Cost-Competitive CO_2 Mitigation with Combined Heat and Power Systems in Calgary

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1. Introduction

1.1. Motivation for Research

Climactic research has demonstrated that anthropogenic CO_2 emissions increase the concentration of greenhouse gases (GHGs) in the Earth's atmosphere, and predicts the possibility of significant climate change as a result (Thomas and Trenberth, 2003). In an effort to avoid the potentially damaging effects of this phenomenon, most industrialized countries, including Canada, agreed to lower their GHG emission levels by ratifying the Kyoto Protocol. The City of Calgary (Alberta) has established its own GHG reduction target, seeking to halve its annual GHG emissions from 1990 levels by 2036 (City Calgary, 2006). In spite of these pledges, the trend of increasing GHG emissions persists. It is estimated Calgary's GHG emissions may have surpassed 17,000 kt CO_2eq in 2009, a 36 percent increase from 1990 levels (CUI, 2008). Current projections indicate that emissions will continually increase to over 20,000 kt CO_2eq by 2036, under business-as-usual (BAU) conditions (CUI, 2008). One way for the city to counter this trend and approach its abatement target is to adopt emissions-saving technologies in its electricity and heating systems. In this paper, we analyze the option of using Combined Heat and Power (CHP) plants to lower the CO_2 intensity of Calgary's electricity grid, and identify conditions under which its adoption may be cost-competitive.

1.2. Combined Heat and Power Background

Varying definitions for CHP systems exist, but we define it to mean any facility that uses cogeneration to produce electricity and heat near the point of consumption, where the heat produced is used for space heating in residential and commercial premises (Jaccard, 2004). A CHP plant uses one fuel feedstock to generate both electrical and thermal energy products, thereby reducing the total GHG emissions that would be associated with the individual production of those products.

In a CHP plant, far greater efficiencies are achieved by combining two processes into one system: a combustion turbine powers a generator to generate electricity, and a heat recovery steam generator recovers the waste heat to generate steam or heated water. Coal-fired power plants have energy efficiencies of around 32-37 percent, and the rest is lost as waste heat (Rosen, 2001; 2003; Pacala and Socolow, 2004). There are many industrial setting in which the heat from CHP systems is captured and utilized for variety of applications in oil and gas operations, pulp and paper industry, food processing, and for space heating or cooling.

In addition to increased energy efficiency, CHP plants offer several other benefits. Several municipalities, especially in Europe, have installed CHP systems out of environmental and cost considerations. When used in municipal settings, advantages of CHP include reduction in electrical transmission and distribution networks costs and avoidance of transmission line losses. Furthermore, CHP systems allow their users to have uninterrupted electricity and heat supply during grid failures and emergencies. In industrial applications, this helps in minimizing the risk and avoidance costs resulting from shutdowns due to peak supply demand failure and power interruptions. In Alberta, for example, industrial CHP plants insulate oil sand operations from unscheduled electrical outages by reducing their reliance on the electrical grid - thereby providing a reliable supply of electricity.

Several municipalities, particularly in Europe, have adopted CHP on a large scale. About 76 percent of Finland’s district heating energy is produced by CHP system, and in its capital Helsinki, a CHP plant can generate over 1000 MW of electricity and heat for its residents and activities (Kirjavainen et al. 2004). DH-CHP currently accounts for more than 37 percent of heat production in Vienna, Austria (Wien Energie, 2009). Small-scale CHP plant (1–20 MW) operators use either natural gas or a combination of wood chips and biomass as fuel to generate electricity and heat for residential and commercial use.

CHP has started gaining popularity in Canada as well. Initially, radar sites in the Arctic region incorporated CHP plants in the 1960s. In the past four decades, CHP plants have been built across the country, mostly for industrial use. However, small-scale, municipal applications of CHP in Canada also exist. Since the early 1990s, CHP plants on the order of 3-5 MW are in operation in the Ontario municipalities of Cornwall, London, Markham, Ottawa, Sudbury, and Windsor (Klein, 2003). Meanwhile, the Central Heat Distribution Company in Vancouver supplied steam for heating, generated from CHP plants, at the lowest prices in North America (Wiggin, 1993). Alberta (with 2.4 GW) and Ontario (2.0 GW) form 65 percent of total cogeneration operating capacity in Canada (Strickland and Nyboer, 2004). However, despite benefits and potential for CHP systems, they currently form only 6 and 3 percent of electricity production and of generation of industrial thermal energy respectively, according to Environment Canada.

CHP developers and operators face complex market and regulatory challenges, including utility rules, environmental regulations, and land use planning and siting requirements, particularly in urban centres. Moreover, CHP developers are required to go through the same permitting process for grid interconnections and have the same transaction costs. Small CHP operators incur high transaction costs for installing CHP exists because of the lack of standards (standby charges, grid interconnection, buy-back rates for power and unsupportive local air emissions policies) (Jaccard, 2004). A CHP operator in residential/commercial sector is usually required to have standby electricity from the local utility company because of generation outages and system maintenance. A customer has to pay the local utility company for the backup electricity (backup/facilities demand charges) supplied during such periods, and may end up paying for the capacity and maintaining the transmission and distribution system even though it is very unlikely to draw electricity from the distribution system during peak periods. Furthermore, CHP operators mostly rely on natural gas and peak demand can produce price spikes for natural gas, leaving the CHP operator exposed to price volatility.

1.3. Contribution to Body of Literature

Several studies have addressed the tradeoffs between the benefits and drawbacks of CHP plants. However, most of the current literature is context-specific, in that it focuses on CHP systems under a pre-existing or an otherwise-specified set of conditions. For example, studies compare different CHP options for a particular city, or examine CHP systems for a particular type of land-use area (Lemar, 2001; Jaccard, 2004; WADE, 2005). Few studies exist that compare CHP options across multiple sets of conditions.

While our analysis is motivated in part by the City of Calgary's emissions-reduction targets, we seek to address this gap by creating a model with user-controlled input parameters that can be used to assess the environmental and economic outcomes of installing CHP across a wide variety of conditions. Specifically, we conduct a quantitative analysis of the financial costs and GHG reductions associated with the use of CHP systems against a BAU case. We then conduct sensitivity analyses on multiple input parameters in our model and identify key variables that affect a CHP system's cost-competitiveness as a GHG-reduction tool. Two plausible 30-year scenarios, specific to the Calgary municipal environment, illustrate the applications of this model. We believe such an analysis to be useful in identifying attractive environments in which CHP systems should be considered as a cost-effective means to meet energy demands, and can help inform policy or business decisions regarding GHG emissions-reducing options.

2. Methods

2.1. Overview

In order to assess the cost-competitiveness of CHP systems, we created an Excel spreadsheet model that simulates the annual costs and GHG emissions associated with operating a natural gas-fired CHP system. The model centres on multiple user-defined inputs, such as CHP plant size, natural gas price, and the type of land-use area where the plant is located; this allows us to evaluate our output metrics across a wide range of conditions. We then compare the CHP costs and GHG emissions to a baseline case, in which the grid and natural gas boilers supply electricity and heat, respectively, in the same amounts as in the CHP case. This comparison yields an "abatement cost" - the incremental financial cost per abated tonne CO_2eq by the CHP system compared to the baseline case – which serves as a key indicator of the CHP system's economic and environmental performance.[2] We claim that this abatement cost is the primary metric of interest to any policy-maker – including the City of Calgary municipal government – concerned with optimizing a set of policies to cost-effectively lower GHG emissions.

We use our model to evaluate the cost-competitiveness of CHP in two ways. First, we examined the sensitivities of the CHP abatement cost to changes in key input parameters, such as CHP size, natural gas price, land-use type and density of the area receiving heat from the CHP system, and grid emissions factor of our baseline case. Secondly, we fix the input parameters in order to analyze two illustrative 30-year scenarios – one in which the CHP system is located in a major commercial area, and another where the system is installed in a greenfield (ie. previously un-developed) residential community.

The remainder of the Methods section is structured as follows. First, we describe the modelling of the costs and GHG emissions for both the CHP and baseline cases. Secondly, we denote the sensitivity analyses that were conducted. Thirdly, we define the two 30-year scenarios and list the key assumptions made in each scenario.

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[2] Note that in a situation where a CHP system is less expensive than the baseline case in providing heat and electricity, the abatement cost would be negative (i.e. it reflects the money saved per tonne CO_2e abated).

2.2. CHP Case Modelling

2.2.1. CHP Plant Expenses

The first portion of our model simulates the cost of generating electricity (in ¢/kWh) in our CHP case. We use the formula:

$$COE = 1/\varepsilon * Fuel\ Cost + VOM + FC/\mu \quad [1]$$

where COE is the cost of electricity, ε is the fuel-to-electricity efficiency of the CHP plant, fuel cost is the unit cost of natural gas, VOM is the variable operational and maintenance costs of running the plant, FC is the plant's annualized fixed costs, and μ is the utilization rate of the plant. Each of these parameters, save for the fixed costs, are user-defined inputs in our model. We calculate the fixed costs by the equation:

$$FC = Capital\ Charge\ Factor * Capital\ Cost + Fixed\ Operational\ and\ Maintenance \quad [2]$$

where the capital cost represents the total capital expenses of the plant project, and the capital charge factor is an interest rate (12% in this case) used to discount the lifetime capital expenses of a project to an annualized cost; each of these parameters are defined inputs in our model. Table A-1 in the appendices summarizes the values for these inputs.

2.2.2. CHP System Piping Costs

The cost of generating electricity is only part of the total CHP system costs; we also estimate the costs associated with laying the piping for the heat distribution network using the equation:

$$Piping\ cost = Installed\ heat\ pipe\ length * unit\ cost\ of\ installing\ heat\ pipes * Capital\ Charge\ Factor\ [3]$$

We estimate the amount of heat piping needed for two situations. In one situation, the CHP system is located in a completely residential area. In the second case, it is sited in a mixed-land use area, such that it supplies a large portion of its heat to a major user (e.g. a large factory or mall) and supplies the remaining heat to surrounding residential areas. For the latter case, we assume that the CHP plant will be sited next to the major user, such that the required pipe infrastructure is dominated by the residential distribution system. For both cases, we model how the CHP system will supply heat to the residential units using a first principles calculation that assumes a simplified configuration for the residential units (in which they occupy equivalent square plots) as shown in Figure 2.1.

