Energy and Cost Optimized Technology Options to Meet Energy Needs of Food Processors

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ABSTRACT

Combined cooling, heating and electric power (CCHP) distributed generation (DG) systems can provide electric power and, heating and cooling capability to commercial and industrial facilities directly onsite, while increasing energy efficiency, security of energy supply, grid independence and enhancing the environmental and economic situation associated with the use of the site. Food processing industries often have simultaneous energy requirements for heating , cooling and electricity. This mixed energy demand makes food processing plants well-suited for the use of CCHP DG systems to support base-load needs or as peak reducing generators enabling reduction of overall energy use intensity.

This paper documents analysis from a project evaluating opportunities enabled by CCHP DG for emission and cost reductions and energy storage systems installed onsite at food processing facilities. In addition, this distributed generation coupled with energy storage demonstrates a non-wires solution[1] to delay or eliminate the need to upgrade and expand the electricity transmission and distribution systems. Results found indicate that a food processing plant in the Pacific Northwest currently purchasing 15,000 MWh/yr of electricity and 190,000 MMBtu/yr of gas could be provided with a 1.1 MW CCHP system reducing the amount of electric power purchased to 450 MWh/yr (97% reduction annually)while increasing the gas demand to 255,000 MMBtu/yr (34% increase annually). The high percentage of hydro-power in this region resulted in CO2 emissions from CCHP to be higher than that attributed to the electric utility/regional energy mix. The value of this work is in documenting a real-world example demonstrating the potential value of CCHP to facility owners and financial decision makers to encourage them to more seriously consider CCHP systems when building or upgrading facilities.

[1] Non-wires solutions or alternatives are those that can help address transmission congestions without retrofitting the power system itself. See BPA Initiatives regarding non-wires solutions: https://www.bpa.gov/Projects/Initiatives/Pages/Non-Wires.aspx

Introduction and Background

The Pacific Northwest National Laboratory (PNNL) and the Northwest Food Processors Association (NWFPA) worked together to evaluate opportunities for energy, emission, and cost savings of combined cooling, heating, and electric power (CCHP) distributed generators (DGs) along with energy storage systems (ESS) installed on-site at energy-intensive food processing facilities. These technologies can provide electricity, heat and cooling services to buildings and industrial processes directly on-site. They can significantly increase energy efficiency, security of energy supply, and grid independence while reducing greenhouse gas emissions. Combined heating and electric power (CHP) systems can utilize the energy losses in a conventional power generating system that occur as heat to address additional loads associated with the site buildings and processes. For instance this heat can be converted to cooling and refrigeration energy with an absorption chiller or absorption heat pump to form a CCHP system. Conventional electric power generators using fossil fuels have a national average efficiency of 45% while CHP systems operate at a much higher efficiency of about 65-75% (EPA 2012).

An objective of this project was to identify strategies for increasing energy efficiency and energy cost savings of NWFPA plants through deployment of novel combinations and designs of variable-output CCHP DG and ESS, without bias towards any technology or manufacturer. A second objective was to understand the benefits of CCHP DG in the management of Bonneville Power Administration's (BPA) grid by leveraging DG and ESS at NWFPA plants. For example, the ability of well-located DG and ESS to alleviate transmission bottlenecks, the ability of certain DG to quickly ramp up and down to reduce over-generation during peak times (i.e. spring run-off), and the ability of combinations of DG and ESS to utilize excess generation. Finally, the results from this study are expected to help stimulate interest by more food processing manufacturers and also other industry sectors to implement CHP, CCHP DG, and/or ESS by increasing knowledge about the techno-economic benefits of these systems. These objectives were pursued by first assessing energy performance of a food processing plant before integration of CCHP DG using historical energy usage data and then comparing that with simulation results that incorporated CCHP DG with the building's process loads as described in the following section.

