Innovative Self-Generation Projects: Case Studies in Canada

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ABSTRACT

This paper presents innovative self-generation projects at three industrial facilities. The objective of this paper is to demonstrate the technical and economic merits of each project, provide a review of the challenges to implementing on-site generation at industrial facilities and a discussion of innovative and practical approaches to overcoming these challenges.

Three case studies are considered:

- By-Product Gas Generation at a Steel Mill: Combustion of blast furnace and coke oven gas, previously flared to atmosphere, is expected to generate approximately 5 MW of electrical power.
- Quad-Generation at a Confectionary Manufacturing Facility: A combined heat and power system designed to supply the plant with electricity, steam, hot water and chilled water.
- Co-generation with CO_2 Fertilization in Greenhouses: Internal combustion engines to supply hot water, electricity and CO_2 for plant fertilization to greenhouses in British Columbia.

The assessments of the technical and economic aspects of each project are based on incentive applications, estimated and actual project costs, technical review results and updated detailed design and commissioning information, where available.

The conclusions of this paper are that incentives, or other financial support, and innovative approaches to maximizing the project benefits are vital in developing viable on-site generation projects. In the current environment, in an appropriate jurisdiction, self-generation projects can be viable from 500 kW and greater.

Introduction

The field of industrial power generation has developed technologies that utilize cleaner fossil fuels, renewable fuels or recovered waste heat, to generate electricity.

This paper presents case studies in power generation in three industries, namely; greenhouses, steel manufacturing and confectionary. In each case, the subject company has, or is in the process of implementing a generation system to cost effectively reduce the amount of electricity purchased from the grid. All three of these projects will also benefit from financial support from a utility either in the form of capital incentives or guaranteed power purchase prices.

Co-generation systems, that consume natural gas to produce electricity, can be cost effective depending on their ability and opportunity to utilize the thermal output to meet plant thermal requirements. Moreover, the current spread between electricity and natural gas cost per unit of energy produced, makes these systems more economically attractive than at any time in the past.

From an economic standpoint, the use of waste heat in power generating systems is highly beneficial given that the system does not require consumption of additional fuel to produce the thermal energy required for electricity generation.

Case Study 1: By-Product Gas Heat Recovery at Steel Plant

Overview

Arcelor-Mittal Dofasco (AMD) operates a steel production facility in Hamilton, Ontario. The plant produces a large range of products ranging from hot-rolled and cold-rolled coils to steel tubes and galvanized products. For many years, significant amounts of the by-product gases from the blast furnace and coke oven were flared to the atmosphere.

Previous to the Industrial Accelerator program, the capital costs and infrastructure constraints prohibited the company from capturing the waste gases for use in processes or electricity generation projects. The company identified a used 6 MW steam driven turbine generator to integrate into their existing boiler and steam network. The anticipated incentives offered through the Industrial Accelerator program were upwards of $4 million. These incentives reduced the simple payback from 2.5 years to 1 year, allowing Arcelor-Mittal to move forward with the project.

Base Case

The Arcelor-Mittal Dofasco plant is a large integrated steel facility that has evolved over the last 100 years. Unlike most steel facilities, the plant was not originally designed for energy self-sufficiency due to the availability of cheap hydro-electric power. Until this project was completed, no electrical generation was done on site. The plant operates three coke ovens and three blast furnaces to produce a wide range of flat rolled and tubular steel products.

Coke is an essential part of the steel-making process. The on-site production of coke produces a gas known as coke oven gas that has low heat content, roughly 45% of that for natural gas. Approximately 90% of the coke oven gas is re-used as fuel in other steelmaking processes. Blast furnaces also produce a by-product gas with a very low heat content which is approximately 8-10% of that for natural gas. The two by-product gases are used directly for process heat, and the remainder of the gas is fired into existing boilers to produce steam. The steam is subsequently used for process heat and turbine-driven equipment such as pumps and fans. Due to the dynamic nature of the steel making process, electricity, steam and by-product gas availability vary significantly over time. Thus, the demand for steam and process heat was such that an excess of by-product gases existed which were being flared. The annual amount of by-product gas flared was 5-8% of the total gas produced. It was estimated that a total of 1.5 million GJ per year was being flared.