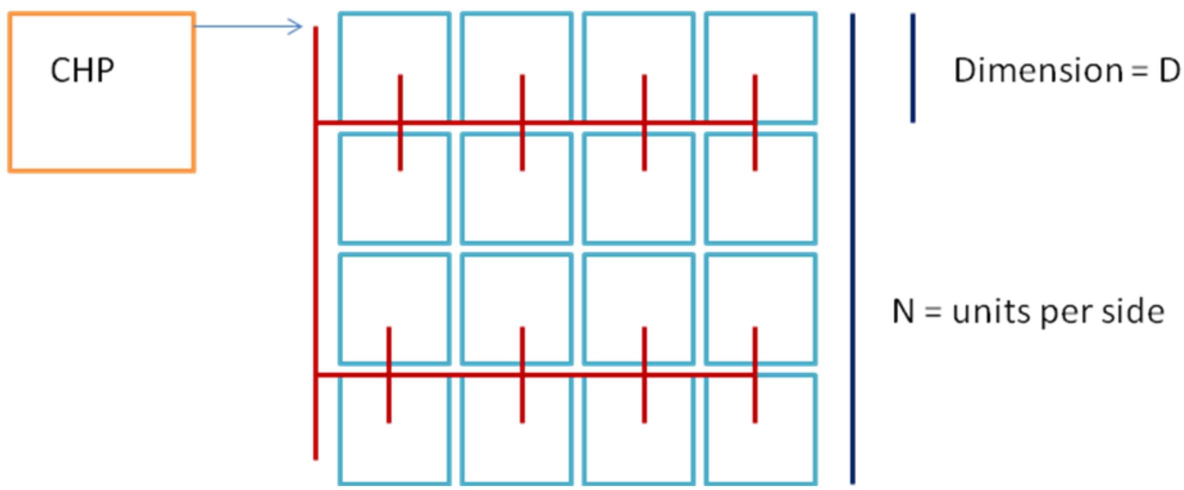


Figure 2.1.: *Simplified residential units configuration*

The dimensions of each square plot and the number of units per side reflects the unit per area density of the residential zone. A density of 45 units per acre (i.e. 45 units per 4096 m^2), for example, can be expressed in the form of 1 unit occupying 91 m^2 of space (assuming equal unit size and equal spacing between units).[3] If the unit can be modelled as a square plot, then each unit would be a 9.5 m x 9.5 m square (i.e. D = 9.5 m). Furthermore, for a given acre of land (64 m x 64 m), each side of the plot would be composed of 6.7 units.

We next make a simplifying assumption by representing the heat piping layout as a feeder line running between two rows of units, with a tie-in piping length equal to half of the unit's dimension (4.75

[3] Note that for stacked configurations e.g. townhomes and low-rise apartments, each unit does not actually occupy its distinct plot of land. However, for the purposes of modelling the piping length, we make an assumption that, for a given acre, the piping distance for a given acre one would avoid by stacking units on top of each other is roughly equivalent to the piping that would need to cover the extra "green space" that is not occupied by a unit. Refining this assumption represents an area for improvement of the current model.

m in our example) for heating to reach each unit. Additionally, a main line, perpendicular to the feeder lines, connects the feeder lines together. Finally, we assume that the distance between the CHP plant and the residential unit plots is negligible, such that the model only considers the length of pipes within the residential area. Under this layout, the total length is calculated as:

$$P = \text{Length of one side of the area} * (\text{Main Line} + \text{No. Feeder Lines}) + \text{No. Units} * \text{Length of Tie-in} \quad [4]$$

or:

$$P = (1 + N/2) * (N*D) + N2 * (D/2) \quad [5]$$

This piping length serves as an input for Equation 3 (above) to determine the total piping costs. We assume a unit cost of piping of $4,000/m, based on conversations with a Calgary-based utility (Czaikowski, 2009), and use an equivalent capital charge factor as that used for the plant expenses. These parameters are also included in Table A-1.

2.2.3. CHP Case GHG Emissions

We calculate the yearly GHG emissions of our CHP case by multiplying the natural gas it uses with a natural gas emissions factor (0.4 tonne CO_2/MWh generated). Importantly, this and all other emissions factors that we use only represent the emissions associated with combusting the fuel at the plant to generate electricity; it does not represent the upstream emissions associated with extracting and transporting the fuel to the generation site. However, multiple life cycle assessments estimate that these upstream emissions only account for a maximum of 10% of the total emissions due to the fuels' processing and use (McCann and Magee 1999; PACE 2009), and we assumed that including the upstream emissions in both the CHP and BAU cases would not have significantly affected our results. We calculate the annual natural gas demanded by the CHP plant as:

$$\text{Natural gas demand} = \text{Capacity} * \mu * 8766 \text{ hours/year} * 1/\varepsilon \quad [6]$$

where, as above, all the parameters are inputs defined in Appendix A.

2.3. BAU Case Modelling

2.3.1. BAU Case Costs

As with the CHP model, the two key calculations for the BAU case are (i) the costs of electricity and heat and (ii) the GHG emissions associated with electricity and heat production. We calculate BAU costs by adding the separate costs of providing the electricity and heat that would be supplied by our proposed CHP system. We take the local electricity price from data provided by the Alberta Electric System Operator (AESO), and the natural gas price as the current trading price in the New York Mercantile Stock Exchange.[4] These are then multiplied by the annual electricity and heat supplied by our CHP system, respectively; we use a correction factor of 1/0.9 in the heating costs calculation to reflect assumed boiler and furnace efficiencies of 0.9.

We calculate the annual amount of electricity supplied from the CHP system by multiplying the CHP capacity (e.g. 10 MW) by 8766 hours/year and the utilization rate. Meanwhile, the amount of heat displaced arises from multiplying the thermal output (380 MM Btu/hr) by the conversion factor of 8766 hours/year and the utilization rate. The two equations for electricity and heating costs are thus:

$$\textit{Electricity \$} = [\textit{Capacity (in kW)}*8766\ \textit{hrs/yr}*\mu] * \textit{unit electricity price (in cents/kWh)} \quad [7]$$

$$\textit{Heat \$} = [\textit{Thermal Output (MM Btu/hr)}*8766\ \textit{hrs/yr}*\mu*1.06\ \textit{GJ/MM Btu}]*\textit{natural gas price (in \$/GJ)} \quad [8]$$

The cost of supplying electricity and heat in our BAU case is simply the sum of these two numbers.

2.3.2. BAU Case GHG Emissions

[4] The NYMEX natural gas price is current as of December 2009. The average electricity price was derived via a linear regression of daily electricity prices from Jan. 2001 to Dec. 2009, with the endpoint of the trendline taken as the current electricity price.

In order to calculate the GHG emissions under the BAU case, we employ similar process whereby the annual emissions of providing the given amount of electricity and heat are calculated separately, and then added together. For the electricity GHG emissions, we determine an average grid emissions factor by using a weighted average of emissions factors from the forecasted grid mix:

$$Avg.\ EF = \%\ Coal * Coal\ EF + \%\ Natural\ gas * NG\ EF + \%\ Wind * Wind\ EF + \%\ Hydro * Hydro\ EF \quad [9]$$

For our sensitivity analyses that do not explicitly look at grid intensity, we use a default grid emissions factor that reflects the current Alberta electricity grid of 0.69 tonne CO_2eq/MWh.

The annual GHG emissions associated with providing electricity under the BAU case are the product of this grid emissions factor and the amount of electricity that would be displaced by the CHP system. The emissions associated with supplying heat in the baseline case, meanwhile, are the product of the heat that would be displaced by the CHP system, the emissions factor for natural gas, and the correction factor of 1/0.9, as described above for calculating the heating costs. The total annual GHG emissions level for the BAU case, in turn, is the sum of the emissions associated with electricity and heat production.
Table A-2 lists the key inputs for these calculations.

2.4. Abatement Cost Calculation

After determining annual emissions and costs for both the CHP and BAU models, we calculate an annual abatement cost as a tool for cost-benefit analysis. This involves dividing the additional annual costs of providing electricity and heat in the CHP case (relative to the baseline case) by the GHG emissions abated by the CHP system over one year:

$$CHP\ Abatement\ cost = [\$\ CHP - \$\ baseline]/[tCO_2eq\ baseline - tCO_2eq\ CHP] \qquad [10]$$

2.5. Sensitivity Analyses

We identify six key parameters that affect the abatement cost of our CHP system, which are either uncertain or are decisions that would be taken by the CHP investor: (i) the future average emissions factor of the Alberta electricity grid, (ii) the capacity of the CHP plant, (iii) the type of built environment served by the CHP system (e.g. commercial, residential, or industrial), (iv) the unit density of the area where the CHP system would be installed, (v) the price of natural gas, and (vi) the sensitivity of the cost of electricity to the natural gas price. In order to analyze how the abatement cost of a CHP system depends on these parameters, we conduct a series of sensitivity analyses, measuring changes in the abatement cost against variations in each of these parameters. These plots allows us to evaluate the parameters that result in the greatest sensitivity for the CHP abatement cost, and (for some parameters) identifies a "break-even" point at which the CHP abatement cost switches from positive (i.e. it costs money to reduce GHG emissions) to negative (it becomes profitable to reduce GHG emissions). Consequently, this type of analysis enables us to identify attractive scenarios for the implementation of CHP. Table A-3 lists the six parameters, the default value for each parameter, and the ranges we consider for the sensitivity analyses.

2.6. Scenario Analysis

We complete our analysis by estimating the cumulative costs, GHG emissions reductions, and abatement cost for our CHP system over 30 years (from 2010 to 2040). This scenario analysis allows for a potential decision-maker to evaluate the environmental and economic consequences of a CHP system over an approximate plant lifetime, and allows us to estimate the total amount of GHG emissions abated due to the system. We select two representative scenarios to evaluate the potential impacts of a CHP system – one in which the CHP plant is located in Calgary's Chinook Activity Centre (a mixed commercial/residential area with a large commercial user of heat and electricity – the Chinook Centre Mall - and an average residential density of 45 UPA), and the other in which the plant is located in a greenfield residential development (with an average density of 30 UPA). In both scenarios, the CHP plant has a capacity of 10 MW and supplies all of its heat to commercial and residential units (all other parameters identified above assume their default value). Analyzing these scenarios allows us to compare the potential impacts of siting a CHP system in an established commercial centre versus building a CHP system in a new residential area.

To evaluate our 30-year CHP scenarios, we create three baseline cases that reflect three distinct paths that the Alberta electricity system can adopt to meet electricity demand over the next 30 years. They are:

(1) A "frozen" scenario with a constant grid mix over 30 years (upper bound grid emissions) implies a continued reliance on coal as the primary source of electricity.
(2) A "probable" scenario where coal power plants begin to be replaced by natural gas-fired plants as they reach their end-of-life (Page, 2009).
(3) A "growth" scenario (lower bound grid emissions) where current growth rates for coal, natural gas, wind, and hydro are maintained over the period of our analysis, resulting in a larger share for wind and natural gas sources of electricity, at the expense of coal use.[5]

These scenarios do not intend to accurately forecast shifts in Alberta's electricity generation, but rather to represent plausible changes to the overall grid electricity factor over the next 30 years. Table A-4 summarizes the electricity mix "endpoints" under each of the three BAU scenarios at the start (2009) and end (2040) of our analysis, and Figures A-1 and A-2 display how the electricity mix and grid intensity change under each BAU scenario.

