

**University of California El Cajon**  
Combined Heat and Power Project

Sample draft report  
(Name of the University and some other entities are fictitious)

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## Executive summary

This report contains suggestions for the proposed University of California El Cajon (UCSC) upgrade for campus energy supply. The University has an annual electrical peak demand of about 8 MW of power, which is covered by SDG&E and an onsite combined heat & power (CHP) plant that is anticipated to grow to about 19 MW by 2020. The university has a CHP system with two reciprocating engines producing about 2.3 MW and 290 KW, respectively. The 2.3 MW engine was originally sized to produce 2.6 MW, with the lower ceiling due to emission restrictions. The remaining power is purchased from SDG&E at about \$2.3 million annual cost.

Increasing the capacity of campus generation will place additional demands on the existing SDG&E gas lines. With campus growth expected to continue steadily for the next 15 years or so, it is important that the gas supply infrastructure be upgraded to maintain minimum pressure requirements at the projected growth level to avoid sustained power outages.

The seasonal weather variation and daily load cycles impose a highly inconsistent thermal load profile on the campus hot water loop. The primary thermal load of the university is for space heating, whereas the primary power load consists of lighting, cooling, and other laboratory equipment. The power load of the University is more consistent than the thermal load. However, the power load slightly changes in the summer, May through October, dropping to about 5 MW peak. The peak lasts about 5 hours and roughly coincides with the cooling load. The total current site cooling load is about 2,370 tons, including the 120-ton absorption chiller.

The most serious problem of the existing CHP system is its inability to respond to the daily and seasonal variation in power and thermal demand, the latter with significant consequence on the system efficiency.

Our suggestions to upgrade Campus power and heat supplies focus on four alternative options listed at Level 1 through Level 4:

**The Level 1 recommendation is a short-term solution** that targets simple modifications to the system in order to eliminate:

- The mixing of return water passing through bidirectional loop with hot water from the heat recovery boiler
- The mixing of return water bypassed through bidirectional loops 1 and 2 with hot water from the boiler(s)
- The recirculation of hot water through the boiler(s), the HRB and the bidirectional loops
- The heat recovery pump, which could be kept as a backup.

Level 1 modifications entail eliminating Pump 2, eliminating bidirectional valves to allow hot water flow only in one direction, and installing a control system on the stack flow to bypass the gas when not needed.

**Level 2 recommendations include installing absorption chiller(s) as an intermediate solution.** This measure will result in recovering the heat during the cooling season, which is also when most of the stack heat is rejected to the ambient. This measure will add significant flexibility to the system while reducing campus cooling energy use by replacing existing chillers. This measure therefore entails purchasing an absorption chiller sized for the Level 1 heat loss.

**The Level 3 recommendation includes installing combined cycle plant with single engine or double engine as a long-term solution that also adds additional flexibility.** A CHP system was sized and recommended. This approach sizes the system for the current campus energy needs leaving sufficient flexibility for future growth. If the load exceeds the supply, which is a likely scenario, the extra power will be purchased from the utility. If it is decided to install a new system, the existing reciprocating engine can be sold for revenue to assist in covering the cost of a more robust campus energy supply system.

**Level 4 recommendations are to install combined cycle and fuel cell system as a strategic solution, which is also the most flexible and environmentally desirable.** In this scenario, the base load of Level 3 will be assisted with a fuel cell.

This analysis concludes that **keeping the existing reciprocating engine may be an economical move to save on the upfront cost in the immediate future, but it significantly limits future expansion of on-site power generation, and is likely to cost the campus more in the long run.** State and Federal financial and administrative incentives are available to support this project. There are also State Environmental Agency rules and regulations that remove unintended barriers to clear the way for installing CHP projects.

## **Background**

**Existing system:** The University of California El Cajon (UCSC) is considering an upgrade to its energy supply system. The university has an annual peak of about 7 MW power covered by SDG&E and onsite CHP plant. A building has come on line in May 2006 and this has increased the power peak to about 8 MW. According to UCSC facility personnel, this growth is anticipated to continue over the next several years, reaching about 19 MW by 2020. Expansion of the campus is indeed rapid and the site covers almost 1,000 hectares. The additions anticipated to come online soon are:

- 2 buildings with average power need of 750 KW total
- A building at an estimated power use of 1.2MW
- A library with about 500 KW of additional power requirement

The university has a combined heat & power (CHP) system which produces about 2.3 MW of power from a reciprocating engine, initially sized for 2.6 MW. The 2.3 MW ceiling is due to emission restrictions. The unit is designed for dual fuel: diesel or natural gas. The university also has another 290 KW reciprocating engine running on natural gas. The remaining power that exceeds the 2.3 MW of in-house production is imported from SDG&E at about \$2.3 million annual cost. The 2.6 MW engine was installed in 1985, and the 290 kW engine two years later. Both systems have had many hardware and control systems upgrades. Both systems have heat recovery.

**Natural Gas Supply:** At present, natural gas for the campus CHP plant is delivered through a 50 psi main line. This 50 psi gas line branches off from the 285 psi main transmission line. The pressure is maintained by a 30,000 CFH gas compressor located adjacent to the plant. The compressor is needed to maintain pressure that has fluctuated from 10 to 50 psi in the past. At 10 psi the campus heat demand can not be satisfied because at least one boiler must be turned off.

Increasing the capacity of campus generation will place additional demands on the existing SDG&E gas lines. With campus growth expected to continue steadily for the next 15 years or so it is important that the gas supply infrastructure be upgraded to maintain minimum pressure requirements at the projected growth level to avoid sustained power outages.

**HVAC:** The University has a low temperature lithium bromide absorption chiller for conditioning the Sine lab, rated at 120 tons. The university's physical plant personnel are familiar with the absorption system as well as the power and thermal sides of the university's demand and supply. The personnel are open to new ideas.

The seasonal weather variation and daily load cycles impose a highly inconsistent thermal load profile on the campus hot water loop. The primary thermal load of the university is for space heating, whereas the primary power load consists of lighting, cooling, and other laboratory equipment. The power load of the university is more

consistent than the thermal load. However, the power load slightly changes in the summer, May through October, dropping to about 5 MW peak. The peak lasts about 5 hours and roughly coincides with the cooling load. Five buildings of the campus are air conditioned:

- |                           |                         |
|---------------------------|-------------------------|
| 1. Green building, 2x300  | = 600 ton chiller       |
| 2. Engineering I 2- 2x250 | = 500 ton               |
| 3. Eng II - 3x60          | = 180 ton               |
| 4. Sine buildings         | = 120 ton               |
|                           | = 250 ton reciprocating |
|                           | = 600 ton centrifugal   |
| 5. Communication - 2x60   | = 120 ton               |



Figure 1: Three boilers currently providing hot water

Total current site cooling load is therefore 2,370 tons, including the 120-ton absorption chiller. The thermal load, primarily for space heating, is satisfied with waste heat recovered from the CHP plant and the 3x30 MMBtu boilers totaling 90 MMBtu (Figure 1), with 21 MMBtu (63 MMBtu total) output. The boilers operate on-demand, producing hot water for the heating loop.

