SourceOne
Energy Solutions

Capital Area System
Central Plant Feasibility Study

PREPARED FOR:

STATE OF CONNECTICUT DPW DEPARTMENT OF PUBLIC WORKS

PREPARED BY:

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1. EXECUTIVE SUMMARY

SourceOne, Inc is pleased to present the following feasibility analysis to the State of Connecticut Department of Public Works (DPW) for the proposed Capital Area System (CAS) central plant to be located in the existing CT Boiler House abutted to the Pump House (474 Capitol Avenue) in Hartford, CT. SourceOne's experience in financial analysis, tariff analysis, combined heat and power plant development, as well as familiarity with the Connecticut energy and construction markets has shaped subsequent conclusions found in this report.

The desired effect of the central plant would be a significant reduction in the energy costs associated with the procurement of steam and chilled water for the CAS hot and chilled water loops from Capitol District Energy Power Plant Center Cogeneration Associates (CDECCA). To that effect, the feasibility study analyzed the cost benefit associated with the construction of a new central plant that would generate steam and chilled water in significant enough quantities to meet the peak demands of all of the facilities utilizing the CAS hot and chilled water loops. The peak hot and chilled water demands were obtained from the hourly 2010 consumption data submitted to the DPW by CDECCA. The feasibility study also analyzed the cost benefit of installing natural gas direct fired chillers as opposed to electric centrifugal ones as well as the installation of a combined heat and power (CHP) plant in the new central plant. The details provided in this report review the financial, environmental, and operational impacts of all of the aforementioned scenarios.

Based upon the hot and chilled water usage for the CAS facilities as well as the electric usage for the 470 Capitol Avenue complex, SourceOne analyzed five (5) central plant configurations. The first option utilizes three (3) 1,800-ton Trane electric centrifugal chillers as well as three (3) 500-BHP Cleaver-Brooks low pressure (i.e. 15 psig) steam boilers. This option also includes the use of a 1,500-ton plate-and-frame heat exchanger that is utilized for "free-cooling". The second option utilizes five (5) 1,107-ton EcoChill natural gas direct fired chillers in conjunction with three (3) 500-BHP Cleaver-Brooks low pressure (i.e. 15 psig) steam boilers. This option also utilizes the 1,500-ton "free cooling" heat exchanger. The third, fourth, and fifth options are the CHP scenarios. The third option utilizes a 1,059-kW Jenbacher 320 reciprocating engine as the prime mover while the fourth option utilizes a 1,210-kW Solar Saturn 20 gas combustion turbine generator, and the fifth option utilizes two (2) 200-kW Capstone C200 MicroTurbines. In all three cases the waste heat from the prime mover is used to produce a combination of chilled and hot water as well as steam, while the electric centrifugal chillers and low pressure steam boilers specified in the first option are utilized for back-up/supplemental purposes. All three CHP scenarios use the same 1,500-ton "free cooling" heat exchanger specified in the first two options. A financial proforma summary of the five options is presented in Table 1 on the next page. In it, the cost benefit of each of the five central plant options is compared to the "Base Case", which is the current cost associated with the CDECCA contract as well as the CL&P electricity payments for the 470 Capitol Avenue complex. As of 2010, the State of Connecticut DPW was paying CDECCA $4.9 million dollars annually for chilled water and steam and CL&P $1.67 million dollars annual for electricity consumed by the complex.

Based upon the results of the financial proforma analysis, SourceOne would recommend that the DPW move forward with the central plant specified under Option #1 that utilizes the electric centrifugal chillers and low pressure steam boilers. Though the simple payback associated with Option #4 is identical, the additional real estate required as well as the construction and operational complexity associated with it make it the less attractive and desirable alternative. It should be noted, however, that all five options have acceptable simple paybacks and provide a reasonable return on investment.

In terms of the DPW's current contract with CDECCA, it should be noted that the Steam and Chilled Water Supply Agreement signed on October 1, 2008 does indicate that if the DPW were to construct their own plant and terminate their contract with CDECCA prior to the expiration of the contract on April 1, 2019, a termination payment would be required. Assuming it takes approximately 30 months to design and build the new CAS central plant the termination payment would amount to $2,287,957. If this termination payment is included in the financial proforma analysis for the new CAS central plant, the simple payback is adversely affected. In particular, the simple payback for the recommended option, Option #1, would increase from 6.31 to 7.15 years.

Annual Expenditure Savings Over Base Case	Annual NEISO Capacity Sales ($2.91/kw/month)	Capital Cost	DPUC Incentive/Rebate ($250/kW for CHP & $300/ton for Gas Chillers)	Simple Payback (Years)
Base Case - CDECCA Contract - Power: Electricity from Utility - Heating: Hot Water from Pump House Steam HX's that are fed by High-Pressure Steam Boilers in CDECCA Plant - Cooling: Chilled Water from CDECCA Electric and Steam Absorption Chillers				
$0	$0	N/A	$0	N/A
Option #1 - Electric Chillers - Power: Electricity from Utility - Heating: Hot Water from Central Plant Steam HX's that are fed by Low-Pressure Steam Boilers - Cooling: Chilled Water from Central Plant Electric Chillers and Free Cooling Plate-and-Frame Heat Exchanger				
$2,727,110	$0	$17,208,738	$0	6.31
Option #2 - Natural Gas Fired Chillers - Power: Electricity from Utility - Heating: Hot Water from Central Plant Steam HX's that are fed by Low-Pressure Steam Boilers - Cooling: Chilled Water from Central Plant Natural Gas Fired Chillers and Free Cooling Plate-and-Frame Heat Exchanger				
$2,998,441	$0	$21,379,159	$1,620,000	6.59
Option #3 - Trigeneration Plant with Reciprocating Engine - Power: Electricity from 1,059 kW Jenbacher 620 Reciprocating Engines (Utility Back-Up) - Heating: Hot Water from Central Plant Steam HX's that are fed by 2,000 lb/hr Low-Pressure HRSG (Central Plant Low-Pressure Steam Boiler Back-Up) - Cooling: Chilled Water from 75 ton Hot Water Absorption Chiller and 120 ton Single-Stage Steam Absorption Chiller (Central Plant Free Cooling Complement and Electric Chiller Back-Up)				
$3,138,538	$36,980	$21,111,784	$264,750	6.56
Option #4 - Trigeneration Plant with Gas Turbine - Power: Electricity from 1,210 kW Solar Saturn 20 Combustion Turbine Generator (Utility Back-Up) - Heating: Hot Water from Central Plant Steam HX's that are fed by 8,100 lb/hr Low-Pressure HRSG (Central Plant Low-Pressure Steam Boiler Back-Up) - Cooling: Chilled Water from 493 ton Single-Stage Steam Absorption Chiller (Central Plant Free Cooling Complement and Electric Chiller Back-Up)				
$3,126,035	$42,253	$20,292,197	$302,500	6.31
Option #5- Trigeneration Plant with MicroTurbine - Power: Electricity from two (2) 200 kW Capstone C200 MicroTurbines (Utility Back-Up) - Heating: Hot Water from Central Plant Steam HX's that are fed by two (2) 1,080 lb/hr Low-Pressure HRSG's (Central Plant Low-Pressure Steam Boiler Back-Up) - Cooling: Chilled Water from 132 ton Single-Stage Steam Absorption Chiller (Central Plant Free Cooling Complement and Electric Chiller Back-Up)				
$3,018,533	$13,968	$20,102,983	$100,000	6.60

Table 1: Financial Proforma Summary of Central Plant Options with No Project Financing
(*Not Including CDECCA Termination Payment)*

The reason why Option #1 yields superior financial results is as follows. The use of natural gas direct fired chillers, as analyzed in Option #2, yields an annual operational savings associated with the cost avoidance arising from the procurement of natural gas instead of electricity for the central plant chillers but this cost avoidance does not compensate for or offset the increase in the capital cost associated with the procurement and installation of the natural gas direct fired chillers; even with the DPUC incentive of $300/ton factored in. Currently, a natural gas direct fired chiller costs almost three times that of an equivalent electric centrifugal chiller. Additionally, the NYMEX Natural Gas Strip Price is trending up over the next three years so some of the savings associated with the procurement of natural gas instead of electricity will be diminished. In terms of the CHP options, the financial benefit associated with the installation of a CHP plant in the central plant is reduced due to the electric load profile for the 470 Capitol Avenue complex as well as the hot and chilled water load profiles for the CAS loops all having low load factors. The electric load factor for the 470 Capitol Avenue complex is 41% while the CAS hot and chilled water load factors are 25% and 22% respectively. Additionally, the cost of electricity relative to natural gas in Hartford is relatively reasonable; the “spark-spread” is not drastic. The CHP financials benefit from the fact that the Connecticut Department of Public Utility Control (DPUC) is currently offering CHP Development Incentives of $250/kW, which helps offset the additional capital cost associated with installing the CHP equipment in the central plant. The incentive used to be $500/kW, but was recently reduced to $250/kW due to a reduction in the allotted budget for the DPUC program. The financials for the smaller MicroTurbine CHP option are adversely impacted by the fact that the cost of a MicroTurbine (on a $/kW basis) is approximately 50% greater than that of a gas turbine.

It should be noted that the simple paybacks noted in Table 1 on the previous page assume that the capital cost of the central plant is paid upfront in “Year 0”. We understand that the DPW currently plans on financing the capital cost over a 20-year term at a 3.5% interest rate. Table 2 on the next page indicates the annual cost savings associated with this financing plan relative to the current energy costs associated with the CDECCA contract. Yet again, the financials presented do not include the termination payment that would be due to CDECCA if the plant is built prior to April 1, 2019. We would estimate a 20-year life cycle for the central plant equipment so the 20-year loan term is appropriate. As can be seen in Table 2, the savings are significant.

Capital Cost Annual Financing Charges (Years 1-20)	Annual Expenditure Savings Over Base Case	Annual NEISO Capacity Sales ($2.91/kw/month)	Total Annual Cost Savings	DPUC Year 1 Incentive/Rebate ($250/kW for CHP & $300/ton for Gas Chillers)
Base Case - CDECCA Contract - Power: Electricity from Utility - Heating: Hot Water from Pump House Steam HX's that are fed by High-Pressure Steam Boilers in CDECCA Plant - Cooling: Chilled Water from CDECCA Electric and Steam Absorption Chillers				
$0	$0	$0	$0	$0
Option #1 - Electric Chillers - Power: Electricity from Utility - Heating: Hot Water from Central Plant Steam HX's that are fed by Low-Pressure Steam Boilers - Cooling: Chilled Water from Central Plant Electric Chillers and Free Cooling Plate-and-Frame Heat Exchanger				
$1,210,825	$1,516,285	$0	$1,516,285	$0
Option #2 - Natural Gas Fired Chillers - Power: Electricity from Utility - Heating: Hot Water from Central Plant Steam HX's that are fed by Low-Pressure Steam Boilers - Cooling: Chilled Water from Central Plant Natural Gas Fired Chillers and Free Cooling Plate-and-Frame Heat Exchanger				
$1,504,261	$1,494,180	$0	$1,494,180	$1,620,000
Option #3 - Trigeneration Plant with Reciprocating Engine - Power: Electricity from 1,059 kW Jenbacher 620 Reciprocating Engines (Utility Back-Up) - Heating: Hot Water from Central Plant Steam HX's that are fed by 2,000 lb/hr Low-Pressure HRSG (Central Plant Low-Pressure Steam Boiler Back-Up) - Cooling: Chilled Water from 75 ton Hot Water Absorption Chiller and 120 ton Single-Stage Steam Absorption Chiller (Central Plant Free Cooling Complement and Electric Chiller Back-Up)				
$1,485,448	$1,653,090	$36,980	$1,690,071	$264,750
Option #4 - Trigeneration Plant with Gas Turbine - Power: Electricity from 1,210 kW Solar Saturn 20 Combustion Turbine Generator (Utility Back-Up) - Heating: Hot Water from Central Plant Steam HX's that are fed by 8,100 lb/hr Low-Pressure HRSG (Central Plant Low-Pressure Steam Boiler Back-Up) - Cooling: Chilled Water from 493 ton Single-Stage Steam Absorption Chiller (Central Plant Free Cooling Complement and Electric Chiller Back-Up)				
$1,427,781	$1,698,254	$42,253	$1,740,507	$302,500
Option #5- Trigeneration Plant with MicroTurbine - Power: Electricity from two (2) 200 kW Capstone C200 MicroTurbines (Utility Back-Up) - Heating: Hot Water from Central Plant Steam HX's that are fed by two (2) 1,080 lb/hr Low-Pressure HRSG's (Central Plant Low-Pressure Steam Boiler Back-Up) - Cooling: Chilled Water from 132 ton Single-Stage Steam Absorption Chiller (Central Plant Free Cooling Complement and Electric Chiller Back-Up)				
$1,414,468	$1,604,065	$13,968	$1,618,033	$100,000

Table 2: Financial Proforma Summary of Central Plant Options with Project Financing (Years 1-20)
(Not Including CDECCA Termination Payment)

2. PROJECT BACKGROUND

The State of Connecticut DPW informed SourceOne that they wanted to thoroughly investigate the cost and process associated with the construction of a stand-alone thermal facility or central plant. This central plant would be designed to provide the necessary chilled water and hot water/steam for the CAS loops. As part of the investigation, SourceOne was tasked with the following:

1. Analyze the existing thermal agreements and contracts with CDECCA to understand terms & conditions, separation clauses, and price sensitivity based on changes to base energy costs (natural gas and grid-supplied electricity) and determine what impact the building of a plant would have.
2. Develop load requirements for both hot and chilled water for the existing CAS buildings/customers. This was to include a profile for a 12-month period that would facilitate an understanding of peak and nominal loads, as well as seasonal variations.
3. Incorporate any and all potential changes to system loads in the load profile.
4. Review existing drawings, documents, and as-builts for the Pump House and CAS for incorporation into the proposed central plant.
5. Review the available footprint of the current Pump House and CT Boiler House to determine if the equipment for the new central plant could be installed inside of the existing facilities.
6. Review other real estate options for locating a central plant if the Pump House and CT Boiler House have inadequate space.
7. Determine the feasibility of incorporating on-site generation through the use of a CHP plant. The analysis was to include a detailed cost estimate for construction and operation as well as a cost savings comparison relative to the base case, which is the existing CDECCA contract. The analysis was also to include a detailed review of existing grants & incentive programs as well as space requirements and permitting/certification/approvals necessary for operating the CHP plant.

3. CDECCA STEAM AND CHILLED WATER SUPPLY AGREEMENT

On October 1, 2008 the State of Connecticut and Capitol District Energy Center Cogeneration Associates (CDECCA) entered into a Steam and Chilled Water Supply Agreement. There were three terms covered under this agreement. The three terms are as follows:

1. **"Initial Term"** - October 1, 2008 to March 31, 2009
2. **"Term 2"** - April 1, 2009 to March 31, 2010
3. **"Term 3"** - April 1, 2010 to March 31, 2019

The three terms were instituted for billing purposes. As highlighted in the supply agreement, during the "Initial Term" as well as "Term 2" the calculation of the costs associated with the procurement of steam and chilled water would be based upon equipment efficiency and performance estimates that were agreed upon by both parties prior to the supply agreement being signed. During "Term 2", however, the supplier (CDECCA) was supposed to conduct appropriate performance testing on the Thermal Energy/Chilled Water Production Facilities under various loading conditions to establish efficiency curves that would be incorporated into a new variable commodity pricing methodology, which would be implemented and utilized in "Term 3". The State of Connecticut and CDECCA agreed to postpone the start date for "Term 3" until a mutually agreed upon and acceptable performance testing methodology was developed between the two parties. This performance testing methodology is currently being developed by the CAS Coordination Committee.

The Coordination Committee was created and established as part of the steam and chilled water supply agreement. It is composed of at least one local representative from each Party who has the experience and training to be able to understand the interface platform between the Energy Plant and the Customer Facilities. The Coordination Committee is the forum for the Parties to coordinate the provision of the services in the most efficient manner for both Parties. It is to, among other things, facilitate continuous communication between the Parties, coordinate and review utility and plant operations and maintenance schedules, and mitigate disruptions in the services.

Contract Quantities

As part of the supply agreement CDECCA must be able and willing to satisfy a maximum demand of:

- Steam – 28,000 lbs/hr
- Chilled Water – 3,200 tons/hr

To satisfy this demand, CDECCA has the following equipment in their Thermal Energy/Chilled Water Production Facility:

- Two (2) 900-ton steam absorption chillers
- Two (2) 1,800-ton electric centrifugal chillers

- One (1) 150,000 lb/hr high-pressure steam auxiliary boiler
- One (1) 27,600 lb/hr high-pressure steam auxiliary boiler

The CDECCA facility also has a gas turbine (GT) and heat recovery steam generator (HRSG) capable of producing high-pressure (125 psig) steam, though when the GT is off-line the HRSG is off-line.

Effect of Natural Gas and Electricity Costs on CDECCA Commodity Pricing

As per the pricing methodology detailed for the "Initial Term" and "Term 2", when the CDECCA gas turbine is not running the State of Connecticut is required to reimburse CDECCA for all natural gas and/or fuel oil commodity costs associated with the operation of the auxiliary boilers, minus the pro-rated share of the costs associated with the steam consumed from auxiliary boilers in CDECCA's facility. In terms of the costs associated with the utility or grid electricity consumption in the steam and chilled water production process, the State of Connecticut is required to reimburse CDECCA for all electricity commodity costs associated with metered consumption of the existing centrifugal chillers as well as the auxiliary equipment for the chilled water and steam systems. The auxiliary equipment electric consumption was to be determined on an hourly basis as per the formula specified in the agreement.

When the CDECCA gas turbine is running, the pricing methodology detailed for "Initial Term" and "Term 2" changes. In particular, the daily steam cost is equal to the summed total of the State of Connecticut's steam volume during the hours when the GT is running multiplied by CDECCA's actual commodity cost of fuel during that same time period. In terms of electric costs, that State of Connecticut is required to reimburse CDECCA for all electric commodity costs associated with the metered consumption of the existing centrifugal chillers as well as the auxiliary equipment for the chilled water and steam systems. The auxiliary equipment electric consumption was to be determined on an hourly basis as per the formula specified in the agreement.

Given the pricing methodology alluded to above, the input commodity costs are essentially passed through to the State of Connecticut, whether it is natural gas or electricity. The result is that the State of Connecticut, not CDECCA, suffers the financial hardship associated with the steam and chilled water system equipment operating poorly or inefficiently. Just by way of an example, in January 2010 CDECCA reported that the State of Connecticut used 19,607 MMBTU of steam in the production of hot water as well as chilled water, which was produced by the auxiliary boilers (GT was off-line) that consumed 31,161 MMBTU of natural gas. This means that the average efficiency of the auxiliary boilers for the month was 62.9%, which seems low. Most high-pressure steam boilers operate with an efficiency of 75-80% on average.

Effect of Natural Gas and Electricity Costs on CDECCA Demand Pricing

As per the supply agreement, the State of Connecticut pays CDECCA three different demand payments:

1. Fixed Demand Payment for Operating and Maintenance Costs
2. Fixed Electrical Demand Payment
3. Fixed Natural Gas Demand Payment

The Fixed Demand Payment for Operating and Maintenance Costs covers CDECCA's new capital expenditures and fixed operating and maintenance costs associated with the Pump House equipment as well as the steam and chilled water equipment inside of the CDECCA facility. The Fixed Demand Payment is comprised of a Monthly Capacity Demand Payment of $100,000 and then a Monthly Operating Demand Payment, which in the "Initial Term" was equal to $95,000 but in "Term 2" and "Term 3" is adjusted annually in accordance with the Consumer Price Index – Urban for the Northeast United States (CPI-U), where the benchmark month and price is established to be the month of the contract execution between the State of Connecticut and CDECCA (i.e. $95,000/month in October 2008). In 2010, the Monthly Operating Demand Payment was calculated to be $95,192 from January to September and $96,578 from October to December.

The Fixed Electrical Demand Payment is to be based upon the actual coincidental peak electric demand of the centrifugal chillers and auxiliary equipment as determined from the hourly metered interval data. The monthly utility demand charges/rates are to be applied to this coincidental peak electric demand value. The resulting product is the Fixed Electrical Demand Payment payable to CDECCA by the State of Connecticut.

The Fixed Natural Gas Demand Payment is comprised of two different components. The first component, whose fixed nature and amount was scheduled to expire on February 14, 2009, consisted of a monthly charge of $57,875 that covered 50% of CDECCA's Connecticut Natural Gas Corporation (CNG) natural gas transportation demand charges. Also associated with that, the State of Connecticut agreed to reimburse CDECCA a variable CNG charge of $0.13/mcf. The second component covered CDECCA's Southern Natural Gas Company (SCG) natural gas commodity demand charges, whose fixed nature and amount is scheduled to expire on September 30, 2011. As of October 2008, the demand charges were fixed at $30,300/month. The State of Connecticut agreed to reimburse CDECCA a portion of these demand charges equal to the product of $30,300 and the ratio of the actual maximum daily quantity (MDQ) of natural gas for the month and 2,000 MMBTU/day, which was the existing MDQ for which the $30,300 demand payment was based upon. A review of the 2010 CDECCA invoices showed that the CNG natural gas transportation demand charges expired with the end of CDECCA's contract with them on February 14, 2009. The State of Connecticut did not pay any CNG demand payments in 2010.

Termination Schedule

The supply agreement states that in the event of the termination of the agreement/contract, the State of Connecticut will have to make a termination payment to CDECCA (if the contract termination is not for acceptable reasons indicated in the contract) in accordance with the following table:

Contract Year	Dates	Termination Payment ($)
1	10/1/08 - 3/31/09	$3,500,403
2	4/1/09 - 3/31/10	$3,305,102
3	4/1/10 - 3/31/11	$3,076,891
4	4/1/11 - 3/31/12	$2,840,114
5	4/1/12 - 3/31/13	$2,569,060
6	4/1/13 - 3/31/14	$2,287,957
7	4/1/14 - 3/31/15	$1,945,974
8	4/1/15 - 3/31/16	$1,617,206
9	4/1/16 - 3/31/17	$1,225,675
10	4/1/17 - 3/31/18	$795,322
11	4/1/18 - 3/31/19	$300,000

Table 3: Termination Payment Schedule

Indemnification

It should be noted that under Section 9 of the steam and chilled water supply agreement it states that "*in no event shall either Party or their respective employees, officers, officials, directors, or agents be liable to the other Party or their respective employees, officers, directors, or agents in connection with this Agreement for any special, indirect, incidental, or consequential damages, including without limitation loss of profits, business interruption losses or any other economic losses*." This statement is significant in the fact that it highlights that neither Party is responsible for profit or other economic losses of the other as a result of the execution of this contract. Therefore, any economic hardships encountered by CDECCA as a result of this contract or other contracts they have executed with various companies should in no way effect, influence, or change the State of Connecticut's relationship and billing methodology with them.

Impact of Building a Central Plant

If the State of Connecticut decided to construct a central plant, SourceOne assumes the end result will be a termination of the CDECCA contract. The only impact that will have is that the State of Connecticut will be forced to pay CDECCA a termination payment based upon the schedule indicated in Table 3 above. Other than that financial repercussion, the supply agreement does not indicate any other legal or financial consequences.

4. LOAD PROFILES

The general approach for the load profile development consisted of organizing 1-hour interval data for the chilled water and steam consumed by the CAS hot and chilled water loop systems from January 1st, 2010 to December 31st, 2010. Electric consumption interval data for the 470 Capitol Avenue complex was also analyzed in conjunction with the CAS chilled water and steam load data since it was assumed that the prime movers for the three (3) CHP (trigeneration) plant options being analyzed would not export power back to the utility grid but instead supply power to the 470 Capitol Avenue complex of buildings and offset most or all of their electric load consumption and demand. In SourceOne's central plant evaluation model, the hourly electric load profile for the 470 Capitol Avenue complex was modified to reflect the additional electric load associated with the operation of the new central plant equipment (i.e. chillers, boilers, auxiliary and parasitic loads….etc.) since the electric service for the Pump House and CT Boiler House branches off of the same utility feeder. This modified electric profile was analyzed with the CAS chilled water and steam load data to determine the optimal central plant configuration.

The overriding assumption in the load profile analysis was that the energy consumption profile for the aforementioned 12-month period would be similar to that seen in the foreseeable future by the CAS as well as the 470 Capitol Avenue complex of buildings. As such, the energy cost savings analysis, to be discussed later in this report, is based upon the cost and quantity of energy consumed in the 2010 calendar year. Later in the report, we analyze the potential future load growth of the CAS in relation to new facilities being added to the loop and their effect on the central plant reserve capacity.

470 Capitol Avenue Complex Electric Load Profile

Connecticut Light & Power (CL&P) currently provides electricity to the 470 Capitol Avenue complex of buildings. The complex has one account number (CL&P Account No. 51502042054) but three different meters. Table 4 below presents the monthly electric consumption, peak demand, and charges for the 470 Capitol Avenue complex. The average cost of electricity for this electric service is $0.1372/kWh. The annual electric cost is $1,666,955. In the case of the CHP or trigeneration plant options, one of the primary goals would be to offset a significant amount of the electricity currently being purchased with electricity generated on-site.

Currently, the annual electric consumption for the 470 Capitol Avenue complex totals 12,161,065 kWhs and the peak electric demand is 3,375 kW.

	January	February	March	April	May	June	July	August	September	October	November	December	Total (kWh)/ Peak (kW)/ Total ($)/ Average ($/kWh)
Total (kWh)	1,044,334	928,201	1,030,170	951,834	1,072,875	1,122,463	1,102,562	1,065,675	1,002,534	933,339	933,489	973,590	**12,161,065**
Actual Peak Demand (kW)	2,287	2,298	2,246	2,408	3,041	2,961	2,650	2,604	2,615	2,235	3,375	2,200	**3,375**
Rachet Demand (kW)	3,375	3,375	3,375	3,375	3,375	3,375	3,375	3,375	3,375	3,375	3,375	3,375	**3,375**
Total Electric Charges ($)	$139,776	$128,570	$138,101	$131,677	$148,127	$152,352	$148,118	$144,192	$138,138	$128,602	$137,044	$132,259	**$1,666,955**
Average Electric Rate ($/kWh)	$0.1338	$0.1385	$0.1341	$0.1383	$0.1381	$0.1357	$0.1343	$0.1353	$0.1378	$0.1378	$0.1468	$0.1358	**$0.1372**

Table 4: Electric Consumption, Peak Demand, and Charges for 470 Capitol Avenue Complex

The hourly January 2010 to December 2010 electric load profile for the 470 Capitol Avenue complex is shown in Figure 1 below. As can be seen from the graph, the minimum load for the facility is approximately 1,000 kW (1.0 MW) with an approximate maximum load of 3,000 kW (3.0 MW) during an early summer peak. The peak electric demand of 3,375 kW reported by CL&P occurred in the month of November. It appears to be an outlier and may be due to the CDECCA plant being back-fed during transformer/feeder maintenance.

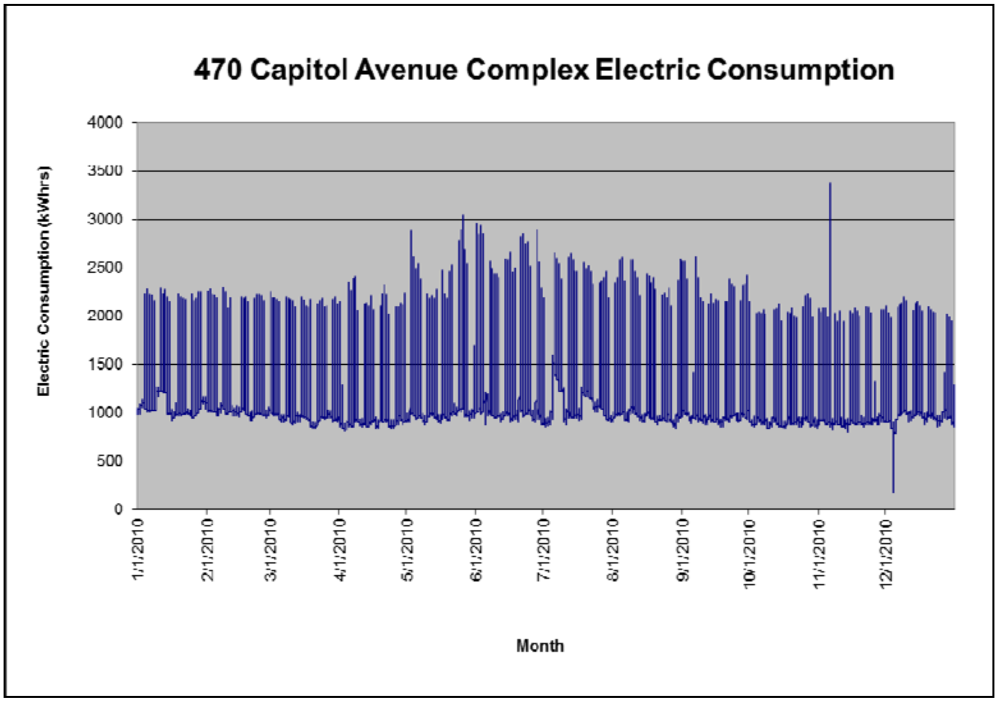


Figure 1: 470 Capitol Avenue Complex Electric Load Profile

Figure 2 presents a load duration curve for the complex based upon the electric load profile. As shown in Figure 2, the majority of the time the facility has a load that is less than 2,000 kW but greater than 900 kW. As such, the trigeneration plant models are sized so that the electric generation equipment's full-load operation point is less than 2,000 kW. This way, the trigeneration plant will be operating at or close to its full-load capabilities the majority of the time. The marginal capital cost associated with installing the electric generation equipment that would be needed to meet the peak annual electric load would far exceed the cost associated with purchasing this electricity from CL&P using their applicable electric tariff rate. Additionally, by installing an absorption chiller the peak annual electric load will be reduced due to the fact that the required chilled water production from the new electric centrifugal chillers will be offset by the chilled water production of the absorption chiller. Also, the electric output of the trigeneration plant will be limited on the high-end by the thermal loads of the CAS hot and chilled water loops. If the full recoverable thermal output is not being utilized the efficiency of the trigeneration plant and hence its cost benefit will be reduced.

As was mentioned earlier, however, the electricity profile used in our models varies from that shown in Figure 1 and 2 in that we included the hourly electric consumption of the new central plant equipment (i.e. chillers, boilers, auxiliary, parasitic….etc.) in order to arrive at a more accurate and revised load profile that is unique to each of the central plant options analyzed.

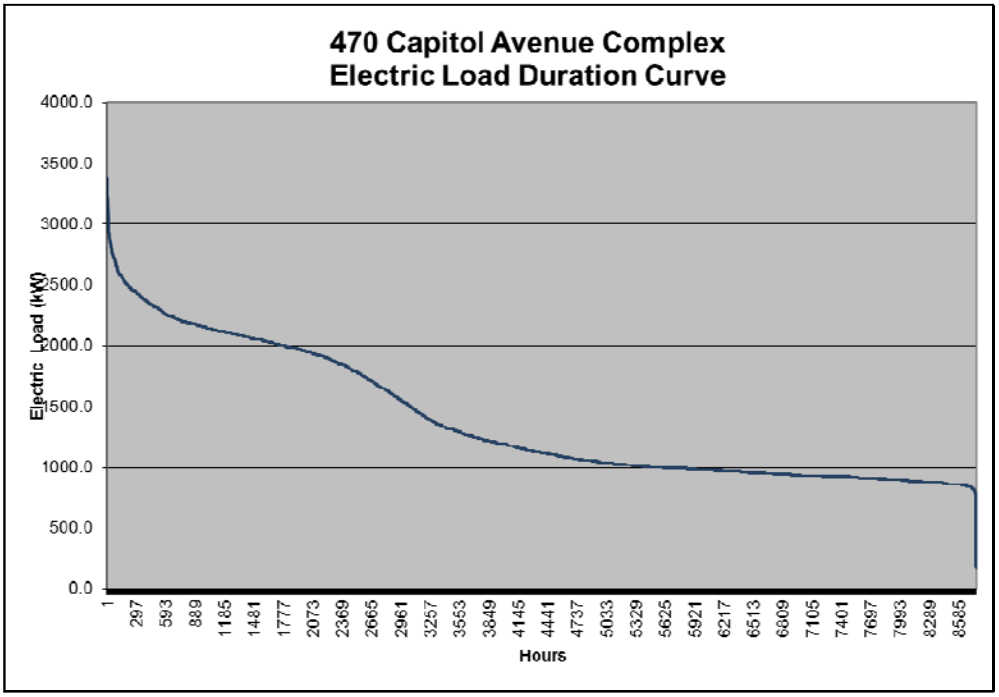


Figure 2: Electric Load Duration Curve for 470 Capitol Avenue Complex

CAS Chilled Water Load Profile

The hourly January 2010 to December 2010 chilled water load profile for the CAS is shown in Figure 3 on the next page. As can be seen from the graph, the chilled water consumption for the facilities fed by the CAS varies significantly throughout the year. This is due to the fact that chilled water is mainly used for air conditioning purposes (cooling) in the summer season. Overall, the CAS appears to have a minimum or base chilled water demand of approximately 200-tons throughout the year with a peak demand of 3,500-tons during the summer cooling season. For our analysis, however, we assumed that the new central plant would have a total capacity of 5,400-tons. That way there is spare capacity to handle future load growth in the system and maintenance (preventative or corrective) can be completed on one of the chillers in the central plant without affecting the plant's ability to meet the peak chilled water load demand for the system.

In order to take advantage of the base cooling load, the CHP or trigeneration plants were modeled to include chillers that could use the thermal energy generated from the waste heat of the electric generation equipment to produce chilled water. The chillers were sized so that they could handle most of or the entire base chilling load without needing one of the electric centrifugal chillers to come on-line and supplement its chilled water production.

The absorption chillers in the trigeneration plant options will allow the reclaimed thermal energy from the electric generation equipment to be utilized year round and will help reduce the electrical consumption of the complex since it will reduce the operating hours and required loading of the electric centrifugal chillers in the central plant. Additionally, a 1,500-ton "free cooling" plate-and-frame heat exchanger is included in each of the central plant options being analyzed. This heat exchanger will allow the chillers to be taken off-line when the ambient air temperature is less than 45°F. Under these conditions, the chilled water in the return loop will be cooled directly by the cooler condenser water that in turn is cooled via forced convection with the cold ambient air in the cooling towers. For the most part, this form of "free cooling" can be utilized during the winter months of October through March when the lower ambient temperatures facilitate its use and the CHP plant will have its reclaimed thermal energy utilized for heating purposes.