To calculate the costs of our CHP and baseline scenarios, we forecast natural gas prices over 30 years. This is done by applying a natural gas price "drift", or average increase in natural gas price per year, from analyzing data from the New York Mercantile Exchange. We also apply a similar drift to forecast the price of grid electricity (using data from the Alberta Electricity Systems Operator). Finally, we calculate the influence of natural gas price on the grid electricity price, such that we can account for an

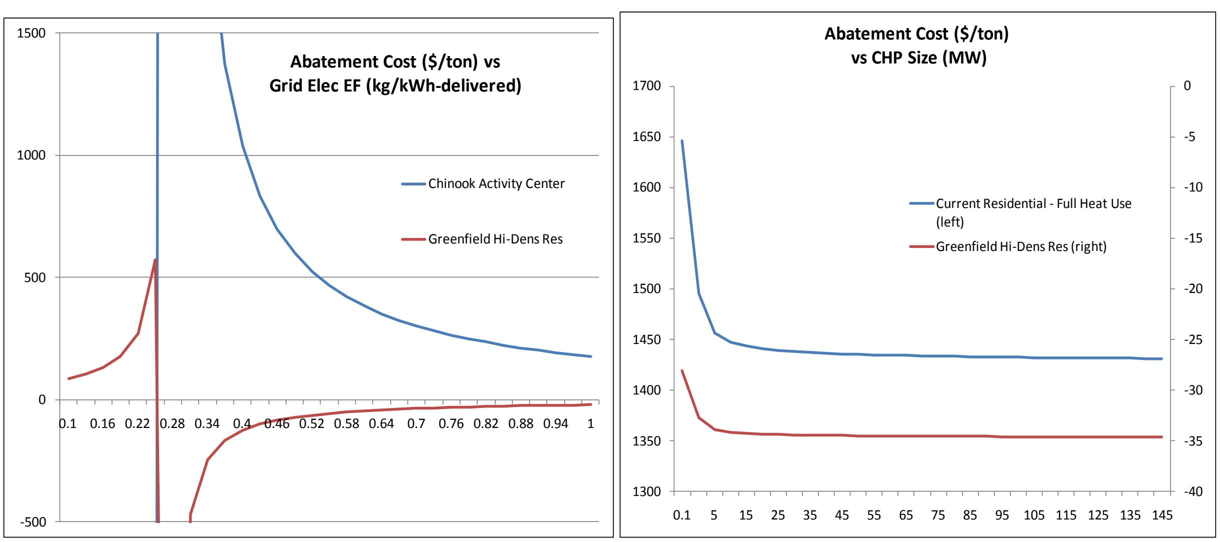
[5] The "current growth rates" used in this model reflect the growth in each source of electricity over the past 11 years according to data from the Alberta Electricity Systems Operator (AESO). Note that the overall wind mix fraction was capped at 30% of Alberta's electricity supply to reflect a realistic boundary of the maximum wind capacity that the current transmission system could accept.

increase in the former when calculating the latter. All three of these parameters – natural gas price drift, grid electricity price drift, and natural gas price influence on grid electricity – are user-defined parameters in our model that can be modified to reflect different scenarios and assumptions.

3. Model Results

Using our numerical model to compare the potential CO_2 mitigation and cost incurrence of a CHP system against a BAU scenario, we examined sensitivities on a number of parameters to identify key areas in which CHP systems would be particularly beneficial. This included sensitivities to the electrical grid emissions factor that the CHP system would displace, the size of the CHP system itself, the presence or absence of proximate large-scale heat consumers, the unit density of potential residential areas to be supplied with heat, and the piping costs associated with expensive retrofits or relatively economical inclusion in greenfield developments. The results of the sensitivity examinations identified two key scenarios for further multi-year simulation of CO_2 mitigation and cost incurrence: a Chinook-like commercial activity centre and a hypothetical greenfield residential development. Plots for both the sensitivity analyses and the multi-year scenarios are located in the body of the text below, and also replicated in enlarged form in Appendix B.

3.1. Abatement Cost Sensitivity to Grid Emissions Factor and CHP System Size



Figures 3.1 & 3.2.: *Abatement cost sensitivity to grid emissions factor and CHP system size.*

The benefits of a proposed CHP system depend strongly on the emissions factor (i.e. carbon intensity) of the grid electricity it displaces. Due to the uncertainty in choices made to de-carbonize the energy system in Alberta, and thus our inability to accurately forecast the displaced grid emissions factor, we conducted a sensitivity analysis on this parameter for CHP systems located both in Calgary's Chinook Activity Centre and in a greenfield residential development. Figure 3.1 shows two curves for the abatement costs associated with the operation of a 10 MW CHP system, under current energy prices, as a function of displaced grid emissions factor. Significantly, there is a large and positive abatement cost associated with the Chinook activity center CHP system, in contrast to the negative abatement cost in the greenfield residential area case. A vertical asymptote in abatement cost is observed where the displaced grid emissions factor is equal to the emissions factor of the CHP system, and thus theoretically no emissions are reduced.

Figure 3.2 shows the sensitivity of abatement cost to CHP system size, run under current fuel prices and with the current grid emissions factor of (0.69 tonne CO_2eq/MWh). The two curves (on separate axes) represent CHP systems in the Chinook Activity Centre and greenfield residential area scenarios. These curves demonstrate that above a certain size threshold near ~1MW, where capital costs cease to dominate overall abatement cost, only minimal further reductions in abatement cost can be achieved with increases in CHP system size. This implies that CHP system operators have relative freedom to scale a CHP system to the electricity and heat demands of the intended geographical area served.

3.2. Abatement Cost Sensitivity to CHP System Location

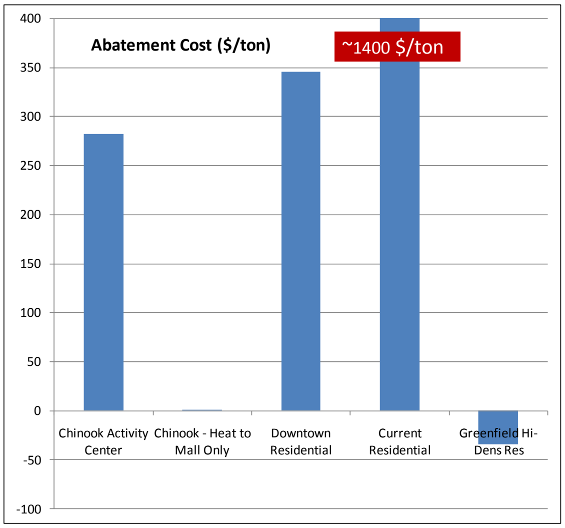
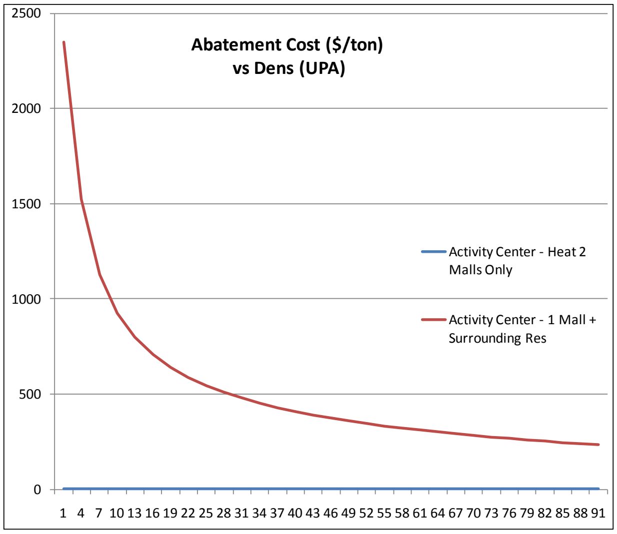


Figure 3.3. *CHP System abatement costs under current conditions, for various Calgary locations.*

In many municipalities, a key barrier to the widespread implementation of CHP systems is the cost of installing heat pipe infrastructure. For this reason, we identified the location of a CHP system as a key parameter affecting its cost competitiveness and calculated the abatement costs of the CHP case (under current fuel prices and grid mix fractions) for various municipal locations. We estimate piping requirements for heat delivery as indicated in Section 2.2.2, using average unit heating demands and unit per acre (UPA) footprint densities specified for different built environments.

Figure 3.3 displays abatement costs for the Chinook Activity Centre and greenfield residential scenarios, along with other municipal locations. The Chinook Activity Centre represents a single large commercial consumer of heat, surrounded by 45 UPA residential developments. The greenfield residential scenario represents a 30 UPA density residential area. Other built environment options displayed in the figure include: the Chinook mall only (i.e. the remaining heat is dumped), a Calgary downtown residential area (90 UPA residential units), and a Calgary suburban residential area (7 UPA residential units). As expected, a CHP system is not a cost-competitive means of CO_2-emissions reduction in low-density development areas. The two scenarios that illustrate a cost-competitive use of the CHP system to mitigate CO_2-emissions are the "commercial heat consumer only" scenario and the greenfield development scenario. This implies that the most attractive opportunities CHP systems in Calgary are in high-density commercial or industrial regions with large scale heat consumers, or in future residential developments where piping costs would be minimal.