### **Challenges of the existing system**

The most serious problem of the existing CHP system is the daily and seasonal variation in power and thermal demand, the latter with significant consequence for the system efficiency. The campus hot water distribution system is shown below with three boilers, a Heat Recovery Boiler (HRB – Figure 2), and two pumps of which Pump 1 operates with a Variable Frequency Drive (VFD). The hot water loop has two bidirectional flow pipes identified in Figure 3 with dotted lines.



Figure 2: Heat Recovery Boiler

The load at the time of the site visit was such that all the three high efficiency boilers were off. The hot water circulatory pump (Pump 1) is on a VFD that matches the flow to and from the campus to the demand, 300 gpm at the time of the assessment. Since Pump 2 operates with a constant flow rate circulating 700 gpm of hot water through the HRB, 400 gpm ( $=700-300$ ) is circulated back to the HRB through the bidirectional pipe 2 as shown in Figure 3. Because there is little heat exchange between the exhaust gas and the already boiling returned water, the HRB operates at a very low efficiency – dumping most of the heat to the ambient environment at 750°F temperature.

Figure 4 shows one inherent problem of the existing hot water distribution system that will be explained further based on data acquired during our site visit on the afternoon of August 8. At the time, the ambient temperature was over 80°F and the campus required only about 300 gpm of hot water.

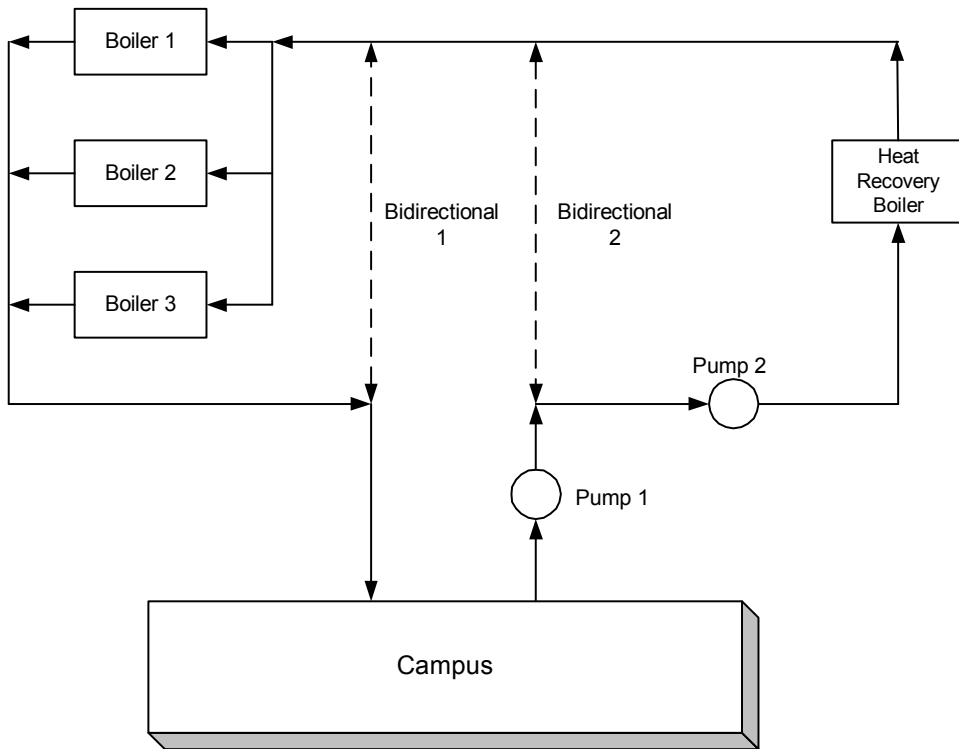


Figure 3: Campus hot water distribution system

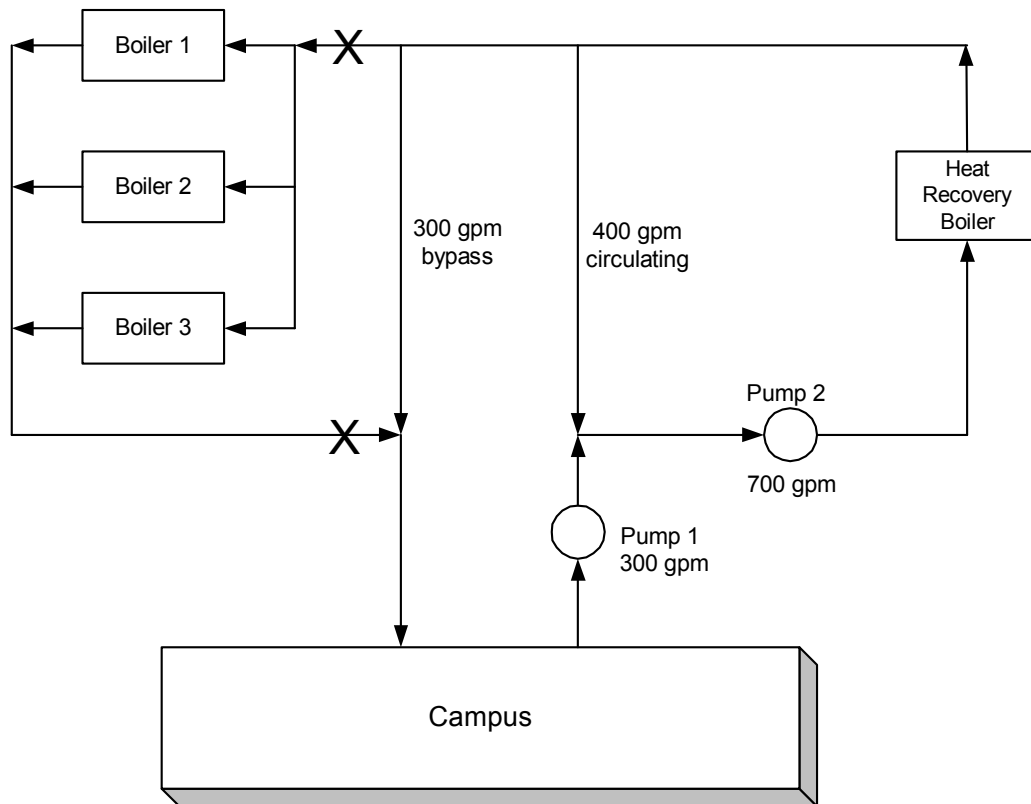


Figure 4: Campus hot water distribution system during a summer afternoon

The hot water loop operated in a radically different scenario in the morning hours of the same day when the heat load was higher. In this morning scenario, one of the boilers operated with the HRB supplying the required 1,000 gpm campus demand. Instead of a 400 gpm circulation through the HRB, 300 gpm was bypassing the HRB altogether, flowing through the bidirectional pipe 2 opposite the direction it did in the morning.

Since each of the three boilers can only accommodate 600 gpm, a more extreme scenario can be imagined on a winter day when the campus hot water need rises to the campus maximum of 2,200 gpm.

