Equilibrium Modeling of Combined Heat and Power Deployment

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Abstract
Combined heat and power (CHP) generates electricity and heat from the same fuel source and can provide these services at higher equivalent conversion efficiency relative to grid-purchased electricity and stand-alone steam production. Previous work has focused on the economic factors and optimal operation strategy that influence the decision to install a single CHP unit. Our approach is to assess the economic potential for CHP in electricity-market equilibrium framework, accounting for the impact that CHP adoption will have on energy prices. We utilize a statistical model of electricity supply and pricing to estimate zonal supply curves for transmission constrained electricity markets. We couple the above model of electricity prices with simulated usage of CHP in different types of buildings, using the Philadelphia area as a case study. Incremental installations of CHP reduce the electricity demand from the grid, thus reducing wholesale electricity prices. The net present value from CHP is modeled as a function of wholesale electricity prices, and thus decreases with each additional unit of CHP installed. Under a range of operational assumptions and fuel prices, substantial CHP deployment could be achieved without reducing returns to the point where incremental CHP installations would become uneconomic.
Keywords: Combined Heat and Power, Energy Efficiency, Electricity market modeling

1. Introduction

About two-thirds of the fuel used for electricity generation is wasted as heat; this is in addition to the transmission and distribution losses (U.S. Environmental Protection Agency 2008a). Electricity generation is the single largest contributor of greenhouse gas emissions in the U.S (U.S Environmental Protection Agency 2010), so the inefficiency of central-station power generation is a contributing factor to emissions. Combined heat and power captures and reuses the waste heat and provides a viable alternative to centralized electricity generation for qualifying applications (Siler-Evans et al 2012; Strachan and Farrell 2006; Strachan and Farrell 2006).

Combined heat and power (CHP) also known as cogeneration, is the onsite production of electricity where the co-produced heat is captured and utilized for space heating, cooling, and
other site specific applications. The most important characteristic of CHP is the on-site generation of electricity and heat from the same fuel source. Commonly, this fuel is natural gas but other fuels such as biomass have potential for utilization in CHP systems as well. Compared to the conventional method of providing electricity through the power grid and producing onsite heat using a gas fired boiler system, CHP can yield substantial equivalent efficiency gains.

A shortcoming with deploying CHP in commercial buildings is the utilization of the rejected heat during summer. However, the heat from CHP is used to run an absorptive chiller to provide air conditioning. This is called tri-generation or combined cooling, heat and power (CCHP). In a case study of small-scale CHP in a hospital, the absorptive chillers were cost-effective addition to the CHP system (Siler-Evans et al 2012). This provides the flexibility of using the heat for space heating in the winter and cooling in the summer. Distributed generation, including CHP, decreases the dependence on power grid and provides reliable power supply along with cost savings and emissions reduction benefits (Zerriffi et al 2007). CHP can act as a backup source of power during power outages caused by natural disasters or breakdowns in the electricity grid. CHP can be linked with district heating schemes in municipalities or university campuses and this practice is proven practical in countries like Denmark and Finland (Kelly and Pollitt 2010; Unterwurzacher 1992).

Despite the potential benefits, CHP’s share of electricity generation in U.S is less than 10 per cent. In comparison, CHP’s share of total electricity production in countries like Finland and Denmark is about 38 percent and 52 percent respectively (International Energy Agency 2008). Some of the hurdles for CHP adoption in the U.S. include electricity rate structures, interconnection issues with the grid, tax treatment and technical barriers related to the flexibility of CHP systems (Oak Ridge National Lab 2008). From an investor’s perspective, adopting CHP is a business decision and economic viability is a crucial factor.

Several studies use net present value and payback period as a measure of feasibility in evaluating the application of CHP to different types of commercial buildings. A general finding is that the combination of low fuel prices and high electricity prices is generally advantageous for distributed generation, including CHP (King and Morgan, 2007). In a study comparing the use of CHP and CCHP units to a supermarket, the CCHP system had better primary energy saving potential but had a higher payback period (Maidment et al 2001). The higher payback period was attributed to the capital costs associated with the absorptive chiller but better payback period is achieved as the size of the chiller unit increased and as the demand for the chiller unit increases. An economic feasibility study of applying CCHP systems to a hospital show that the project and low payback period and high net present value (Ziher and Poredos 2006). A study conducted to study the emission reduction potential of CHP systems in seven types of commercial buildings showed that hospitals had the highest reduction of CO₂, NOₓ, and CH₄ emissions (Pedro J. Mago and Smith 2012). In addition, schools and small offices showed an increase in primary energy consumption.
The application of CHP systems to various commercial buildings requires understanding of the difference in energy consumption patterns and thermal and electric ratios. In a report assessing the market potential for cogeneration, commercial buildings types were ranked based on the size, hours of operation, system configuration and concurrence in thermal and electric loads (Lawrence Berkeley National Lab 1991). The report suggests that CHP does not offer similar benefits to all types of buildings. Hospitals are the best candidates among commercial buildings for deploying CHP because of the large size, continuous operation throughout the year and high electricity and heating demand.