Plant Selection

A plant selection process was performed to select one plant to serve as a pilot for analysis of CCHP integration potential and feasibility. There are about 550 food processing plants located in the Pacific Northwest, of which about 200 plant sites are NWFPA members. One hundred and thirty of these plants were identified as potential candidate plants to study the feasibility of integrating CCHP systems based on their membership in NWFPA, interest, availability, and willingness to share energy related data. A survey was administered to the 130 NWFPA plants with the objective of determining each plant's quantity of energy use, yearly energy demand profile, and interest. Data collected included North American Industry Classification System (NAICS) codes, annual energy use, monthly energy use (provided by 67 plants), production data, the utility serving each plant and its type (i.e., public or investor owned). Other information gathered were identification of the relative cut plane[2] location of each site and Geographic

[2] Cut plane may be defined as transmission lines and facilities owned by the utility on a constrained portion of utility's internal network transmission grid, or transmission lines and facilities owned by a utility and one or more neighboring transmission providers that are interconnected and the separately owned facilities are operated in

Information System (GIS) maps for the region that include information on the electricity flow gates.

Electricity and natural gas data for the year 2011 for 67 sites were obtained and analyzed to identify plants where CCHP DG integration would maximize their energy, economic, and emission savings. These sites were examined for potential energy savings and economic benefits. Several criteria were used for screening and down-selecting site, which included: 1) being exposed to high costs for heating, cooling, and/or electricity and to low costs for natural gas and/or biogas fuels, either currently or expected in the near future as compared to average costs in the region, 2) having high minimum year-round heating or cooling demands as compared to average demands in the region, so as to economically justify CHP or CCHP, 3) having access to high-quality energy data for their site, including data describing electricity, heating, and cooling demand over time, energy costs, and the efficiency of current technologies providing energy to the site, 4) having access to either natural gas fuel or bio-residue streams for conversion to renewable biogas fuel for DG, 5) having strong internal support for implementing DG and ESS and a commitment to ultimately installing and operating these systems, and 6) having excellent potential for non-wires solutions, such as being situated in a strategic location where it could play a role in alleviating BPA's regional transmission bottlenecks. Approximately 20 food processing plants were expected to fulfill down-selection criteria.

The three criteria established for analysis to select the plant with maximum potentials in terms of energy use were: 1) high annual electricity use to achieve maximum payback, 2) consistent energy use throughout the year – CCHP systems have continuous and consistent energy generation, which makes them more desirable for plants with a constant base load; and 3) availability of steam or hot water from a utility provider – the low cost and emissions of such centralized systems increase the payback period from installing a CCHP DG system.

Based on these criteria, plants that received steam or hot water from a thermal provider (for instance, a utility power plant or other industrial process located nearby providing steam or hot water) were eliminated. The remaining plants were categorized into three groups of: high seasonal energy use, consistent low energy use, and consistent high energy use with short term reduced load in summer. After eliminating plants that did not meet criteria established, four plants remained in the consistent high category, three were in the consistent low category, and one was between high and low. Finally, the plant with the most complete data available and highest interest from the plant owner/management and operators to collaborate was selected for analysis. Power quality issues at this plant contributed to a high level of interest from plant management.

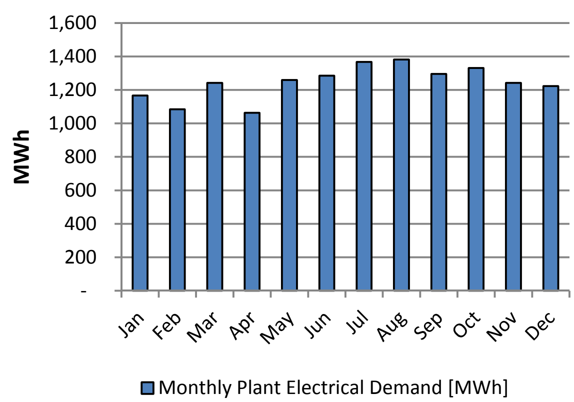
Description and Characteristics of Plant Selected

The plant selected for analysis was a dairy processing manufacturer. This facility is on a 24-hour operation schedule and runs for 363 days per year. The primary use of electricity in this plant is associated with milk processing- 36% , refrigeration (compressors, condensers, and evaporators)-33%, followed by packaging (10%), compressed air (9%), and lighting (4%). Boiler room, space heating/cooling, and product handling each consume less than 3% of total electricity consumed. In 2011, the average power required to operate the plant was 1,714 kW with a peak of 3,121 kW, and annual electricity use of 15,011,600 kWh.

parallel in a coordinated manner, and each of the owners has an agreed upon allocated share of the transfer capability.