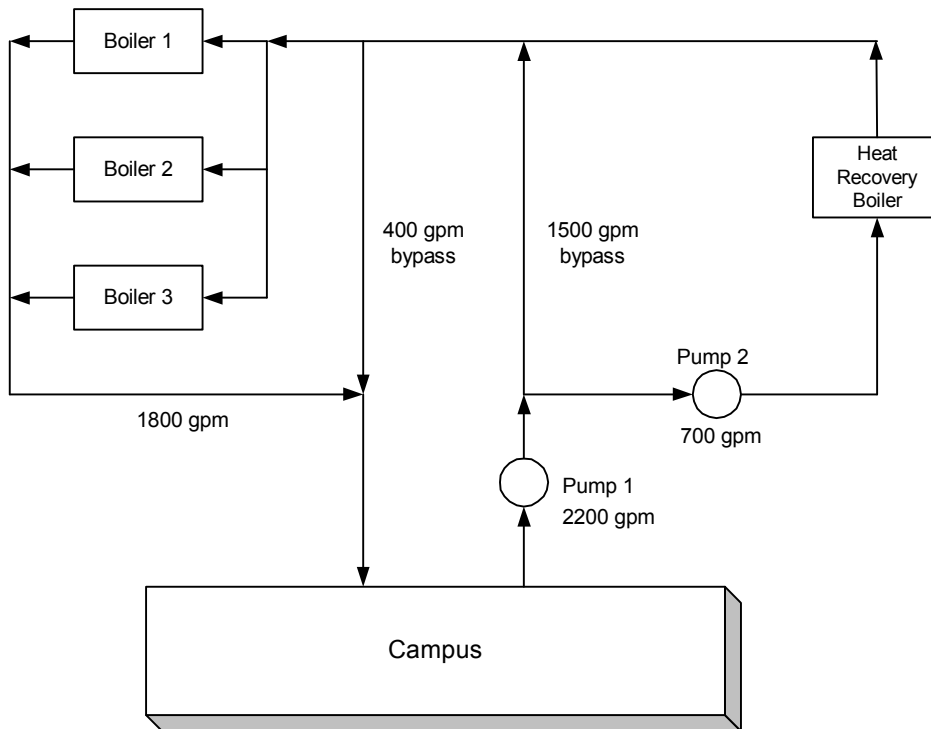


Figure 5:

Hot water distribution system during winter

In this scenario 1,500 gpm bypasses the HRB, and 400 gpm bypasses the boilers (Figure 5). These bypasses reduce the temperature of the hot water. This also increases the need to operate the boiler at system capacity above the real need of the campus.

The above challenges are compounded by the inability of the reciprocating engine to operate with an economizer, i.e. recover the waste heat from the stack when campus heat load is low. The engine is equipped with a turbocharger (Figure 6), which conveniently boosts the power output. However, the turbocharger also increases the intake temperature of the engine to about 350°F at 45 inches of mercury. This high intake temperature is not tolerated by the engine as it initiates detonation, colloquially known as “knock.” Therefore, the air has to be cooled by an under-sized cooling tower to about 100°F. The exhaust temperature from the engine can reach 1,000° F. when no heat

recovery takes place, dropping slightly at the stack. This heat is rejected to the atmosphere when the campus heat load drops and the HRB is bypassed. This state of low efficiency operation constitutes significant percentage of the overall operating hours, well over 50% during the summer.



Figure 6: Exhaust routing for the turbocharger

Power reliability is also a problem as some parts of the campus have frequent outages. The local network is prone to voltage sags - up to 63% has been recorded. One of the two feeders from which the campus receives service is prone to negative current that trips the generator. Distribution around the campus is all 12 kV underground, but the campus owns its own substation and takes power from SDG&E at 21 kV. The large engine is manually resynchronized to the grid. Power is purchased at a standard commercial tariff. The campus has a total of 44 standby generators; most are NG with propane backup. The campus avoids diesel because all emissions, including testing of backups count towards the campus emission ceiling of 150 lb NO<sub>x</sub>/day.

Our suggestions to upgrade campus power and heat supplies focus on four hierarchical options:

1. Short-term and minor changes to the existing system that do not require high capital expenditure – **Level 1 recommendations**

2. Provide intermediate suggestions that would involve addition of equipment to the system in order to enhance overall system performance - **Level 2 recommendations**
3. Add flexibility to the Campus power and thermal supply to permit more heat recovery that can better respond to daily and seasonal weather/load variations. These changes would accommodate anticipated short and long term growth of the campus or can be installed at the current power need level without compromising future options - **Level 3 recommendations**
4. Incorporate state of the art and environmentally-preferred technologies in which the university can pride itself both for public relations and also for instructional purposes - **Level 4 recommendations**

## System Flexibility

To address the flexibility of the system, we model seven hypothetical circumstances to represent all thermal load scenarios:

No heating load, only cooling load, which represents summer cases:

- i. Maximum cooling, all chillers operating
- ii. Average cooling, chillers operate partially
- iii. Minimum cooling, chillers operate at low part-load

Small cooling and heating, seasonal intermediates:

- iv. Parallel cooling and heating are needed at very low load levels

No cooling load, only heating load, which represents winter cases:

- v. Minimum heating, HRB is on
- vi. Average heating, HRB and at least one boiler is on
- vii. Maximum heating, the HRB and all boilers are on

An ideal system would run near the maximum efficiency during all these load scenarios with minimum heat loss to the ambient environment. The existing system is designed for the maximum heating scenario, i.e., operating at very low efficiency as the system heat load drops, reaching its worst phase during the transition and cooling hours when no heat is recovered.

## Recommendations

### 2. Level 1 recommendation, existing equipment configuration modification - a short-term solution

A short term solution targets simple modifications to the system in order to eliminate:

- The mixing of return water passing through bidirectional loop 2 (Figure 3) with hot water from the HRB
- The mixing of return water bypassed through bidirectional loops 1 and 2 with hot water from the boiler(s)

- The recirculation of hot water through the boiler(s) and the bidirectional loop 1
- The recirculation of hot water through the HRB and the bidirectional loop 2
- The heat recovery pump, which could be kept as a backup.

Level 1 modification shown in Figure 7 therefore entails:

- Eliminating Pump 2
- Eliminating bidirectional valves to allow hot water flow only in one direction
- Installing a control system on the stack flow to bypass the gas when not needed

These measures improve overall system performance and also prepare the system for Level 2 modifications that would render the system even more flexible by improving heat recovery. This does not necessarily expand the flexibility of the system to address the seven load scenarios introduced above.