Previous work has focused on the economic factors and optimal operation strategy that influence the decision to install a single CHP unit or assess the technical potential of CHP. Our approach is to assess the economic potential for CHP in electricity-market equilibrium framework, accounting for the impact that CHP adoption will have on energy prices. We couple an econometric model of electricity prices with simulated usage of CHP in different types of buildings, using the Philadelphia area, which falls under the PECO zone of PJM electricity market, as a case study. We find that under certain operational and fuel-price scenarios, the equilibrium level of economical CHP deployment is substantially lower than the technical potential. Incremental installations of CHP reduce the demand for electricity provided by the grid, thus reducing wholesale electricity prices. The net present value from CHP (i.e., the discounted value of the energy cost savings) is modeled as a function of wholesale electricity prices, and thus decreases with each additional unit of CHP installed.

The remainder of this paper is organized as follows - Section 2 introduces some background work on supply curve modeling and developing a working model of electricity prices and fuels utilization in the PECO zone, which will reflect changes in electricity prices with various levels of CHP deployment. Section 3 describes the equilibrium modeling of CHP deployment. Section 4 gives a brief description of the case study along with the relevant data and methodology. Section 5 discusses the results of the case study and section 6 provides conclusions.

2. Background on supply curve modeling

In modern restructured electricity markets, such as the PJM market in the United States, market prices change frequently and are influenced primarily by the level of electricity demand. Prices are set by the supply offer of the generating unit that clears the market – i.e., the last unit dispatched to equate total system supply and demand. Shifts in demand will affect the set of generating units dispatched and thus the clearing price in the electricity market. Our approach models the impact of CHP adoption on electricity demand in Greater Philadelphia, and thus the wholesale price of electricity along with the utilization of different fuels to serve aggregate demand for grid-provided power in Greater Philadelphia. We do not consider impacts on prices for capacity or ancillary services in this paper, but the costs of these services would be expected to rise and fall along with actual or projected electricity demand.
Modeling electricity prices and fuels utilization in a transmission-constrained electricity markets is complex. Actual supply curves based on cost data from the generation owners or transmission system operators are not public information. Much of the existing literature estimates short run supply curves using data from the Emissions and Generation Resource Integrated Database (eGRID 2007) published by the U.S. Environmental Protection Agency (Newcomer and Apt 2009; Newcomer et al. 2008). Figure 1 is the estimated short run supply curve for PJM electricity market using the above methodology.

![Short run supply curve for PJM electricity market](image)

Figure 1 - Short run supply curve for PJM electricity market. Each marker represents a generator.

These supply curves built in previous work typically model coal generators as being dispatched before natural gas generators in PJM electricity market. This scenario, however, is changing as the recent discovery of Marcellus shale gas reserves has led to a decrease in gas prices in the Mid-Atlantic region. The share of natural gas for power generation has been growing and the share of coal has been declining. Also, coal fired power plants are increasingly facing regulatory hurdles and increased costs related to air emissions of various pollutants (Newcomer and Apt 2009).

A second drawback with this approach is that it ignores transmission constraints on the electricity network. Transmission constraints can induce a different marginal fuel and prices at two different locations within in the same interconnected power system (Sahraei-Ardakani et al. 2012). For example, in a location with high demand, oil will be the marginal fuel and therefore higher electricity prices as compared to a location with relatively lower demand where coal or gas will be on the margin and lower electricity prices.
To address this issue, we draw on recent work (Sahraei-Ardakani et al 2012) that estimates statistical models of electricity supply and pricing in transmission constrained electricity markets. These estimated supply curves incorporate the transmission constraints in an electricity network unlike the short run marginal cost curves (like the one shown in Figure 1) that are estimated using individual plant level data. The approach taken by Sahraei-Ardakani, et al., is to construct an econometric model that estimates prices on a sub-system or “zonal” basis, using publicly-available data on fuel prices and electricity loads. The fuel on the margin in a zone (i.e., the fuel whose price best explains variations in electricity price over a relevant range of demands) is a function of the zonal demand, total system demand and the relative fuel prices. Supply curves for each type of fuel (coal, gas and oil) are determined and each segment represents the influence of the fuel on the electricity price.