In this plant, processes are served by direct ammonia, 28–30°F glycol, 38°F chilled water, 60°F city water and 70–80°F cooling tower water to supply some cooling and tempering requirements. To satisfy the heating requirements of the plant, hot water is produced at 260 gallons/minute at 160°F and stored in hot water storage with a capacity of 12,000 gallons. The cooling requirements (33°F to 39°F and 40°F to 42°F for cold storage warehouse) are served by an ammonia vapor-compression refrigeration system to cool two glycol chillers, one cold storage warehouse, and supply chilled water to a chilled water supply. There are four rotary screw compressors (two 350-horsepower, one 600-horsepower, and one 350-horsepower with a variable frequency drive) with 100 ton installed capacity, 50 ton average load, and a coefficient of performance (COP) of 3.0.

The generic process involved in converting raw milk to pasteurized fluid milk includes: clarification of raw milk for particulation (using electricity), cooling milk to 39.2°F (using electricity for refrigeration), standardization (using electricity), pasteurization (using steam), homogenization (using electricity), cooling (using electricity for refrigeration), and packaging (Brush et al. 2011). Analysis of plant energy use data indicates that there is a simultaneous demand for electricity and natural gas as seen in Figure 1. In addition, the electric demand over the year is relatively constant with use for each month being between 7.1% and 9.2% of the annual total, and natural gas demand being between 6.5% and 9.2% of the annual total.



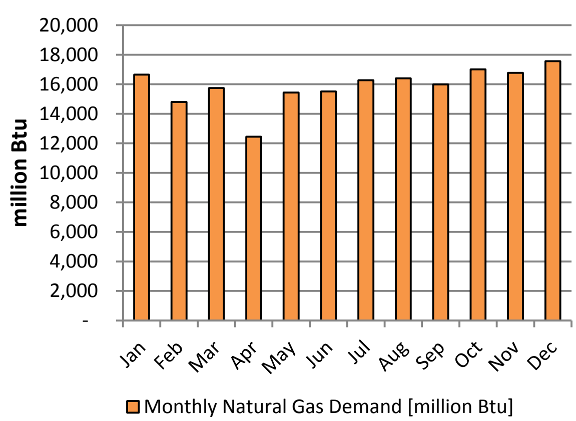


Figure 1. Left: Plant monthly electrical demand in 2012 (total 14,943 MWh). 65% of the time, the demand is between 1500 and 2000 kW. Right: Plant monthly gas demand in 2012 (total 190,569 MMBtu). 73% of the time, the demand is between 20 and 26 MMBtu (200 and 260 therms).

Power Quality

The plant selected was continuously monitored for power quality and reliability events for 18 months from January 2012 to June 2013. A total of 39 significant power quality and power reliability events were recorded during this time period. Results of the monitoring showed that events occurred randomly during the year and over the course of a day (period of 24 hours). Data indicated that the number of events was higher from April to June and also in October. The number of events reported were between 1 to 5 on average at each hour. Assuming $15,000 per incident as reported by the plant[3], there is an estimated power outage cost of $15,000 to $100,000 per hour

[3] This cost was estimated by the plant based on a requirement that the plant dump the entire batch of milk being processed at any time there is an interruption in power.

on average. This suggests the need for an active backup power generator and/or ESS that can support the plant during power system failures or at times when there are power quality issues.

Cost of Electricity

In this study, both the utility's cost of electricity and an industrial customer's cost of electricity were examined. The local utility serving the subject plant provides service to 3,026 industrial customers at an average rate of $0.071/kWh, which includes all charges of basic, transmission and service, distribution, energy, and system usage (based on 2012 data). The rate at the plant is $0.085/kWh on average including demand charges. The data analysis performed included a comparison of total cost of electricity for three consecutive years. Based on this analysis, the total amount paid for electricity by the plant increased by about 11% each year. Beside demand usage charges and facility charges, all other charges including but not limited to basic, system usage and transmission had increased. Such a consistent annual increase enhances the profitability of CCHP DG for the plant over the long term.