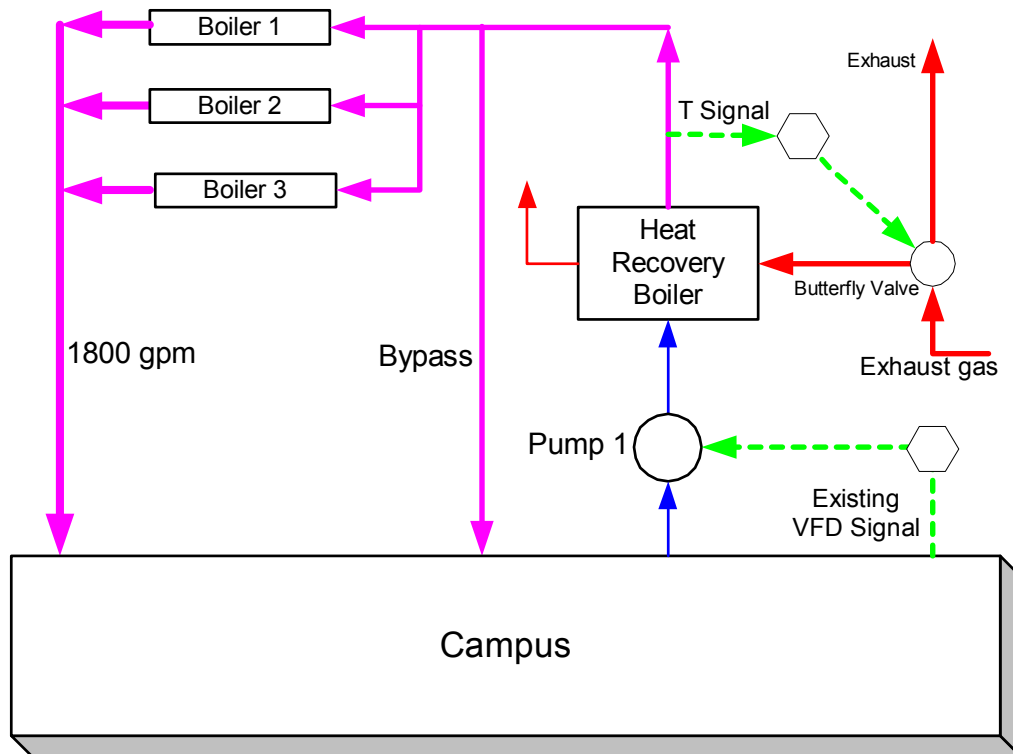


Figure 7: Suggested Level 1 modification to the existing system

### 3. Level 2 recommendation, install absorption chiller (Figure 8)

This intermediate solution will recover heat during the cooling season, which is also when most of the stack heat is rejected to the atmosphere. This measure will add significant flexibility to the system while reducing campus cooling energy use by replacing existing chillers. Campus personnel are very familiar with absorption systems because of the existing 120-ton chiller.

This measure therefore entails purchasing an absorption chiller, sized for the heat loss that can be quantified from the Level 1 configuration mentioned above.

**Sizing the absorption chiller:** The absorption chiller can be sized for the current campus cooling load of about 2,370 ton – mindful of a flexibility that would allow future expansion.

Absorption chiller units can be direct or indirect fired as well as single or multiple effect. Direct fired chillers have burners whereas indirect fired chillers use steam or hot water as a heat source. Single-effect absorption chillers use thermal energy to drive a single refrigeration cycle whereas multiple effect absorption chillers use two or more refrigeration cycles. In the case of two-stage units, the first stage is driven by a high temperature source and the second stage is driven by low temperature source, for example by energy rejected by condenser of the previous cycle. For this reason multiple effect chillers are more efficient than single effect chillers, but require a higher grade of thermal input. Single effect chillers may be driven by hot water ranging from 160 to 200 F. Double-effect chillers are also much more expensive, which makes them less common than single-effect, indirect fired types.

Absorption chillers have a lower Coefficient of Performance (COP) than mechanical chillers. However, in a scenario like the UCSC campus, absorption chillers can substantially reduce operating costs because they operate using waste heat, i.e., they replace the existing vapor compression chillers that are motor driven. COP is the chiller load divided by the heat input. Low-pressure, steam-driven absorption chillers are available in capacities up to 1,500 tons. Single-effect machines provide a COP of about 0.7. This value suggests that the 2,370-ton load can be met by about 40 MMbtu waste heat. This is well within the CHP capacity.

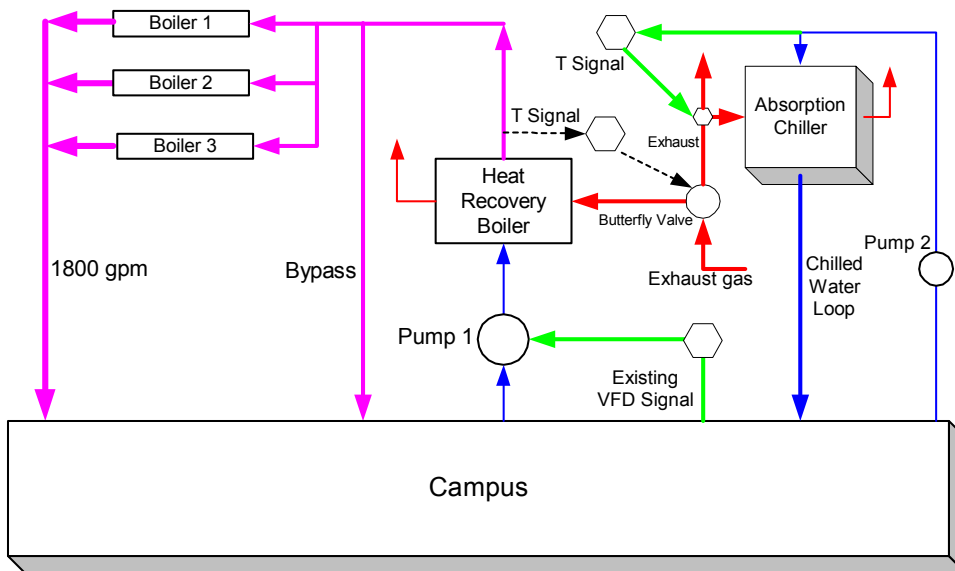


Figure 8: Suggested Level 2 modification to the existing system

**4. Level 3 recommendation, install combined cycle plant with single engine (figure 9a) or double engine, (Figure 9b) – long term solution, most flexible**

The flexibility of this recommendation can be demonstrated based on the seven energy load scenarios covering all load ranges. The **backup boiler shown in Figure 9 may not be necessary** if the plant is assumed to run always to produce base power for the site. However, a backup boiler will be handy if an extended down-time of the power side is anticipated in the future.