![Price in PECO vs Load in PECO](image)

Figure 2 - Supply curve with transmission constraints for PECO zone estimated by Sahraei-Ardakani et al (2012)

The estimated supply curve is piecewise linear with three segments associated with the three different fuels (coal, gas and oil; other fuels are generally price-setters in the PJM system). Thresholds based on demand levels where the marginal input fuel switches differentiate the three segments. The threshold value when the marginal fuel switches from coal to gas is ‘3846 MW’ and ‘8140 MW’ for gas to oil. There is a small discontinuity when the fuel at the margin changes
from coal to gas indicating that marginal cost of producing electricity from gas is comparable to coal plants. This transition point is modeled using a fuzzy logic type of approach (Sahraei-Ardakani et al 2012) where the marginal fuel is actually a mixture of two different fuels, such as coal and gas. Saharei-Ardakani, et al (2012) also suggest that the gap could be widened with changes in relative fuel prices i.e. decline in natural gas prices or increase in coal prices.

3. Model description

A large-scale deployment of CHP will decrease the demand for grid-provided electricity and thus will decrease location-based prices in wholesale electricity markets. Unlike previous work examining investment incentives for a single CHP unit, or estimating technical potential for CHP deployment, our goal is to estimate an equilibrium model of CHP deployment, using the Philadelphia zone within the PJM electricity market as a case study. Our approach represents an equilibrium model in that it incorporates feedbacks in electricity prices on the net present value of additional CHP installations. In other words, we estimate the level of CHP deployment such that additional investments in CHP in that region will not be beneficial or a marginal CHP investment will have a negative net present value.

The zonal electricity price is a function of the zonal demand in the grid and a decrease in demand will decrease the electricity prices. The savings from CHP is a function of the real-time electricity prices, so a decrease in the demand will tend to lower savings, holding the natural gas price constant. The demand reduction depends on the number of CHP units installed. Figure 3 explains the model of equilibrium CHP market deployment.
A single CHP unit will be beneficial to the building owner in the form of avoided costs associated with the additional electricity bought from the utility without a CHP unit. The demand satisfied by a single CHP unit is small relative to the zonal demand, and will not reduce demand sufficiently to change the zonal electricity price. A substantial number of CHP installations will, however, reduce the demand for electricity provided by the grid, thus reducing wholesale electricity prices. The net present value from CHP (i.e., the discounted value of the energy cost savings) is modeled as a function of wholesale electricity prices, and thus decreases with each additional unit of CHP installed. Therefore, incremental CHP deployment will be beneficial until savings from avoided electricity costs can offset the associated cost for CHP installation and operation. Figure 4 illustrates the relation between wholesale electricity price and incremental CHP installation.
The capital cost for CHP is the upfront cost of the power generating unit and the variable cost includes fuel (natural gas) cost for CHP system operation and the maintenance cost. The gross savings from CHP is the difference between the electricity purchase costs with and without the CHP system. We assume that the customers see real-time electricity prices. The equations involved in the cash flow model are,

\begin{align}
\text{Fixed Costs, } C_i &= C_{i,p\text{gu}} \\
\text{Variable Costs, } VC_i &= C_{i,f} + C_{i,o&\text{m}} \\
\text{Gross Savings, } S_i &= P_B \times Q_B - P_i \times Q_i
\end{align}

where \( i \) denotes the number of CHP units deployed. \( C_{i,p\text{gu}} \) is the cost of the power generating unit. \( C_{i,f} \) is the cost of fuel to run the CHP unit and \( C_{i,o&\text{m}} \) is the operating and maintenance costs. \( Q_B \) is the demand and \( P_B \) is the electricity price without any CHP unit. \( Q_i \) is the reduced demand and \( P_i \) is the new electricity price with \( i \) CHP units. So, if \( N \) CHP units are deployed, the net present value calculated over time \( T \) with a discount rate of \( r \) will be,
\[ NPV = \sum_{i=1}^{N} \left\{ \sum_{t=0}^{T} \frac{(P_B \cdot Q_B - P_l \cdot Q_l)_t - (C_{lf} + C_{lo&m})_t}{(1+r)^t} \right\} - C_{L,pgu} \]  

(4)

The savings potential of CHP depends on the zonal electricity price and operation strategy of the CHP unit. At some level of CHP deployment, the savings will be equal to the costs (discounted). At this equilibrium point, a marginal CHP investment will not be beneficial and will have a net present value of zero.