The cost of electricity paid by industrial consumers increase as a result of increase in the cost of power generation, transmission, and distribution. The utility's cost of electricity in the Northwest is influenced by different factors including the potential for hydro power generation. At the time this assessment was conducted (year 2014), the water reservoir for power generation in the Pacific Northwest was expected to be lower than average due to reduced snowpack. Given the high percentage of hydro power generation in the NW, the cost of electricity for the region was expected to increase. Using Mid-Columbia daily weighted average electricity prices in 2012 (EIA 2015) and a prediction of weighted average prices considering a 300% increase during high peak months (July and August) and a 250% increase during the rest of the year[4], Figure 2 shows the monthly cost of electricity for the utility to serve the plant during 2012 and a projection for 2014. This expected growth in cost increases the potential benefits of installation of a CCHP system at the plant from the point of view of both the utility and the plant.

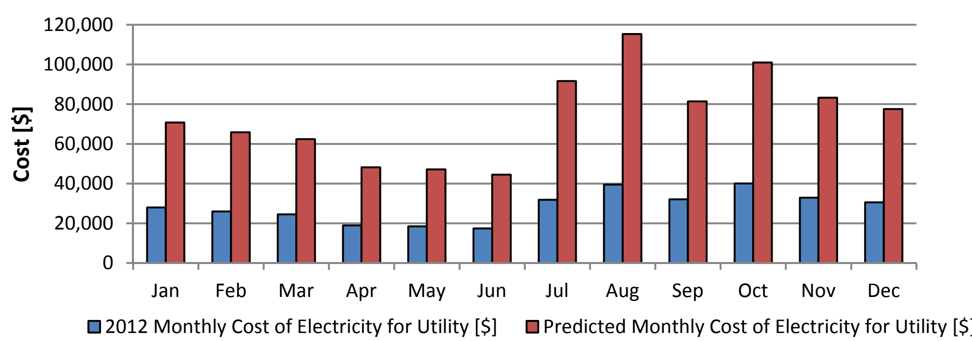


Figure 2: Monthly cost of electricity for the utility to serve the selected plant in 2012 (total $341K per year) vs. the predicted cost with the forecasted price increase in 2014 (total $891K per year)

[4] The 300% and 250% increase are assumptions made in this study. These assumptions are based on expert knowledge of the utility's cost of electricity in the Pacific Northwest.

CCHP System Sizing and Selection

A modeling framework was defined in this work to effectively size and select a CCHP system that maximizes the benefits of CCHP for the food processing plant. Models were constructed with spreadsheets to maximize the flexibility needed for detailed data-driven modeling and analysis of the behavior of newer non-traditional systems such as CCHP. This provided a basis to create a system-specific modeling engine that can be developed.

The modeling approach enabled us to effectively use actual measured time-series energy use data available from the plant and successfully analyze data needed for system selection, sizing, and calculations of energy, savings, and emissions. The flexibility afforded by the spreadsheet modeling provided the ability to estimate the benefits of integrating a CCHP system with potential future electric rate increases. The models included input parameters describing the ramp rate limitations of three DG options – engines, fuel cells, and turbines – which can be used for fast-ramping "supply response" within ramp rate and range limitations included in the models.

The steps involved to model and evaluate potential benefits of integrating CCHP in this plant include: 1) analyzing historical time series data for gas and power consumed to determine the annual demand profile, 2) calculating the peak, base, and average heating and cooling demands of the plant for the process and spaces to find and match CCHP energy output with the plant energy demand, 3) analyzing heat energy use in the forms of process steam, direct process heat, process hot water, space heating and domestic hot water, individually, given the differences in temperature requirements, 4) sizing and selecting the prime mover based on the ratio of electricity to heat demand as well as the operation and maintenance cost of the building, 5) selecting an absorption heat pump (described in a following section) to provide cooling (i.e., chilled water) requirement , and 6) calculating energy use, cost, and reductions in emissions were calculated.