3.3. Abatement Cost Sensitivity to Unit Density, for Commercial, and Greenfield Residential CHP System Locations



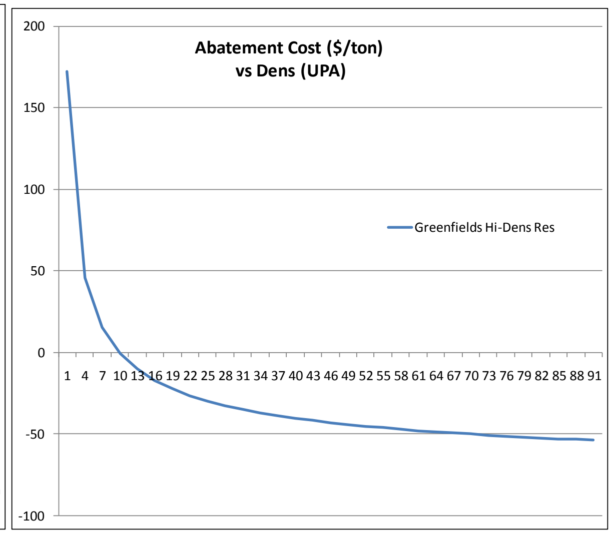


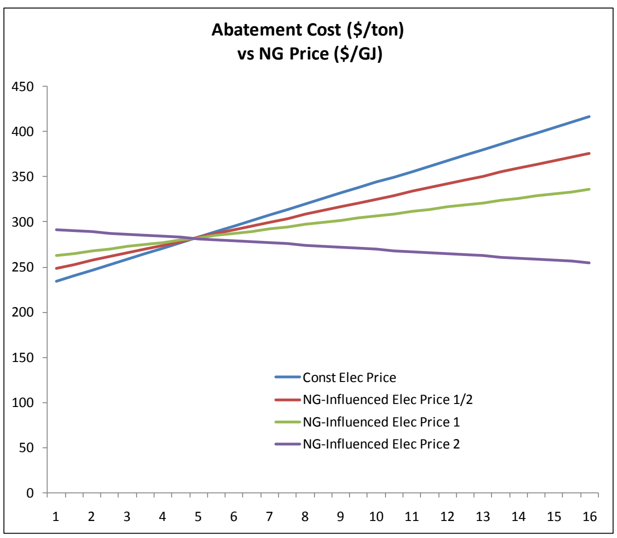
Figure 3.4 & 3.5: *Abatement cost sensitivities to residential area densities (in units per acre, or UPA) for Chinook Activity Centre and greenfield residential area scenarios.*

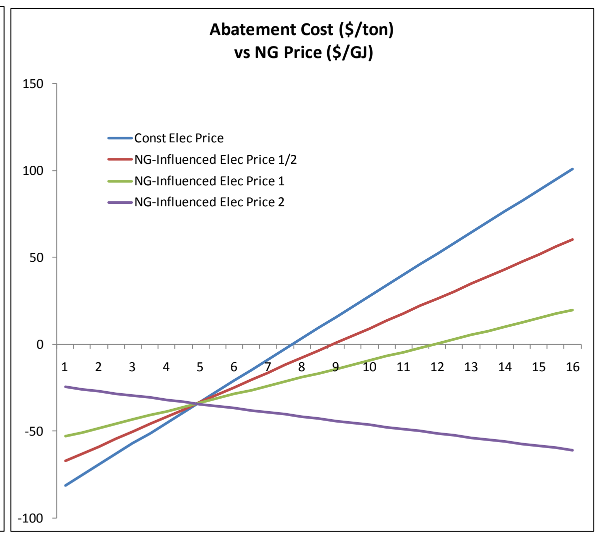
As previously mentioned, CHP system costs can be dominated by heat-piping infrastructure costs if installed in pre-existing built environments, where piping costs can be as high as $4000/m. Thus, the density of commercial and residential areas served by the CHP system will strongly influence the overall cost of the system, due to the effect of density on the total heat pipe required. Figures 3.4 and 3.5 illustrate the sensitivity of CHP system abatement cost, for a 10 MW facility operated under current fuel prices and grid emissions factors, to built environment UPA density.

Figure 3.4 shows abatement costs for two possible scenarios involving the use of a CHP system in the Chinook Activity Centre. One curve shows the dependence of abatement cost on surrounding residential density, after a significant fraction of the heat generated is supplied to a large commercial consumer such as a mall; the second displays the abatement cost when heat is provided only to the equivalent of two large, proximate commercial centers. The fact that this latter curve shows a lower abatement cost than the former, for all likely residential unit densities, illustrates that even at high surrounding residential area densities, a CHP operator would achieve a much lower abatement cost by simply supplying heat to local commercial consumers, and dumping the rest of the heat produced to a cooling system and thus avoiding large piping infrastructure costs. This option coincidentally results in a near-zero abatement cost.

Figure 3.5 shows a relationship between abatement cost and density for a new greenfield residential development, where incremental piping costs are estimated to be on the order of $250/m. This curve shows that a theoretical 10 MW CHP system would be cost-competitive in virtually any of Calgary's future planned low- to medium-density residential areas, and would deliver cost savings compared to the BAU case in residential areas with densities greater than 10 UPA.

3.4. Sensitivity of Abatement Costs Natural Gas Price





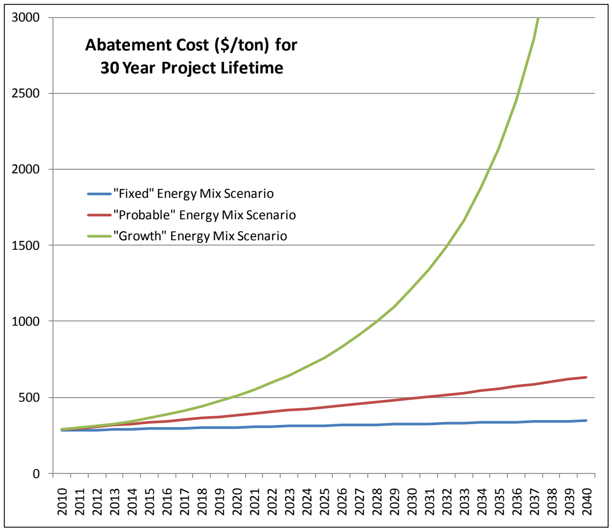
Figures 3.6 & 3.7: *Abatement cost sensitivity to fuel price volatility, for a commercial activity centre (left) and for a greenfield residential development (right), respectively.*

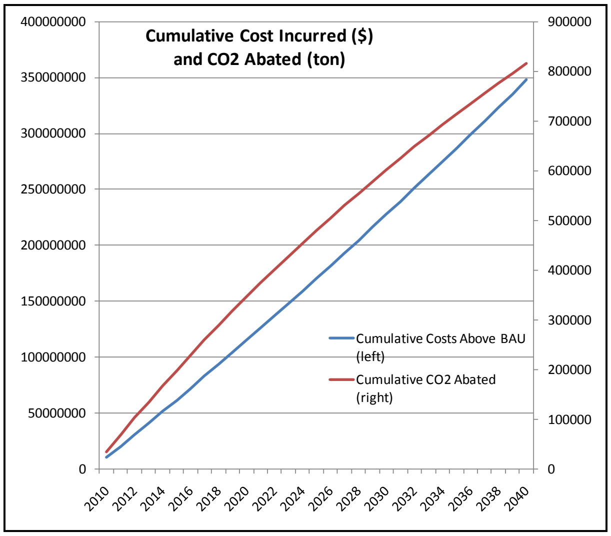
One of the key vulnerabilities of a natural gas-fired CHP system is its exposure to the inherent volatility of natural gas prices. A potential increase in natural gas price has a two-fold impact on the cost-effectiveness of a CHP system. First, it increases the cost of the fuel feed-stock to the system, thus increasing the cost of electricity and heat generated. Secondly, in any region in which natural gas supplies a significant fraction of the electricity grid mix, an increase in natural gas price will also increase the avoided costs of CHP-displaced grid electricity and heat generation.

Using our model, we considered two sensitivities associated with fuel feed-stock prices: a) the price of natural gas itself; and b) the sensitivity of grid electricity price to changes in natural gas price. We call this the “natural gas-influenced electricity price”. Commodity prices for both natural gas and grid electricity were thoroughly examined for correlation, but a satisfactory linkage could not be found due to the inherent volatility in both prices. Thus, we estimated electricity price sensitivity to natural gas price by considering the fraction of electrical generation from natural gas, and the ratio of cost-of-natural-gas-powered-electricity to natural gas feedstock costs. For commonly accepted capital costs and efficiencies for natural gas turbine electricity generation, and for the current Alberta grid mix, we estimate that a sustained natural gas price increase of $1/GJ will induce an increase in electricity price of ~0.3 ¢/kWh.

Figures 3.6 and 3.7 show the sensitivity of an abatement cost generated with current grid mix fractions for the preceding two scenarios of the Chinook Activity Centre and a greenfield residential development. The figures reiterate the previous result of respective positive and negative abatement costs for the scenarios at current energy prices, and also show the sensitivity to changes in natural gas price. The different curves are plotted for multiples of 0x, ½x, 1x, and 2x the natural-gas-influence factor [0, 0.15, 0.3, and 0.6 (¢/kWh) per ($/GJ) respectively]. These curves show that in a future grid mix where natural gas contributes a higher mix fraction to electricity generation than current (influence factor 2x, for example), exposure of the CHP system abatement cost to high natural gas prices actually diminishes.

3.5. Chinook Activity Center Scenario – 30 Year Forecast



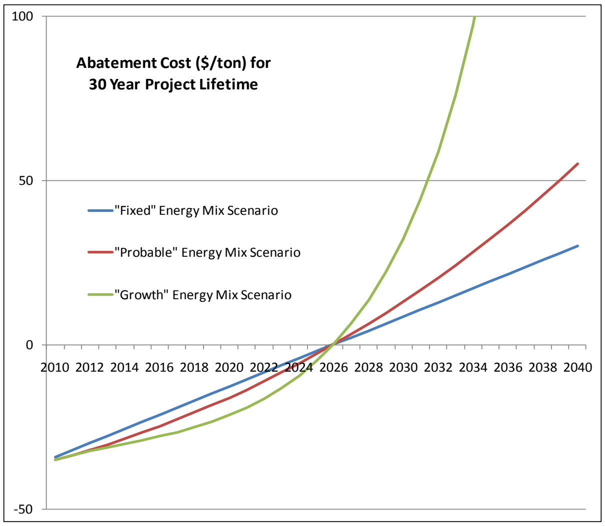


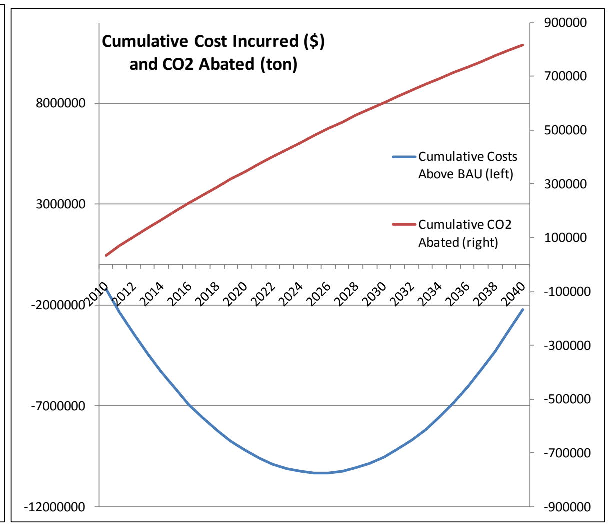
Figures 3.8 & 3.9: *Chinook Activity Centre Scenario – 30-year project forecast.*

Our model showed that a 10 MW CHP system, installed in a "Chinook-like" Activity Centre in Calgary, could indeed reduce CO_2 emissions from BAU case, but would do so at a significant – likely uncompetitive – abatement cost. At current Alberta electricity grid mix fractions, and with current prices for natural gas feedstock and for displaced grid electricity, the abatement cost is ~280 $/tonne CO_2eq. As can be seen in Figure 3.8, the abatement cost associated with the CHP system in question rises modestly with increasing natural gas and electricity costs over its 30-year project lifetime (compared to our "fixed" BAU scenario). In scenarios where the Alberta grid mix is aggressively de-carbonized, such as in our "growth" scenario, the CHP system delivers much lower CO_2 emissions reductions, and thus does so at an ever increasing abatement cost. This illustrates the effect that CO_2-abatement benefits over the lifetime of a CHP system are strongly dependent on the carbon intensity of the displaced grid electricity.