4. Description of the case study

This study focuses on the deployment of single-user CHP among various types of commercial buildings in Philadelphia, in Southeastern Pennsylvania. A typical single-user building CHP installation would represent a few megawatts or less of power generation capacity. Larger installations (tens of megawatts), as would be typical of industrial applications, are not considered in our analysis. Philadelphia falls in the PECO zone of the PJM electricity market. Primarily due to transmission constraints, prices in the PECO zone have historically been higher than average for the PJM market as a whole.

Data on Philadelphia’s commercial building stock was obtained from the CoStar database (Econsult Corporation 2011). While the database does not capture the universe of commercial buildings in Philadelphia, it does provide the best available representation of the region’s commercial building stock and the distribution of building stock among different building types. Table 1 shows the number of buildings in eight types of commercial buildings in Philadelphia.

Table 1 - Commercial buildings stock in Philadelphia

<table>
<thead>
<tr>
<th>Rank(^1)</th>
<th>Building Type</th>
<th>Number of buildings</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Hospital</td>
<td>50</td>
</tr>
<tr>
<td>2</td>
<td>Large Hotel</td>
<td>74</td>
</tr>
<tr>
<td>3</td>
<td>Restaurant</td>
<td>29</td>
</tr>
<tr>
<td>4</td>
<td>Large Office</td>
<td>284</td>
</tr>
<tr>
<td>5</td>
<td>Supermarket</td>
<td>51</td>
</tr>
<tr>
<td>6</td>
<td>School(^2)</td>
<td>63</td>
</tr>
<tr>
<td>7</td>
<td>Motel</td>
<td>22</td>
</tr>
<tr>
<td>8</td>
<td>Warehouse</td>
<td>439</td>
</tr>
</tbody>
</table>

\(^1\) Priority rankings for CHP deployment in different types of commercial buildings developed by Lawrence Berkley National Laboratory(Lawrence Berkeley National Lab 1991)
2 The Costar database did not include information on the school buildings in the region and this number was obtained from National Center for Education Statistics. Online at <http://nces.ed.gov/datatools/>.

4.1 Building Hourly loads

Comprehensive energy demand profiles of buildings are not commonly recorded. The Building - CHP Screening tool (BCHP), developed by Oak Ridge National Lab, was used to develop hourly electricity, heating and cooling demand profiles for the eight types of buildings under study (Oak Ridge National Lab 2005). The BCHP tool estimates energy demand profiles for various types of commercial buildings based on user-defined parameters such as building dimensions, location and occupancy schedules. Input parameters for the eight types of commercial building were obtained from by U.S Department of Energy Commercial Reference Building Models of the National Building Stock (National Renewable Energy Lab 2011). For each type of building, three scenarios were developed – Baseline without CHP, CHP system following thermal loads (CHP-FTL) and CHP system following electrical load (CHP-FEL) (P. J. Mago, Fumo, and Chamra 2009).

The baseline scenario is a reference case without any CHP units installed. For CHP following thermal load, the system is operated to maximize the delivery of thermal load required at the site for various processes such as space heating, space cooling, dehumidification and other site related applications. In the process of operating the CHP unit to meet thermal demands, some amount of electricity is generated. The recovered heat from the CHP system will displace much, if not all, of the fossil fuel required that would have been required in a conventional boiler for the site and the electricity produced meets some of the demand. For CHP following electric load, the CHP system operates to meet the site’s electricity demand. In general, this is not economical because onsite generation of electricity from CHP cannot compete with central station generation of electricity on a cost per kWh basis. In addition, the recovered heat does not match with the thermal demand; hence a complete advantage of the fuel savings is not realized.