Prime Movers

The prime mover in a CCHP system uses natural gas (or biofuel) to produce electricity on site. The exhaust heat from the engine and the heat from the cooling jacket water are recovered to generate heating (steam and hot water), and refrigeration (using an absorption chiller or absorption heat pump) for use at the plant. In this study, prime movers based on internal combustion engines were considered as documented in Table 3. Here, specifications for internal combustion engines from the manufacturer were used in modeling and calculations. However, specifications from manufacturers of other types of prime movers may easily be "plugged in" for a more comprehensive evaluation of available options. The ratio of electricity to heat from a micro-turbine or fuel cell and the initial cost and maintenance complexity of fuel cells and micro-turbines compared to prime movers based on internal combustion engines, reduced their feasibility for consideration in the application evaluated in this project.

Table 3: Key characteristics of prime movers considered

Option No.	Cost of Delivered System [$]	Electrical Power [kW]	Thermal Output [kW]	Thermal Output Exhaust [MMBtu/hr]	Thermal Output Jacket Water [MMBtu/hr]	10 Year Avg. Cost [$/kWh]	Energy Input [kW]
1	$2.26M	1,941	1,444	3.73	1.20	0.068	4,685
2	$2.22M	1,548	1,333	2.74	1.81	0.067	3,765
3	$1.85M	1,149	586	0.89	1.11	0.067	2,822

Absorption Heat Pump (AHP)

Absorption heat pumps are thermally powered engines used to provide both heating and cooling (CEC 2007). These systems can simultaneously deliver hot water (150°F) and chilled fluid (20 to 45°F). Lower temperature refrigeration can also be delivered that provides for a temperature as low as minus 40°F when combined with a cooling tower or air cooling. The heat source can be steam, exhaust (e.g., from an engine, boiler, or turbine), solar hot water, geothermal hot water, or engine jacket water; the water temperature must be higher than 250°F for heat-pumped hot water and 180°F for refrigeration. Heat sources with temperatures above 150°F are required to provide refrigeration below minus 40°F.

A steam driven absorption heat pump may deliver heat-pumped hot water at 130°F to 170°F and refrigeration at 20°F to 45°F (CEC 2008). If there is no hot water demand, then refrigeration may be delivered as cold as minus 40°F. For each Btu/hr of heat supplied, such an AHP may deliver 1.6 Btu/hr of hot water and 0.6 Btu/hr of refrigeration capacity, with a net COP of 2.2.

A tunable refrigerant flow rate-to-heat ratio can be achieved in a CCHP DG by, for example, altering the quantity of heat sent from the DG to an absorption chiller to provide cooling power. Heat can either be directed for process heating, or to an absorption chiller to provide cooling power. The quantity of heat diverted from one effort to another can be quickly modulated, thereby enabling a variable or tunable refrigerant flow rate-to-heat ratio. In addition to providing energy efficiency gains, variable refrigerant flow rate designs can also be part of non-wires solutions for BPA. For example, during periods of over-generation, a worthwhile supply response option to evaluate is to reduce the electrical supply by DG with a variable heat-to-power ratio, produce more heat, and convert this additional heat into cooling power with a variable refrigerant flow rate absorption chiller.

Energy Storage

Integration of an ESS should be considered to ensure that power quality is appropriately addressed. Without an efficient and reliable ESS, the CHP generator needs to be oversized to ensure the reliability of the CHP system and to enable the load to be met at all times, especially during periods of high demand. However, because CHP systems run continuously throughout the day, they result in excess electricity being generated during hours when demand is low. Excess generation then is either wasted or necessitates consideration of putting it back into the grid. This results in lower efficiency of the CHP system than necessary. By adding an ESS, energy can be stored during hours of low demand and be supplied when demand is high. This eliminates the need to purchase electricity from the grid during hours of high demand or as noted above having to address grid interconnection issues. By adding ESS, the following goals can be achieved:

1. The CHP generator can be downsized, which results in:
    a. reduction in the cost of fuel used by the CHP
    b. decrease in the capital cost of the CHP system
    c. reduction in emissions associated with the CHP
2. The number of power outages is reduced by providing a more reliable power supply.
3. The system provides reliable "just-in-time" energy delivery.
4. Operating efficiency is improved.
5. Insurance costs associated with product losses are reduced.