Figure 3.9 illustrates the cumulative CO_2 emissions avoided, and the cumulative costs incurred, over the CHP system 30-year project time-frame, under the assumption of a "probable" grid mix scenario. At the end of its 30-year project time-frame, this 10 MW CHP system would have incurred costs of ~$347,000,000 above the cost of purchasing grid electricity and natural gas-fired boiler heat in the BAU case, and would avoid the emission of ~800,000 tons of CO_2, for an average abatement cost of ~400 \$/tonne CO_2eq.

3.6. Greenfield Residential Scenario – 30 Year Forecast





Figures 3.10 & 3.11: *Greenfield high-density residential scenario – 30-year project forecast.*

The primary CHP system cost driver in the preceding “Chinook Activity Centre” case was the high capital expenditure required to distribute the leftover heat from the commercial consumers in the immediate vicinity to nearby residential areas. Construction and installation costs for heat pipe infrastructure in existing built environments can be as high as \$4000/m, contributing a large fraction to the overall costs associated with CHP if used in low-density residential areas. With this in consideration, we used our model to evaluate a number of other locations for a proposed 10 MW CHP system within the municipal region of Calgary (see Figure 3.3). Some of the most promising locations for CHP systems are potential medium/high-density future residential communities. Pre-installing heat pipe infrastructure, rather than natural gas lines for individual home furnaces, would avoid much of the piping costs associated with a CHP system. Thus, the CO_2 mitigation benefits of a CHP system could be enabled at a much lower abatement cost. We made an order-of-magnitude calculation that heat pipe infrastructure could be installed for \$250/m, after considering the avoided cost of natural gas pipe infrastructure in a new community.

Our model showed (Figures 3.10 and 3.11) that a 10 MW CHP system installed in a new high-density residential area would avoid CO_2 emissions at a significant, negative abatement cost. The current (2009) abatement cost associated with new residential area use of CHP is -30 \$/tonne CO_2eq. We evaluated the cumulative costs and emissions reductions for this CHP scenario against the "probable" BAU scenario, and even with rising energy prices and diminishing carbon intensity of the displaced grid electricity, this CHP system showed net savings of ~\$2,000,000 and abatement of ~800,000 tonnes of CO_2 over its 30-year project time-frame.

4. Discussion

4.1. Discussion of Results

Assuming that this simulation is accurate, implementing one 10 MW CHP system in Calgary results in a cumulative abatement of approximately 816 kt CO_2eq over 30 years relative to the BAU case, and an average annual abatement of approximately 26 kt CO_2eq per year (independent of where the CHP is sited). Without the CHP system, supplying electricity and heat to the Chinook Activity Centre or a greenfield development would result in an average of 71 kt CO_2eq emissions per year.

Our analysis evaluated several potential locations for the installation of a CHP system and calculated the cost of CO_2 abatement for each of these settings. Although we found that the cost of abatement could be as high as $1400/tonne CO_2eq to retrofit a residential area for a CHP system, it could be more cost-effective to install CHP systems for large heat consumers, or to integrate CHP in new municipal areas under development, where in fact there can be cost savings associated with abatement. In the “Chinook Activity Centre” scenario, for example, the cost of abatement was high when heat was supplied to surrounding residential areas that needed expensive piping retrofits, but low when heat was supplied only to proximate commercial zones with the remaining excess heat (and its associated CO_2 abatement benefits) dumped. In the scenario representing CHP deployment in a new greenfield residential development, where piping costs were assumed to be much lower, abatement costs were shown to be competitive or even negative, suggesting cost savings. Additionally, an unexplored alternative for existing low-density areas could be the installation of micro-CHP systems at individual households that integrate with the existing natural gas infrastructure already installed throughout the city.

Based on our model results, policies and regulations that encourage the deployment of CHP systems in new residential developments can achieve cost-competitive CO_2 emissions reductions. However, the examination of specific policies that give incentive to CHP development is out of the scope of this paper.

4.2. Model Limitations

One of the most significant cost drivers identified for the deployment of CHP systems is the cost associated with installing or retro-fitting heat pipe infrastructure to deliver heat to consumers. Our numerical model used unit-length piping costs that were based solely on piping materials costs for greenfields locations, but that were representative of associated construction for locations requiring retrofits. These retrofit piping costs in particular are in reality strongly dependant on location and construction schedule, and thus the exclusion of these considerations represents a critical limitation of our model. Also, while we believe that our idealized grid pattern used to estimate heat piping infrastructure costs associated with CHP systems of various sizes deployed in various locations represents a useful method to assess CHP system costs and benefits, we recognize that piping infrastructure layouts are much more complex and location-specific in reality.

In addition to difficulty in data collection on CHP parameters, limitations to this model also include how it forecasts the environmental and economic impacts of CHP over a 30-year scenario. Key uncertainties involved in this forecasting were how the price of natural gas, the price of electricity, and the provincial grid mix change over time. Unlike the data on CHP specifications, uncertainty in these calculations cannot be completely resolved with more accurate data, as they are dependent on a series of assumptions about how prices and electricity generation will change in the future.

We assumed other input parameters such as the capital cost of the system, its efficiency, its capital charge factor, and several other values, based on existing literature and industry values in order to create a working model. Stand-by charges for electricity production, daily fluctuations in operational costs, and non-technical costs (public communications, licensing fees, etc) have a negligible impact in our model.

Beyond modelling assumptions, several factors limit the strength with which we can draw conclusions from our analysis. One limitation is that we did not thoroughly assess the social impacts of a proposed CHP system, which would have enabled us to consider these impacts with the calculated environmental and economic impacts, to allow a more complete description of the various trade-offs associated with the deployment of a CHP system. While certain social impacts, such as a municipality's "green credentials" or reputation as a desirable place to live, are difficult to measure, others, including human health impacts and increased traffic due to construction of the CHP system, could be included in a comprehensive impact assesment. An area of future work, therefore, would be to include these social impacts into an expanded cost estimate of installing a CHP system that would more accurately reflect the social costs of this proposal.

A second limitation to our analysis relates to the quality of the data on CHP plant specifications that we used in the model. Most of the required specifications were found from literature sources; this introduces a degree of uncertainty with respect to the applicability of these data (e.g. capital expenses) in relation to the Calgary-specific context (e.g. Alberta labour costs). Where possible, we used estimates provided by the Enmax (a Calgary-based utility) in our model, as it will likely be the key operator of any public CHP systems in Calgary. Even when data was provided by Enmax officials, it was often given as a range of values, reflecting the limited experience of building CHP systems in the city.

Finally, our analysis only considered average annual heat and electricity demand, rather than specific hourly or daily demand and production. Potential imbalances and mismatches between heat and electricity supply and demand are not considered by our model when evaluating the CHP system. These mismatches do indeed play a significant role in the cost-competitive deployment of CHP systems in the real world.

4.3. Model Applicability

We created this model as a tool to inform policymakers in making decisions with regard to emissions-reducing technologies. Although our intention was to evaluate CHP systems across a variety of conditions, our model was specifically focused on the feasibility analysis of CHP in Calgary and may lose some significance for CHP systems implemented in other areas.

In Calgary, natural gas is already integrated in a distribution system, and assumed to be the feedstock for the CHP system, whereas other areas may use other sources such as coal or solar power.

This not only affects the costs, but also the emissions value associated with the produced power. The costs of several key units in this model reflect Calgary-area prices and may be different depending on geographic area. These include the price of electricity, natural gas, construction and labour.

In addition, carbon is not priced in Alberta, and as a result of this, only a negative abatement cost of emissions reduction would naturally result in a feasible CHP system. An explicit price on CO_2 emissions and a different grid emissions value will affect the feasibility of CHP in other regions beyond the expected varying costs of electricity, natural gas, labour and construction. In addition to pricing of CO_2, other key policies, such as financial incentives for CHP and emissions intensity standards, may affect the feasibility of CHP.

4.4. Future Work

In order to improve our CHP cost-benefit model, we would like to refine its predictive accuracy, and increase its predictive scope. Improving accuracy would involve obtaining more accurate model parameters (piping costs, CHP system capital costs, etc.) from both literature sources and from industry. We would also like to re-configure our model to include more site-specific parameters such as presence or lack of major road crossings for the piping infrastructure, as well as shorter time-scale effects such as fluctuations in relative heating and electricity demands. To increase the predictive scope of our model, we would in particular like to quantitatively assess the impacts of various policy choices, such as carbon pricing, or emissions factor-based electricity generation incentives.

5. Conclusions

The adoption of CHP is one option available to countries and municipalities seeking to reduce their GHG emissions. Multiple studies have assessed the economic viability and emissions-reducing impact of CHP in specific situations; we have sought to build upon this literature by creating a model with user-defined inputs that can simulate the adoption of CHP under a variety of conditions. This has allowed us to identify attractive sets of conditions for the adoption of CHP. We evaluate the effects key variables, such as piping costs (expressed through built environment types and residential density) and natural gas price, that significantly influence the cost-effectiveness of CHP. Based on our results, CHP adoption would be most attractive in the City of Calgary in greenfield residential developments, and in large commercial areas such as the Chinook Activity Centre, if the heat is only provided to the major commercial user. While our model is limited by the quality and context-specific nature of some of our data, we believe that such an analysis may be useful in informing policymakers and financial investors in making decisions on emissions-reducing technologies such as CHP.

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Appendix A: Model Input Data

Table A-1. *Key CHP input values*

Input	Value
Efficiency (ε)	0.365[6]
Fuel Cost of Natural Gas [$/GJ]	4.90
Variable Operation and Maintenance [$/kWh]	0.004
Utilization rate (μ)	0.9
Capital Charge Factor	0.12
Capital Costs [$/kW installed]	340
Fixed Operational and Maintenance [$]	0
Thermal output [MM Btu/hr]	380
Natural gas emissions factor [kg CO_{2eq}/kWh generated]	0.4
Unit piping costs [$/m]	4,000
Default unit plot size [m x m]	9.5 x 9.5

Table A-2: *Key BAU case inputs*

Input	Value
Cost of electricity [cents/kWh]	9.16
Natural Gas price [$/GJ]	4.90
Coal EF [tonne CO_2eq/MWh delivered]	0.96
Natural Gas EF [tonne CO_2eq/MWh delivered]	0.4
Wind EF [tonne CO_2eq/MWh delivered]	0.0
Hydro EF [tonne CO_2eq/MWh delivered]	0.0

[6] Most of the data in this table are taken from Lemar, P.L. (2001). The natural gas price is taken from the New York Mercantile Stock Exchange, and the natural gas emissions factor is taken from AESO 2009. The capital charge factor and utilization rates are assumed based on standard values for these parameters in electricity projects.