Table 2 provides the area, building occupancy schedule and hours of generator operation used in the BCHP tool for each type of building. We assumed the generators operated when the electricity demand was high. The periods of high demand for each type of building was estimated based on the baseline case simulation results.
Table 2 - Buildings occupancy schedule and peak-electricity demand periods

<table>
<thead>
<tr>
<th>Building type</th>
<th>Area (m²)</th>
<th>Hours of generator operation</th>
<th>Building occupancy schedule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hospital</td>
<td>22422</td>
<td>8 am to 6 pm</td>
<td>weekdays - 24 hours</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>weekends - 24 hours</td>
</tr>
<tr>
<td>Large Office</td>
<td>46320</td>
<td>9 am to 3 pm</td>
<td>weekdays - 7 am to 8 pm</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>weekends - closed</td>
</tr>
<tr>
<td>Large Hotel</td>
<td>11345</td>
<td>7 am to 2 pm, 6 pm to 9 pm</td>
<td>weekdays - 24 hours</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>weekends - 24 hours</td>
</tr>
<tr>
<td>Motel</td>
<td>4014</td>
<td>7 am to 11 am, 7 pm to 9 pm</td>
<td>weekdays - 24 hours</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>weekends - 24 hours</td>
</tr>
<tr>
<td>Supermarket</td>
<td>4181</td>
<td>8 am to 5 pm</td>
<td>weekdays - 8 am to 8 pm</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>weekends - 8 am to 8 pm</td>
</tr>
<tr>
<td>Restaurant</td>
<td>511</td>
<td>10 am to 7 pm</td>
<td>weekdays - 9 am to midnight</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>weekends - 9 am to midnight</td>
</tr>
<tr>
<td>School</td>
<td>19572</td>
<td>10 am to 2 pm</td>
<td>weekdays - 8 am to 10 pm</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>weekends - closed</td>
</tr>
<tr>
<td>Warehouse</td>
<td>4835</td>
<td>9 am to 4 pm</td>
<td>weekdays – 8 am to 6 pm</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>weekends - closed</td>
</tr>
</tbody>
</table>

Table 3 compares the energy intensities from the BCHP tool and the energy intensities for buildings in Mid-Atlantic region obtained from the Commercial Building Energy Consumption Survey (Energy Information Administration 2006). The CBECs is a nation-wide survey of energy consumption of commercial buildings in the U.S. Energy intensities for certain building types were missing under the Mid-Atlantic census division. The missing values were obtained from Buildings Energy Data Book (US Department of Energy 2011). There are some substantial differences between the energy intensities from CBECs and from BCHP. In particular, BCHP’s estimates of energy intensity for supermarkets and warehouses are more than 20% higher than estimates from CBECs.
Table 3 - Energy Intensity Validation

<table>
<thead>
<tr>
<th>Building Type</th>
<th>Energy Intensity from CBECs (1000 Btu/SF)</th>
<th>Energy Intensity from BCHP (1000 Btu/SF)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hospital</td>
<td>214</td>
<td>201</td>
</tr>
<tr>
<td>Large Office</td>
<td>81</td>
<td>64</td>
</tr>
<tr>
<td>Large Hotel</td>
<td>110</td>
<td>113</td>
</tr>
<tr>
<td>Small Hotel/Motel</td>
<td>75</td>
<td>102</td>
</tr>
<tr>
<td>Supermarket</td>
<td>74</td>
<td>89</td>
</tr>
<tr>
<td>Restaurant</td>
<td>198</td>
<td>172</td>
</tr>
<tr>
<td>Secondary School</td>
<td>80</td>
<td>69</td>
</tr>
<tr>
<td>Warehouse</td>
<td>49</td>
<td>72</td>
</tr>
</tbody>
</table>

The BCHP tool calculates the generator sizing using the DOE-2 sizing run. The sizing depends on the maximum load for each building type since we model the generator to operate during periods of high demand. Table 4 gives the generator sizing for each building type.

Table 4 - Generator sizing for each type of building

<table>
<thead>
<tr>
<th>Building Type</th>
<th>Generator Size(kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hospital</td>
<td>1500</td>
</tr>
<tr>
<td>Large Hotel</td>
<td>420</td>
</tr>
<tr>
<td>Restaurant</td>
<td>30</td>
</tr>
<tr>
<td>Large Office</td>
<td>1820</td>
</tr>
<tr>
<td>Supermarket</td>
<td>200</td>
</tr>
<tr>
<td>School</td>
<td>550</td>
</tr>
<tr>
<td>Small Hotel/Motel</td>
<td>125</td>
</tr>
<tr>
<td>Warehouse/Flex-industrial</td>
<td>100</td>
</tr>
</tbody>
</table>
3.2 Average Costs estimates for a CHP system

The costs associated with a CHP system include capital costs, and operating costs such as fuel and maintenance. It is assumed that all the CHP units run on natural gas. Average cost estimates for a typical CHP unit were obtained from the U.S. Environmental Protection Agency (Environmental Protection Agency 2008b). Table 5 gives an average capital and operation and maintenance cost for a typical CHP system. The natural gas consumption under each operational strategy is obtained from BCHP tool to estimate the fuel cost.