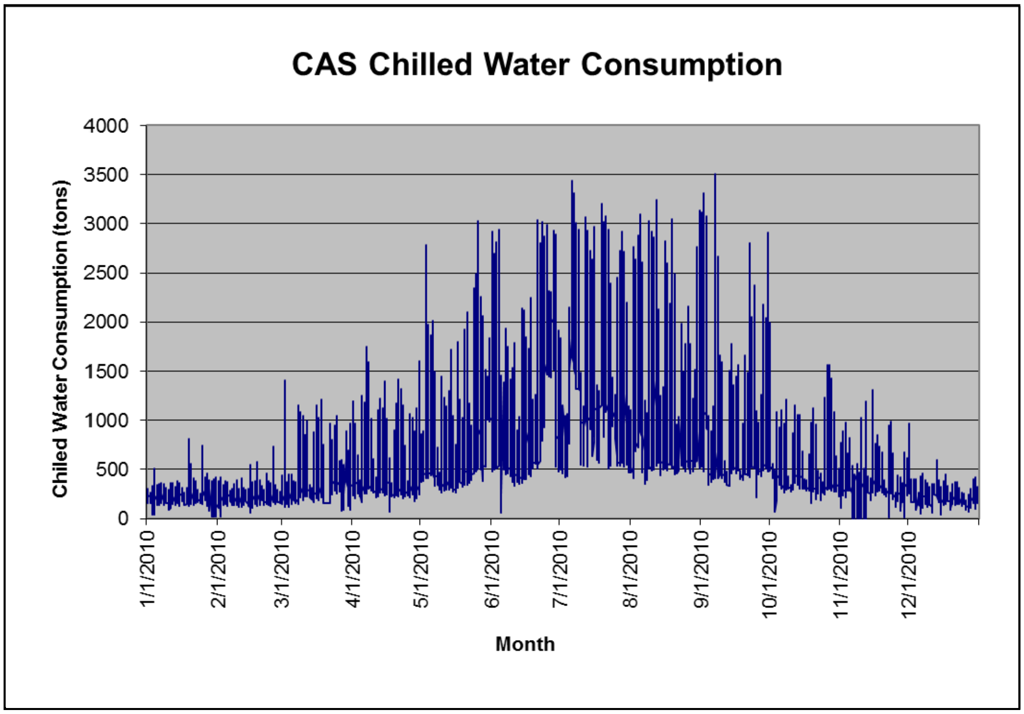


Figure 3: CAS Chilled Water Load Profile

CAS Steam Load Profile

The hourly January 2010 to December 2010 steam load profile for the CAS is shown in Figure 4 on the next page. As can be seen from the graph, the steam consumption of the heat exchangers creating the hot water for the facilities fed by the CAS (the heat exchangers use the vast majority of the steam consumed) as well as the other steam consuming entities on Capitol Avenue varies significantly throughout the year. This is due to the fact that the CAS hot water is mainly used for heating purposes in the winter season. Overall, the CAS appears to have a minimum or base steam demand of approximately 1 MMBTU throughout the year with a peak demand of 38 MMBTU (32,000 lb/hr) during the winter heating season. For our analysis, however, we assumed that the new central plant would have a total capacity of 54 MMBTU/hr or 45,000 lb/hr of 15 psig steam. That way there is spare capacity to handle future load growth in the system and maintenance (preventative or corrective) can be completed on one of the boilers in the central plant without affecting the plant's ability to meet the peak steam load demand for the system. The steam operating pressure was reduced from 125 psig to 15 psig to allow the DPW to operate the central plant unmanned (without 24X7 coverage) and without high pressure boiler licensed operators.

Since the steam load profile varies so significantly throughout the year, the trigeneration plant options were equipped with steam absorption chillers that could use the excess steam not needed by the hot water heat exchangers during the summer to create chilled water. During the winter season, however, all of the steam created by the heat recovery steam generators (HRSG's) would be used by the hot water heat exchangers in the Pump House to heat the hot water for the CAS loop. The HRSG steam production would be supplemented by the steam boilers.

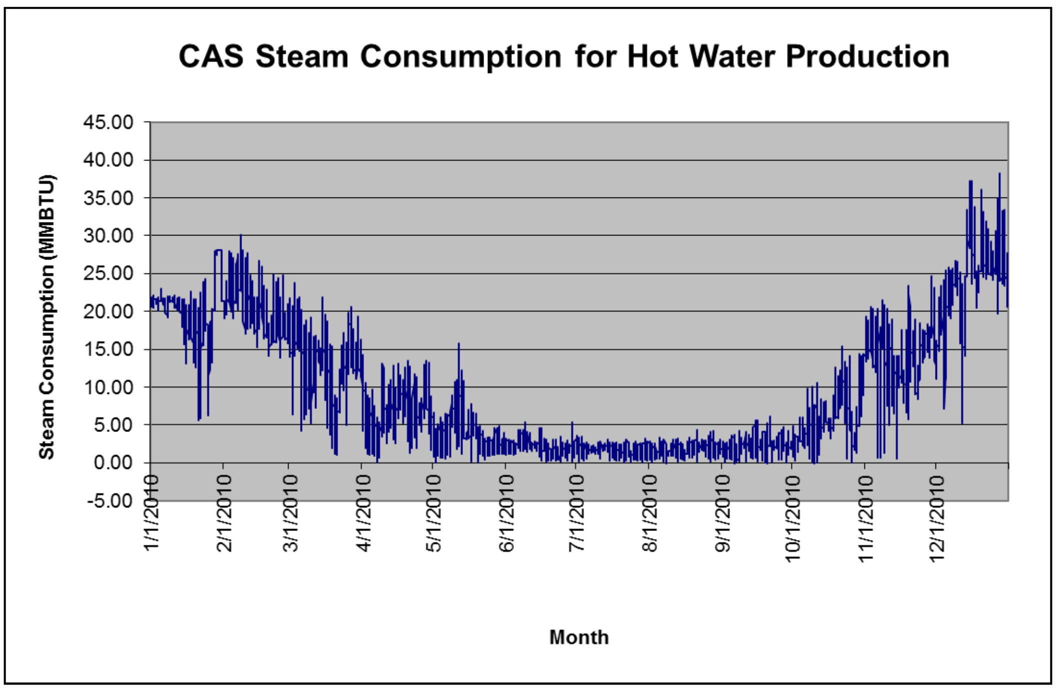


Figure 4: CAS Steam Load Profile

5. CENTRAL PLANT OPTIONS

The determination of the potential central plant options was made based upon the following:

1. Electric, steam, and chilled water load profiles
2. Available space in the Pump House and CT Boiler House

Load Profile Utilization

The load profiles were incorporated into a spreadsheet style performance model developed by SourceOne, which allowed the central plant options to be evaluated against the energy use load profiles. As alluded to previously, in the model the hourly electric load profile for the 470 Capitol Avenue complex was modified to reflect the additional electric load associated with the operation of the new central plant equipment (i.e. chillers, boilers, auxiliary and parasitic loads….etc.). This modified electric profile was analyzed with the CAS chilled water and steam load data to determine the optimal central plant configuration. The minimum, maximum, and average electric, steam, and chilled water loads determined the electric and thermal energy generation equipment selections for the model.

Available Space

SourceOne believes that the most practical location for the new central plant would be the CT Boiler House abutted to the Pump House. The Pump House itself does not have much available space, but the CT Boiler House does. Figure 5 and 6 show the interior of the CT Boiler House.

Figure 5: CT Boiler House Interior (Looking at Existing Auxiliary Boilers)

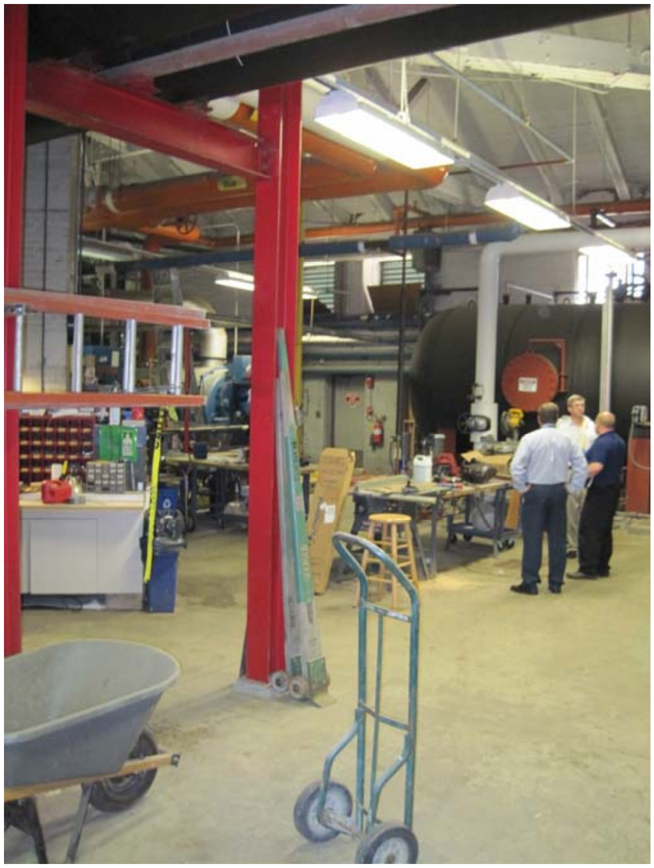


Figure 6: CT Boiler House Interior (Looking at Existing Chilled Water Expansion/Surge Tank)

One of the benefits associated with constructing the central plant in the CT Boiler House is that for the non-CHP options a new enclosure or structure will not have to be built to house the equipment, which reduces the capital cost associated with construction. Another benefit is that the new low pressure steam boilers could use the existing flue-gas stack located on top of the facility. This will like-wise reduce the capital cost associated with the project and may help with the air permitting/equipment registration process. Also, the existing foundation/platform upon which the old retired-in-place cooling towers are currently located in the back of the facility can be reused for the new central plant cooling towers. A picture of this platform is shown in Figure 7 on the next page.

Another benefit of locating the central plant in the CT Boiler House is that the facility abuts the Pump House, which is the final destination of the steam and chilled water produced by the central plant. Locating the central plant as close as possible to the Pump House reduces the interconnection costs associated with the central plant's steam mains and the Pump House's hot water heat exchangers as well as the central plant's chillers and the Pump House's chilled water supply and return pipes.

Figure 7: Retired-In-Place Cooling Towers and Associated Platform

In regards to the electrical output from the prime movers in the trigeneration plant options, the closest state-owned facilities to the Pump House would be the 470 Capitol Avenue complex of buildings, which is why their electric service would be the ideal one to tie into. Based upon the "High Voltage Supply One Line Diagram" supplied to SourceOne by the State of Connecticut DPW, which is shown in Figure 8 on the next page, there appears to be ample loads on the main to support and consume the power from the proposed prime movers. A determination will have to be made in the next phase of design where exactly to make the interconnection. Ideally the interconnection could take place either on the 4160V or 480V side of the 2000kVA transformer serving the complex.

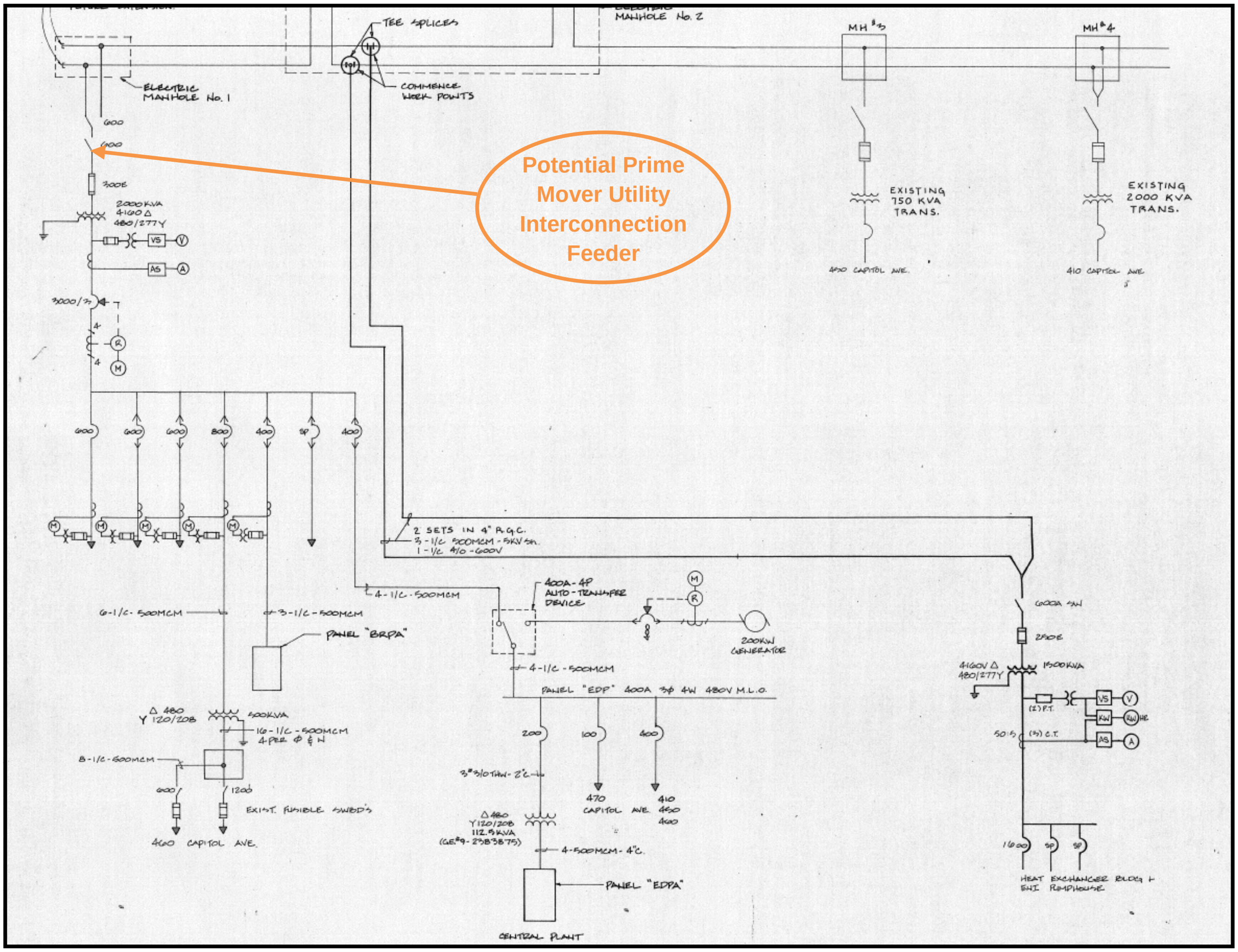


Figure 8: High Voltage Supply One Line Diagram

Figure 9 on the next page overlays the proposed central plant equipment footprint for what is called Option #1 (electric centrifugal chillers and low pressure steam boilers) on top of a 1st floor general arrangement diagram for the CT Boiler House. As can be seen in Figure 9, all of the proposed equipment for that option can be fit within the existing space constraints of the CT Boiler House.

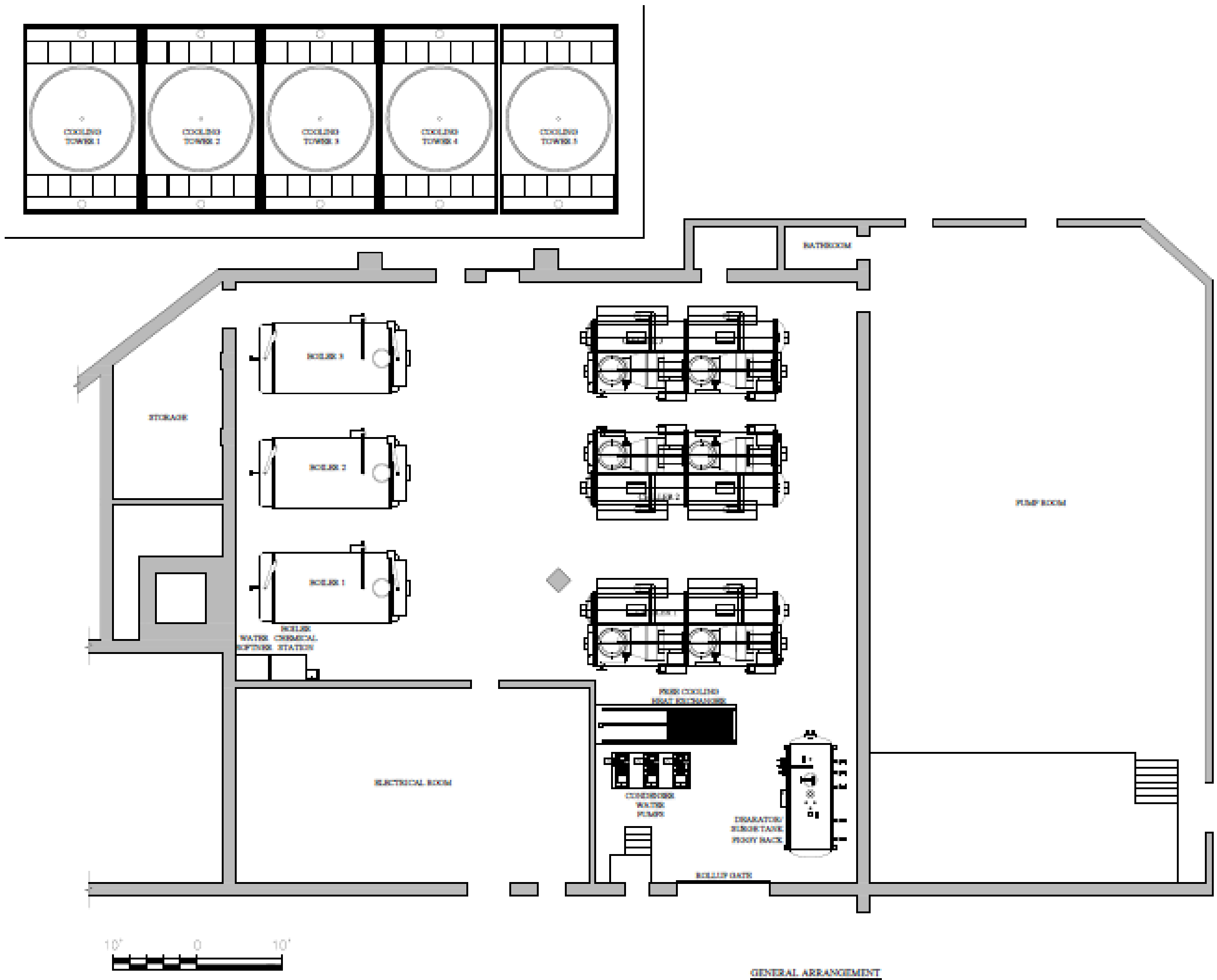


Figure 9: General Arrangement Diagram of CT Boiler House with Option #1 Central Plant Equipment

Based upon the electric, steam, and chilled water load profiles as well as the available space detailed above, SourceOne developed five (5) central plant options for the State of Connecticut.

1. ***Option #1 (Electric Chillers)***
   - ***Power***: Electricity from Utility
   - ***Heating***: Steam from Central Plant Boilers
   - ***Cooling***: Chilled Water from Central Plant Electric Chillers and Free Cooling Heat Exchanger

2. ***Option #2 (Natural Gas Direct Fired Chillers)***
   - ***Power***: Electricity from Utility
   - ***Heating***: Steam from Central Plant Boilers

- ***Cooling***: Chilled Water from Central Plant Natural Gas Direct Fired Chillers and Free Cooling Heat Exchanger

3. ***Option #3 (Trigeneration Plant with Reciprocating Engine)***

    - ***Power***: Electricity from 1,059 kW Jenbacher 620 Reciprocating Engine (Utility Backup)
    - ***Heating***: Steam from 2,000 lb/hr HRSG (Central Plant Boiler Backup)
    - ***Cooling***: Chilled Water from 75-ton Hot Water Absorption Chiller and 120-ton Single-Stage Steam Absorption Chiller (Central Plant Electric Chiller and Free Cooling Heat Exchanger Backup)

4. ***Option #4 (Trigeneration Plant with Gas Turbine)***

    - ***Power***: Electricity from 1,210 kW Solar Saturn 20 Gas Turbine (Utility Backup)
    - ***Heating***: Steam from 8,100 lb/hr HRSG (Central Plant Boiler Backup)
    - ***Cooling***: Chilled Water from 493-ton Single-Stage Steam Absorption Chiller (Central Plant Electric Chiller and Free Cooling Heat Exchanger Backup)

5. ***Option #5 (Trigeneration Plant with MicroTurbines)***

    - ***Power***: Electricity from two (2) 200 kW Capstone C200 MicroTurbines (Utility Backup)
    - ***Heating***: Steam from two (2) 1,080 lb/hr HRSG's (Central Plant Boiler Backup)
    - ***Cooling***: Chilled Water from 132-ton Single-Stage Steam Absorption Chiller (Central Plant Electric Chiller and Free Cooling Heat Exchanger Backup)

It should be noted that in Option #3, #4, and #5 SourceOne assumed that the trigeneration or CHP plant availability level would be 95%. This availability level takes into account scheduled maintenance and forced outages, which SourceOne estimated would total 18 days/year.

<u>Option #1 – Steam Boilers and Electric Chillers</u>

Figure 10 below depicts the major equipment comprising the central plant for Option #1. In order to simplify the diagram, the condenser water system (cooling towers etc.), the 1,500-ton "free cooling" heat exchanger that is common to all of the options, and the auxiliary equipment (pumps, fans, etc.) are not shown.

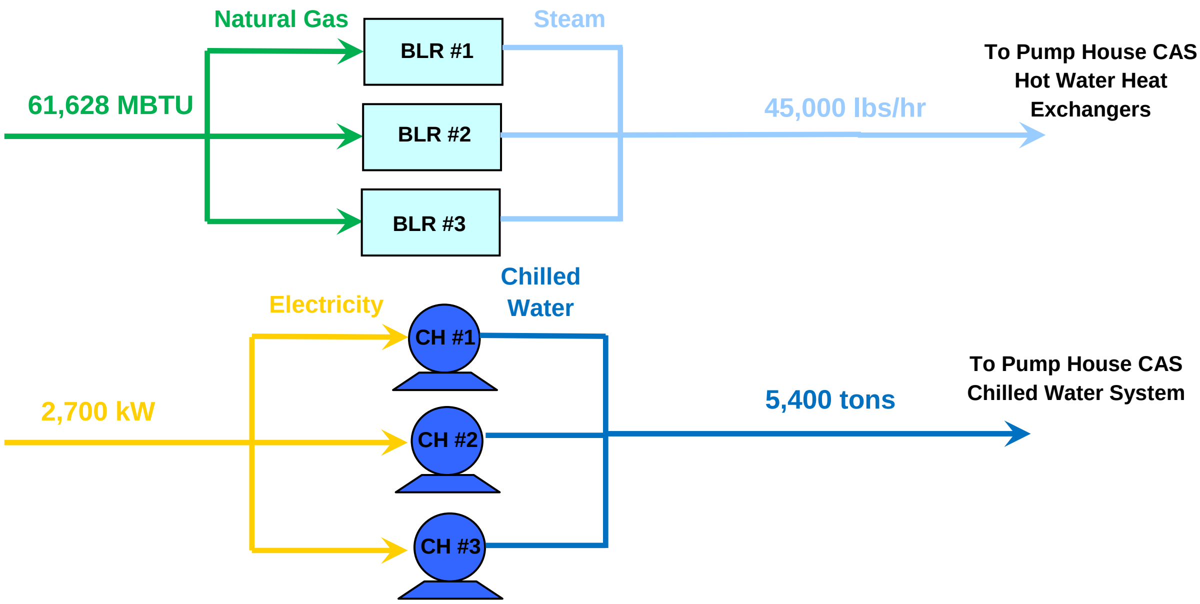


Figure 10: Option #1 Central Plant Main System Components and Energy Flow

Option #1 utilizes three (3) 1,800-ton electric centrifugal chillers, which for our analysis we utilized the Trane CenTraVac Duplex Model CDHF2000 chiller. It also utilizes three (3) 15,000 lb/hr low pressure steam boilers, which for our analysis we utilized the Cleaver Brooks Model CB-LE 500 BHP steam boiler.

Since the maximum chilled water demand for the CAS is approximately 3,500-tons and the maximum steam demand for the CAS is approximately 32,000 lb/hr, this configuration allows the central plant to meet the peak system demand loads even with one boiler or one chiller off-line for preventative or corrective maintenance. Additionally, the 1,500-ton plate-and-frame heat exchanger utilized for "free cooling" allows the central plant to meet the chilled water load demands of the CAS during the winter season without the need of supplemental cooling from the electric centrifugal chillers. "Free Cooling" mode will be utilized whenever the ambient outdoor temperature is below 45°F.

Based upon the aforementioned equipment as well as the electric, steam, and chilled water load profiles, SourceOne estimates the output of this proposed central plant to be as shown in Table 5 on the next page.

	Mechanical Cooling (Chilled Water)		**Heating (Steam)**		**Free Cooling (Chilled Water)**	
	tons (peak)	ton-hrs (annual)	lbs/hr (peak)	lbs (annual)	tons (peak)	ton-hrs (annual)
Central Plant	3,509	5,737,300	32,820	72,835,482	1,407	963,576

	Installed Cooling Capacity (Chilled Water)	**Installed Heating Capacity (Steam)**	**Installed Free Cooling Capacity (Chilled Water)**
	tons	lbs/hr	tons
Central Plant	5,400	45,000	1,500

Table 5: Option #1 Central Plant Annual Output and Capacity

Option #2 – Steam Boilers and Natural Gas Direct Fired Chillers

Figure 11 below depicts the major equipment comprising the central plant for Option #2. In order to simplify the diagram, the condenser water system (cooling towers etc.), the 1,500-ton "free cooling" heat exchanger that is common to all of the options, and the auxiliary equipment (pumps, fans, etc.) are not shown.

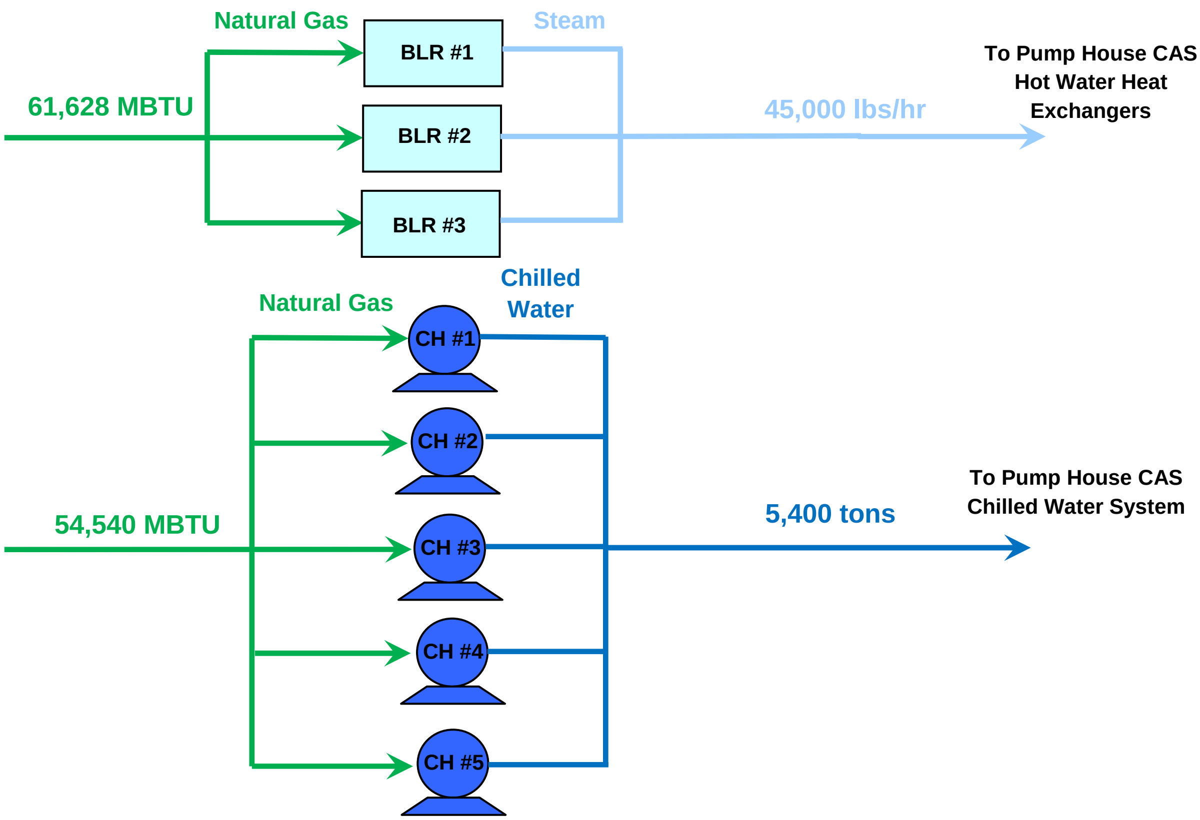


Figure 11: Option #2 Central Plant Main System Components and Energy Flow

Option #2 utilizes five (5) 1,080-ton natural gas direct fired chillers, which for our analysis we utilized the EcoChill (now Thermax) Model GD 70B CX chiller. It also utilizes three (3) 15,000 lb/hr low pressure steam boilers, which for our analysis we utilized the Cleaver Brooks Model CB-LE 500 BHP steam boiler. Five chillers were needed instead of three since the physical dimensions of the direct fired chillers limits their production sizes (ratings). The size of a direct fired chiller is much greater than that of an equally rated (tons) electric centrifugal chiller.

Since the maximum chilled water demand for the CAS is approximately 3,500-tons and the maximum steam demand for the CAS is approximately 32,000 lb/hr, this configuration allows the central plant to meet the peak system demand loads even with one boiler or one chiller off-line for preventative or corrective maintenance. Additionally, the 1,500-ton plate-and-frame heat exchanger utilized for "free cooling" allows the central plant to meet the chilled water load demands of the CAS during the winter season without the need of supplemental cooling from the electric centrifugal chillers. "Free Cooling" mode will be utilized whenever the ambient outdoor temperature is below 45°F.

Based upon the aforementioned equipment as well as the electric, steam, and chilled water load profiles, SourceOne estimates the output of this proposed central plant to be as shown in Table 6 below.

	Mechanical Cooling (Chilled Water)		**Heating (Steam)**		**Free Cooling (Chilled Water)**	
	tons (peak)	ton-hrs (annual)	lbs/hr (peak)	lbs (annual)	tons (peak)	ton-hrs (annual)
Central Plant	3,509	5,737,300	32,820	72,835,482	1,407	963,576

	Installed Mechanical Cooling Capacity (Chilled Water)	**Installed Heating Capacity (Steam)**	**Installed Free Cooling Capacity (Chilled Water)**
	tons	lbs/hr	tons
Central Plant	5,400	45,000	1,500

Table 6: Option #2 Central Plant Annual Output and Capacity

<u>Option #3 – Trigeneration Plant with a Reciprocating Engine</u>

Figure 12 below depicts the equipment comprising the trigeneration plant for Option #3. In order to simplify the diagram, the condenser water system (cooling towers etc.), the 1,500-ton "free cooling" heat exchanger that is common to all of the options, and the auxiliary equipment (pumps, fans, etc.) are not shown.

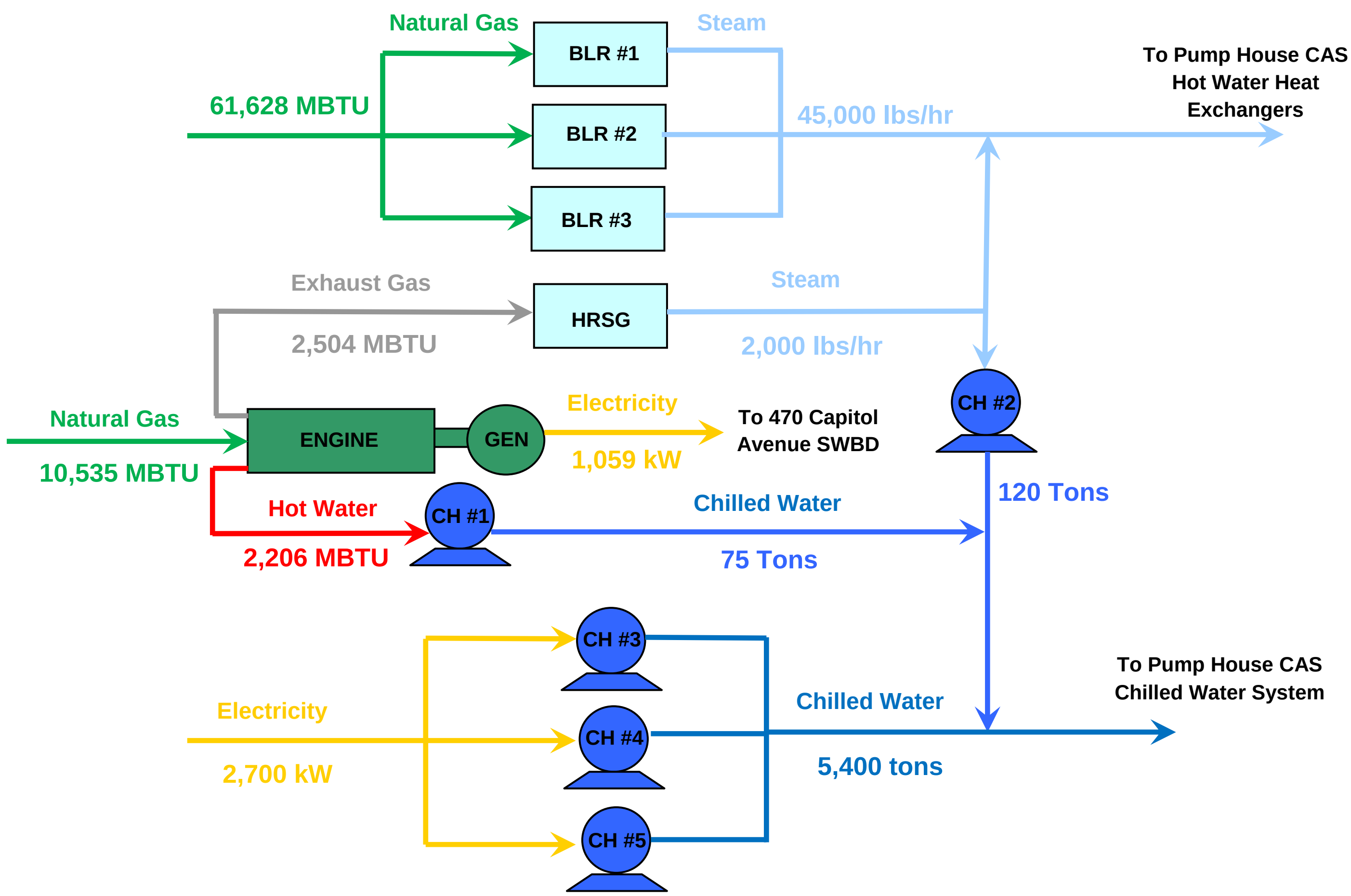


Figure 12: Option #3 Central Plant Main System Components and Energy Flow

Option #3 utilizes one (1) 1,059 kW Jenbacher 320 reciprocating engine. Its engine has 4,710 MBTU/hr of recoverable thermal energy from the waste heat it produces in the electric generation process at full-load. Figure 13 illustrates the thermal (waste heat) recovery system components.

As can be seen from Figure 13 on the next page, there are four main components to the waste heat recovery system for this option. Those components are:

1. Intercooler (1st Stage) – 561 MBTU/hr
2. Lube Oil Heat Exchanger – 430 MBTU/hr

3. Engine Jacket – 1,215 MBTU/hr
4. Exhaust Gas Heat Recovery System – 2,504 MBTU/hr

The first three components listed above (Intercooler, Lube Oil Heat Exchanger, and Engine Jacket) can be used to produce 185 °F hot water. This hot water can then be used in an absorption chiller to produce chilled water. SourceOne specified the use of a 75-ton Carrier Model 16LJ11 Single-Stage Hot Water Absorption Chiller. Since the minimum chilled water load for the CAS is approximately 200-tons, this means that the trigeneration plant hot water absorption chiller should be in operation year-round on a "first-in, last-out" operation schedule.

