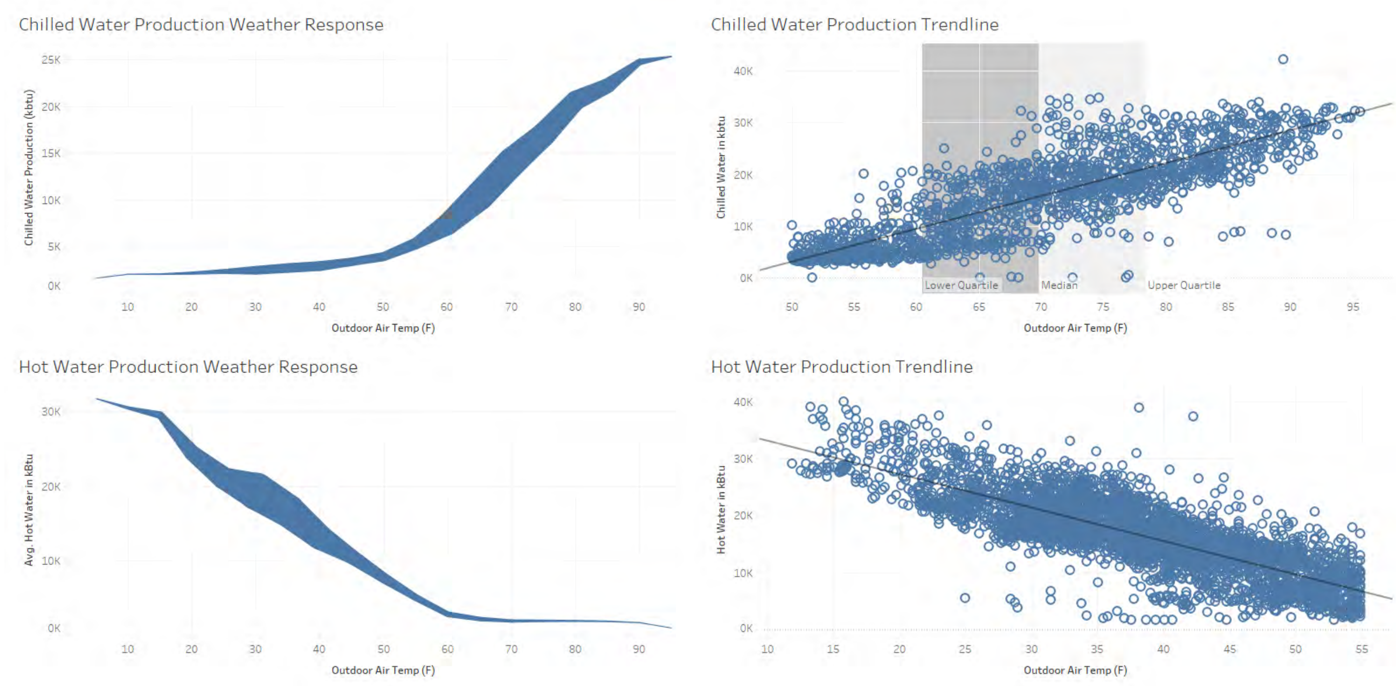


4.6. Weather Response

The charts below show the weather response for chilled water and hot water production for the central plant. The charts on the left present a bin analysis of production vs. outdoor air temperatures. It is clear that the plant ramps up its production of its hot water and chilled water production at a switchover point of approximately 60°F outdoor air temperature. The plant generates an average of 30 MMBTU/hr of hot water at the coldest outdoor air temperatures. Similarly, it generates an average of 25 MMBTU/hr of chilled water at the hottest outdoor air temperatures.

The charts on the right show a regression of outdoor air temperature vs. chilled water and hot water production. The charts have been filtered to only show days and hours where offtaker buildings are most likely to be occupied. It is clear that there is a strong correlation between outdoor air temperature and the amount of energy produced by the plant.

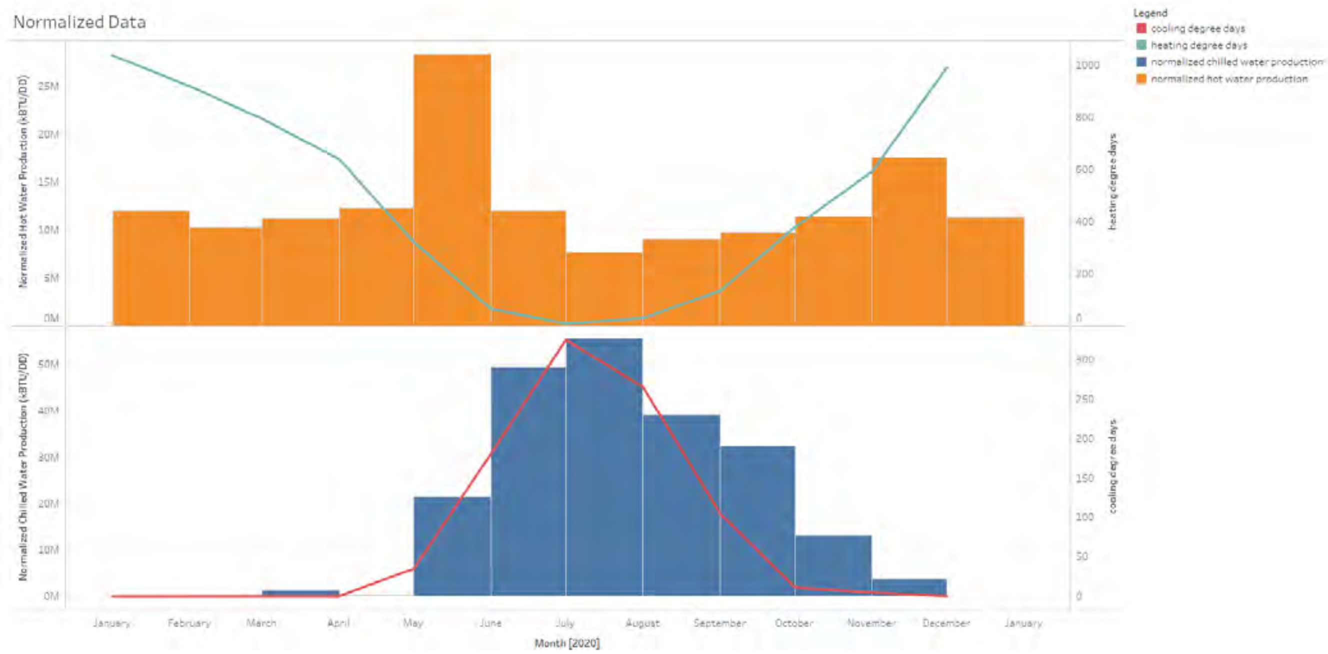
FIGURE 6: Weather Response



4.7. Normalized Energy Consumption

In this slide, energy production was normalized using heating and cooling degree days. For hot water production, it is clear that the normalized plant monthly production remains the same throughout the years except for one significant outlier in May. It is not clear why this happens, but it could be due to the fact that May is a shoulder season with an average outdoor temperature hovering around the switchover point. The normalized chilled water production does not behave identically to the normalized hot water production, but it remains very closely correlated with the number of cooling degree days.

FIGURE 7: Normalized Energy Consumption



4.8. Potential Energy Savings per Building

In order to evaluate the opportunity within every building, the EUI for each building and for each energy type was used to evaluate if the building is outside the normally accepted ranges for buildings of their type. For buildings that exceeded their expected EUI, potential savings was calculated as 50% of the difference between their current EUI and the proposed EUI average, then multiplied by their square footage to obtain the energy savings value in kBTU (where 'k' = 1,000).

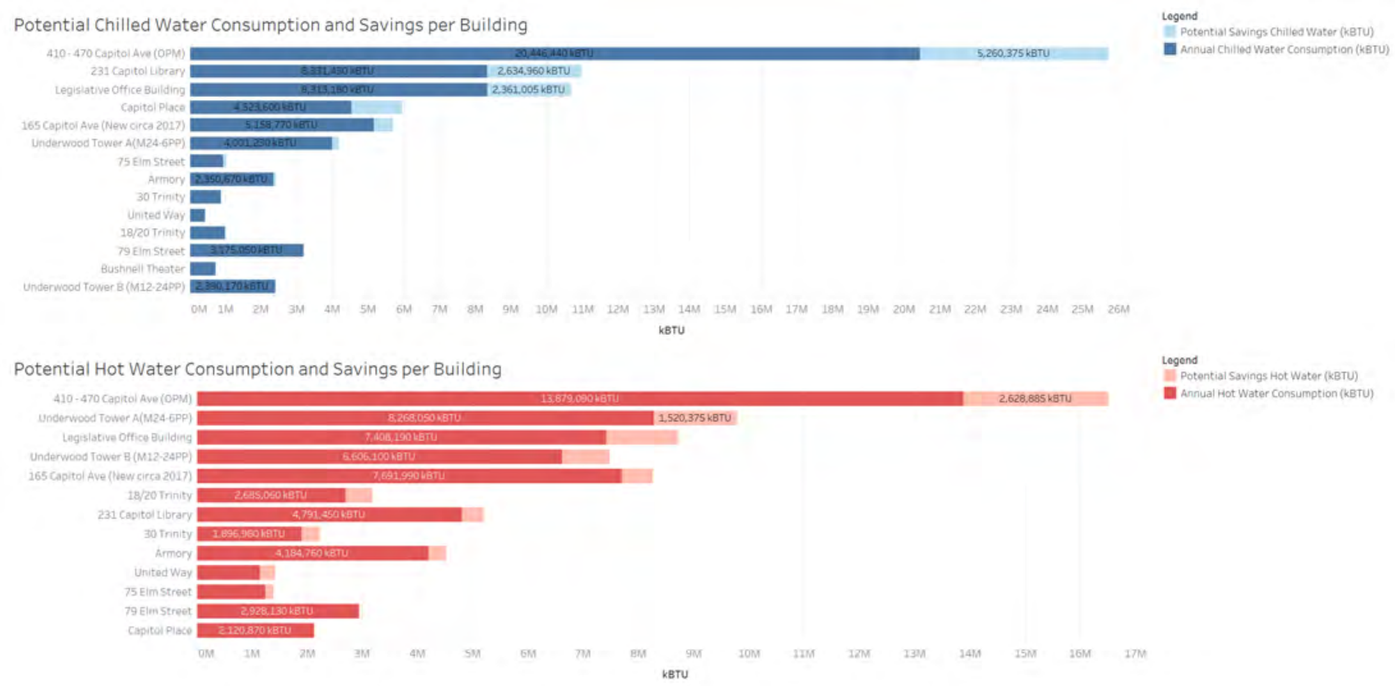
The charts below line up closely with the charts presented in Figures 3 and 4. The largest opportunities for chilled water savings appear to be at the following locations:

- 410-470 Capitol Ave (5.3M kBTU or 5,300 MMBTU)
- 231 Capitol Library (2.6M kBTU or 2,600 MMBTU)
- Legislative Office Building (2.4M kBTU or 2,400 MMBTU)

The largest opportunities for hot water/steam savings appear to be at the following locations:

- 410-470 Capitol Ave (2.6M kBTU or 2,600 MMBTU)
- Underwood Tower A (1.5M kBTU or 1,500 MMBTU)
- Legislative Office Building (1.3M kBTU or 1,300 MMBTU)

FIGURE 8: Potential Energy Savings per Building



Total potential annual savings were estimated to be 12.6M kBTU of chilled water and 7.1M kBTU of hot water/steam, roughly 19% and 10% of the total chilled water and hot water/steam consumption, respectively, by all offtakers. These estimated savings are based only on comparisons relative to typical average EUIs. A more detailed investigation into individual building operating conditions may reveal higher or lower potential energy savings. Assuming that 25% of these reductions at individual buildings occur concurrently, it can be estimated that a 5% reduction in existing peak chilled water peak demand (197 tons/hr) and 2.5% reduction in existing hot water/steam peak demand (1,137 MMBTU/hr) would result. However, without hourly offtaker data it is difficult to accurately estimate by how much these savings would reduce peak heating and cooling loads, and therefore the required peak capacity of the central plant.

4.9. Potential Energy Conservation Measures

As this data was reviewed, it was clear that some opportunities for energy conservation are present at some offtaker building locations. Unfortunately, granular data is not available for the individual buildings, but these measures are typically applicable:

1. Retro-commissioning: As described above, this process of inspecting, testing and adjusting an HVAC system to improve its energy efficiency, comfort and reliability. It is typically performed on buildings that have never had a commissioning completed after construction. Retro-commissioning identifies issues with controls, air balancing, leaks and other similar issues, and attempts to rectify them through no-cost/low-cost improvements.

2. Night setbacks: It is clear that most buildings connected to the loop do not have strict night setbacks, especially for heating. This is apparent when evaluating the central plant's average daily profile. Night baseline hot water production is only 10-20% lower than occupied/day production. Instituting night setbacks at the buildings would reduce hot water demand from the central plant.
3. Switchover point optimization: Investigate the need for hot water and chilled water when the outdoor temperature is between 55°F and 65°F. While the plant doesn't produce a significant amount of hot water and chilled water when the outdoor temperature is in that range, it is possible to reduce that even further if certain steps are taken.
4. Sequence of Operation Optimization: If more data is obtained, we would evaluate individual chiller and boiler performance at different loadings and temperatures and the sequence of operations of the plant could be adjusted to allow for a more efficient operation.
5. Demand Controlled Ventilation (DCV): It is not clear if this is currently in use, but DCV in public buildings is a great measure to control heating and cooling costs when the building has low occupancy. DCV should only be considered if the BMS has been retro-commissioned and is in good working condition.
6. Temperature setpoint optimization: While a retro-commissioning effort would investigate and correct issues with temperature sensors, it is recommended that the occupied setpoints for heating and cooling be reviewed and adjusted as needed. Occupied heating setpoints could be as low as 66°F. Occupied cooling setpoints could be as high as 74°F.

APPENDIX F

Deliverable 5: Thermal Distribution System Evaluation Memo Report

September 27, 2023

Noel Petra
Managing Director
Strategic Redevelopment
Real Estate & Construction Services
Department of Administrative Services
450 Columbus Boulevard, Suite 1301
Hartford, CT 06103
Noel.Petra@ct.gov

SUBJECT: **Contract No.: OC-DCS-ENGY-0030 Task No. 3**
Deliverable 5: Thermal Distribution System Evaluation Memo Report

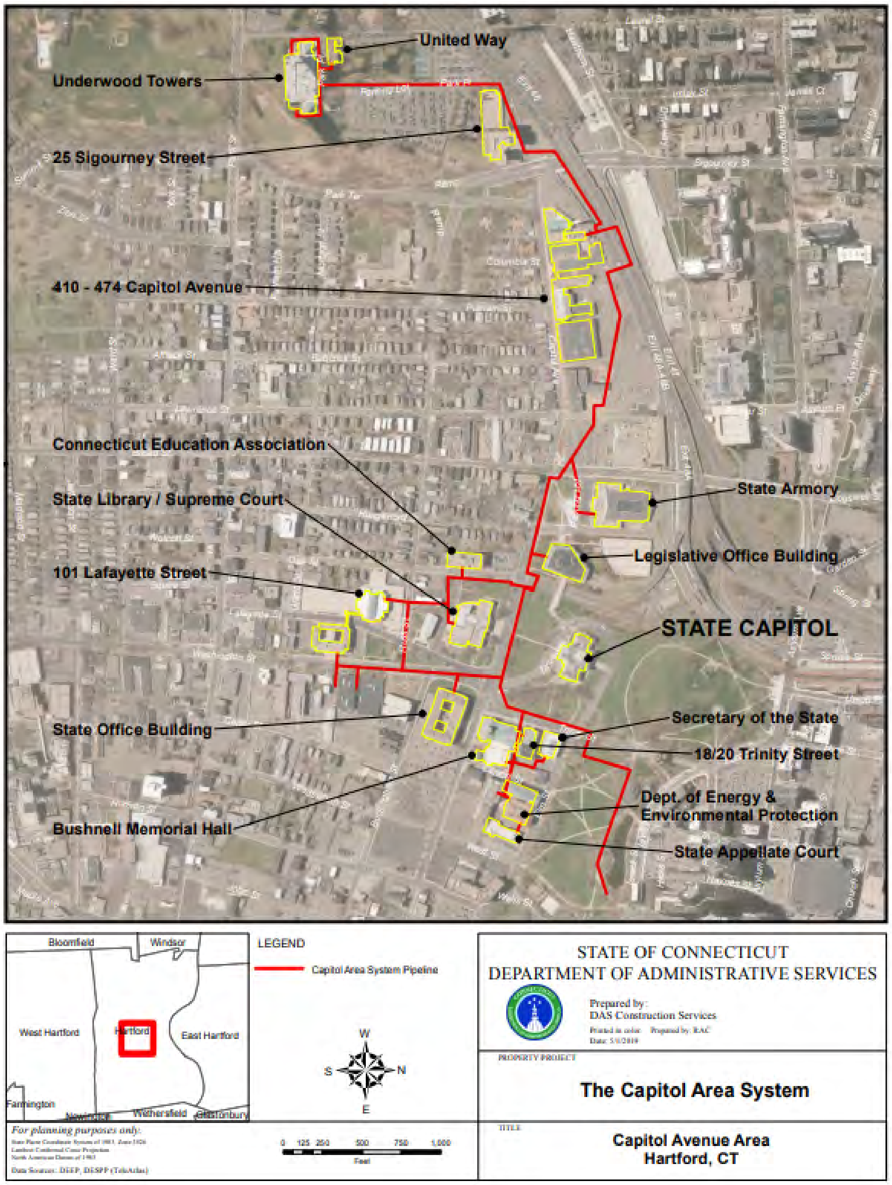
Dear Noel,

Veolia has prepared the following memo report as Deliverable 5: Thermal Distribution System Evaluation for the CAS Decarbonization Project. This is the fifth of eight (8) deliverables under Contract No.: OC-DCS-ENGY-0030 Task No. 3. The purpose of this deliverable is to provide a summary of initial findings of potential impacts to the thermal distribution system loop and off-taker distribution systems that may occur due to proposed supply temperature adjustments since lower temperature supply would result in the need for higher flow to meet the same energy demand and/or significant modifications to the thermal equipment at the offtaker buildings.

1. Background

The Capitol Area System (CAS) district heating and cooling loop serves both State and private users in the Capitol area. The loop is made up of over three (3) miles of underground piping which is used to deliver hot water and chilled water produced by the central plant to the current fifteen (15) offtakers as shown in Figure 1 below, with plans to expand the loop to include several other buildings, including the State Capitol and Superior Court building. The original portions of the loop were installed in 1996-1998, with several expansions over the years, and was generally designed for 180°F hot-water supply (HWS). While a lower hot-water supply (HWS) temperature can increase the efficiency of the equipment which provides the hot water, providing the necessary heating capacity with a lower HWS temperature requires a higher fluid flow rates and pressures than a high HWS temperature.

FIGURE 1: CAS Thermal Distribution System Loop



2. CAS Thermal Distribution System Loop Evaluation

On May 19, 2023 Veolia spoke with Emory Allaire of Tucker Mechanical, the company responsible for operation and maintenance of the CAS thermal distribution system loop, in order to obtain information on the operation and condition of the loop. Key takeaways from the discussion include the following:

- The CAS distribution system was originally designed to provide hot water (HW) at 200°F on a design day of 0°F outdoor air temperature. This was later increased to a design day of 5°F outdoor air temperature.

- The loop HW temperature was later reduced to 180°F; however, the system struggles to maintain temperature in some buildings when the outdoor temperature is in the teens so HW temperature is increased by 10°F increments up to 200°F to meet building loads.
- Emory suspects that some of the heat exchangers in the buildings were designed for 200°F so they struggle to supply enough heat at 180°F.
- The HW loop is where most leaks occur and it currently averages approximately three (3) leaks repaired per year. Leaks are typically only visually detectable when they reach 4-5 gal/min. Corrosion occurs on the outside of the pipe due ground water getting through the protective jacket. In general there is always approximately 1-2 gal/min leakage.
- The original underground section of the loop is approximately 2.5 miles long and is constructed of schedule 15 equivalent piping.
- Less than 1% of the original loop has been replaced. All replacements and additions to the loop are constructed of schedule 40 piping.
- Generally, when a leak is repaired, only a foot or two of pipe is replaced.
- The HW loop operates at approximately 40-45 psig and the chilled water (CHW) loop operates at approximately 100 psig. The hot water loop is an 'open loop system' while the chilled water loop is a 'closed loop system'.
- There are concerns regarding increasing flow/pressure in the loop in order to lower the HW supply temperature due to the age and condition of the original piping.

Based on as-built drawings and flow schematics for the CAS loop, HW distribution piping main lines are 12 to 14 inches in diameter, with smaller branch lines ranging from 6 to 8 inches in diameter, and CHW distribution piping main lines are 20 inches in diameter, with smaller branch lines ranging from 8 to 10 inches in diameter.

3. Offtaker Thermal Distribution Systems Evaluation

Based on the limited design documents provided for the offtaker buildings, historic heating loop supply temperatures and discussions with site personnel it appears that the offtaker buildings' heating systems were generally designed for 180°F supply hot-water. At each offtaker location hot water and chilled water for the building are provided through an energy transfer station connected to the CAS thermal distribution loop, with the exceptions of 166 Capitol Avenue and 101 Lafayette which receive chilled water only and 410 - 470 Capitol Avenue which receives steam instead of hot water. This system provides and meters hot water/steam and chilled water to the buildings, billing by the MMBtu (for hot water/steam) and Day-Ton (DTon) for chilled water. The energy consumption is measured by flow meters and temperature sensors in each building. Distribution systems in each building vary but generally consist of chilled water and hot water/steam piping networks which distribute energy to a mix of air handling units (AHUs), fan coil units (FCUs), variable air volume (VAV) boxes and radiators.

4. Potential Distribution System Impacts

4.1. CAS Thermal Distribution Loop

Before increasing flow and pressure in the underground piping loop additional engineering studies and flow tests would need to be performed in order to understand potential impacts to the system. While providing HWS at a lower temperature would require additional pumping energy in order to overcome potential restrictions in the piping system, the effect of increased flows and pressure on the piping network itself is impossible to determine without a detailed engineering study and flow tests. Based on the age of most of the underground piping loop and history of documented leaks at existing flows and pressures it is possible that significant upgrades to the system could be required. Therefore, for the purposes of this study Veolia has estimated the additional pumping energy required to provide HWS at a lower temperature and included this in our cost estimates where applicable; however, no estimate for potential improvements/upgrades to the underground piping system have been included in cost estimates.

Energy transferred at each offtaker is limited by the heat exchanger size, the flow rates and the loop-side temperature delta between supply and return. If heat exchanger size and temperature delta are held constant, an increase to flow rate will be required to account for the reduction in heat transfer across the surface area of the heat exchanger. The estimated increase in pumping energy required for providing HWS at a lower temperature was calculated based on existing main and branch line pipe diameters and existing and estimated increased flow rates. Following the proposed installation of new pumps and variable frequency drives (VFDs) to circulate water through the HW and CHW loops, a reduction in annual pumping energy is expected, on the order of ~30%. Lowering the supply temperature of the hot water loop, however, is expected to increase the annual pumping energy by 100% for the hot water loop. This equates to a blended annual increase of 20% for both loops over the 2020 pumping energy requirements.

Changes to the thermal infrastructure at offtaker buildings could potentially keep flow requirements and the associated pumping costs lower but additional offtaker building analysis is required.

4.2. Offtaker Thermal Distribution System

Since providing the necessary heating capacity with a lower HWS temperature requires a higher fluid flow rate than a high HWS temperature, this may require additional hot-water coil rows in end-use HVAC equipment to provide the required heating capacity, as well as a higher fluid flow rate, which can affect the size of pipes, pumps, and valves, and can also increase pumping energy use. Buildings may also require weatherization to reduce heating loads and radiator redesign to meet building heating needs.

While efficiency increases at the CAS plant would not result in energy savings at the offtaker buildings themselves, and may actually increase electric use due to higher pumping rates, ensuring that the offtaker buildings could maintain heating capacity at a lower HWS temperature would be critical before deciding to lower the HWS temperature of the loop. The first step would likely be to conduct tests at each offtaker building in order to observe how its systems respond to reduced hot water temperatures and increased flow rates and determine if they are capable of meeting heating requirements under those supply conditions. Based on the age of most of the systems in the offtaker buildings and discussions with representatives from Trane, an HVAC equipment manufacturer, regarding similar low HWS temperature conversions projects it appears that the more likely outcome is that major HVAC equipment modifications and/or replacements would be required. Since 165 Capitol Avenue was the only offtaker building for which detailed HVAC design drawings were provided and it had recently undergone a major renovation of its systems using equipment from Trane, Trane was requested to provide budgetary pricing to upgrade major pieces of equipment (air handling units, variable air volume boxes, etc.) to operate at low HWS temperatures. Using this pricing, Veolia developed an estimated $/square foot cost to upgrade major HVAC equipment at each of the offtaker buildings resulting in a total estimated cost of approximately $45M for all fifteen (15) buildings. However, this cost could vary significantly from actual costs developed from building testing and a full engineering study.

APPENDIX G

Deliverable 6: Supply Side Evaluation Memo Report

September 27, 2023

Noel Petra
Managing Director
Strategic Redevelopment
Real Estate & Construction Services
Department of Administrative Services
450 Columbus Boulevard, Suite 1301
Hartford, CT 06103
Noel.Petra@ct.gov

SUBJECT: **Contract No.: OC-DCS-ENGY-0030 Task No. 3**
Deliverable 6: Supply Side Evaluation Memo Report

Dear Noel,

Veolia has prepared the following memo report as Deliverable 6: Supply Side Evaluation for the CAS Decarbonization Project. This is the sixth of eight (8) deliverables under Contract No.: OC-DCS-ENGY-0030 Task No. 3. The purpose of this deliverable is to provide a concept design basis and summary of constraints and criteria for each supply side scenario, which will include order of magnitude capital, operating and carbon costs for each scenario.