Avg. grid EF [tonne CO_2eq/MWh delivered]	0.73
Boiler and furnace efficiency	0.9

Table A-3: *Parameters considered in the sensitivity analysis section*

Parameter	**Default Value**	**Range**
Average Grid Emissions Factor [tonne CO_2eq/MWh delivered]	0.69 (reflects "frozen" scenario)	0.1 – 1.0
Natural Gas Price [$/GJ]	4.90	1 - 16
Electricity Price Sensitivity [(cents/kWh)/($/GJ)]	0.3	0 – 0.6
Unit Density [units/acre]	45	1 - 91
Capacity of CHP [MW]	10	0.1 – 145
Land use area	Commercial area (represented by the Chinook Activity Centre in Calgary)	Commercial area, central business district, existing residential neighbourhood, new greenfield area

Table A-4: *30-Year Baseline Grid Electricity Mix Scenarios*

Baseline Scenario	**Coal**		**Natural Gas**		**Wind**		**Hydro**	
	2009	2040	2009	2040	2009	2040	2009	2040
Frozen	0.62	0.62	0.33	0.33	0.02	0.02	0.03	0.03
Probable	0.62	0.31	0.33	0.54	0.02	0.14	0.03	0.02
Growth	0.62	0.03	0.33	0.66	0.02	0.31	0.03	0.01

Figure A-1: *30-year BAU electricity mix projections*

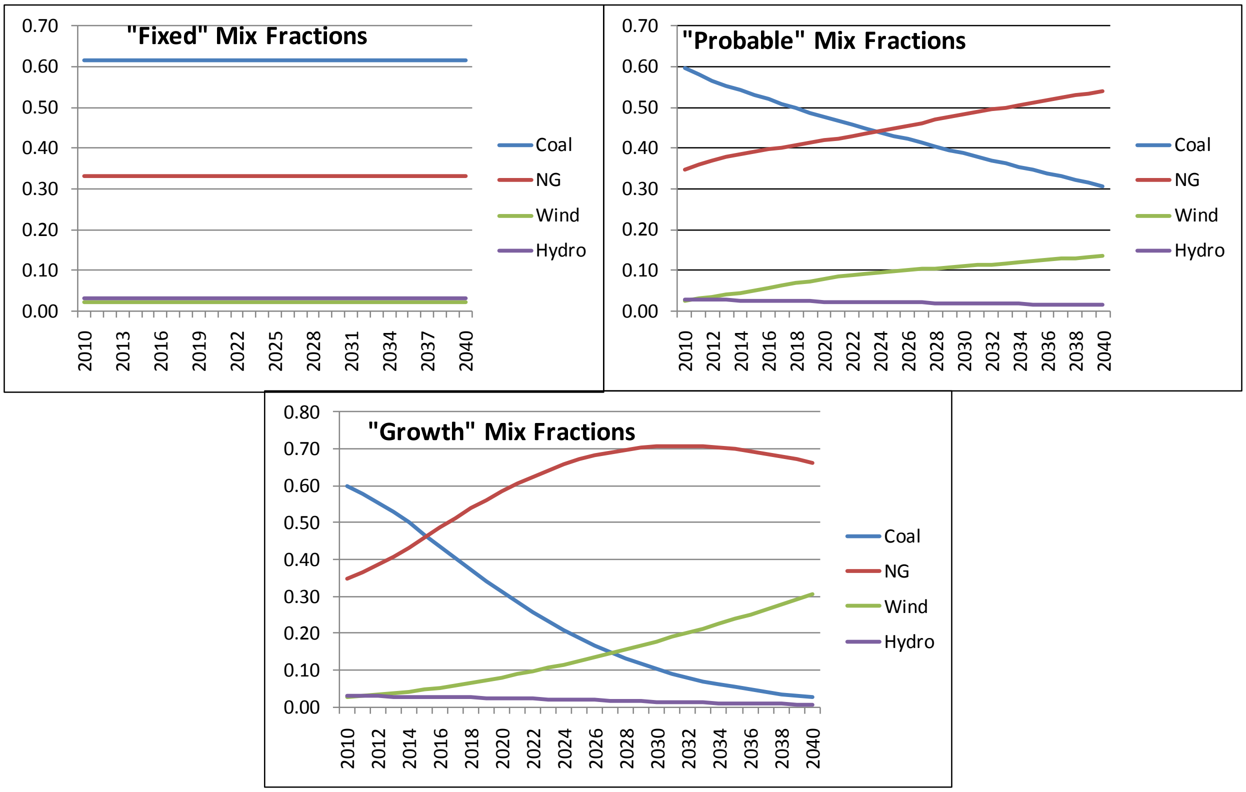
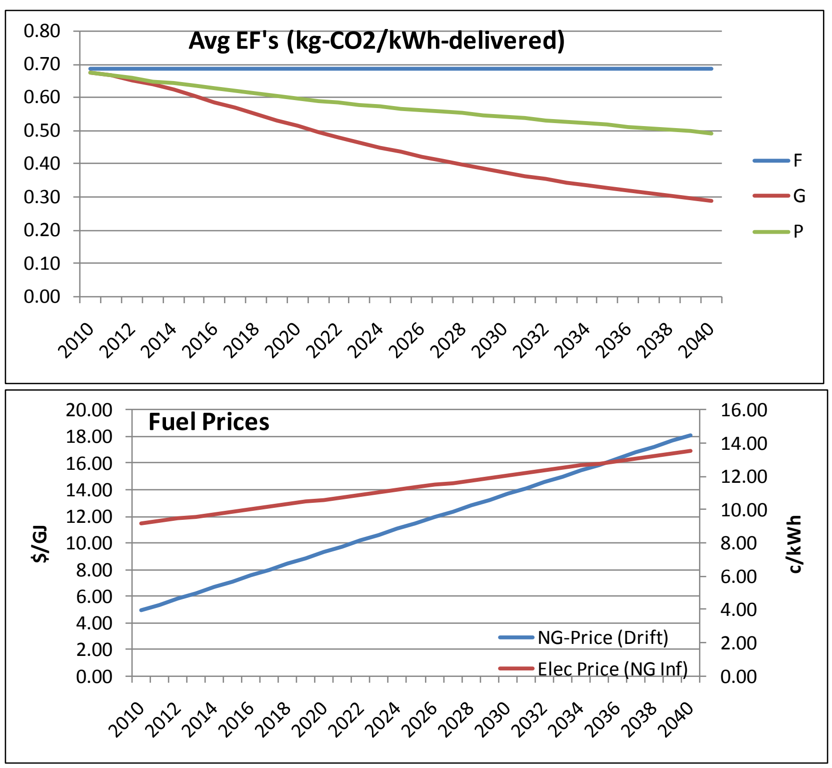


Figure A-2: *Average emissions factors and fuel prices for 30-year scenarios*



Appendix B: Model Output Data

Figure B-1: *Abatement Cost of CHP in 30-year "Chinook Activity Centre" scenario*

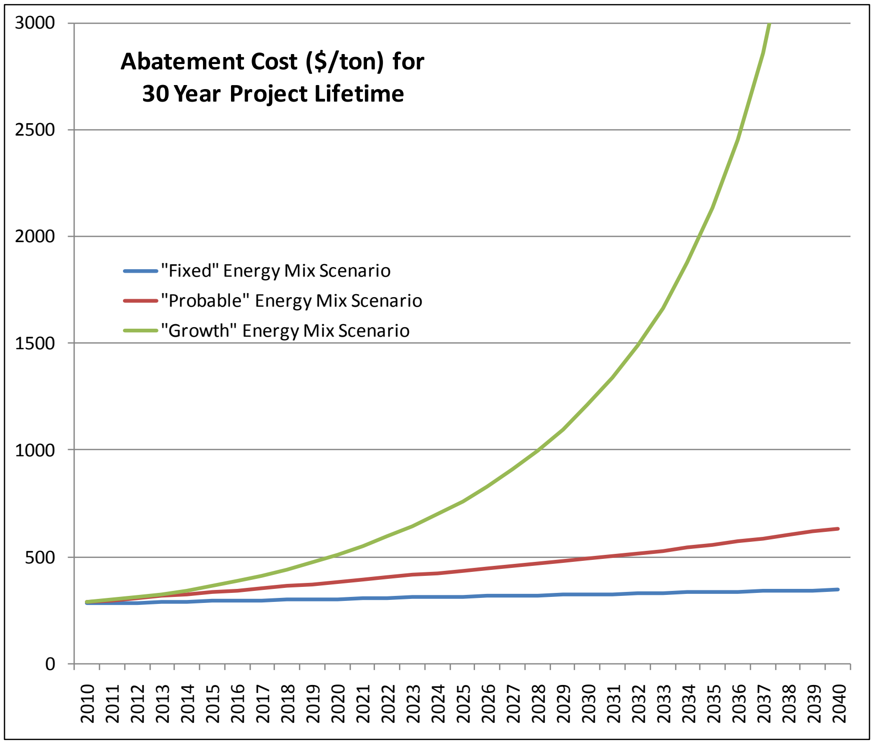


Figure B-2: *CO_2 abatement and cost incurred of CHP in 30-year "Chinook Activity Centre" scenario*