A commercially available 250 kW Uninterruptible Power Supply (UPS) system currently costs about $160,000 for the system itself not including installation cost. Such a system will be capable of delivering recovery power in 2 to 4 milliseconds at an efficiency of 98% and may be installed outdoors eliminating additional costs and safety considerations associated with interior ESS applications.

System Selection

The prime mover capacity was determined by calculating the electric utilization for three CCHP electrical output capacities and selecting the size with the highest capacity utilization. This was calculated by examining the relationship between the energy generated by the CCHP and the energy required by the plant over one year assuming constant CCHP operation. In this preliminary study, it was assumed that down time for maintenance will be similar for all the sizes examined. Plant data summarized and documented in Tables 1 and 2 were used for system selection, sizing and other assessments included.

Table 1: Plant information used in electrical calculations for CCHP integration

Electricity cost for plant [$/kWh]	0.085
Utility demand charges [%]	5.0
Cooling demand (electricity) to be offset by AHP (35%) [kWh/yr]	5,229,976
Electricity demand by plant process [kWh/yr]	9,712,812
Annual plant electrical demand [kWh/yr]	14,942,788
Cost of electricity purchased from utility in 2012 [$/yr]	1,333,644
Cost of electricity for the utility to serve the plant [$/yr]	341,238

Table 2: Plant information used in thermal calculations for CCHP integration

Total natural gas purchased by the plant in 2012 [MMBtu]	190,569
Gas cost for plant [$/MMBtu]	4.50
Total cost of natural gas in 2012 [$]	857,560
Thermal demand considering boiler efficiency [MMBtu]	161,983
Efficiency of current boiler [%]	85
Temperature of exhaust after AHP (°F)	250

The thermal energy demand for the plant is large enough that with all sizes less than 1% of the CCHP thermal output is not utilized. This is documented below in Tables 4, 5, and 6.

Table 4: Results for 2012 potential electricity demand after CCHP integration (based on calculations)

	1.9MW	1.5MW	1.1MW
CCHP electrical output to be used in calculation [kW]	1,941	1,548	1,149
CCHP total electrical output (assuming 24×7×366) [kWh/yr]	17,049,744	13,597,632	10,092,816
Electrical output not used [kWh/yr]	7,334,991	3,883,715	821,339
Percentage of time electrical output not used [%]	43	29	8
Hours of 100% electricity utilization [hours/yr]	1	16	4,087
Percentage of time electrical output is not fully used [%]	100	10	53
Electricity to be purchased from utility [kWh/yr]	0	443	442,484
Percent of electrical demand to be purchased from utility [%]	0	< 0.1	4.5

Table 5: Results for 2012 potential natural gas demand after CCHP integration (based on calculations)

	1.9MW	1.5MW	1.1MW
CHP total thermal output [MMBtu][a]	43,300	39,963	17,566
Thermal energy needed by the boiler [MMBtu]	118,960	122,265	144,496
Natural gas to be purchased for plant processes [MMBtu]	139,953	143,842	169,996
Total natural gas to be purchased including fuel for CCHP[b] [MMBtu]	280,392	256,703	254,589
Percent increase in plant natural gas demand [%]	47	35	34
(a) Less than 1% of the CHP thermal output is not used. (b) Considering boiler efficiency of 85%			

Table 6: Summary of potential cost savings with the integration of CCHP

	1.9MW	1.5MW	1.1MW
CHP total electrical output (assuming 24×7×366) [kWh]	17,049,744	13,597,632	10,092,816
Electricity to be purchased [kWh/yr]	0	443	442,484
Cost of electricity to be purchased [$/yr]	$0	$40	$39,492
Reduction in cost of electricity to be purchased [$/yr]	$1,333,644	$1,333,604	$1,294,152
Reduction in natural gas demand for plant processes [MMBtu/yr]	50,616	46,727	20,573
Reduction in natural gas cost for plant processes [$/yr]	$227,771	$210,273	$92,579
Cost of CCHP generation assuming 0.067$/kWh [$/year]	$1,159,383	$911,041	$676,219
Amount saved in plant electric and gas costs by CCHP [$/year]	$402,032	$632,836	$710,512

Installation criteria for integrating the CCHP supply with the plant system configuration were considered, including integration of the AHP with an ammonia refrigeration system. The physical location for the system installation was considered such that it would be proximate to both steam and refrigerant lines to connect the new refrigerant source from the AHP.