Project

To utilize the significant amount of heat in the waste gas being flared, a steam driven turbine generator was proposed. The boilers had capacity to produce more steam, so new boilers were not required. To reduce capital requirements, a used turbine/generator (TG) system was sourced with a 6 MW capacity. Given the size of the by-product gas resource, a larger turbine could have been sized; however, the company saved a significant amount of capital by importing a used turbine, overhauling it and re-winding the generator.

The facility operates on a 24x7 basis, thus the TG was expected to be running at all times, except for a two-week maintenance shutdown each year. During the technical review of the system, the expected performance of the system was estimated as shown below. The turbine was expected to operate at an 88% load factor. Table 1 illustrates the resulting reduction in average demand and electricity savings as determined during the technical review of the project.

Table 1. Technical Review Results for Case Study 1

Gross Generation (GWh/year)	45.9
Parasitic Demands (GWh/year)	11.5
Annual Net Generation (GWh/year)	34.400
Average Demand Reduction (MW)	3.93
Annual Electricity Savings ($/year)	$2.75 Million

One of the challenges with the proposed system was to ensure 24x7 operation of the TG within the context of the high variation in by-product gas flows. Steam turbines have a minimum steam flow cut-off. A control strategy needed to be developed to ensure the turbine had enough steam to meet its minimum cut-off when availability of the by-product gases was low. During the technical review it was noted that the boilers at Arcelor-Mittal Dofasco had a back-up fuel system that fired bunker C oil to meet plant steam demands when by-product gas demands were low. The rules of the program disallowed this fuel source for self-generation projects, meaning either a fuel source switch or other changes needed to be made in the design. Originally, the l strategy selected would see the turbine idle while bunker C oil was being fired. Special consideration in the measurement and verification strategy was given to the bunker C oil measurement so that the turbine's output would not be counted towards program electrical contributions while bunker C oil was being fired.

Eventually, as the system was installed, natural gas was added to the two largest boilers, greatly reducing the amount of bunker oil used for back-up. Natural gas is an allowed fuel under the program so no special Measurement and Verification (M&V) considerations are required when firing on natural gas. However, the bunker oil is still in place and still fired in the boilers from time to time. To further lower steam demand throughout the plant to reduce bunker oil firing, a large steam driven turbine pump can be switched to an electric back-up pump. The pump fuel switch effectively frees up steam capacity to further reduce the times that the back-up fuel system was firing, increasing the turbine's output. An electric meter was added to the electric pump and its electrical consumption counted as a parasitic load on the turbine system for M&V purposes.

Current Status

During the installation of the system, the turbine was overhauled and the generator re-wound. The re-winding improved the output of the turbine beyond what was expected during the technical review, increasing the output to 9 MW. During operation of the turbine, short-term peaks of up to 9.5 MW have been recorded.

The first quarterly M&V results for the project are summarized in the table below, prorated to an annual basis. The project is realizing 123% of the anticipated and contracted electricity savings that were expected from the program. Table 2 summarizes these results.

Table 2. M&V Results for Case Study 1

Gross Generation (GWh/year)	47.8
Reduction in Generation from Bunker C Oil (GWh/year)	1.82
Other Parasitic Loads (GWh/year)	3.44
Net Generation (GWh/year)	42.54
Average Demand Reduction (MW)	5.3

Case Study 2: Quad Generation at a Confectionary Manufacturing Facility

Overview

Ferrero Canada Ltd. is a leading global chocolate and confectionary manufacturer. Ferrero contracted Doherty Engineering to investigate the potential to implement a natural gas fired combined heat and power (CHP) plant to supply their Ontario plant with electricity, steam, hot water and chilled water – the given name of "Quad-gen" is indicative of the number of different loads to be supplemented by the CHP system. On a concurrent timeline, Ferrero planned to build a new warehouse, which would increase existing electrical, hot water and chilled water loads, which were incorporated into the generation project scope.