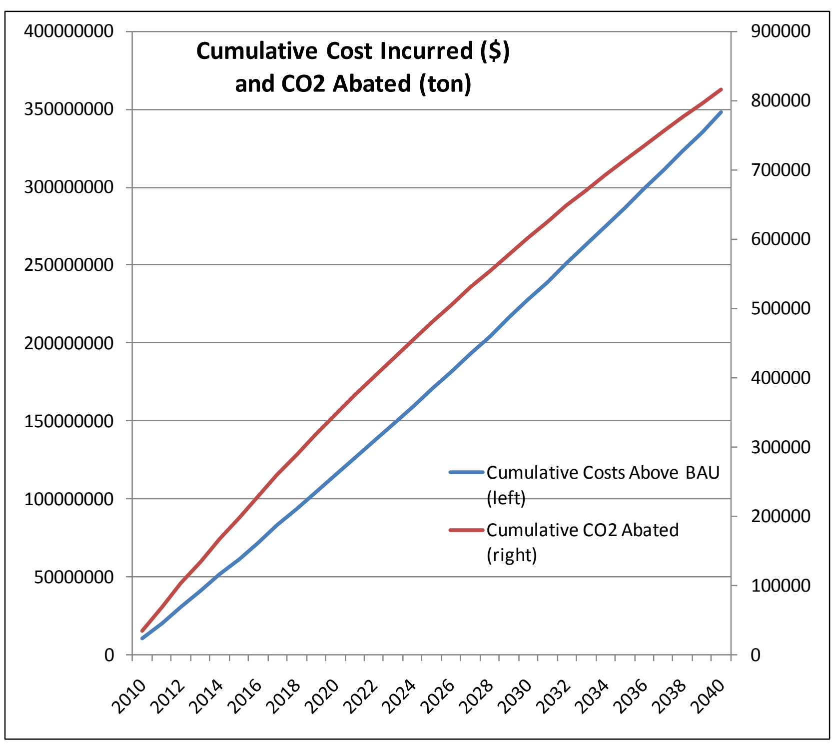


Figure B-3: *Abatement Cost of CHP in 30-year greenfield scenario*

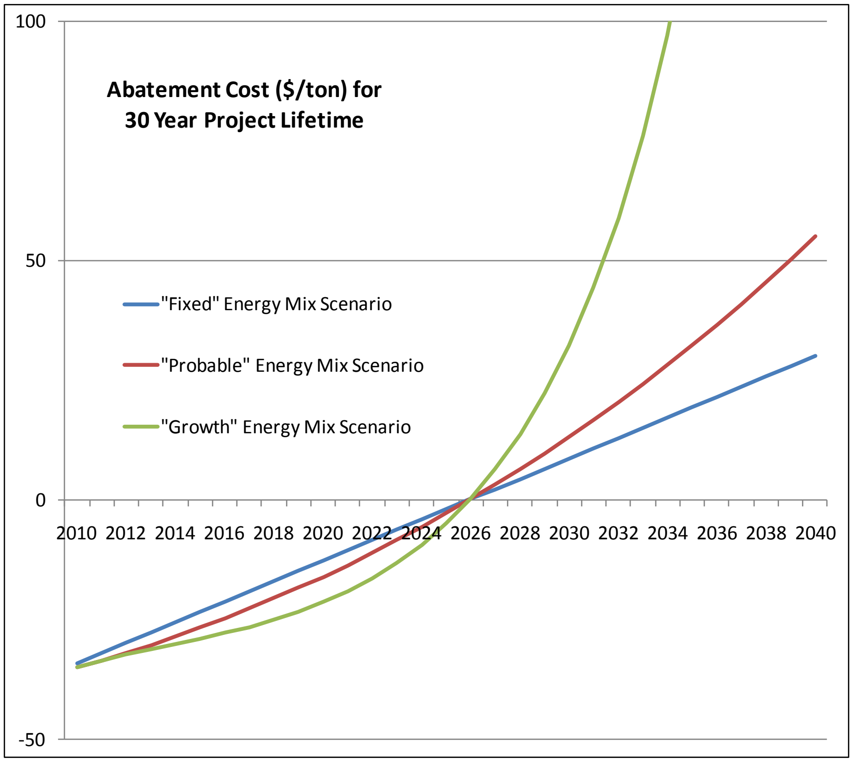


Figure B-4: *CO_2 abatement and cost incurred of CHP in 30-year greenfield scenario*

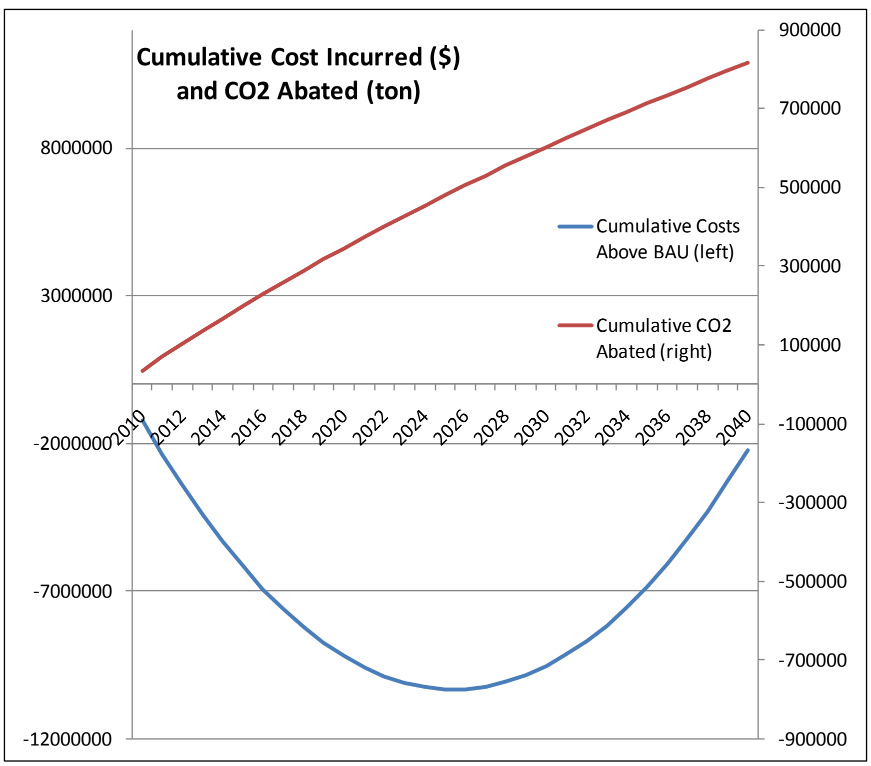


Figure B-5: *Abatement cost sensitivity to natural gas price and natural gas price influence on electricity price, Chinook Activity Centre*

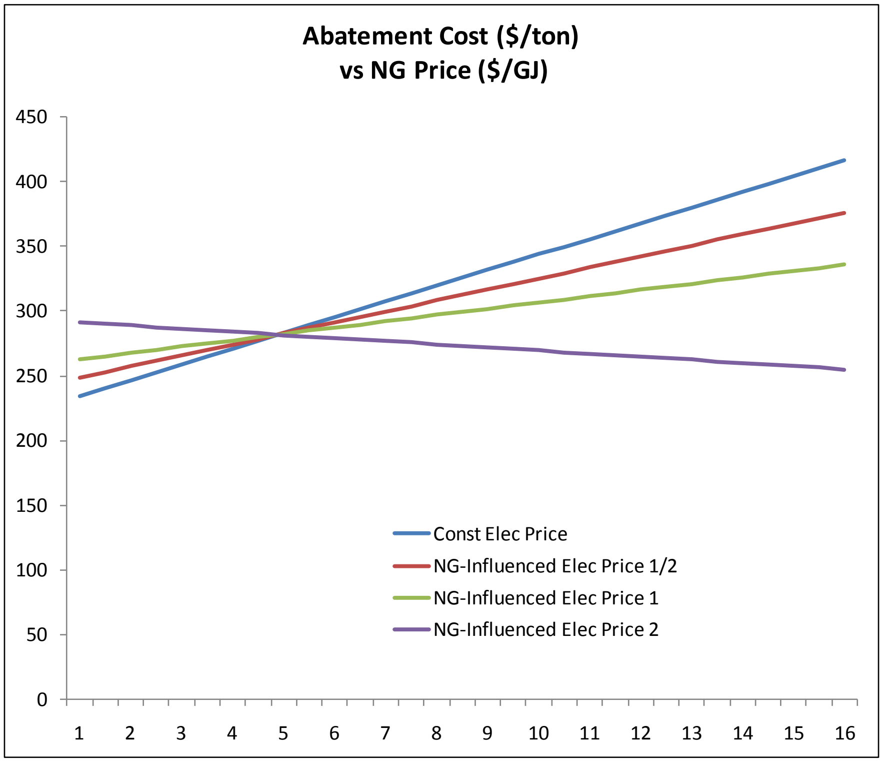


Figure B-6: *Abatement cost sensitivity to natural gas price, greenfield residential development*