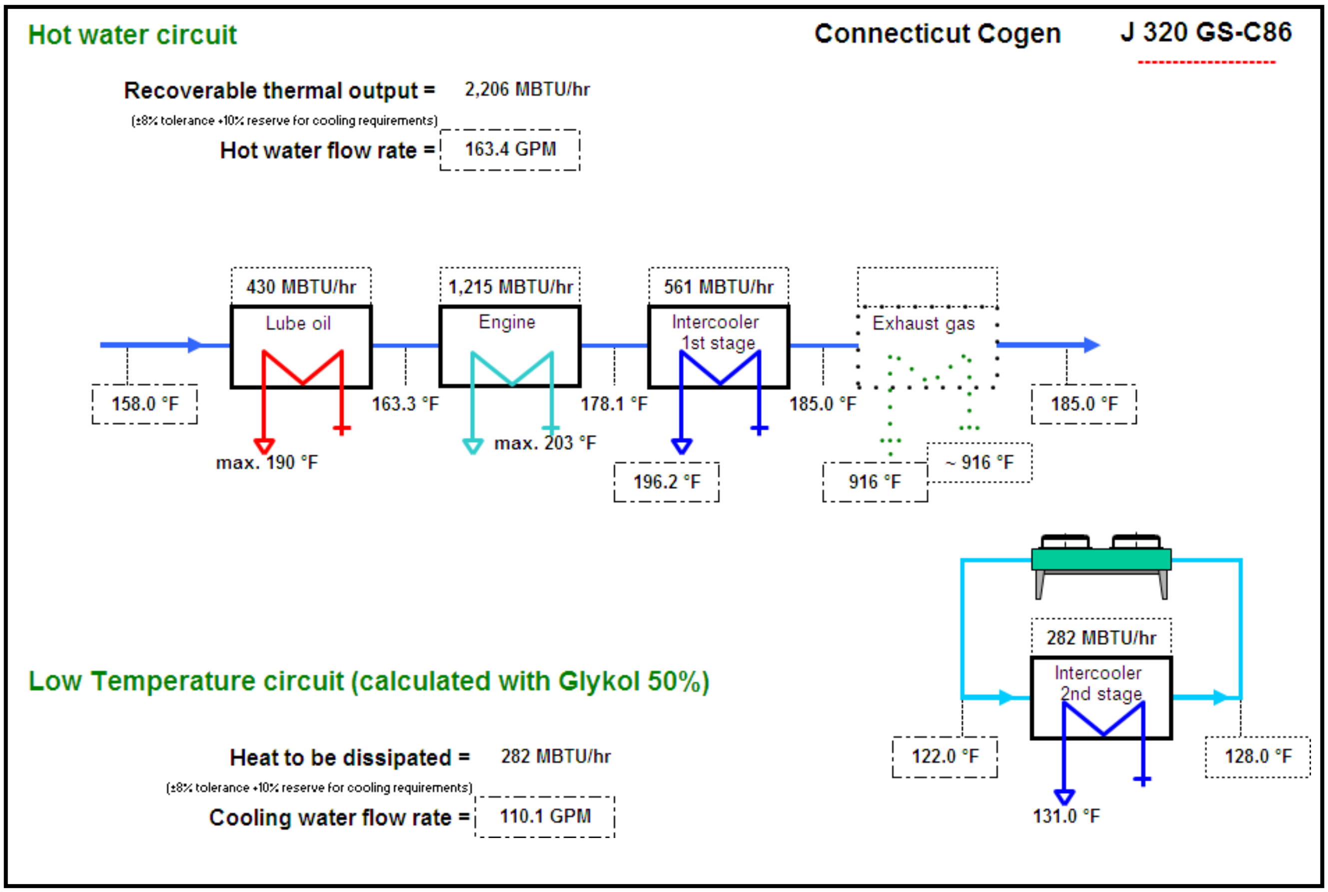


Figure 13: Hot Water Circuit Recoverable Thermal Output System Components

The fourth component of the waste heat recovery system (Exhaust Gas Heat Recovery System) recovers thermal energy from the exhaust gas stream of the reciprocating engines to either produce hot water or steam. Figure 13 shows the exhaust gas being used to produce additional hot water. In the case of this application, however, SourceOne would recommend the use of a heat recovery steam generator (HRSG) for each reciprocating engine, which would use the 916°F exhaust gas stream to produce low pressure (15 psig) steam from recycled condensate that could then be used by a steam absorption chiller to produce chilled water. The HRSG specified in SourceOne's model is capable of producing approximately 2,000 lb/hr of low pressure steam and has an efficiency rating of approximately 90% at full electric load. The steam absorption chiller specified by SourceOne is a 120-ton Carrier Model 16TJ12 Single-Stage Steam Absorption Chiller. At full electric load, approximately 120-tons of chiller water per hour can be generated using 2,070 lb/hr of steam. With this being the case, when the trigeneration plant is fully loaded, it can produce a maximum of 195-tons of chilled water. Just to reiterate, since the minimum chilled water load for the facility is approximately 200-tons, both the hot water and steam absorption chillers should be in operation during the summer cooling season on a “first-in, last-out” operation schedule in order to maximize the trigeneration plant’s utilization rate and efficiency. During the winter heating season, the HRSG steam can be used to heat the CAS hot water loop and the chilled water load will be handled the majority of the time by the “free cooling” system (i.e. when temperature below 45°F).

Option #3 also utilizes three (3) 1,800-ton electric centrifugal chillers, which for our analysis we used the Trane CenTraVac Duplex Model CDHF2000 chiller. Additionally, it uses three (3) 15,000 lb/hr low pressure steam boilers, which for our analysis we utilized the Cleaver Brooks Model CB-LE 500 BHP steam boiler. The electric chillers and low pressure steam boilers are for supplemental/back-up purposes.

Since the maximum chilled water demand for the CAS is approximately 3,500-tons and the maximum steam demand for the CAS is approximately 32,000 lb/hr, this configuration allows the central plant to meet the peak system demand loads even with one boiler or one chiller off-line for preventative or corrective maintenance. In fact, the whole trigeneration plant can be off-line and the central plant will still be able to meet the full system demand needs.

Based upon the aforementioned equipment as well as the electric, steam, and chilled water load profiles, SourceOne estimates the output of this central plant to be as shown in Table 7 below.

	Power (Electricity)		**Mechanical Cooling (Chilled Water)**		**Heating (Steam)**	
	kW (peak)	kWhrs (annual)	tons (peak)	ton-hrs (annual)	Mlbs (peak)	Mlbs (annual)
Trigeneration Plant	1,059	8,807,010	195	867,350	2	16,656

	Mechanical Cooling (Chilled Water)		**Heating (Steam)**		**Free Cooling (Chilled Water)**	
	tons (peak)	ton-hrs (annual)	lbs/hr (peak)	lbs (annual)	tons (peak)	ton-hrs (annual)
Central Plant	3,314	4,869,949	31,017	64,254,990	1,407	963,576

	Installed Mechanical Cooling Capacity (Chilled Water)	**Installed Heating Capacity (Steam)**	**Installed Free Cooling Capacity (Chilled Water)**
	tons	lbs/hr	tons
Central Plant	5,400	45,000	1,500

Table 7: Option #3 Central Plant Annual Output and Capacity

Option #4 – Trigeneration Plant with a Gas Turbine

Figure 14 below depicts the equipment comprising the trigeneration plant for Option #4. In order to simplify the diagram, the condenser water system (cooling towers etc.), the 1,500-ton "free cooling" heat exchanger that is common to all of the options, and the auxiliary equipment (pumps, fans, etc.) are not shown.

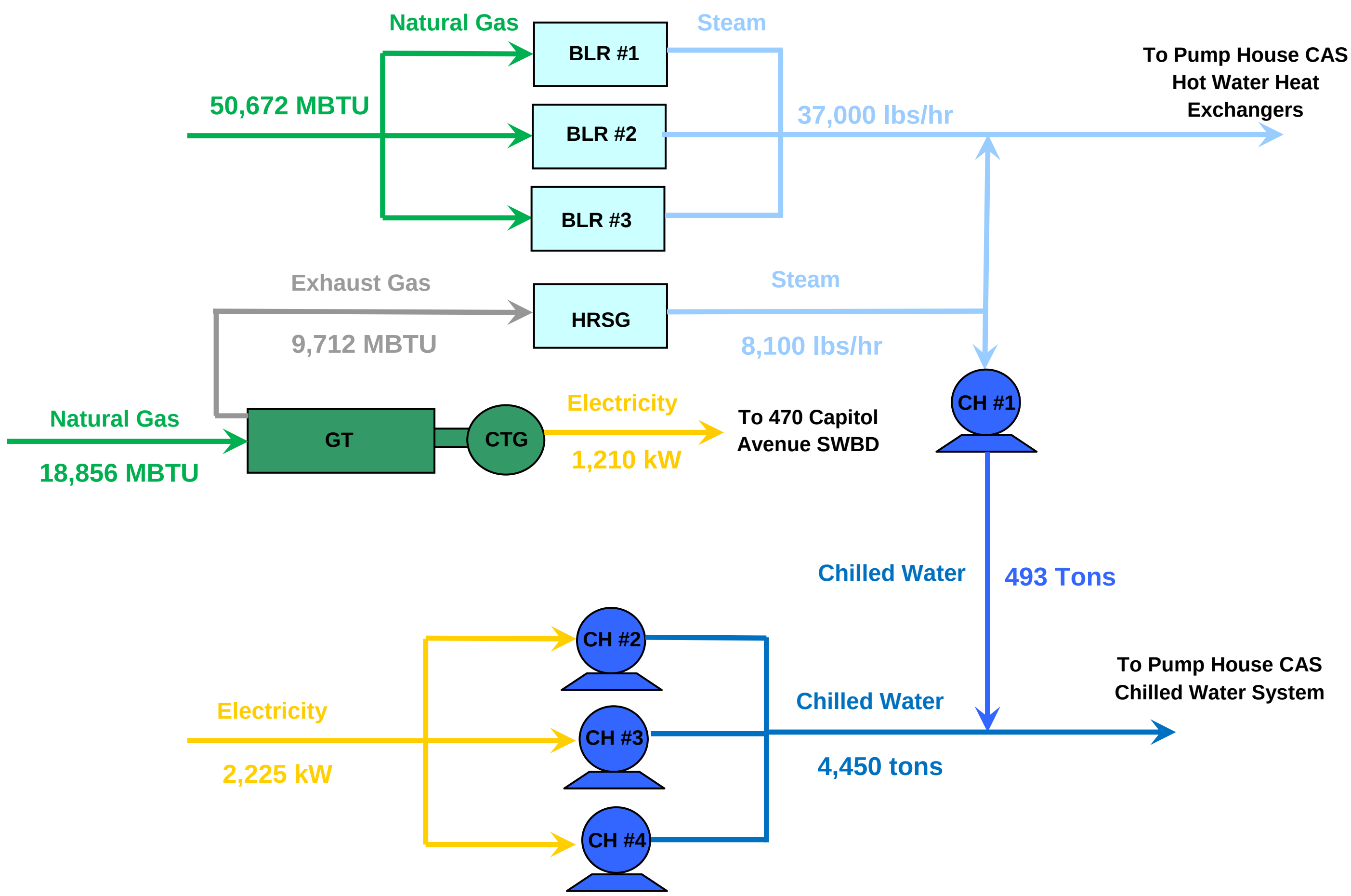


Figure 14: Option #4 Cogeneration Plant System Components and Energy Flow

Option #4 utilizes one (1) nominal 1,210 kW Solar Saturn 20 gas turbine with associated combustion turbine generator to produce electricity. The gas turbine's exhaust gas has approximately 9,712 MBTU/hr of recoverable thermal energy from the waste heat it produces in the electric generation process at full-load. Unlike the reciprocating engines, the gas turbine does not have any waste heat streams that can be used to produce hot water directly; instead its waste heat is solely retrievable and inherent in its exhaust gas.

In this option a HRSG, which uses the 960°F gas turbine exhaust gas stream, is utilized to produce low pressure (15 psig) steam from recycled condensate. This steam is then used to power a steam absorption chiller. The HRSG specified in SourceOne's model is capable of producing 8,100 lb/hr of low pressure steam. The steam absorption chiller specified by SourceOne is a 493-ton ProChill Model SS 40B C Single-Stage Steam Absorption Chiller. At full electric load, approximately 484-tons of chilled water per hour can be generated using 8,100 lb/hr of steam. This derate is due to the fact that the 493-ton production level requires 8,290 lb/hr of steam. Since the minimum chilled water load for the facility is approximately 200-tons this steam absorption chiller can be operated year-round on a "first-on, last-out" operating schedule. This will maximize the trigeneration plant's utilization rate and hence efficiency. During the winter heating season, the HRSG steam can be used to heat the CAS hot water loop and the chilled water load will be handled the majority of the time by the "free cooling" system (i.e. when temperature below 45°F).

It should be noted, however, that unlike the reciprocating engines the maximum output of the CTG set is drastically affected by the ambient outdoor air temperature since this air is used in the combustion process. Table 8 presents various CTG parameters at specific ambient outdoor air temperatures. One way to mitigate this would be to install an inlet chiller for the supply air that would lower the temperature of the air being used in the combustion process and hence increase the production capabilities of the CTG set. This option will be looked at in more detail during the detailed design phase of the project.

Ambient Temperature (°F)	CTG Power (kW)	CTG HHV Heat Rate (Btu/kWh)	CTG Exhaust Gas Temperature (°F)	CTG Exhaust Gas Stream (lbs/hr)	HRSG Steam Production (lbs/hr)
0	1,204	15,848	716.0	56,449	7,336
20	1,204	15,661	795.0	54,785	7,890
40	1,204	15,586	872.0	53,438	8,084
60	1,204	15,602	946.0	51,793	8,100
80	1,127	15,882	977.0	49,764	8,035
100	1,046	16,299	999.0	47,394	7,948

Table 8: Outdoor Ambient Air Temperature Effect on CTG Performance

Option #4 also utilizes three (3) 1,480-ton electric centrifugal chillers, which for our analysis we used the Trane CenTraVac Model CVHF1470 chiller. Additionally, it uses three (3) 12,300 lb/hr low pressure steam boilers, which for our analysis we utilized the Cleaver Brooks Model CB-LE 350 BHP steam boiler. The electric chillers and low pressure steam boilers are for supplemental/back-up purposes.

Since the maximum chilled water demand for the CAS is approximately 3,500-tons and the maximum steam demand for the CAS is approximately 32,000 lb/hr, this configuration allows the central plant to meet the peak system demand loads even with one boiler/HRSG or one electric/absorption chiller off-line for preventative or corrective maintenance. In fact, the whole trigeneration plant can be off-line and the central plant will still be able to meet the full system demand needs.

Based upon the aforementioned equipment as well as the electric, steam, and chilled water load profiles, SourceOne estimates the output of this proposed central plant to be as shown in Table 9 below.

	Power (Electricity)		Mechanical Cooling (Chilled Water)		Heating (Steam)	
	kW (peak)	kWhrs (annual)	tons (peak)	ton-hrs (annual)	Mlbs (peak)	Mlbs (annual)
Trigeneration Plant	1,210	9,868,219	484	1,472,750	8	41,006

	Mechanical Cooling (Chilled Water)		Heating (Steam)		Free Cooling (Chilled Water)	
	tons (peak)	ton-hrs (annual)	MMBTU (peak)	MMBTU (annual)	tons (peak)	ton-hrs (annual)
Central Plant	3,242	4,264,550	30	41,826	1,407	963,576

	Installed Mechanical Cooling Capacity (Chilled Water)	Installed Heating Capacity (Steam)	Installed Free Cooling Capacity (Chilled Water)
	tons	lbs/hr	tons
Central Plant	5,400	45,000	1,500

Table 9: Option #4 Central Plant Annual Output and Capacity

Option #5 – Trigeneration Plant with a MicroTurbines

Figure 15 below depicts the equipment comprising the trigeneration plant for Option #5. In order to simplify the diagram, the condenser water system (cooling towers etc.), the 1,500-ton "free cooling" heat exchanger that is common to all of the options, and the auxiliary equipment (pumps, fans, etc.) are not shown.

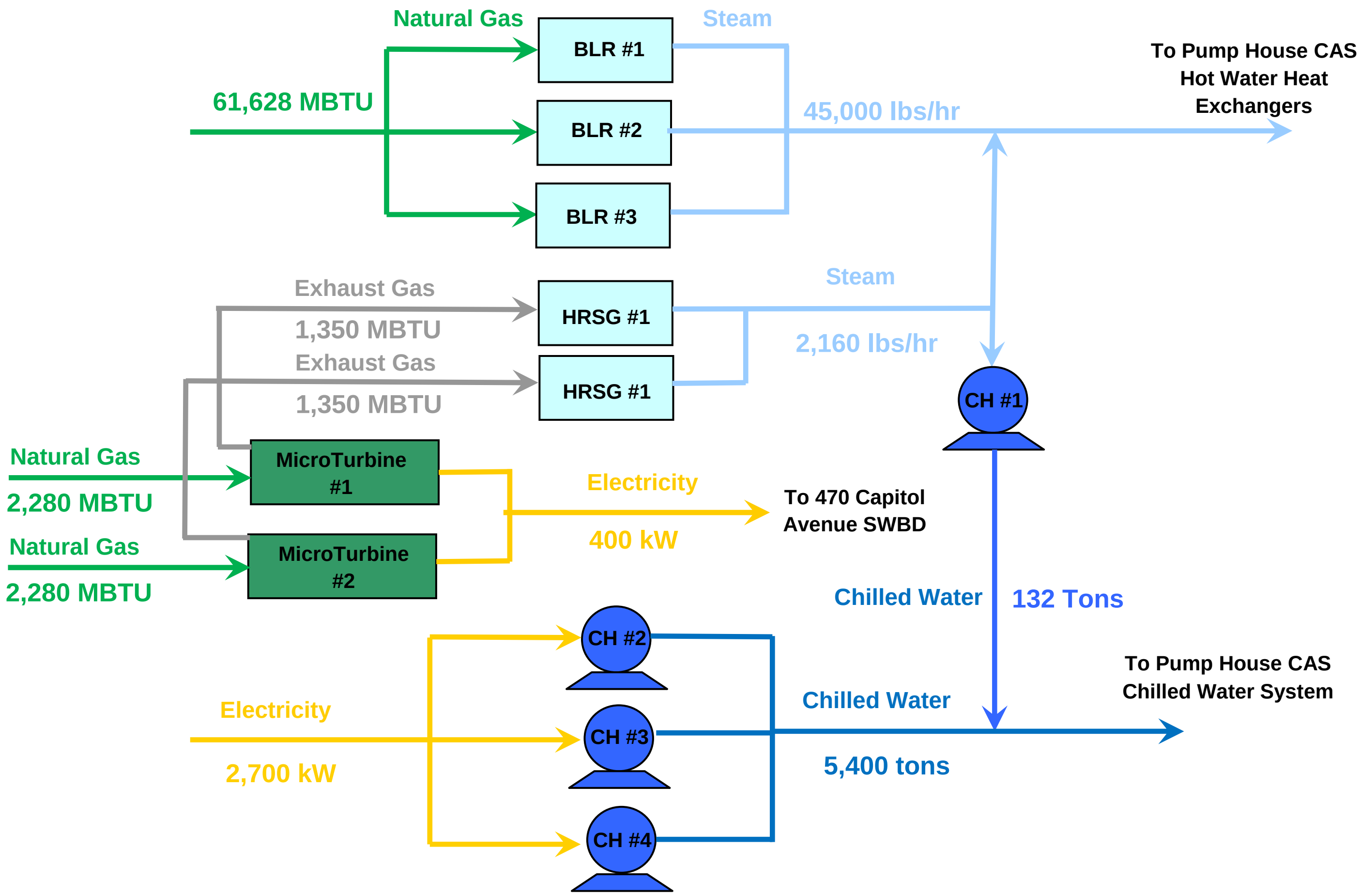


Figure 15: Option #5 Cogeneration Plant System Components and Energy Flow

Option #5 utilizes two (2) nominal 200 kW Capstone C200 MicroTurbines to produce electricity. Each MicroTurbine's exhaust gas has approximately 1,350 MBTU/hr of recoverable thermal energy from the waste heat it produces in the electric generation process at full-load.

In this option, two (2) HRSG's, which use the 535°F MicroTurbine exhaust gas stream, are utilized to produce low pressure (15 psig) steam from recycled condensate. This steam is then used to power a steam absorption chiller. The HRSG specified in SourceOne's model is capable of producing 1,080 lb/hr of low pressure steam, resulting in a combined capacity of 2,160 lb/hr for the two units combined. The steam absorption chiller specified by SourceOne is a 132-ton ProChill Model SS 20A C Single-

Stage Steam Absorption Chiller. At full electric load, approximately 126-tons of chilled water per hour can be generated using 2,160 lb/hr of steam. This derate is due to the fact that the 132-ton production level requires 2,251 lb/hr of steam. Since the minimum chilled water load for the facility is approximately 200-tons this steam absorption chiller can be operated year-round on a “first-on, last-out” operating schedule. This will maximize the trigeneration plant’s utilization rate and hence efficiency. During the winter heating season, the HRSG steam can be used to heat the CAS hot water loop and the chilled water load will be handled the majority of the time by the “free cooling” system (i.e. when temperature below 45°F).

It should be noted, however, that unlike the reciprocating engines the maximum output of the MicroTurbines are drastically affected by the ambient outdoor air temperature since this air is used in the combustion process. Table 9 presents various CTG parameters at specific ambient outdoor air temperatures. One way to mitigate this would be to install an inlet chiller for the supply air that would lower the temperature of the air being used in the combustion process and hence increase the production capabilities of the MicroTurbines. This option will be looked at in more detail during the detailed design phase of the project.

Ambient Temperature (°F)	MicroTurbine Power (kW)	MicroTurbine HHV Heat Rate (Btu/kWh)	MicroTurbine Exhaust Gas Temperature (°F)	MicroTurbine Exhaust Gas Stream (lbs/hr)	HRSG Steam Production (lbs/hr)
0	200	11,579	404.9	11,379	978
20	200	11,443	449.6	11,043	1,052
40	200	11,388	493.2	10,772	1,078
60	200	11,400	535.0	10,440	1,080
80	193	11,605	552.5	10,031	1,071
100	173	11,909	565.0	9,553	1,060

Table 9: Outdoor Ambient Air Temperature Effect on MicroTurbine Performance

Option #5 also utilizes three (3) 1,800-ton electric centrifugal chillers, which for our analysis we used the Trane CenTraVac Duplex Model CDHF2000 chiller. Additionally, it uses three (3) 15,000 lb/hr low pressure steam boilers, which for our analysis we utilized the Cleaver Brooks Model CB-LE 500 BHP steam boiler. The electric chillers and low pressure steam boilers are for supplemental/back-up purposes.

Since the maximum chilled water demand for the CAS is approximately 3,500-tons and the maximum steam demand for the CAS is approximately 32,000 lb/hr, this configuration allows the central plant to meet the peak system demand loads even with one boiler/HRSG or one electric/absorption chiller off-line for preventative or corrective maintenance. In fact, the whole trigeneration plant can be off-line and the central plant will still be able to meet the full system demand needs.

Based upon the aforementioned equipment as well as the electric, steam, and chilled water load profiles, SourceOne estimates the output of this proposed central plant to be as shown in Table 10 on the next page.

	Power (Electricity)		Mechanical Cooling (Chilled Water)		Heating (Steam)	
	kW (peak)	kWhrs (annual)	tons (peak)	ton-hrs (annual)	Mlbs (peak)	Mlbs (annual)
Trigeneration Plant	400	3,326,019	129	120,205	2	15,777

	Mechanical Cooling (Chilled Water)		Heating (Steam)		Free Cooling (Chilled Water)	
	tons (peak)	ton-hrs (annual)	MMBTU (peak)	MMBTU (annual)	tons (peak)	ton-hrs (annual)
Central Plant	3,453	5,617,094	36	68,259	1,407	963,576

	Installed Mechanical Cooling Capacity (Chilled Water)	Installed Heating Capacity (Steam)	Installed Free Cooling Capacity (Chilled Water)
	tons	lbs/hr	tons
Central Plant	5,400	45,000	1,500

Table 10: Option #5 Central Plant Annual Output and Capacity

6. FINANCIAL ANALYSIS

A financial analysis was conducted on the five central plant options described in the previous section in order to ascertain what their annual expenses would be relative to their upfront capital cost. In this way a simple payback analysis could be performed in order to determine how lucrative the installation of each central plant would be. This section will detail the financial analysis for each central plant option. In particular, the upfront capital cost will be compared to the following annual expenses for all central plant options:

1. Electric Expense
   - ⇒ This is the expense associated with purchasing electricity from CL&P.
2. Natural Gas Expense
   - ⇒ This is the expense associated with purchasing natural gas from CNG.
3. Water and Chemical Treatment Expense
   - ⇒ This is the expense associated with purchasing and chemically treating the make-up water that must be introduced into the Boiler/HRSG feedwater systems as well as the make-up water required for the condenser water system.
4. Operation and Maintenance (O&M)
   - ⇒ The O&M expense is the cost associated with operating and maintaining the central plant. In particular the electric generation equipment, HRSG, boilers, and chillers.

Option #1 – Steam Boilers and Electric Chillers

The load profile analysis for Option #1 determined that there would be approximately 17,894,126 kWhs of electricity that would have to be purchased annually from CL&P under their LGS (Large General Service) tariff rate. Based upon the monthly distribution of the aforementioned 17,894,126 kWhs of electricity over the course of the year, as well as the rates listed in CL&P's tariff, SourceOne estimated that the annual electricity expense would be $2,515,065. A table listing the monthly on-peak and off-peak electric consumption as well as peak demand and charges is presented in the Appendix of this report.

In regards to the annual natural gas expense, SourceOne determined that based upon the load profile analysis for Option #1 the facility would have to purchase 99,750 decatherms of natural gas over the course of a year. This required volume of gas is based upon the heat rate and efficiency of the Cleaver Brooks boiler specified for this option. For the financial analysis it was assumed that the supply, transmission, and distribution charges for the natural gas would be issued by CNG under their LGS (Large General Service) tariff rate. Based upon the monthly distribution of the aforementioned 99,750 decatherms of natural gas over the course of a year, as well as the CNG rate structure, SourceOne estimated that the annual natural gas expense would be $771,406. A table listing the monthly natural gas consumption as well as the peak day demand and charges is presented in the Appendix of this report.

In reference to the annual water and chemical treatment expense, SourceOne determined that based upon the load profile analysis for Option #1 the facility would have to purchase 17,188,576 gallons of make-up water. This required volume is based upon the industry standard estimate of 5% losses in the feedwater, steam, and condensate recovery distribution and recirculation systems as well as 2.5 gallons per ton-hr for the condenser water make-up system. For the financial analysis a unit cost for water was developed that was based upon The Metropolitan District (MDC) water rates as well as typical industry standard estimates for chemical treatment. Using the unit cost rate in conjunction with the annual requirement for make-up water, SourceOne estimated the annual cost of water and chemical treatment to be $91,924.

The O&M expense for Option #1 centers on the cost to operate and maintain the new central plant steam boilers, electric chillers, "free cooling" heat exchanger, and cooling towers as well as the existing equipment in the Pump House. For each one of these major pieces of equipment there are industry standard and manufacture recommended maintenance rates that are based upon average run-hours, loading, operating environment, required preventative maintenance, and the normal wear-and-tear associated with the equipment component parts. These maintenance rates include the costs associated with maintaining the balance of plant (BOP) and auxiliary equipment as well. Based upon the size of the equipment specified in SourceOne's model as well as these industry standard rates, the annual maintenance expenses associated with the equipment alone are estimated to be $399,267 for Option #1. This includes the maintenance costs associated with the Pump House equipment and the "free cooling" heat exchanger. The State of Connecticut DPW indicated that they would prefer to sub-contract the equipment maintenance to a 3rd-Party firm. As such, SourceOne added an additional 10% margin on top of the maintenance costs to account for the 3rd-Party firm mark-up. Since the boilers being specified are low pressure steam boilers, the State of Connecticut will not need to staff the central plant with a 24X7 operations crew. The central plant will be highly automated and for the most part will not require manual operator intervention. As such, the State of Connecticut DPW is currently estimating that they will only need an operator at the plant for approximately 4 hours per day to conduct routine rounds in the facility and ensure that the plant is operating normally with no significant alarms present or equipment deficiencies. We are currently assuming that the Director of Capitol Area System (CAS) will operate as the Plant Manager, so there will be no additional expense associated with hiring a plant manager. Since the maintenance activities will be sub-contracted to a 3rd-Party firm, the State of Connecticut will not have to hire any mechanics, electricians, or instrumentation & controls technicians for the central plant. Therefore, SourceOne estimates that the staffing costs will be limited to the part-time operator. SourceOne is estimating this cost to be $61,600 per year. Since the State of Connecticut DPW indicated that they would prefer to sub-contract the equipment operation to a 3rd-Party firm as well, presumably the same one responsible for the equipment maintenance, this staffing cost estimate includes an additional 10% margin on top of the normal operator costs to account for the 3rd-Party firm mark-up. Therefore, the total annual O&M expense for Option #1 is estimated to be $460,867. A table listing the maintenance rates for the equipment under discussion in Option #1 as well as the estimated staff salaries is presented in the Appendix of this report.

The capital cost associated with Option #1 was calculated by SourceOne based upon industry standard estimates of the unit costs associated with procuring and installing low pressure steam boilers, electric chillers, switchboards, cooling towers, plate-and-frame heat exchangers, control valves, distributed control systems, and chilled/condenser water piping in the State of Connecticut. The unit costs were adjusted to account for the proposed installation site of the equipment in the CT Boiler House. The unit costs are also dependent upon the required production capabilities of the equipment. Based upon all of these factors, SourceOne was able to estimate a capital cost of $17,208,738 for Option #1. Also, it should be noted that these capital costs are calculated assuming an upfront payment of the full balance. If the central plant was to be financed over the course of several years, which is currently the plan with an assumption of a 20-year loan term and 3.5% interest rate, the actual capital cost would be greater and dependent upon the loan term and finance rate. The Appendix of this report contains SourceOne's capital cost analysis. Additionally, SourceOne presents a simple annuity calculation that shows what the monthly payments would be for the central plant if it was financed over the course of 20 years at an interest rate of 3.5%. The result is a monthly finance payment of $100,902.

Table 11 below summarizes the results of the financial analysis for Option #1. As can be seen there, the result is a simple payback of 6.31 years for the central plant.

Annual Electricity Expense for 470 Capitol Ave Complex	Annual Natural Gas Expense	Annual Water Expense (Local Utility + Chemical Treatment)	Annual O&M Expense	Total Annual Expenditures	Capital Cost	Annual Expenditure Savings Over Base Case	Annual NEISO Capacity Sales ($2.91/kw/ month)	Additional Capital Expenditure Over Base Case	DPUC Incentive/ Rebate ($250/kW for CHP & $300/ton for Gas Chillers)	Simple Payback (Years)
Base Case - CDECCA Contract										
- Power: Electricity from Utility - Heating: Hot Water from Pump House Steam HX's that are fed by High-Pressure Steam Boilers in CDECCA Plant - Cooling: Chilled Water from CDECCA Electric and Steam Absorption Chillers										
$1,666,955	$0	$0	$4,899,417	$6,566,372	$0	$0	$0	N/A	$0	N/A
Option #1 - Electric Chillers										
- Power: Electricity from Utility - Heating: Hot Water from Central Plant Steam HX's that are fed by Low-Pressure Steam Boilers - Cooling: Chilled Water from Central Plant Electric Chillers and Free Cooling Plate-and-Frame Heat Exchanger										
$2,515,065	$771,406	$91,924	$460,867	$3,839,262	$17,208,738	$2,727,110	$0	$17,208,738	$0	6.31

Table 11: Option #1 Financial Summary

<u>Option #2 – Steam Boilers and Natural Gas Direct Fired Chillers</u>

The load profile analysis for Option #2 determined that there would be approximately 13,136,625 kWhs of electricity that would have to be purchased annually from CL&P under their LGS (Large General Service) tariff rate. Based upon the monthly distribution of the aforementioned 13,136,625 kWhs of electricity over the course of the year, as well as the rates listed in CL&P's tariff, SourceOne estimated that the annual electricity expense would be $1,781,622 A table listing the monthly on-peak and off-peak electric consumption as well as peak demand and charges is presented in the Appendix of this report.

In regards to the annual natural gas expense, SourceOne determined that based upon the load profile analysis for Option #2 the facility would have to purchase 157,703 decatherms of natural gas over the course of a year. This required volume of gas is based upon the heat rate and efficiency of the Cleaver Brooks boiler as well as the EcoChill natural gas direct fired chiller specified for this option. For the financial analysis it was assumed that the supply, transmission, and distribution charges for the natural gas would be issued by CNG under their LGS (Large General Service) tariff rate. Based upon the monthly distribution of the aforementioned 157,703 decatherms of natural gas over the course of a year, as well as the CNG rate structure, SourceOne estimated that the annual natural gas expense would be $1,214,585. A table listing the monthly natural gas consumption as well as the peak day demand and charges is presented in the Appendix of this report.

In reference to the annual water and chemical treatment expense, SourceOne determined that based upon the load profile analysis for Option #2 the facility would have to purchase 17,188,576 gallons of make-up water. This required volume is based upon the industry standard estimate of 5% losses in the feedwater, steam, and condensate recovery distribution and recirculation systems as well as 2.5 gallons per ton-hr for the condenser water make-up system. For the financial analysis a unit cost for water was developed that was based upon The Metropolitan District (MDC) water rates as well as typical industry standard estimates for chemical treatment. Using the unit cost rate in conjunction with the annual requirement for make-up water, SourceOne estimated the annual cost of water and chemical treatment to be $91,924.

The O&M expense for Option #2 centers on the cost to operate and maintain the new central plant steam boilers, natural gas direct fired chillers, "free cooling" heat exchanger, and cooling towers as well as the existing equipment in the Pump House. For each one of these major pieces of equipment there are industry standard and manufacture recommended maintenance rates that are based upon average run-hours, loading, operating environment, required preventative maintenance, and the normal wear-and-tear associated with the equipment component parts. These maintenance rates include the costs associated with maintaining the balance of plant (BOP) and auxiliary equipment as well. Based upon the size of the equipment specified in SourceOne's model as well as these industry standard rates, the annual maintenance expenses associated with the equipment alone are estimated to be $418,201 for Option #2. This includes the maintenance costs associated with the Pump House equipment and the "free cooling" heat exchanger. The State of Connecticut DPW indicated that they would prefer to sub-contract the equipment maintenance to a 3rd-Party firm. As such, SourceOne added an additional 10% margin on top of the maintenance costs to account for the 3rd-Party firm mark-up. Since the boilers being specified are low pressure steam boilers, the State of Connecticut will not need to staff the central plant with a 24X7 operations crew. The central plant will be highly automated and for the most part will not require manual operator intervention. As such, the State of Connecticut DPW is currently estimating that they will only need an operator at the plant for approximately 4 hours per day to conduct routine rounds in the facility and ensure that the plant is operating normally with no significant alarms present or equipment deficiencies. We are currently assuming that the Director of Capitol Area System (CAS) will operate as the Plant Manager, so there will be no additional expense associated with hiring a plant manager. Since the maintenance activities will be sub-contracted to a 3rd-Party firm, the State of Connecticut will not have to hire any mechanics, electricians, or instrumentation & controls technicians for the central plant. Therefore, SourceOne estimates that the staffing costs will be limited to the part-time operator. SourceOne is estimating this cost to be \$61,600 per year. Since the State of Connecticut DPW indicated that they would prefer to sub-contract the equipment operation to a 3rd-Party firm as well, presumably the same one responsible for the equipment maintenance, this staffing cost estimate includes an additional 10% margin on top of the normal operator costs to account for the 3rd-Party firm mark-up. Therefore, the total annual O&M expense for Option #2 is estimated to be \$479,801. A table listing the maintenance rates for the equipment under discussion in Option #2 as well as the estimated staff salaries is presented in the Appendix of this report.