To improve the economic viability of the project, Ferrero applied for a project incentive through their local distribution utility to the Ontario Power Authority's saveONenergy program. The anticipated project incentive was $6,143,400, which improved the project's simple payback from 4.12 to 1.69 years.

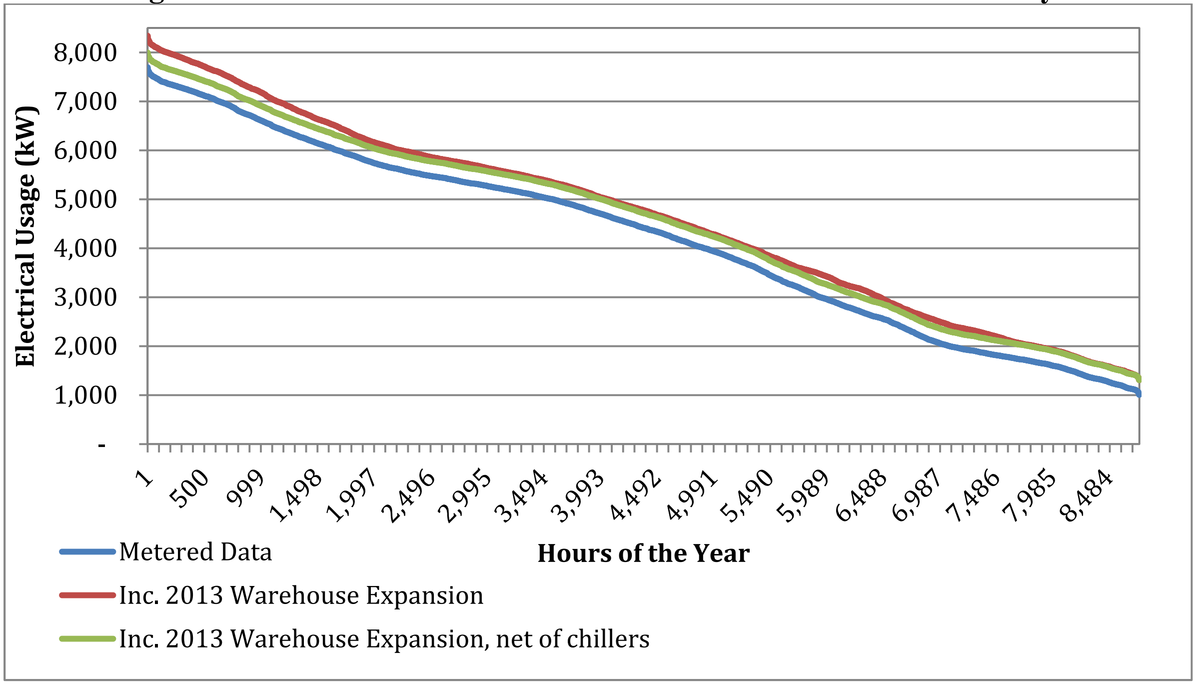
Base Case

Currently, there is no on-site electricity generation at the Ferrero plant. From an electrical perspective, the base case includes the facility's current electrical load and the estimated electrical loads associated with the new warehouse. The warehouse loads are projected to operate uniformly throughout the year. The plant's thermal requirements are currently met by two 500 horsepower Cleaver Brooks natural gas fired tube boilers.

The existing facility does not have any process hot water loads; however with the addition of the new warehouse, hot water will be required to meet the space heating and dehumidification loads. In the absence of the project, it is expected that Ferrero would use the existing boilers to meet this need.

There are currently ten York electric chillers that supply chilled water to the existing facility; however, there is an increased cooling load associated with the new warehouse. As the existing chillers are currently running at full load to meet the facility's cooling loads, in the absence of the project, the additional loads would be met with an additional electric chiller with the assumed COP of 4.0. Figure 1 shows Ferrero's electrical loads using 2011 metered data. Three scenarios have been graphed.