Table 5 - Average cost estimates for a typical CHP system

<table>
<thead>
<tr>
<th>Capital Cost ($/kW)</th>
<th>1200</th>
</tr>
</thead>
<tbody>
<tr>
<td>Incremental O&amp;M cost ($/kWh)</td>
<td>0.01</td>
</tr>
</tbody>
</table>

3.3 Methodology

We model CHP deployment according to the priority rankings developed by the Lawrence Berkley National Laboratory (Lawrence Berkeley National Lab 1991). Our analysis assumes that CHP units will be installed at the most advantageous sites first (according to the LBNL rankings) followed by deployment at progressively less advantageous sites. We thus assume that CHP units will be installed first in all the hospitals (which are ranked the most advantageous single-use cases for CHP) followed by large hotels and so on, as shown in Table 1. Reflecting a limitation in the CoStar data, we assume that building types have homogeneous thermal and electric load profiles within type and those demand profiles are well-represented by the BCHP tool. The BCHP tool is utilized to generate hourly CHP usage profiles for each building type. For each deployment scenario, hourly CHP usage is aggregated across all simulated CHP installations; this represents the electricity demand taken off the PJM electric grid in each hour. We thus reduce hourly demand in the PECO zone of the PJM electricity markets (using demand in 2010 as the baseline) with every CHP unit deployed and estimate the zonal price change with incremental CHP units deployed. Figure 5 shows the load duration curves for the baseline case and the reduced demand with CHP units following thermal load (FTL) and electric load (FEL) for all 1,012 CHP units corresponding to the commercial building stock represented in the CoStar database. CHP-FEL has more on-site generation compared to CHP-FTL and hence higher displacement of grid-provided electricity.
Reductions in grid-provided electricity, however, are reasonably modest in magnitude no matter what operational strategy is modeled (FEL or FTL). The average demand for electricity from the grid reduces from 4879 MW (baseline) to 4820 MW in case of CHP-FTL and 4720 MW in case of CHP-FEL. The standard deviation for base line, CHP-FTL and CHP-FEL are 1011, 1009 and 1025 MW respectively.

Large-scale CHP deployment might affect both natural gas and electricity prices, in opposite directions (since CHP would increase demand for natural gas while decreasing demand for grid-provided electricity). Natural gas prices affect the operating costs of CHP and also the zonal electricity prices (hence savings). We capture uncertainty in the price of natural gas using three gas price scenarios ($2/ mm Btu, $4/ mm Btu and $8/ mm Btu). Prices for coal and oil (other fuels utilized in the Philadelphia region) are assumed to remain constant (coal - $2 / mm Btu, oil – $10.667/ mm Btu). The net present value on a CHP investment is calculated for three natural gas price scenarios for a 10-year period with a discount rate 10%. The return on investment is calculated assuming first year (2010) savings are achieved every year.

Figure 5 - Load duration curves for a) Baseline demand, b) CHP-FTL, c) CHP- FEL
5. Results

The technical potential for CHP in Philadelphia is substantial. Incremental installations of CHP, however, reduce the demand for electricity provided by the grid, thus reducing wholesale electricity prices. The return on incremental investment is a function of the electricity prices, decreases as the number of CHP units installed increases. Figure 6 shows the price duration curves corresponding to the load duration curves in figure 5.

![Price duration curves for a) Baseline demand, b) CHP-FEL, c) CHP-FTL.](image)

Fuel prices are assumed to be, coal - $2 / mm Btu, gas - $8/mm Btu, oil – $10/ mm Btu.