The capital cost associated with Option #2 was calculated by SourceOne based upon industry standard estimates of the unit costs associated with procuring and installing low pressure steam boilers, natural gas direct fired chillers, switchboards, cooling towers, plate-and-frame heat exchangers, distributed control systems, and chilled/condenser water piping in the State of Connecticut. The unit costs were adjusted to account for the proposed installation site of the equipment in the CT Boiler House. The unit costs are also dependent upon the required production capabilities of the equipment. Based upon all of these factors, SourceOne was able to estimate a capital cost of \$21,379,159 for Option #2. Also, it should be noted that these capital costs are calculated assuming an upfront payment of the full balance. If the central plant was to be financed over the course of several years, which is currently the plan with an assumption of a 20-year loan term and 3.5% interest rate, the actual capital cost would be greater and dependent upon the loan term and finance rate. The Appendix of this report contains SourceOne's capital cost analysis. Additionally, SourceOne presents a simple annuity calculation that shows what the monthly payments would be for the central plant if it was financed over the course of 20 years at an interest rate of 3.5%. The result is a monthly finance payment of \$125,355.

Table 12 below summarizes the results of the financial analysis for Option #2. As can be seen there, the result is a simple payback of 6.59 years for the central plant. The simple payback for Option #2 is worse than that of Option #1 because the equipment price of a natural gas direct fired chiller is actually three times that of an electric centrifugal chiller of the same size. This additional capital cost offsets the cost savings from the procurement of natural gas for the chillers as opposed to electricity.

Annual Electricity Expense for 470 Capitol Ave Complex	Annual Natural Gas Expense	Annual Water Expense (Local Utility + Chemical Treatment)	Annual O&M Expense	Total Annual Expenditures	Capital Cost	Annual Expenditure Savings Over Base Case	Annual NEISO Capacity Sales (\$2.91/kw/ month)	Additional Capital Expenditure Over Base Case	DPUC Incentive/ Rebate (\$250/kW for CHP & \$300/ton for Gas Chillers)	Simple Payback (Years)
Base Case - CDECCA Contract - Power: Electricity from Utility - Heating: Hot Water from Pump House Steam HX's that are fed by High-Pressure Steam Boilers in CDECCA Plant - Cooling: Chilled Water from CDECCA Electric and Steam Absorption Chillers										
\$1,666,955	\$0	\$0	\$4,899,417	\$6,566,372	\$0	\$0	\$0	N/A	\$0	N/A
Option #2 - Natural Gas Fired Chillers - Power: Electricity from Utility - Heating: Hot Water from Central Plant Steam HX's that are fed by Low-Pressure Steam Boilers - Cooling: Chilled Water from Central Plant Natural Gas Fired Chillers and Free Cooling Plate-and-Frame Heat Exchanger										
\$1,781,622	\$1,214,585	\$91,924	\$479,801	\$3,567,931	\$21,379,159	\$2,998,441	\$0	\$21,379,159	\$1,620,000	6.59

Table 12: Option #2 Financial Summary

It should be noted that the Connecticut Department of Public Utility Control (DPUC) is currently offering an incentive for natural gas driven chiller installations. Currently the incentive is set at \$300/ton with no cap on the maximum allowable incentive per project. With this being the case, the proposed central plant in Option #2 would be eligible for a \$1,620,000 incentive rebate. With this being the case, there is the chance that the actual capital costs for the plant could be reduced to \$19,759,159.

<u>Option #3 – Trigeneration Plant with a Reciprocating Engine</u>

The load profile analysis for Option #3 determined that there would be approximately 8,914,498 kWhs of electricity that would have to be purchased annually from CL&P under their LGS (Large General Service) Distributed Generation (DG) Rider tariff rate. Based upon the monthly distribution of the aforementioned 8,914,498 kWhs of electricity over the course of the year, as well as the rates listed in CL&P's DG Rider tariff, SourceOne estimated that the annual electricity expense would be \$1,517,424. A table listing the monthly on-peak and off-peak electric consumption as well as peak demand and charges is presented in the Appendix of this report.

In regards to the annual natural gas expense, SourceOne determined that based upon the load profile analysis for Option #3 the facility would have to purchase 175,619 decatherms of natural gas over the course of a year. This required volume of gas is based upon the heat rate and efficiency of the Cleaver Brooks boiler as well as the Jenbacher 320 reciprocating engine specified for this option. For the financial analysis it was assumed that the supply, transmission, and distribution charges for the natural gas would be issued by CNG under their LGS (Large General Service) Distributed Generation Rebate Rider (Rider DG) tariff rate. Based upon the monthly distribution of the aforementioned 175,619 decatherms of natural gas over the course of a year, as well as the CNG rate structure, SourceOne estimated that the annual natural gas expense would be \$1,207,871. A table listing the monthly natural gas consumption as well as the peak day demand and charges is presented in the Appendix of this report.

In reference to the annual water and chemical treatment expense, SourceOne determined that based upon the load profile analysis for Option #3 the facility would have to purchase 17,236,959 gallons of make-up water. This required volume is based upon the industry standard estimate of 5% losses in the feedwater, steam, and condensate recovery distribution and recirculation systems as well as 2.5 gallons per ton-hr for the condenser water make-up system. For the financial analysis a unit cost for water was developed that was based upon The Metropolitan District (MDC) water rates as well as typical industry standard estimates for chemical treatment. Using the unit cost rate in conjunction with the annual requirement for make-up water, SourceOne estimated the annual cost of water and chemical treatment to be \$92,182.

The O&M expense for Option #3 centers on the cost to operate and maintain the new central plant steam boilers, electric chillers, plate-and-frame heat exchanger, control valves, and cooling towers as well as the existing equipment in the Pump House and the new trigeneration plant equipment (reciprocating engine, HRSG, hot water absorption chiller, single-stage low-pressure steam absorption chiller). For each one of these major pieces of equipment there are industry standard and manufacture recommended maintenance rates that are based upon average run-hours, loading, operating environment, required preventative maintenance, and the normal wear-and-tear associated with the equipment component parts. These maintenance rates include the costs associated with maintaining the balance of plant (BOP) and auxiliary equipment as well. Based upon the size of the equipment specified in SourceOne's model as well as these industry standard rates, the annual maintenance expenses associated with the equipment alone are estimated to be $548,756 for Option #3. This includes the maintenance costs associated with the Pump House equipment and the "free cooling" heat exchanger. The State of Connecticut DPW indicated that they would prefer to sub-contract the equipment maintenance to a 3rd-Party firm. As such, SourceOne added an additional 10% margin on top of the maintenance costs to account for the 3rd-Party firm mark-up. Since the boilers and HRSG being specified produce low pressure steam, the State of Connecticut will not need to staff the central plant with a 24X7 operations crew. The central plant will be highly automated and for the most part will not require manual operator intervention. As such, the State of Connecticut DPW is currently estimating that they will only need an operator at the plant for approximately 4 hours per day to conduct routine rounds in the facility and ensure that the plant is operating normally with no significant alarms present or equipment deficiencies. We are currently assuming that the Director of Capitol Area System (CAS) will operate as the Plant Manager, so there will be no additional expense associated with hiring a plant manager. Since the maintenance activities will be sub-contracted to a 3rd-Party firm, the State of Connecticut will not have to hire any mechanics, electricians, or instrumentation & controls technicians for the central plant. Therefore, SourceOne estimates that the staffing costs will be limited to the part-time operator. SourceOne is estimating this cost to be $61,600 per year. Since the State of Connecticut DPW indicated that they would prefer to sub-contract the equipment operation to a 3rd-Party firm as well, presumably the same one responsible for the equipment maintenance, this staffing cost estimate includes an additional 10% margin on top of the normal operator costs to account for the 3rd-Party firm mark-up. Therefore, the total annual O&M expense for Option #3 is estimated to be $610,356. A table listing the maintenance rates for the equipment under discussion in Option #3 as well as the estimated staff salaries is presented in the Appendix of this report.

The capital cost associated with Option #3 was calculated by SourceOne based upon industry standard estimates of the unit costs associated with procuring and installing low pressure steam boilers, electric centrifugal chillers, switchboards, cooling towers, reciprocating engines, HRSG's, absorption chillers, plate-and-frame heat exchangers, distributed control systems, and chilled/condenser water piping in the State of Connecticut. The unit costs were adjusted to account for the proposed installation site for the steam boilers and electric chillers in the CT Boiler House as well as for the new enclosure that would have to be built for the trigeneration plant. The unit costs are also dependent upon the required production capabilities of the equipment. Based upon all of these factors, SourceOne was able to estimate a capital cost of $21,111,784 for Option #3. Also, it should be noted that these capital costs are calculated assuming an upfront payment of the full balance. If the central plant was to be financed over the course of several years, which is currently the plan with an assumption of a 20-year loan term and 3.5% interest rate, the actual capital cost would be greater and dependent upon the loan term and finance rate. The Appendix of this report contains SourceOne's capital cost analysis. Additionally, SourceOne presents a simple annuity calculation that shows what the monthly payments would be for the central plant if it was financed over the course of 20 years at an interest rate of 3.5%. The result is a monthly finance payment of $123,787.

Table 13 below summarizes the results of the financial analysis for Option #3. As seen there, the result is a simple payback of 6.56 years for the central plant, which includes the trigeneration plant.

Annual Electricity Expense for 470 Capitol Ave Complex	Annual Natural Gas Expense	Annual Water Expense (Local Utility + Chemical Treatment)	Annual O&M Expense	Total Annual Expenditures	Capital Cost	Annual Expenditure Savings Over Base Case	Annual NEISO Capacity Sales ($2.91/kw/ month)	Additional Capital Expenditure Over Base Case	DPUC Incentive/ Rebate ($250/kW for CHP & $300/ton for Gas Chillers)	Simple Payback (Years)
Base Case - CDECCA Contract **- Power: Electricity from Utility** **- Heating: Hot Water from Pump House Steam HX's that are fed by High-Pressure Steam Boilers in CDECCA Plant** **- Cooling: Chilled Water from CDECCA Electric and Steam Absorption Chillers**										
$1,666,955	$0	$0	$4,899,417	$6,566,372	$0	$0	$0	N/A	$0	N/A
Option #3 - Trigeneration Plant with Reciprocating Engine **- Power: Electricity from 1,059 kW Jenbacher 620 Reciprocating Engines (Utility Back-Up)** **- Heating: Hot Water from Central Plant Steam HX's that are fed by 2,000 lb/hr Low-Pressure HRSG (Central Plant Low-Pressure Steam Boiler Back-Up)** **- Cooling: Chilled Water from 75 ton Hot Water Absorption Chiller and 120 ton Single-Stage Steam Absorption Chiller (Central Plant Free Cooling Complement and Electric Chiller Back-Up)**										
$1,517,424	$1,207,871	$92,182	$610,356	$3,427,834	$21,111,784	$3,138,538	$36,980	$21,111,784	$264,750	6.56

Table 13: Option #3 Financial Summary

It should be noted that the Connecticut Department of Public Utility Control (DPUC) is currently offering an incentive for CHP plant installations. Although the revised numbers have not been completely approved within the DPUC, it is believed that the current incentive level will decrease from $500/kW to $250/kW. With this being the case, the proposed trigeneration plant in Option #3 would be eligible for a $264,750 incentive rebate. With this being the case, there is the chance that the actual capital costs for the plant could be reduced to $20,847,034.

Also, as an electricity producing entity, the State of Connecticut would be eligible for capacity payments from the New England Independent System Operator since the electricity produced by the reciprocating engine in Option #3 will reduce the utility grid load demands and required installed capacity. Currently, those capacity payments are equal to $3.64/kW/month (installed capacity). SourceOne is assuming that the State of Connecticut will need a 3rd party form to file all of the appropriate paperwork on a monthly basis, so we estimated that the State of Connecticut will have to pay that contract administrator 20% of the capacity sales. Therefore, the State of Connecticut would be eligible for $2.91/kw/month or $36,980 in revenue from the trigeneration plant.

Option #4 – Trigeneration Plant with a Gas Turbine

The load profile analysis for Option #4 determined that there would be approximately 7,181,693 kWhs of electricity that would have to be purchased annually from CL&P under their LGS (Large General Service) Distributed Generation (DG) Rider tariff rate. Based upon the monthly distribution of the aforementioned 7,181,693 kWhs of electricity over the course of the year, as well as the rates listed in CL&P's DG Rider tariff, SourceOne estimated that the annual electricity expense would be $1,334,629. A table listing the monthly on-peak and off-peak electric consumption as well as peak demand and charges is presented in the Appendix of this report.

In regards to the annual natural gas expense, SourceOne determined that based upon the load profile analysis for Option #4 the facility would have to purchase 201,684 decatherms of natural gas over the course of a year. This required volume of gas is based upon the heat rate and efficiency of the Cleaver Brooks boiler as well as the Solar Saturn 20 gas turbine specified for this option. The Solar Saturn 20 gas turbine has a nominal higher heating value of 15,602 BTU/kWh. This is substantially more than the heat rate of the Jenbacher 320 reciprocating engine, which is 9,949 BTU/kWh. This means that the amount of gas required to produce each kWh of electricity using a gas turbine is greater than that associated with its production via a reciprocating engine. This also means, however, that the recoverable energy from the flue gas stream of a gas turbine is much greater than that of a reciprocating engine. For the financial analysis it was assumed that the supply, transmission, and distribution charges for the natural gas would be issued by CNG under their LGS (Large General Service) Distributed Generation Rebate Rider (Rider DG) tariff rate. Based upon the monthly distribution of the aforementioned 201,684 decatherms of natural gas over the course of a year, as well as the CNG rate structure, SourceOne estimated that the annual natural gas expense would be $1,387,140. A table listing the monthly natural gas consumption as well as the peak day demand and charges is presented in the Appendix of this report.

In reference to the annual water and chemical treatment expense, SourceOne determined that based upon the load profile analysis for Option #4 the facility would have to purchase 17,361,837 gallons of make-up water. This required volume is based upon the industry standard estimate of 5% losses in the feedwater, steam, and condensate recovery distribution and recirculation systems as well as 2.5 gallons per ton-hr for the condenser water make-up system. For the financial analysis a unit cost for water was developed that was based upon The Metropolitan District (MDC) water rates as well as typical industry standard estimates for chemical treatment. Using the unit cost rate in conjunction with the annual requirement for make-up water, SourceOne estimated the annual cost of water and chemical treatment to be $92,850.

The O&M expense for Option #4 centers on the cost to operate and maintain the new central plant steam boilers, electric chillers, plate-and-frame heat exchanger, control valves, and cooling towers as well as the existing equipment in the Pump House and the new trigeneration plant equipment (gas turbine/combustion turbine generator, HRSG, single-stage low pressure steam absorption chiller). For each one of these major pieces of equipment there are industry standard and manufacture recommended maintenance rates that are based upon average run-hours, loading, operating environment, required preventative maintenance, and the normal wear-and-tear associated with the equipment component parts. These maintenance rates include the costs associated with maintaining the balance of plant (BOP) and auxiliary equipment as well. Based upon the size of the equipment specified in SourceOne's model as well as these industry standard rates, the annual maintenance expenses associated with the equipment alone are estimated to be $564,119 for Option #4. This includes the maintenance costs associated with the Pump House equipment and the "free cooling" heat exchanger. The State of Connecticut DPW indicated that they would prefer to sub-contract the equipment maintenance to a 3rd-Party firm. As such, SourceOne added an additional 10% margin on top of the maintenance costs to account for the 3rd-Party firm mark-up. Since the boilers and HRSG being specified produce low pressure steam, the State of Connecticut will not need to staff the central plant with a 24X7 operations crew. The central plant will be highly automated and for the most part will not require manual operator intervention. As such, the State of Connecticut DPW is currently estimating that they will only need an operator at the plant for approximately 4 hours per day to conduct routine rounds in the facility and ensure that the plant is operating normally with no significant alarms present or equipment deficiencies. We are currently assuming that the Director of Capitol Area System (CAS) will operate as the Plant Manager, so there will be no additional expense associated with hiring a plant manager. Since the maintenance activities will be sub-contracted to a 3rd-Party firm, the State of Connecticut will not have to hire any mechanics, electricians, or instrumentation & controls technicians for the central plant. Therefore, SourceOne estimates that the staffing costs will be limited to the part-time operator. SourceOne is estimating this cost to be $61,600 per year. Since the State of Connecticut DPW indicated that they would prefer to sub-contract the equipment operation to a 3rd-Party firm as well, presumably the same one responsible for the equipment maintenance, this staffing cost estimate includes an additional 10% margin on top of the normal operator costs to account for the 3rd-Party firm mark-up. Therefore, the total annual O&M expense for Option #4 is estimated to be $625,719. A table listing the maintenance rates for the equipment under discussion in Option #4 as well as the estimated staff salaries is presented in the Appendix of this report.

The capital cost associated with Option #4 was calculated by SourceOne based upon industry standard estimates of the unit costs associated with procuring and installing low pressure steam boilers, electric centrifugal chillers, switchboards, plate-and-frame heat exchangers, control valves, cooling towers, gas turbines/combustion turbine generators, HRSG's, absorption chillers, distributed control systems, and chilled/condenser water piping in the State of Connecticut. The unit costs were adjusted to account for the proposed installation site for the steam boilers and electric chillers in the CT Boiler House as well as for the new enclosure that would have to be built for the trigeneration plant. The unit costs are also dependent upon the required production capabilities of the equipment. Based upon all of these factors, SourceOne was able to estimate a capital cost of $20,292,197 for Option #4. Also, it should be noted that these capital costs are calculated assuming an upfront payment of the full balance. If the central plant was to be financed over the course of several years, which is currently the plan with an assumption of a 20-year loan term and 3.5% interest rate, the actual capital cost would be greater and dependent upon the loan term and finance rate. The Appendix of this report contains SourceOne's capital cost analysis. Additionally, SourceOne presents a simple annuity calculation that shows what the monthly payments would be for the central plant if it was financed over the course of 20 years at an interest rate of 3.5%. The result is a monthly finance payment of $118,982.

Table 14 below summarizes the results of the financial analysis for Option #4. As can be seen there, the result is a simple payback of 6.31 years for the central plant, which includes the trigeneration plant.

Annual Electricity Expense for 470 Capitol Ave Complex	Annual Natural Gas Expense	Annual Water Expense (Local Utility + Chemical Treatment)	Annual O&M Expense	Total Annual Expenditures	Capital Cost	Annual Expenditure Savings Over Base Case	Annual NEISO Capacity Sales ($2.91/kw/ month)	Additional Capital Expenditure Over Base Case	DPUC Incentive/ Rebate ($250/kW for CHP & $300/ton for Gas Chillers)	Simple Payback (Years)
Base Case - CDECCA Contract - Power: Electricity from Utility - Heating: Hot Water from Pump House Steam HX's that are fed by High-Pressure Steam Boilers in CDECCA Plant - Cooling: Chilled Water from CDECCA Electric and Steam Absorption Chillers										
$1,666,955	$0	$0	$4,899,417	$6,566,372	$0	$0	$0	N/A	$0	N/A
Option #4 - Trigeneration Plant with Gas Turbine - Power: Electricity from 1,210 kW Solar Saturn 20 Combustion Turbine Generator (Utility Back-Up) - Heating: Hot Water from Central Plant Steam HX's that are fed by 8,100 lb/hr Low-Pressure HRSG (Central Plant Low-Pressure Steam Boiler Back-Up) - Cooling: Chilled Water from 493 ton Single-Stage Steam Absorption Chiller (Central Plant Free Cooling Complement and Electric Chiller Back-Up)										
$1,334,629	$1,387,140	$92,850	$625,719	$3,440,337	$20,292,197	$3,126,035	$42,253	$20,292,197	$302,500	6.31

Table 14: Option #4 Financial Summary

It should be noted that the Connecticut Department of Public Utility Control (DPUC) is currently offering an incentive for CHP plant installations. Although the revised numbers have not been completely approved within the DPUC, it is believed that the current incentive level will decrease from $500/kW to $250/kW. With this being the case, the proposed trigeneration plant in Option #4 would be eligible for a $302,500 incentive rebate. With this being the case, there is the chance that the actual capital costs for the plant could be reduced to $19,989,697.

Also, as an electricity producing entity, the State of Connecticut would be eligible for capacity payments from the New England Independent System Operator since the electricity produced by the combustion turbine generator in Option #4 will reduce the utility grid load demands and required installed capacity. Currently, those capacity payments are equal to $3.64/kW/month (installed capacity). SourceOne is assuming that the State of Connecticut will need a 3rd party form to file all of the appropriate paperwork on a monthly basis, so we estimated that the State of Connecticut will have to pay that contract administrator 20% of the capacity sales. Therefore, the State of Connecticut would be eligible for $2.91/kw/month or $42,253 in revenue from the trigeneration plant.

<u>Option #5 – Trigeneration Plant with MicroTurbines</u>

The load profile analysis for Option #5 determined that there would be approximately 14,548,868 kWhs of electricity that would have to be purchased annually from CL&P under their LGS (Large General Service) Distributed Generation (DG) Rider tariff rate. Based upon the monthly distribution of the aforementioned 14,548,868 kWhs of electricity over the course of the year, as well as the rates listed in CL&P's DG Rider tariff, SourceOne estimated that the annual electricity expense would be $2,127,254. A table listing the monthly on-peak and off-peak electric consumption as well as peak demand and charges is presented in the Appendix of this report.

In regards to the annual natural gas expense, SourceOne determined that based upon the load profile analysis for Option #5 the facility would have to purchase 118,278 decatherms of natural gas over the course of a year. This required volume of gas is based upon the heat rate and efficiency of the Cleaver Brooks boiler as well as the Capstone C200 MicroTurbine specified for this option. The Capstone C200 MicroTurbine has a nominal higher heating value of 11,400 BTU/kWh. This is substantially less than the heat rate of the Solar Saturn 20 gas turbine, which is 15,602 BTU/kWh. This means that the amount of gas required to produce each kWh of electricity using a MicroTurbine is less than that associated with its production via a gas turbine. This also means, however, that the recoverable energy from the flue gas stream of a gas turbine is much greater than that of a MicroTurbine. For the financial analysis it was assumed that the supply, transmission, and distribution charges for the natural gas would be issued by CNG under their LGS (Large General Service) Distributed Generation Rebate Rider (Rider DG) tariff rate. Based upon the monthly distribution of the aforementioned 118,278 decatherms of natural gas over the course of a year, as well as the CNG rate structure, SourceOne estimated that the annual natural gas expense would be $813,493. A table listing the monthly natural gas consumption as well as the peak day demand and charges is presented in the Appendix of this report.

In reference to the annual water and chemical treatment expense, SourceOne determined that based upon the load profile analysis for Option #5 the facility would have to purchase 17,210,316 gallons of make-up water. This required volume is based upon the industry standard estimate of 5% losses in the feedwater, steam, and condensate recovery distribution and recirculation systems as well as 2.5 gallons per ton-hr for the condenser water make-up system. For the financial analysis a unit cost for water was developed that was based upon The Metropolitan District (MDC) water rates as well as typical industry standard estimates for chemical treatment. Using the unit cost rate in conjunction with the annual requirement for make-up water, SourceOne estimated the annual cost of water and chemical treatment to be $92,040.

The O&M expense for Option #5 centers on the cost to operate and maintain the new central plant steam boilers, electric chillers, plate-and-frame heat exchanger, control valves, and cooling towers as well as the existing equipment in the Pump House and the new trigeneration plant equipment (MicroTurbines, HRSG's, single-stage low pressure steam absorption chiller). For each one of these major pieces of equipment there are industry standard and manufacture recommended maintenance rates that are based upon average run-hours, loading, operating environment, required preventative maintenance, and the normal wear-and-tear associated with the equipment component parts. These maintenance rates include the costs associated with maintaining the balance of plant (BOP) and auxiliary equipment as well. Based upon the size of the equipment specified in SourceOne's model as well as these industry standard rates, the annual maintenance expenses associated with the equipment alone are estimated to be $453,453 for Option #5. This includes the maintenance costs associated with the Pump House equipment and the "free cooling" heat exchanger. The State of Connecticut DPW indicated that they would prefer to sub-contract the equipment maintenance to a 3rd-Party firm. As such, SourceOne added an additional 10% margin on top of the maintenance costs to account for the 3rd-Party firm mark-up. Since the boilers and HRSG being specified produce low pressure steam, the State of Connecticut will not need to staff the central plant with a 24X7 operations crew. The central plant will be highly automated and for the most part will not require manual operator intervention. As such, the State of Connecticut DPW is currently estimating that they will only need an operator at the plant for approximately 4 hours per day to conduct routine rounds in the facility and ensure that the plant is operating normally with no significant alarms present or equipment deficiencies. We are currently assuming that the Director of Capitol Area System (CAS) will operate as the Plant Manager, so there will be no additional expense associated with hiring a plant manager. Since the maintenance activities will be sub-contracted to a 3rd-Party firm, the State of Connecticut will not have to hire any mechanics, electricians, or instrumentation & controls technicians for the central plant. Therefore, SourceOne estimates that the staffing costs will be limited to the part-time operator. SourceOne is estimating this cost to be $61,600 per year. Since the State of Connecticut DPW indicated that they would prefer to sub-contract the equipment operation to a 3rd-Party firm as well, presumably the same one responsible for the equipment maintenance, this staffing cost estimate includes an additional 10% margin on top of the normal operator costs to account for the 3rd-Party firm mark-up. Therefore, the total annual O&M expense for Option #5 is estimated to be $515,053. A table listing the maintenance rates for the equipment under discussion in Option #5 as well as the estimated staff salaries is presented in the Appendix of this report.

The capital cost associated with Option #5 was calculated by SourceOne based upon industry standard estimates of the unit costs associated with procuring and installing low pressure steam boilers, electric centrifugal chillers, switchboards, plate-and-frame heat exchangers, control valves, cooling towers, MicroTurbines, HRSG's, absorption chillers, distributed control systems, and chilled/condenser water piping in the State of Connecticut. The unit costs were adjusted to account for the proposed installation site for the steam boilers and electric chillers in the CT Boiler House as well as for the new enclosure that would have to be built for the trigeneration plant. The unit costs are also dependent upon the required production capabilities of the equipment. Based upon all of these factors, SourceOne was able to estimate a capital cost of $20,102,983 for Option #5. The capital cost for Option #5 is similar to that of Option #4 because on a cost per unit basis ($/kW) the cost of a MicroTurbine is 50% greater than that of a traditional gas turbine. Also, it should be noted that these capital costs are calculated assuming an upfront payment of the full balance. If the central plant was to be financed over the course of several years, which is currently the plan with an assumption of a 20-year loan term and 3.5% interest rate, the actual capital cost would be greater and dependent upon the loan term and finance rate. The Appendix of this report contains SourceOne's capital cost analysis. Additionally, SourceOne presents a simple annuity calculation that shows what the monthly payments would be for the central plant if it was financed over the course of 20 years at an interest rate of 3.5%. The result is a monthly finance payment of $117,872.

Table 15 below summarizes the results of the financial analysis for Option #5. As can be seen there, the result is a simple payback of 6.60 years for the central plant, which includes the trigeneration plant.

Annual Electricity Expense for 470 Capitol Ave Complex	Annual Natural Gas Expense	Annual Water Expense (Local Utility + Chemical Treatment)	Annual O&M Expense	Total Annual Expenditures	Capital Cost	Annual Expenditure Savings Over Base Case	Annual NEISO Capacity Sales ($2.91/kw/ month)	Additional Capital Expenditure Over Base Case	DPUC Incentive/ Rebate ($250/kW for CHP & $300/ton for Gas Chillers)	Simple Payback (Years)
Base Case - CDECCA Contract - Power: Electricity from Utility - Heating: Hot Water from Pump House Steam HX's that are fed by High-Pressure Steam Boilers in CDECCA Plant - Cooling: Chilled Water from CDECCA Electric and Steam Absorption Chillers										
$1,666,955	$0	$0	$4,899,417	$6,566,372	$0	$0	$0	N/A	$0	N/A
Option #5 - Trigeneration Plant with MicroTurbine - Power: Electricity from two (2) 200 kW Capstone C200 MicroTurbines (Utility Back-Up) - Heating: Hot Water from Central Plant Steam HX's that are fed by two (2) 1,080 lb/hr Low-Pressure HRSG's (Central Plant Low-Pressure Steam Boiler Back-Up) - Cooling: Chilled Water from 132 ton Single-Stage Steam Absorption Chiller (Central Plant Free Cooling Complement and Electric Chiller Back-Up)										
$2,127,254	$813,493	$92,040	$515,053	$3,547,839	$20,102,983	$3,018,533	$13,968	$20,102,983	$100,000	6.60

Table 15: Option #5 Financial Summary

It should be noted that the Connecticut Department of Public Utility Control (DPUC) is currently offering an incentive for CHP plant installations. Although the revised numbers have not been completely approved within the DPUC, it is believed that the current incentive level will decrease from $500/kW to $250/kW. With this being the case, the proposed trigeneration plant in Option #5 would be eligible for a $100,000 incentive rebate. With this being the case, there is the chance that the actual capital costs for the plant could be reduced to $20,002,983.

Also, as an electricity producing entity, the State of Connecticut would be eligible for capacity payments from the New England Independent System Operator since the electricity produced by the MicroTurbines in Option #5 will reduce the utility grid load demands and required installed capacity. Currently, those capacity payments are equal to $3.64/kW/month (installed capacity). SourceOne is assuming that the State of Connecticut will need a 3rd party form to file all of the appropriate paperwork on a monthly basis, so we estimated that the State of Connecticut will have to pay that contract administrator 20% of the capacity sales. Therefore, the State of Connecticut would be eligible for $2.91/kw/month or $13,968 in revenue from the trigeneration plant.

7. UTILITY INTERCONNECTIONS

This section will focus on the feasibility, technical challenges, and potential locations for the central plant's electric and natural gas utility interconnections.

Electric Interconnection

As previously discussed, in regards to the electrical output from the prime movers in the trigeneration plant options, the closest state-owned facilities to the Pump House would be the 470 Capitol Avenue complex of buildings, which is why their electric service would be the ideal one to tie into. Based upon the "High Voltage Supply One Line Diagram" supplied to SourceOne by the State of Connecticut DPW, which is shown in Figure 8 previously in this report, there appears to be ample loads on the main to support and consume the power from the proposed prime movers. A determination will have to be made in the next phase of design where exactly to make the interconnection. Ideally the interconnection could take place either on the 4160V or 480V side of the 2000kVA transformer serving the complex.

CL&P requires all customers planning to connect generation (>10kW) to the system to complete the application and approval process outlined in their "Guidelines for Generator Interconnection – Fast Track and Study Processes". The technical requirements are discussed in their supplemental document entitled "Exhibit B – Generator Interconnection Technical Requirements". Since SourceOne is not recommending one of trigeneration plant options, we will not discuss the two documents in detail in this report but they are included as part of the Appendix. The process is rather involved and the interconnection requirements stringent, so if the State of Connecticut does decide to move forward with one of the trigeneration plant options we would recommend that a DPW representative contact the Electric Distribution Company's (EDC's) Facilitator for CL&P in the Distributed Resources Group to review the proposed project with them.

Natural Gas Interconnection

In regards to the preferred option, which is Option #1, SourceOne does not foresee any natural gas interconnection issues. The existing three (3) auxiliary boilers in the CT Boiler House each have a rating of 5,000 lbs/hr and are natural gas-fired. Therefore, there is already a natural gas line entering the CT Boiler House from CNG's transmission/distribution main in the street. This existing CNG natural gas line may be utilized for the new boilers, though CNG will have to analyze if it can handle the required capacity and peak demand of the new low pressure steam boilers. If the State of Connecticut decides to go with Option #3, #4, or #5 however, than the existing natural gas line may not be sufficient in size or pressure. In regards to Option #2, the existing natural gas line should still be sufficient since the peak natural gas demand for the direct fired chillers does not coincide with the peak demand for the low pressure steam boilers. In fact, the peak daily demand under Option #2 is 917 decatherms, which happens to be identical to that under Option #1. In the case of Option #3, #4, and #5 the prime movers for the trigeneration plants will be operating at the same time as the low pressure steam boilers so the peak daily natural gas demand is significantly greater than that of

Option #1 (1,110 decatherms for Option #3; 1,136 decatherms for Option #4; 964 decatherms for Option #5). The end result is that the State of Connecticut may have to pay CNG to install a new, larger, natural gas line for the CT Boiler House. If the State of Connecticut wishes to pursue either Option #3, #4, or #5 SourceOne would recommend a meeting with CNG to review the monthly natural gas consumption and daily peak demand estimates so that CNG can review the capacity in their existing line as well as in the area adjacent to the CT Boiler House.

8. GHG AND AIR POLLUTANT EMISSIONS

The installation of any of the five central plant options will result in a modification to the overall attributable greenhouse gas (GHG) and air pollutant emission levels of the site.

GHG Emissions

The GHG production of the site, defined as the 470 Capitol Avenue Complex of buildings as well as the CT Boiler House and Pump House, is based upon the energy consumption of the site and is not dependent upon whether the energy consumed is produced on-site or off-site. Table 16 below presents the eGrid Conversion Factors for GHG emissions based upon the various types of energy or fuel consumed by a site in Connecticut.

eGrid Conversion Factors				
	lbs/kWh	GHG Factor	GHG Weighting	
CO2	827.95	1	827.95	lbs/MWh
Methane	0.07698	25	1.9245	lbs/MWh
N2O	0.0152	298	4.5296	lbs/MWh
Total for Electricity			834.4041	lbs/MWh
			379.27	kg/MWh
Total for District Steam			86.845	kg/Mlb
Total for Natural Gas			53.27	kg/MMBTU

Table 16: eGrid Conversion Factors for GHG Emissions in Connecticut

Using Table 16 above, SourceOne was able to estimate the current GHG production level for the State of Connecticut's 470 Capitol Avenue complex electrical service as well as their district hot and chilled water systems. The chilled water system greenhouse gas emissions are based upon the electricity consumed by the CDECCA electric chillers and auxiliary chilled water equipment as well as the natural gas consumed by the CDECCA auxiliary boilers providing steam to the absorption chillers. The hot water system greenhouse gas emissions are based upon the natural gas consumed by the auxiliary boilers providing steam to the hot water heat exchangers as well as the electricity consumed by the auxiliary hot water and steam equipment. The total estimated GHG production level under the base case is shown in Table 17 below.

	Energy Consumption	Unit	eGrid Conv Factor	Unit	GHG	Unit
Natural Gas	225,737	MMBTU	53.27	kg/MMBTU	12,025	Metric Tons
470 Capital Ave. Electricity	12,161	MWh	379.27	kg/MWh	4,612	Metric Tons
Hot and Chilled Water System Electricity	6,034	MWh	379.27	kg/MWh	2,289	Metric Tons
Total					**18,926**	Metric Tons

Table 17: Current GHG Production Level under CDECCA Contract

Tables 18, 19, 20, 21, and 22 present the revised GHG production levels for the site with each central plant option installed.