1. Supply Side Design Scenarios

As defined in Deliverable 1: Client Kickoff Workshop #1 Memo Report, the following section defines the supply side scenarios for the generation of thermal heating and cooling products. The fuels considered to feed these supply side technologies (i.e. raw energy supply mix) include conventional grid electricity, conventional natural gas, geothermal, and renewable electricity.

TABLE 1: Supply Side Design Scenarios

Scenario	Description
A.1.H	Condenser Water Source HP w/ Electric Boilers - High Temperature
A.1.H	Condenser Water Source HP w/ Electric Boilers - High Temperature
A.1.L	Condenser Water Source HP w/ Electric Boilers - Low Temperature
A.2.H	Condenser & Ground Source HP w/ Electric Boilers - High Temperature
A.2.L	Condenser & Ground Source HP w/ Electric Boilers - Low Temperature
A.3.H	Condenser & Air Source HP w/ Electric Boilers - High Temperature
A.3.L	Condenser & Air Source HP w/ Electric Boilers - Low Temperature
B.1.H	Electric Boiler - Tech 1 - High Temperature
B.1.L	Electric Boiler - Tech 1 - Low Temperature

C.1.H	Condenser Water Source HP - High Temperature
C.1.L	Condenser Water Source HP - Low Temperature
C.2.H-2	Ground Source HP - High Temperature
C.2.L	Ground Source HP - Low Temperature
C.3.H	Air Source HP - High Temperature
C.3.L	Air Source HP - Low Temperature
D.1.H	Condenser Water Source HP w/ Natural Gas Boilers - High Temperature
D.1.L	Condenser Water Source HP w/ Natural Gas Boilers - Low Temperature
D.2.H	Ground Source HP w/ Natural Gas Boilers - High Temperature
D.2.L	Ground Source HP w/ Natural Gas Boilers - Low Temperature
D.3.H	Air Source HP w/ Natural Gas Boilers - High Temperature
D.3.L	Air Source HP w/ Natural Gas Boilers - Low Temperature
E.1.H	Natural Gas Boiler - High Temperature
E.1.L	Natural Gas Boiler- Low Temperature

1.1. Supply Side Design Scenario Definitions

The following are brief definitions of the CAS plant operating scenarios evaluated as part of this study.

1.1.1. Scenario A.1.H - Hybrid Water Source Heat Pump & Electric Boiler (High Temp)

Water source heat pumps coupled with electric boilers provide hot water to the heating loop at existing supply temperatures (approximately 180° F to 200° F). The water source for the heat pump is the existing condenser water loop that serves the water cooled chillers. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop. Therefore, the sizing of the heat pumps were limited by the condenser water leaving the water cooled chillers. The remaining hot water load will be met by the electric boilers.

1.1.2. Scenario A.1.L - Hybrid Water Source Heat Pump & Electric Boiler (Low Temp)

Water source heat pumps coupled with electric boilers provide hot water to the heating loop at reduced supply temperatures (approximately 130° F). The water source for the heat pump is the existing condenser water loop that serves the water cooled chillers. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop. Therefore, the sizing of the heat pumps were limited by the condenser water leaving the water cooled chillers. The remaining hot water load will be met by the electric boilers.

1.1.3. Scenario A.2.H - Hybrid Ground Source Heat Pump & Electric Boiler (High Temp)

Ground source heat pumps as the primary heat source, coupled with electric boilers and water source heat pumps provide hot water to the heating loop at existing supply temperatures (approximately 180° F to 200° F). The source for the ground source heat pump is geothermal wells. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop.

Therefore, the sizing of the water source heat pumps were limited by the condenser water leaving the water cooled chillers. While the ratio of ground source heat pumps to electric boiler capacity is adjusted to optimize financial benefit based on capital and operating expenses, the remaining heat demand will be met by these technologies.

1.1.4. Scenario A.2.L - Hybrid Ground Source Heat Pump & Electric Boiler (Low Temp)

Ground source heat pumps as the primary heat source, coupled with electric boilers and condenser water source heat pumps provide hot water to the heating loop at reduced supply temperatures (approximately 130° F). The source for the ground source heat pump is geothermal wells. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop. Therefore, the sizing of the water source heat pumps were limited by the condenser water leaving the water cooled chillers. While the ratio of ground source heat pumps to electric boiler capacity is adjusted to optimize financial benefit based on capital and operating expenses, the remaining heat demand will be met by these technologies.

1.1.5. Scenario A.3.H - Hybrid Air Source Heat Pump & Electric Boiler (High Temp)

Air source heat pumps as the primary heat source, coupled with electric boilers and condenser water source heat pumps provide hot water to the heating loop at existing supply temperatures (approximately 180° F to 200° F). The air source for the heat pump is ambient air. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop. Therefore, the sizing of the water source heat pumps were limited by the condenser water leaving the water cooled chillers. While the ratio of air source heat pumps to electric boiler capacity is adjusted to optimize financial benefit based on capital and operating expenses, the remaining heat demand will be met by these technologies.

1.1.6. Scenario A.3.L - Hybrid Air Source Heat Pump & Electric Boiler (Low Temp)

Air source heat pumps as the primary heat source, coupled with electric boilers and condenser water source heat pumps provide hot water to the heating loop at reduced supply temperatures (approximately 130° F). The air source for the heat pump is ambient air. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop. Therefore, the sizing of the water source heat pumps were limited by the condenser water leaving the water cooled chillers. While the ratio of air source heat pumps to electric boiler capacity is adjusted to optimize financial benefit based on capital and operating expenses, the remaining heat demand will be met by these technologies.

1.1.7. Scenario B.1.H - Electric Boilers (High Temp)

Electric boilers provide hot water to the heating loop at existing supply temperatures (approximately 180° F to 200° F). Electric chillers are used to serve the chilled water loop.

1.1.8. Scenario B.1.L - Electric Boilers (Low Temp)

Electric boilers provide hot water to the heating loop at reduced supply temperatures (approximately 130° F). Electric chillers are used to serve the chilled water loop.

1.1.9. Scenario C.1.H - Water Source Heat Pump (High Temp)

Water source heat pumps provide hot water to the heating loop at existing supply temperatures (approximately 180° F to 200° F). The water source for the heat pump is the existing condenser water loop that serves the water cooled chillers, therefore it restricts the size of the water source heat pump. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop.

1.1.10. Scenario C.1.L - Water Source Heat Pump (Low Temp)

Water source heat pumps provide hot water to the heating loop at reduced supply temperatures (approximately 130° F). The water source for the heat pump is the existing condenser water loop that serves the water cooled chillers, therefore it restricts the size of the water source heat pump. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop.

1.1.11. Scenario C.2.H - Ground Source Heat Pump (High Temp)

Ground source heat pumps as the primary heat source, coupled with condenser water source heat pumps provide hot water to the heating loop at existing supply temperatures (approximately 180° F to 200° F). The ground source for the heat pump is geothermal wells. The water source for the other heat pump is the existing condenser water loop that serves the water cooled chillers, therefore it restricts the size of the water source heat pump. The remaining heat load will be met by the ground source heat pump. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop.

1.1.12. Scenario C.2.L - Ground Source Heat Pump (Low Temp)

Ground source heat pumps as the primary heat source, coupled with condenser water source heat pumps provide hot water to the heating loop at reduced supply temperatures (approximately 130° F). The ground source for the heat pump is geothermal wells. The water source for the other heat pump is the existing condenser water loop that serves the water cooled chillers, therefore it restricts the size of the water source heat pump. The remaining heat load will be met by the ground source heat pump. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop.

1.1.13. Scenario C.3.H - Air Source Heat Pump (High Temp)

Air source heat pumps as the primary heat source, coupled with condenser water source heat pumps to provide hot water to the heating loop at existing supply temperatures (approximately 180° F to 200° F).

The air source for the heat pump is ambient air. The water source for the other heat pump is the existing condenser water loop that serves the water cooled chillers, therefore it restricts the size of the water source heat pump. The remaining heat load will be met by the air source heat pump. Electric chillers are used to serve the chilled water loop.

1.1.14. Scenario C.3.L - Air Source Heat Pump (Low Temp)

Air source heat pumps as the primary heat source, coupled with condenser water source heat pumps provide hot water to the heating loop at reduced supply temperatures (approximately 130° F). The air source for the heat pump is ambient air. The water source for the other heat pump is the existing condenser water loop that serves the water cooled chillers, therefore it restricts the size of the water source heat pump. The remaining heat load will be met by the air source heat pump. Electric chillers are used to serve the chilled water loop.

1.1.15. Scenario D.1.H - Hybrid Water Source Heat Pump & Natural Gas Boiler (High Temp)

Water source heat pumps coupled with natural gas boilers provide hot water to the heating loop at existing supply temperatures (approximately 180° F to 200° F). The water source for the heat pump is the existing condenser water loop that serves the water cooled chillers. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop. Therefore, the sizing of the heat pumps were limited by the condenser water leaving the water cooled chillers. The remaining hot water load will be met by the natural gas boilers.

1.1.16. Scenario D.1.L - Hybrid Water Source Heat Pump & Natural Gas Boiler (Low Temp)

Water source heat pumps coupled with natural gas boilers provide hot water to the heating loop at reduced supply temperatures (approximately 130° F). The water source for the heat pump is the existing condenser water loop that serves the water cooled chillers. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop. Therefore, the sizing of the heat pumps were limited by the condenser water leaving the water cooled chillers. The remaining hot water load will be met by the natural gas boilers.

1.1.17. Scenario D.2.H - Hybrid Ground Source Heat Pump & Natural Gas Boiler (High Temp)

Ground source heat pumps as the primary heat source, coupled with natural gas boilers and condenser water source heat pumps provide hot water to the heating loop at existing supply temperatures (approximately 180° F to 200° F). The source for the ground source heat pump is geothermal wells. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop. Therefore, the sizing of the water source heat pumps were limited by the condenser water leaving the water cooled chillers. While the ratio of ground source heat pumps to natural gas boiler capacity is adjusted to optimize financial benefit based on capital and operating expenses, the remaining heat demand will be met by these technologies.

1.1.18. Scenario D.2.L - Hybrid Ground Source Heat Pump & Natural Gas Boiler (Low Temp)

Ground source heat pumps as the primary heat source, coupled with natural gas boilers and condenser water source heat pumps provide hot water to the heating loop at reduced supply temperatures (approximately 130° F). The source for the ground source heat pump is geothermal wells. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop. Therefore, the sizing of the water source heat pumps were limited by the condenser water leaving the water cooled chillers. While the ratio of ground source heat pumps to natural gas boiler capacity is adjusted to optimize financial benefit based on capital and operating expenses, the remaining heat demand will be met by these technologies.

1.1.19. Scenario D.3.H - Hybrid Air Source Heat Pump & Natural Gas Boiler (High Temp)

Air source heat pumps as the primary heat source, coupled with natural gas boilers and condenser water source heat pumps provide hot water to the heating loop at existing supply temperatures (approximately 180° F to 200° F). The air source for the heat pump is ambient air. Electric chillers are used to serve the chilled water loop. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop. Therefore, the sizing of the water source heat pumps were limited by the condenser water leaving the water cooled chillers. While the ratio of air source heat pumps to natural gas boiler capacity is adjusted to optimize financial benefit based on capital and operating expenses, the remaining heat demand will be met by these technologies.

1.1.20. Scenario D.3.L - Hybrid Air Source Heat Pump & Natural Gas Boiler (Low Temp)

Air source heat pumps as the primary heat source, coupled with natural gas boilers and condenser water source heat pumps provide hot water to the heating loop at reduced supply temperatures (approximately 130° F). The air source for the heat pump is ambient air. Electric chillers are used to serve the chilled water loop. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop. Therefore, the sizing of the water source heat pumps were limited by the condenser water leaving the water cooled chillers. While the ratio of air source heat pumps to natural gas boiler capacity is adjusted to optimize financial benefit based on capital and operating expenses, the remaining heat demand will be met by these technologies.

1.1.21. Scenario B.1.H - Natural Gas Boiler (High Temp)

Natural gas boilers provide hot water to the heating loop at existing supply temperatures (approximately 180° F to 200° F). Electric chillers are used to serve the chilled water loop.

1.1.22. Scenario B.1.L - Natural Gas Boiler (Low Temp)

Natural gas boilers provide hot water to the heating loop at reduced supply temperatures (approximately 130° F). Electric chillers are used to serve the chilled water loop.

2. Financial Assumptions

2.1. Discount Rate

A discount rate is the rate of return used to discount future cash flows back to their present value. This rate is often a Weighted Average Cost of Capital (WACC), required rate of return, or the cost of debt (e.g. bond rate). For the financial analyses conducted as part of this study the State bond rate of 3.77% has been used as the discount rate.

2.2. Potential Incentives

Veolia researched available federal and state incentives which may be applicable to the scenarios described in Section 2. Based on this evaluation, only the Investment Tax Credit (ITC), as modified under the Inflation Reduction Act (IRA) of 2022, is applicable to the financial analysis in this deliverable. Additionally, only those scenarios with a geothermal heat pump system would be eligible for the ITC. A geothermal heat pump system includes any equipment that uses the ground or ground water as a thermal energy source to heat a structure or as a thermal energy sink to cool a structure. Only the portion of equipment used to produce, distribute, or use energy derived from a geothermal deposit is eligible for the credit. For the purposes of this study it is assumed that the project will meet the prevailing wage requirements and therefore a 30% ITC would be applicable. Construction of a qualified geothermal heat pump system must begin before January 1, 2035.

Veolia has facilitated meetings with Eversource to determine available incentives. As of the date of this report, Eversource is evaluating a custom incentive and has preliminarily indicated interest in participating in this project due to the large scale heat pump concepts currently being evaluated. Veolia has requested indicative incentive values so as to include them in the final phase of the study.

2.3. Social Cost of Carbon (SC-CO2)

As defined by the US EPA, the Social Cost of Carbon (or SC-CO2) is a measure, in dollars, of the long-term damage done by a ton of carbon dioxide (CO2) emissions in a given year. This dollar figure also represents the value of damages avoided for a small emission reduction (i.e., the benefit of a CO2 reduction). During discussion with the State it was determined that the State's SC-CO2 is still being developed. As such, it was agreed that until a State specific SC-CO2 has been provided, Veolia would use the following EPA SC-CO2 value for 2022 as a placeholder in its calculations. These values were obtained from Table 4.2.1 of the EPA's September 2022 *"Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances"* [1] using a discount rate of 1.5%.

[1] https://www.epa.gov/system/files/documents/2022-11/epa_scghg_report_draft_0.pdf

TABLE 2: Social Cost of Carbon (SC-CO2)

	SC-CO2
	2020 dollars per metric ton of CO2
Emission Year	(Discount Rate: 1.5%)
2022	$346

All financial analyses are presented both with and without the SC-CO2 as a financial consideration.

2.4. Escalation Factors

An annual escalation factor of 2.5% is used for all commodities and expenses over the 30-year term, including but not limited to the following:

- Electricity cost
- Natural gas cost
- Water cost
- Labor costs
- Equipment costs
- O&M costs

This is roughly equivalent to the US Treasury 20-year Breakeven Inflation Rate of 2.48% (https://fred.stlouisfed.org/series/T20YIEM).

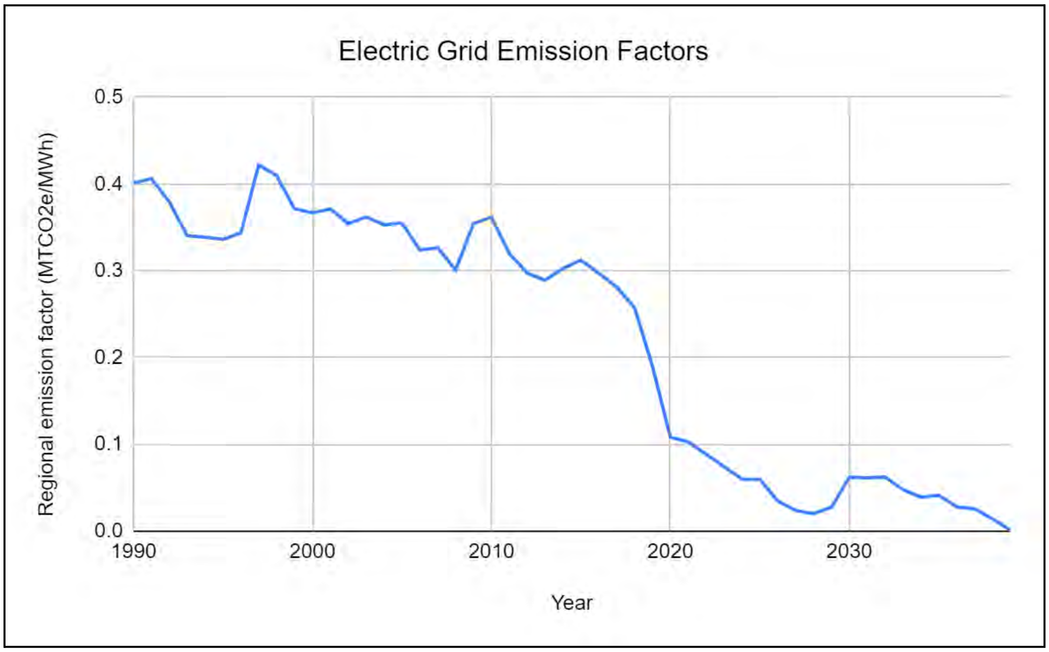
3. Carbon Emission Factors

The following emissions factors provided by the State have be used to calculate the potential emissions for various fuels that have been used in the past or may be used in the future by CAS:

TABLE 3: Electric Grid Emission Factors

Year	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**
Regional emission factor (MTCO2e/MWh)	0.4010502	0.4061386	0.3795461	0.3404675	0.3388742	0.3361012	0.3437698	0.4220527	0.4095980	0.3715102
Year	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
Regional emission factor (MTCO2e/MWh)	0.3668755	0.3712683	0.3545979	0.3621470	0.3530752	0.3551884	0.3239771	0.3264649	0.3010504	0.3545080
Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Regional emission factor (MTCO2e/MWh)	0.3617302	0.3201608	0.2973487	0.2891816	0.3027548	0.3124441	0.2971545	0.2812257	0.2576408	0.1898702
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Regional emission factor (MTCO2e/MWh)	0.1084224	0.1030013	0.0886471	0.0742929	0.0599387	0.0597731	0.0348407	0.0238254	0.0201063	0.0275437
Year	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
Regional emission factor (MTCO2e/MWh)	0.0622150	0.0616437	0.0623892	0.0477784	0.0392287	0.0414464	0.0279418	0.0257219	0.0144276	0.0009504

FIGURE 1: Electric Grid Emission Factors



Based on discussions during Workshop #1, it was agreed that CAS plant electricity purchases will conform with Executive Order No. 21-3; specifically, Section 3B which states that "By 2030, all electricity purchased and generated by the Executive Branch will be 100% zero carbon". As such, it will be assumed that starting in 2030 all electricity purchased by the plant will be 100% zero carbon. This assumption implies that dedicated zero carbon electric supply contracts will need to be procured in lieu of grid supplied power, which in accordance with Table 4 above, contains carbon in 2030 and beyond.

TABLE 4: Natural Gas Emission Factors

Natural Gas		
kg CO2/scf	kg CH4/scf	kg N2O/scf
0.054440	0.00000103	0.0000001

TABLE 5: RNG and H2 Emission Factors

	RNG (Landfill Gas)			RNG (Other Biomass Gases)			Green Hydrogen
Emission Type	kg CO2 /scf	kg CH4/scf	kg N2O/scf	kg CO2 /scf	kg CH4/scf	kg N2O/scf	kg CO2e/kgH2
Combustion	0.00	1.55×10^{-6}	0.306×10^{-6}	0.00	2.10×10^{-6}	0.413×10^{-6}	2.00
Biogenic	0.02530	-	-	0.034100	-	-	2.00

Note: For RNG, where applicable, accounting for biogenic CO2 will be calculated on the basis of the above factors and noted as a sidebar.

Since the State requires that the future availability of any alternative fuels must also be considered, renewable natural gas (RNG) and green hydrogen are not considered viable options at this time due to the uncertainty surrounding their long term availability. However, Veolia will evaluate natural gas burning equipment that is RNG and hydrogen “ready” and will include market outlooks, define the carbon lifecycle of RNG and green hydrogen, as well as a brief narrative on each as an option. Although a full financial analysis has not been conducted, a comparison of potential emissions should natural gas burning equipment be converted to RNG or hydrogen in the future is included.

4. Utility Supply Options

This section provides an overview of market options for utility services required by the CAS including a summary of procurement methods for carbon free electricity.

4.1. Power Market Forecast

Veolia’s market price forecast is used to estimate the future cost of various decarbonization strategies under consideration. There are two components to the forecast:

- Base Supply: Veolia’s 17 year forecast of grid power supply from either the utility or a 3rd party supplier.
- Renewable Energy Premium: the estimated incremental cost to completely offset the site’s scope 2 carbon emissions using Class I Renewable Energy Credits (RECs).

The Base Supply forecast is derived from prevailing forward market rates for wholesale power in Connecticut, capacity, ancillaries and Connecticut's Renewable Portfolio Standard (RPS). Many of these subcomponents are highly susceptible to change based on underlying market conditions. The forecast extends to Year 17, based on available market projections. After Year 17, an annual escalation of 3% is assumed.

We assume Class I RECs are the most likely instrument the State would use to offset its Scope 2 emissions. This is an acceptable compliance instrument under CT PURA regulations and it is consistent with state regulatory policy. We have considered an out-of-region “national green-e” REC option with a lower price point, but suspect there could be sensitivity around using RECs from markets outside of New England or that are not otherwise used for Connecticut RPS compliance purposes. We also considered power purchase agreements (ie., new project RECs and energy), however we determined that consumption at the site was too low to garner any commercial options at a reasonable price point. It’s also worth noting that PPAs tend to require a fixed level of output for a longer term tenor (e.g., > 10 years), which doesn’t fit well with the grid’s declining emissions trend.

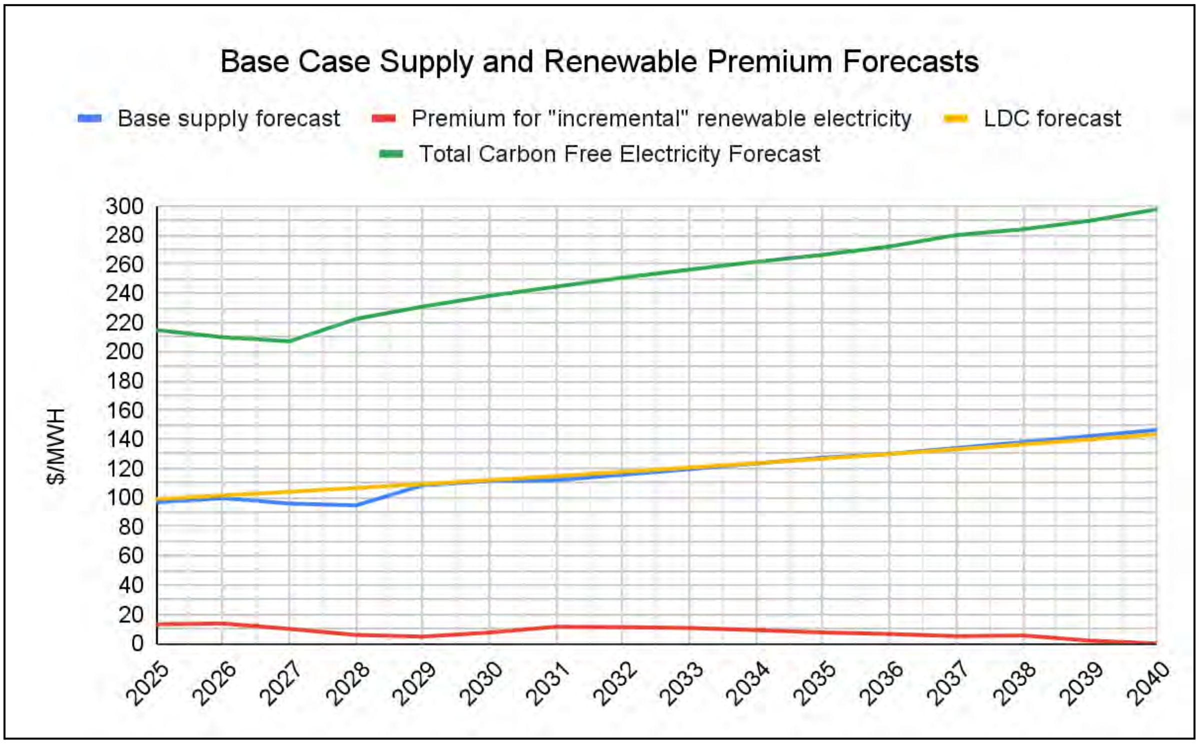
For the calculation of the Renewable Energy Premium, we first quantified the carbon balance, in metric tons, that the site would need to offset from 2030 to 2040, the assumption being that the green purchases are superfluous thereafter as the electric supply must be carbon free under state law (see e.g, Public Act 22-5 (Senate Bill 10)[2]. To calculate the carbon balance, we used a CT power supply emissions factor forecast provided by DEEP. We also verified this using an alternative approach, which is to calculate the difference between the 100% offset goal and the projected state RPS % each year. The two

[2] https://www.cga.ct.gov/2022/act/pa/pdf/2022PA-00005-R00SB-00010-PA.pdf

approaches yielded fairly consistent results with respect to cost impact. It's worth noting that Connecticut's Tier 1 REC requirement under the RPS tops out at 40% in 2030 under current regulations, however Connecticut statute requires 100% carbon-free power by 2040. In the absence of regulation, we've therefore made a conservative assumption that the RPS will increase by 6% percent per year from 2030 to 2040. This ignores potential contracts with other carbon free resources such as nuclear and is therefore probably a conservative assumption. Finally, our forecast of the renewable energy premium, as well as our base case supply forecast, is heavily influenced by our forecast of the Class I RECs. There is limited liquidity in this market, however it is generally anticipated that prices will decline rapidly in the next 5 years–from $40 to roughly $20 per REC–as large offshore wind projects reach commercial operation.