Figure 1. Estimated Electrical Load Duration Curves for Case Study 2



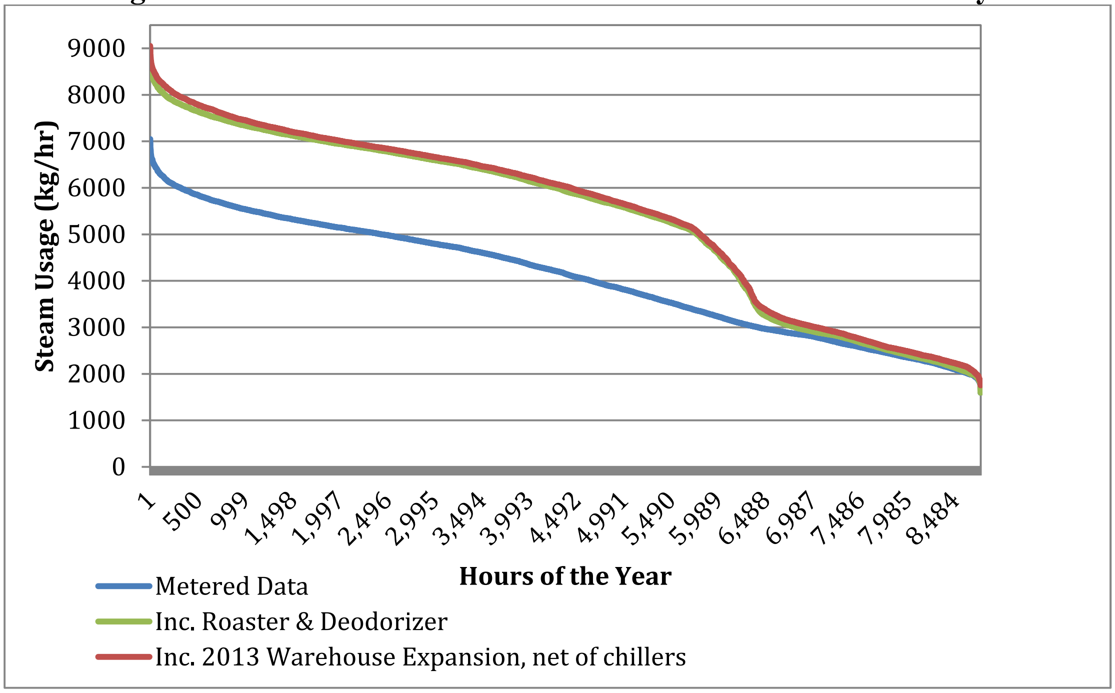
The curve that includes the new warehouse expansion, net of chillers depicts the electrical generation base case scenario that is anticipated in absence of the project. The minimum electrical demand expected is 1.3 MW and the maximum electrical demand is 8.0 MW. The average electrical load is 4.5 MW.

The 2011 thermal profile (natural gas input) was adjusted to account for the roaster and deodorizer that were installed in fall 2011, and the additional hot water loads resulting from the new warehouse. The boiler natural gas usage was measured through Ferrero's Johnson Metasys system and translated into hourly steam load requirements that would be offset by the quattro-gen system.

There are currently no process hot water loads, but with the addition of the new warehouse, hot water will be required for space heating and dehumidification. In the absence of the project, the space heating and dehumidification would be provided by the existing boilers at approximately 200 kg/hour. The following steam load duration curves (Figure 2) were developed for three scenarios: Metered data, Metered data, including the roaster and deodorizer loads, and metered data including the roaster and deodorizer and the new warehouse additional thermal loads, netting out the absorption chiller loads.

The curve that includes the roaster and deodorizer illustrates the steam load that will be offset by the project. The maximum steam load is 8,846 kg/hour while the minimum steam load is 1,592 kg/hour. The average steam load is 5,350 kg/hour of steam. Ferrero's total annual steam load that can be offset by the project is projected to be 46,862,137 kilograms.

Figure 2. Estimated Steam Load Duration Curves for Case Study 2



Project

The project consists of two main elements:

- Electricity and Steam Generation – a 5 MW gas turbine generator (GTG) to generate and provide electricity to the plant. A heat recovery steam generator (HRSG) for process steam complete with a duct burner to provide supplementary steam production for high demand periods are critical parts of the quattro-gen system that are inter-related to the output of the GTG.
- Chiller Replacement – two absorption chillers totaling 426 tons in place of an electric chiller that would be installed for the new warehouse, in absence of the project.