Results and Findings

Benefits of Integrated CCHP for the Utility

The average efficiency of power generation in the United States is 45% (EPA 2012). A significant portion of the energy in the fuel is lost in waste heat. In addition to heat losses, about 7% of the electricity generated by central plant power stations is lost before it reaches an end user as a result of losses in the transmission and distribution (T&D) system (EIA 2014). An alternative to this approach is to generate electricity at or near the customer load centers to avoid line losses and use the heat energy resulting from the electricity generation, e.g. implementing CCHP on the utility side of the meter “close” to the plant. By using waste heat recovery technology to capture a significant proportion of this wasted heat, CCHP systems typically achieve total system efficiencies of 65% to 75% (EPA 2012), compared to only 45% (EPA 2012) for producing electricity and thermal energy separately.

As an example, in data centers where the thermal load is almost entirely cooling rather than heating, CCHP can still provide an overall efficiency advantage. The waste heat from the generator is used in absorption chillers to produce cooling, which displaces electricity-powered chillers rather than displacing direct fuel purchases for heating. Therefore, the total electricity provided and displaced by a combined cooling and power system can be up to 135% of the on-site generator capacity (EPA 2007).

Savings for the Plant

Figures 3 and 4 show comparisons of the electricity and natural gas to be purchased from the utility to operate the plant before and after the integration of a 1.1 MW CCHP system. The peak electricity demand is reduced by a factor of five (2.50 MW to 0.53 MW) assuming that the electric refrigeration system is replaced by an engine-exhaust-heat driven absorption heat pump. There is an overall increase of 34% in the amount of natural gas to be purchased from the utility to operate the CCHP system. Results of our analysis indicate that after integration of a CCHP system, over the course of a year, 53% of the time no electricity needs to be purchased from the utility and 25% of the time less than 100 kW is required to be purchased from the utility. With CCHP, the natural gas demand is between 26 and 34 MMBtu 82% of the time.

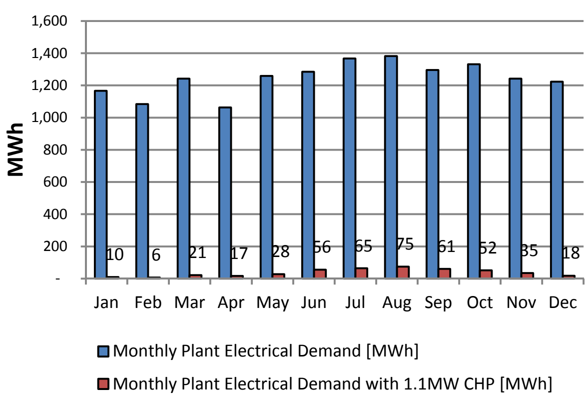


Figure 3. Plant electricity use in 2012 (total 14,943 MWh) and amount to be purchased from the utility with 1.1 MW CCHP system (estimated total 442 MWh)

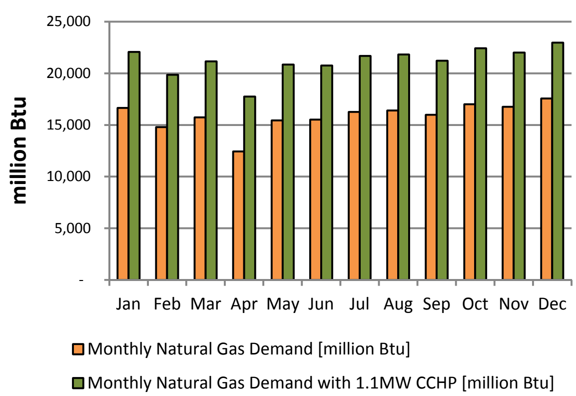


Figure 4. Monthly natural gas demand before and after (estimated) 1.1 MW CCHP integration. Annual total before CCHP was190,569 MMBtu; after, 254,589 MMBtu, an increase of 34%.