The following plot shows base case and renewable energy premium forecasts:

FIGURE 2: Base Case Supply and Renewable Premium Forecasts



- The blue curve ('Base supply forecast') represents the price forecast for electricity supply, whether that is through Eversource or a third party supplier. This electricity is generated from a mix of resources.
- The yellow curve ('LDC forecast') represents the local distribution company (LDC - Eversource) price forecast for delivery electrical supply to the CAS.
- The red curve ('Premium for "incremental" renewable electricity') represents the price forecast for obtaining the balance of carbon free electricity (the volume required beyond that which is supplied by Eversource through the RPS as described above.

- The green curve is the sum of all curves and is the forecast that is used in the study model to represent the price of electricity for the CAS

We have introduced various scenarios in which the CAS Plant may continue to rely on natural gas boilers. For these scenarios, we have also provided carbon mitigation options that assume the use of carbon offsets. Carbon offsets can be acquired from a large diversity of technologies, projects, and regions. There can also be a wide price range for these products. In our carbon offset price assumptions, we have used a midpoint of pricing received from various projects within the North American Improved Forestry Management category. Credits would be secured from reputable certification standards such as Gold Standard, Verra, or American Carbon Registry.

4.2. Electricity Rate

According to Eversource, when the existing high tension service is decommissioned and a new lower tension service is established, the Large Time-of-Day (Rate 58) tariff will apply. From the plot above, the green forecast line represents the sum of Eversource supply, their distribution costs and the premium the State can expect to pay to decarbonize the balance of electricity supplied by Eversorce.

This forecast can then be compared to other supply options such as renewable PPA's, on or offsite solar or utility based programs. Section 4.5 below provides an overview of such procurement options.

4.3. Natural Gas Utility RatE

The existing local utility's (Connecticut Natural Gas) applicable tariff structure for natural gas is the Large General Service (LGS) Customer rate, which is defined as a customer whose anticipated consumption is greater than 30,000 CCF per year. The estimated blended rate determined as of May 21, 2023 is $5.50 of $8.25 per MMBTU was used for this study.

4.4. Water Utility Rate

Water supplied to the CAS plant by the Metropolitan District (MDC) was calculated at a blended rate of $8.28 per CCF.

4.5. Carbon Free Electricity Options

There are several options for mitigating carbon emission beyond making physical changes to energy consuming equipment which may include the following categories:

4.5.1. RECs & Carbon Offsets

These are environmental attributes associated with renewable energy or carbon offset – uncoupled from physical delivery of electricity or natural gas and fall into two categories:

- National Voluntary RECs
- Local Compliance RECs

Both have well defined auditing processes in place to verify the existence and usage of the RECs. National Voluntary RECs are the cheapest available and the types of energy and regions can usually be defined. Compliance RECs are used for compliance with state Regional Portfolio Standards (RPS) and carry higher price but more specificity.

4.5.2. Power Purchase Agreements (PPAs)

Through PPAs, customers contract directly for the power off-take of a renewable energy generator and settle power transactions through the Independent System Operator (ISO). They can be set up with multiple options either within a region or in another ISO:

- Operate as a wholesale participant within the ISO and establish a PPA with a regional renewable energy asset within the ISO
- Contractual relationship where supplier carves out part of a larger renewable project
- Renewable power outside of the respective ISO can be procured but will likely be a financial Contract for Differences structure
- Behind-the-Meter PPAs offset retail consumption relieve customer from owning and operating assets

4.5.3. Special Case Utility Programs

Many utilities have voluntary renewable energy options, both in restructured and vertically integrated territories with a range of opportunities made available by state policy:

- Virtual Net Metering contracts
- REC purchase or PPA purchase with consolidated billing options
- Community choice solar, wind, or battery tariff

The incumbent utility is typically the interface in these arrangements but not always and the agreements vary by utility and state. In many cases they do NOT transfer title to the customer so they must adhere to the buyer's internal sustainability goals.

4.5.4. Owned Assets

These are renewable assets owned and operated by the end-user and require capital outlays for construction/acquisition, as well as operating costs. Depending on the operating profile, user-owned generation can provide economic benefits and flexibility of options. Such assets can be developed behind-the-meter or off-site, however the latter will typically require counterparty involvement. Additionally, the area required to provide enough generation to fully offset usage can be a significant challenge for many urban buildings.

4.6. Installed Solar PV

Solar PV could potentially be installed at state-owned offtaker buildings either as a PPA or an owned asset. While the electricity generated would not flow directly to the CAS plant its attributes could be used to offset electrical consumption at the plant. Veolia conducted a high level desktop solar PV screening of state owned offtaker buildings and determined that approximately 2,200,000 kWh of electricity could potentially be generated (Appendix A). Additional considerations such as the age and and structural integrity of the roof at each location would need to be evaluated prior to determining the feasibility of any solar installation.

5. Operational Costs

5.1. Operations & Maintenance

Under an Operations and Maintenance Agreement dated October 7, 2020, IHI Power Services Corp. (IHI) provides operations and maintenance (O&M) services for the CAS plant. Using 2023 labor projections, annual O&M services provided by IHI are expected to be:

● Annual Operator Fee	$200,000 per year
● Labor	$415,829 per year
● Other Reimbursable Expenses	$1,000 per month (estimated)
○ Total	$627,829 per year

All proposed operating scenarios in Section 2 are anticipated to require a similar magnitude of O&M as currently provided, however there are differences as to the long term maintenance and repair costs based on the specific technology deployed. Therefore, the total operating and maintenance budget for each scenario includes the annual fee as is currently provided by IHI plus technology specific repair and maintenance values.

5.2. Eversource High Tension Service

The existing annual cost for Eversource high tension service O&M is $23,034 according to Eversource. Veolia has requested that Eversource provide a projected annual cost for future service but this cost has not yet been provided. Therefore, the existing annual cost has been carried for all scenarios.

5.3. Repairs & Maintenance

Based on Veolia's experience operating similar plants, an annual budget for each scenario has been assumed to cover performance guarantees, spare parts and repairs.

6. Geothermal Screening

A high level desktop screening was used to determine the feasibility of geothermal heat pumps. Publicly available tools such as the National Renewable Energy Laboratory (NREL) REopt® (https://reopt.nrel.gov/tool/) and Department of the Interior U. S. Geological Survey maps, as well as information from other sites where Veolia has been involved with geothermal studies and installations, was used to estimate required geothermal well layout area and depth, existing bedrock and water depths, and order of magnitude costs. Based on available information it appears that groundwater is present at approximately 10-20 feet below grade and bedrock is present at approximately 50-100 feet below grade at the site. Generally, the presence of groundwater and bedrock at relatively shallow depths is conducive to geothermal installations.

Based on estimated required flow rates and peak heating demand requirements (as determined in Deliverable 2: Total Energy Requirements/Design Basis Memo Report) and using the open parking areas adjacent to the CAS plant to the east (Figure 3) it was estimated that, depending on subsurface conditions, 400-850 geothermal wells drilled to a depth of 1,500 feet could be required for the installation of a geothermal heat pump system. An installed cost for geothermal wells at the site, including drilling and piping, based on a cost per unit of energy recovery rate ($/MMBTU/Hr), was estimated based on a range of pricing from similar installations and this cost was applied to each geothermal scenario based on energy flow requirements.

In order to fully evaluate the feasibility of geothermal heat pumps at the site a detailed on-site subsurface investigation including test wells and pumping tests would be required in order to determine actual bedrock depth and composition, as well as other factors such as groundwater flow transmissivity through the bedrock. The results of this investigation would also determine the actual number, depth and cost of geothermal wells required for any geothermal heat pump installation.

FIGURE 3: Proposed Geothermal Well Field Area

7. Supply Side Design Scenario Screening Results

The table below presents key performance figures for the lowest Net Present Cost (NPC) for each technology option. The NPC includes initial capital costs (CapEx) and 30 year operating costs (OpEx) (fuel, operation and maintenance (O&M), repairs, etc.). It is assumed that equipment life is 30 years and no full replacements will be required. Revenues from sales to the offtakers have not been calculated as part of NPC but are expected to be the same across all scenarios and therefore will not affect scenario rankings. A full list of scenario results can be found in Appendix B. Total installed heating and cooling capacity was based on agreed upon parameters in Deliverable 2: Total Energy Requirements/Design Basis Memo Report. Heating equipment capacities for each scenario are also included in Appendix B.

Two (2) scenarios were determined to be technologically infeasible due to constraints of the input heat source. The condenser water heat pump only solution (C.1.H & C.1.L) was limited by the volume of condenser water available and could not generate enough heat as a stand alone solution. Similarly, an air source pump only solution (C.3.H & C.3.L) could not generate enough heat on the coldest days to meet heating demand without a supplemental heat source.

Although the low temperature solution had a lower NPC in some scenarios, the difference between the high temperature solution and the low temperature solution NPC was generally only on the order of around 5% over the assumed project term of 30 years. Since there is a greater uncertainty regarding the cost of system improvements that may be required at the offtaker buildings and/or distribution systems to implement the low temperature solution, further evaluation may indicate that the high temperature solution is the preferred scenario. An estimated cost of $45M for system improvements at all fifteen (15) buildings has been included in the CapEx for all low temperature hot water scenarios.

All or partial electric solutions have a higher Year 1 OpEx compared to all natural gas solutions due to the significantly higher cost per unit of energy for electricity versus natural gas, even after factoring in expected increases in equipment efficiency. Existing annual OpEx (fuel, O&M) is approximately $3.5M. However, when based on the anticipated increased future loads which are used in all of the above scenarios OpEx would be expected to increase to approximately $4.4M under baseline 2020 operating conditions. This does not include the estimated cost of equipment repairs, which has been included in the scenario evaluations.

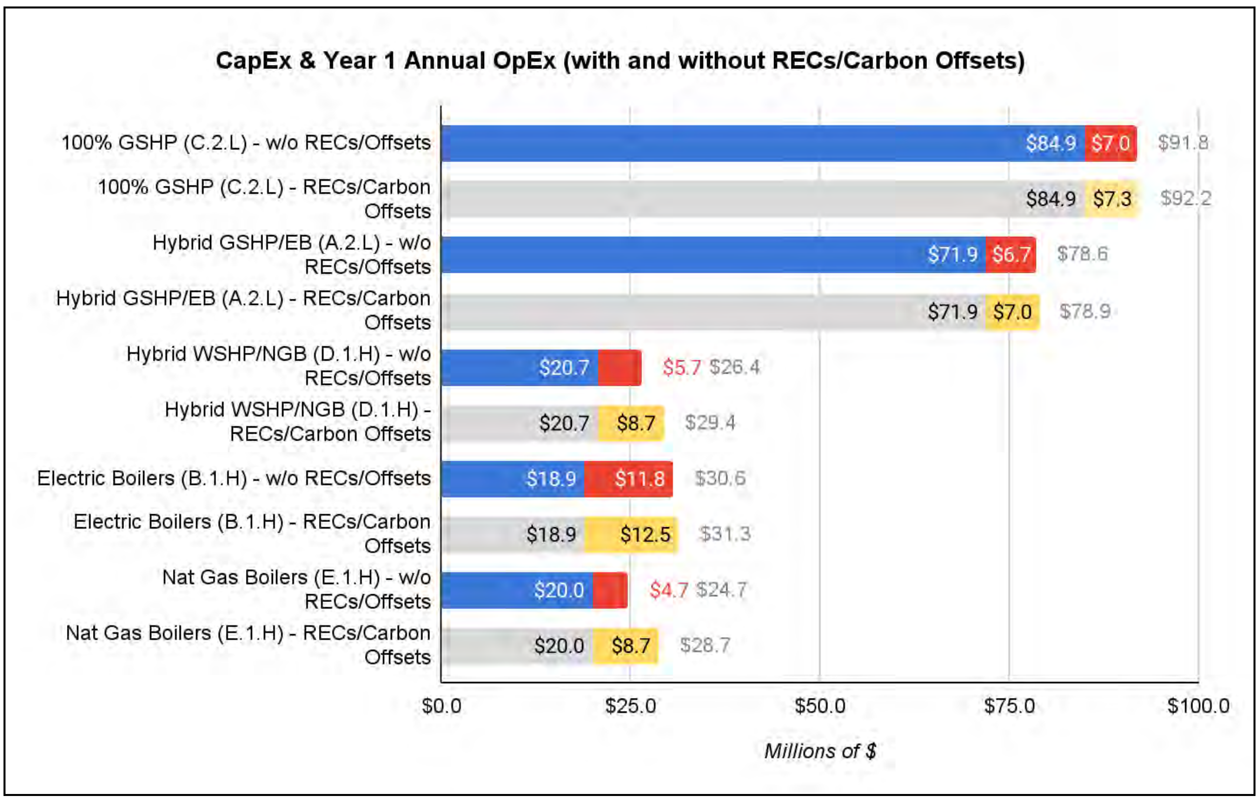
TABLE 6: Lowest NPC Performance Figures for Each Technology Option

Scenario		CapEx	CapEx w/ITC	Year 1 OpEx w/Social Cost of Carbon	NPC w/Social Cost of Carbon	Year 1 OpEx w/o Carbon Costs	NPC w/o Carbon Costs
A.2.L	Hybrid of GS Heat Pumps & Electric Boilers	$78.0	$71.9	$7.22	$242	$6.7	$238
B.1.H	100% Electric Boilers	$18.9	$18.9	$12.90	$324	$11.8	$316
C.2.L	100% GS Heat Pumps	$97.1	$84.9	$7.47	$261	$7.0	$257

D.1.H	Hybrid of WS Heat Pumps & Natural Gas Condensing Boilers	$20.7	$20.7	$8.22	$205	$5.7	$164
E.1.H	100% Natural Gas Condensing Boilers	$20.0	$20.0	$7.94	$194	$4.7	$137

Note: All values shown in nominal Millions of USD (2023).

FIGURE 3: CapEx & Year 1 Annual OpEx (with and without RECs/Carbon Offsets)



Attachments:

Appendix A: Modeled Potential Offtaker Building Annual Solar PV Production

Appendix B: Full List of Scenario Results

APPENDIX A

Modeled Potential Offtaker Building Annual Solar PV Production

Building Address	Ownership	Potential Annual MWh
300 Capitol Ave (LOB)	State-owned	153
2 Park Place (P.P. Tower A)	Private	0
24 Park Place (P.P. Tower B)	Private	0
166 Capitol Ave (Bushnell Theater)	Private	91
30 Laurel St (United Way)	Private	0
18-20 Trinity St (Ethics)	Private	35
30 Trinity St (Sec. of State)	Private	40
231 Capitol Ave (Judicial/Supreme Court)	State-owned	87
360 Broad St (Armory)	State-owned	348
21 Oak St (CEA)	Private	0
79 Elm St (DEEP)	State-owned	0
75 Elm St (Judicial)	State-owned	61
410 - 470 Capitol Ave (OPM) Roof	State-owned	410
410 - 470 Capitol Ave (OPM) Parking Lot	State-owned	936
101 Lafayette (Judicial)	State-owned	94
165 Capitol Ave (State Office Building)	State-owned	147
	State-owned Total	**2,236**
	Private Total	**166**

APPENDIX B

Full List of Scenario Results

Scenario	A.1.H	A.1.L	A.2.H	A.2.L	A.3.H	A.3.L
Description	Condenser Water Source HP w/ Electric Boilers	Condenser Water Source HP w/ Electric Boilers	Condenser & Ground Source HP w/ Electric Boilers	Condenser & Ground Source HP w/ Electric Boilers	Condenser & Air Source HP w/ Electric Boilers	Condenser & Air Source HP w/ Electric Boilers
Supply Temperature	High	Low	High	Low	High	Low
CapEx	$19.6	$58.2	$42.8	$78.0	$28.3	$62.3
CapEx w/ Incentives	$19.6	$58.2	$35.7	$71.9	$28.3	$62.3
Year 1 OpEx (w/ Social Cost of Carbon)	$11.7	$11.3	$10.2	$7.2	$10.7	$8.3
Year 1 OpEx (w/ RECs/Carbon Offsets)	$11.4	$10.9	$9.9	$7.0	$10.4	$8.0
Year 1 OpEx (w/o Carbon Costs)	$10.7	$10.3	$9.4	$6.7	$9.9	$7.6
NPC (w/ Social Cost of Carbon)	$297	$324	$278	$242	$284	$258
NPC (w/ Carbon Offsets)	$294	$321	$276	$240	$281	$256
NPC (w/o Carbon Costs)	$289	$316	$272	$238	$277	$253
Lifetime Carbon (30-Year Tons)	29,852	28,714	23,561	16,001	25,019	19,231
Assumed Heat Pump Capacity (MMBTU/hr)	4	4	34	34	24	24
Assumed Boiler Capacity (MMBTU/hr)	68	68	38	38	48	48
Estimated Electricity Demand (MW)	37	37	31	31	33	33

Notes: 1. All costs are in millions of dollars.
2. 100% Condenser water heat pump scenarios (C.1.H & C.1.L) and 100% air source heat pump scenarios (C.2.H & C.2.L) were determined to not be feasible and are not included in this table.

Scenario	B.1.H	B.1.L	C.2.H	C.2.L	D.1.H	D.1.L
Description	Electric Boiler	Electric Boiler	Ground Source HP	Ground Source HP	Condenser Water Source HP w/ Natural Gas Boilers	Condenser Water Source HP w/ Natural Gas Boilers
Supply Temperature	High	Low	High	Low	High	Low
CapEx	$18.9	$57.9	$53.4	$97.1	$20.7	$59.2
CapEx w/ Incentives	$18.9	$57.9	$42.7	$84.9	$20.7	$59.2
Year 1 OpEx (w/ Social Cost of Carbon)	$12.9	$13.0	$10.0	$7.5	$8.2	$7.4
Year 1 OpEx (w/ RECs/Carbon Offsets)	$12.5	$12.6	$9.7	$7.3	$8.7	$7.9
Year 1 OpEx (w/o Carbon Costs)	$11.8	$11.9	$9.3	$7.0	$5.7	$5.0
NPC (w/ Social Cost of Carbon)	$324	$365	$281	$261	$205	$222
NPC (w/ Carbon Offsets)	$321	$361	$278	$260	$235	$251
NPC (w/o Carbon Costs)	$316	$356	$275	$257	$164	$182
Lifetime Carbon (30-Year Tons)	33,330	33,649	21,829	15,095	202,889	195,982
Assumed Heat Pump Capacity (MMBTU/hr)	0	0	49	49	4	4
Assumed Boiler Capacity (MMBTU/hr)	72	72	0	0	68	68
Estimated Electricity Demand (MW)	38	38	21	21	17	17

Notes: 1. All costs are in millions of dollars.

2. 100% Condenser water heat pump scenarios (C.1.H & C.1.L) and 100% air source heat pump scenarios (C.2.H & C.2.L) were determined to not be feasible and are not included in this table.

Scenario	D.2.H	D.2.L	D.3.H	D.3.L	E.1.H	E.1.L
Description	Ground Source HP w/ Natural Gas Boilers	Ground Source HP w/ Natural Gas Boilers	Air Source HP w/ Natural Gas Boilers	Air Source HP w/ Natural Gas Boilers	Natural Gas	Natural Gas
Supply Temperature	High	Low	High	Low	High	Low
CapEx	$43.0	$78.7	$33.2	$65.3	$20.0	$59.0
CapEx w/ Incentives	$35.9	$72.6	$33.2	$65.3	$20.0	$59.0
Year 1 OpEx (w/ Social Cost of Carbon)	$10.3	$7.3	$10.3	$7.6	$7.9	$7.7
Year 1 OpEx (w/ RECs/Carbon Offsets)	$10.1	$7.2	$10.3	$7.6	$8.7	$8.5
Year 1 OpEx (w/o Carbon Costs)	$9.3	$6.5	$8.8	$6.3	$4.7	$4.7
NPC (w/ Social Cost of Carbon)	$279	$244	$274	$240	$194	$228
NPC (w/ Carbon Offsets)	$280	$246	$284	$250	$236	$266
NPC (w/o Carbon Costs)	$268	$235	$254	$222	$137	$175
Lifetime Carbon (30-Year Tons)	46,397	40,858	94,358	83,994	276,673	257,498
Assumed Heat Pump Capacity (MMBTU/hr)	30	30	30	30	0	0
Assumed Boiler Capacity (MMBTU/hr)	42	42	60	60	72	72
Estimated Electricity Demand (MW)	20	20	20	20	17	17

Notes: 1. All costs are in millions of dollars.

2. 100% Condenser water heat pump scenarios (C.1.H & C.1.L) and 100% air source heat pump scenarios (C.2.H & C.2.L) were determined to not be feasible and are not included in this table.

APPENDIX H

Deliverable 7: Initial Screening Assessment Results

State of Connecticut DAS

CAS Decarbonization Study

Deliverable 7:
Initial Screening Assessment Results
(Client Workshop #2)

Revision 1
September 18, 2023

PREPARED FOR:

PREPARED BY:
Veolia North America

TABLE OF CONTENTS

GLOSSARY OF TERMS

Capital Expenditure (CapEx) - Funds used to acquire, upgrade, and maintain physical assets.

Carbon Offsets - Carbon offsets are a trading mechanism that allows entities to compensate for (i.e. "offset") their greenhouse gas emissions by supporting projects that reduce, avoid, or remove emissions elsewhere.

Heating, Ventilation, and Air Conditioning (HVAC) - Collective term for all the different types of cooling and heating systems and components.

Independent System Operator (ISO) - Independent, non-profit created to operate regional power systems, implement wholesale markets, ensure open access to transmission lines.

Investment Tax Credit (ITC) - Provides a tax credit for investment in renewable energy projects as part of the Inflation Reduction Act (IRA) of 2022. For tax years beginning after December 31, 2022, most tax-exempt organizations, government entities, Indian tribal governments, and rural electric cooperatives may elect to treat certain credits as direct federal tax payments.

Net Present Cost (NPC) - The net present cost (or life-cycle cost) is an economic tool used to equate the total cost of a project over a specified time period to the total cost today, taking into account the time value of money.

Operating Expense (OpEx) - Expense incurred through normal business operations (fuel, payroll, repairs, etc).

Power Purchase Agreement (PPA) - Long-term contract between an electricity generator and a customer, during which time the power purchaser buys energy at a pre-negotiated price.

Renewable Energy Credits (RECs) - Market-based instrument that certifies the bearer owns one megawatt-hour (MWh) of electricity generated from a renewable energy resource. REC values in this report are based in the ISO New England region.

Renewable Portfolio Standard (RPS) - Policies that require that a specified minimum percentage of the electricity utilities sell comes from eligible renewable resources.

Renewable Natural Gas (RNG) - Biogas from a variety of sources that has been upgraded for use in place of fossil natural gas.

Social Cost of Carbon (SC-CO2) - Per the US EPA, The SC-CO2 is an estimate of the economic damages associated with a small increase in carbon dioxide (CO2) emissions, conventionally one metric ton, in a given year. (https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf) Note that SCC, Social Cost of Carbon, is a more encompassing term inclusive of other greenhouse gas emissions. This report references SC-C02 as defined here.

Virtual Net Metering (VNM) - Allows a renewable energy system's owner to share the billing credits that are generated when the system produces more power than the owner uses.

Weighted Average Cost of Capital (WACC) - Average rate to finance capital projects, also considered to be the discount rate in the NPC calculation .

1. Executive Summary

1.1. Summary of Findings

Based on the scope of work completed to date and with Stakeholder agreement on Deliverables[1] 1 and 2, Veolia has evaluated 22 discrete scenarios to serve the thermal energy requirements of the CAS.

For ease of use and reference purpose we have developed a naming convention for the scenarios as follows: Scenario X.#.Y: Where "X" refers to a general configuration/class of heating technologies with values of A, B, C, D or E; "#" refers to the unique combination of heating technologies with values of 1,2 or 3; and "Y" refers to either high or low temperature/enthalpy application, designated with 'H' for high temp/enthalpy and 'L' for low temperature/enthalpy.

Additional descriptions are as follows:

TABLE 1: Scenario Description

General Configuration / Class of Heating Technologies		Technology & Fuel
A	Hybrid of Heat Pumps & Electric Boilers	Air, water and ground source heat pumps, electric boilers all supplied with renewable, zero carbon electricity or Class I REC's claiming the same.
B	100% Electric Boilers	
C	100% Heat Pumps	
D	Hybrid of Heat Pumps & Natural Gas Condensing Boilers	Heat pumps supplied with renewable, zero carbon electricity or Class I REC's claiming the same. Boilers supplied with natural gas with equivalent carbon offsets to claim decarbonization.
E	100% Natural Gas Condensing Boilers	

The table below presents key performance figures for the lowest Net Present Cost (NPC) for each technology option. The NPC includes initial capital costs (CapEx) and 30 year operating costs (OpEx) (fuel, operation and maintenance (O&M), repairs, etc.). It is assumed that equipment life is 30 years and no full replacements will be required. Revenues from sales to the offtakers have not been calculated as part of NPC but are expected to be the same across all scenarios and therefore will not affect scenario rankings. A full list of scenario results can be found in Appendix A.