	Energy Consumption	Unit	eGrid Conv Factor	Unit	GHG	Unit
Natural Gas	99,750	MMBTU	53.27	kg/MMBTU	5,314	Metric Tons
470 Capital Ave. Electricity	17,894	MWh	379.27	kg/MWh	6,787	Metric Tons
Total					**12,100**	Metric Tons

Table 18: GHG Emission Level with Central Plant Option #1 (Electric Chillers) Installed

	Energy Consumption	Unit	eGrid Conv Factor	Unit	GHG	Unit
Natural Gas	157,703	MMBTU	53.27	kg/MMBTU	8,401	Metric Tons
470 Capital Ave. Electricity	13,137	MWh	379.27	kg/MWh	4,982	Metric Tons
Total					**13,383**	Metric Tons

Table 19: GHG Emission Level with Central Plant Option #2 (Gas Chillers) Installed

	Energy Consumption	Unit	eGrid Conv Factor	Unit	GHG	Unit
Natural Gas	175,619	MMBTU	53.27	kg/MMBTU	9,355	Metric Tons
470 Capital Ave. Electricity	8,914	MWh	379.27	kg/MWh	3,381	Metric Tons
Total					**12,736**	Metric Tons

Table 20: GHG Emission Level with Central Plant Option #3 (Recip CHP) Installed

	Energy Consumption	Unit	eGrid Conv Factor	Unit	GHG	Unit
Natural Gas	201,684	MMBTU	53.27	kg/MMBTU	10,744	Metric Tons
470 Capital Ave. Electricity	7,182	MWh	379.27	kg/MWh	2,724	Metric Tons
Total					**13,468**	Metric Tons

Table 21: GHG Emission Level with Central Plant Option #4 (GT CHP) Installed

	Energy Consumption	Unit	eGrid Conv Factor	Unit	GHG	Unit
Natural Gas	118,278	MMBTU	53.27	kg/MMBTU	6,301	Metric Tons
470 Capital Ave. Electricity	14,549	MWh	379.27	kg/MWh	5,518	Metric Tons
Total					**11,819**	Metric Tons

Table 22: GHG Emission Level with Central Plant Option #5 (MicroTurbine CHP) Installed

As can be seen from Tables 18, 19, 20, 21, and 22 the implementation of any of the five central plant options analyzed by SourceOne results in a ***net decrease*** in the GHG emission levels attributable to the site, which in this case is the 470 Capitol Avenue complex of buildings and the CAS CT Boiler House and Pump House. This is mainly due to the fact that the central plants proposed by SourceOne will have higher performance efficiencies than those currently being seen by the CDECCA plant.

Air Pollutant Emissions

The operation of the low pressure steam boilers, natural gas direct fired chillers, internal combustion reciprocating engine, combustion turbine generator set, or the MicroTurbines will result in the production and emission of air pollutants by the central plant. SourceOne analyzed the annual pollutant emission levels based upon the hourly production/loading levels for the equipment specified under Option #1, #2, #3, #4, and #5. Tables 23, 24, 25, 26, and 27 present summaries of the significant air pollutants as well as their annual emission levels for each of the proposed central plants.

Annual Boiler Air Contaminent Emissions		
NOx	**1.7**	tons
CO	**2.0**	tons
UHC	**0.2**	tons

Table 23: Central Plant Option #1 (Electric Chillers) Annual Air Contaminant Emission Levels

Annual Chiller Air Contaminent Emissions		
NOx	**0.2**	tons
CO	**0.1**	tons
UHC	**0.1**	tons
Annual Boiler Air Contaminent Emissions		
NOx	**1.7**	tons
CO	**2.0**	tons
UHC	**0.2**	tons

Table 24: Central Plant Option #2 (Gas Chillers) Annual Air Contaminant Emission Levels

Annual Jen 320 Air Contaminent Emissions		
NOx	**9.0**	tons
CO	**17.9**	tons
NMEHC	**9.0**	tons
Annual Boiler Air Contaminent Emissions		
NOx	**1.5**	tons
CO	**1.8**	tons
UHC	**0.2**	tons

Table 25: Central Plant Option #3 (Recip CHP) Annual Air Contaminant Emission Levels

Annual Saturn 20 Air Contaminent Emissions		
NOx	**22**	tons
CO	**11**	tons
UHC	**11**	tons
Annual Boiler Air Contaminent Emissions		
NOx	**0.9**	tons
CO	**1.0**	tons
UHC	**0.1**	tons

Table 26: Central Plant Option #4 (GT CHP) Annual Air Contaminant Emission Levels

Annual C200 Air Contaminent Emissions		
NOx	**0.7**	tons
CO	**0.3**	tons
UHC	**0.3**	tons

Annual Boiler Air Contaminent Emissions		
NOx	**1.4**	tons
CO	**1.6**	tons
UHC	**0.2**	tons

Table 27: Central Plant Option #5 (MicroTurbine CHP) Annual Air Contaminant Emission Levels

It should be noted that the air contaminant/pollution emission levels listed above for Option #3 and #4 do not assume or include the use of any SCR/Oxidation Catalysts on the reciprocating engine or gas turbine emission stacks. With the use of a SCR/Oxidation Catalyst the emission levels could be reduced by a factor of five.

9. REGULATORY EVALUATION

Currently the State of Connecticut DPW has a "General Permit" that allows them to operate the boilers in the various state-owned facilities on Capitol Avenue under a "Permit-by-Rule". This means that the boilers are not required to have individual permits but rather fall under the umbrella of the "Permit-by-Rule", which is valid for all emitting sources that emit less than 15 tons per year of any individual air pollutant (i.e. PD-2.5, PM-10, Sox, NOx, VOC, CO, Lead, and GHG). The "General Permit" for all of the facilities under the DPW's control is allowed as long as the boilers as a combined whole do not exceed 50 tons per year of any of the aforementioned pollutants or 100,000 tons per year of GHG (CO_2e basis). The City of Hartford is classified as a serious ozone non-attainment area, hence the 50 tons per year limit. If the city had been declared a severe ozone non-attainment area the limit would have been 25 tons per year.

In regards to the proposed central plants, as long as the individual boilers, natural gas direct fired chillers, HRSG's, reciprocating engine, gas turbine, or MicroTurbines produce less than 15 tons per year of any individual air pollutant they would be covered under the DPW's "Permit-by-Rule" and not require an individual equipment permit. As can be seen from Table 25 and 26, the proposed Jenbacher 320 reciprocating engine and Solar Saturn 20 gas turbine ***would*** require individual permits since their annual CO and NOx production levels would surpass the 15 ton limit. Even though the individual equipment permitting process is ministerial in nature, it can take between 4-6 months to obtain. The steam boilers, natural gas direct fired chillers, and MicroTurbines however, would be covered under the "Permit-by-Rule" and not require individual permits. Also, as long as their production levels do not put the DPW's summed total emission levels over the 50 tons per year limit, the installed boilers, natural gas direct fired chillers, and MicroTurbines would be covered under the existing "General Permit". The DPW would simply have to submit the permit revision paperwork, which would remove the existing CT Boiler House boilers from the "General Permit" and add the new boilers, chillers, and MicroTurbines as need be. It should be noted that although the prime movers in Option #3 and #4 would require individual equipment permits, as long as the summed total emissions for all DPW equipment covered under the "General Permit" is less than the 50 ton per year limit, the CHP plants could be covered under the existing DPW "General Permit". If the 50 ton per year limit is exceeded, however, the DPW would have to file for a Title V permit, which is an involved process that could take up to two years to complete. There is also a significant amount of emission testing that must be completed as part of the Title V permit requirements.

10. CAS EXPANSION IMPACT ON CENTRAL PLANT RESERVE CAPACITY

Table 28 below presents the annual peak chilled and hot water demands for the CAS as well as the proposed central plant capacity under Option #1.

	Mechanical Cooling (Chilled Water)		Heating (Steam)		Free Cooling (Chilled Water)	
	tons (peak)	ton-hrs (annual)	lbs/hr (peak)	lbs (annual)	tons (peak)	ton-hrs (annual)
Central Plant	3,509	5,737,300	32,820	72,835,482	1,407	963,576

	Installed Cooling Capacity (Chilled Water)	Installed Heating Capacity (Steam)	Installed Free Cooling Capacity (Chilled Water)
	tons	lbs/hr	tons
Central Plant	5,400	45,000	1,500

Table 28: Option #1 Central Plant Annual Output and Capacity

As can be seen in Table 28, the current peak CAS cooling load is 3,509-tons of chilled water and the current peak CAS heating load is 32,820 lbs/hr of low pressure steam (steam demand was converted from high pressure to low pressure). The proposed central plant under Option #1 will have a cooling capacity of 5,400-tons and a heating capacity of 45,000 lbs/hr of low pressure steam. Therefore, there is 35% reserve cooling capacity and 27% reserve heating capacity. This configuration allows the central plant to essentially meet the peak system demand loads even with one boiler or one chiller off-line for preventative or corrective maintenance, which enhances the reliability and robustness of the system.

The State of Connecticut DPW has indicated that they are currently in discussions with various agencies to potentially connect several additional buildings to the CAS. In particular, there are four (4) buildings on Washington Street, two (2) buildings on Lafayette Street, and one (1) on Capitol Avenue that may tie into the CAS in the future. Table 29 below highlights those facilities along with their applicable square footage, type of use, and estimated peak heating and cooling load.

Address	Square Footage	Type of Use	Annual Peak Steam Heating Load (lb/hr)	Annual Peak Cooling Load (tons)
165 Capitol	350,000	Offices	4,133	875
80 Washington	54,000	Offices/Courts	638	103
90 Washington	79,000	Offices/Courts	933	150
95 Washington	128,880	Offices/Courts	1,522	245
100 Washington	22,657	Offices/Courts	268	43
101 Lafayette	125,727	Offices/Courts	1,485	239
179 Lafayette	20,000	Church	236	31
Total	780,264		9,214	1,687

Table 29: CAS Expansion – Potential New Facilities

As can be seen from Table 29, these seven (7) facilities represent an additional peak heating load of 9,214 lb/hr of low pressure steam and a peak cooling load of 1,687-tons of chilled water. The result would be that the reserve capacity of the central plant under Option #1 would decrease to 2,967 lbs/hr of low pressure steam (6.6%) and 204-tons of chilled water (3.8%). This means that the central plant under Option #1 could handle the potential CAS expansion without the installation of any additional equipment. The one drawback, however, would be that the reserve capacity would be reduced, which would mean that the central plant would not be able to meet the peak system demand loads with one boiler or one chiller off-line for preventative or corrective maintenance. Therefore, system reliability and robustness could be adversely affected. It has to be kept in mind, however, that this scenario would only come into play during a peak load day with one of the boilers or chillers off-line. Since the load factor for the CAS hot and chilled water loops is so low, the likelihood of running into this condition is minimal.

Additionally, the State of Connecticut DPW believes that the most likely scenario in the near future would be the tie-in of only three (3) of the seven (7) facilities. Those three facilities would be 165 Capitol Avenue, 80 Washington Street, and 179 Lafayette Street. If this proves to be the case than the reserve capacity of the plant will not be as adversely affected by the expansion. The tie-in of the three aforementioned facilities would result in the reserve capacity of the central plant under Option #1 decreasing to 7,173 lbs/hr of low pressure steam (15.9%) and 882-tons of chilled water (16.3%).

APPENDIX

- SourceOne Financial Proforma Analysis Worksheets
- Option #1 Central Plant General Arrangement Drawing (With Mezzanine)
- Option #1 Central Plant General Arrangement Drawing (Without Mezzanine)
- Equipment Performance and Specification Sheets
- CL&P Guidelines for Generator Interconnections
- CL&P Generator Interconnection Technical Requirements
- Checklist for Permits, Certifications, and Approvals

SourceOne Financial Proforma Analysis Worksheets

State of CT DPW Central Plant Installation
Proforma Summary
(Capital Cost Financed - Shown for Years 1-20)

Annual Electricity Expense for 470 Capitol Ave Complex	Annual Natural Gas Expense	Annual Water Expense (Local Utility + Chemical Treatment)	Annual O&M Expense	Capital Cost Financing Charges (Years 1-20)	Total Annual Expenditures	Annual Expenditure Savings Over Base Case	Annual NEISO Capacity Sales ($2.91/kw/month)	Total Annual Cost Savings	DPUC Year 1 Incentive/Rebate ($250/kW for CHP & $300/ton for Gas Chillers)
Base Case - CDECCA Contract - Power: Electricity from Utility - Heating: Hot Water from Pump House Steam HX's that are fed by High-Pressure Steam Boilers in CDECCA Plant - Cooling: Chilled Water from CDECCA Electric and Steam Absorption Chillers									
$1,666,955	$0	$0	$4,899,417	$0	$6,566,372	$0	$0	$0	$0
Option #1 - Electric Chillers - Power: Electricity from Utility - Heating: Hot Water from Central Plant Steam HX's that are fed by Low-Pressure Steam Boilers - Cooling: Chilled Water from Central Plant Electric Chillers and Free Cooling Plate-and-Frame Heat Exchanger									
$2,515,065	$771,406	$91,924	$460,867	$1,210,825	$5,050,087	$1,516,285	$0	$1,516,285	$0
Option #2 - Natural Gas Fired Chillers - Power: Electricity from Utility - Heating: Hot Water from Central Plant Steam HX's that are fed by Low-Pressure Steam Boilers - Cooling: Chilled Water from Central Plant Natural Gas Fired Chillers and Free Cooling Plate-and-Frame Heat Exchanger									
$1,781,622	$1,214,585	$91,924	$479,801	$1,504,261	$5,072,192	$1,494,180	$0	$1,494,180	$1,620,000
Option #3 - Trigeneration Plant with Reciprocating Engine - Power: Electricity from 1,059 kW Jenbacher 620 Reciprocating Engines (Utility Back-Up) - Heating: Hot Water from Central Plant Steam HX's that are fed by 2,000 lb/hr Low-Pressure HRSG (Central Plant Low-Pressure Steam Boiler Back-Up) - Cooling: Chilled Water from 75 ton Hot Water Absorption Chiller and 120 ton Single-Stage Steam Absorption Chiller (Central Plant Free Cooling Complement and Electric Chiller Back-Up)									
$1,517,424	$1,207,871	$92,182	$610,356	$1,485,448	$4,913,282	$1,653,090	$36,980	$1,690,071	$264,750
Option #4 - Trigeneration Plant with Gas Turbine - Power: Electricity from 1,210 kW Solar Saturn 20 Combustion Turbine Generator (Utility Back-Up) - Heating: Hot Water from Central Plant Steam HX's that are fed by 8,100 lb/hr Low-Pressure HRSG (Central Plant Low-Pressure Steam Boiler Back-Up) - Cooling: Chilled Water from 493 ton Single-Stage Steam Absorption Chiller (Central Plant Free Cooling Complement and Electric Chiller Back-Up)									
$1,334,629	$1,387,140	$92,850	$625,719	$1,427,781	$4,868,118	$1,698,254	$42,253	$1,740,507	$302,500
Option #5 - Trigeneration Plant with MicroTurbine - Power: Electricity from two (2) 200 kW Capstone C200 MicroTurbines (Utility Back-Up) - Heating: Hot Water from Central Plant Steam HX's that are fed by two (2) 1,080 lb/hr Low-Pressure HRSG's (Central Plant Low-Pressure Steam Boiler Back-Up) - Cooling: Chilled Water from 132 ton Single-Stage Steam Absorption Chiller (Central Plant Free Cooling Complement and Electric Chiller Back-Up)									
$2,127,254	$813,493	$92,040	$515,053	$1,414,468	$4,962,307	$1,604,065	$13,968	$1,618,033	$100,000

State of CT DPW Central Plant Installation
Proforma Summary
(Capital Cost Paid Upfront)

Annual Electricity Expense for 470 Capitol Ave Complex	Annual Natural Gas Expense	Annual Water Expense (Local Utility + Chemical Treatment)	Annual O&M Expense	Total Annual Expenditures	Capital Cost	Annual Expenditure Savings Over Base Case	Annual NEISO Capacity Sales ($2.91/kw/ month)	Additional Capital Expenditure Over Base Case	DPUC Incentive/ Rebate ($250/kW for CHP & $300/ton for Gas Chillers)	Simple Payback (Years)
Base Case - CDECCA Contract - Power: Electricity from Utility - Heating: Hot Water from Pump House Steam HX's that are fed by High-Pressure Steam Boilers in CDECCA Plant - Cooling: Chilled Water from CDECCA Electric and Steam Absorption Chillers										
$1,666,955	$0	$0	$4,899,417	$6,566,372	$0	$0	$0	N/A	$0	N/A
Option #1 - Electric Chillers - Power: Electricity from Utility - Heating: Hot Water from Central Plant Steam HX's that are fed by Low-Pressure Steam Boilers - Cooling: Chilled Water from Central Plant Electric Chillers and Free Cooling Plate-and-Frame Heat Exchanger										
$2,515,065	$771,406	$91,924	$460,867	$3,839,262	$17,208,738	$2,727,110	$0	$17,208,738	$0	6.31
Option #2 - Natural Gas Fired Chillers - Power: Electricity from Utility - Heating: Hot Water from Central Plant Steam HX's that are fed by Low-Pressure Steam Boilers - Cooling: Chilled Water from Central Plant Natural Gas Fired Chillers and Free Cooling Plate-and-Frame Heat Exchanger										
$1,781,622	$1,214,585	$91,924	$479,801	$3,567,931	$21,379,159	$2,998,441	$0	$21,379,159	$1,620,000	6.59
Option #3 - Trigeneration Plant with Reciprocating Engine - Power: Electricity from 1,059 kW Jenbacher 620 Reciprocating Engines (Utility Back-Up) - Heating: Hot Water from Central Plant Steam HX's that are fed by 2,000 lb/hr Low-Pressure HRSG (Central Plant Low-Pressure Steam Boiler Back-Up) - Cooling: Chilled Water from 75 ton Hot Water Absorption Chiller and 120 ton Single-Stage Steam Absorption Chiller (Central Plant Free Cooling Complement and Electric Chiller Back-Up)										
$1,517,424	$1,207,871	$92,182	$610,356	$3,427,834	$21,111,784	$3,138,538	$36,980	$21,111,784	$264,750	6.56
Option #4 - Trigeneration Plant with Gas Turbine - Power: Electricity from 1,210 kW Solar Saturn 20 Combustion Turbine Generator (Utility Back-Up) - Heating: Hot Water from Central Plant Steam HX's that are fed by 8,100 lb/hr Low-Pressure HRSG (Central Plant Low-Pressure Steam Boiler Back-Up) - Cooling: Chilled Water from 493 ton Single-Stage Steam Absorption Chiller (Central Plant Free Cooling Complement and Electric Chiller Back-Up)										
$1,334,629	$1,387,140	$92,850	$625,719	$3,440,337	$20,292,197	$3,126,035	$42,253	$20,292,197	$302,500	6.31
Option #5 - Trigeneration Plant with MicroTurbine - Power: Electricity from two (2) 200 kW Capstone C200 MicroTurbines (Utility Back-Up) - Heating: Hot Water from Central Plant Steam HX's that are fed by two (2) 1,080 lb/hr Low-Pressure HRSG's (Central Plant Low-Pressure Steam Boiler Back-Up) - Cooling: Chilled Water from 132 ton Single-Stage Steam Absorption Chiller (Central Plant Free Cooling Complement and Electric Chiller Back-Up)										
$2,127,254	$813,493	$92,040	$515,053	$3,547,839	$20,102,983	$3,018,533	$13,968	$20,102,983	$100,000	6.60

State of CT DPW Central Plant Analysis - Base Case: CDECCA Contract

CDECCA Monthly Charges

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Chilled Water and Steam Consumption													
Chilled Water Consumption (ton-hrs)	212,280	373,344	322,272	401,424	680,016	890,400	2,358,576	2,005,776	766,224	373,680	241,392	195,720	8,821,104
Steam (MMBTU)	15,053	13,871	9,573	4,790	2,858	1,451	1,141	1,188	1,575	4,276	10,454	18,745	84,975
Aux Blr. Natural Gas Consumption (MMBTU)	31,161	28,068	21,713	15,020	13,249	12,106	11,305	12,615	12,547	15,388	20,195	32,370	225,737
Hot and Chilled Water Equipment Electricity Consumption (kWhs)	273,024	248,693	417,191	384,546	555,053	752,499	951,465	772,797	598,605	370,900	466,493	243,036	6,034,304
Monthly Charges													
Total Variable Commodity & Demand Charges ($)	$352,643	$281,069	$213,077	$151,142	$166,818	$190,598	$214,634	$204,325	$173,205	$138,901	$179,731	$286,810	$2,552,953
Monthly Demand Payment ($)	$195,192	$195,192	$195,192	$195,192	$195,192	$195,192	$195,192	$195,192	$195,192	$196,578	$196,578	$196,578	$2,346,463
Total Monthly CDECCA Charges ($)	$547,835	$476,261	$408,269	$346,334	$362,010	$385,791	$409,826	$399,517	$368,397	$335,479	$376,309	$483,388	$4,899,417

470 Capitol Avenue Complex Electricity Expense - Base Case

	January	February	March	April	May	June	July	August	September	October	November	December
Total On-Peak (kWh)	626,600	556,921	618,102	571,101	643,725	673,478	661,537	639,405	601,520	560,003	560,093	584,154
Total Off-Peak (kWh)	417,734	371,280	412,068	380,734	429,150	448,985	441,025	426,270	401,014	373,336	373,395	389,436
Total (kWh)	1,044,334	928,201	1,030,170	951,834	1,072,875	1,122,463	1,102,562	1,065,675	1,002,534	933,339	933,489	973,590
Actual Peak Demand (kW)	2,287	2,298	2,246	2,408	3,041	2,961	2,650	2,604	2,615	2,235	3,375	2,200
Rachet Demand (kW)	3,375	3,375	3,375	3,375	3,375	3,375	3,375	3,375	3,375	3,375	3,375	3,375
	Transmission Charges											
Transmission Charge Factor ($/kW)	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93
Transmission Charge kW Total ($)	$13,560	$13,629	$13,321	$14,278	$18,035	$17,557	$15,712	$15,439	$15,507	$13,253	$20,016	$13,048
	Distribution Charges											
Customer Service Charge ($)	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025
Distribution Charge kW Factor ($/kW)	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02
Distribution Charge kW Total ($)	$20,320	$20,320	$20,320	$20,320	$20,320	$20,320	$20,320	$20,320	$20,320	$20,320	$20,320	$20,320
FMCC Delivery Charge On Peak Factor ($/kWh)	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055
FMCC Delivery Charge On Peak Total ($)	$3,459	$3,074	$3,412	$3,152	$3,553	$3,718	$3,652	$3,530	$3,320	$3,091	$3,092	$3,225
FMCC Delivery Charge Off Peak Factor ($/kWh)	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012
FMCC Delivery Charge Off Peak Total ($)	$501	$446	$494	$457	$515	$539	$529	$512	$481	$448	$448	$467
Competitive Transition Assessment												
Demand Charge Factor ($/kW)	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46
Demand Charge Total ($)	$3,339	$3,355	$3,280	$3,515	$4,440	$4,323	$3,868	$3,801	$3,818	$3,263	$4,928	$3,212
CTA kWh Charge Factor ($/kWh)	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219
CTA kWh Charge Total ($)	$2,287	$2,033	$2,256	$2,085	$2,350	$2,458	$2,415	$2,334	$2,196	$2,044	$2,044	$2,132
Combined Public Benefits Charge ($/kWh)	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426
Combined Public Benefits Total ($)	$4,449	$3,954	$4,389	$4,055	$4,570	$4,782	$4,697	$4,540	$4,271	$3,976	$3,977	$4,147
Economic Transition Charge ($/kWh)	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379
Economic Transition Charge Total ($)	$3,958	$3,518	$3,904	$3,607	$4,066	$4,254	$4,179	$4,039	$3,800	$3,537	$3,538	$3,690
Total Transmission and Delivery Charges ($)	**$52,898**	**$51,353**	**$52,401**	**$52,494**	**$58,874**	**$58,974**	**$56,396**	**$55,538**	**$54,737**	**$50,957**	**$59,387**	**$51,266**
	Supply											
Supply Charge Factor ($/kWh)	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319
Total Supply Charges ($)	**$86,878**	**$77,217**	**$85,700**	**$79,183**	**$89,252**	**$93,378**	**$91,722**	**$88,653**	**$83,401**	**$77,644**	**$77,657**	**$80,993**
	Total											
Total Electric Charges ($)	**$139,776**	**$128,570**	**$138,101**	**$131,677**	**$148,127**	**$152,352**	**$148,118**	**$144,192**	**$138,138**	**$128,602**	**$137,044**	**$132,259**
Average Electric Rate ($/kWh)	$0.13	$0.14	$0.13	$0.14	$0.14	$0.14	$0.13	$0.14	$0.14	$0.14	$0.15	$0.14

Total Annual Electrcity Expense ($):	**$1,666,955**

State of CT DPW Central Plant Analysis - Option 1: Electric Chillers

Central Plant Low-Pressure Steam Boiler Efficiency	85%	%
Central Plant Chilled Water System Electric Consumption	0.85	kW/ton
Central Plant Boiler System Electric Consumption	10.10	kW/MMBTU

Enthalpy of Steam @ 15 psig	1164.1	BTU/lb

Electric Side

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Electric Consumption (kWh)	1,196,368	1,068,299	1,126,979	1,313,936	1,704,364	2,016,770	2,152,503	1,934,267	1,672,869	1,311,800	1,235,377	1,160,594	17,894,126
Peak Electric Demand (kW)	2,530	2,545	2,435	3,754	5,605	5,422	5,524	5,245	5,266	3,796	3,856	2,483	5,605
Electricity Purchased (kWh)	1,196,368	1,068,299	1,126,979	1,313,936	1,704,364	2,016,770	2,152,503	1,934,267	1,672,869	1,311,800	1,235,377	1,160,594	17,894,126
Peak Demand on Electricity Purchases (kW)	2,530	2,545	2,435	3,754	5,605	5,422	5,524	5,245	5,266	3,796	3,856	2,483	5,605

Gas Side

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Central Plant Boiler Fuel Consumed (decatherms)	17,709	16,319	11,277	5,635	3,402	1,707	1,342	1,398	1,853	5,042	12,283	21,783	99,750
Central Plant Boiler Peak Daily Fuel Demand (decatherms)	792	705	528	297	263	98	65	68	92	346	540	917	917

Hot Water Side

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Hours in the Month	744	672	744	720	744	720	744	744	720	744	720	744	8,760
Steam Consumption (MMBTU)	15,053	13,871	9,585	4,790	2,892	1,451	1,141	1,188	1,575	4,286	10,441	18,515	84,788
Peak Steam Demand (MMBTU)	28	30	24	14	16	5	4	4	6	15	25	38	38
Steam Produced by Central Plant Boilers (MMBTU)	15,053	13,871	9,585	4,790	2,892	1,451	1,141	1,188	1,575	4,286	10,441	18,515	84,788
Peak Central Plant Steam Production (MMBTU)	28	30	24	14	16	5	4	4	6	15	25	38	38

Chilled Water Side

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Chilled Water Consumption (ton-hrs)	202,638	182,122	322,184	399,180	708,568	1,034,887	1,221,670	1,007,751	769,909	394,325	268,471	189,169	6,700,876
Peak Chilled Water Demand (tons)	808	729	1,407	1,750	3,032	3,040	3,439	3,242	3,509	1,993	1,307	964	3,509
Central Plant Electric Chiller Production (ton-hrs)	0	0	0	369,086	708,568	1,034,887	1,221,670	1,007,751	769,909	394,325	231,103	0	5,737,300
Peak Central Plant Electric Chillers Production (tons)	0	0	0	1,750	3,032	3,040	3,439	3,242	3,509	1,993	1,307	0	3,509
Central Plant Free-Cooling Production (ton-hrs)	202,638	182,122	322,184	30,094	0	0	0	0	0	0	37,369	189,169	963,576
Peak Central Plant Free-Cooling Production (tons)	808	729	1,407	674	0	0	0	0	0	0	551	964	1,407

470 Capitol Avenue Complex Electricity Expense - Option 1: Electric Chillers

	January	February	March	April	May	June	July	August	September	October	November	December
Total On-Peak (kWh)	717,821	640,979	676,188	788,362	1,022,618	1,210,062	1,291,502	1,160,560	1,003,721	787,080	741,226	696,356
Total Off-Peak (kWh)	478,547	427,320	450,792	525,574	681,745	806,708	861,001	773,707	669,147	524,720	494,151	464,238
Total (kWh)	1,196,368	1,068,299	1,126,979	1,313,936	1,704,364	2,016,770	2,152,503	1,934,267	1,672,869	1,311,800	1,235,377	1,160,594
Actual Peak Demand (kW)	2,530	2,545	2,435	3,754	5,605	5,422	5,524	5,245	5,266	3,796	3,856	2,483
Rachet Demand (kW)	5,605	5,605	5,605	5,605	5,605	5,605	5,605	5,605	5,605	5,605	5,605	5,605
	Transmission Charges											
Transmission Charge Factor ($/kW)	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93
Transmission Charge kW Total ($)	$15,001	$15,092	$14,438	$22,260	$33,240	$32,155	$32,757	$31,102	$31,230	$22,509	$22,867	$14,724
	Distribution Charges											
Customer Service Charge ($)	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025
Distribution Charge kW Factor ($/kW)	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02
Distribution Charge kW Total ($)	$33,744	$33,744	$33,744	$33,744	$33,744	$33,744	$33,744	$33,744	$33,744	$33,744	$33,744	$33,744
FMCC Delivery Charge On Peak Factor ($/kWh)	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055
FMCC Delivery Charge On Peak Total ($)	$3,962	$3,538	$3,733	$4,352	$5,645	$6,680	$7,129	$6,406	$5,541	$4,345	$4,092	$3,844
FMCC Delivery Charge Off Peak Factor ($/kWh)	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012
FMCC Delivery Charge Off Peak Total ($)	$574	$513	$541	$631	$818	$968	$1,033	$928	$803	$630	$593	$557
Competitive Transition Assessment												
Demand Charge Factor ($/kW)	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46
Demand Charge Total ($)	$3,693	$3,716	$3,555	$5,481	$8,184	$7,917	$8,065	$7,657	$7,689	$5,542	$5,630	$3,625
CTA kWh Charge Factor ($/kWh)	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219
CTA kWh Charge Total ($)	$2,620	$2,340	$2,468	$2,878	$3,733	$4,417	$4,714	$4,236	$3,664	$2,873	$2,705	$2,542
Combined Public Benefits Charge ($/kWh)	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426
Combined Public Benefits Total ($)	$5,097	$4,551	$4,801	$5,597	$7,261	$8,591	$9,170	$8,240	$7,126	$5,588	$5,263	$4,944
Economic Transition Charge ($/kWh)	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379
Economic Transition Charge Total ($)	$4,534	$4,049	$4,271	$4,980	$6,460	$7,644	$8,158	$7,331	$6,340	$4,972	$4,682	$4,399
Total Transmission and Delivery Charges ($)	**$70,252**	**$68,568**	**$68,576**	**$80,947**	**$100,109**	**$103,140**	**$105,795**	**$100,671**	**$97,162**	**$81,228**	**$80,601**	**$69,405**
	Supply											
Supply Charge Factor ($/kWh)	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319
Total Supply Charges ($)	**$99,526**	**$88,872**	**$93,753**	**$109,306**	**$141,786**	**$167,775**	**$179,067**	**$160,912**	**$139,166**	**$109,129**	**$102,771**	**$96,550**
	Total											
Total Electric Charges ($)	**$169,778**	**$157,440**	**$162,329**	**$190,253**	**$241,895**	**$270,915**	**$284,861**	**$261,582**	**$236,328**	**$190,357**	**$183,372**	**$165,954**
Average Electric Rate ($/kWh)	$0.14	$0.15	$0.14	$0.14	$0.14	$0.13	$0.13	$0.14	$0.14	$0.15	$0.15	$0.14

Total Annual Electrcity Expense ($):	**$2,515,065**

State of CT DPW Central Plant Natural Gas Expense - Option 1: Electric Chillers

	January	February	March	April	May	June	July	August	September	October	November	December
Natural Gas Consumption (therms)	177,093	163,189	112,765	56,353	34,019	17,069	13,420	13,982	18,535	50,420	122,832	217,827
Adjustments (therms)	-	-	-	-	-	-	-	-	-	-	-	-
Total Consumption (therms)	177,093	163,189	112,765	56,353	34,019	17,069	13,420	13,982	18,535	50,420	122,832	217,827
Total Consumption (CCF)	171,768	158,283	109,375	54,658	32,996	16,556	13,016	13,562	17,977	48,904	119,139	211,277
Demand Peak Day (therms)	7,921	7,047	5,276	2,966	2,632	985	646	680	922	3,463	5,402	9,166
Demand Charge Rate ($/CCF)	$1.1783	$1.1783	$1.1783	$1.1783	$1.1783	$1.1783	$1.1783	$1.1783	$1.1783	$1.1783	$1.1783	$1.1783
Demand Charges ($)	$9,053	$8,054	$6,029	$3,390	$3,008	$1,125	$738	$777	$1,054	$3,958	$6,174	$10,475
Delivery Rate First 5000 CCF ($/CCF)	$0.0925	$0.0925	$0.0925	$0.0925	$0.0925	$0.0925	$0.0925	$0.0925	$0.0925	$0.0925	$0.0925	$0.0925
Total Delivery Rate First 5000 CCF	$463	$463	$463	$463	$463	$463	$463	$463	$463	$463	$463	$463
Delivery Rate Rest of CCF ($/CCF)	$0.0250	$0.0250	$0.0250	$0.0250	$0.0250	$0.0250	$0.0250	$0.0250	$0.0250	$0.0250	$0.0250	$0.0250
Total Delivery Charge Rest of CCF ($)	$4,169	$3,832	$2,609	$1,241	$700	$289	$200	$214	$324	$1,098	$2,853	$5,157
Rate Credit Factor ($/CCF)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)
Rate Credit Total ($)	($10,598)	($9,766)	($6,748)	($3,372)	($2,036)	($1,021)	($803)	($837)	($1,109)	($3,017)	($7,351)	($13,036)
SSC Rate ($/CCF)	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324
SSC Total ($)	$5,565	$5,128	$3,544	$1,771	$1,069	$536	$422	$439	$582	$1,584	$3,860	$6,845
Customer Charge	$255	$255	$255	$255	$255	$255	$255	$255	$255	$255	$255	$255
Telemetering Charge	$17	$17	$17	$17	$17	$17	$17	$17	$17	$17	$17	$17
Transportation Service Charge ($/CCF)	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
Transportation Service Supply Cost ($)	$125,391	$115,546	$79,844	$39,900	$24,087	$12,086	$9,502	$9,900	$13,124	$35,700	$86,971	$154,232
Conservation Adjustment Rate ($/CCF)	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084
Conservation Adjustment Charge ($/CCF)	$1,443	$1,330	$919	$459	$277	$139	$109	$114	$151	$411	$1,001	$1,775
Total Natural Gas Charges ($)	**$135,758**	**$124,859**	**$86,931**	**$44,124**	**$27,841**	**$13,889**	**$10,904**	**$11,343**	**$14,861**	**$40,468**	**$94,243**	**$166,184**
Average Natural Gas Rate ($/decatherm)	7.67	7.65	7.71	7.83	8.18	8.14	8.13	8.11	8.02	8.03	7.67	7.63

Total Annual Gas Expense ($):	**$771,406**

State of CT DPW Central Plant Water Expense - Option 1: Electric Chillers

	January	February	March	April	May	June	July	August	September	October	November	December
Steam Production (Mlbs)	12,931	11,916	8,234	4,115	2,484	1,246	980	1,021	1,353	3,682	8,969	15,905
Steam Production (lbs)	12,930,914	11,915,727	8,233,874	4,114,743	2,484,012	1,246,347	979,883	1,020,944	1,353,364	3,681,529	8,968,911	15,905,233
Total Make-up Water Requirements (lbs)	646,546	595,786	411,694	205,737	124,201	62,317	48,994	51,047	67,668	184,076	448,446	795,262
Total Make-up Water Requirements (gallons)	77,474	71,392	49,332	24,653	14,883	7,467	5,871	6,117	8,109	22,058	53,736	95,295

Total Hot Water Production System Make-up Water (gallons)	436,386

	January	February	March	April	May	June	July	August	September	October	November	December
Chilled Water Production (ton-hrs)	202,638	182,122	322,184	399,180	708,568	1,034,887	1,221,670	1,007,751	769,909	394,325	268,471	189,169
Evaporated Cooling Water Make-up to Cooling Tower (gallons)	506,595	455,305	805,460	997,950	1,771,421	2,587,217	3,054,176	2,519,378	1,924,773	985,812	671,178	472,924

Total Evaporated Cooling Tower Water (gallons)	16,752,190

Total Water Usage (gallons)	**17,188,576**

Cost of Water and Chemicals:	$5.00	$/1000 gallons
CT State and Local Surcharges:	0.96	%
State and Local Taxes:	6.00	%

Cost of Water and Chemicals ($)	$85,943
CT State and Local Surcharges ($):	$824
CT Sales Tax ($):	$5,157
Total Annual Water Expense ($):	**$91,924**

State of CT DPW Central Plant Analysis O&M Expense - Option 1: Electric Chillers

	Mechanical Cooling (Chilled Water)		Heating (Steam)		Free Cooling (Chilled Water)	
	tons (peak)	ton-hrs (annual)	MMBTU (peak)	MMBTU (annual)	tons (peak)	ton-hrs (annual)
Central Plant	3,509	5,737,300	38	84,788	1,407	963,576

O&M Rate (Steam Boiler and Auxiliaries):	$0.300	$/MMBTU
O&M Rate (Electric Chiller and Auxiliaries):	$0.012	$/ton-hr
O&M Rate (Cooling Tower and Auxiliaries):	$0.005	$/ton-hr
Pump House Equipment Maintenance	$225,000	$/yr
Free-Cooling Heat Exchanger Mtce.	$15,000	$/yr

Annual Equipment Mtce Cost*:	$399,267

Note: Includes 10% mark-up by 3rd party contractor.