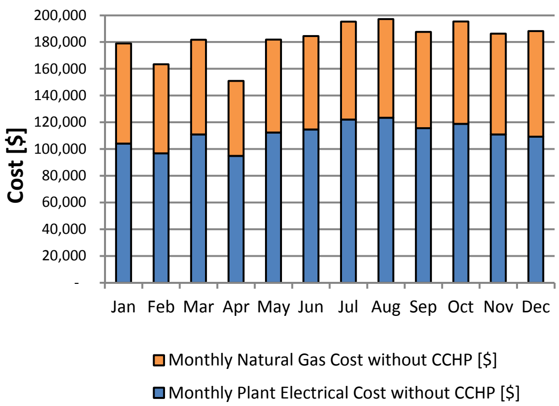


Figure 5: Plant utility cost in 2012. Total cost for electricity $1.33 million, total cost for natural gas $857K.

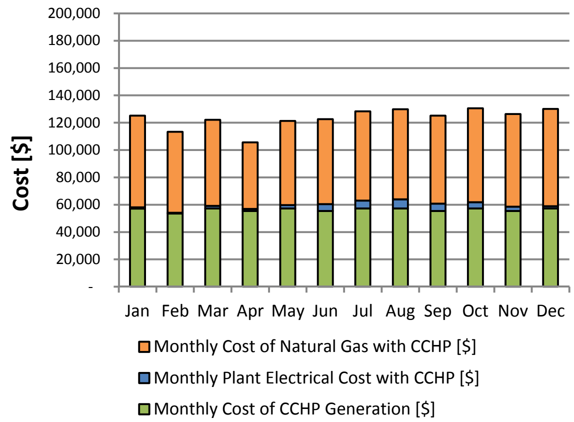


Figure 6. Estimated plant utility cost with 1.1 MW CCHP system. The utility cost includes the cost of fuel to generate electricity and heat using the CCHP.

Figures 5 and 6 illustrate the total utility costs for the plant in 2012 and total utility costs estimated after application of a 1.1 MW CCHP system. The reduction of electrical demand is expected to result in a standby or backup charge for the plant, which has not been factored into costs calculated in this study. In addition, it is assumed that the costs for the CCHP system are paid up front with no financing costs. In 2012, the electricity cost was $1.33 million and natural gas cost $857K. With the 1.1 MW CCHP system, the cost of electricity to be purchased from the utility is estimated to be $39K, the cost of natural gas is estimated to be $765K, and the cost of CCHP generation (operation, maintenance, and fuel for the CCHP generator) is estimated to be $676K. Total utility cost before CCHP is $2.19 million; after CCHP integration it is estimated to be $1.48 million (i.e. $39K + $765K + $676K).

Installation of DG at industrial facilities may be among the non-wires solutions considered by a utility to address load growth and congestion on the transmission system. An analysis of the location of BPA electrical transmission system "bottlenecks" or cut planes with the geographic location for food processing plants revealed a high concentration of plants near Portland, OR and Seattle, WA, regions where it is particularly challenging to wheel in electrical power (as understood by the cut plane locations). Power consumption is also at its highest in these regions. There is a benefit to having multiple NWFPA plants near the Seattle and Portland areas, because, if a greater concentration of DG and storage was also co-located with these plants, they could more readily provide non-wires solutions, including reverse demand response and fast-ramping supply. This solution will help maintain power reliability for food processing plants as well as the region. In the case of the plant studied in this work, integration of 1.1 MW CCHP results in shifting 9,271 MWh of electricity off the grid and thereby reducing congestion on the transmission system. During peak time (which is an annual peak rather than a daily peak), the plant still needs to purchase about 400–550 kW from the grid 0.16% of the year; a fraction of the electricity needed by the plant during the peak time. In 2012, this was 30% of the electricity needed at the highest peak.

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