The electrical output of the generator was determined by Doherty Engineering using an Excel-based model that assumed the Quattro-gen system would operate based on whether the thermal or electrical load would be satisfied first and the remainder of the respective other load will either be supplied from the electrical grid or supplemented by the duct burner respectively. The model also determined the fuel input associated with the generator output. Figure 3 illustrates the expected GTG electrical output over a one year period. It also shows the plant electrical load profile, for the same period.

The CHP model estimates the maximum gross output of the generator to be 5.13 MW with an average demand of 3.51 MW. The first year reduction in electricity consumption and average demand were identified as 28,259 MWh and 3.40 MW, respectively.

Figure 3. Simulated Electrical Load and Gas Turbine Output

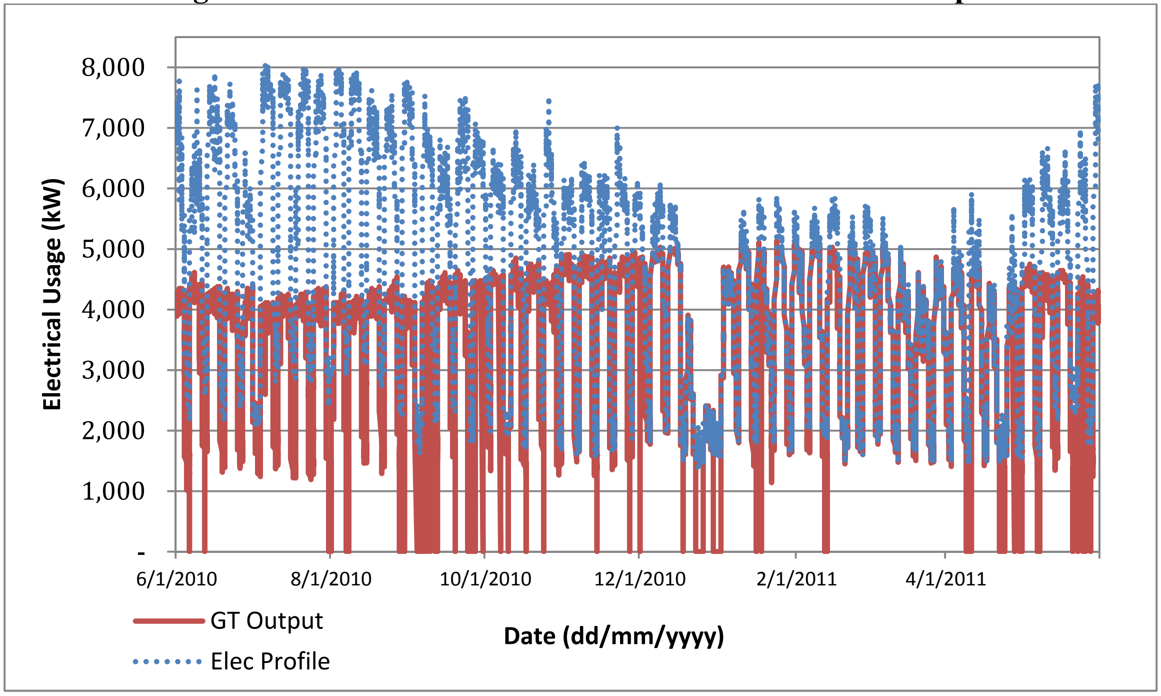


Figure 4 illustrates the thermal output produced by the GTG over a one year period. It also shows the plant steam load profile, for the same period. Any additional load, required to meet plant peak steam demands, will be provided by the supplemental duct burner. As revealed by the electrical and steam profiles, the Quattro-gen system has been sized appropriately, to optimize the electrical and thermal output.

The new chilled water demand was isolated to identify the 997 MWh and 0.194 MW first year electricity savings resulting from the Chiller Replacement Measure. As the electric chiller has been replaced with an absorption chiller, the electricity savings equals the electrical baseline of the electrical chillers accounting for the parasitic loads associated with the absorption chiller.