	# of Employees Required	Employee Salary ($/yr)	Employee Benefits	3rd Party Contractor Markup (10%)	Total Annual Expenditure
Plant Manager	0.0	$90,000	$36,000	$12,600	$0
Operator	0.5	$80,000	$32,000	$11,200	$61,600
Mechanic/Electrician	0.0	$70,000	$28,000	$9,800	$0
I&C Technician	0.0	$70,000	$28,000	$9,800	$0
Totals	0.5				$61,600

***Note*:** Benefits are assumed to be 40% of the employees salary. Final value includes 10% mark-up by 3rd party contractor.

Annual O&M Cost:	**$460,867**

State of CT DPW Central Plant Analysis Capital Expense
- Option 1: Electric Chillers

	Mechanical Cooling (Chilled Water)		Heating (Steam)		Free Cooling (Chilled Water)	
	tons (peak)	ton-hrs (annual)	lbs/hr (peak)	lbs (annual)	tons (peak)	ton-hrs (annual)
Central Plant	3,509	5,737,300	32,820	72,835,482	1,407	963,576

	Installed Cooling Capacity (Chilled Water)	Installed Heating Capacity (Steam)	Installed Free Cooling Capacity (Chilled Water)
	tons	lbs/hr	tons
Central Plant	5,400	45,000	1,500

Central Plant

Electric Chillers and Auxiliaries	$1,000	$/ton
Steam Boilers and Auxiliaries	$50,000	$/MMBTU
Cooling Towers and Auxiliaries	$280	$/ton

Electric Chillers and Chilled Water Pumps ($):	**$5,400,000**
Steam Boilers ($):	**$2,619,225**
Electrical Switchboard and MCC ($):	**$415,000**
Chilled and Condenser Water Piping ($):	**$450,000**
Cooling Towers ($):	**$1,512,000**
Free-Cooling Heat Exchanger and Control Valves ($):	**$225,000**
Distributed Control System ($):	**$520,000**
Engineering ($):	**$972,647**
Construction Management ($):	**$442,112**
Commissioning and Start-up ($):	**$221,056**
10% Overhead and Profit Margin ($):	**$1,277,704**
20% Estimating and Construction Contingency ($):	**$2,555,408**
Permitting ($):	**$41,525**
5% Sales Tax ($):	**$557,061**

Total Capital Expenditure ($):	**$17,208,738**

Financing Charges

Length of Loan (years):	20	years
Cost of Capital (decimal equivalent):	0.0350	

Monthly Payment ($):	**$100,902**

State of CT DPW Central Plant Capital Expense
- Option 1: Electric Chillers

Greenhouse Gas Emission

eGrid Conversion Factors				
	lbs/kWh	GHG Factor	GHG Weighting	
CO_2	827.95	1	827.95	lbs/MWh
Methane	0.07698	25	1.9245	lbs/MWh
N_2O	0.0152	298	4.5296	lbs/MWh
Total for Electricity			834.4041	lbs/MWh
			379.27	kg/MWh
Total for District Steam			86.845	kg/Mlb
Total for Natural Gas			53.27	kg/MMBTU

Option 1: Low-Pressure Steam Boilers and Electric Chillers

	Energy Consumption	Unit	eGrid Conv Factor	Unit	GHG	Unit
Natural Gas	99,750	MMBTU	53.27	kg/MMBTU	5,314	Metric Tons
470 Capital Ave. Electricity	17,894	MWh	379.27	kg/MWh	6,787	Metric Tons
Total					**12,100**	Metric Tons

Base Case: CDECCA Contract

	Energy Consumption	Unit	eGrid Conv Factor	Unit	GHG	Unit
Natural Gas	225,737	MMBTU	53.27	kg/MMBTU	12,025	Metric Tons
470 Capital Ave. Electricity	12,161	MWh	379.27	kg/MWh	4,612	Metric Tons
Hot and Chilled Water System Electricity	6,034	MWh	379.27	kg/MWh	2,289	Metric Tons
Total					**18,926**	Metric Tons

Net GHG Reduction with Option #1 (Metric Tons)	**6,826**

Air Pollutant Emission

Air Contaminent Emission Rates for Boilers		
NOx	0.035	lb/MMBtu
CO	0.04	lb/MMBtu
UHC	0.004	lb/MMBtu

Annual Boiler Air Contaminent Emissions		
NOx	**1.7**	tons
CO	**2.0**	tons
UHC	**0.2**	tons

State of CT DPW Central Plant Analysis - Option 2: Gas Fired Chillers

Central Plant Low-Pressure Steam Boiler Efficiency	85%	%
Central Plant Chilled Water System Electric Consumption	0.85	kW/ton
Central Plant Boiler System Electric Consumption	10.10	kW/MMBTU

Electric Chiller Efficiency	0.50	kW/ton
Gas Fired Chiller Efficiency	10.10	MBTU/ton
Gas Fired Chiller Electric Parasitic Load	0.021	kW/ton
Enthalpy of Steam @ 15 psig	1164.1	BTU/lb

Electric Side

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Electric Consumption (kWh)	1,196,368	1,068,299	1,126,979	1,007,881	1,116,802	1,158,618	1,139,465	1,098,616	1,034,442	984,817	1,043,741	1,160,594	13,136,625
Peak Electric Demand (kW)	2,530	2,545	2,435	2,447	3,106	3,031	2,735	2,678	2,673	2,308	3,492	2,483	3,492
Electricity Purchased (kWh)	1,196,368	1,068,299	1,126,979	1,007,881	1,116,802	1,158,618	1,139,465	1,098,616	1,034,442	984,817	1,043,741	1,160,594	13,136,625
Peak Demand on Electricity Purchases (kW)	2,530	2,545	2,435	2,447	3,106	3,031	2,735	2,678	2,673	2,308	3,492	2,483	3,492

Gas Side

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Central Plant Plant Total Fuel Consumed (decatherms)	17,709	16,319	11,277	9,363	10,559	12,160	13,682	11,578	9,630	9,025	14,618	21,783	157,703
Central Plant Total Peak Daily Fuel Demand (decatherms)	792	705	528	408	508	653	701	554	550	437	632	917	917

Hot Water Side

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Hours in the Month	744	672	744	720	744	720	744	744	720	744	720	744	8,760
Steam Consumption (MMBTU)	15,053	13,871	9,585	4,790	2,892	1,451	1,141	1,188	1,575	4,286	10,441	18,515	84,788
Peak Steam Demand (MMBTU)	28	30	24	14	16	5	4	4	6	15	25	38	38
Steam Produced by Central Plant Boilers (MMBTU)	15,053	13,871	9,585	4,790	2,892	1,451	1,141	1,188	1,575	4,286	10,441	18,515	84,788
Peak Central Plant Steam Production (MMBTU)	28	30	24	14	16	5	4	4	6	15	25	38	38

Chilled Water Side

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Chilled Water Consumption (ton-hrs)	202,638	182,122	322,184	399,180	708,568	1,034,887	1,221,670	1,007,751	769,909	394,325	268,471	189,169	6,700,876
Peak Chilled Water Demand (tons)	808	729	1,407	1,750	3,032	3,040	3,439	3,242	3,509	1,993	1,307	964	3,509
Central Plant Gas-Fired Chiller Production (ton-hrs)	0	0	0	369,086	708,568	1,034,887	1,221,670	1,007,751	769,909	394,325	231,103	0	5,737,300
Peak Central Plant Gas-Fired Chiller Production (tons)	0	0	0	1,750	3,032	3,040	3,439	3,242	3,509	1,993	1,307	0	3,509
Central Plant Free-Cooling Production (ton-hrs)	202,638	182,122	322,184	30,094	0	0	0	0	0	0	37,369	189,169	963,576
Peak Central Plant Free-Cooling Production (tons)	808	729	1,407	674	0	0	0	0	0	0	551	964	1,407

470 Capitol Avenue Complex Electricity Expense - Option 2: Gas Fired Chillers

	January	February	March	April	May	June	July	August	September	October	November	December
Total On-Peak (kWh)	717,821	640,979	676,188	604,729	670,081	695,171	683,679	659,170	620,665	590,890	626,245	696,356
Total Off-Peak (kWh)	478,547	427,320	450,792	403,153	446,721	463,447	455,786	439,447	413,777	393,927	417,497	464,238
Total (kWh)	1,196,368	1,068,299	1,126,979	1,007,881	1,116,802	1,158,618	1,139,465	1,098,616	1,034,442	984,817	1,043,741	1,160,594
Actual Peak Demand (kW)	2,530	2,545	2,435	2,447	3,106	3,031	2,735	2,678	2,673	2,308	3,492	2,483
Rachet Demand (kW)	3,492	3,492	3,492	3,492	3,492	3,492	3,492	3,492	3,492	3,492	3,492	3,492
	Transmission Charges											
Transmission Charge Factor ($/kW)	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93
Transmission Charge kW Total ($)	$15,001	$15,092	$14,438	$14,510	$18,416	$17,974	$16,219	$15,878	$15,850	$13,685	$20,708	$14,724
	Distribution Charges											
Customer Service Charge ($)	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025
Distribution Charge kW Factor ($/kW)	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02
Distribution Charge kW Total ($)	$21,022	$21,022	$21,022	$21,022	$21,022	$21,022	$21,022	$21,022	$21,022	$21,022	$21,022	$21,022
FMCC Delivery Charge On Peak Factor ($/kWh)	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055
FMCC Delivery Charge On Peak Total ($)	$3,962	$3,538	$3,733	$3,338	$3,699	$3,837	$3,774	$3,639	$3,426	$3,262	$3,457	$3,844
FMCC Delivery Charge Off Peak Factor ($/kWh)	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012
FMCC Delivery Charge Off Peak Total ($)	$574	$513	$541	$484	$536	$556	$547	$527	$497	$473	$501	$557
Competitive Transition Assessment												
Demand Charge Factor ($/kW)	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46
Demand Charge Total ($)	$3,693	$3,716	$3,555	$3,572	$4,534	$4,425	$3,993	$3,909	$3,902	$3,369	$5,098	$3,625
CTA kWh Charge Factor ($/kWh)	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219
CTA kWh Charge Total ($)	$2,620	$2,340	$2,468	$2,207	$2,446	$2,537	$2,495	$2,406	$2,265	$2,157	$2,286	$2,542
Combined Public Benefits Charge ($/kWh)	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426
Combined Public Benefits Total ($)	$5,097	$4,551	$4,801	$4,294	$4,758	$4,936	$4,854	$4,680	$4,407	$4,195	$4,446	$4,944
Economic Transition Charge ($/kWh)	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379
Economic Transition Charge Total ($)	$4,534	$4,049	$4,271	$3,820	$4,233	$4,391	$4,319	$4,164	$3,921	$3,732	$3,956	$4,399
Total Transmission and Delivery Charges ($)	**$57,529**	**$55,846**	**$55,853**	**$54,272**	**$60,668**	**$60,704**	**$58,248**	**$57,250**	**$56,315**	**$52,921**	**$62,499**	**$56,682**
	Supply											
Supply Charge Factor ($/kWh)	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319
Total Supply Charges ($)	**$99,526**	**$88,872**	**$93,753**	**$83,846**	**$92,907**	**$96,385**	**$94,792**	**$91,394**	**$86,055**	**$81,927**	**$86,829**	**$96,550**
	Total											
Total Electric Charges ($)	**$157,055**	**$144,717**	**$149,607**	**$138,117**	**$153,575**	**$157,090**	**$153,040**	**$148,644**	**$142,370**	**$134,847**	**$149,328**	**$153,232**
Average Electric Rate ($/kWh)	$0.13	$0.14	$0.13	$0.14	$0.14	$0.14	$0.13	$0.14	$0.14	$0.14	$0.14	$0.13

Total Annual Electrcity Expense ($):	**$1,781,622**

State of CT DPW Central Plant Natural Gas Expense - Option 2: Gas Fired Chillers

	January	February	March	April	May	June	July	August	September	October	November	December
Natural Gas Consumption (therms)	177,093	163,189	112,765	93,634	105,592	121,604	136,822	115,776	96,304	90,251	146,176	217,827
Adjustments (therms)	-	-	-	-	-	-	-	-	-	-	-	-
Total Consumption (therms)	177,093	163,189	112,765	93,634	105,592	121,604	136,822	115,776	96,304	90,251	146,176	217,827
Total Consumption (CCF)	171,768	158,283	109,375	90,819	102,417	117,947	132,708	112,295	93,408	87,537	141,781	211,277
Demand Peak Day (therms)	7,921	7,047	5,276	4,078	5,075	6,534	7,005	5,536	5,498	4,375	6,315	9,166
Demand Charge Rate ($/CCF)	$1.1783	$1.1783	$1.1783	$1.1783	$1.1783	$1.1783	$1.1783	$1.1783	$1.1783	$1.1783	$1.1783	$1.1783
Demand Charges ($)	$9,053	$8,054	$6,029	$4,661	$5,800	$7,468	$8,006	$6,327	$6,284	$5,000	$7,217	$10,475
Delivery Rate First 5000 CCF ($/CCF)	$0.0925	$0.0925	$0.0925	$0.0925	$0.0925	$0.0925	$0.0925	$0.0925	$0.0925	$0.0925	$0.0925	$0.0925
Total Delivery Rate First 5000 CCF	$463	$463	$463	$463	$463	$463	$463	$463	$463	$463	$463	$463
Delivery Rate Rest of CCF ($/CCF)	$0.0250	$0.0250	$0.0250	$0.0250	$0.0250	$0.0250	$0.0250	$0.0250	$0.0250	$0.0250	$0.0250	$0.0250
Total Delivery Charge Rest of CCF ($)	$4,169	$3,832	$2,609	$2,145	$2,435	$2,824	$3,193	$2,682	$2,210	$2,063	$3,420	$5,157
Rate Credit Factor ($/CCF)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)
Rate Credit Total ($)	($10,598)	($9,766)	($6,748)	($5,604)	($6,319)	($7,277)	($8,188)	($6,929)	($5,763)	($5,401)	($8,748)	($13,036)
SSC Rate ($/CCF)	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324
SSC Total ($)	$5,565	$5,128	$3,544	$2,943	$3,318	$3,821	$4,300	$3,638	$3,026	$2,836	$4,594	$6,845
Customer Charge	$255	$255	$255	$255	$255	$255	$255	$255	$255	$255	$255	$255
Telemetering Charge	$17	$17	$17	$17	$17	$17	$17	$17	$17	$17	$17	$17
Transportation Service Charge ($/CCF)	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
Transportation Service Supply Cost ($)	$125,391	$115,546	$79,844	$66,298	$74,765	$86,102	$96,877	$81,975	$68,188	$63,902	$103,500	$154,232
Conservation Adjustment Rate ($/CCF)	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084
Conservation Adjustment Charge ($/CCF)	$1,443	$1,330	$919	$763	$860	$991	$1,115	$943	$785	$735	$1,191	$1,775
Total Natural Gas Charges ($)	**$135,758**	**$124,859**	**$86,931**	**$71,941**	**$81,595**	**$94,663**	**$106,037**	**$89,373**	**$75,465**	**$69,871**	**$111,908**	**$166,184**
Average Natural Gas Rate ($/decatherm)	7.67	7.65	7.71	7.68	7.73	7.78	7.75	7.72	7.84	7.74	7.66	7.63

Total Annual Gas Expense ($):	**$1,214,585**

State of CT DPW Central Plant Water Expense - Option 2: Gas Fired Chillers

	January	February	March	April	May	June	July	August	September	October	November	December
Steam Production (Mlbs)	12,931	11,916	8,234	4,115	2,484	1,246	980	1,021	1,353	3,682	8,969	15,905
Steam Production (lbs)	12,930,914	11,915,727	8,233,874	4,114,743	2,484,012	1,246,347	979,883	1,020,944	1,353,364	3,681,529	8,968,911	15,905,233
Total Make-up Water Requirements (lbs)	646,546	595,786	411,694	205,737	124,201	62,317	48,994	51,047	67,668	184,076	448,446	795,262
Total Make-up Water Requirements (gallons)	77,474	71,392	49,332	24,653	14,883	7,467	5,871	6,117	8,109	22,058	53,736	95,295

Total Hot Water Production System Make-up Water (gallons)	436,386

	January	February	March	April	May	June	July	August	September	October	November	December
Chilled Water Production (ton-hrs)	202,638	182,122	322,184	399,180	708,568	1,034,887	1,221,670	1,007,751	769,909	394,325	268,471	189,169
Evaporated Cooling Water Make-up to Cooling Tower (gallons)	506,595	455,305	805,460	997,950	1,771,421	2,587,217	3,054,176	2,519,378	1,924,773	985,812	671,178	472,924

Total Evaporated Cooling Tower Water (gallons)	16,752,190

Total Water Usage (gallons)	**17,188,576**

Cost of Water and Chemicals:	$5.00	$/1000 gallons
CT State and Local Surcharges:	0.96	%
State and Local Taxes:	6.00	%

Cost of Water and Chemicals ($)	$85,943
CT State and Local Surcharges ($):	$824
CT Sales Tax ($):	$5,157
Total Annual Water Expense ($):	**$91,924**

State of CT DPW Central Plant Analysis O&M Expense - Option 2: Gas Fired Chillers

	Mechanical Cooling (Chilled Water)		Heating (Steam)		Free Cooling (Chilled Water)	
	tons (peak)	ton-hrs (annual)	MMBTU (peak)	MMBTU (annual)	tons (peak)	ton-hrs (annual)
Central Plant	3,509	5,737,300	38	84,788	1,407	963,576

O&M Rate (Steam Boiler and Auxiliaries):	$0.300	$/MMBTU
O&M Rate (Gas Fired Chiller and Auxiliaries):	$0.015	$/ton-hr
O&M Rate (Cooling Tower and Auxiliaries):	$0.005	$/ton-hr
Pump House Equipment Maintenance	$225,000	$/yr
Free-Cooling Heat Exchanger Mtce.	$15,000	$/yr

Annual Equipment Mtce Cost:	$418,201

Note: Includes 10% mark-up by 3rd party contractor.

	# of Employees Required	Employee Salary ($/yr)	Employee Benefits	3rd Party Contractor Markup (10%)	Total Annual Expenditure
Plant Manager	0.0	$90,000	$36,000	$12,600	$0
Operator	0.5	$80,000	$32,000	$11,200	$61,600
Mechanic/Electrician	0.0	$70,000	$28,000	$9,800	$0
I&C Technician	0.0	$70,000	$28,000	$9,800	$0
Totals	0.5				$61,600

Note **:** Benefits are assumed to be 40% of the employees salary. Final value includes 10% mark-up by 3rd party contractor.

Annual O&M Cost:	**$479,801**

State of CT DPW Central Plant Analysis Capital Expense - Option 2: Gas Fired Chillers

	Mechanical Cooling (Chilled Water)		Heating (Steam)		Free Cooling (Chilled Water)	
	tons (peak)	ton-hrs (annual)	lbs/hr (peak)	lbs (annual)	tons (peak)	ton-hrs (annual)
Central Plant	3,509	5,737,300	32,820	72,835,482	1,407	963,576

	Installed Mechanical Cooling Capacity (Chilled Water)	Installed Heating Capacity (Steam)	Installed Free Cooling Capacity (Chilled Water)
	tons	lbs/hr	tons
Central Plant	5,400	45,000	1,500

Central Plant

Gas-Fired Chillers and Auxiliaries	$1,500	$/ton
Steam Boilers and Auxiliaries	$50,000	$/MMBTU
Cooling Towers and Auxiliaries	$280	$/ton

Gas-Fired Chillers and Chilled Water Pumps ($):	**$8,100,000**
Steam Boilers ($):	**$2,619,225**
Electrical Switchboard and MCC ($):	**$415,000**
Chilled and Condenser Water Piping ($):	**$450,000**
Cooling Towers ($):	**$1,512,000**
Free-Cooling Heat Exchanger and Control Valves ($):	**$225,000**
Distributed Control System ($):	**$520,000**
Engineering ($):	**$1,208,361**
Construction Management ($):	**$549,255**
Commissioning and Start-up ($):	**$274,627**
10% Overhead and Profit Margin ($):	**$1,587,347**
20% Estimating and Construction Contingency ($):	**$3,174,694**
Permitting ($):	**$51,589**
5% Sales Tax ($):	**$692,061**

Total Capital Expenditure ($):	**$21,379,159**

Financing Charges

Length of Loan (years):	20	years
Cost of Capital (decimal equivalent):	0.0350	

Monthly Payment ($):	**$125,355**

State of CT DPW Central Plant Capital Expense
- Option 2: Gas Fired Chillers

Greenhouse Gas Emission

eGrid Conversion Factors				
	lbs/kWh	GHG Factor	GHG Weighting	
CO_2	827.95	1	827.95	lbs/MWh
Methane	0.07698	25	1.9245	lbs/MWh
N_2O	0.0152	298	4.5296	lbs/MWh
Total for Electricity			834.4041	lbs/MWh
			379.27	kg/MWh
Total for District Steam			86.845	kg/Mlb
Total for Natural Gas			53.27	kg/MMBTU

Option 2: Low-Pressure Steam Boilers and Natural Gas-Fired Chillers

	Energy Consumption	Unit	eGrid Conv Factor	Unit	GHG	Unit
Natural Gas	157,703	MMBTU	53.27	kg/MMBTU	8,401	Metric Tons
470 Capital Ave. Electricity	13,137	MWh	379.27	kg/MWh	4,982	Metric Tons
Total					**13,383**	Metric Tons

Base Case: CDECCA Contract

	Energy Consumption	Unit	eGrid Conv Factor	Unit	GHG	Unit
Natural Gas	225,737	MMBTU	53.27	0.00	12,025	Metric Tons
470 Capital Ave. Electricity	12,161	MWh	379.27	kg/MWh	4,612	Metric Tons
Hot and Chilled Water System Electricity	6,034	MWh	379.27	kg/MWh	2,289	Metric Tons
Total					**18,926**	Metric Tons

Net GHG Reduction with Option #2 (Metric Tons)	**5,543**

Air Pollutant Emission

Air Contaminent Emission Rates for Natural Gas Fired Chiller		
NOx	50	ppmv
CO	25	ppmv
UHC	25	ppmv

Annual Chiller Air Contaminent Emissions		
NOx	**0.2**	tons
CO	**0.1**	tons
UHC	**0.1**	tons

Air Contaminent Emission Rates for Boilers		
NOx	0.035	lb/MMBtu
CO	0.04	lb/MMBtu
UHC	0.004	lb/MMBtu

Annual Boiler Air Contaminent Emissions		
NOx	**1.7**	tons
CO	**2.0**	tons
UHC	**0.2**	tons

State of CT DPW Central Plant Analysis - Option 3: Jenbacher 320 Reciprocating Engine

Number of Jenbacher 320 Engines	1	
Output of Each Engine	1059	kW
Net Heat Rate [LHV]	8,954	BTU/kWh
Net Heat Rate [HHV]	9,949	BTU/kWh
One Therm	100,000	BTU

Cogen Plant Size	1059	kW

Number of Hours Trigen Plant Off-Line*	432	hrs/year
Number of Days Trigen Off-Line*	18	days/year
Trigen Plant Reliability	95.07%	%

**Note: Forced or Maintenance Outage (Jan - 3 days; April - 7 days; July - 3 days; Oct - 7 days)*

Enthalpy of Steam @ 15 psig	1164.1	BTU/lb
HRSG Steam Capacity	2,003	lb/hr
Thermal Production per Unit	4710	MBTU/hr
Electric Chiller Efficiency	0.50	kW/ton
Hot Water Absorption Chiller Rating	75	tons
Hot Water Absoprtion Chiller Hot Water Consumption	2.19	GPM/ton
Full-Load Hot Water Absorption Chiller Credit	38	kW
Hot Water Absorption Chiller Annual Electric Credit	202,324	kWh
Steam Absorption Chiller Rating	120	tons
Steam Absoprtion Chiller Steam Consumption	17.25	(lb/hr)/ton
Full-Load Steam Absorption Chiller Credit	60	kW
Steam Absorption Chiller Annual Electric Credit	233,953	kWh
Central Plant Hot Water Boiler Efficiency	85%	%
Thermal Energy Plant Boiler System Electric Consumption	10.10	kW/MMBTU
Thermal Energy Plant Chilled Water System Electric Consumption	0.85	kW/ton

Electric Side

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Electric Consumption (kWh)	1,236,898	1,107,431	1,160,998	1,299,335	1,654,856	1,954,732	2,088,541	1,874,427	1,611,169	1,286,616	1,242,560	1,203,945	17,721,508
Trigen Plant Electric Production (kWh)	737,064	711,648	606,311	761,467	787,896	762,207	787,896	737,064	762,480	609,503	759,543	783,932	8,807,010
Peak Electric Demand (kW)	2,588	2,603	2,493	3,667	5,519	5,336	5,438	5,159	5,180	3,777	3,851	2,541	5,519
Peak Trigen Plant Electric Production (kW)	1,059	1,059	1,059	1,059	1,059	1,059	1,059	1,059	1,059	1,059	1,059	1,059	1,059
Electricity Purchased (kWh)	499,834	395,783	554,687	537,869	866,960	1,192,526	1,300,645	1,137,363	848,689	677,114	483,017	420,013	8,914,498
Peak Electricity Purchased (kW)	2,486	1,544	2,387	2,608	4,460	4,277	4,379	4,879	4,121	3,030	3,049	1,482	4,879

Gas Side

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Trigen Plant Fuel Consumed (decatherms)	7,333	7,080	6,032	7,576	7,839	7,583	7,839	7,333	7,586	6,064	7,557	7,799	87,620
Trigen Plant Peak Fuel Demand (decatherms)	11	11	11	11	11	11	11	11	11	11	11	11	11
Central Plant Boiler Fuel Consumed (decatherms)	15,991	14,660	9,913	4,212	2,614	1,591	1,328	1,366	1,681	4,147	10,541	19,955	87,999
Central Plant Boiler Peak Fuel Demand (decatherms)	31	33	26	14	16	4	3	4	5	16	26	42	42
Total Natural Gas Consumption (decatherms)	23,324	21,740	15,945	11,787	10,453	9,174	9,167	8,699	9,266	10,211	18,098	27,755	175,619
Total Peak Gas Daily Demand (decatherms)	986	898	721	490	460	328	313	319	328	540	734	1,110	1,110

Hot Water Side

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Hours in the Month	744	672	744	720	744	720	744	744	720	744	720	744	8,760
Hot Water Consumption (MMBTU)	15,053	13,871	9,585	4,790	2,892	1,451	1,141	1,188	1,575	4,286	10,441	18,515	84,788
Trigen Plant Steam Production (Mlb)	1,394	1,346	1,147	1,440	1,490	1,441	1,490	1,394	1,442	1,153	1,436	1,483	16,656
Trigen Plant Steam Production for Heating (Mlb)	1,394	1,346	1,106	1,155	639	94	11	26	140	726	1,413	1,483	9,534
Trigen Plant Hot Water Production (MMBTU)	1,475	1,424	1,213	1,524	1,577	1,525	1,577	1,475	1,526	1,220	1,520	1,569	17,626
Trigen Plant Hot Water Production for Heating (MMBTU)	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak Hot Water Demand (MMBTU)	28	30	24	14	16	5	4	4	6	15	25	38	38
Peak Trigen Steam Production (Mlbs)	2	2	2	2	2	2	2	2	2	2	2	2	2
Peak Trigen Steam Production for Heating (Mlbs)	2	2	2	2	2	2	1	1	2	2	2	2	2
Peak Trigen Hot Water Production for Heating (MMBTU)	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam Produced by Central Plant Boilers (MMBTU)	13,592	12,461	8,426	3,580	2,222	1,352	1,129	1,161	1,429	3,525	8,960	16,962	74,799
Peak Central Plant Steam Production for Heating (MMBTU)	26	28	22	12	14	3	3	3	4	13	23	36	36
Steam Produced by Central Plant Boilers (Mlbs)	11,676	10,704	7,238	3,075	1,909	1,162	970	997	1,227	3,028	7,697	14,571	64,255
Peak Central Plant Steam Production for Heating (Mlbs)	22	24	19	10	12	3	2	3	3	11	19	31	31

Chilled Water Side

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Chilled Water Consumption (ton-hrs)	202,638	182,122	322,184	399,180	708,568	1,034,887	1,221,670	1,007,751	769,909	394,325	268,471	189,169	6,700,876
Trigen Plant Chilled Water Production (ton-hrs)	0	0	0	71,610	120,000	139,204	145,080	135,720	138,840	75,499	41,398	0	867,350
Central Plant Electric Chiller Production (ton-hrs)	0	0	0	297,476	588,568	895,683	1,076,590	872,031	631,069	318,826	189,705	0	4,869,949
Peak Chilled Water Demand (tons)	808	729	1,407	1,750	3,032	3,040	3,439	3,242	3,509	1,993	1,307	964	3,509
Peak Trigen Plant Chilled Water Production (tons)	0	0	0	195	195	195	195	195	195	195	195	0	195
Peak Central Plant Electric Chillers Chilled Water Production (tons)	0	0	0	1,555	2,837	2,845	3,244	3,242	3,314	1,824	1,232	0	3,314
Absorption Chiller Electric Consumption Reduction* (kWh)	0	0	0	36,020	60,360	70,020	72,975	68,267	69,837	37,976	20,823	0	436,277
Central Plant Free-Cooling Production (ton-hrs)	202,638	182,122	322,184	30,094	0	0	0	0	0	0	37,369	189,169	963,576
Peak Central Plant Free-Cooling Production (tons)	808	729	1,407	674	0	0	0	0	0	0	551	964	1,407

***Note:** *This electric consumption reduction is reflected in the "Electric Side" Electric Consumption values shown above.*

470 Capitol Avenue Complex Back-up/Standby Electricity Expense
- Option 3: Jenbacher 320 Reciprocating Engine

	January	February	March	April	May	June	July	August	September	October	November	December
Total On-Peak (kWh)	299,900	237,470	332,812	322,721	520,176	715,515	780,387	682,418	509,213	406,268	289,810	252,008
Total Off-Peak (kWh)	199,933	158,313	221,875	215,148	346,784	477,010	520,258	454,945	339,475	270,845	193,207	168,005
Total (kWh)	499,834	395,783	554,687	537,869	866,960	1,192,526	1,300,645	1,137,363	848,689	677,114	483,017	420,013
Actual Peak Demand (kW)	2,486	1,544	2,387	2,608	4,460	4,277	4,379	4,879	4,121	3,030	3,049	1,482
Rachet Demand (kW)	4,879	4,879	4,879	4,879	4,879	4,879	4,879	4,879	4,879	4,879	4,879	4,879
	Transmission Charges											
Transmission Charge Factor ($/kW)	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93
Transmission Charge kW Total ($)	$14,744	$9,158	$14,157	$15,468	$26,448	$25,363	$25,965	$28,930	$24,438	$17,965	$18,078	$8,790
	Distribution Charges											
Customer Service Charge ($)	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025
Distribution Charge kW Factor ($/kW)	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02
Distribution Charge kW Total ($)	$29,369	$29,369	$29,369	$29,369	$29,369	$29,369	$29,369	$29,369	$29,369	$29,369	$29,369	$29,369
FMCC Delivery Charge On Peak Factor ($/kWh)	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055
FMCC Delivery Charge On Peak Total ($)	$1,655	$1,311	$1,837	$1,781	$2,871	$3,950	$4,308	$3,767	$2,811	$2,243	$1,600	$1,391
FMCC Delivery Charge Off Peak Factor ($/kWh)	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012
FMCC Delivery Charge Off Peak Total ($)	$240	$190	$266	$258	$416	$572	$624	$546	$407	$325	$232	$202
Competitive Transition Assessment												
Demand Charge Factor ($/kW)	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46
Demand Charge Total ($)	$3,630	$2,255	$3,486	$3,808	$6,512	$6,245	$6,393	$7,123	$6,017	$4,423	$4,451	$2,164
CTA kWh Charge Factor ($/kWh)	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219
CTA kWh Charge Total ($)	$1,095	$867	$1,215	$1,178	$1,899	$2,612	$2,848	$2,491	$1,859	$1,483	$1,058	$920
Combined Public Benefits Charge ($/kWh)	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426
Combined Public Benefits Total ($)	$2,129	$1,686	$2,363	$2,291	$3,693	$5,080	$5,541	$4,845	$3,615	$2,885	$2,058	$1,789
Economic Transition Charge ($/kWh)	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379
Economic Transition Charge Total ($)	$1,894	$1,500	$2,102	$2,039	$3,286	$4,520	$4,929	$4,311	$3,217	$2,566	$1,831	$1,592
Total Transmission and Delivery Charges ($)	**$55,781**	**$47,360**	**$55,820**	**$57,218**	**$75,519**	**$78,735**	**$81,002**	**$82,406**	**$72,758**	**$62,284**	**$59,701**	**$47,242**
	Supply											
Supply Charge Factor ($/kWh)	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319
Total Supply Charges ($)	**$41,581**	**$32,925**	**$46,144**	**$44,745**	**$72,122**	**$99,206**	**$108,201**	**$94,617**	**$70,602**	**$56,329**	**$40,182**	**$34,941**
	Total											
Total Electric Charges ($)	**$97,363**	**$80,285**	**$101,965**	**$101,963**	**$147,642**	**$177,941**	**$189,203**	**$177,024**	**$143,360**	**$118,613**	**$99,883**	**$82,183**
Average Electric Rate ($/kWh)	$0.19	$0.20	$0.18	$0.19	$0.17	$0.15	$0.15	$0.16	$0.17	$0.18	$0.21	$0.20

Total Annual Electrcity Expense ($):	**$1,517,424**

State of CT DPW Central Plant Natural Gas Expense - Option 3: Jenbacher 320 Reciprocating Engine