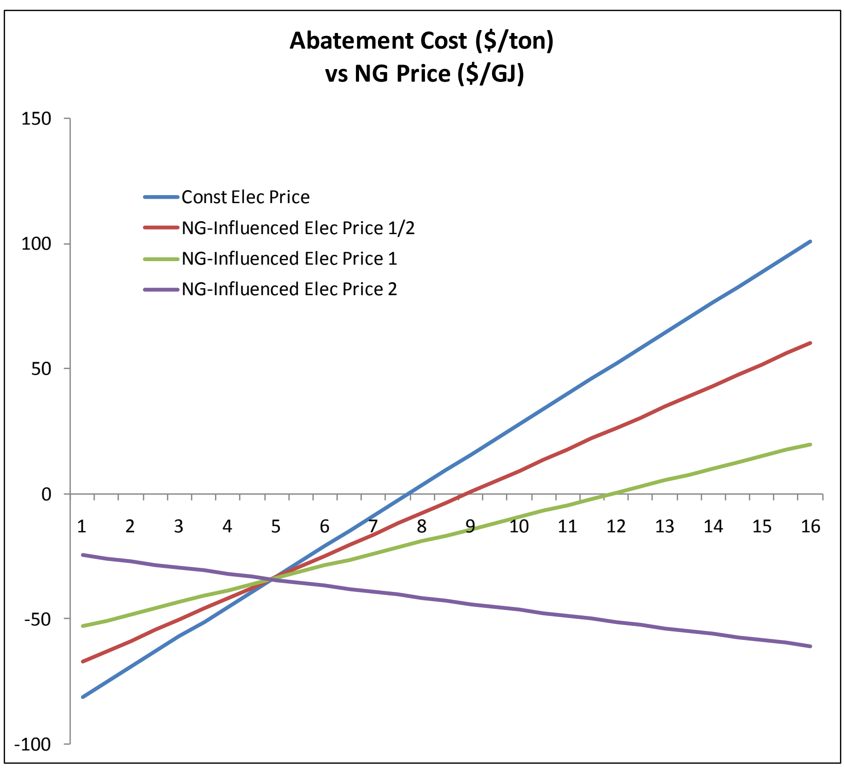


Figure B-7: *Abatement cost sensitivity to built environment type*

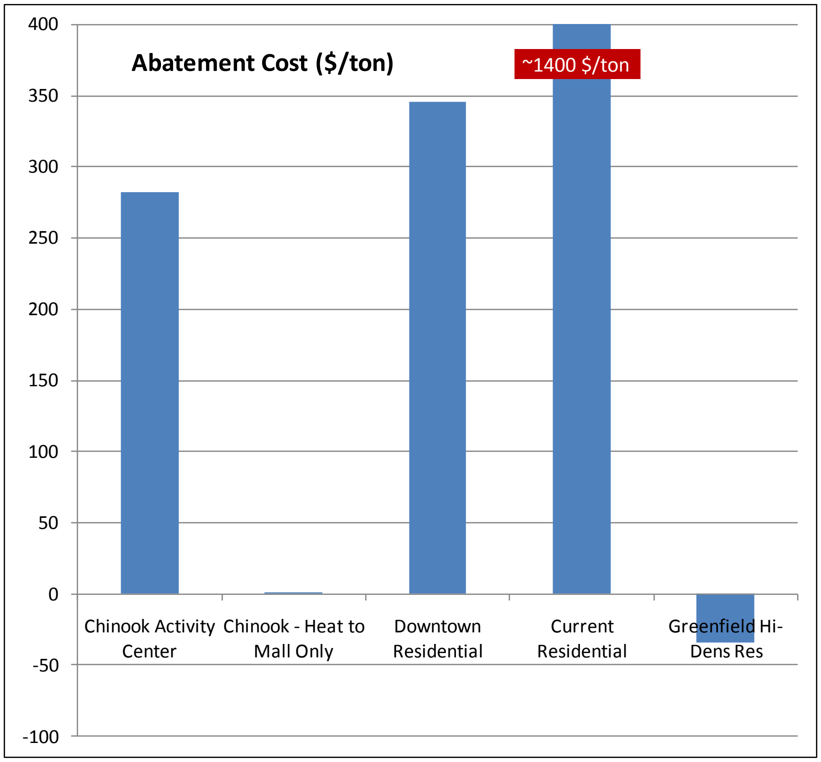


Figure B-8: *Abatement cost sensitivity to grid electricity factor*

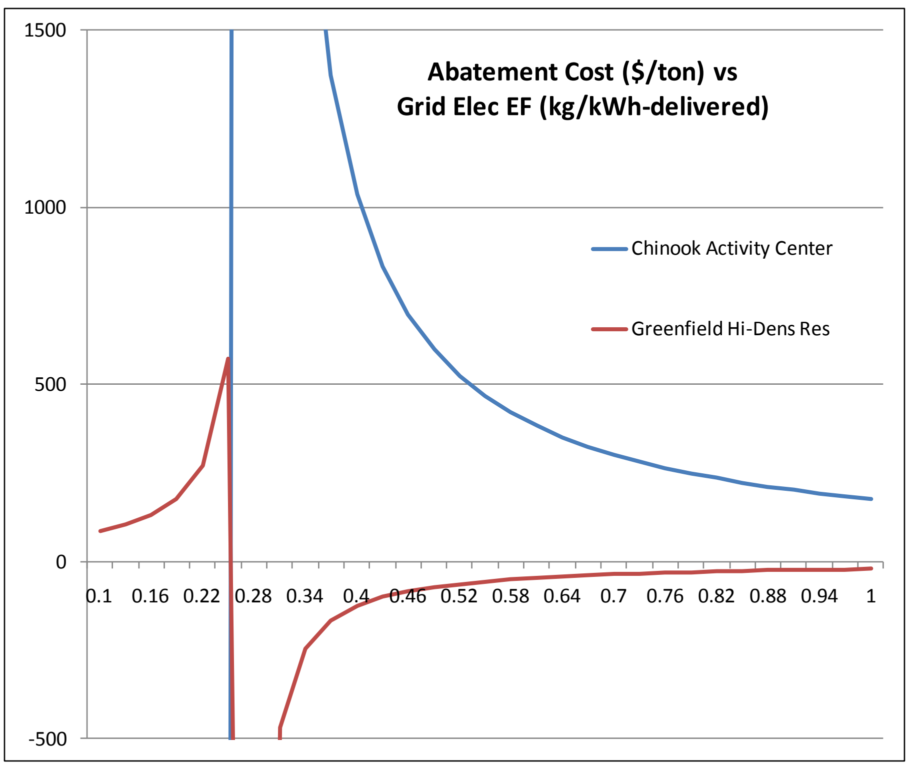


Figure B-9: *Abatement cost sensitivity to UPA density, Chinook Activity Centre*

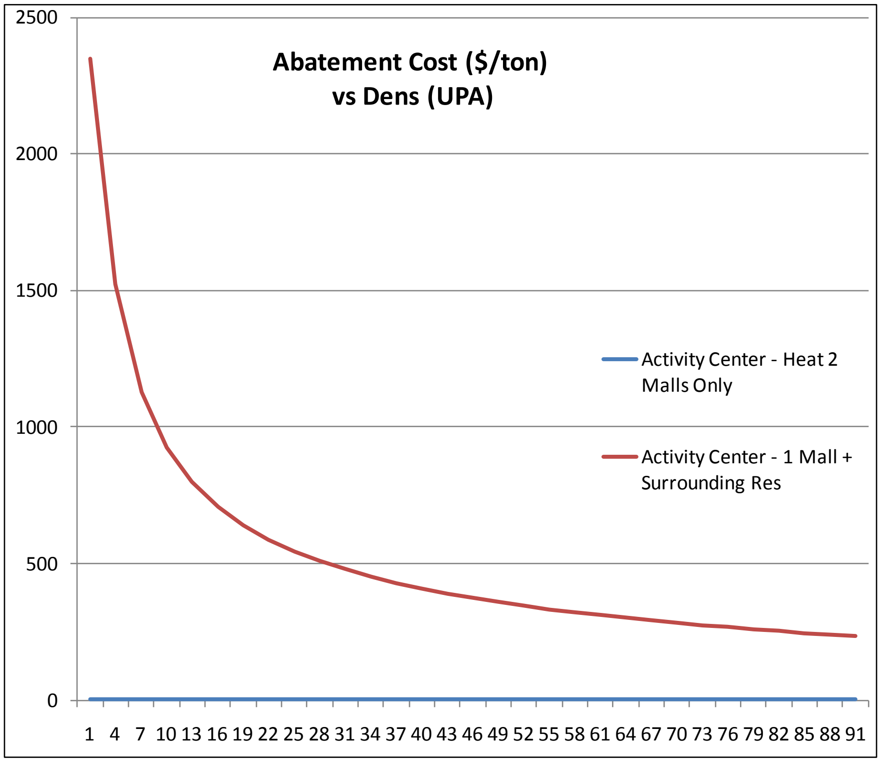


Figure B-10: *Abatement cost sensitivity to UPA density, existing residential development*

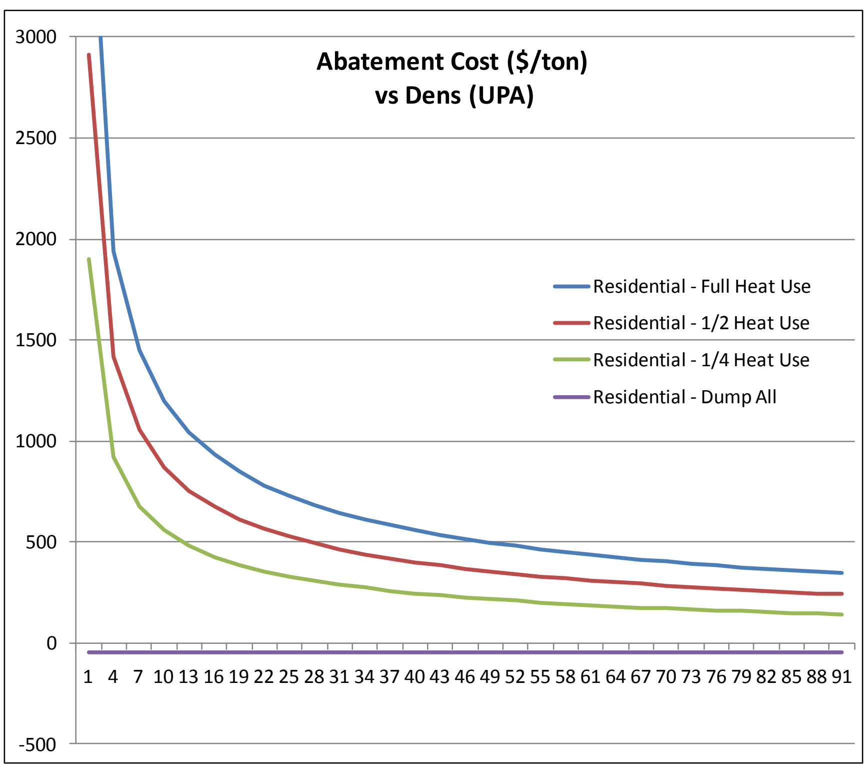


Figure B-11: *Abatement cost sensitivity to UPA density, greenfield residential development*

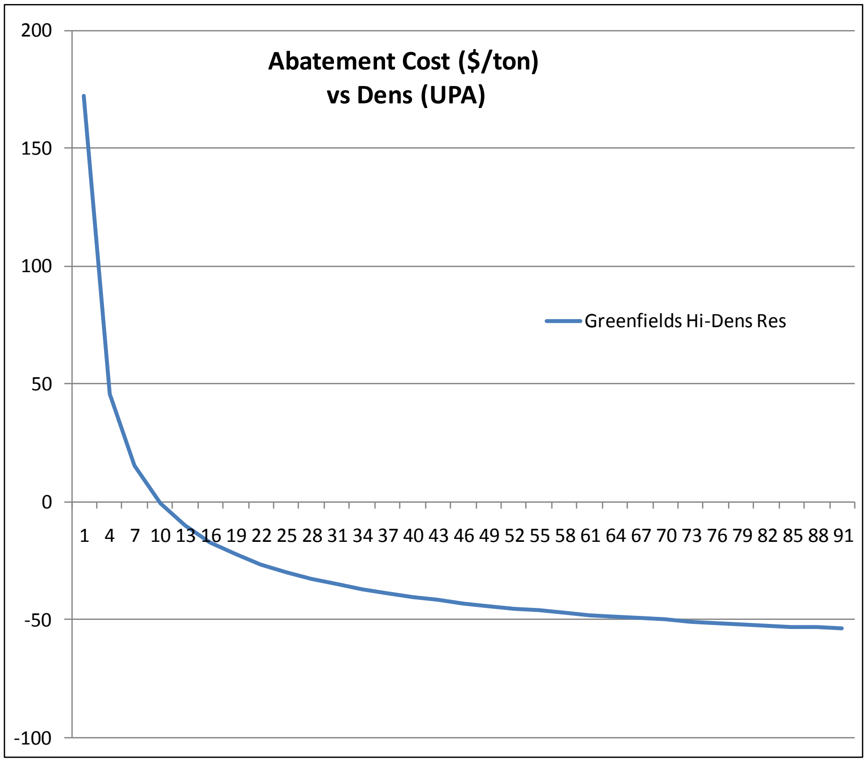


Figure B-12: *Abatement cost sensitivity to CHP size*