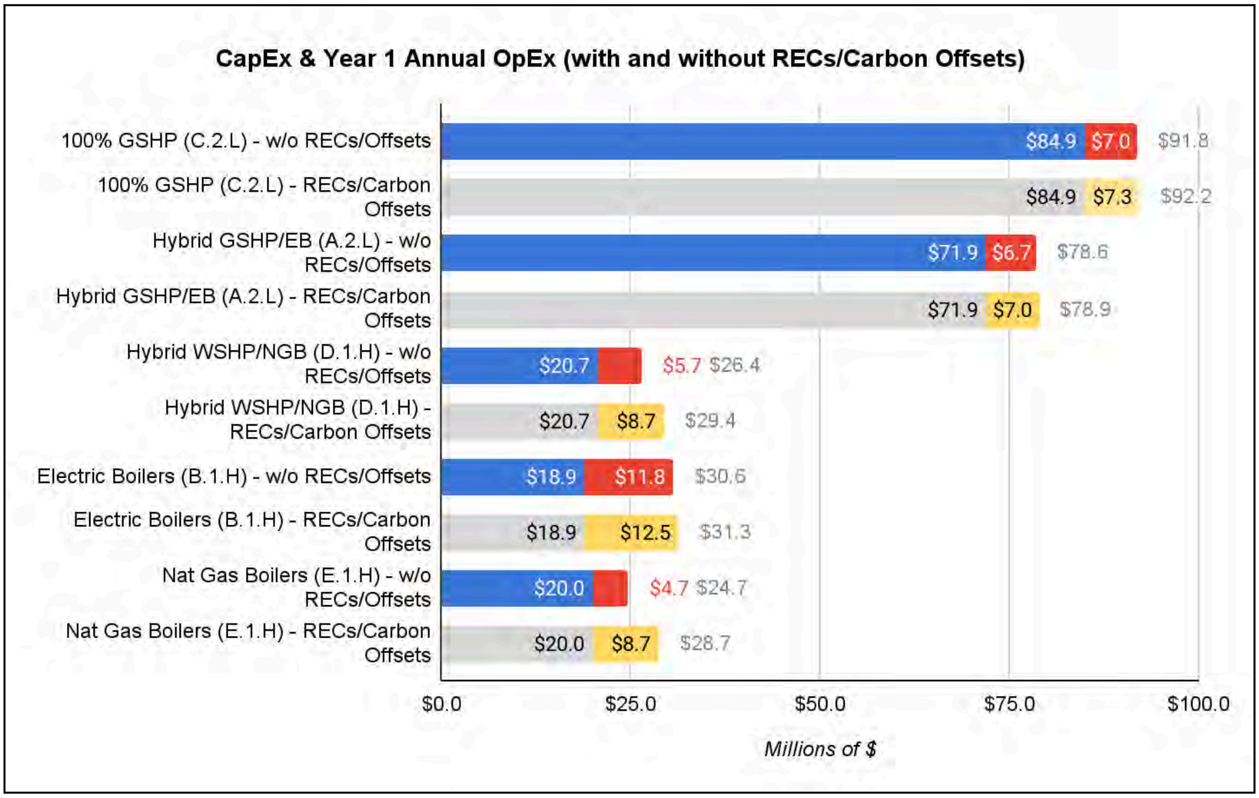
[1] Deliverable 1: Client Kickoff Workshop #1 Memo Report, Deliverable 2: Total Energy Requirements/Design Basis Memo Report

TABLE 2: Lowest NPC Performance Figures for Each Technology Option

Scenario		CapEx	CapEx w/ ITC	OpEx w/ Social Cost of Carbon	NPC w/ Social Cost of Carbon	OpEx w/o Carbon Costs	NPC w/o Carbon Costs
		Year 0 Cost	*Year 0 Cost*	*Year 1 Cost*	*30-Year Cost*	*Year 1 Cost*	*30-Year Cost*
A.2.L	Hybrid of GS Heat Pumps & Electric Boilers	$78.0	$71.9	$7.22	$242	$6.7	$238
B.1.H	100% Electric Boilers	$18.9	$18.9	$12.90	$324	$11.8	$316
C.2.L	100% GS Heat Pumps	$97.1	$84.9	$7.47	$261	$7.0	$257
D.1.H	Hybrid of WS Heat Pumps & Natural Gas Condensing Boilers	$20.7	$20.7	$8.22	$205	$5.7	$164
E.1.H	100% Natural Gas Condensing Boilers	$20.0	$20.0	$7.94	$194	$4.7	$137

Note: All values shown in nominal Millions of USD (2023).

FIGURE 1: CapEx & Year 1 Annual OpEx (with and without RECs/Carbon Offsets)



1.2. Recommendations

Upon inspection of the screening results, the following observations are made.

1. The lowest CapEx option is B.1.H (100% Electric Boilers)
2. The highest CapEx option is C.2.L (100% Heat Pumps)
3. The highest OpEx option, not taking into account the social cost of carbon or procurement of carbon free electricity or offsets is B.1.H (100% Electric Boilers)
4. The highest OpEx option, taking into account the social cost of carbon or procurement of carbon free electricity or offsets is B.1.H (100% Electric Boilers)
5. The lowest OpEx option, not taking into account the social cost of carbon or procurement of carbon free electricity or offsets is E.1.H (100% Natural Gas Condensing Boilers)
6. The lowest OpEx option, taking into account the social cost of carbon or procurement of carbon free electricity or offsets is C.2.L (100% Heat Pumps)
7. The lowest NPC option, not taking into account the social cost of carbon or procurement of carbon free electricity or offsets is E.1.H (100% Natural Gas Condensing Boilers)
8. The highest NPC option, taking into account the social cost of carbon or procurement of carbon free electricity or offsets is B.1.H (100% Electric Boilers)

Two (2) scenarios were determined to be technologically infeasible due to constraints of the input heat source. The condenser water heat pump only solution (C.1.H & C.1.L) was limited by the volume of condenser water available and could not generate enough heat as a stand alone solution. Similarly, an air source pump only solution (C.3.H & C.3.L) could not generate enough heat on the coldest days to meet heating demand without a supplemental heat source.

Although the low temperature solution had a lower NPC in some scenarios, the difference between the high temperature solution and the low temperature solution NPC was generally only on the order of around 5% over the assumed project term of 30 years. Since there is a greater uncertainty regarding the cost of system improvements that may be required at the offtaker buildings and/or distribution systems to implement the low temperature solution, further evaluation may indicate that the high temperature solution is the lower NPC scenario. An estimated cost of $45M for system improvements at all fifteen (15) buildings has been included in the CapEx for all low temperature hot water scenarios.

All or partial electric solutions have a higher Year 1 OpEx compared to all natural gas solutions due to the significantly higher cost per unit of energy for electricity versus natural gas, even after factoring in expected increases in equipment efficiency. Existing annual OpEx (fuel, O&M) is approximately $3.5M. However, when based on the anticipated increased future loads which are used in all of the above scenarios OpEx would be expected to increase to approximately $4.4M under baseline 2020 operating conditions. This does not include the estimated cost of equipment repairs, which has been included in the scenario evaluations.

As a next step we recommend conducting a workshop to discuss the full set of results in order to determine the three (3) scenarios which merit more detailed investigation.

1.3. Background

In April 2023, the Department of Administrative Services (DAS) retained Veolia to perform a Capitol Area System (CAS) Decarbonization Study as part of On-Call Contract (No. OC-DCS-ENGY-0030, Task No. 3, Project No. BI-2B-414). The purpose of the CAS Decarbonization Study is to define, develop, and assess options for modifying CAS operations to meet Executive Orders 1 and 21-3 (“EO 1”) and (“EO 21-3”). Incorporated into EO 1 is GreenerGov CT, a “Lead by Example” initiative with a mission of advancing environmental leadership, reducing operating costs and environmental impacts of State government operations, and generating savings for taxpayers. EO 21-3 calls for executive branch state agencies to take significant actions within their authority to reduce carbon emissions and “by 2030, all electricity purchased and generated by the Executive Branch will be 100% zero carbon”.

Decarbonization of the CAS, as it relates to Scope 2 emissions[2], can impact the entire supply and demand chain of energy source, generation, distribution and end use. The proposed study evaluates the use of various mechanisms to achieve a decarbonized CAS, chief among them include:

- Combination of State and Private demand side modifications to accept highly efficient, low to no carbon thermal supply sources

[2] https://ghgprotocol.org/scope-2-guidance

- Utility and Non-Utility supply options such as renewable electricity in the form of Power Purchase Agreements (PPAs), renewable supply contracts and/or carbon offsets[3]
- State-owned supply-side options such as geothermal and PV systems

Baseline operating conditions are detailed in Appendix B.

1.4. Summary of Approach

Decarbonization of CAS energy systems is complex and multifaceted and solutions must find a balance among technical, economic, regulatory and policy constraints and criteria. A simple decarbonization approach can keep conditions the same while offsetting natural gas and electric consumption with carbon offsets and renewable electricity credits. However, this study expands on this approach by looking at supply side options for electrification of natural gas (i.e. fuel switching from natural gas to electricity) with a range of technologies. Some of these technologies require significant changes to offtaker HVAC systems to enable lower temperature supply conditions, which can only be found through field testing, trial and error methods. During initial workshops and through subsequent deliverables, stakeholders concluded the market for "renewable" fuel sources, such as hydrogen (H2), Renewable Natural Gas (RNG) or other green fuels were not adequate to serve the thermal loads of the CAS and therefore were removed from further analysis. Taking this decision leaves only carbon free electrification as an option for decarbonizing thermal supply.

Given electricity as the option for decarbonization, efforts turn towards securing the minimum amount of carbon free electricity at the best price while maintaining reliability of thermal supply. This requires optimization of both supply and demand side systems, that is, efficiency first then right size supply systems. By considering CT's existing renewable portfolio standard (CT RPS) alongside EO 21-3, we have determined the volume of renewable electricity needed for decarbonization to be the amount above that supplied by Eversource[4] through RPS compliance.

2. Supply Side Design Scenario Definitions

The following are brief definitions of the CAS plant operating scenarios evaluated as part of this study.

2.1. Scenario A.1.H - Hybrid Water Source Heat Pump & Electric Boiler (High Temp)

Water source heat pumps coupled with electric boilers to provide hot water to the heating loop at existing supply temperatures (approximately 180° F to 200° F). The water source for the heat pump is the existing condenser water loop that serves the water cooled chillers. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop. Therefore, the sizing of the heat pumps were limited by the condenser water leaving the water cooled chillers. The remaining hot water load will be met by the electric boilers.

[3] Carbon offsets for natural gas consumption, otherwise carbon free electricity sources via Eversource, RECs, power purchase agreements,special case utility programs or owned assets

[4] See Section 6. Utility Supply Options for further details on carbon free electricity procurement options

2.2. Scenario A.1.L - Hybrid Water Source Heat Pump & Electric Boiler (Low Temp)

Water source heat pumps coupled with electric boilers to provide hot water to the heating loop at reduced supply temperatures (approximately 130° F). The water source for the heat pump is the existing condenser water loop that serves the water cooled chillers. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop. Therefore, the sizing of the heat pumps were limited by the condenser water leaving the water cooled chillers. The remaining hot water load will be met by the electric boilers.

2.2. Scenario A.2.H - Hybrid Ground Source Heat Pump & Electric Boiler (High Temp)

Ground source heat pumps as the primary heat source, coupled with electric boilers and water source heat pumps to provide hot water to the heating loop at existing supply temperatures (approximately 180° F to 200° F). The source for the ground source heat pump is geothermal wells. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop. Therefore, the sizing of the water source heat pumps were limited by the condenser water leaving the water cooled chillers. While the ratio of ground source heat pumps to electric boiler capacity is adjusted to optimize financial benefit based on capital and operating expenses, the remaining heat demand will be met by these technologies.

2.4. Scenario A.2.L - Hybrid Ground Source Heat Pump & Electric Boiler (Low Temp)

Ground source heat pumps as the primary heat source, coupled with electric boilers and condenser water source heat pumps to provide hot water to the heating loop at reduced supply temperatures (approximately 130° F). The source for the ground source heat pump is geothermal wells. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop. Therefore, the sizing of the water source heat pumps were limited by the condenser water leaving the water cooled chillers. While the ratio of ground source heat pumps to electric boiler capacity is adjusted to optimize financial benefit based on capital and operating expenses, the remaining heat demand will be met by these technologies.

2.5. Scenario A.3.H - Hybrid Air Source Heat Pump & Electric Boiler (High Temp)

Air source heat pumps as the primary heat source, coupled with electric boilers and condenser water source heat pumps to provide hot water to the heating loop at existing supply temperatures (approximately 180° F to 200° F). The air source for the heat pump is ambient air. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop. Therefore, the sizing of the water source heat pumps were limited by the condenser water leaving the water cooled chillers. While the ratio of air source heat pumps to electric boiler capacity is adjusted to optimize financial benefit based on capital and operating expenses, the remaining heat demand will be met by these technologies.

2.6. Scenario A.3.L - Hybrid Air Source Heat Pump & Electric Boiler (Low Temp)

Air source heat pumps as the primary heat source, coupled with electric boilers and condenser water source heat pumps to provide hot water to the heating loop at reduced supply temperatures (approximately 130° F). The air source for the heat pump is ambient air. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop. Therefore, the sizing of the water source heat pumps were limited by the condenser water leaving the water cooled chillers. While the ratio of air source heat pumps to electric boiler capacity is adjusted to optimize financial benefit based on capital and operating expenses, the remaining heat demand will be met by these technologies.

2.7. Scenario B.1.H - Electric Boilers (High Temp)

Electric boilers provide hot water to the heating loop at existing supply temperatures (approximately 180° F to 200° F). Electric chillers are used to serve the chilled water loop.

2.8. Scenario B.1.L - Electric Boilers (Low Temp)

Electric boilers provide hot water to the heating loop at reduced supply temperatures (approximately 130° F). Electric chillers are used to serve the chilled water loop.

2.9. Scenario C.1.H - Water Source Heat Pump (High Temp)

Water source heat pumps to provide hot water to the heating loop at existing supply temperatures (approximately 180° F to 200° F). The water source for the heat pump is the existing condenser water loop that serves the water cooled chillers, therefore it restricts the size of the water source heat pump. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop.

2.10. Scenario C.1.L - Water Source Heat Pump (Low Temp)

Water source heat pumps to provide hot water to the heating loop at reduced supply temperatures (approximately 130° F). The water source for the heat pump is the existing condenser water loop that serves the water cooled chillers, therefore it restricts the size of the water source heat pump. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop.

2.11. Scenario C.2.H - Ground Source Heat Pump (High Temp)

Ground source heat pumps as the primary heat source, coupled with condenser water source heat pumps to provide hot water to the heating loop at existing supply temperatures (approximately 180° F to 200° F). The ground source for the heat pump is geothermal wells. The water source for the other heat pump is the existing condenser water loop that serves the water cooled chillers, therefore it restricts the size of the water source heat pump. The remaining heat load will be met by the ground source heat pump. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop.

2.12. Scenario C.2.L - Ground Source Heat Pump (Low Temp)

Ground source heat pumps as the primary heat source, coupled with condenser water source heat pumps to provide hot water to the heating loop at reduced supply temperatures (approximately 130° F).

The ground source for the heat pump is geothermal wells. The water source for the other heat pump is the existing condenser water loop that serves the water cooled chillers, therefore it restricts the size of the water source heat pump. The remaining heat load will be met by the ground source heat pump. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop.

2.13. Scenario C.3.H - Air Source Heat Pump (High Temp)

Air source heat pumps as the primary heat source, coupled with condenser water source heat pumps to provide hot water to the heating loop at existing supply temperatures (approximately 180° F to 200° F). The air source for the heat pump is ambient air. The water source for the other heat pump is the existing condenser water loop that serves the water cooled chillers, therefore it restricts the size of the water source heat pump. The remaining heat load will be met by the air source heat pump. Electric chillers are used to serve the chilled water loop.

2.14. Scenario C.3.L - Air Source Heat Pump (Low Temp)

Air source heat pumps as the primary heat source, coupled with condenser water source heat pumps to provide hot water to the heating loop at reduced supply temperatures (approximately 130° F). The air source for the heat pump is ambient air. The water source for the other heat pump is the existing condenser water loop that serves the water cooled chillers, therefore it restricts the size of the water source heat pump. The remaining heat load will be met by the air source heat pump. Electric chillers are used to serve the chilled water loop.

2.15. Scenario D.1.H - Hybrid Water Source Heat Pump & Natural Gas Boiler (High Temp)

Water source heat pumps coupled with natural gas boilers to provide hot water to the heating loop at existing supply temperatures (approximately 180° F to 200° F). The water source for the heat pump is the existing condenser water loop that serves the water cooled chillers. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop. Therefore, the sizing of the heat pumps were limited by the condenser water leaving the water cooled chillers. The remaining hot water load will be met by the natural gas boilers.

2.16. Scenario D.1.L - Hybrid Water Source Heat Pump & Natural Gas Boiler (Low Temp)

Water source heat pumps coupled with natural gas boilers to provide hot water to the heating loop at reduced supply temperatures (approximately 130° F). The water source for the heat pump is the existing condenser water loop that serves the water cooled chillers. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop. Therefore, the sizing of the heat pumps were limited by the condenser water leaving the water cooled chillers. The remaining hot water load will be met by the natural gas boilers.

2.17. Scenario D.2.H - Hybrid Ground Source Heat Pump & Natural Gas Boiler (High Temp)

Ground source heat pumps as the primary heat source, coupled with natural gas boilers and condenser water source heat pumps to provide hot water to the heating loop at existing supply temperatures (approximately 180° F to 200° F). The source for the ground source heat pump is geothermal wells. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop. Therefore, the sizing of the water source heat pumps were limited by the condenser water leaving the water cooled chillers. While the ratio of ground source heat pumps to natural gas boiler capacity is adjusted to optimize financial benefit based on capital and operating expenses, the remaining heat demand will be met by these technologies.

2.18. Scenario D.2.L - Hybrid Ground Source Heat Pump & Natural Gas Boiler (Low Temp)

Ground source heat pumps as the primary heat source, coupled with natural gas boilers and condenser water source heat pumps to provide hot water to the heating loop at reduced supply temperatures (approximately 130° F). The source for the ground source heat pump is geothermal wells. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop. Therefore, the sizing of the water source heat pumps were limited by the condenser water leaving the water cooled chillers. While the ratio of ground source heat pumps to natural gas boiler capacity is adjusted to optimize financial benefit based on capital and operating expenses, the remaining heat demand will be met by these technologies.

2.19. Scenario D.3.H - Hybrid Air Source Heat Pump & Natural Gas Boiler (High Temp)

Air source heat pumps as the primary heat source, coupled with natural gas boilers and condenser water source heat pumps to provide hot water to the heating loop at existing supply temperatures (approximately 180° F to 200° F). The air source for the heat pump is ambient air. Electric chillers are used to serve the chilled water loop. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop. Therefore, the sizing of the water source heat pumps were limited by the condenser water leaving the water cooled chillers. While the ratio of air source heat pumps to natural gas boiler capacity is adjusted to optimize financial benefit based on capital and operating expenses, the remaining heat demand will be met by these technologies.

2.20. Scenario D.3.L - Hybrid Air Source Heat Pump & Natural Gas Boiler (Low Temp)

Air source heat pumps as the primary heat source, coupled with natural gas boilers and condenser water source heat pumps to provide hot water to the heating loop at reduced supply temperatures (approximately 130° F). The air source for the heat pump is ambient air. Electric chillers are used to serve the chilled water loop. The cold side of the heat pump is used to increase the existing efficiency of the electric chillers that serve the chilled water loop. Therefore, the sizing of the water source heat pumps were limited by the condenser water leaving the water cooled chillers. While the ratio of air source heat pumps to natural gas boiler capacity is adjusted to optimize financial benefit based on capital and operating expenses, the remaining heat demand will be met by these technologies.

2.21. Scenario B.1.H - Natural Gas Boiler (High Temp)

Natural gas boilers provide hot water to the heating loop at existing supply temperatures (approximately 180° F to 200° F). Electric chillers are used to serve the chilled water loop.

2.22. Scenario B.1.L - Natural Gas Boiler (Low Temp)

Natural gas boilers provide hot water to the heating loop at reduced supply temperatures (approximately 130° F). Electric chillers are used to serve the chilled water loop.

3. Financial Assumptions

3.1. Discount Rate

A discount rate is the rate of return used to discount future cash flows back to their present value. This rate is often a Weighted Average Cost of Capital (WACC), required rate of return, or the cost of debt (e.g. bond rate). For the financial analyses conducted as part of this study the State bond rate of 3.77% has been used as the discount rate.

3.2. Potential Incentives

Veolia researched available federal and state incentives which may be applicable to the scenarios described in Section 2. Based on this evaluation, only the Investment Tax Credit (ITC), as modified under the Inflation Reduction Act (IRA) of 2022, is applicable to the financial analysis in this deliverable. Additionally, only those scenarios with a geothermal heat pump system would be eligible for the ITC. A geothermal heat pump system includes any equipment that uses the ground or ground water as a thermal energy source to heat a structure or as a thermal energy sink to cool a structure. Only the portion of equipment used to produce, distribute, or use energy derived from a geothermal deposit is eligible for the credit. For the purposes of this study it is assumed that the project will meet the prevailing wage requirements and therefore a 30% ITC would be applicable. Construction of a qualified geothermal heat pump system must begin before January 1, 2035.

Veolia has facilitated meetings with Eversource to determine available incentives. As of the date of this report, Eversource is evaluating a custom incentive and has preliminarily indicated interest in participating in this project due to the large scale heat pump concepts currently being evaluated. Veolia has requested indicative incentive values to be provided by early September so as to include them in the final phases of the study.

3.3. Social Cost of Carbon (SC-CO2)

As defined by the US EPA, the SC-CO2 is a measure, in dollars, of the long-term damage done by a ton of carbon dioxide (CO2) emissions in a given year. This dollar figure also represents the value of damages avoided for a small emission reduction (i.e., the benefit of a CO2 reduction). During discussion with the State it was determined that the State's SC-CO2 is still being developed. As such, it was agreed that until a State specific SC-CO2 has been provided, Veolia would use the following EPA SC-CO2 value for 2022 as a placeholder in its calculations. These values were obtained from Table 4.2.1 of the EPA's September 2022 *"Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances"* (https://www.epa.gov/system/files/documents/2022-11/epa_scghg_report_draft_0.pdf) using a discount rate of 1.5%.

TABLE 3: Social Cost of Carbon

	SC-CO2
	(2020 dollars per metric ton of CO2)
Emission Year	(Discount Rate: 1.5%)
2022	$346

All financial analyses are presented both with and without the SC-CO2 as a financial consideration.

3.5. Escalation Factors

An annual escalation factor of 2.5% is used for all commodities and expenses over the 30-year term, including but not limited to the following:

- Electricity cost
- Natural gas cost
- Water cost
- Labor costs
- Equipment costs
- O&M costs

This is roughly equivalent to the US Treasury 20-year Breakeven Inflation Rate of 2.48% (https://fred.stlouisfed.org/series/T20YIEM).

4. Carbon Emission Factors

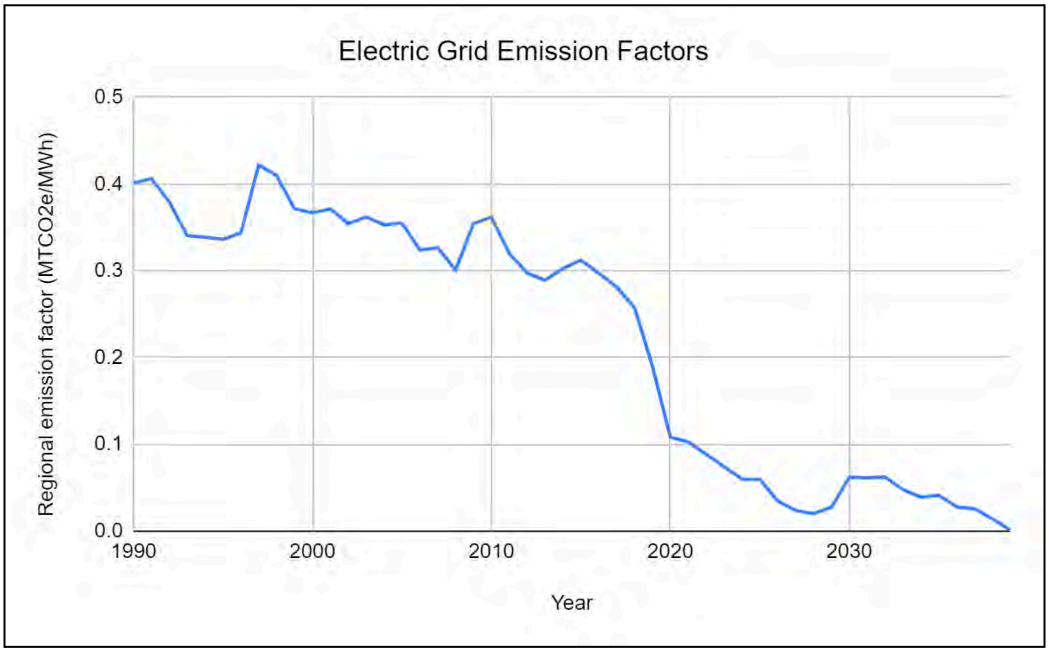
The following emissions factors provided by the State have be used to calculate the potential emissions for various fuels that have been used in the past or may be used in the future by CAS:

TABLE 4: Electric Grid Emission Factors

Year	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**
Regional emission factor (MTCO2e/MWh)	0.4010502	0.4061386	0.3795461	0.3404675	0.3388742	0.3361012	0.3437698	0.4220527	0.4095980	0.3715102
Year	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
Regional emission factor (MTCO2e/MWh)	0.3668755	0.3712683	0.3545979	0.3621470	0.3530752	0.3551884	0.3239771	0.3264649	0.3010504	0.3545080
Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Regional emission factor (MTCO2e/MWh)	0.3617302	0.3201608	0.2973487	0.2891816	0.3027548	0.3124441	0.2971545	0.2812257	0.2576408	0.1898702
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Regional emission factor	0.1084224	0.1030013	0.0886471	0.0742929	0.0599387	0.0597731	0.0348407	0.0238254	0.0201063	0.0275437

(MTCO2e/MWh)										
Year	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
Regional emission factor (MTCO2e/MWh)	0.0622150	0.0616437	0.0623892	0.0477784	0.0392287	0.0414464	0.0279418	0.0257219	0.0144276	0.0009504

FIGURE 2: Electric Grid Emission Factors



Based on discussions during Workshop #1 it was agreed that CAS plant electricity purchases will conform with Executive Order No. 21-3; specifically, Section 3B which states that "By 2030, all electricity purchased and generated by the Executive Branch will be 100% zero carbon". As such, it will be assumed that starting in 2030 all electricity purchased by the plant will be 100% zero carbon. This assumption implies that dedicated zero carbon electric supply contracts will need to be procured in lieu of grid supplied power, which in accordance with Table 4 above, contains carbon in 2030 and beyond.