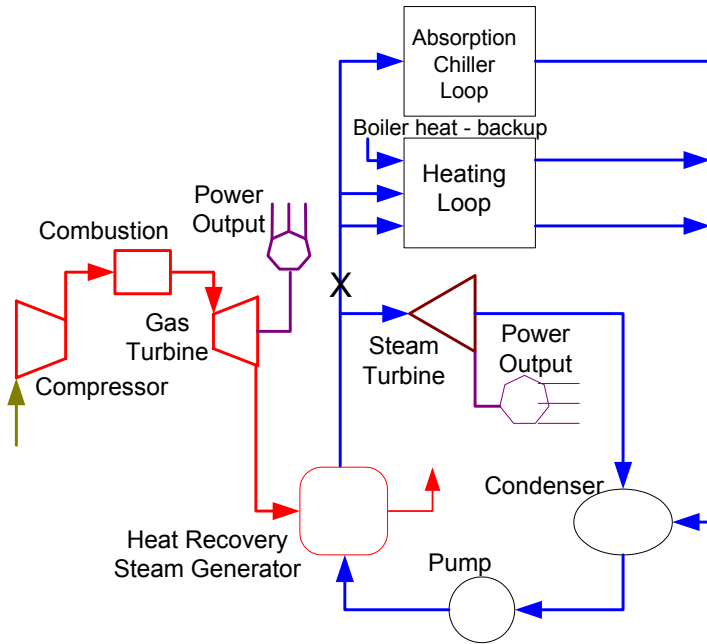


Figure 9a: Suggested Level 3 installation, combined cycle plant with absorption chiller

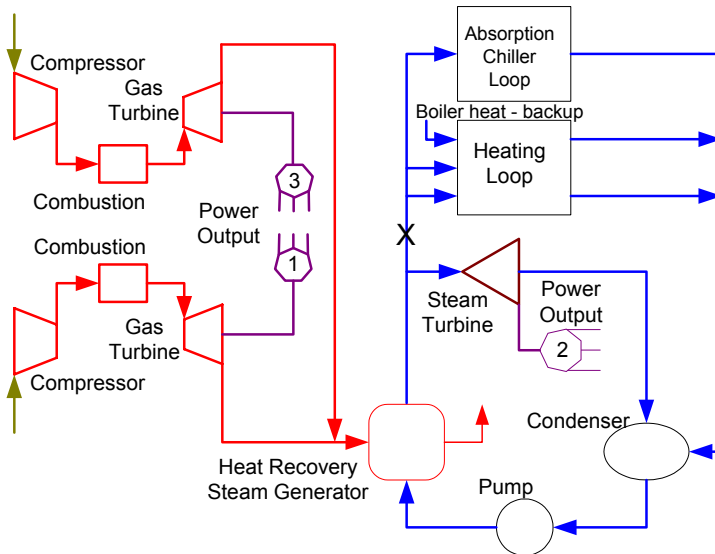


Figure 9b: Suggested Level 3 installation, combined cycle plant with multiple gas turbine engines.

**Scenario 1** represents a very hot summer day without heating needed. In this case all the heat from exhaust is used by the absorption chiller(s) for space cooling. The power from the Rankine cycle (P2) is turned off in order to maximize the cooling energy supply. If the cooling need drops, P3 can be turned off but mindful that the power supply also drops, which approaches scenario 2. Alternately, P1, P2, and P3 can remain on, which supplies maximum power during a mild summer day.

<b>Scenario 1</b>	
P1 (Base)	ON
P2	-
P3	ON
Heat. Loop	-
Absorption	ON
Power Level	NO P2

**Scenario 2** represents a mild summer day without heating need. Only the base turbine (P1) produces power, without P2 or P3. This leaves sufficient exhaust heat for the absorption chiller. If the cooling need drops, P2 can be turned on, approaching scenario 3.

<b>Scenario 2</b>	
P1 (Base)	ON
P2	-
P3	-
Heat. Loop	-
Absorption	ON
Power Level	NO P2 NO P3
	OR, KEEP P1, P2, P3 ON

**Scenario 3** represents a mild weather day when minimum cooling is needed without heating. The base load, P1, runs in a combined-cycle mode with the Rankine cycle, P2. The remaining heat is assumed enough to supply the cooling energy need. The Rankine cycle can be switched off to boost the cooling load if the ambient temperature rises, say in the early afternoon. If the temperature is such that it warrants no cooling or heating, a rare or an unlikely scenario, the exhaust from the base load will be bypassed and discharged to the ambient environment.

<b>Scenario 3</b>	
P1 (Base)	ON
P2	ON
P3	-
Heat. Loop	-
Absorption	ON
Power Level	NO P3

**Scenario 4** represents minimum heating and minimum cooling loads, variant of a mild summer day. Both heating and cooling loops are on. Because the total air conditioning load is assumed small, the Rankine cycle is on, sharing the exhaust load and producing power.

<b>Scenario 4</b>	
P1 (Base)	ON
P2	ON
P3	-
Heat. loop	ON
Absorption	ON
Power Level	NO P3

**Scenario 5** illustrates minimum heat load without any cooling demand. The combined cycle runs with the Rankine cycle, P2, allowing a bypass to run the heating loop. If the heating need increases with the power need dropping or remaining about the same, the Rankine cycle can be turned off. Alternatively, P3 can be turned on with P2 which increases the power output but keeps the heat supply about the same.

<b>Scenario 5</b>	
P1 (Base)	ON
P2	ON
P3	-
Heat. Loop	ON
Absorption	-
Power Level	NO P3

**Scenario 6** represents a need for average heating without any cooling. The base load operates without the Rankine cycle, which is bypassed to boost the heating loop. If more power is needed with the heating load remaining about the same, P3 can be turned on with P2.

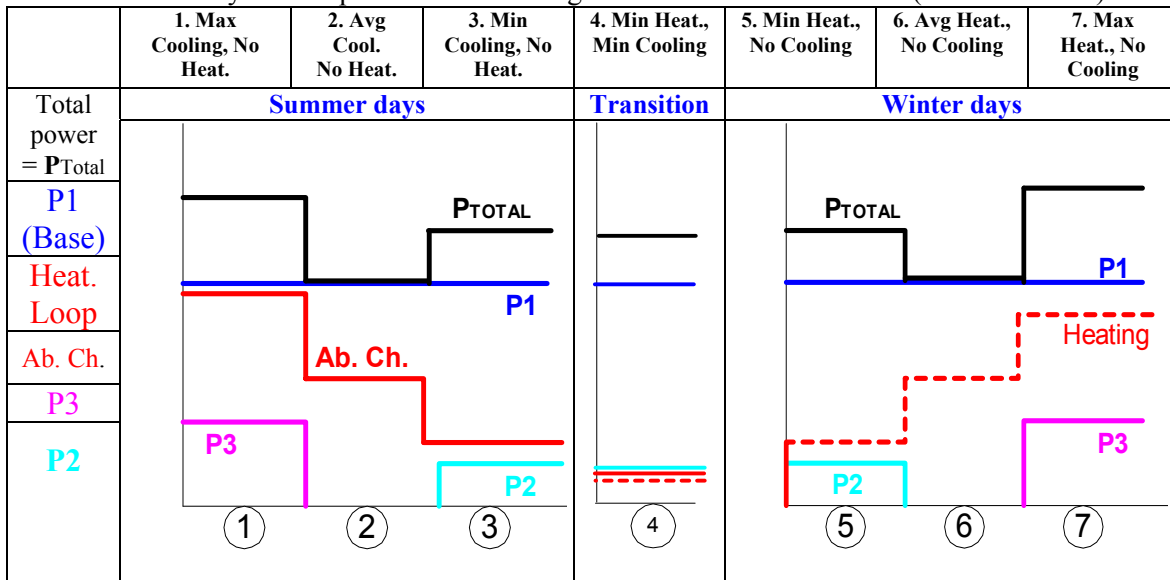
<b>Scenario 6</b>	
P1 (Base)	ON
P2	-
P3	-
Heat. Loop	ON
Absorption	-
Power Level	NO P2 NO P3

**Scenario 7** represents a very cold winter day. In this case, all heat from exhaust is used for (space) heating. The power output from the Rankine cycle (P2) is bypassed to maximize the heating energy supply. P2 can come on line as the heating demand decreases.