Based on production forecasts, Ferrero has projected both the electrical and steam consumption to increase by 30% over the ten-year contract life of the project. The chiller loads are expected to increase by 1% each year over the duration of the ten-year contract life. These projections were factored into the estimated reduction in electricity consumption. A summary of the project economics is provided in Table 3. The estimated other costs include the fuel to operate the GTG, the extended service agreement required for the GTG and the stand-by utility costs based on the capacity of the generator.

Figure 4. Simulated Steam Profile And HRSG Steam Output

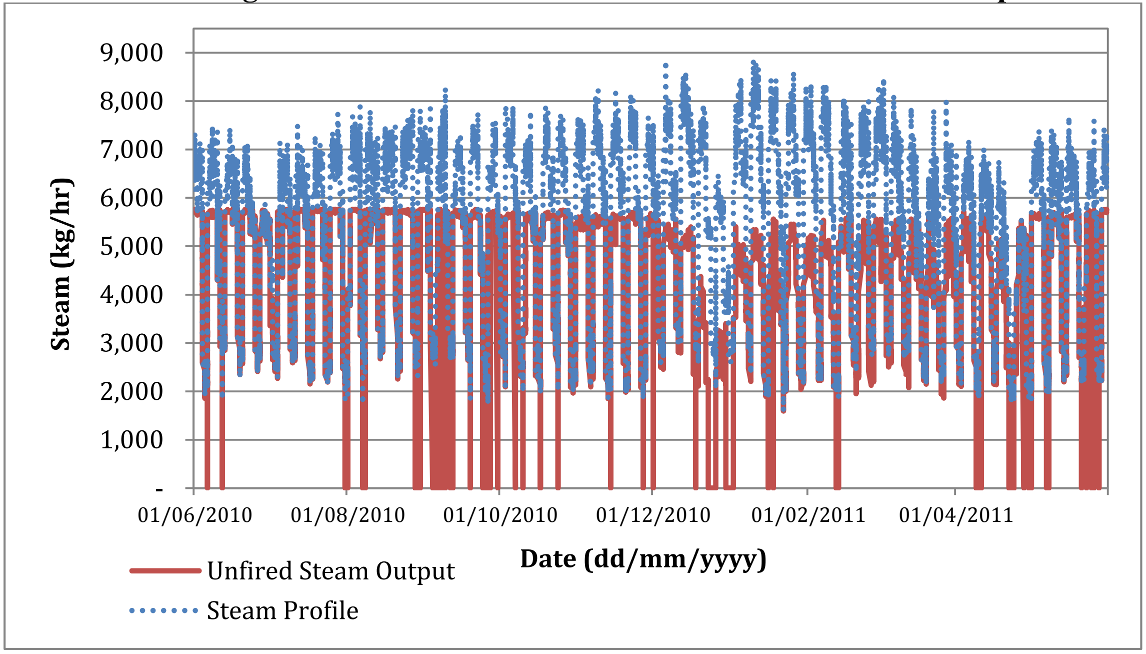


Table 3. Case Study 2 Economic Benefits

Net Annualized Electricity Generation (GWh/yr)	30.72
Estimated Demand Savings (MW)	3.74
Estimated Electricity Bill Savings ($)	$4,146,795
Estimated Other Costs ($)	($1,619,364)
Project Benefits ($/year)	$2,527,431
Project Costs	$10,415,735
Project Incentive (@ $200 / MWh)	$6,143,400
Simple Payback before Incentive (years)	4.12
Simple Payback with Incentive (years)	1.69