TABLE 5: Natural Gas Emission Factors

Natural Gas		
kg CO2/scf	**kg CH4/scf**	**kg N2O/scf**
0.054440	0.00000103	0.0000001

TABLE 6: RNG and H2 Emission Factors

	RNG (Landfill Gas)			RNG (Other Biomass Gases)			Green Hydrogen
Emission Type	**kg CO2 /scf**	**kg CH4/scf**	**kg N2O/scf**	**kg CO2/scf**	**kg CH4/scf**	**kg N2O/scf**	**kg CO2e/kg**
Combustion	0.00	1.55×10^{-6}	0.306×10^{-6}	0.00	2.10×10^{-6}	0.413×10^{-6}	2.00
Biogenic	0.02530	-	-	0.034100	-	-	2.00

Note: For RNG, where applicable, accounting for biogenic CO2 will be calculated on the basis of the above factors and noted as a sidebar.

Since the State requires that the future availability of any alternative fuels must also be considered, renewable natural gas (RNG) and green hydrogen (H2) are not considered viable options at this time due to the uncertainty surrounding their long term availability. However, Veolia will evaluate natural gas burning equipment that is RNG and hydrogen "ready" and will include market outlooks, define the carbon lifecycle of RNG and green hydrogen, as well as a brief narrative on each as an option. Although a full financial analysis has not been conducted, a comparison of potential emissions should natural gas burning equipment be converted to RNG or hydrogen in the future is included.

5. Utility Supply Options

This section provides an overview of market options for utility services required by the CAS including a summary of procurement methods for carbon free electricity.

5.1. Power Market Forecast

Our market price forecast is used to estimate the future cost of various decarbonization strategies under consideration. There are two components to the forecast:

- Base Supply: our 17 year forecast of grid power supply from either the utility or a 3rd party supplier.
- Renewable Energy Premium: the estimated incremental cost to completely offset the site's scope 2 carbon emissions using Class I Renewable Energy Credits (RECs).

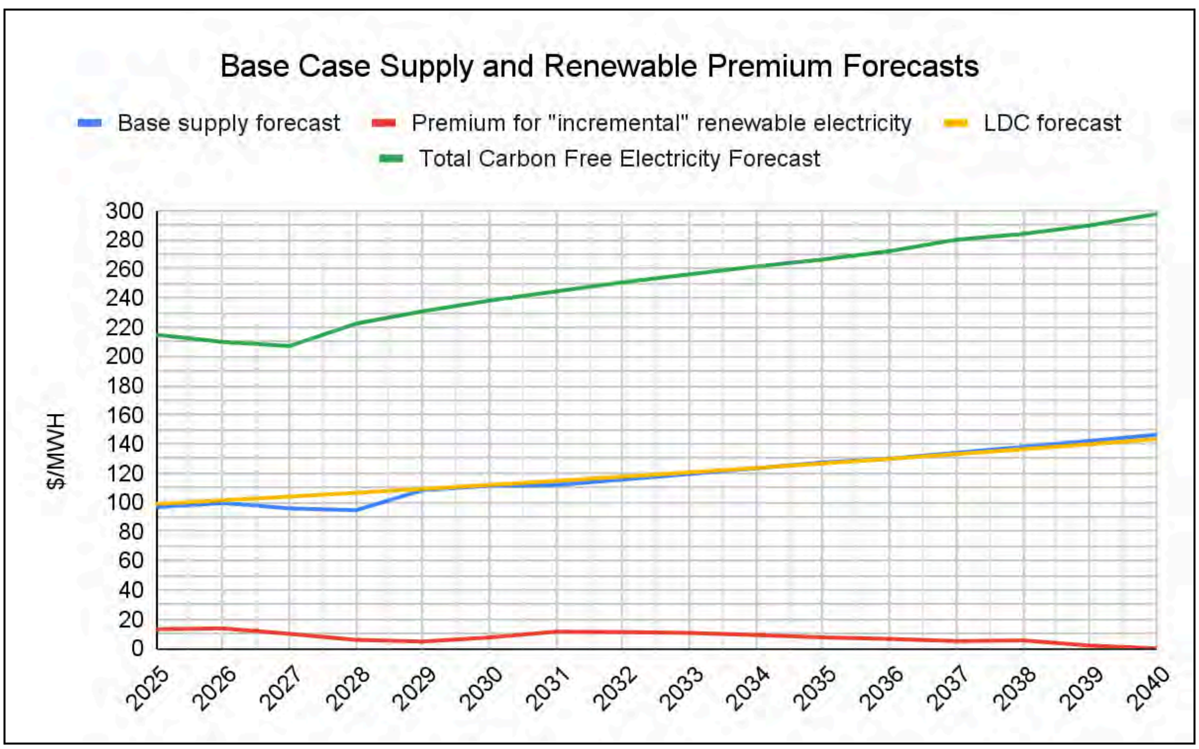
The Base Supply forecast is derived from prevailing forward market rates for wholesale power in Connecticut, capacity, ancillaries and Connecticut's Renewable Portfolio Standard (RPS). Many of these subcomponents are highly susceptible to change based on underlying market conditions. The forecast extends to Year 17, based on available market projections. After Year 17, an annual escalation of 3% is assumed.

We assume Class I RECs are the most likely instrument the State would use to offset its scope 2 emissions. This is an acceptable compliance instrument under CT PURA regulations and it is consistent with state regulatory policy. We have considered an out-of-region "national green-e" REC option with a lower price point, but suspect there could be sensitivity around using RECs from markets outside of New England or that are not otherwise used for Connecticut RPS compliance purposes. We also considered power purchase agreements (ie., new project RECs and energy), however we determined that consumption at the site was too low to garner any commercial options at a reasonable price point. It's also worth noting that PPAs tend to require a fixed level of output for a longer term tenor (e.g., > 10 years), which doesn't fit well with the grid's declining emissions trend.

For the calculation of the Renewable Energy Premium, we first quantified the carbon balance, in metric tons, that the site would need to offset from 2030 to 2040, the assumption being that the green purchases are superfluous thereafter as the electric supply must be carbon free under state law (see e.g, Public Act 22-5 (Senate Bill 10)[5]. To calculate the carbon balance, we used a CT power supply emissions factor forecast provided by DEEP. We also verified this using an alternative approach, which is to calculate the difference between the 100% offset goal and the projected state RPS % each year. The two approaches yielded fairly consistent results with respect to cost impact. It's worth noting that Connecticut's Tier 1 REC requirement under the RPS tops out at 40% in 2030 under current regulations, however Connecticut statute requires 100% carbon-free power by 2040. In the absence of regulation, we've therefore made a conservative assumption that the RPS will increase by 6% percent per year from 2030 to 2040. This ignores potential contracts with other carbon free resources such as nuclear and is therefore probably a conservative assumption. Finally, our forecast of the renewable energy premium, as well as our base case supply forecast, is heavily influenced by our forecast of the Class I RECs. There is limited liquidity in this market, however it is generally anticipated that prices will decline rapidly in the next 5 years–from $40 to roughly $20 per REC–as large offshore wind projects reach commercial operation.

The following plot shows base case and renewable energy premium forecasts:

FIGURE 3: Base Case Supply and Renewable Premium Forecasts



[5] https://www.cga.ct.gov/2022/act/pa/pdf/2022PA-00005-R00SB-00010-PA.pdf

- The blue curve ('Base supply forecast') represents the price forecast for electricity supply, whether that is through Eversource or a third party supplier. This electricity is generated from a mix of resources.
- The yellow curve ('LDC forecast') represents the local distribution company (LDC - Eversource) price forecast for delivery electrical supply to the CAS.
- The red curve ('Premium for "incremental" renewable electricity') represents the price forecast for obtaining the balance of carbon free electricity (the volume required beyond that which is supplied by Eversource through the RPS as described above.
- The green curve is the sum of all curves and is the forecast that is used in the study model to represent the price of electricity for the CAS

We have introduced various scenarios in which the CAS Plant may continue to rely on natural gas boilers. For these scenarios, we have also provided carbon mitigation options that assume the use of carbon offsets. Carbon offsets can be acquired from a large diversity of technologies, projects, and regions. There can also be a wide price range for these products. In our carbon offset price assumptions, we have used a midpoint of pricing received from various projects within the North American Improved Forestry Management category. Credits would be secured from reputable certification standards such as Gold Standard, Verra, or American Carbon Registry.

Per discussions with the State regarding the options for accounting for the potential purchase of offsets for carbon emissions at the CAS plant as capital costs rather than operating costs, it is likely that the Class I REC and carbon offset market structures would allow for that. Class I RECs to offset the carbon emissions associated with electricity are more typically delivered on an annual basis but they can be committed and purchased for multi-year terms. We see no reason why they could not be secured and accounted for as an annual capital expense. Carbon credits to offset the carbon emissions associated with natural gas use at the CAS plant are generally longer term contracts (1 to 10 years) and could similarly be included as a capital expense with adjustments made as contracts expire and new ones are negotiated. The only risk to upfront commitments are that there will undoubtedly be deviations between estimated and actual quantities needed, however this can typically be addressed by remarketing excess or making spot market purchases for shortages.

5.2. Electricity Rate

According to Eversource, when the existing high tension service is decommissioned and a new lower tension service is established, the Large Time-of-Day (Rate 58) tariff will apply. From the plot above, the green forecast line represents the sum of Eversource supply, their distribution costs and the premium the State can expect to pay to decarbonize the balance of electricity supplied by Eversorce.

This forecast can then be compared to other supply options such as renewable PPA's, on or offsite solar or utility based programs. Section 5.5 below provides an overview of such procurement options.

5.3. Natural Gas Utility Rate

The existing local utility's (Connecticut Natural Gas) applicable tariff structure for natural gas is the Large General Service (LGS) Customer rate, which is defined as a customer whose anticipated consumption is greater than 30,000 CCF per year. An estimated blended rate of $8.25 per MMBTU was used for this study.

5.4. Water Utility Rate

Water supplied to the CAS plant by the MDC water was calculated at a blended rate of $8.28 per CCF.

5.5. Carbon Free Electricity Options

There are several options for mitigating carbon emission beyond making physical changes to energy consuming equipment which may include the following categories:

5.5.1 Renewable Energy Credits

Renewable Energy Credits (RECs) are environmental attributes associated with renewable energy production, uncoupled from physical delivery of electricity. A REC indicates ownership of the environmental attributes associated with 1 MWh of renewable energy production.

Power consumers can purchase equivalent quantities of RECs to match their scope 2 emissions in order to make qualifying claims about their actions to financially mitigate their carbon emissions. This methodology is central to carbon accounting frameworks such GHG Protocol, CDP, and others. Typically, carbon accounting frameworks allow for consideration of both active and passive measures. In other words, a site that purchases power from a region or state with a low-emissions profile, as is the expectation in Connecticut, will be able to account for that lower emissions rate in its baseline carbon profile before using RECs to offset the remaining carbon imbalance.

At a high level they fall into two categories:

- National Voluntary RECs
- Regional Compliance RECs

Both have well defined auditing processes in place to verify the authenticity of the certificate and to avoid double counting. National Voluntary RECs are the lowest cost REC available and the types of energy and regions can sometimes be defined, though they are typically sourced from the Midwest and Texas. Compliance RECs may also be used for compliance with state Regional Portfolio Standards (RPS). They carry higher prices but more with specificity and restrictions around location, technology types, in-service dates, and eligible tracking platforms. RECs are prevalent in their use across North America, likely due to standardized measurement and verification, and their origin as a public policy tool for state RPS goals.

5.5.2 Carbon Offsets

A carbon offset indicates comparable ownership rights associated with the abatement of 1 metric ton of CO2, from a wide variety of qualifying actions. Carbon offsets are more nuanced than RECs because of the wider variety of potential source projects, e.g. these range from sustainable forestry management to direct carbon capture to the flaring of methane gas release at wellheads. The measurement and verification standards for carbon credits are therefore more flexible and the parties involved in this function are more distributed. Most carbon offset projects develop their own unique measurement and verification plans, and while these are subject to third party verification, they are non-uniform. Therefore, carbon offsets are seldom used in state or municipal-administered programs. There is also a wide disparity in the type and quality of carbon offsets, both in actual and perceived terms, so there may be a higher public relations risk unless buyers are deliberate about the category and messaging pertaining to the offsets they choose.

It is also worth noting more broadly that while financial offset mechanisms such as RECs and carbon offsets may be generally acceptable by major carbon accounting frameworks, the State should carefully consider whether their use is consistent with the policy goals and public statements made on the subject. While there are many interpretations of acceptable pathways towards decarbonization, there is consensus that heavy reliance on RECs and offsets is not a long-term strategy. For this simple reason, some conventional mitigation frameworks, such as the Greenhouse Gas Mitigation Hierarchy, prioritize the functions of GHG avoidance, reduction, and replacement over financial measures such as RECs and offsets. We recognize there may be any number of constraints that the state must consider while weighing the alternative approaches. Veolia is therefore not proposing any prescriptive mitigation pathway or hierarchy, however we do wish to highlight that there may be qualitative and reputational differences between the solutions, particularly with respect to those involving heavy reliance on carbon offsets and RECs.

5.5.3 Power Purchase Agreements (PPAs)

Through PPAs customers contract directly for the power off-take of a renewable energy generator and settle power transactions through the Independent System Operator (ISO). They can be set up with multiple options either within a region or in another ISO:

- Operate as a wholesale participant within the ISO and establish a PPA with a regional renewable energy asset within the ISO
- Contractual relationship where supplier carves out part of a larger renewable project
- Renewable power outside of the respective ISO can be procured but will likely be a financial Contract for Differences structure
- Behind-the-Meter PPAs offset retail consumption relieve customer from owning and operating assets

5.5.4 Special Case Utility Programs

Many utilities have voluntary renewable energy options, both in restructured and vertically integrated territories with a range of opportunities made available by state policy:

- Virtual Net Metering contracts
- REC purchase or PPA purchase with consolidated billing options
- Community choice solar, wind, or battery tariff

The incumbent utility is typically the interface in these arrangements but not always and the agreements vary by utility and state. In many cases they do NOT transfer title to the customer so they must adhere to the buyer's internal sustainability goals.

5.5.5 Owned Assets

These are renewable assets owned and operated by the end-user and require capital outlays for construction/acquisition, as well as operating costs. Depending on the operating profile, user-owned generation can provide economic benefits and flexibility of options. Such assets can be developed behind-the-meter or off-site, however the latter will typically require counterparty involvement. Additionally, the area required to provide enough generation to fully offset usage can be a significant challenge for many urban buildings.

5.6. Installed Solar PV

Solar PV could potentially be installed at state-owned offtaker buildings either as a PPA or an owned asset. While the electricity generated would not flow directly to the CAS plant its attributes could be used to offset electrical consumption at the plant. Veolia conducted a high level desktop solar PV screening of state owned offtaker buildings and determined that approximately 2,200,000 kWh of electricity could potentially be generated (Appendix C). Additional considerations such as the age and and structural integrity of the roof at each location would need to be evaluated prior to determining the feasibility of any solar installation.

6.0 Operational Costs

6.1. Operations & Maintenance

Under an Operations and Maintenance Agreement dated October 7, 2020, IHI Power Services Corp. (IHI) provides operations and maintenance (O&M) services for the CAS plant. Using 2023 labor projections, annual O&M services provided by IHI are expected to be:

- Annual Operator Fee — $200,000 per year
- Labor — $415,829 per year
- Other Reimbursable Expenses — $1,000 per month (estimated)
    - Total — $627,829 per year

All proposed operating scenarios in Section 2 are anticipated to require a similar magnitude of O&M as currently provided, however there are differences as to the long term maintenance and repair costs based on the specific technology deployed. Therefore, the total operating and maintenance budget for each scenario includes the annual fee as is currently provided by IHI plus technology specific repair and maintenance values.

6.2. Eversource High Tension Service

The existing annual cost for Eversource high tension service O&M is $23,034 according to Eversource. Veolia has requested that Eversource provide a projected annual cost for future service but this cost has not yet been provided. Therefore, the existing annual cost has been carried for all scenarios.

6.3. Repairs & Maintenance

Based on Veolia's experience operating similar plants an annual budget for each scenario has been assumed to cover performance guarantees, spare parts and repairs.

7.0 Supply Side Design Scenario Screening Results

The table below presents key performance figures for each option. A full list of scenario results can be found in Appendix A. Total installed heating and cooling capacity was based on agreed upon parameters in Deliverable 2: Total Energy Requirements/Design Basis Memo Report. Heating equipment capacities for each scenario are also included in Appendix A.

Two (2) scenarios were determined to be technologically infeasible due to constraints of the input heat source. The condenser water heat pump only solution (C.1.H & C.1.L) was limited by the volume of condenser water available and could not generate enough heat as a stand alone solution. Similarly, an air source pump only solution (C.3.H & C.3.L) could not generate enough heat on the coldest days to meet heating demand without a supplemental heat source.

Although the low temperature solution had a lower NPC in some scenarios, the difference between the high temperature solution and the low temperature solution NPC was generally only on the order of around 5% over the assumed project term of 30 years. Since there is a greater uncertainty regarding the cost of system improvements that may be required at the offtaker buildings and/or distribution systems to implement the low temperature solution, further evaluation may indicate that the high temperature solution is the lower NPC scenario. An estimated cost of $45M for system improvements at all fifteen (15) buildings has been included in the CapEx for all low temperature hot water scenarios.

All or partial electric solutions have a higher Year 1 OpEx compared to all natural gas solutions due to the significantly higher cost per unit of energy for electricity versus natural gas, even after factoring in expected increases in equipment efficiency. Existing annual OpEx (fuel, O&M) is approximately $3.5M. However, when based on the anticipated increased future loads which are used in all of the above scenarios OpEx would be expected to increase to approximately $4.4M under baseline 2020 operating conditions. This does not include the estimated cost of equipment repairs, which has been included in the scenario evaluations.

TABLE 7: Lowest NPC Performance Figures for Each Technology Option

Scenario		CapEx	CapEx w/ ITC	OpEx w/ Social Cost of Carbon	NPC w/ Social Cost of Carbon	OpEx w/o Carbon Costs	NPC w/o Carbon Costs
		Year 0 Cost	*Year 0 Cost*	*Year 1 Cost*	*30-Year Cost*	*Year 1 Cost*	*30-Year Cost*
A.2.L	Hybrid of GS Heat Pumps & Electric Boilers	$78.0	$71.9	$7.22	$242	$6.7	$238

B.1.H	100% Electric Boilers	$18.9	$18.9	$12.90	$324	$11.8	$316
C.2.L	100% GS Heat Pumps	$97.1	$84.9	$7.47	$261	$7.0	$257
D.1.H	Hybrid of WS Heat Pumps & Natural Gas Condensing Boilers	$20.7	$20.7	$8.22	$205	$5.7	$164
E.1.H	100% Natural Gas Condensing Boilers	$20.0	$20.0	$7.94	$194	$4.7	$137

Note: All values shown in nominal Millions of USD (2023).

8.0 Demand Side Design Considerations

The following demand side design considerations were originally provided as part of Deliverable 4: Demand Side Evaluation, which was intended to provide a summary of technical and financial feasibility of adopting demand side (load reduction) strategies as part of decarbonization efforts.

8.1. Low Temperature Hot Water Conversions

Based on the limited design documents provided, historic heating loop supply temperatures and discussions with site personnel it appears that the offtaker buildings' heating systems were generally designed for 180°F supply hot-water. While a lower hot-water supply (HWS) temperature (110°F -140°F) can increase the efficiency of the equipment which provides the hot water, providing the necessary heating capacity with a lower HWS temperature requires a higher fluid flow rate than a high HWS temperature. This may require additional hot-water coil rows in end-use HVAC equipment to provide the required heating capacity, as well as a higher fluid flow rate, which can affect the size of pipes, pumps, and valves, and can also increase pumping energy use. Buildings may also require weatherization to reduce heating loads and radiator redesign to meet building heating needs.

While efficiency increases at the CAS plant would not result in energy savings at the offtaker buildings themselves, and may actually increase electric use due to higher pumping rates, ensuring that the offtaker buildings could maintain heating capacity at a lower HWS temperature would be critical before deciding to lower the HWS temperature of the loop. The first step would likely be to conduct tests at each offtaker building in order to observe how its systems respond to reduced hot water temperatures and increased flow rates and determine if they are capable of meeting heating requirements under those supply conditions. Based on the age of most of the systems in the offtaker buildings and discussions with representatives from Trane, an HVAC equipment manufacturer, regarding similar low

HWS temperature conversions projects it appears that the more likely outcome is that major HVAC equipment modifications and/or replacements would be required. Since 165 Capitol Avenue was the only offtaker building for which detailed HVAC design drawings were provided and it had recently undergone a major renovation of its systems using equipment from Trane, Trane was requested to provide budgetary pricing to upgrade major pieces of equipment (air handling units, variable air volume boxes, etc.) to operate at lower HWS temperatures of 130°F. Using this pricing Veolia developed an estimated $/square foot cost to upgrade major HVAC equipment at each of the offtaker buildings resulting in a total estimated cost of approximately $45M for all fifteen (15) buildings. This figure does not include potential costs for upgrading pumping systems or existing piping distribution networks in the buildings or the CAS loop itself and could vary significantly from actual costs developed from building testing and a full engineering study. Additional engineering studies and flow tests on the CAS loop would need to be performed before increasing flow and pressure in the system. Based on the history of documented leaks at existing flows and pressures it is possible that significant upgrades to the system could be required.

8.2. Potential Offtaker Energy Savings

In order to evaluate the opportunity within every building, the Energy Use Intensity (EUI) for each building and for each energy type was used to evaluate if the building is outside the normally accepted ranges for buildings of their type. For buildings that exceeded their expected EUI, potential savings was calculated as 50% of the difference between their current EUI and the proposed EUI average, then multiplied by their square footage to obtain the energy savings value in kBTU.

Total potential annual savings were estimated to be 12.6M kBTU of chilled water and 7.1M kBTU of hot water/steam, roughly 19% and 10% of the total chilled water and hot water/steam consumption, respectively, by all offtakers. These estimated savings are based only on comparisons relative to typical average EUIs. A more detailed investigation into individual building operating conditions may reveal higher or lower potential energy savings. Assuming that 25% of these reductions at individual buildings occur concurrently it can be estimated that a 5% reduction in existing peak chilled water peak demand (197 tons/hr) and 2.5% reduction in existing hot water/steam peak demand (1,137 MMBTU/hr) would result. However, without hourly offtaker data it is difficult to accurately estimate by how much these savings would reduce peak heating and cooling loads, and therefore the required peak capacity of the central plant.

9.0 Additional Findings & Assumptions

9.1. Metering

Based on numerous metered data errors encountered during our analysis the State should conduct a thorough metering reading and billing assessment to support future design development efforts and to establish proper revenue recovery mechanisms. Veoila recommends the following specific actions related to meter reading and billing process as the State continues the redevelopment and repurposing of the CAS system:

1. Confirm calibration of the major metered energy streams into and out of the thermal generation equipment and distribution systems: Electricity, Chilled Water, Condenser Water, Hot Water and Makeup Water.
2. Document via flow chart, the current meter reading and billing process from field instrumentation to customer invoice.
3. Remove use of efficiency curves to determine variable cost of energy and replace them with direct metered consumption.
4. 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.

Accurate metered data will enable proper design basis and revenue recovery.

9.2. Low System Differential Temperatures

Metered temperature data shows extremely low differential temperatures between chilled and hot water supply and return that are causing inefficiencies and need to be addressed. According to Trane's submittal documentation for the plant's most recent 1,800 ton chilled replacement, the design chilled water supply is 42° F with a return of 52° F (10° F delta T) coupled with a condenser supply of 85° F and a return of 95° F (10° F delta T). Metered data shows an average of 3.4° F delta T for chilled water and a 4° F delta T for condenser water which is significantly lower than the design delta T of 10° F.

This situation, known as Low Delta T syndrome, results from the inefficient use of chilled and hot water at the point of consumption and leads to improper sequencing of chillers, boilers and pumps (operating more than necessary), consequently increasing energy consumption. The offtakers' secondary side of the Energy Transfer Stations (ETS) need to be better controlled to enable a higher delta T on the primary distribution system. There are several technical measures that can be implemented such as installation of pressure independent control valves (PICVs, better VFD control, correct coil sizing for the design delta T, and correct overall building management system (BMS) control.

As a supplier of thermal energy the State can implement financial measures to address low delta T in the form of penalties if return temperatures are not in line with required values, forcing end users to address the situation. Ignoring the low delta T situation can lead to an electrification basis of design that is rooted in higher than required capacities and increased long term operational costs.

9.3. Chilled Water Production Costs

Returning the chilled water plant temperatures to chilled design conditions will improve performance and reduce operating costs. For purposes of this study, existing metered electrical consumption at each chiller is used as the status quo/business as usual/do nothing scenarios. For all future scenarios we have assumed the existing chilled water plant will be optimized (i.e. increased efficiency) and additional chilled water load will be served by a combination of new electric chillers and/or heat pumps, depending on the scenario at hand.

9.4. Hot Water Production Costs

Returning the hot water plant temperatures to design conditions will improve performance and reduce operating costs. For purposes of this study, 2020 was used as a base operating year with the assumption that, from a carbon and cost standpoint, the steam boilers provide hot water to the system. We acknowledge current hot water boilers (2021-present) as a temporary solution, therefore capturing operating and carbon costs of this configuration would not provide the State a representative comparative analysis.

APPENDIX A

Full List of Scenario Results

Scenario	A.1.H	A.1.L	A.2.H	A.2.L	A.3.H	A.3.L
Description	Condenser Water Source HP w/ Electric Boilers	Condenser Water Source HP w/ Electric Boilers	Condenser & Ground Source HP w/ Electric Boilers	Condenser & Ground Source HP w/ Electric Boilers	Condenser & Air Source HP w/ Electric Boilers	Condenser & Air Source HP w/ Electric Boilers
Supply Temperature	High	Low	High	Low	High	Low
CapEx	$19.6	$58.2	$42.8	$78.0	$28.3	$62.3
CapEx w/ Incentives	$19.6	$58.2	$35.7	$71.9	$28.3	$62.3
Year 1 OpEx (w/ Social Cost of Carbon)	$11.7	$11.3	$10.2	$7.2	$10.7	$8.3
Year 1 OpEx (w/ RECs/Carbon Offsets)	$11.4	$10.9	$9.9	$7.0	$10.4	$8.0
Year 1 OpEx (w/o Carbon Costs)	$10.7	$10.3	$9.4	$6.7	$9.9	$7.6
NPC (w/ Social Cost of Carbon)	$297	$324	$278	$242	$284	$258
NPC (w/ Carbon Offsets)	$294	$321	$276	$240	$281	$256
NPC (w/o Carbon Costs)	$289	$316	$272	$238	$277	$253
Lifetime Carbon (30-Year Tons)	29,852	28,714	23,561	16,001	25,019	19,231
Assumed Heat Pump Capacity (MMBTU/hr)	4	4	34	34	24	24
Assumed Boiler Capacity (MMBTU/hr)	68	68	38	38	48	48
Estimated Electricity Demand (MW)	37	37	31	31	33	33

Notes: 1. All costs are in millions of dollars.