	January	February	March	April	May	June	July	August	September	October	November	December
Natural Gas Consumption (therms)	233,241	217,402	159,454	117,873	104,526	91,740	91,670	86,986	92,664	102,109	180,980	277,545
Adjustments (therms)	-	-	-	-	-	-	-	-	-	-	-	-
Total Consumption (therms)	233,241	217,402	159,454	117,873	104,526	91,740	91,670	86,986	92,664	102,109	180,980	277,545
Total Consumption (CCF)	226,228	210,865	154,659	114,329	101,383	88,982	88,914	84,370	89,878	99,039	175,538	269,200
Demand Peak Day (therms)	9,857	8,983	7,212	4,902	4,604	3,277	3,132	3,189	3,276	5,400	7,338	11,102
Demand Charge Rate ($/CCF)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Demand Charges ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Delivery Rate First 5000 CCF ($/CCF)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Total Delivery Charge First 5000 CCF	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Delivery Rate Rest of CCF ($/CCF)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Total Delivery Charge Rest of CCF ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Rate Credit Factor ($/CCF)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)
Rate Credit Total ($)	($13,958)	($13,010)	($9,542)	($7,054)	($6,255)	($5,490)	($5,486)	($5,206)	($5,545)	($6,111)	($10,831)	($16,610)
SSC Rate ($/CCF)	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324
SSC Total ($)	$7,330	$6,832	$5,011	$3,704	$3,285	$2,883	$2,881	$2,734	$2,912	$3,209	$5,687	$8,722
Customer Charge	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Telemetering Charge	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transportation Service Charge ($/CCF)	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
Transportation Service Supply Cost ($)	$165,146	$153,931	$112,901	$83,460	$74,010	$64,957	$64,907	$61,590	$65,611	$72,298	$128,143	$196,516
Conservation Adjustment Rate ($/CCF)	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084
Conservation Adjustment Charge ($/CCF)	$1,900	$1,771	$1,299	$960	$852	$747	$747	$709	$755	$832	$1,475	$2,261
Total Natural Gas Charges ($)	**$160,418**	**$149,524**	**$109,669**	**$81,071**	**$71,891**	**$63,097**	**$63,049**	**$59,827**	**$63,732**	**$70,228**	**$124,474**	**$190,890**
Average Natural Gas Rate ($/decatherm)	6.88	6.88	6.88	6.88	6.88	6.88	6.88	6.88	6.88	6.88	6.88	6.88

Total Annual Gas Expense ($):	**$1,207,871**

State of CT DPW Central Plant Water Expense - Option 3: Jenbacher 320 Reciprocating Engine

	January	February	March	April	May	June	July	August	September	October	November	December
Steam Production (Mlbs)	13,070	12,050	8,385	4,515	3,399	2,603	2,460	2,391	2,669	4,181	9,134	16,053
Steam Production (lbs)	13,070,308	12,050,315	8,385,101	4,515,310	3,398,715	2,603,157	2,460,000	2,391,087	2,669,142	4,180,756	9,133,516	16,053,491
Total Make-up Water Requirements (lbs)	653,515	602,516	419,255	225,765	169,936	130,158	123,000	119,554	133,457	209,038	456,676	802,675
Total Make-up Water Requirements (gallons)	78,309	72,198	50,238	27,053	20,363	15,597	14,739	14,326	15,992	25,049	54,723	96,183

Total Hot Water Production System Make-up Water (gallons)	484,769

	January	February	March	April	May	June	July	August	September	October	November	December
Chilled Water Production (ton-hrs)	202,638	182,122	322,184	399,180	708,568	1,034,887	1,221,670	1,007,751	769,909	394,325	268,471	189,169
Evaporated Cooling Water Make-up to Cooling Tower (gallons)	506,595	455,305	805,460	997,950	1,771,421	2,587,217	3,054,176	2,519,378	1,924,773	985,812	671,178	472,924

Total Evaporated Cooling Tower Water (gallons)	16,752,190

Total Water Usage (gallons)	**17,236,959**

Cost of Water and Chemicals:	$5.00	$/1000 gallons
CT State and Local Surcharges:	0.96	%
State and Local Taxes:	6.00	%

Cost of Water and Chemicals ($)	$86,185
CT State and Local Surcharges ($):	$827
CT Sales Tax ($):	$5,171
Total Annual Water Expense ($):	**$92,182**

State of CT DPW Central Plant O&M Expense
- Option 3: Jenbacher 320 Reciprocating Engine

	Power (Electricity)		Mechanical Cooling (Chilled Water)		Heating (Steam)	
	kW (peak)	kWhrs (annual)	tons (peak)	ton-hrs (annual)	Mlbs (peak)	Mlbs (annual)
Trigeneration Plant	1,059	8,807,010	195	867,350	2	16,656

	Mechanical Cooling (Chilled Water)		Heating (Steam)		Free Cooling (Chilled Water)	
	tons (peak)	ton-hrs (annual)	MMBTU (peak)	MMBTU (annual)	tons (peak)	ton-hrs (annual)
Central Plant	3,314	4,869,949	36	74,799	1,407	963,576

O&M Rate (Generators)	$0.015	$/kWhr
O&M Rate (HRSG):	$0.251	$/Mlb
O&M Rate (Absorption Chillers):	$0.015	$/ton-hr
O&M Rate (Steam Boiler and Auxiliaries):	$0.300	$/MMBTU
O&M Rate (Electric Chiller and Auxiliaries):	$0.012	$/ton-hr
O&M Rate (Cooling Tower and Auxiliaries):	$0.005	$/ton-hr
Free-Cooling Heat Exchanger Mtce.	$15,000	$/yr
Pump House Equipment Maintenance	$225,000	$/yr

Annual Equipment Mtce Cost*:	$548,756

Note: Includes 10% mark-up by 3rd party contractor.

	# of Employees Required	Employee Salary ($/yr)	Employee Benefits	3rd Party Contractor Markup (10%)	Total Annual Expenditure
Plant Manager	0.0	$90,000	$36,000	$12,600	$0
Operator	0.5	$80,000	$32,000	$11,200	$61,600
Mechanic/Electrician	0.0	$70,000	$28,000	$9,800	$0
I&C Technician	0.0	$70,000	$28,000	$9,800	$0
Totals	0.5				$61,600

Note**:** Benefits are assumed to be 40% of the employees salary. Final value includes 10% mark-up by 3rd party contractor.

Annual O&M Cost	**$610,356**

State of CT DPW Central Plant Capital Expense
- Option 3: Jenbacher 320 Reciprocating Engine

	Power (Electricity)		Mechanical Cooling (Chilled Water)		Heating (Steam)	
	kW (peak)	kWhrs (annual)	tons (peak)	ton-hrs (annual)	Mlbs (peak)	Mlbs (annual)
Trigeneration Plant	1,059	8,807,010	195	867,350	2	16,656

	Mechanical Cooling (Chilled Water)		Heating (Steam)		Free Cooling (Chilled Water)	
	tons (peak)	ton-hrs (annual)	lbs/hr (peak)	lbs (annual)	tons (peak)	ton-hrs (annual)
Central Plant	3,314	4,869,949	31,017	64,254,990	1,407	963,576

	Installed Mechanical Cooling Capacity (Chilled Water)	Installed Heating Capacity (Steam)	Installed Free Cooling Capacity (Chilled Water)
	tons	lbs/hr	tons
Central Plant	5,400	45,000	1,500

Central Plant

Generators and HRSG's	$2,500	$/kW
Absorption Chillers	$1,400	$/ton
Electric Chillers and Auxiliaries	$1,000	$/ton
Steam Boilers and Auxiliaries	$50,000	$/MMBTU
Cooling Towers and Auxiliaries	$280	$/ton

Generators, HRSG's and Auxiliary Equipment ($):	**$2,647,500**
Absorption Chillers and Auxiliary Equipment ($):	**$273,000**
Electric Chillers and Chilled Water Pumps ($):	**$5,205,000**
Steam Boilers and Auxiliaries ($):	**$2,502,653**
Electrical Switchboard and MCC ($):	**$1,660,000**
Chilled and Condenser Water Piping ($):	**$393,750**
Cooling Towers ($):	**$1,512,000**
Free-Cooling Heat Exchanger and Control Valves ($):	**$225,000**
Trigeneration Plant Enclosure ($):	**$360,000**
Distributed Control System ($):	**$780,000**
Engineering ($):	**$1,358,317**
Construction Management ($):	**$617,417**
Commissioning and Start-up ($):	**$308,708**
10% Overhead and Profit Margin ($):	**$1,784,334**
20% Estimating and Construction Contingency ($):	**$3,568,669**
Permitting ($):	**$57,991**
5% Sales Tax ($):	**$777,945**

Total Capital Expenditure ($):	**$21,111,784**

Financing Charges

Length of Loan (years):	20	years
Cost of Capital (decimal equivalent):	0.0350	

Monthly Payment ($):	**$123,787**

State of CT DPW Central Plant Capital Expense
- Option 3: Jenbacher 320 Reciprocating Engine

Greenhouse Gas Emission

eGrid Conversion Factors				
	lbs/kWh	GHG Factor	GHG Weighting	
CO2	827.95	1	827.95	lbs/MWh
Methane	0.07698	25	1.9245	lbs/MWh
N2O	0.0152	298	4.5296	lbs/MWh
Total for Electricity			834.4041	lbs/MWh
			379.27	kg/MWh
Total for District Steam			86.845	kg/Mlb
Total for Natural Gas			53.27	kg/MMBTU

Option 3: Reciprocating Engine CHP Plant

	Energy Consumption	Unit	eGrid Conv Factor	Unit	GHG	Unit
Natural Gas	175,619	MMBTU	53.27	kg/MMBTU	9,355	Metric Tons
470 Capital Ave. Electricity	8,914	MWh	379.27	kg/MWh	3,381	Metric Tons
Total					**12,736**	Metric Tons

Base Case: CDECCA Contract

	Energy Consumption	Unit	eGrid Conv Factor	Unit	GHG	Unit
Natural Gas	225,737	MMBTU	53.27	0.00	12,025	Metric Tons
470 Capital Ave. Electricity	12,161	MWh	379.27	kg/MWh	4,612	Metric Tons
Hot and Chilled Water System Electricity	6,034	MWh	379.27	kg/MWh	2,289	Metric Tons
Total					**18,926**	Metric Tons

Net GHG Reduction with Option #3 (Metric Tons)	**6,190**

Air Pollutant Emission

Air Contaminant Emission Rates for Jenbacher 320		
NOx	0.6	g/bhp-hr
CO	1.2	g/bhp-hr
NMEHC	0.6	g/bhp-hr

Annual Jen 320 Air Contaminant Emissions		
NOx	**9.0**	tons
CO	**17.9**	tons
NMEHC	**9.0**	tons

Air Contaminent Emission Rates for Boilers		
NOx	0.035	lb/MMBtu
CO	0.04	lb/MMBtu
UHC	0.004	lb/MMBtu

Annual Boiler Air Contaminent Emissions		
NOx	**1.5**	tons
CO	**1.8**	tons
UHC	**0.2**	tons

State of CT DPW Central Plant Analysis - Option 4: Solar Saturn 20 Gas Turbine

Number of Solar Saturn 20 Gas Turbines	1	
Nominal Output of Each Engine	1210	kW
Nominal Net Heat Rate [LHV]	14,732	BTU/kWh
Nominal Net Heat Rate [HHV]	16,369	BTU/kWh
One Therm	100,000	BTU
Central Plant Hot Water Boiler Efficiency	85%	%
Nominal Trigen Plant Size	1210	kW
Thermal Energy Plant Boiler System Electric Consumption	10.10	kW/MMBTU
Thermal Energy Plant Chilled Water System Electric Consumption	0.85	kW/ton

Enthalpy of Steam @ 15 psig	1164.1	BTU/lb
Plant Operating Point	100%	%
Individual HRSG Steam Capacity	8,100	lb/hr
Electric Chiller Efficiency	0.50	kW/ton
Absorption Chiller Rating	493	tons
Absoprtion Chiller 15 psig Steam Consumption	8,290	lb/hr
Full-Load Absorption Chiller Credit	248	kW
Absorption Chiller Annual Electric Credit	0	kWh
Number of Hours Trigen Plant Off-Line*	432	hrs/year
Number of Days Trigen Off-Line*	18	days/year
Trigen Plant Reliability	95.07%	%

**Note: Forced or Maintenance Outage (Jan - 3 days; April - 7 days; July - 3 days; Oct - 7 days)*

Electric Side

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Electric Consumption (kWh)	1,199,916	1,071,021	1,132,567	1,272,625	1,591,035	1,854,772	1,972,234	1,773,181	1,522,839	1,259,378	1,235,921	1,164,423	17,049,912
Trigen Plant Electric Production (kWh)	832,456	801,075	655,743	854,809	893,377	863,787	880,886	824,315	859,381	678,813	847,180	876,399	9,868,219
Peak Electric Demand (kW)	2,534	2,548	2,439	3,460	5,326	5,148	5,281	4,994	5,013	3,648	3,859	2,488	5,326
PeakTrigen Plant Electric Production (kW)	1,204	1,204	1,204	1,204	1,204	1,204	1,204	1,204	1,204	1,204	1,204	1,204	1,204
Electricity Purchased (kWh)	367,460	269,946	476,825	417,816	697,658	990,985	1,091,348	948,866	663,458	580,565	388,741	288,024	7,181,693
Peak Electricity Purchased (kW)	2,486	1,344	2,387	2,256	4,122	3,944	4,077	4,879	3,809	3,030	3,146	1,284	4,879

Gas Side

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Trigen Plant Fuel Consumed (decatherms)	12,956	12,407	9,788	13,163	13,898	13,441	13,794	12,870	13,302	10,389	12,981	13,488	152,477
Trigen Plant Peak Fuel Demand (decatherms)	19	19	19	19	19	19	19	19	19	19	19	19	19
Central Plant Boiler Fuel Consumed (decatherms)	11,008	9,795	6,145	485	99	0	0	87	0	1,513	5,368	14,706	49,207
Central Plant Boiler Peak Fuel Demand (decatherms)	26	26	26	7	9	0	0	4	0	11	19	35	35
Total Natural Gas Consumption (decatherms)	23,963	22,202	15,933	13,648	13,997	13,441	13,794	12,958	13,302	11,902	18,349	28,193	201,684
Total Peak Gas Daily Demand (decatherms)	1,011	921	740	509	501	451	446	446	451	559	750	1,136	1,136

Hot Water Side

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Hours in the Month	744	672	744	720	744	720	744	744	720	744	720	744	8,760
Hot Water Consumption (MMBTU)	15,053	13,871	9,585	4,790	2,892	1,451	1,141	1,188	1,575	4,286	10,441	18,515	84,788
Trigen Plant Steam Production (Mlb)	5,437	5,293	4,163	5,680	6,005	5,819	6,010	5,611	5,784	4,572	5,708	5,742	65,824
Peak Trigen Plant Steam Production (Mlb)	8	8	8	8	8	8	8	8	8	8	8	8	8
Trigen Plant Steam Production for Heating (Mlb)	5,437	5,293	4,163	4,178	2,679	1,385	1,089	1,064	1,504	2,863	5,610	5,742	41,006
Peak Hot Water Demand (MMBTU)	28	30	24	14	16	5	4	4	6	15	25	38	38
Peak Trigen Steam Production for Heating (Mlbs)	8	8	8	8	8	5	3	4	6	8	8	8	8
Hot Water Produced by Central Plant Boilers (MMBTU)	9,356	8,326	5,223	412	85	0	0	74	0	1,286	4,563	12,500	41,826
Peak Central Plant Hot Water Production (MMBTU)	22	22	22	6	7	0	0	3	0	9	16	30	30

Chilled Water Side

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Chilled Water Consumption (ton-hrs)	202,638	182,122	322,184	399,180	708,568	1,034,887	1,221,670	1,007,751	769,909	394,325	268,471	189,169	6,700,876
Trigen Plant Chilled Water Production (ton-hrs)	0	0	0	89,306	197,792	263,187	292,692	270,454	254,366	100,620	4,332	0	1,472,750
Trigen Plant Absorption Chiller Steam Consumption (Mlbs)	0	0	0	1,502	3,326	4,434	4,922	4,548	4,280	1,709	97	0	24,818
Central Plant Electric Chiller Production (ton-hrs)	0	0	0	279,780	510,777	771,699	928,978	737,297	515,543	293,705	226,770	0	4,264,550
Peak Chilled Water Demand (tons)	808	729	1,407	1,750	3,032	3,040	3,439	3,242	3,509	1,993	1,307	964	3,509
PeakTrigen Plant Chilled Water Production (tons)	0	0	0	479	482	474	478	484	484	483	342	0	484
Peak Central Plant Electric Chillers Chilled Water Production (tons)	0	0	0	1,301	2,636	2,644	3,071	3,242	3,099	1,691	1,307	0	3,242
Absorption Chiller Electric Consumption Reduction* (kWh)	0	0	0	44,921	99,489	132,383	147,224	136,038	127,946	50,612	2,179	0	740,793
Central Plant Free-Cooling Production (ton-hrs)	202,638	182,122	322,184	30,094	0	0	0	0	0	0	37,369	189,169	963,576
Peak Central Plant Free-Cooling Production (tons)	808	729	1,407	674	0	0	0	0	0	0	551	964	1,407

***Note:** *This electric consumption reduction is reflected in the "Electric Side" Electric Consumption values shown above.*

State of CT DPW Central Plant Analysis - Full-Load Performance Data for Solar Saturn 20 CTG and Cleaver-Brooks HRSG

Ambient Temperature (°F)	CTG Power (kW)	CTG HHV Heat Rate (Btu/kWh)	CTG Exhaust Gas Temperature (°F)	CTG Exhaust Gas Stream (lbs/hr)	HRSG Steam Production (lbs/hr)
0	1,204	15,848	716.0	56,449	7,336
20	1,204	15,661	795.0	54,785	7,890
40	1,204	15,586	872.0	53,438	8,084
60	1,204	15,602	946.0	51,793	8,100
80	1,127	15,882	977.0	49,764	8,035
100	1,046	16,299	999.0	47,394	7,948

470 Capitol Avenue Complex Back-up/Standby Electricity Expense - Option 4: Solar Saturn 20 Gas Turbine

	January	February	March	April	May	June	July	August	September	October	November	December
Total On-Peak (kWh)	220,476	161,968	286,095	250,690	418,595	594,591	654,809	569,320	398,075	348,339	233,245	172,814
Total Off-Peak (kWh)	146,984	107,978	190,730	167,127	279,063	396,394	436,539	379,546	265,383	232,226	155,497	115,210
Total (kWh)	367,460	269,946	476,825	417,816	697,658	990,985	1,091,348	948,866	663,458	580,565	388,741	288,024
Actual Peak Demand (kW)	2,486	1,344	2,387	2,256	4,122	3,944	4,077	4,879	3,809	3,030	3,146	1,284
Rachet Demand (kW)	4,879	4,879	4,879	4,879	4,879	4,879	4,879	4,879	4,879	4,879	4,879	4,879
	Transmission Charges											
Transmission Charge Factor ($/kW)	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93
Transmission Charge kW Total ($)	$14,744	$7,968	$14,157	$13,378	$24,441	$23,386	$24,179	$28,930	$22,588	$17,965	$18,658	$7,613
	Distribution Charges											
Customer Service Charge ($)	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025
Distribution Charge kW Factor ($/kW)	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02
Distribution Charge kW Total ($)	$29,369	$29,369	$29,369	$29,369	$29,369	$29,369	$29,369	$29,369	$29,369	$29,369	$29,369	$29,369
FMCC Delivery Charge On Peak Factor ($/kWh)	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055
FMCC Delivery Charge On Peak Total ($)	$1,217	$894	$1,579	$1,384	$2,311	$3,282	$3,615	$3,143	$2,197	$1,923	$1,288	$954
FMCC Delivery Charge Off Peak Factor ($/kWh)	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012
FMCC Delivery Charge Off Peak Total ($)	$176	$130	$229	$201	$335	$476	$524	$455	$318	$279	$187	$138
Competitive Transition Assessment												
Demand Charge Factor ($/kW)	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46
Demand Charge Total ($)	$3,630	$1,962	$3,486	$3,294	$6,017	$5,758	$5,953	$7,123	$5,561	$4,423	$4,594	$1,874
CTA kWh Charge Factor ($/kWh)	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219
CTA kWh Charge Total ($)	$805	$591	$1,044	$915	$1,528	$2,170	$2,390	$2,078	$1,453	$1,271	$851	$631
Combined Public Benefits Charge ($/kWh)	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426
Combined Public Benefits Total ($)	$1,565	$1,150	$2,031	$1,780	$2,972	$4,222	$4,649	$4,042	$2,826	$2,473	$1,656	$1,227
Economic Transition Charge ($/kWh)	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379
Economic Transition Charge Total ($)	$1,393	$1,023	$1,807	$1,584	$2,644	$3,756	$4,136	$3,596	$2,515	$2,200	$1,473	$1,092
Total Transmission and Delivery Charges ($)	**$53,924**	**$44,112**	**$54,728**	**$52,929**	**$70,642**	**$73,443**	**$75,839**	**$79,761**	**$67,853**	**$60,929**	**$59,100**	**$43,923**
	Supply											
Supply Charge Factor ($/kWh)	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319
Total Supply Charges ($)	**$30,569**	**$22,457**	**$39,667**	**$34,758**	**$58,038**	**$82,440**	**$90,789**	**$78,936**	**$55,193**	**$48,297**	**$32,339**	**$23,961**
	Total											
Total Electric Charges ($)	**$84,493**	**$66,569**	**$94,395**	**$87,687**	**$128,680**	**$155,883**	**$166,629**	**$158,698**	**$123,046**	**$109,226**	**$91,440**	**$67,884**
Average Electric Rate ($/kWh)	$0.23	$0.25	$0.20	$0.21	$0.18	$0.16	$0.15	$0.17	$0.19	$0.19	$0.24	$0.24

Total Annual Electrcity Expense ($):	**$1,334,629**

State of CT DPW Central Plant Natural Gas Expense - Option 4: Solar Saturn 20 Gas Turbine

	January	February	March	April	May	June	July	August	September	October	November	December
Natural Gas Consumption (therms)	239,632	222,024	159,331	136,477	139,971	134,415	137,941	129,577	133,023	119,023	183,491	281,935
Adjustments (therms)	-	-	-	-	-	-	-	-	-	-	-	-
Total Consumption (therms)	239,632	222,024	159,331	136,477	139,971	134,415	137,941	129,577	133,023	119,023	183,491	281,935
Total Consumption (CCF)	232,427	215,348	154,540	132,373	135,763	130,373	133,793	125,681	129,024	115,444	177,974	273,457
Demand Peak Day (therms)	10,112	9,212	7,396	5,092	5,011	4,508	4,455	4,464	4,508	5,587	7,497	11,357
Demand Charge Rate ($/CCF)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Demand Charges ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Delivery Rate First 5000 CCF ($/CCF)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Total Delivery Charge First 5000 CCF	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Delivery Rate Rest of CCF ($/CCF)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Total Delivery Charge Rest of CCF ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Rate Credit Factor ($/CCF)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)
Rate Credit Total ($)	($14,341)	($13,287)	($9,535)	($8,167)	($8,377)	($8,044)	($8,255)	($7,754)	($7,961)	($7,123)	($10,981)	($16,872)
SSC Rate ($/CCF)	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324
SSC Total ($)	$7,531	$6,977	$5,007	$4,289	$4,399	$4,224	$4,335	$4,072	$4,180	$3,740	$5,766	$8,860
Customer Charge	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Telemetering Charge	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transportation Service Charge ($/CCF)	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
Transportation Service Supply Cost ($)	$169,671	$157,204	$112,814	$96,632	$99,107	$95,173	$97,669	$91,747	$94,187	$84,274	$129,921	$199,624
Conservation Adjustment Rate ($/CCF)	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084
Conservation Adjustment Charge ($/CCF)	$1,952	$1,809	$1,298	$1,112	$1,140	$1,095	$1,124	$1,056	$1,084	$970	$1,495	$2,297
Total Natural Gas Charges ($)	**$164,814**	**$152,704**	**$109,584**	**$93,866**	**$96,269**	**$92,448**	**$94,873**	**$89,120**	**$91,491**	**$81,862**	**$126,201**	**$193,909**
Average Natural Gas Rate ($/decatherm)	6.88	6.88	6.88	6.88	6.88	6.88	6.88	6.88	6.88	6.88	6.88	6.88

Total Annual Gas Expense ($):	**$1,387,140**

State of CT DPW Central Plant Water Expense - Option 4: Solar Saturn 20 Gas Turbine

	January	February	March	April	May	June	July	August	September	October	November	December
Steam Production (Mlbs)	13,475	12,445	8,650	6,034	6,078	5,819	6,010	5,675	5,784	5,677	9,627	16,479
Steam Production (lbs)	13,474,625	12,444,997	8,650,186	6,034,287	6,077,897	5,818,853	6,010,496	5,675,095	5,783,761	5,676,940	9,627,272	16,479,411
Total Make-up Water Requirements (lbs)	673,731	622,250	432,509	301,714	303,895	290,943	300,525	283,755	289,188	283,847	481,364	823,971
Total Make-up Water Requirements (gallons)	80,732	74,563	51,827	36,154	36,415	34,863	36,011	34,002	34,653	34,013	57,681	98,735

Total Hot Water Production System Make-up Water (gallons)	609,647

	January	February	March	April	May	June	July	August	September	October	November	December
Chilled Water Production (ton-hrs)	202,638	182,122	322,184	399,180	708,568	1,034,887	1,221,670	1,007,751	769,909	394,325	268,471	189,169
Evaporated Cooling Water Make-up to Cooling Tower (gallons)	506,595	455,305	805,460	997,950	1,771,421	2,587,217	3,054,176	2,519,378	1,924,773	985,812	671,178	472,924

Total Evaporated Cooling Tower Water (gallons)	16,752,190

Total Water Usage (gallons)	**17,361,837**

Cost of Water and Chemicals:	$5.00	$/1000 gallons
CT State and Local Surcharges:	0.96	%
State and Local Taxes:	6.00	%

Cost of Water and Chemicals ($)	$86,809
CT State and Local Surcharges ($):	$833
CT Sales Tax ($):	$5,209
Total Annual Water Expense ($):	**$92,850**

State of CT DPW Central Plant O&M Expense
- Option 4: Solar Saturn 20 Gas Turbine

	Power (Electricity)		Mechanical Cooling (Chilled Water)		Heating (Steam)	
	kW (peak)	kWhrs (annual)	tons (peak)	ton-hrs (annual)	Mlbs (peak)	Mlbs (annual)
Trigeneration Plant	1,210	9,868,219	484	1,472,750	8	41,006

	Mechanical Cooling (Chilled Water)		Heating (Steam)		Free Cooling (Chilled Water)	
	tons (peak)	ton-hrs (annual)	MMBTU (peak)	MMBTU (annual)	tons (peak)	ton-hrs (annual)
Central Plant	3,242	4,264,550	30	41,826	1,407	963,576

O&M Rate (Generators)	$0.015	$/kWhr
O&M Rate (HRSG):	$0.251	$/Mlb
O&M Rate (Absorption Chillers):	$0.015	$/ton-hr
O&M Rate (Steam Boiler and Auxiliaries):	$0.300	$/MMBTU
O&M Rate (Electric Chiller and Auxiliaries):	$0.012	$/ton-hr
O&M Rate (Cooling Tower and Auxiliaries):	$0.005	$/ton-hr
Free-Cooling Heat Exchanger Mtce.	$15,000	$/yr
Pump House Equipment Maintenance	$225,000	$/yr

Annual Equipment Mtce Cost*:	$564,119

Note: Includes 10% mark-up by 3rd party contractor.

	# of Employees Required	Employee Salary ($/yr)	Employee Benefits	3rd Party Contractor Markup (10%)	Total Annual Expenditure
Plant Manager	0.0	$90,000	$36,000	$12,600	$0
Operator	0.5	$80,000	$32,000	$11,200	$61,600
Mechanic/Electrician	0.0	$70,000	$28,000	$9,800	$0
I&C Technician	0.0	$70,000	$28,000	$9,800	$0
Totals	0.5				$61,600

Note: Benefits are assumed to be 40% of the employees salary. Final value includes 10% mark-up by 3rd party contractor.

Annual O&M Cost	**$625,719**

State of CT DPW Central Plant Capital Expense
- Option 4: Solar Saturn 20 Gas Turbine

	Power (Electricity)		Mechanical Cooling (Chilled Water)		Heating (Steam)	
	kW (peak)	kWhrs (annual)	tons (peak)	ton-hrs (annual)	Mlbs (peak)	Mlbs (annual)
Trigeneration Plant	1,210	9,868,219	484	1,472,750	8	41,006

	Mechanical Cooling (Chilled Water)		Heating (Steam)		Free Cooling (Chilled Water)	
	tons (peak)	ton-hrs (annual)	MMBTU (peak)	MMBTU (annual)	tons (peak)	ton-hrs (annual)
Central Plant	3,242	4,264,550	30	41,826	1,407	963,576

	Installed Mechanical Cooling Capacity (Chilled Water)	Installed Heating Capacity (Steam)	Installed Free Cooling Capacity (Chilled Water)
	tons	lbs/hr	tons
Central Plant	5,400	45,000	1,500

Central Plant

Generators and HRSG's	$2,000	$/kW
Absorption Chillers	$1,750	$/ton
Electric Chillers and Auxiliaries	$1,000	$/ton
Steam Boilers and Auxiliaries	$50,000	$/MMBTU
Cooling Towers and Auxiliaries	$280	$/ton

Generators, HRSG's and Auxiliary Equipment ($):	**$2,420,000**
Absorption Chillers and Auxiliary Equipment ($):	**$847,293**
Electric Chillers and Chilled Water Pumps ($):	**$4,907,000**
Steam Boilers and Auxiliaries ($):	**$2,147,765**
Electrical Switchboard and MCC ($):	**$1,660,000**
Chilled and Condenser Water Piping ($):	**$393,750**
Cooling Towers ($):	**$1,512,000**
Free-Cooling Heat Exchanger and Control Valves ($):	**$225,000**
Trigeneration Plant Enclosure ($):	**$360,000**
Distributed Control System ($):	**$780,000**
Engineering ($):	**$1,331,594**
Construction Management ($):	**$605,270**
Commissioning and Start-up ($):	**$302,635**
10% Overhead and Profit Margin ($):	**$1,749,231**
20% Estimating and Construction Contingency ($):	**$3,498,461**
Permitting ($):	**$56,850**
5% Sales Tax ($):	**$762,640**

Total Capital Expenditure ($):	**$20,292,197**

Financing Charges

Length of Loan (years):	20	years
Cost of Capital (decimal equivalent):	0.0350	

Monthly Payment ($):	**$118,982**

State of CT DPW Central Plant Emissions
- Option 4: Solar Saturn 20 Gas Turbine

Greenhouse Gas Emission

eGrid Conversion Factors				
	lbs/kWh	GHG Factor	GHG Weighting	
CO_2	827.95	1	827.95	lbs/MWh
Methane	0.07698	25	1.9245	lbs/MWh
N_2O	0.0152	298	4.5296	lbs/MWh
Total for Electricity			834.4041	lbs/MWh
			379.27	kg/MWh
Total for District Steam			86.845	kg/Mlb
Total for Natural Gas			53.27	kg/MMBTU

Option 4: Gas Turbine CHP Plant

	Energy Consumption	Unit	eGrid Conv Factor	Unit	GHG	Unit
Natural Gas	201,684	MMBTU	53.27	kg/MMBTU	10,744	Metric Tons
470 Capital Ave. Electricity	7,182	MWh	379.27	kg/MWh	2,724	Metric Tons
Total					**13,468**	Metric Tons

Base Case: CDECCA Contract

	Energy Consumption	Unit	eGrid Conv Factor	Unit	GHG	Unit
Natural Gas	225,737	MMBTU	53.27	0.00	12,025	Metric Tons
470 Capital Ave. Electricity	12,161	MWh	379.27	kg/MWh	4,612	Metric Tons
Hot and Chilled Water System Electricity	6,034	MWh	379.27	kg/MWh	2,289	Metric Tons
Total					**18,926**	Metric Tons

Net GHG Reduction with Option #4 (Metric Tons)	**5,459**

Air Pollutant Emission

Air Contaminent Emission Rates for Saturn 20		
NOx	100	ppmv
CO	50	ppmv
UHC	50	ppmv

Annual Saturn 20 Air Contaminent Emissions		
NOx	**22**	tons
CO	**11**	tons
UHC	**11**	tons

Air Contaminent Emission Rates for Boilers		
NOx	0.035	lb/MMBtu
CO	0.04	lb/MMBtu
UHC	0.004	lb/MMBtu

Annual Boiler Air Contaminent Emissions		
NOx	**0.9**	tons
CO	**1.0**	tons
UHC	**0.1**	tons

State of CT DPW Central Plant Analysis - Option 5: Capstone C200 MicroTurbine

Number of Capstone C200 MicroTurbines	2	
Nominal Output of Each MicroTurbine	200	kW
Nominal Net Heat Rate [LHV]	10,260	BTU/kWh
Nominal Net Heat Rate [HHV]	11,400	BTU/kWh
One Therm	100,000	BTU
Central Plant Hot Water Boiler Efficiency	85%	%
Nominal Trigen Plant Size	400	kW
Thermal Energy Plant Boiler System Electric Consumption	10.10	kW/MMBTU
Thermal Energy Plant Chilled Water System Electric Consumption	0.85	kW/ton

Enthalpy of Steam @ 15 psig	1164.1	BTU/lb
Plant Operating Point	100%	%
Individual HRSG Steam Capacity	1,080	lb/hr
Electric Chiller Efficiency	0.50	kW/ton
Absorption Chiller Rating	132	tons
Absoprtion Chiller 15 psig Steam Consumption	2,251	lb/hr
Full-Load Absorption Chiller Credit	66	kW
Absorption Chiller Annual Electric Credit	0	kWh
Number of Hours Trigen Plant Off-Line*	432	hrs/year
Number of Days Trigen Off-Line*	18	days/year
Trigen Plant Reliability	95.07%	%

**Note: Forced or Maintenance Outage (Jan - 3 days; April - 7 days; July - 3 days; Oct - 7 days)*

Electric Side

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Electric Consumption (kWh)	1,201,752	1,073,375	1,131,502	1,317,576	1,703,001	2,008,114	2,136,092	1,918,927	1,665,530	1,312,535	1,240,093	1,166,391	17,874,887
Trigen Plant Electric Production (kWh)	278,400	268,800	230,400	288,000	297,600	288,000	294,996	276,370	288,000	230,400	287,481	297,572	3,326,019
Peak Electric Demand (kW)	2,537	2,552	2,442	3,700	5,566	5,388	5,521	5,231	5,253	3,803	3,863	2,491	5,566
PeakTrigen Plant Electric Production (kW)	400	400	400	400	400	400	400	400	400	400	400	400	400
Electricity Purchased (kWh)	923,352	804,575	901,102	1,029,576	1,405,401	1,720,114	1,841,096	1,642,557	1,377,530	1,082,135	952,611	868,820	14,548,868
Peak Electricity Purchased (kW)	2,486	2,152	2,387	3,300	5,166	4,988	5,121	4,879	4,853	3,403	3,463	2,091	5,166