Current Status

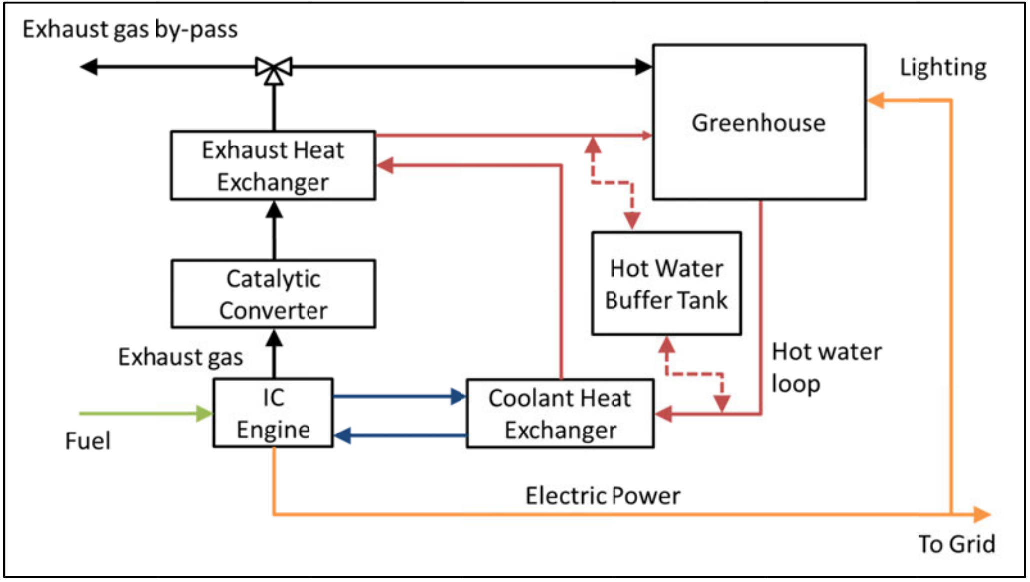
The project is currently under construction and at the 50% progress draw with the expected In-Service date is September 2013. There have been no significant deviations in the project that impact the expected electricity savings.

Case Study 3: Co-generation with CO_2 Fertilization in Greenhouses

Overview

Large greenhouses represent a unique and innovative opportunity for co-generation projects. While the greenhouse co-generation projects have been around for some time, recent innovations in exhaust cleaning and low natural gas prices have led to increased interest in them. The idea is to use an internal combustion engine to produce electricity that can be used for lights, greenhouse loads or exported to the grid. Heat for hot water and space heating can be extracted from the engine. A further advantage can be gained by cleaning the exhaust gas and injecting the cooled CO_2 stream into the greenhouse to act as a fertilizer for the plants (Noren, 2002). Typically, a greenhouse co-generation system will be designed for 1 MW per 5 acres. A greenhouse system with an internal combustion engine is shown in Figure 5.

Figure 5. Typical Greenhouse Co-generation System



(*Adapted from: http://www.ge-energy.com/solutions/co2_fertilization_for_greenhouses.jsp*)

The CO_2 exhaust needs to be cleaned extensively before it can be used in the greenhouse. Small concentrations of NOx and CO can harm the plants and at worst destroy whole crops. The CO_2 and space heating work in conjunction to increase plant production – warmer atmospheres in greenhouses contribute to faster plant growth and more CO_2 consumption. In some cases, other benefits such as shorter flowering times and increased sugars for fruit crops can be gained. CO_2 fertilization is done at many greenhouses that don't have co-generation system, which can purchase an average of $7,000 per acre per year in liquid CO_2. Other greenhouses may have the CO2 pumped in from a nearby industrial process. The amount of CO_2 absorbed by the operation is highly dependent on the type of crops, but can range from 40 to 80 tons/acre per year. Co-generation systems add the benefit of high efficiency by combining electricity production, heat generation and CO_2 fertilization in one system.

Greenhouse Projects in British Columbia

In 2002, the first British Columbia (BC) greenhouse co-generation project was completed. The project is a public-private partnership between a greenhouse, a power generation company and a municipal landfill. Landfill gas is collected from the landfill and is used to generate power through a 5.6 MW gas turbine. The greenhouse benefits from the hot water supply from the turbine. Previous to this project, the landfill gas was collected and flared. The project saves an estimated 30,000 tonnes of CO_2 per year while supplying the greenhouse with 100,000 GJ of heat in the form of hot water.