2. 100% Condenser water heat pump scenarios (C.1.H & C.1.L) and 100% air source heat pump scenarios (C.2.H & C.2.L) were determined to not be feasible and are not included in this table.

Scenario	B.1.H	B.1.L	C.2.H	C.2.L	D.1.H	D.1.L
Description	Electric Boilers	Electric Boilers	Ground Source HP	Ground Source HP	Condenser Water Source HP w/ Natural Gas Boilers	Condenser Water Source HP w/ Natural Gas Boilers
Supply Temperature	High	Low	High	Low	High	Low
CapEx	$18.9	$57.9	$53.4	$97.1	$20.7	$59.2
CapEx w/ Incentives	$18.9	$57.9	$42.7	$84.9	$20.7	$59.2
Year 1 OpEx (w/ Social Cost of Carbon)	$12.9	$13.0	$10.0	$7.5	$8.2	$7.4
Year 1 OpEx (w/ RECs/Carbon Offsets)	$12.5	$12.6	$9.7	$7.3	$8.7	$7.9
Year 1 OpEx (w/o Carbon Costs)	$11.8	$11.9	$9.3	$7.0	$5.7	$5.0
NPC (w/ Social Cost of Carbon)	$324	$365	$281	$261	$205	$222
NPC (w/ Carbon Offsets)	$321	$361	$278	$260	$235	$251
NPC (w/o Carbon Costs)	$316	$356	$275	$257	$164	$182
Lifetime Carbon (30-Year Tons)	33,330	33,649	21,829	15,095	202,889	195,982
Assumed Heat Pump Capacity (MMBTU/hr)	0	0	49	49	4	4
Assumed Boiler Capacity (MMBTU/hr)	72	72	0	0	68	68
Estimated Electricity Demand (MW)	38	38	21	21	17	17

Notes: 1. All costs are in millions of dollars.

2. 100% Condenser water heat pump scenarios (C.1.H & C.1.L) and 100% air source heat pump scenarios (C.2.H & C.2.L) were determined to not be feasible and are not included in this table.

Scenario	D.2.H	D.2.L	D.3.H	D.3.L	E.1.H	E.1.L
Description	Ground Source HP w/ Natural Gas Boilers	Ground Source HP w/ Natural Gas Boilers	Air Source HP w/ Natural Gas Boilers	Air Source HP w/ Natural Gas Boilers	Natural Gas Boilers	Natural Gas Boilers
Supply Temperature	High	Low	High	Low	High	Low
CapEx	$43.0	$78.7	$33.2	$65.3	$20.0	$59.0
CapEx w/ Incentives	$35.9	$72.6	$33.2	$65.3	$20.0	$59.0
Year 1 OpEx (w/ Social Cost of Carbon)	$10.3	$7.3	$10.3	$7.6	$7.9	$7.7
Year 1 OpEx (w/ RECs/Carbon Offsets)	$10.1	$7.2	$10.3	$7.6	$8.7	$8.5
Year 1 OpEx (w/o Carbon Costs)	$9.3	$6.5	$8.8	$6.3	$4.7	$4.7
NPC (w/ Social Cost of Carbon)	$279	$244	$274	$240	$194	$228
NPC (w/ Carbon Offsets)	$280	$246	$284	$250	$236	$266
NPC (w/o Carbon Costs)	$268	$235	$254	$222	$137	$175
Lifetime Carbon (30-Year Tons)	46,397	40,858	94,358	83,994	276,673	257,498
Assumed Heat Pump Capacity (MMBTU/hr)	30	30	30	30	0	0
Assumed Boiler Capacity (MMBTU/hr)	42	42	60	60	72	72
Estimated Electricity Demand (MW)	20	20	20	20	17	17

Notes: 1. All costs are in millions of dollars.
2. 100% Condenser water heat pump scenarios (C.1.H & C.1.L) and 100% air source heat pump scenarios (C.2.H & C.2.L) were determined to not be feasible and are not included in this table.

Appendix B

Baseline Conditions

The CAS was designed to utilize natural gas-fired steam boilers and an electric chilled water plant to deliver hot water (HW) and chilled water (CHW) via 3 miles of distribution piping in Hartford, CT. A pump house/energy transfer station was used to convert steam to hot water before being pumped through the distribution piping. The plant was originally a natural gas-fired, dual fuel capable (natural gas and fuel oil), combined-cycle cogeneration merchant plant with a generation nameplate capacity of 62.1 MW and provided peaking energy to the ISO New England power market, as well as thermal supply for the district network. As of April 2021, the electrical turbines have been decommissioned and delisted from the ISO. The plant remains powered through a 115 kV electric service by the local utility who is urging its decommissioning with the establishment of a new lower voltage service. The four (4) fuel oil storage tanks have been cleaned and removed and the facility is no longer dual fuel capable.

In August 2021, an explosion rendered the pump house (point of coupling between central plant and district piping) useless thereby requiring temporary pumping and hot water boilers. Currently, three (3) water-cooled electric centrifugal chillers and a combination of existing (steam) and temporary (hot water) rental boilers provide cooling and heating to all fifteen (15) offtakers on the distribution network. The cost for the rental boilers is reported to be approximately $150,000 per month.

Baseline Energy Use

Existing Baseline CAS Production

In order to establish baseline energy use at CAS Veolia reviewed plant steam and chilled water production hourly data for the years 2019 and 2020, the last two full years of operation before the explosion at the pump house. The data was compiled for Veolia by plant staff from the plant's PI data historian. A summary of the annual steam and chilled water produced by the plant in 2019 and 2020 for offtaker use is presented below:

TABLE A1: CAS Plant Production For Offtaker Use Data

	CAS Plant PI Data	
	2019	**2020**
Total Steam/HW (MMBTU/year)	93,819	90,814
Peak Steam/HW Load (MMBTU/hr)	49.96	40.03
Total CHW (Ton-Hr/year)	4,672,724	4,917,031
Peak CHW (Tons)	3,020	3,519
Total Steam & CHW (MMBTU/year)	**149,892**	**149,818**

As shown in Table A1, total energy sent to the CAS offtakers was very similar in 2019 and 2020 despite the beginning of Covid-19 restrictions in 2020. Hourly load profiles and load duration curves for steam and chilled water for 2020 are depicted below. The load duration curves are a representation of how much time the load is at or above a certain value. For example, for the steam, 25% of the time the load is ~17,000 MMBTU/hr or greater, 75% of the time the load is ~2,000 MMBTU/hr or greater, etc.

FIGURE A1: Hourly Steam Export (2020)

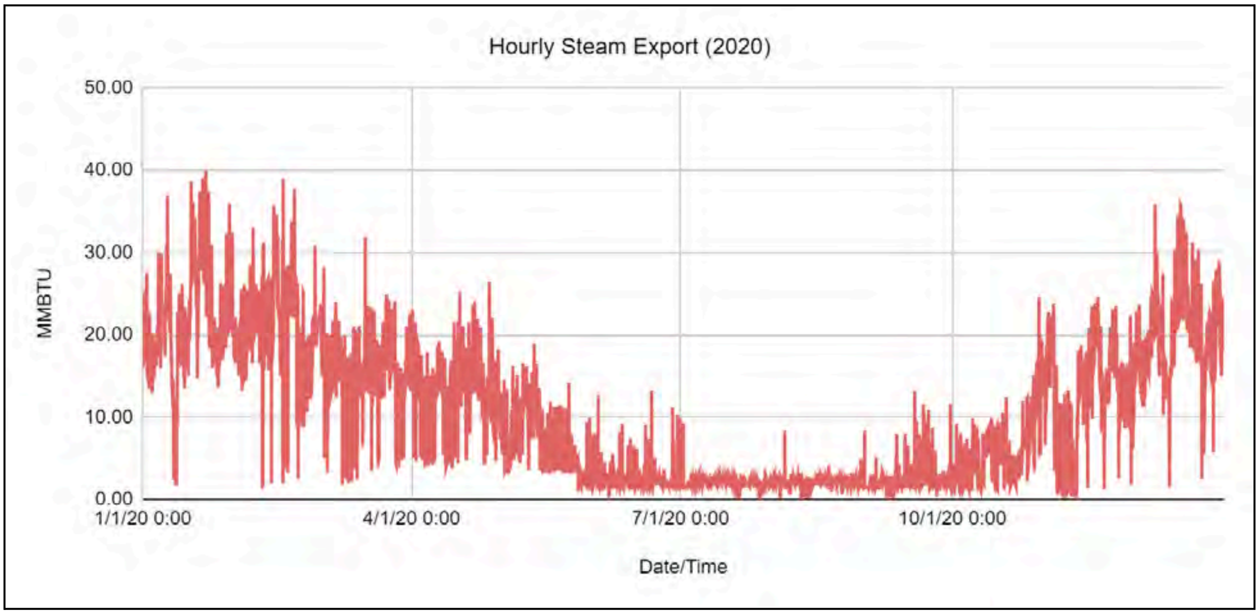


FIGURE A2: Steam Export Load Duration Curve (2020)

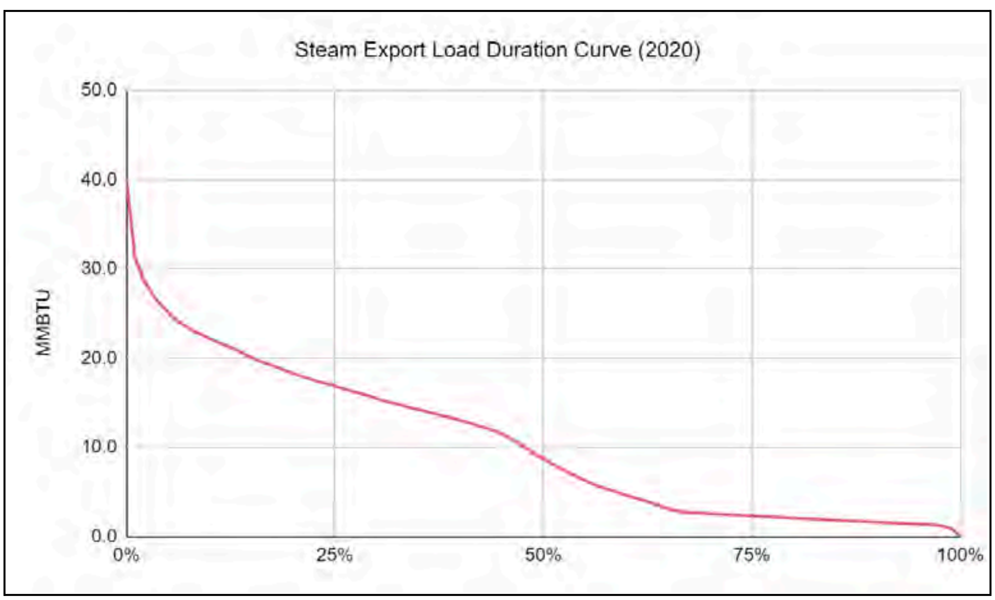


FIGURE A3: Hourly Chilled Water Export (2020)

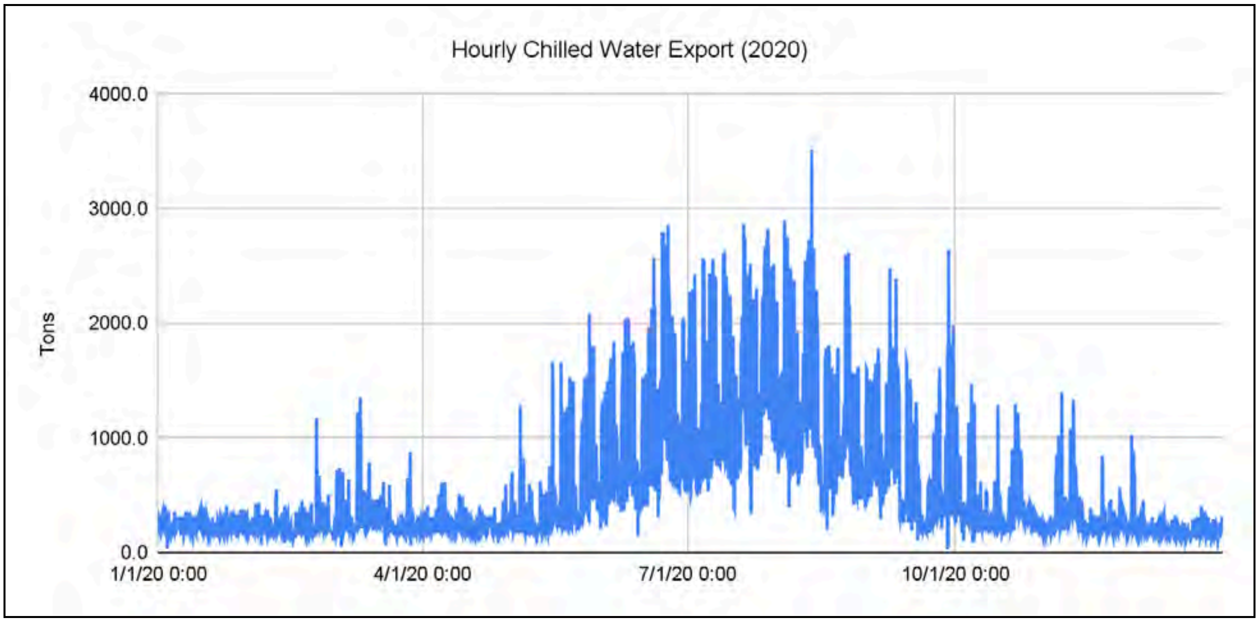
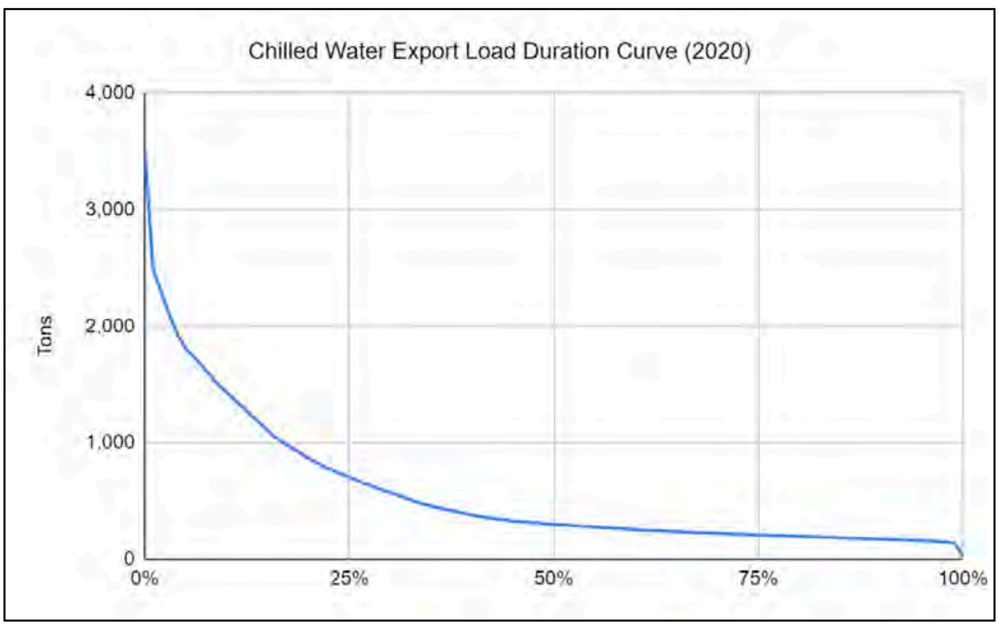


FIGURE A4: Chilled Water Export Load Duration Curve (2020)



Veolia also reviewed monthly meter data for the fifteen (15) offtaker buildings which was provided for the period July 2019 to April 2023. Annual chilled water and hot water usage for the offtaker buildings for 2020 is presented in the table below.

TABLE A2: 2020 Offtaker Use Data

Building Description	Building Address	2020	
		Annual CHW (MMBtu)	Annual HW (MMBtu)
Legislative Office Building	300 Capitol Ave (LOB)	8,313	7,408
Underwood Tower A(M24-6PP)	2 Park Place (P.P. Tower A)	4,001	8,268
Underwood Tower B (M12-24PP)	24 Park Place (P.P. Tower B)	2,390	6,606
Bushnell Theater	166 Capitol Ave (Bushnell)	722	0
United Way	30 Laurel St (United Way)	410	1,147
18/20 Trinity	18~20 Trinity St (Ethics)	974	2,685
30 Trinity	30 Trinity St (Sec. of State)	854	1,897
231 Capitol Library	231 Capitol Ave (Judicial/Supreme Court)	8,331	4,791
Armory	360 Broad St (Armory)	2,351	4,185
Capitol Place	21 Oak St (CEA)	4,524	2,121
79 Elm Street	79 Elm St (DEEP)	3,175	2,928
75 Elm Street	75 Elm St (Judicial)	927	1,238
Cap Ave Complex	410 - 470 Capitol Ave (OPM)	20,446	13,879
101 Lafayette	101 Lafayette (Judicial)	2,156	0
165 Capitol Ave (New circa 2017)	165 Capitol Ave (State Office Building)	5,159	7,692

Because of the similarity of annual plant output to the CAS offtakers in 2019 and 2020 and the lack of a full year of offtaker meter data for 2019, the year 2020 was selected as the representative CAS plant production/offtaker use period with the most complete data set. This is also the most recent full year before the pumphouse explosion in August 2021, after which a temporary hot water system was installed and plant operations were no longer representative of historic production. Hourly meter for the offtakers was requested but was unavailable for 2020.

Existing Baseline CAS Energy Use

The following figures depict monthly electric, natural gas and water use at the CAS plant in 2020. Natural gas use is for the steam boilers only and shows lower use in the summer when heat loads are lower and higher use in the winter. It does not include natural gas use for the gas turbine, which was in its last full year of operation and only ran for approximately 230 hours. However, natural gas use for the boilers was adjusted to account for increased run times had the gas turbine not been producing steam while it was operating. Electric use shows less seasonal variation than natural gas as it is used year round for ancillary equipment (pumps, fans, etc.) but does peak in the summer when the electric chillers are providing more chilled water. Water use also peaks in the summer when evaporation from the cooling tower is greatest and more make-up water is required.

FIGURE A5: Baseline Monthly Electric Usage (2020)

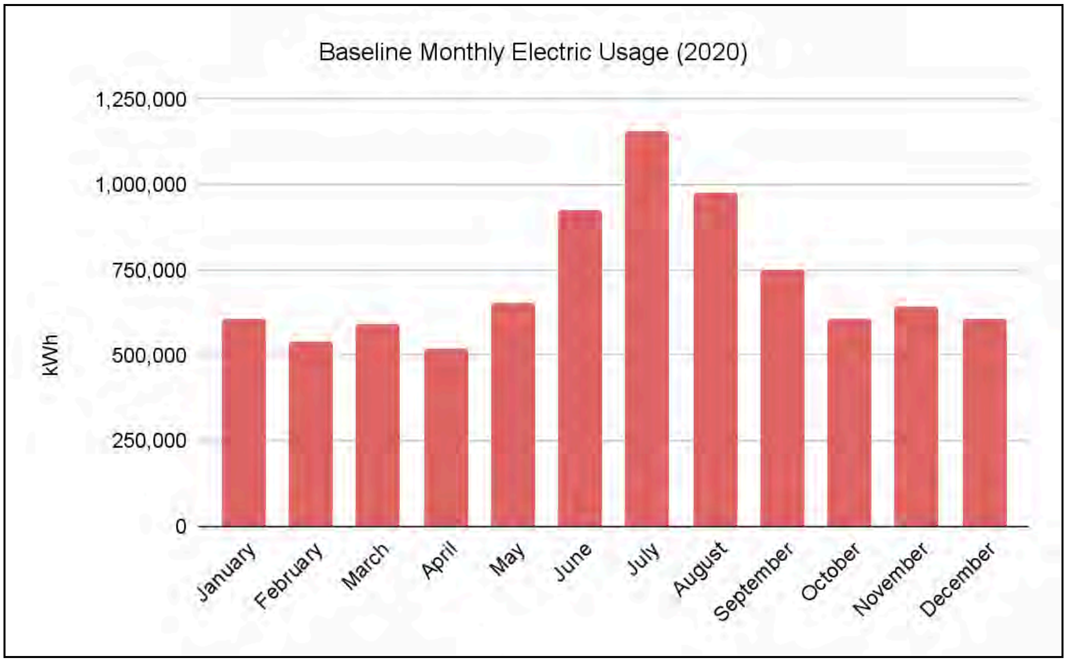


FIGURE A6: Baseline Monthly Natural Gas Usage (2020)

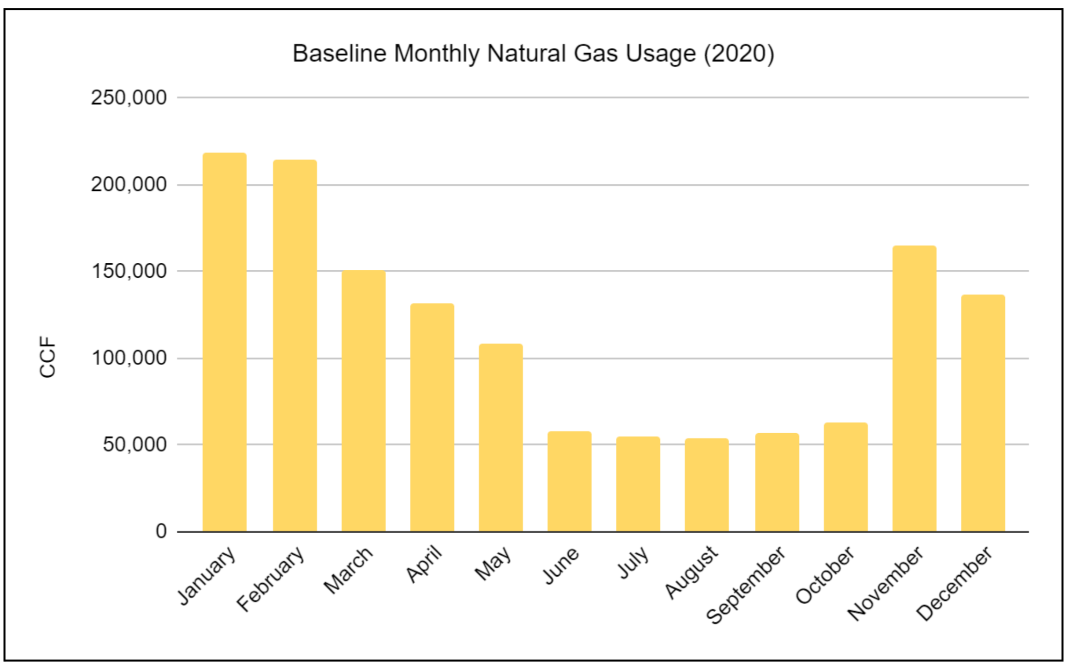
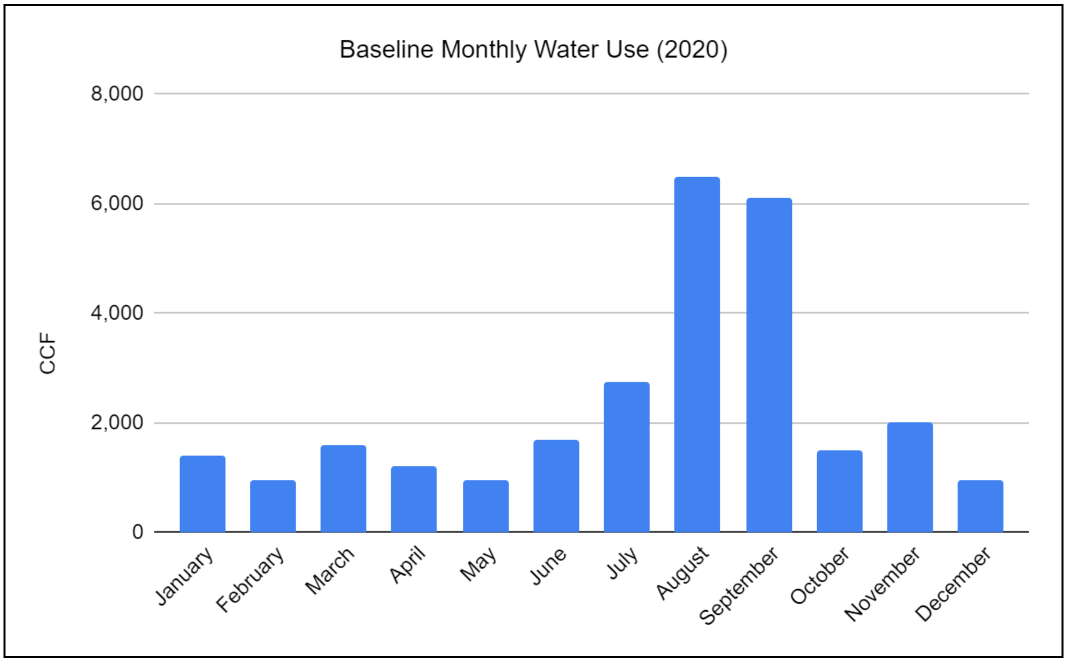


FIGURE A7: Baseline Water Usage (2020)



Projected Baseline CAS Export

Existing and future total peak design demand for hot water and chilled water was calculated based on schematics of existing and future loads prepared by the State[6]. A summary of these schematics is shown in the following table:

TABLE A3: Existing & Future Demand Loads

Building Description	Building Address	CHW Demand (Tons)	CHW Demand Status	HW Demand (MBH)	HW Demand Status
Legislative Office Building	300 Capitol Ave	546	Existing	3,202	Existing
Underwood Tower A	2 Park Place	154	Existing	4,455	Existing
Underwood Tower B	24 Park Place	120	Existing	3,550	Existing
Bushnell Theater	166 Capitol Ave	76	Existing	708	Future
United Way	30 Laurel St	27	Existing	482	Existing
Ethics	18~20 Trinity St	38	Existing	1,858	Existing
Secretary of State	30 Trinity St	59	Existing	1,791	Existing
Judicial Supreme Court	231 Capitol Ave	279	Existing	3,363	Existing
Armory	360 Broad St	128	Existing	2,096	Existing
Capitol Place (CEA)	21 Oak St	193	Existing	928	Existing
DEEP	79 Elm St	189	Existing	1,928	Existing

[6] State of CT provided markups to RMF's Hot Water and Chilled Water Schematic drawings to depict future and future thermal demands.