Gas Side

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Trigen Plant Fuel Consumed (decatherms)	3,186	3,071	2,636	3,280	3,391	3,283	3,378	3,162	3,283	2,625	3,273	3,405	37,974
Trigen Plant Peak Fuel Demand (decatherms)	5	5	5	5	5	5	5	5	5	5	5	5	5
Central Plant Boiler Fuel Consumed (decatherms)	15,904	14,562	9,791	3,769	1,633	223	48	187	328	3,617	10,388	19,853	80,304
Central Plant Boiler Peak Fuel Demand (decatherms)	30	33	26	14	16	4	2	4	5	15	26	42	42
Total Natural Gas Consumption (decatherms)	19,090	17,633	12,427	7,050	5,024	3,506	3,426	3,349	3,612	6,242	13,662	23,258	118,278
Total Peak Gas Daily Demand (decatherms)	840	752	575	342	309	145	119	122	145	392	586	964	964

Hot Water Side

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Hours in the Month	744	672	744	720	744	720	744	744	720	744	720	744	8,760
Hot Water Consumption (MMBTU)	15,053	13,871	9,585	4,790	2,892	1,451	1,141	1,188	1,575	4,286	10,441	18,515	84,788
Trigen Plant Steam Production (Mlb)	1,464	1,426	1,206	1,553	1,606	1,555	1,604	1,501	1,555	1,243	1,551	1,565	17,828
Peak Trigen Plant Steam Production (Mlb)	2	2	2	2	2	2	2	2	2	2	2	2	2
Trigen Plant Steam Production for Heating (Mlb)	1,464	1,426	1,206	1,514	1,435	1,204	1,050	983	1,237	1,156	1,537	1,565	15,777
Peak Hot Water Demand (MMBTU)	28	30	24	14	16	5	4	4	6	15	25	38	38
Peak Trigen Steam Production for Heating (Mlbs)	2	2	2	2	2	2	2	2	2	2	2	2	2
Hot Water Produced by Central Plant Boilers (MMBTU)	13,519	12,378	8,322	3,204	1,388	190	41	159	279	3,074	8,830	16,875	68,259
Peak Central Plant Hot Water Production (MMBTU)	26	28	22	12	13	3	1	3	4	13	22	36	36

Chilled Water Side

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Chilled Water Consumption (ton-hrs)	202,638	182,122	322,184	399,180	708,568	1,034,887	1,221,670	1,007,751	769,909	394,325	268,471	189,169	6,700,876
Trigen Plant Chilled Water Production (ton-hrs)	0	0	0	2,285	9,995	20,610	32,498	30,377	18,643	5,071	727	0	120,205
Trigen Plant Absorption Chiller Steam Consumption (Mlbs)	0	0	0	39	170	351	554	518	318	86	13	0	2,051
Central Plant Electric Chiller Production (ton-hrs)	0	0	0	366,801	698,574	1,014,277	1,189,172	977,374	751,266	389,254	230,376	0	5,617,094
Peak Chilled Water Demand (tons)	808	729	1,407	1,750	3,032	3,040	3,439	3,242	3,509	1,993	1,307	964	3,509
PeakTrigen Plant Chilled Water Production (tons)	0	0	0	124	127	119	123	129	129	129	100	0	129
Peak Central Plant Electric Chillers Chilled Water Production (tons)	0	0	0	1,656	2,989	2,987	3,424	3,242	3,453	1,993	1,307	0	3,453
Absorption Chiller Electric Consumption Reduction* (kWh)	0	0	0	1,149	5,027	10,367	16,347	15,280	9,377	2,551	366	0	60,463
Central Plant Free-Cooling Production (ton-hrs)	202,638	182,122	322,184	30,094	0	0	0	0	0	0	37,369	189,169	963,576
Peak Central Plant Free-Cooling Production (tons)	808	729	1,407	674	0	0	0	0	0	0	551	964	1,407

***Note:** *This electric consumption reduction is reflected in the "Electric Side" Electric Consumption values shown above.*

State of CT DPW Central Plant Analysis - Full-Load Performance Data for Option 5: Capstone C200 MicroTurbine and Associated HRSG

Ambient Temperature (°F)	MicroTurbine Power (kW)	MicroTurbine HHV Heat Rate (Btu/kWh)	MicroTurbine Exhaust Gas Temperature (°F)	MicroTurbine Exhaust Gas Stream (lbs/hr)	HRSG Steam Production (lbs/hr)
0	200	11,579	404.9	11,379	978
20	200	11,443	449.6	11,043	1,052
40	200	11,388	493.2	10,772	1,078
60	200	11,400	535.0	10,440	1,080
80	193	11,605	552.5	10,031	1,071
100	173	11,909	565.0	9,553	1,060

470 Capitol Avenue Complex Back-up/Standby Electricity Expense
- Option 5: Capstone C200 MicroTurbine

	January	February	March	April	May	June	July	August	September	October	November	December
Total On-Peak (kWh)	554,011	482,745	540,661	617,745	843,240	1,032,069	1,104,658	985,534	826,518	649,281	571,567	521,292
Total Off-Peak (kWh)	369,341	321,830	360,441	411,830	562,160	688,046	736,438	657,023	551,012	432,854	381,045	347,528
Total (kWh)	923,352	804,575	901,102	1,029,576	1,405,401	1,720,114	1,841,096	1,642,557	1,377,530	1,082,135	952,611	868,820
Actual Peak Demand (kW)	2,486	2,152	2,387	3,300	5,166	4,988	5,121	4,879	4,853	3,403	3,463	2,091
Rachet Demand (kW)	5,166	5,166	5,166	5,166	5,166	5,166	5,166	5,166	5,166	5,166	5,166	5,166
	Transmission Charges											
Transmission Charge Factor ($/kW)	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93	$5.93
Transmission Charge kW Total ($)	$14,744	$12,763	$14,157	$19,569	$30,634	$29,578	$30,368	$28,930	$28,778	$20,180	$20,537	$12,398
	Distribution Charges											
Customer Service Charge ($)	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025
Distribution Charge kW Factor ($/kW)	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02
Distribution Charge kW Total ($)	$31,099	$31,099	$31,099	$31,099	$31,099	$31,099	$31,099	$31,099	$31,099	$31,099	$31,099	$31,099
FMCC Delivery Charge On Peak Factor ($/kWh)	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055
FMCC Delivery Charge On Peak Total ($)	$3,058	$2,665	$2,984	$3,410	$4,655	$5,697	$6,098	$5,440	$4,562	$3,584	$3,155	$2,878
FMCC Delivery Charge Off Peak Factor ($/kWh)	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012
FMCC Delivery Charge Off Peak Total ($)	$443	$386	$433	$494	$675	$826	$884	$788	$661	$519	$457	$417
Competitive Transition Assessment												
Demand Charge Factor ($/kW)	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46	$1.46
Demand Charge Total ($)	$3,630	$3,142	$3,486	$4,818	$7,542	$7,282	$7,477	$7,123	$7,085	$4,968	$5,056	$3,053
CTA kWh Charge Factor ($/kWh)	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219	$0.00219
CTA kWh Charge Total ($)	$2,022	$1,762	$1,973	$2,255	$3,078	$3,767	$4,032	$3,597	$3,017	$2,370	$2,086	$1,903
Combined Public Benefits Charge ($/kWh)	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426	$0.00426
Combined Public Benefits Total ($)	$3,933	$3,427	$3,839	$4,386	$5,987	$7,328	$7,843	$6,997	$5,868	$4,610	$4,058	$3,701
Economic Transition Charge ($/kWh)	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379	0.00379
Economic Transition Charge Total ($)	$3,500	$3,049	$3,415	$3,902	$5,326	$6,519	$6,978	$6,225	$5,221	$4,101	$3,610	$3,293
Total Transmission and Delivery Charges ($)	**$63,454**	**$59,319**	**$62,411**	**$70,958**	**$90,020**	**$93,121**	**$95,802**	**$91,225**	**$87,317**	**$72,457**	**$71,084**	**$59,766**
	Supply											
Supply Charge Factor ($/kWh)	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319	$0.08319
Total Supply Charges ($)	**$76,814**	**$66,933**	**$74,963**	**$85,650**	**$116,915**	**$143,096**	**$153,161**	**$136,644**	**$114,597**	**$90,023**	**$79,248**	**$72,277**
	Total											
Total Electric Charges ($)	**$140,267**	**$126,251**	**$137,374**	**$156,608**	**$206,936**	**$236,217**	**$248,963**	**$227,869**	**$201,913**	**$162,480**	**$150,332**	**$132,043**
Average Electric Rate ($/kWh)	$0.15	$0.16	$0.15	$0.15	$0.15	$0.14	$0.14	$0.14	$0.15	$0.15	$0.16	$0.15

Total Annual Electrcity Expense ($):	**$2,127,254**

State of CT DPW Central Plant Natural Gas Expense - Option 5: Capstone C200 MicroTurbine

	January	February	March	April	May	June	July	August	September	October	November	December
Natural Gas Consumption (therms)	190,899	176,328	124,270	70,498	50,240	35,064	34,259	33,489	36,116	62,417	136,617	232,584
Adjustments (therms)	-	-	-	-	-	-	-	-	-	-	-	-
Total Consumption (therms)	190,899	176,328	124,270	70,498	50,240	35,064	34,259	33,489	36,116	62,417	136,617	232,584
Total Consumption (CCF)	185,159	171,026	120,534	68,379	48,729	34,010	33,229	32,482	35,030	60,541	132,510	225,591
Demand Peak Day (therms)	8,397	7,516	5,752	3,422	3,089	1,452	1,192	1,222	1,451	3,919	5,857	9,642
Demand Charge Rate ($/CCF)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Demand Charges ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Delivery Rate First 5000 CCF ($/CCF)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Total Delivery Charge First 5000 CCF	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Delivery Rate Rest of CCF ($/CCF)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Total Delivery Charge Rest of CCF ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Rate Credit Factor ($/CCF)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)	($0.0617)
Rate Credit Total ($)	($11,424)	($10,552)	($7,437)	($4,219)	($3,007)	($2,098)	($2,050)	($2,004)	($2,161)	($3,735)	($8,176)	($13,919)
SSC Rate ($/CCF)	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324	$0.0324
SSC Total ($)	$5,999	$5,541	$3,905	$2,215	$1,579	$1,102	$1,077	$1,052	$1,135	$1,962	$4,293	$7,309
Customer Charge	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Telemetering Charge	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transportation Service Charge ($/CCF)	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
Transportation Service Supply Cost ($)	$135,166	$124,849	$87,990	$49,916	$35,572	$24,827	$24,257	$23,712	$25,572	$44,195	$96,732	$164,681
Conservation Adjustment Rate ($/CCF)	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084
Conservation Adjustment Charge ($/CCF)	$1,555	$1,437	$1,012	$574	$409	$286	$279	$273	$294	$509	$1,113	$1,895
Total Natural Gas Charges ($)	**$131,297**	**$121,275**	**$85,471**	**$48,487**	**$34,554**	**$24,116**	**$23,563**	**$23,033**	**$24,840**	**$42,929**	**$93,963**	**$159,967**
Average Natural Gas Rate ($/decatherm)	6.88	6.88	6.88	6.88	6.88	6.88	6.88	6.88	6.88	6.88	6.88	6.88

Total Annual Gas Expense ($):	**$813,493**

State of CT DPW Central Plant Water Expense - Option 5: Capstone C200 MicroTurbine

	January	February	March	April	May	June	July	August	September	October	November	December
Steam Production (Mlbs)	13,077	12,058	8,354	4,305	2,798	1,718	1,639	1,637	1,795	3,884	9,136	16,062
Steam Production (lbs)	13,077,361	12,058,279	8,354,432	4,305,083	2,797,978	1,718,179	1,639,043	1,637,245	1,795,009	3,883,628	9,136,062	16,061,765
Total Make-up Water Requirements (lbs)	653,868	602,914	417,722	215,254	139,899	85,909	81,952	81,862	89,750	194,181	456,803	803,088
Total Make-up Water Requirements (gallons)	78,352	72,246	50,055	25,793	16,764	10,294	9,820	9,809	10,755	23,268	54,738	96,232

Total Hot Water Production System Make-up Water (gallons)	458,127

	January	February	March	April	May	June	July	August	September	October	November	December
Chilled Water Production (ton-hrs)	202,638	182,122	322,184	399,180	708,568	1,034,887	1,221,670	1,007,751	769,909	394,325	268,471	189,169
Evaporated Cooling Water Make-up to Cooling Tower (gallons)	506,595	455,305	805,460	997,950	1,771,421	2,587,217	3,054,176	2,519,378	1,924,773	985,812	671,178	472,924

Total Evaporated Cooling Tower Water (gallons)	16,752,190

Total Water Usage (gallons)	**17,210,316**

Cost of Water and Chemicals:	$5.00	$/1000 gallons
CT State and Local Surcharges:	0.96	%
State and Local Taxes:	6.00	%

Cost of Water and Chemicals ($)	$86,052
CT State and Local Surcharges ($):	$825
CT Sales Tax ($):	$5,163
Total Annual Water Expense ($):	**$92,040**

State of CT DPW Central Plant O&M Expense
- Option 5: Capstone C200 MicroTurbine

	Power (Electricity)		Mechanical Cooling (Chilled Water)		Heating (Steam)	
	kW (peak)	kWhrs (annual)	tons (peak)	ton-hrs (annual)	Mlbs (peak)	Mlbs (annual)
Trigeneration Plant	400	3,326,019	129	120,205	2	15,777

	Mechanical Cooling (Chilled Water)		Heating (Steam)		Free Cooling (Chilled Water)	
	tons (peak)	ton-hrs (annual)	MMBTU (peak)	MMBTU (annual)	tons (peak)	ton-hrs (annual)
Central Plant	3,453	5,617,094	36	68,259	1,407	963,576

O&M Rate (Generators)	$0.015	$/kWhr
O&M Rate (HRSG):	$0.251	$/Mlb
O&M Rate (Absorption Chillers):	$0.015	$/ton-hr
O&M Rate (Steam Boiler and Auxiliaries):	$0.300	$/MMBTU
O&M Rate (Electric Chiller and Auxiliaries):	$0.012	$/ton-hr
O&M Rate (Cooling Tower and Auxiliaries):	$0.005	$/ton-hr
Free-Cooling Heat Exchanger Mtce.	$15,000	$/yr
Pump House Equipment Maintenance	$225,000	$/yr

Annual Equipment Mtce Cost*:	$453,453

Note: Includes 10% mark-up by 3rd party contractor.

	# of Employees Required	Employee Salary ($/yr)	Employee Benefits	3rd Party Contractor Markup (10%)	Total Annual Expenditure
Plant Manager	0.0	$90,000	$36,000	$12,600	$0
Operator	0.5	$80,000	$32,000	$11,200	$61,600
Mechanic/Electrician	0.0	$70,000	$28,000	$9,800	$0
I&C Technician	0.0	$70,000	$28,000	$9,800	$0
Totals	0.5				$61,600

***Note*:** Benefits are assumed to be 40% of the employees salary.

Annual O&M Cost	**$515,053**

Note: *Includes 10% mark-up by 3rd party contractor.*

State of CT DPW Central Plant Capital Expense
- Option 5: Capstone C200 MicroTurbine

	Power (Electricity)		Mechanical Cooling (Chilled Water)		Heating (Steam)	
	kW (peak)	kWhrs (annual)	tons (peak)	ton-hrs (annual)	Mlbs (peak)	Mlbs (annual)
Trigeneration Plant	400	3,326,019	129	120,205	2	15,777

	Mechanical Cooling (Chilled Water)		Heating (Steam)		Free Cooling (Chilled Water)	
	tons (peak)	ton-hrs (annual)	MMBTU (peak)	MMBTU (annual)	tons (peak)	ton-hrs (annual)
Central Plant	3,453	5,617,094	36	68,259	1,407	963,576

	Installed Mechanical Cooling Capacity (Chilled Water)	Installed Heating Capacity (Steam)	Installed Free Cooling Capacity (Chilled Water)
	tons	lbs/hr	tons
Central Plant	5,400	45,000	1,500

Central Plant

Generators and HRSG's	$3,000	$/kW
Absorption Chillers	$1,750	$/ton
Electric Chillers and Auxiliaries	$1,000	$/ton
Steam Boilers and Auxiliaries	$50,000	$/MMBTU
Cooling Towers and Auxiliaries	$280	$/ton

Generators, HRSG's and Auxiliary Equipment ($):	**$1,200,000**
Absorption Chillers and Auxiliary Equipment ($):	**$225,918**
Electric Chillers and Chilled Water Pumps ($):	**$5,268,000**
Steam Boilers and Auxiliaries ($):	**$2,493,502**
Electrical Switchboard and MCC ($):	**$1,660,000**
Chilled and Condenser Water Piping ($):	**$393,750**
Cooling Towers ($):	**$1,512,000**
Free-Cooling Heat Exchanger and Control Valves ($):	**$225,000**
Trigeneration Plant Enclosure ($):	**$180,000**
Distributed Control System ($):	**$780,000**
Engineering ($):	**$1,216,824**
Construction Management ($):	**$553,102**
Commissioning and Start-up ($):	**$276,551**
10% Overhead and Profit Margin ($):	**$1,598,465**
20% Estimating and Construction Contingency ($):	**$3,196,930**
Permitting ($):	**$51,950**
5% Sales Tax ($):	**$696,909**

Total Capital Expenditure ($):	**$20,102,983**

Financing Charges

Length of Loan (years):	20	years
Cost of Capital (decimal equivalent):	0.0350	

Monthly Payment ($):	**$117,872**

State of CT DPW Central Plant Emissions
- Option 5: Capstone C200 MicroTurbine

Greenhouse Gas Emission

eGrid Conversion Factors				
	lbs/kWh	GHG Factor	GHG Weighting	
CO2	827.95	1	827.95	lbs/MWh
Methane	0.07698	25	1.9245	lbs/MWh
N2O	0.0152	298	4.5296	lbs/MWh
Total for Electricity			834.4041	lbs/MWh
			379.27	kg/MWh
Total for District Steam			86.845	kg/Mlb
Total for Natural Gas			53.27	kg/MMBTU

Option 5: MicroTurbine CHP Plant

	Energy Consumption	Unit	eGrid Conv Factor	Unit	GHG	Unit
Natural Gas	118,278	MMBTU	53.27	kg/MMBTU	6,301	Metric Tons
470 Capital Ave. Electricity	14,549	MWh	379.27	kg/MWh	5,518	Metric Tons
Total					**11,819**	Metric Tons

Base Case: CDECCA Contract

	Energy Consumption	Unit	eGrid Conv Factor	Unit	GHG	Unit
Natural Gas	225,737	MMBTU	53.27	0.00	12,025	Metric Tons
470 Capital Ave. Electricity	12,161	MWh	379.27	kg/MWh	4,612	Metric Tons
Hot and Chilled Water System Electricity	6,034	MWh	379.27	kg/MWh	2,289	Metric Tons
Total					**18,926**	Metric Tons

Net GHG Reduction with Option #5 (Metric Tons)	**7,107**

Air Pollutant Emission

Air Contaminent Emission Rates for C200 MicroTurbine		
NOx	0.4	lb/MWh
CO	0.2	lb/MWh
UHC	0.2	lb/MWh

Annual C200 Air Contaminent Emissions		
NOx	**0.7**	tons
CO	**0.3**	tons
UHC	**0.3**	tons

Air Contaminent Emission Rates for Boilers		
NOx	0.035	lb/MMBtu
CO	0.04	lb/MMBtu
UHC	0.004	lb/MMBtu

Annual Boiler Air Contaminent Emissions		
NOx	**1.4**	tons
CO	**1.6**	tons
UHC	**0.2**	tons

State of CT DPW Central Plant - Future Load Growth

Address	Square Footage	Type of Use	Annual Peak Steam Heating Load (lb/hr)	Annual Peak Cooling Load (tons)
165 Capitol	350,000	Offices	4,133	875
80 Washington	54,000	Offices/Courts	638	103
90 Washington	79,000	Offices/Courts	933	150
95 Washington	128,880	Offices/Courts	1,522	245
100 Washington	22,657	Offices/Courts	268	43
101 Lafayette	125,727	Offices/Courts	1,485	239
179 Lafayette	20,000	Church	236	31
Total	780,264		9,214	1,687

	Cooling Capacity - Chilled Water (tons)	Heating Capacity - Steam (lbs/hr)
Central Plant Capacity	5,400	45,000
CAS Peak Demand Load	3,509	32,820
Future Load Growth*	1,009	5,007
Surplus Central Plant Capacity	882	7,173
Surplus Central Plant Capcity (%)	**16.3%**	**15.9%**

*Only 165 Capitol, 80 Washington, and 179 Lafayette are included since they are the most likely tie-ins.

Cooling (Chilled Water) Parameters

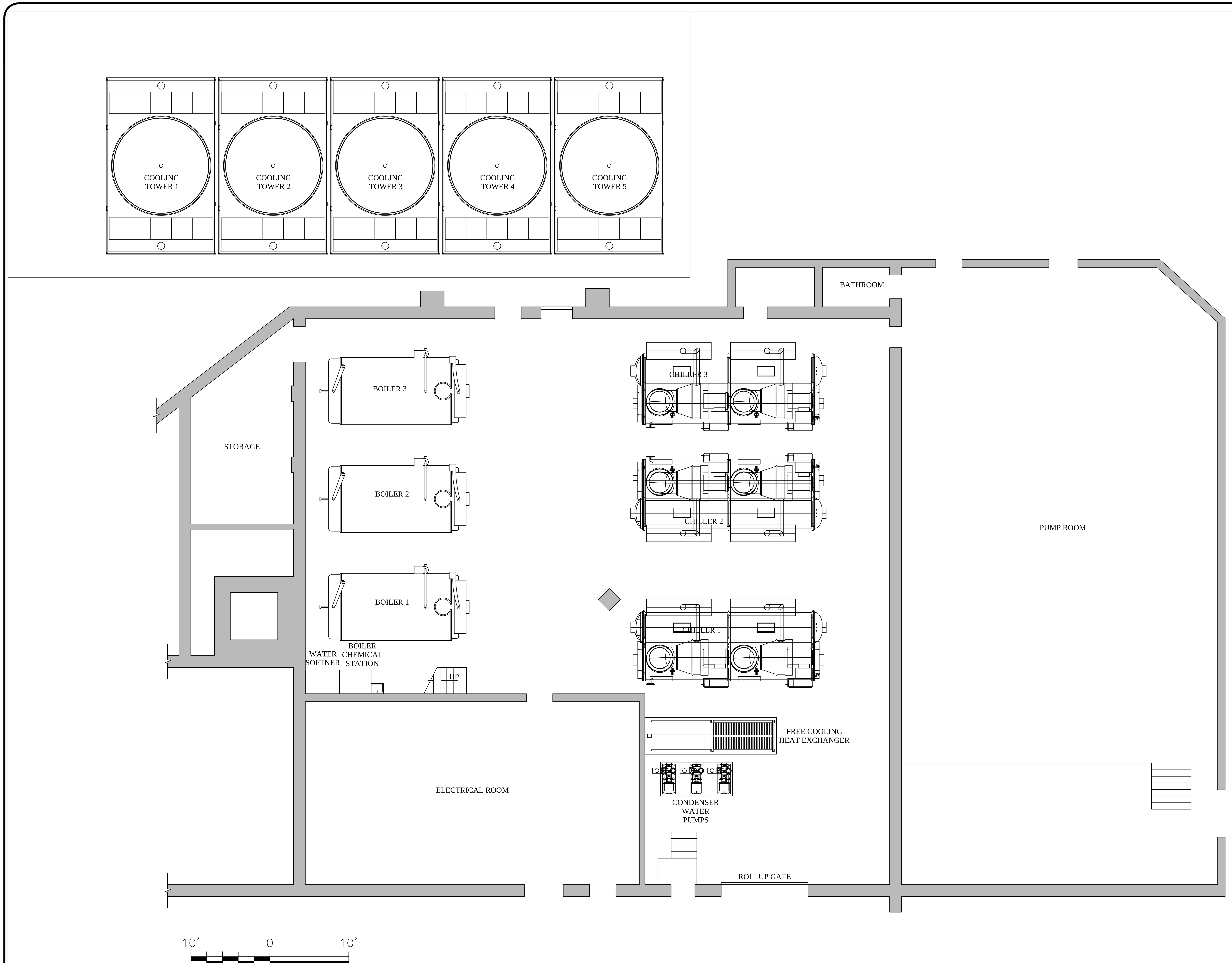
	Cooling Load Factor (%)											
	January	February	March	April	May	June	July	August	September	October	November	December
Monthly Load Factor	0%	0%	5%	10%	30%	40%	50%	50%	40%	30%	10%	0%

Cooling Capacity	
Type of Facility	**Cooling Capacity (ft^2/ton)**
Structured Parking Lot	0
Meeting and Banquet Room	875
Exhibition Room	650
Kitchen	525
Receiving/Storage Area	875
Locker Room	650
Laundry Room	525
Engineering/Maintenance Shop	725
Office Area	400
Hotel Guestroom	900
Hotel Lobby	875
Residential Condominium	775
Residential Loft	775
Residential Townhouse	775
Arena (Inside)	650
Arena (Outside)	675
Athletic Complex	550
Retail and Restaurants	500
Cinema	675

Heating (Hot Water) Parameters

	Heating Capacity (Btu/ft2)											
Type of Facility	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Office Building	4,090.82	2,879.23	1,228.22	326.84	(80.08)	(100.00)	(100.00)	(100.00)	(100.00)	676.06	1,627.87	3,698.22
Residential	3,876.35	3,708.47	3,557.56	1,769.29	756.32	303.59	186.63	54.59	256.43	512.98	1,499.54	4,561.10
Retail/Restaurant	4,412.29	4,582.99	3,811.01	3,175.28	3,155.47	2,002.23	1,134.64	1,436.94	2,285.45	3,263.84	5,187.83	4,559.62

Option #1 Central Plant General Arrangement Drawing (With Mezzanine Level)



GENERAL ARRANGEMENT

CITY OF HARTFORD CONNECTICUT
DEPARTMENT OF PUBLIC WORKS

No	DATE	BY	REVISION
A	08/04/11	SAH	FEASIBILITY STUDY

NOTES:
THIS DRAWING MAY BE PRINTED IN REDUCED SCALE

CONSULTANT:

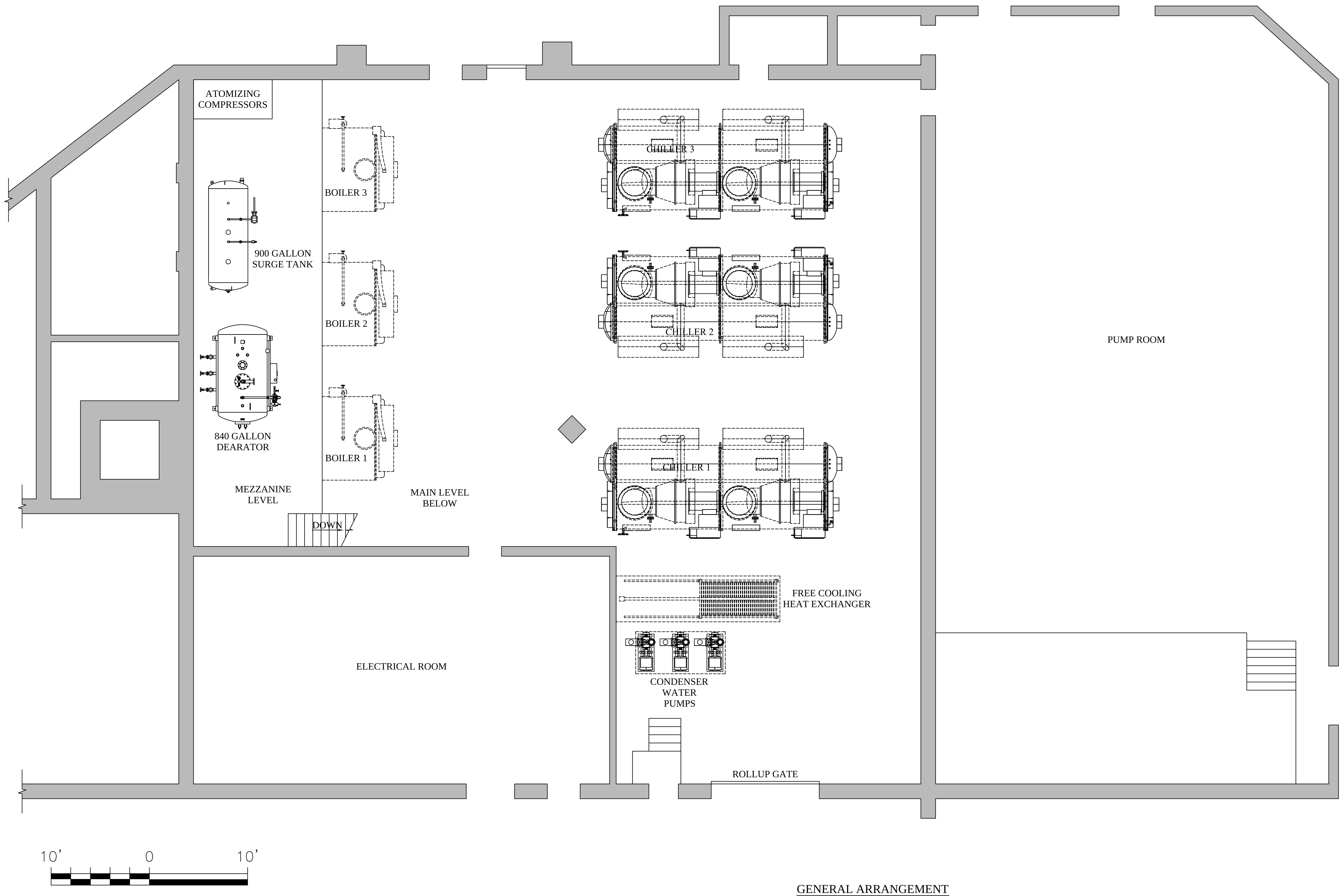
SourceOne

370 SEVENTH AVE, NEW YORK, NY 10001
Telephone: (212) 612-7600 Fax: (212) 612-7601
www.s1inc.com

PROJECT:
**BOILER/CHILLER PLANT REPLACEMENT
474 CAPITOL AVE.
HARTFORD CONNECTICUT**

TITLE:
**MAIN LEVEL
GENERAL ARRANGEMENT**

DRAWN BY: SAH	CHECKED BY: SS
DATE: 8/4/11	DATE CHECKED: 8/4/11
SCALE: NONE	DRAWING No:
SHEET: 1 OF 1	**M-001**



GENERAL ARRANGEMENT

CITY OF HARTFORD CONNECTICUT
DEPARTMENT OF PUBLIC WORKS

No	DATE	BY	REVISION
A	08/04/11	SAH	FEASIBILITY STUDY

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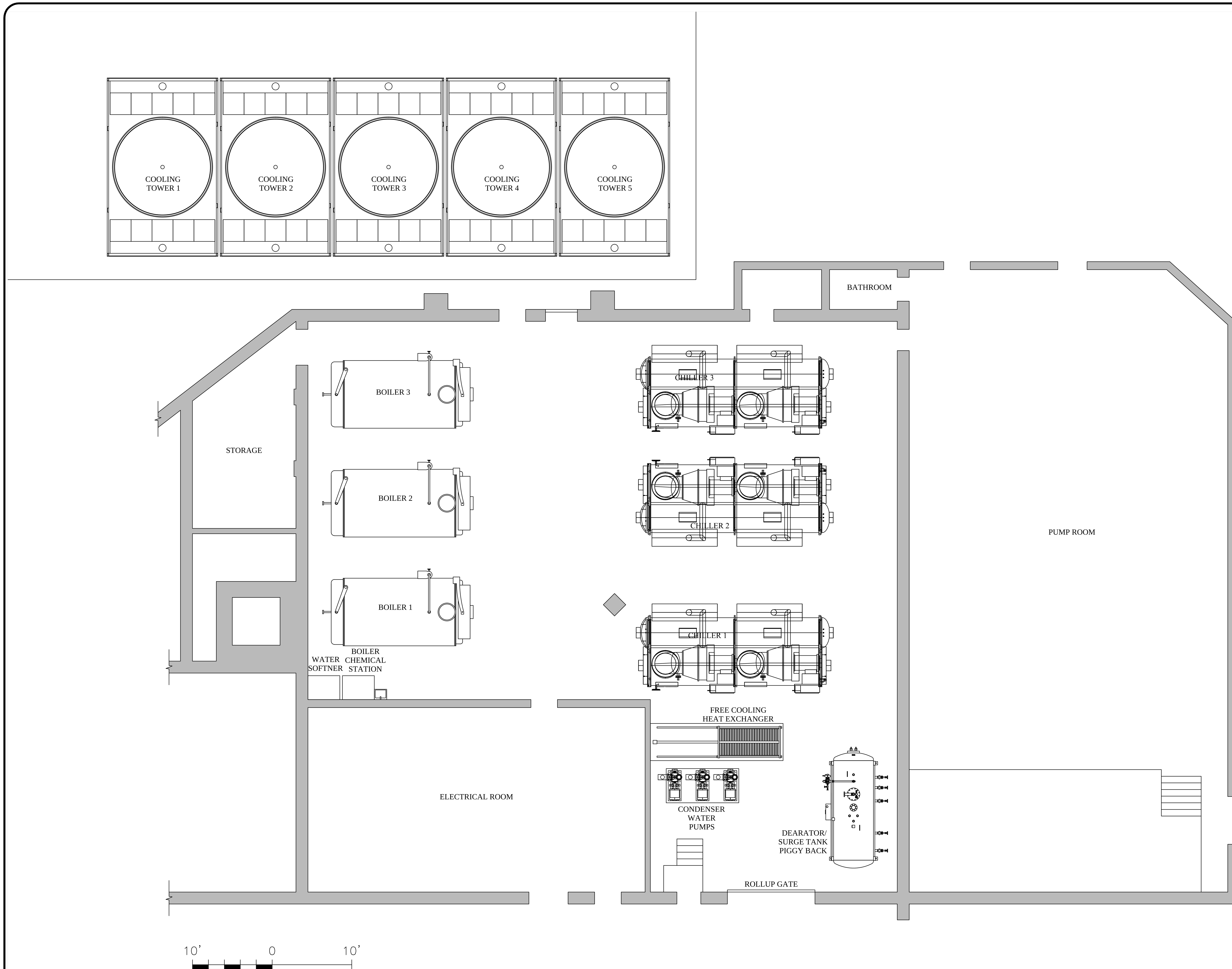
PROJECT:
BOILER/CHILLER PLANT REPLACEMENT
474 CAPITOL AVE.
HARTFORD CONNECTICUT

TITLE:
MEZZANINE LEVEL
GENERAL ARRANGEMENT

DRAWN BY: SAH	CHECKED BY: SS
DATE: 8/4/11	DATE CHECKED: 8/4/11
SCALE: NONE	DRAWING No:
SHEET: 1 OF 1	**M-002**

Option #1 Central Plant General Arrangement Drawing (Without Mezzanine Level)



GENERAL ARRANGEMENT

CITY OF HARTFORD CONNECTICUT
DEPARTMENT OF PUBLIC WORKS

No	DATE	BY	REVISION
A	08/04/11	SAH	FEASIBILITY STUDY

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PROJECT:
**BOILER/CHILLER PLANT REPLACEMENT
474 CAPITOL AVE.
HARTFORD CONNECTICUT**

TITLE:
**MAIN LEVEL
GENERAL ARRANGEMENT**

DRAWN BY:	SAH	CHECKED BY:	SS
DATE:	8/4/11	DATE CHECKED:	8/4/11
SCALE:	NONE	DRAWING No:	**M-001**
SHEET:	1 OF 1		

Equipment Performance and Specification Sheets

CL&P Guidelines for Generator Interconnections

CL&P Generator Interconnection Technical Requirements

Checklist for Permits, Certifications, and Approvals