Recently, BC Hydro, the electric utility has introduced the Standing Offer Program (SOP), to encourage clean and renewable private power production in BC (BCHydro, 2013). The program accepts projects from new and existing generators generating electricity through renewable energy or high-efficiency co-generation. The program offers a guaranteed price of $100/MWh for generated electricity. As a stipulation of the program all power must be exported to the grid, requiring most generators to add a separate distribution line on site. Co-generation projects must demonstrate efficiency over 85% on a lower heating value basis.

BC Hydro's Standing Offer Program has spurred a big interest from the greenhouse growers in BC. Currently, a number of greenhouses are applying through the program to integrate co-generation systems into their greenhouse operation. Currently, five greenhouse growers are considering projects, totaling 36 MW of generation capacity.

It is important to note that the greenhouses are located near a major load center for British Columbia, making them ideal projects for helping to reduce peak demands and potentially defer major capital projects to the grid, such as transmission line expansions and distribution upgrades. Most sites consider two systems to add some redundancy and also improve part load performance of the generators to better balance hot water, CO_2 and electrical production.

Typical greenhouse project economics are shown in Table 4. The economics shown are for a generic greenhouse; however, the economics are dependent on the type of product being grown, whether the greenhouse makes CO_2 purchases, the requirement for heat and the amount of electricity produced.

Table 4. Typical Economics for a Generic Greenhouse Co-generation System

Load Factor:	68%
Capital Cost:	$2,200/kW (electric)
Annual O&M Cost:	$590/kW (electric)/year
Percent of heat energy displaced:	76%
Simple Payback	4.5 to 6 years

Discussion

In the US, there is approximately 85 GW of installed CHP capacity, and as shown in (Chittum and Kaufman, 2011), the market for co-generation varies significantly from state to state. A recent study estimated that co-generation achievable potential is as much as 241 GW by 2030 (Shipley et. al., 2008). This would represent approximately 20% of US electrical capacity.

In Canada, a significant effort has been made to increase CHP capacity. Currently there is 9 GW installed throughout Canada, which has increased by 34% between 2005 and 2009 (Nyboer et. al., 2011). Most of this growth has been in the oil and gas industry. Much like the US, the co-generation market varies significantly between provinces. Both countries are promoting co-generation at the national level. In the US, a recent executive order pushed for a nationwide goal of increasing co-generation capacity by 40 GW by 2020 (Trombley, 2013).

A number of challenges are encountered by industrial facilities wishing to integrate co-generation into their existing plants:

- The added generation has to be sized correctly to work within the existing industrial process while meeting utility constraints
- In the absence of capital incentives or guaranteed power prices, the paybacks on systems can be long, increasing the risk to industry which typically require paybacks in the 1 to 3 year range

- Interconnection requirements can vary by jurisdiction and can be cumbersome, or prohibitive
- Utilities may not have detailed programs or procedures for customer based generation. Power contracting and negotiations can be burdensome for industrial customers
- Further municipal air permitting or emission regulations may also be required depending on jurisdiction
- Typically, many parties are involved in the process, slowing down the project timeline

Conclusions

Self-generation projects are an efficient means of generating electricity when all benefits are considered. Many industrial plants can benefit from the improved efficiency; however, a number a challenges do exist. To overcome the challenges for industrial plants:

- Look for innovative opportunities to maximize benefits and minimize costs – e.g. waste energy and by-product gases, identifying heating and cooling loads for viable use of lower grade heat, refurbishing used equipment
- Develop understanding of and leverage available incentives and other funding, wherever available.
- Look at the lifetime benefits (NPV) and other financial considerations (e.g. tax credits/exemptions) rather than simple payback
- Quantify other benefits, such as energy security, reliability, or production and product quality impacts (e.g. plant fertilization)
- Build relationships with all parties involved; seek out and vet service providers for knowledge and experience in generation project development, design and engineering and local interconnection, permitting and regulations

As demonstrated within this paper, there is a significant potential for the installation of cost effective self-generation projects in North America. However, incentives, or other financial support, and collaborative efforts to maximize (and quantify) project benefits, while addressing other challenges, are vital to achieving wide-spread implementation of self-generation projects at industrial facilities in North America.

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