Scenario 7	
P1 (Base)	ON
P2	-
P3	ON
Heat. Loop	ON
Absorption	-
Power Level	NO P2

These seven scenarios do not account for power load variations, which can be matched to the site load or maintained slightly above import to avoid peak charges. This may result in mismatch between heating/ cooling demand and supply, forcing some waste heat bypass to the atmosphere. The overall performance will however still be acceptable. The operating profile of the system is shown in Table 1.

Table 1: Possible system response to a wide range of thermal load variations (the 7 scenarios)



In order to size the system it is important to develop typical day power load profiles for all seasons (Figure 10, 11, 12).

Table 2 shows seasonal power variations of the campus that provide valuable hints to size the system. It makes more sense to size the system for the power side assuming the heat load will be compensated by the existing boilers when and if the recovered heat is too small to cover the heating need.

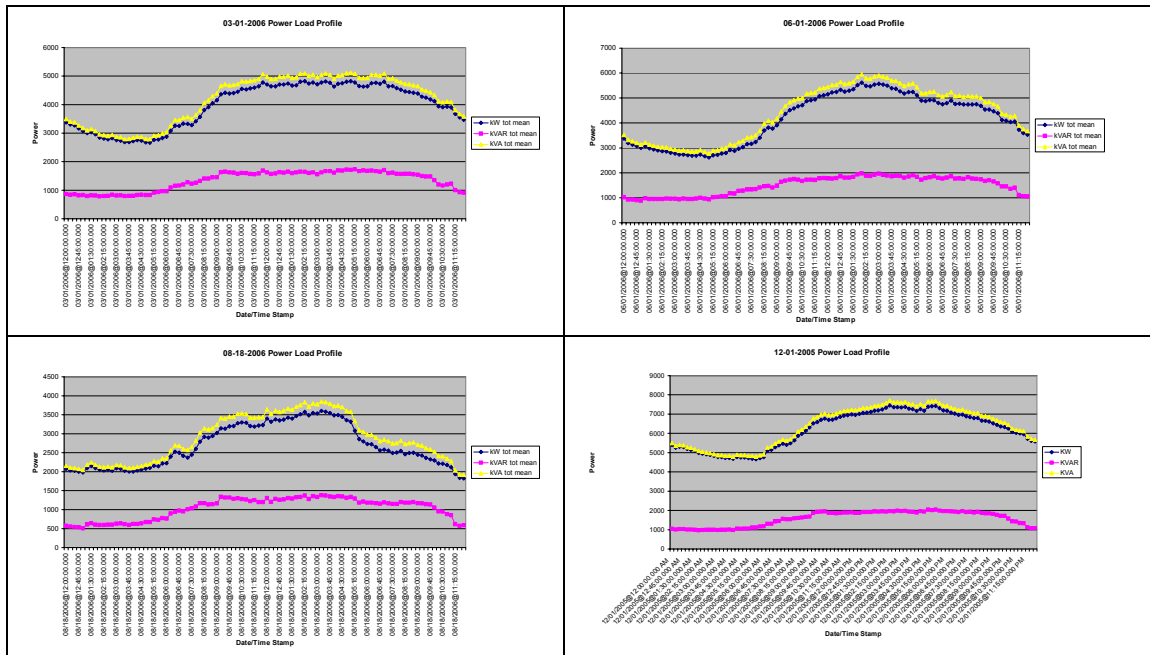


Figure 10: Typical day of season utility power load profile

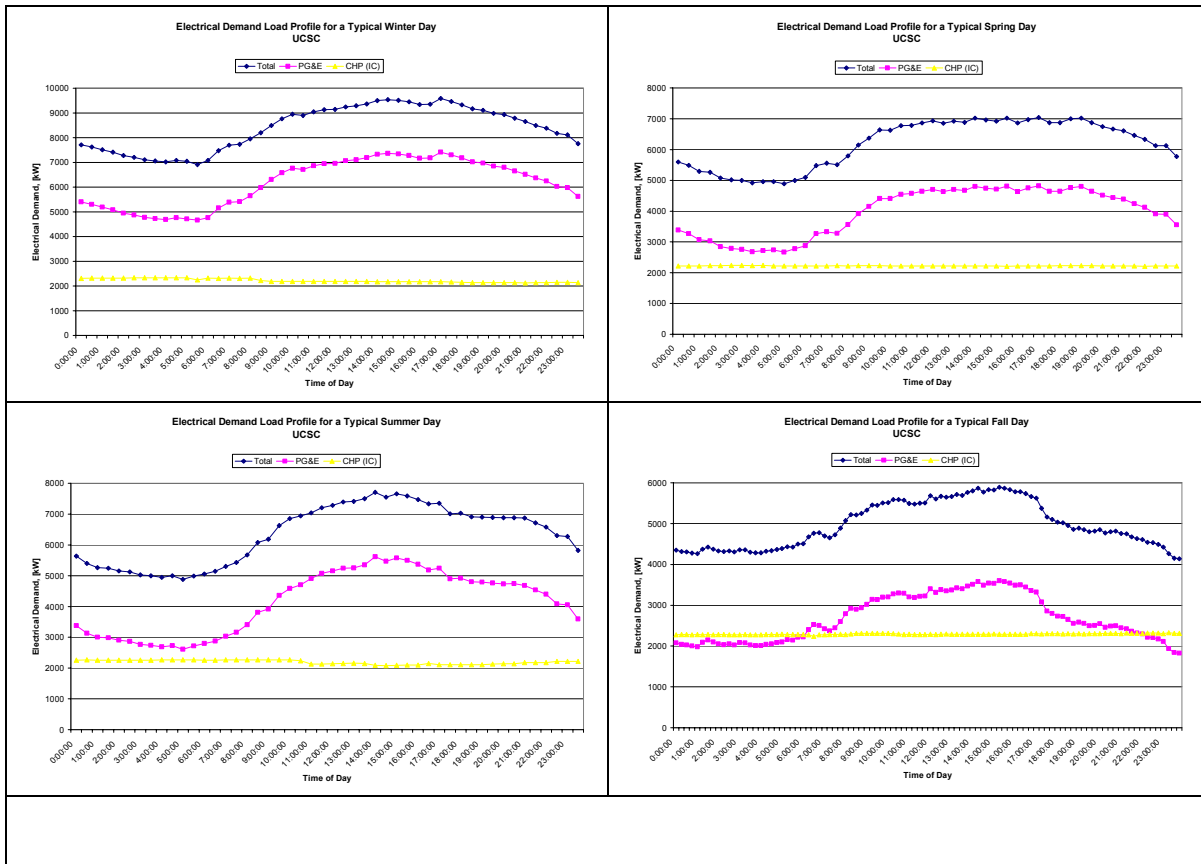


Figure 11a: Seasonal utility power use profile

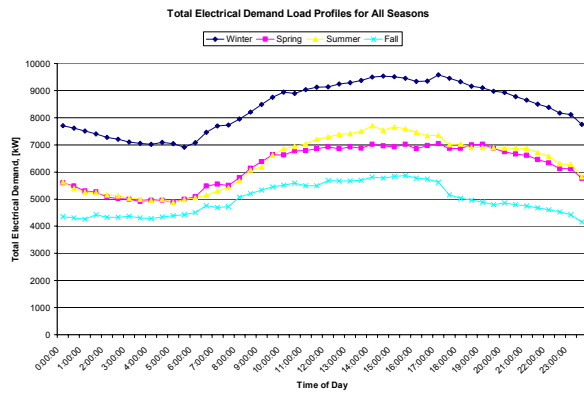


Figure 11b: Annual utility power use profile

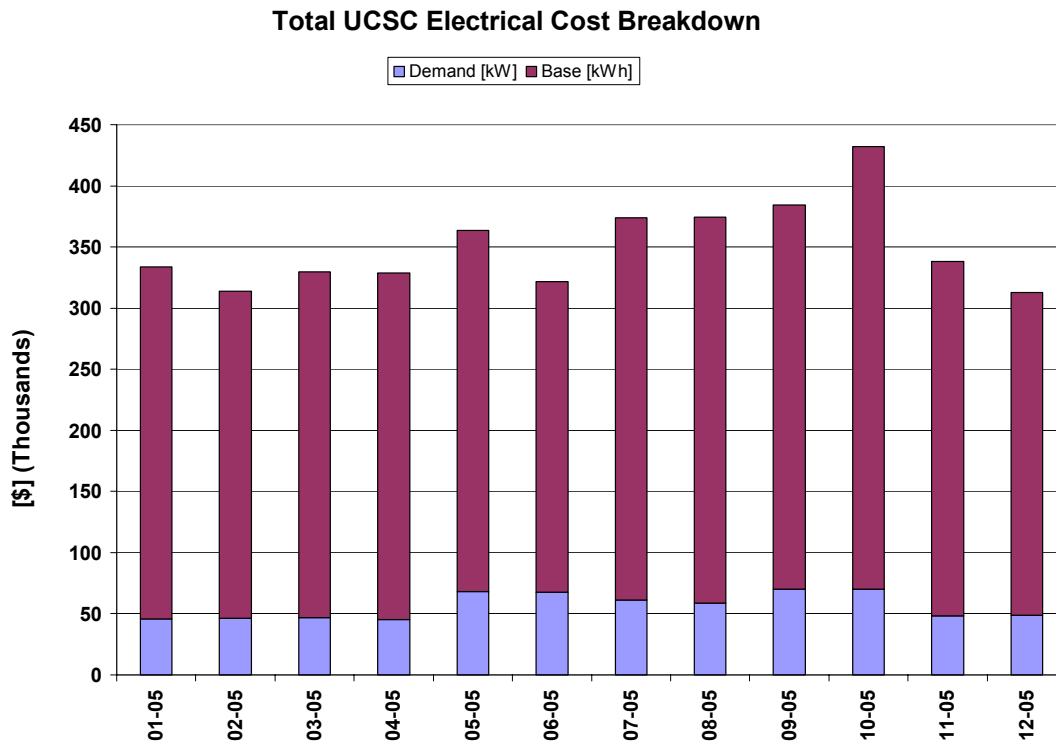


Figure 12: Annual utility bill profile

Table 2: Seasonal utility power variation

Month	Approx. Min kW	Approx. Max MW
March	2.8	5.1
Jun	2.6	6.0
Aug	2.0	3.9
Dec	4.7	7.8

**Note:** If an absorption chiller is installed, the site power load will be offset by the kW of the chillers replaced by the absorption chiller, about 1.6 MW total. Since a system with

less capacity could be purchased is absorption chiller is opted for, this measure also reduces the upfront cost of the power side.

Level 3 recommendations entail installing a single or dual engine of which the total capacity is equal to the sum of the dual engines. For sizing and selection of the system, CogenPro, a CHP sizing software developed by SDSU/IAC was used. The assumed demand is about 8 MW.

**Level 3 Recommendation:**

Inputs are for gas turbine engine system. Hot water requirements are:

- 205° F.
- 132,000gal/hr (=2,200GPM)
- Yes, hot water will return
- Boiler operates 8hrs/day, 7/wk, 52/yr = 2,912hr/yr
- Total boiler load 90,000,000 btu/hr
- Elect. Demand = 8,178kW
- Yearly demand charges = \$677,762.03