Judicial	75 Elm St	53	Existing	1,215	Existing
Cap Ave Complex (OPM)	410 - 470 Capitol Ave	910	Existing	6,599	Existing
Judicial	101 Lafayette	359	Existing	5,029	Future
State Office Building	165 Capitol Ave	800	Existing	14,000	Existing
State Capitol	210 Capitol Ave	0	Future	10,000	Future
-	80 Washington St	154	Future	2,160	Future
-	90 Washington St	226	Future	3,164	Future
Supreme Court	95 Washington St	368	Future	5,155	Future
-	100 Washington St	65	Future	906	Future
		4,744	**Total CHW Demand**	**72,589**	**Total HW Demand**
		3,931	***Existing CHW Demand***	***45,467***	***Existing HW Demand***
		813	***Future CHW Demand***	***27,122***	***Future HW Demand***

The Total CHW Demand and Total HW Demand from Table A3 are considered to be representative of all offtaker loads which are currently or planned to be served by the CAS plant. These demand values were used to size proposed equipment for all operational scenarios and to determine equipment requirements for N+1 redundancy to provide resilience that ensures system availability in the event of component failure. It should be noted that these values are design demand loads and may not necessarily represent actual demand at each building. While the billing meters at each building are capable of recording and exporting the hourly data needed to calculate demand, currently that data can only be accessed by connecting directly to the meters at the buildings. Once remote data logging capability is reestablished full annual hourly data for each building can be recorded and used to determine actual hourly loads and demand.

Projected future hourly load profiles and load duration curves for hot water and chilled water were created based on the projected percent increases in peak demand for hot water and chilled water, respectively, and are depicted below. These projected hourly loads were used in all modeling and financial analyses in this study.

FIGURE A8: Projected Hourly Hot Water Export

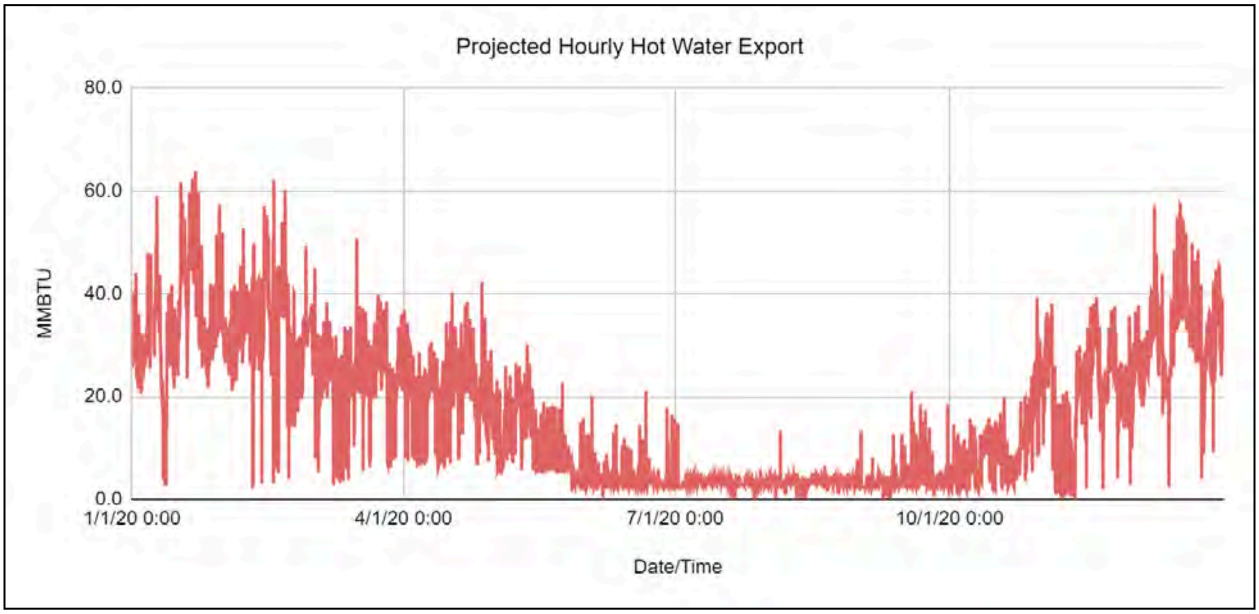


FIGURE A9: Projected Hot Water Export Load Duration Curve

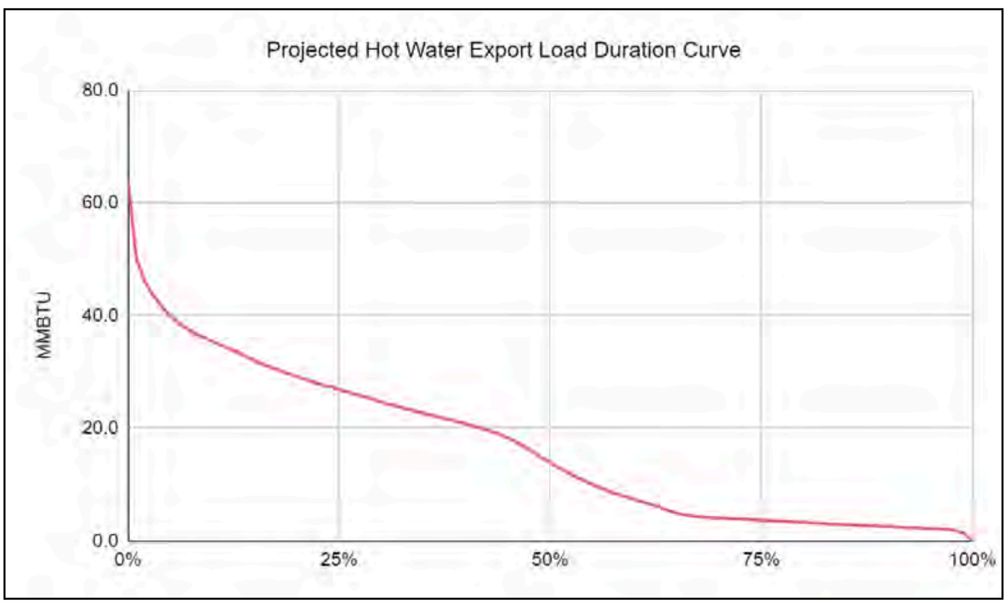


FIGURE A10: Projected Hourly Chilled Water Export

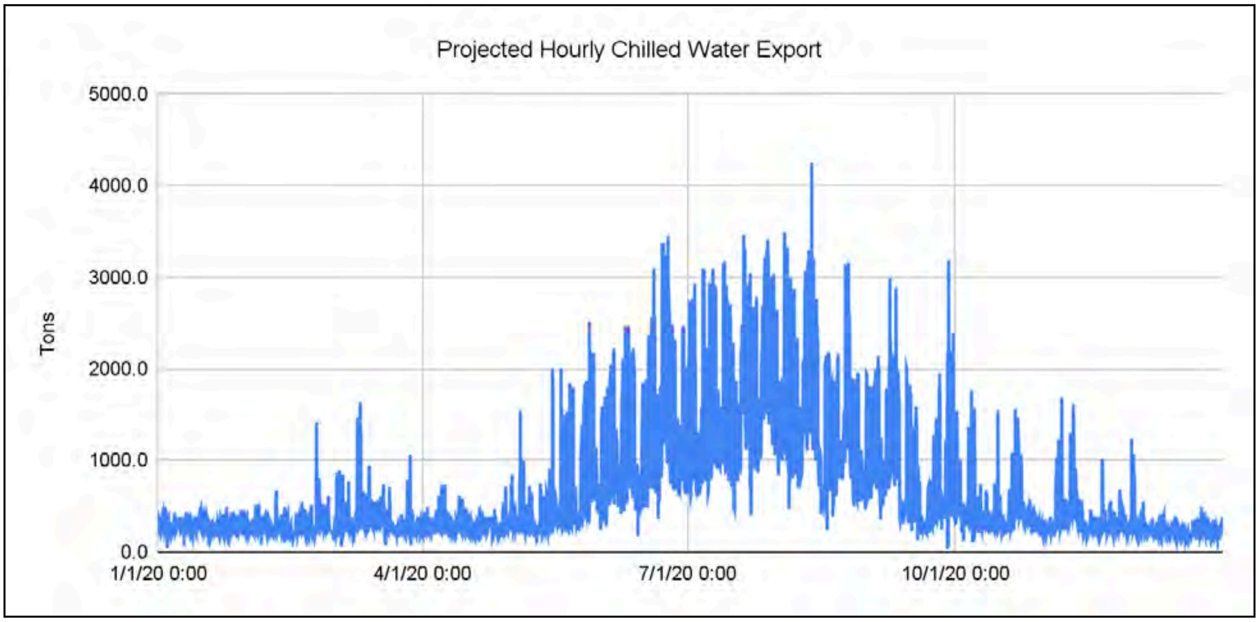
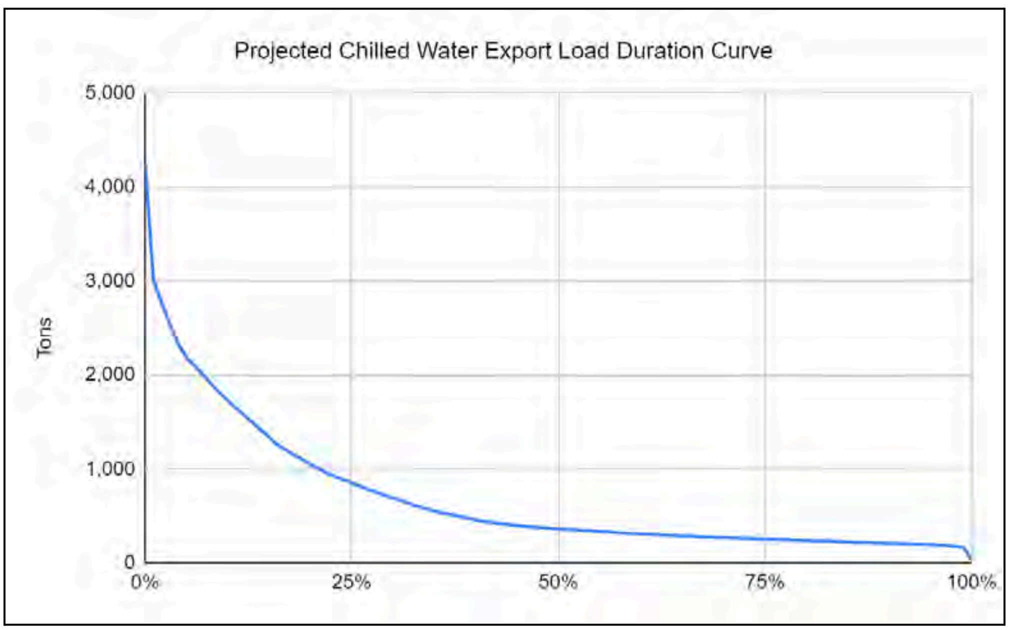


FIGURE A11: Projected Chilled Water Export Load Duration Curve



Baseline Carbon Emissions

Baseline carbon emissions, broken out for electricity and natural gas, for 2020 and projected future plant hot water and chilled water loads are presented in the following table. Natural gas emissions for 2020 do not include the gas turbine, which was in its last full year of operation and only ran for approximately 230 hours. However, natural gas use for the boilers was adjusted to account for increased run times had the gas turbine not been producing steam while it was operating. Projected carbon emissions assume that the plant operates in the same configuration as in 2020 but without the gas turbine. Projected carbon emissions were used as the comparison point for all future operating scenarios evaluated as part of this study. Emission factors for a base year of 2020 were used for both 2020 and projected carbon emissions.

TABLE A4: Baseline CO_2 Emissions

	Natural Gas CO2 Emissions		Electricity CO2 Emissions		Total
	Total CCF	Metric Tons CO2	Total kWh	Metric Tons CO2	Metric Tons CO2
2020	1,476,898	8,040	7,989,949	866	8,907
Projected	2,357,898	12,836	8,627,831	935	13,772

Appendix C

TABLE C1: Modeled Potential Offtaker Building Annual Solar PV Production

Building Address	Ownership	Potential Annual MWh
300 Capitol Ave (LOB)	State-owned	153
2 Park Place (P.P. Tower A)	Private	0
24 Park Place (P.P. Tower B)	Private	0
166 Capitol Ave (Bushnell Theater)	Private	91
30 Laurel St (United Way)	Private	0
18-20 Trinity St (Ethics)	Private	35
30 Trinity St (Sec. of State)	Private	40
231 Capitol Ave (Judicial/Supreme Court)	State-owned	87
360 Broad St (Armory)	State-owned	348
21 Oak St (CEA)	Private	0
79 Elm St (DEEP)	State-owned	0
75 Elm St (Judicial)	State-owned	61
410 - 470 Capitol Ave (OPM) Roof	State-owned	410
410 - 470 Capitol Ave (OPM) Parking Lot	State-owned	936
101 Lafayette (Judicial)	State-owned	94
165 Capitol Ave (State Office Building)	State-owned	147
	State-owned Total	**2,236**
	Private Total	**166**

APPENDIX I

TABLE C1: Modeled Potential Offtaker Building Annual Solar PV Production

Building Address	Ownership	Potential Annual MWh
300 Capitol Ave (LOB)	State-owned	153
2 Park Place (P.P. Tower A)	Private	0
24 Park Place (P.P. Tower B)	Private	0
166 Capitol Ave (Bushnell Theater)	Private	91
30 Laurel St (United Way)	Private	0
18-20 Trinity St (Ethics)	Private	35
30 Trinity St (Sec. of State)	Private	40
231 Capitol Ave (Judicial/Supreme Court)	State-owned	87
360 Broad St (Armory)	State-owned	348
21 Oak St (CEA)	Private	0
79 Elm St (DEEP)	State-owned	0
75 Elm St (Judicial)	State-owned	61
410 - 470 Capitol Ave (OPM) Roof	State-owned	410
410 - 470 Capitol Ave (OPM) Parking Lot	State-owned	936
101 Lafayette (Judicial)	State-owned	94
165 Capitol Ave (State Office Building)	State-owned	147
	State-owned Total	**2,236**
	Private Total	**166**

APPENDIX J

FIGURE D1: Selection Criteria by State

CAS Decarbonization Study - Initial Screening Assessment Results

List of Scenario Key Metrics

NOTES

1. ***CapEx, OpEx & NPC costs are in millions of dollars.***
2. 100% Condenser water heat pump scenarios (C.1.H & C.1.L) and 100% air source heat pump scenarios (C.2.H & C.2.L) were determined to not be feasible and are not inlcuded in this table.
3. MTCO2e - metric tons of carbon dioxide equivalent
4. Baseline carbon emissions based on 2020 plant operating conditions and future projected plant loads as outlined in Deliverable 2: Total Energy Requirements/Design Basis Memo Report.
5. Unit Cost of Carbon Reduction based on 30-Year NPC divided by carbon reduction compared to baseline carbon emissions.
6. All costs presented in this table are commensurate with the level of project definition and have an expected range of accuracy between -30% to 50%. Low temperature and geothermal scenarios likely will have the highest CapEx uncertainty and require the most additional study to determine feasibilty.

Scenario	A.1.H	A.1.L	A.2.H	A.2.L	A.3.H	A.3.L	B.1.H	B.1.L
TOP 3 RANKED	8	7	5	2	6	3	9	10
Description	Condenser Water Source HP w/ Electric Boilers	Condenser Water Source HP w/ Electric Boilers	Condenser & Ground Source HP w/ Electric Boilers	Condenser & Ground Source HP w/ Electric Boilers	Condenser & Air Source HP w/ Electric Boilers	Condenser & Air Source HP w/ Electric Boilers	Electric Boilers	Electric Boilers
Supply Temperature NOTE: Existing system is High Temp	High Temp	Low Temp	High Temp	Low Temp	High Temp	Low Temp	High Temp	Low Temp
CapEx	$19.60	$58.20	$42.80	$78.00	$28.30	$62.30	$18.90	$57.90
CapEx w/ Incentives	$19.60	$58.20	$35.70	$71.90	$28.30	$62.30	$18.90	$57.90
Year 1 OpEx (w/ Social Cost of Carbon)	$11.70	$11.30	$10.20	$7.20	$10.70	$8.30	$12.90	$13.00
Year 1 OpEx (w/ RECs/Carbon Offsets)	$11.40	$10.90	$9.90	$7.00	$10.40	$8.00	$12.50	$12.60
Year 1 OpEx (w/o Carbon Costs)	$10.70	$10.30	$9.40	$6.70	$9.90	$7.60	$11.80	$11.90
NPC (30-Year w/ Social Cost of Carbon)	$297	$324	$278	$242	$284	$258	$324	$365
NPC (30-Year w/ RECs/Carbon Offsets)	$294	$321	$276	$240	$281	$256	$321	$361
NPC (30-Year w/o Carbon Costs)	$289	$316	$272	$238	$277	$253	$316	$356
Lifetime Carbon (30-Year MTCO2e)	29,852	28,714	23,561	16,001	25,019	19,231	33,330	33,649
Baseline Carbon (30-Year MTCO2e) [4]	390,994	390,994	390,994	390,994	390,994	390,994	390,994	390,994
Carbon Reduction from Baseline (30-Year MTCO2e)	361,142	362,280	367,433	374,993	365,975	371,762	357,664	357,345
Unit Cost of Carbon Reduction ($/MTCO2e w/ Social Cost of Carbon) [5]	$824	$894	$757	$645	$775	$693	$907	$1,021
Unit Cost of Carbon Reduction ($/MTCO2e w/ RECs/Carbon Offsets) [5]	$815	$885	$750	$641	$768	$688	$897	$1,011
Unit Cost of Carbon Reduction ($/MTCO2e w/o Carbon Costs) [5]	$802	$873	$740	$634	$757	$680	$882	$996

Scenario	C.2.H	C.2.L	D.1.H	D.1.L	D.2.H	D.2.L	D.3.H	D.3.L	E.1.H	E.1.L
TOP 3 RANKED	4	1	16	15	12	11	14	13	18	17
Description	Ground Source HP	Ground Source HP	Condenser Water Source HP w/ Natural Gas Boilers	Condenser Water Source HP w/ Natural Gas Boilers	Ground Source HP w/ Natural Gas Boilers	Ground Source HP w/ Natural Gas Boilers	Air Source HP w/ Natural Gas Boilers	Air Source HP w/ Natural Gas Boilers	Natural Gas Boilers	Natural Gas Boilers
Supply Temperature NOTE: Existing system is High Temp	High Temp	Low Temp	High Temp	Low Temp	High Temp	Low Temp	High Temp	Low Temp	High Temp	Low Temp
CapEx	$53.40	$97.10	$20.70	$59.20	$43.00	$78.70	$33.20	$65.30	$20.00	$59.00
CapEx w/ Incentives	$42.70	$84.90	$20.70	$59.20	$35.90	$72.60	$33.20	$65.30	$20.00	$59.00
Year 1 OpEx (w/ Social Cost of Carbon)	$10.00	$7.50	$8.20	$7.40	$10.30	$7.30	$10.30	$7.60	$7.90	$7.70
Year 1 OpEx (w/ RECs/Carbon Offsets)	$9.70	$7.30	$8.70	$7.90	$10.10	$7.20	$10.30	$7.60	$8.70	$8.50
Year 1 OpEx (w/o Carbon Costs)	$9.30	$7.00	$5.70	$5.00	$9.30	$6.50	$8.80	$6.30	$4.70	$4.70
NPC (30-Year w/ Social Cost of Carbon)	$281	$261	$205	$222	$279	$244	$274	$240	$194	$228
NPC (30-Year w/ RECs/Carbon Offsets)	$278	$260	$235	$251	$280	$246	$284	$250	$236	$266
NPC (30-Year w/o Carbon Costs)	$275	$257	$164	$182	$268	$235	$254	$222	$137	$175
Lifetime Carbon (30-Year MTCO2e)	21,829	15,095	202,889	195,982	46,397	40,858	94,358	83,994	276,673	257,498
Baseline Carbon (30-Year MTCO2e) [4]	390,994	390,994	390,994	390,994	390,994	390,994	390,994	390,994	390,994	390,994
Carbon Reduction from Baseline (30-Year MTCO2e)	369,165	375,898	188,105	195,012	344,597	350,136	296,636	306,999	114,320	133,496
Unit Cost of Carbon Reduction ($/MTCO2e w/ Social Cost of Carbon) [5]	$760	$695	$1,091	$1,140	$810	$696	$925	$783	$1,694	$1,704
Unit Cost of Carbon Reduction ($/MTCO2e w/ RECs/Carbon Offsets) [5]	$754	$691	$1,247	$1,287	$813	$703	$958	$814	$2,061	$1,996
Unit Cost of Carbon Reduction ($/MTCO2e w/o Carbon Costs) [5]	$744	$684	$870	$934	$778	$670	$856	$724	$1,201	$1,311

*Blue text below can be manually entered *Black text is calculated

Scoring Matrix - Prioritize Decarb	% matters
Capital Expenditures	0%
Operating Exp	0%
Net Pres Cost	0%
Lifetime Carbon	100%
Unit Cost of Carbon	0%
Use of Credits	0%
	100%

Top 3 Ranked	Scenario Abbreviation	Scenario Name	Operating Temperature
	C.2.L	Ground Source HP	Low
	A.2.L	Cond W & Ground HP + Elect Boile	Low
	A.3.L	Cond W & Air HP + Elect Boiler	Low

Scoring Matrix - Prioritize Cost	% matters
Capital Expenditures	25%
Operating Exp	50%
Net Pres Cost	10%
Lifetime Carbon	10%
Unit Cost of Carbon	5%
Use of Credits	0%
	100%

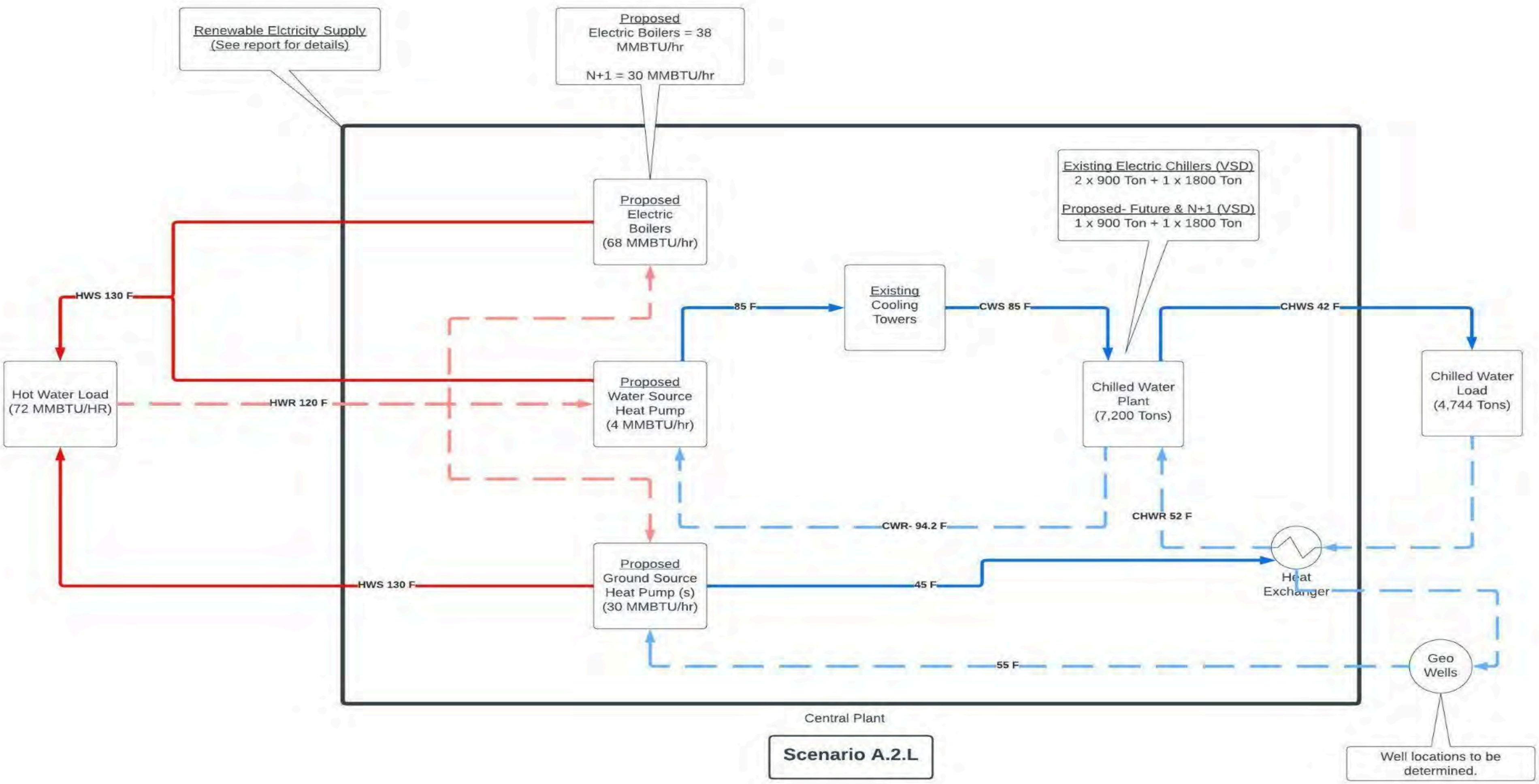
Top 3 Ranked	Scenario Abbreviation	Scenario Name	Operating Temperature
	E.1.H	Nat Gas Boiler	High
	D.1.H	Cond W + NG Boiler	High
	A.2.H	Cond & GS HP + Elect Boiler	High