With natural gas prices of $2/mm Btu and $4/mm Btu (and $2/mm Btu coal price) we do not observe substantial differences in the effects on the price duration curve arising from 1,012 CHP installations operated according to FEL and FTL. The results suggest that price reduction (and savings) is sensitive to natural gas prices and the operational strategy of CHP. In particular, we find that the impacts of CHP adoption will have larger impacts on the electricity price duration curve under high gas-price scenarios. This is due primarily to the reductions in peak-time electricity demand. We also find that operating CHP units in FEL mode has a larger impact.
on the electricity price duration curve (through larger reductions in demand for grid-provided electricity) than does operating CHP units in FTL mode.

The gross savings from a CHP unit are the avoided costs from purchasing additional electricity bought from the utility without a CHP unit (net savings would incorporate the cost of natural gas to fuel the CHP unit, plus other operational or maintenance costs). As shown in figure 5 and 6, there will be decrease in demand and price every hour in a year. We estimate the hourly savings using equation (3) and aggregate it to get yearly savings from avoided electricity costs. Figures 7, 8 and 9 show gross electricity cost savings as a function of the number of CHP units deployed and the operational strategy (FEL or FTL). The figures calculate gross electricity cost savings over a 10-year period under three gas-price scenarios ($2/mm Btu, $4/mm Btu and $8/mm Btu). Higher savings were achieved with higher $8/mm Btu natural gas price as there will be more savings from avoided electricity costs as compared to a $2/mm Btu natural gas price. The savings from CHP-FEL is higher since there will be more onsite electricity generation, hence higher avoided electricity costs as compared to CHP-FTL. The total savings curve tends to flatten as number of CHP unit deployed increases indicating that the incremental savings from CHP decreases.

Figure 7 - Total Savings with a $2/mm Btu natural gas price
Figure 8 - Total Savings with a $4/mm Btu natural gas price
After about 300 CHP installations, the savings from CHP-FEL decreases for a $2/mm Btu natural gas price (figure 7). This happens because of low zonal electricity prices resulting because of substantial demand taken off the grid coupled with lower natural gas price. At this point, the price of electricity from the utility is cheaper than generating on-site electricity from CHP. This means that any further deployment of CHP-FEL will not be beneficial to the building owner.

Figures 10, 11 and 12 show the incremental energy cost savings (which we term “marginal savings” for CHP installations, for the three natural gas price scenarios and the two CHP operation strategies. The marginal savings from CHP-FTL decreases with increase in the number of CHP units for all three price scenarios. Marginal savings from CHP-FEL actually increase for deployment in hospitals (the first 50 CHP units), since the savings in grid-purchased electricity is large compared to the impact on LMPs in the PECO zone. As less advantageous CHP units are deployed, the marginal savings begins to decrease more rapidly. Marginal savings flattens out once roughly 100 to 300 CHP units are deployed, reflecting a combination of lower reductions in the demand for grid-provided electricity and a shift inwards of electricity demand towards the less-elastic portion of the PECO supply curve.
Figure 10 - Marginal savings with a $2/mm Btu natural gas price

Figure 11 - Marginal savings with a $4/mm Btu natural gas price
Figure 12 - Marginal savings with a $8/mm Btu natural gas price

For all levels of the natural gas price, we observe fluctuations in the incremental savings from additional CHP installations. This effect appears most prominent under the FEL mode of operation. The reason for this behavior is related to the mixture of coal and natural gas on the margin in the PECO zone of PJM (which we referred to as the “fuzzy gap” in section 2), especially in those scenarios with low gas prices. The supply curve model in section 2 was estimated with a natural gas price of $8/mm Btu, a coal price of $2/mm Btu and an oil price of $10.66/mm Btu. With these fuel prices, the partial supply curves associated with coal, gas, oil and the threshold level is well-defined. With low natural gas prices, the cost of generating electricity from gas is as cheap as generating electricity from coal with a low natural gas price (say $2/mm Btu). The threshold between the coal portion of the supply curve and the natural-gas portion of the supply curve becomes less well-defined. The fuel at the margin keeps switching between coal and natural gas leading to fluctuations in electricity prices. The savings from CHP is a function of the zonal electricity price and hence there are fluctuations in incremental savings. Also, the deviations are minimal when the natural gas price is $8/mm Btu which suggests that the supply curve model works better for higher natural gas prices. The fluctuations are minimal with CHP-FTL as compared to CHP-FEL because the demand reduction is not high enough to create significant fluctuations in electricity prices.