- Yearly kWh = 47,328,907
- Yearly kWh cost = \$3,528,962.34
- Yearly therm/yr = 3,800,000
- Yearly gas cost = \$5,586,000
- OH = 8,400hr/yr
- CHP availability = 95%

**Samples of CogenPro output:**

1. One unit of Allison RR 6,750kW
  - a. Implementation: \$16,875,000
  - b. Savings: \$3,134,107
2. One unit of RR 6,420kW
  - a. Implementation: \$16,050,000
  - b. Savings: \$3,049,774
3. Two units of Solar 4,180kW
  - a. Implementation: \$20,900,000
  - b. Savings: \$2,979,443
4. Four units of Opra 1,630kW
  - a. Implementation: \$16,300,000
  - b. Savings: \$2,907,256
5. Five units of Opra 1,630kW
  - a. Implementation: \$20,375,000
  - b. Savings: \$2,778,790

The above values are of course rough estimates and do not reflect the effect of available incentives to reduce project capital costs. We recommend installing two unequal sizes to better serve the fluctuating campus load. For example:

- Two Solar Turbine systems for 3,515 kW and 5,500 kW, providing a total of 9,015 kW, or
- One 1,550 kW Kawasaki Heavy Ind., and another 6,700 kW unit, for a total of 8,250 kW, or
- A 3,942 kW and a 5,046 kW Alston Power systems, for a total of 8,988kW to serve as lead and lag systems respectively.

Similar systems can also be selected from other leading systems including Vericor and GE Aero Energy.

This approach sizes the system for the current campus energy needs leaving sufficient flexibility for future growth. If the load exceeds the supply, which is a likely scenario, the extra power will be purchased from the utility company. A more economical scenario can also be opted for with penalty to space and flexibility for future expansion by selecting a smaller capacity, say, a 3-4 MW combined cycle. If the campus chooses to keep the existing 2.3 MW piston engine, this would approximately cover the campus base load. This less expensive scenario requires more space, control, and piping systems to tie the new and old systems. More importantly, and simply stated, **keeping the existing reciprocating engine may be an economical move to save on the upfront cost in the immediate future, but it significantly limits future expansion of on-site power generation - meaning it likely costs the Campus more in the long run.** If a new system is selected as stated in our Level 3 or 4 suggestions, the existing reciprocating engine can be sold for revenue to assist cover the cost of a more robust campus energy supply system.