Scoring Matrix - Balance	% matters
Capital Expenditures	12.5%
Operating Exp	25.0%
Net Pres Cost	12.5%
Lifetime Carbon	30.0%
Unit Cost of Carbon	20.0%
Use of Credits	0.0%
	100%

Top 3 Ranked	Scenario Abbreviation	Scenario Name	Operating Temperature
	A.2.L	Cond W & Ground HP + Elect Boile	Low
	A.3.L	Cond W & Air HP + Elect Boiler	Low
	A.2.H	Cond & GS HP + Elect Boiler	High

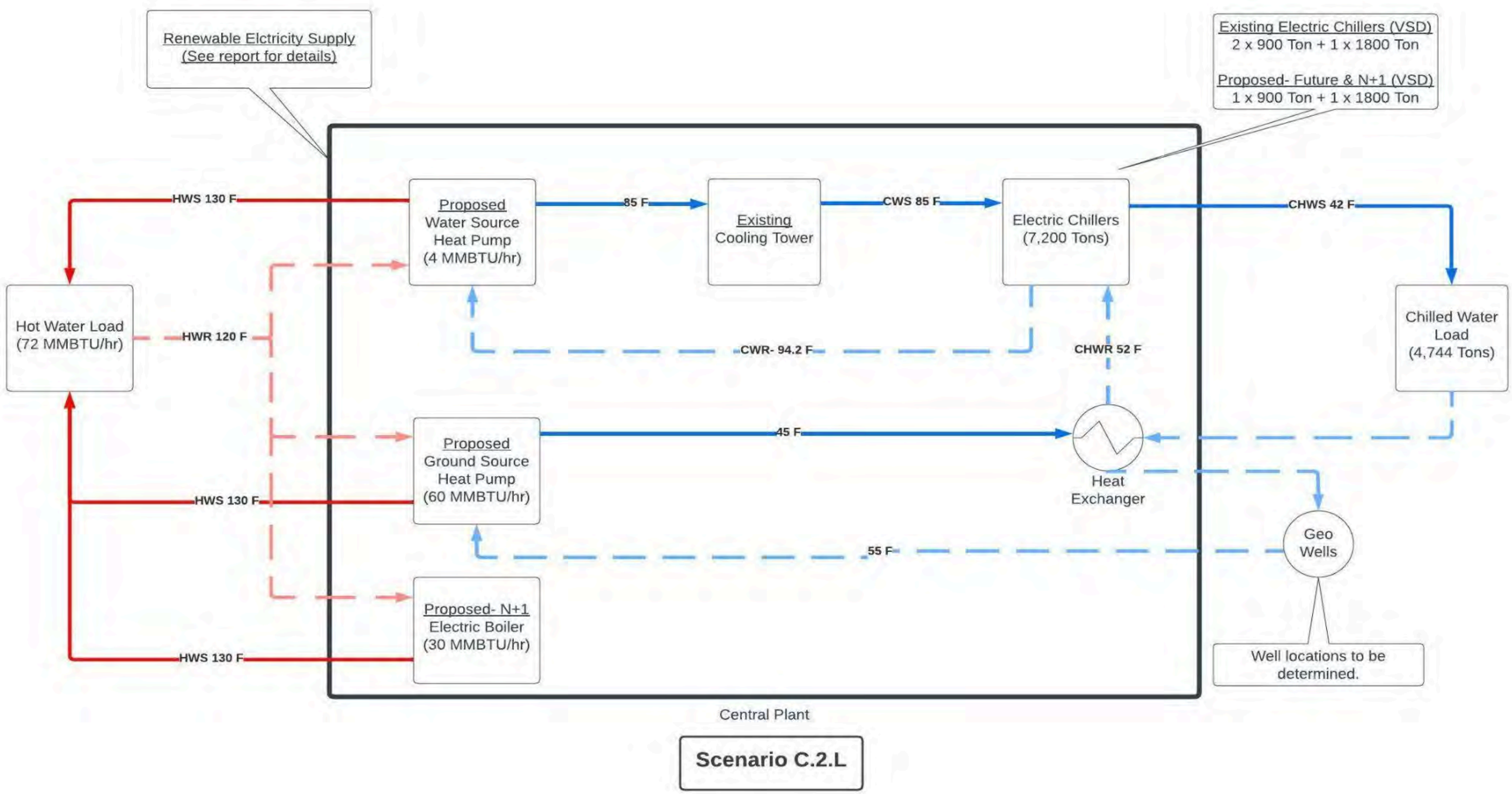
APPENDIX K

FIGURE E.1: Block Diagram for A.2.L



APPENDIX K (Continued)

FIGURE E.2: Block Diagram for C.2.L



APPENDIX K (Continued)

FIGURE E.2: Block Diagram for E.1.H

APPENDIX L

On-Call Task Assignment for a Study Contract No.: OC-DCS-ENGY-0030 Task No. 3

DEPARTMENT OF ADMINISTRATIVE SERVICES

4/11/2023

On-Call Task Assignment for a Study
Contract No.: OC-DCS-ENGY-0030
Task No. 3
CAS Decarbonization Study
490 Capitol Avenue
Hartford, CT 06103
Project No. BI-2B-414

Source Once Inc. (DE)
Attn: Matt Cinadr
53 State Street, 14th Floor
Boston, MA 02109

Dear Mr. Cinadr:

In accordance with the applicable provisions of the subject on-call contract, and the applicable provisions of the Department of Administrative Services (DAS) Consultants Procedure Manual approved by the DAS Commissioner dated September 2016, Source Once Inc. (DE) is hereby authorized to perform the following scope of services for the subject project. In this task letter the term Consultant shall be interpreted to mean Engineer, as identified in the contract for on-call services.

The purpose of the CAS Decarbonization Study is to define, develop, and assess options for modifying CAS operations to meet Executive Orders 1 and 21-3 ("EO 1") and ("EO 21-3"). Incorporated into EO 1 is GreenerGov CT, a "Lead by Example" initiative with a mission of advancing environmental leadership, reducing operating costs and environmental impacts of State government operations, and generating savings for taxpayers. Further, EO 21-3 calls for executive branch state agencies to take significant actions within their authority to reduce carbon emissions. Decarbonization involves the entire supply and demand chain of energy source, generation, distribution and end use. The proposed study involves the use of decarbonized Utility and Non-Utility supply options, State-owned supply-side options and both State and Private demand sides. Through the modification or replacement of these systems, the entire CAS becomes decarbonized.

1. Scope

The engineer shall conduct a study that will follow a stage gate process starting with an initial screening assessment to support a rank and score process which will identify options to advance to a detailed feasibility phase. The process will begin with a client working session to determine the list of options or design scenarios to be included for further technical and economic evaluation along with a ranking and scoring system. Reduction and optimization of demand side systems through holistic energy efficiency measures and active load management will play a key role in the selection and advancement of supply side options, their capacities and cost.

The Engineer shall evaluate the scenarios in the tables below during the study. All scenarios are subject to modification through the initial client workshop and are intended to convey the most applicable solutions based on known asset conditions, energy infrastructure and load profile requirements. Table 1- Supply Side Scenarios defines the energy supply options for the generation of thermal heating and cooling products. The fuels considered to feed these supply side technologies (i.e. raw energy supply mix) include conventional natural gas, renewable natural gas, renewable fuels, geothermal, conventional electricity and renewable electricity. Table 2-Demand Side Scenarios outlines the range of load requirements for each of the end users, that is the quality and quality of the thermal products necessary to meet the end user/off-taker requirements.

Table 1: Supply Side Design Scenario Definitions

Supply Side Design Scenarios	**A**	**B**	**C**	**D**	**E**	**F**
Description	Hybrid of Heat Pumps & Electric Boilers	100% Electric Boilers	100% Heat Pumps	Hybrid of Heat Pumps & Natural Gas Condensing Boilers	100% Natural Gas Condensing Boilers	Defined per Client Workshop
Fuels	Renewable Electricity	Renewable Electricity	Renewable Electricity	Renewable Electricity, Renewable Fuels & Conventional natural Gas, H2 Ready	Renewable Fuels & Conventional natural Gas, H2 Ready	Ex: Strategically sited networked heat pumps, local solar thermal, H2 ready CHP, heat recovery systems

Table 2: Demand Side Design Scenario Definitions

Demand Side Design Scenarios	**1**	**2**	**3**
Description	Reduce loads via energy efficiency at public and private facilities and reduce heating supply temperature	Reduce loads via energy efficiency at public facilities and keep heating supply temperature as is	Keep loads and heating supply temperature as is
Systems Impacted	Public & Private demand side, distribution and supply side systems	Public demand side and supply side systems	Supply side systems

Phased Scope of Work

Phase 1: Screening Assessment.

Initial Screening Assessment Task 1: Study Kickoff – Client Workshop #1

The purpose of this initial working session is to define the list of assumptions, scenarios and rank and scoring metrics to be used in the preliminary analysis to support final study selection(s). Carbon related assumptions such as $/ton, discount rate, grid emission factor forecasts, zero carbon and cost-effective carbon reduction definitions and others required as part of a life cycle cost analysis shall be provided to the State for review ahead of the workshop. This is an opportunity for the State to convey any other scenarios or configurations to include in the study. The Engineer shall send meeting minutes and workshop notes to all participants. Minutes and notes shall include all agreed upon ranking and scoring systems to be used to filter scenarios for advancement from screening to feasibility level of analysis.

Deliverable 1: The Engineer shall submit client workshop and documentation of agreed upon study assumptions, inputs, parameters, definitions, scenarios and the corresponding life cycle analysis results such as NPV, IRR, CO2 and others as required by the State.

Task 2: Total Energy Requirements/Design Basis

Securing accurate thermal and electric profiles is a critical first step in forming the basis of design for decarbonization. To support this effort the Engineer shall review historical, current and planned energy consumption and related metering data sets to construct representative electric and thermal load profiles. This assessment conducted by the engineer will reconcile supply-based data sets from the central plant to demand based/off-taker metered data sets. The Engineer shall identify data gaps or inconsistencies and define the specific meter and billing assessment recommendations.

Deliverable 2: The Engineer shall confirm the historical, existing and planned supply and demand metered thermal and electric load data for use in the decarbonization basis of design. The Engineer shall conduct conference calls or workshops to review and confirm baseline energy requirements before proceeding with further analysis.

Task 3: Regulatory Evaluation

The Engineer shall develop representative financial and schedule impacts for incentives and grants from Federal, State and Utility sponsored programs for inclusion in life cycle cost analysis. The Engineer shall hold early working sessions with DEEP, CT Green Bank, Eversource and CNG to inform them of the scenarios under investigation and discuss applicable financing or grant availability for inclusion in preliminary life cycle costing.

On the federal level, the Engineer shall review DOE's Energy Infrastructure Reinvestment Financing (section 1703) and compare its financing terms with those traditionally used by DAS to fund such initiatives. With respect to the Inflation Reduction Act ("IRA") the Engineer shall evaluate the expansion of the Advanced Energy Project Tax Credit to determine applicability of direct payment of the credit in the absence of a federal tax liability. The Engineer shall identify sensitivity and risk factors and apply to areas of the IRA where Treasury guidance is undefined.

The Engineer's infrastructure team, supported by rate and tariff subject matter experts, shall hold discussions with Eversource and Connecticut Natural Gas regarding schedule and cost impacts due to changes to electric and gas service for the various decarbonization scenarios.

Deliverable 3: The Engineer shall supply a summary of applicable financial incentives per scenario and conduct conference calls to review and confirm analysis application of such incentives and financing terms.

Task 4: Demand Side Evaluation

The Engineer shall conduct building assessments on all CAS off-takers to determine the technical and financial feasibility of the demand side scenarios presented in Table 2 (above) and their resulting impacts on total energy requirements. The demand side evaluation will also identify constraints and criteria of reducing supply thermal supply temperatures and document the extent of necessary capital upgrades to achieve a low enthalpy, zero carbon system. Through an initial desktop study followed by field/site investigations of each facility, the Engineer shall verify the partial information on the HVAC configuration of the 15 CAS off-takers provided by the State.

The Engineer shall examine building energy systems to identify and quantify demand side opportunities. This will include the building envelope, lighting, HVAC, domestic hot water, plug loads, and any process uses. The Engineer shall produce an analysis of building energy consumption which will quantify base loads, seasonal variation, and energy costs. The Engineer shall assess lighting, air quality, temperature, ventilation, humidity, and other conditions that could affect energy performance and occupant comfort. The Engineer shall evaluate thermal storage and heat recovery from thermal heating and cooling equipment to optimize equipment capacity factors and arbitrage opportunities while leveraging simultaneous heating and cooling opportunities through waste heat recovery applications. The Engineer shall conduct and order performance calculations and cost estimating for each identified demand reduction measure according to building and simple payback.

Deliverable 4: The Engineer shall provide a summary of technical and financial feasibility of adopting demand side (load reduction) strategies as part of decarbonization efforts. The Engineer shall confirm high, medium and low energy consumption profiles for equipment sizing and configuration tasks under the supply side evaluation and identify for each scenario demand side project economics combined with supply side economics to inform total project economics.

Task 5: Thermal Distribution System Evaluation

The Engineer shall conduct a preliminary mass balance on the thermal distribution system to determine where restrictions may occur due to proposed supply temperature adjustments since lower temperature supply results in the need for higher flow to meet the same energy demand. The Engineer shall identify where restrictions are and prepare a concept design and construction budget which will be incorporated into screening, and if required, shall be revised in greater detail in subsequent pro forma development.

Deliverable 5: The Engineer shall provide a summary of initial findings impacting thermal distribution system and off-takers. The Engineer shall refine during the feasibility phase, as applicable, final modifications, operational and financial impacts.

Task 6: Supply Side Evaluation

The Engineer shall conduct a supply side evaluation, which will identify and document major design constraints and criteria for each of the scenarios presented in Table 1. The Engineer shall develop concept designs, installation and operating bases for each scenario along with order of magnitude capital, operating and carbon costs to inform initial life cycle cost analysis. The Engineer shall develop preliminary operating models to represent annual utility and carbon costs for each scenario. The Engineer shall use existing published geotechnical data to determine initial feasibility of geo-source and air source heat pump scenarios. If geo-source proves favorable, the Engineer shall consider and provide a geotechnical study including test wells under a separate scope.

Deliverable 6: The Engineer shall provide a concept design basis and summary of constraints and criteria for each supply side scenario, which will include order of magnitude capital, operating and carbon costs for each scenario presented in Table 1.

Task 7: Initial Screening Assessment Results (Client Workshop #2)

By combining Tasks 1–6 into a comprehensive evaluation model the Engineer shall have the basis for screening each scenario. The Engineer shall provide a suggested screening criteria to the State, which will be workshopped and agreed upon in advance of the completion of Tasks 4, 5 and 6. Using the agreed upon criteria, the Engineer shall score and rank the options to yield a final list of demand and supply side options to include in the feasibility study.

Deliverable 7: The Engineer shall provide the results of screening scores, net present costs and a summary of the pros and cons of each scenario in the form of an Executive Presentation. The Engineer shall also provide an accompanying memo that will memorialize the scope boundaries and inputs and assumptions used to arrive at the recommended scenarios.

Phase 2: Feasibility Study

Task 8: Advance Technical Development

It is assumed three scenarios will fall out of the initial screening assessment, per rank and scoring criteria, and advance to the detailed feasibility phase. For each of the three scenarios the Engineer shall advance the technical, financial (including subsidies) and regulatory analysis to refine the capital and operating costs for each option.

For scenarios involving adjustment of current supply temperature to achieve energy and carbon savings, as identified under Task 4 above, the Engineer shall conduct a more detailed analysis to determine plausible temperature profiles for the district system. The temperature study shall involve interviews with building operators and the State's HVAC contractors in conjunction with a review of current building HVAC equipment and end use requirements. The Engineer shall recommend temperature adjustment testing at specific locations on a trial-and-error basis to support further project development efforts.

Task 9: Regulatory and Financing Strategies

With the top three options identified, the Engineer team shall revisit the project with DEEP, CT Green Bank, Eversource and CNG to determine if any interactive effects between the agencies would impact pursuing IIRJA or IRA funding mechanisms and associated timelines. The Engineer shall develop a strategy for pursuing funding under various scenarios as determined through discussions and meetings with various stakeholders and agencies.

Task 10: Develop Capital and Operating Budgets

The Engineer shall develop capital and operating budgets and an overview of the operating impacts compared to current thermal plant operations for each scenario. Costs developed will include the cost of any electric infrastructure upgrade needed for the grid connection. The Engineer shall assess cost impacts on private, non-state-owned facilities to determine the approach, strategy and allocation of changes across each type of end user. The Engineer shall forecast operating budgets across the agreed upon project term, typically 30 years. The Engineer shall apply similar analysis to any future loads added through district expansion efforts.

The level of Project definition (i.e. level of design) developed for each of the three advanced options will fall between 10 and 15% percent, which includes conceptual design, equipment selection and budgetary pricing. Accordingly, capital and operating cost estimates will be commensurate with the level of project definition and will have an expected range of accuracy between -30 to 50 percent.

Deliverable: The Engineer shall provide a draft, final report, and executive presentation, which will include the following:

- Concept basis of designs for each scenario
- Forecasts and assumptions summary
- Cost benefit analysis, total cost of ownership and life cycle cost in the form of project proformas capturing applicable financing terms, incentives, grants, project capital, operating and carbon costs
- Capital cost estimate details commensurate with the level of project definition
- Baseline versus proposed operating cost comparisons for State and Private sector off-takers
- NPV, IRR, \$/ton CO_2 abated values for each scenario
- Sensitivity and risk analysis results
- Milestone schedules for each deployment
- Brief project execution narrative

2. Phased Fee:

The Consultant's total shall not exceed the fee of Two Hundred Forty-Seven Thousand One Hundred Dollars **($247,100.00)** and shall be paid as indicated below for the completion of the work specified where previously authorized in writing and after the Department of Administrative Services receives and accepts each phase of the work. Said fee includes all sub-consultant fees and the Consultant's overhead and profit.

2A. Screening Assessment: Is not to exceed the amount of One Hundred Ninety-Two Thousand Seven Hundred Four Dollars **($192,704.00)** broken down as follows**:**

a. **Task 1 Client Kickoff Workshop #1 (60 hours): $20,630.00**

b. **Task 2 Total Energy Requirements/Design Basis (11 hours): $3,641.00**

c. **Task 3 Regulatory Evaluation (60 hours): $13,620.00**.

d. **Task 4 Demand Side Evaluation (206 hours)**: **$51,200.00**

e. **Task 5 Thermal Distribution System Evaluation (126 hours)**: **$28,224.00**

f. **Task 6 Supply Side Evaluation (138 hours)**: **$29,700.00**

g. **Task 7 Screening Assessment Results, Workshop #2 (188 hours)**: **$45,689.00**

2B. Feasibility Study: Is not to exceed the amount of Fifty-Four Thousand Three Hundred Ninety-Six Dollars **($54,396.00)** broken down as follows**:**

a. **Task 8 Advance Technical Development (109 hours): $24,152.00**

b. **Task 9 Regulatory and Financing Strategies (37 hours): $8,084.00**

c. **Task 10 Develop Capital and Operating Budgets (96 hours): $22,160.00**

Labor Rate Table:

Labor Category	**Hourly Rate**
Principal in Charge	$350.00
Project Manager	$275.00
Project Manager	$250.00
Senior Engineer/ SPM	$210.00
Engineer	$180.00
Field Engineer	$180.00

The Consultant's requests for payment shall be submitted on properly prepared invoice forms with attachments showing actual hours worked and rates applied. Overtime or any other expenses shall not be invoiced unless previously authorized by the DAS in writing. The Consultant shall certify that each amount invoiced is both accurate and commensurate with the work performed for the State under this contract. The State shall have the right to audit records associated with said task letter at any reasonable time. It is specifically understood that the pre-approved hourly rates shall only apply for the period of time that the person is actually working on the project.

3. Submittals/Time Period

The Consultant shall provide the work pursuant to an agreed upon time frame as shown in the table below.

Task	Estimated Weeks from NTP
Phase 1 Screening Assessment	
Internal Mobilization	1
Study Kickoff – Client Workshop #1	2
Deliverable – Memo confirming scenarios, inputs and assumptions confirmed by the State	3
Regulatory Evaluation	5
Demand Side Evaluation	10
Distribution & Geothermal System Evaluation	10
Supply Side Evaluation	11
Deliver Results of Initial Screening Assessment	**14**
Client Feedback & Confirm Advancement to Feasibility Phase	15
Phase 2: Feasibility Study	
Detailed operating budgets	16
Reconvene w/ regulatory authorities and refresh related assumptions, costs, schedules	16
Advance level of design	18
Advance cost estimates	19
Prepare Final Report/ Exec Presentation	20
Deliver Final:	21

ANNUAL CERTIFICATION

If the aggregate value of the subject contract is $50,000.00 or more, including all amendments and/or commission letters, then the On-Call Multi-Disciplinary Engineer shall annually submit electronically, on or within two (2) weeks of the anniversary date of the execution of the contract, a completed Gift and Campaign Contribution Certification and notify the DAS Legal Unit that it has been uploaded. Said certification shall be uploaded on the Department of Administrative Services' website. For the purposes of this section, the execution date of the contract shall be the date the Commissioner of DAS signed the contract.

All the terms and conditions of the subject on-call contract and any prior task letters for the same project under the same on-call contract shall remain in full force and effect except as modified herein.

Please indicate your acceptance by signing this original task letter and returning it to the Department of Administrative Services, Construction Services, Office of Legal Affairs, Policy and Procurement, 450 Columbus Blvd., Ste. 1307, Hartford, CT 06103.

You are now authorized to proceed with the above-noted work.

Sincerely,

DocuSigned by:
Darren Hobbs
25EC340DBE54445...

Darren Hobbs — 4/11/2023
Deputy Commissioner — Date

Source Once Inc. (DE)

DocuSigned by:
Louis Schoen
5350D1CF46CC460...

ACCEPTED: Consultant — 4/12/2023 Date

Louis Schoen
Print/Type Name

Vice President
Title

DH/nar

xc: State Properties Review Board
User Agency Representative – Nick Garcia
Managing Director Strategic Redevelopment – Noel G. Petra
Chief Architect – David Barkin
Director Construction Support Services – Craig Russell
Fiscal Administrative Supervisor – Glenn Knapsack
On-Call Contract File
Team File

APPENDIX M

Notes:

1. All costs are in millions of dollars.
2. All costs presented in this table are commensurate with the level of project definition and have an expected range of accuracy between -30% to 50%. Low temperature and geothermal scenarios likely will have the highest CapEx uncertainty and require the most additional study to determine feasibility.
3. NPC figures include CapEx with incentives.
4. 2023 is considered as the baseline year for key performance escalations.

5 Years Escalation				
Scenario	**Baseline**	**A.2.L**	**C.2.L**	**E.1.H**
Description	Operational Year 2020	Condenser & Ground Source HP w/ Electric Boilers	Ground Source HP	Natural Gas Boilers
CapEx	$10.6	$88.7	$110.4	$22.6
CapEx w/ Incentives	$10.6	$81.7	$96.5	$22.6
Year 1 OpEx (w/ SC-CO2)	$11.8	$8.2	$8.5	$9.0
Year 1 OpEx (w/ RECs & Carbon Offsets)	$13.2	$8.0	$8.3	$9.9
Year 1 OpEx (w/o Carbon Costs)	$6.6	$7.6	$7.9	$5.3
NPC (30-Year w/ SC-CO2)	$267	$275	$296	$219
NPC (30-Year w/ RECs & Carbon Offsets)	$337	$273	$295	$267
NPC (30-Year w/o Carbon Costs)	$175	$269	$292	$155

10 Years Escalation				
Scenario	**Baseline**	**A.2.L**	**C.2.L**	**E.1.H**
Description	Operational Year 2020	Condenser & Ground Source HP w/ Electric Boilers	Ground Source HP	Natural Gas Boilers
CapEx	$12.0	$100.3	$124.9	$25.6
CapEx w/ Incentives	$12.0	$92.5	$109.1	$25.6
Year 1 OpEx (w/ SC-CO2)	$13.3	$9.3	$9.6	$10.2
Year 1 OpEx (w/ RECs & Carbon Offsets)	$14.9	$9.0	$9.4	$11.2
Year 1 OpEx (w/o Carbon Costs)	$7.4	$8.6	$8.9	$6.0
NPC (30-Year w/ SC-CO2)	$302	$311	$335	$248
NPC (30-Year w/ RECs & Carbon Offsets)	$381	$309	$334	$302
NPC (30-Year w/o Carbon Costs)	$198	$305	$330	$175

APPENDIX M (Continued)

15 Years Escalation				
Scenario	**Baseline**	**A.2.L**	**C.2.L**	**E.1.H**
Description	Operational Year 2020	Condenser & Ground Source HP w/ Electric Boilers	Ground Source HP	Natural Gas Boilers
CapEx	$13.6	$113.5	$141.3	$28.9
CapEx w/ Incentives	$13.6	$104.6	$123.5	$28.9
Year 1 OpEx (w/ SC-CO2)	$15.1	$10.5	$10.9	$11.5
Year 1 OpEx (w/ RECs & Carbon Offsets)	$16.8	$10.2	$10.6	$12.7
Year 1 OpEx (w/o Carbon Costs)	$8.4	$9.7	$10.1	$6.8
NPC (30-Year w/ SC-CO2)	$342	$352	$379	$281
NPC (30-Year w/ RECs & Carbon Offsets)	$432	$349	$378	$342
NPC (30-Year w/o Carbon Costs)	$224	$345	$374	$198