The net present value modeled as a function of electricity prices is estimated using equation (4), assuming a 10-year decision horizon and a 10% annual discount rate. Figures 13, 14 and 15 show how the marginal NPV for CHP installations changes with the three price scenarios. While we observe some fluctuations in the NPV of an incremental CHP installation at low levels of CHP utilization, we generally observe a decline in the NPV of the marginal CHP unit, as anticipated. Not only does marginal NPV decreases with incremental CHP installations and under certain operational and fuel-price scenarios, the equilibrium level of economical CHP deployment is substantially lower than the technical potential. With a $2/mmBtu natural gas price the operating costs of a CHP unit is less but at the same time the savings is also less because of lower electricity costs. With a $8/mmBtu natural gas price, the high operating costs is offset by the higher savings from avoided electricity prices.
Figure 13 - Marginal NPV with a $2/mm Btu natural gas price

Figure 14 - Marginal NPV with a $4/mm Btu natural gas price
For the natural gas price scenarios of $2 and $4 /mm Btu the marginal NPV declines quickly under the FTL operational strategy, approaching zero by the time 100 to 150 CHP units are installed and operating. Thus, if all CHP units are operated according to FTL, then the economic extent of the market in Philadelphia is around one-tenth of the technical potential for these lower gas prices scenarios. In the case of CHP-FEL, for a gas price of $2/ mm Btu the marginal NPV becomes zero after 282 units are installed; for a gas price of $4/ mm Btu the marginal NPV becomes zero for after 424 CHP units are installed. These points suggests that any further CHP deployment will not be beneficial. The marginal NPV doesn’t cross zero with a $8/mm Btu for CHP-FEL and CHP-FTL. Thus, if all CHP units are operated according to FEL, the economic potential is larger (around three to four times as large as under FTL operations) but still substantially smaller than the technical potential in the lower gas price scenarios.

We draw three policy-relevant lessons from our analysis of CHP deployment in the Philadelphia region. First, higher gas prices in and of themselves do not economically disadvantage CHP – the spark spread (difference between gas and electricity prices) is the more relevant variable, as also pointed out by King and Morgan (2005). Our model of electricity pricing in Philadelphia and the operational costs of single-user CHP suggests that increases in natural gas prices will disproportionately affect electricity prices relative to CHP operational
costs. Second, the operational strategy adopted for CHP matters just as much in determining profitable deployment levels as does the fuel price. Perhaps driven by high peak-time prices for electricity in Philadelphia, we find that an operational strategy of electric load following (FEL) yields larger economic savings than thermal load following (FTL) when CHP has relatively low levels of adoption. At higher levels of adoption, FTL may be a more economical operational strategy when fuel prices are low (see Figures 7, 10 and 13). Third, except in the highest fuel-price scenarios, the economic potential for CHP in the Philadelphia region is substantially smaller than the technical potential. This conclusion suggests that additional policy measures to support CHP adoption (including the feed-in tariff policy option suggested by Siler-Evans et al, 2012) would need to be justified by further analysis of the social benefits of CHP in reducing greenhouse-gas emissions; improving local air quality; or improving the resiliency of electrical networks.

6. Conclusions

CHP represents a near-term solution to improve energy efficiency and reduce greenhouse gas emissions but its adoption has been slow for various reasons. The Philadelphia region has significant technical potential for CHP and with the recent development of Marcellus Shale, CHP could represent a substantial consumer of regionally-produced natural gas. While previous analyses have modeled the individual decision to adopt CHP based on electricity market prices and other relevant variables, our analysis utilizes a statistical model of electricity supply and pricing in the Philadelphia region is used to capture relevant feedbacks between adoption rates, electricity pricing and the economic viability of incremental CHP adoption. Marginal savings and marginal NPV curves were estimated for three gas price scenarios and two CHP operation strategies (i.e., CHP-FTL and CHP-FEL). The marginal savings and marginal NPV decrease as the number of CHP units increase for all three-gas price scenarios and two CHP operation strategies. This study suggests that the priority rankings for CHP deployment are important considering a large-scale adoption of CHP in a region. The results suggests that higher natural gas prices and hence higher electricity prices, is favorable for CHP adoption. Under a range of operational assumptions and fuel prices, substantial CHP deployment could be achieved without reducing returns to the point where existing and incremental CHP installations would become uneconomic. The results of this study leads to a number of policy related questions such as how the natural gas demand created by a large-scale deployment of CHP might affect regional natural gas prices, assessing the importance of CHP as a source of reliable power, the associated environmental benefits, and factors affecting individual decisions to install CHP.

Bibliography