#### **5. Level 4 recommendation, install combined cycle and fuel cell system – a strategic solution, most flexible and environmentally desirable**

In this scenario, the base load of Level 3 will be assisted with a fuel cell as shown in Figure 13. The fuel cell may operate on a continuous basis as long as fuel and oxidant are supplied. Hydrogen is frequently used as the fuel so that the products of the fuel cell are only electricity, water, and heat.

**Fuel cell background:** Fuel cells can utilize hydrogen produced from renewable sources such as solar or wind energy. Alternately, and perhaps more likely, hydrogen can be produced from methane that can be collected from biomass - digestion of site farm byproducts, a feasible scenario for UCSC. Hydrogen may also be produced from hydrocarbon fuels such as natural gas, gasoline, or diesel fuel. Some fuel cells use hydrocarbon fuels directly. When hydrogen is required, a "fuel reformer" is frequently used to extract the hydrogen from the hydrocarbon.

There are two types of fuel cells: low temperature and high temperature. These can be employed optionally as shown in Figure 13 – dotted yellow lines for low temperature and continuous yellow lines for high temperature. Low temperature fuel cells are the most commercialized so far and are more common in hospitals, office buildings, schools,

airports, etc. A phosphoric acid fuel cell available at a 200 kW level operating at about 400° F. is an example of low temperature fuel cell. Their power generating efficiencies can reach 40%. The waste heat from these cells is used to supply hot water or warm air for space heating increasing the combined efficiency of the fuel cell to about 85%.

High temperature fuel cells are less common than low temperature fuel cells. The high operating temperature makes cogeneration an important advantage. A typical example is the Molten Carbonate Fuel Cell (MCFC). Existing molten carbonate fuel cells have been operated utilizing natural gas, propane, ethanol, landfill gas, marine diesel, and simulated coal gasification products. Natural gas can be reacted directly within the cell to eliminate the need for external conversion of the fuel to hydrogen. In MCFCs, the electrolyte is made up of lithium-potassium carbonate salts heated to about 1,200° F. (650° C.). Reliability has been proven with some units operating for 49,000 hours.

Fuel cells are generally quiet and can be installed indoors with no additional soundproofing requirements – a plus for an academic environment. Unlike conventional power plants whose efficiencies drop when their capacities drop, fuel cells maintain high efficiency even at smaller capacities. Furthermore, unlike alkaline, phosphoric acid, and polymer electrolyte membrane fuel cells, MCFCs don't require an external reformer to convert more energy-dense fuels to hydrogen. Due to the high temperatures at which MCFCs operate, these fuels are converted to hydrogen within the fuel cell itself by internal reforming, which also reduces cost. They can reach fuel-to-electricity efficiencies of about 55%, considerably higher than the 37-42% efficiencies of a phosphoric acid fuel cell plant. When the waste heat is captured and used, overall thermal efficiencies can exceed 75%. The electrodes of a molten carbonate fuel cell can be made of nickel catalysts rather than the more costly platinum of phosphoric acid systems. This contributes to lower costs. As an emerging technology, MCFC still faces significant challenges including durability and other issues. However, significant advances are being made on a continuous basis, and it is a technology deserving serious consideration.

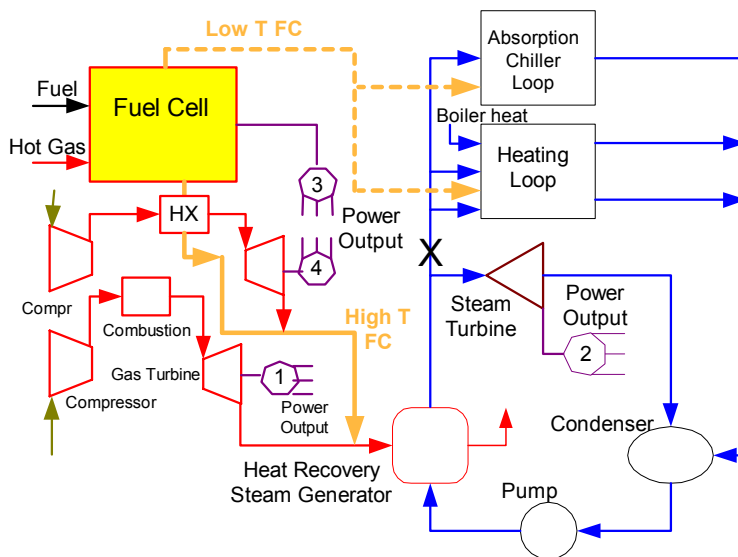


Figure 13: Combined cycle and two optional (high or low temperature) fuel cell systems

It should be noted that a fuel cell requires relatively large space. A low-capacity fuel cell can be installed to save space with a larger gas turbine capacity installed to meet site power requirement. The interconnections between the exhaust from the fuel cell and the gas turbine engine should be optimized and synchronized in more details than what is apparent from Figure 13. The stack temperature and available exhaust heat for some fuel cell capacities are listed in Table 3.

Table 3: Fuel cell options

Manufacturer	Power Output kW	T <sub>stack</sub> F	Heat to Exhaust MMBtu/hr
Fuel Cell Energy	2,000	725	2.5
Fuel Cell Energy	1,000	725	1.3
Fuel Cell Energy	200	Unknown	0.9
Int. Fuel Cells	250	750	0.35

### Incentives and regulatory issues

State and Federal financial and administrative incentives are available to support this project. The utility liaison and the California Energy Commission are generally familiar with CHP incentives available in California. The primary program is the California Public Utilities Commission Self Generation Incentive Program (SGIP), with current incentive levels of \$600-800/kW for engine and microturbine-based CHP systems and up to \$4,500 per kW for fuel cell-based CHP systems. These incentives will be available through 2007, and possibly beyond pending legislative action to extend them. The incentives are available for systems of up to 5 MW, but only apply to the first 1 MW.

The EPA CHP Partnership at [http://www.epa.gov/chp/funding\\_opps-chp.htm](http://www.epa.gov/chp/funding_opps-chp.htm) provides listings of State and Federal CHP incentives; State and Federal Biomass/Biogas incentives; and Utility, State Utility Commission, and State Environmental Agency rules and regulations that remove unintended barriers to clean distributed generation projects. The information is reviewed and updated twice a month.

EPA also has an environmental siting page at [http://www.eere.energy.gov/femp/technologies/derchp\\_env\\_siting.cfm](http://www.eere.energy.gov/femp/technologies/derchp_env_siting.cfm), which addresses emissions, noise, and visual impacts created by a CHP and DER systems.

Several local, regional, state, and Federal environmental and other regulatory restrictions may apply in the implementation of such projects. Agencies such as the Monterey Bay Unified Air Pollution Control District may have more complete information in this regard.