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Distributed cogeneration for commercial buildings: Can we make the economics work?

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ABSTRACT

Although the benefits of distributed cogeneration are widely cited, adoption has been slow in the United States. Adoption could be encouraged by making cogeneration more economically attractive, either by increasing the expected returns or decreasing the risks of such investments. We evaluate the expected returns from demand response, capacity markets, regulation markets, accelerated depreciation, pricing CO_2 emissions, and net metering. We find that (1) there is an incentive to overcommit in the capacity market due to lenient non-response penalties, (2) there is significant revenue potential in the regulation market, though demand-side resources are yet to participate, (3) a price on CO_2 emissions will make cogeneration more attractive relative to conventional, utility-supplied energy, and (4) accelerated depreciation is an easy and effective mechanism for improving the economics of cogeneration. We go on to argue that uncertainty in fuel and electricity prices present a significant risk to cogeneration projects, and we evaluate the effectiveness of feed-in tariffs at mitigating these risks. We find that guaranteeing a fixed electricity payment is not effective. A two-part feed-in tariff, with an annual capacity payment and an energy payment that adjusts with fuel costs, can eliminate energy-price risks.

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1. Introduction

Concerns over emissions and natural resources are causing many to rethink the century-old paradigm of centralized electricity generation. On average, fossil-fueled power plants in the U.S. have an efficiency of only 35%, with roughly 6% of the electricity lost across the transmission and distribution (T&D) lines (EPA, 2007; EIA, 2010a).

Cogeneration, or combined heat and power generation (CHP), has long been recognized as a more efficient alternative to central-station power. By generating electricity near customers and utilizing the co-produced heat, cogeneration can achieve net efficiencies in excess of 80% (Strachan and Farrell, 2006). Heat from cogeneration can also run an absorptive chiller to provide air conditioning. These combined cooling, heat and power (CCHP or *trigeneration*) generators have the flexibility to provide heating in the winter and cooling in the summer.

Recognizing the potential for efficiency gains, the U.S. Congress passed the Public Utilities Regulatory Act of 1978 (PURPA), clearing many of the regulatory barriers to cogeneration. Since then, cogeneration capacity grew four times faster than total U.S. capacity—from approximately 11 GW_e (gigawatt electric) in 1978 to 84 GW_e in 2010 (Energy and Environmental Analysis, 2010; EIA, 2010c; Lemar, 2001).

Despite steady growth, cogeneration plays a relatively minor role in the U.S., accounting for roughly 7.5% of total electricity supply (EIA, 2010b). Industrial cogeneration in the U.S. is estimated to be only one-half to one-third of the economical market potential (Lemar, 2001; RDC, 2003). Adoption is also well short of levels demonstrated in several European countries. For example, cogeneration accounts for more than 50% of electricity production in Denmark and 30% in the Netherlands (Riddoch, 2007).

Studies commonly cite regulatory and utility barriers as reasons for lower–than–expected adoption in the U.S. (see Alderfer et al., 2000). Alternatively, adoption of cogeneration may be low simply because it is not economically attractive. Some argue that this is the case because the benefits of cogeneration are not properly valued. For example, cogeneration may reduce CO_2 emissions and ease the burden on T&D networks, but these benefits are generally not rewarded (Costa et al., 2008; Stovall et al., 2005).

Several previous studies have evaluated the economics—and strategies for improving the economics—of cogeneration. In a comparison of distributed generation (DG) options across a range of building types, Medrano et al. (2008) found that absorptive chillers improved both the efficiency and the economics of CHP systems. Siddiqui et al. (2007) found that the value of CHP

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projects could be improved with low-grade heat storage. Lemar (2001) explores how different public policies and programs affect CHP adoption, estimating that aggressive policies could induce 70 GW_e of new cogeneration over 20 years. Strachan and Dowlatabadi (2002) compare CHP adoption in the Netherlands with that of the UK. While both governments had policies to promote DG, Strachan found that the Netherlands was much more successful due to (1) utility cooperation, (2) high buy-back rate for excess electricity (i.e., net metering), and (3) adoption of larger DG units that benefited from economies of scale. King and Morgan (2007) found that using cogeneration to serve small aggregates of customers, in what is called a "microgrid", has significant advantages compared to single-customer applications; these microgrids would be cost effective for many customer classes, under existing rate structures, in several regions of the U.S.

Building on the above literature, the goal of this work is to evaluate additional strategies for making cogeneration more attractive to potential adopters, either by increasing the expected revenue to decreasing the risks of such investments. Using a case study of a hypothetical hospital in New Jersey, we explore the value of: demand response, capacity markets, regulation markets, accelerated depreciation, pricing CO_2 emissions, and net metering. We go on to examine the effectiveness of feed-in tariffs at mitigating the risks resulting from uncertain energy prices.

The organization of this paper is as follows. Section 2 describes the case-study hospital and cogeneration equipment, Section 3 introduces several mechanisms for improving the economics of cogeneration, and Section 4 summarizes the mathematical model and key assumptions used in the analysis. Base-case results and a sensitivity analysis are presented in Section 5, strategies for increasing the revenue to cogeneration are presented in Section 6, and Section 7 evaluates the use of feed-in tariffs for mitigating energy-price risks. We conclude in Section 8.

2. Description of the case study

This analysis focuses on a case study of a hypothetical hospital in Newark, New Jersey. We evaluate the use of a 300 kW_e reciprocating engine for CHP and, in the case of CCHP, the same generator paired with a 260 kW_{th} (75 ton) absorptive chiller.

The location was chosen because it has a relatively high spark-spread (the difference between electricity and fuel prices), which is favorable for cogeneration. Previous analyses have shown that hospitals are good candidates for cogeneration (e.g. King and Morgan, 2007). Medrano et al. (2008) note that hospitals are both ubiquitous and energy intensive, representing 3% of all commercial floor space and more than 11% of commercial building energy use.

Currently there are approximately 320 cogeneration projects operating in the health services industry (Standard Industry Classification (SIC) code 80), 75% of which use reciprocating engines. Total CHP capacity in this industry is 730 MW_e, or about 10% of the estimated market potential (Energy and Environmental Analysis, 2010; Lemar, 2002).

2.1. Building energy demands

We use the Building–CHP screening tool (BCHP), developed by Oak Ridge National Lab, to generate hourly thermal and electrical demand profiles for the hospital (Oak Ridge National Lab, 2005). The BCHP tool estimates energy demands based on user inputs, such as building dimensions, location, and type (e.g. hospital, office, hotel, etc.). The peak and average energy demands for the simulated hospital are shown in Table 1. Thermal demand includes both space and water heating.

Table 1 also shows a comparison of energy intensities from the BCHP model and those from the Commercial Buildings Energy Consumption Survey (CBECS). The CBECS data are based on a 2003 nation-wide survey, which includes approximately 8000 inpatient hospitals (EIA, 2006). While the comparison shows close agreement for electrical and cooling demands, the heat intensity from the BCHP model is about half of the CBECS value. If in fact the BCHP model underestimates the buildings' heat demand, then results presented here will tend to underestimate the value of the cogeneration project.

2.2. Characteristics of the CHP unit

We select a 300 kW_e reciprocating engine for the case study. The generator was sized for base-load operation, where the unit runs at a high capacity factor with minimal load following.

Performance and cost characteristics for the generator are shown in Table 2. Note that the capital costs include interconnection costs, heat recovery equipment, and other installation costs. Variable operation and maintenance (O&M) does not include fuel costs, which are discussed in a later section.

2.3. Characteristics of the absorptive chiller

Heat from cogeneration can run an absorptive chiller—a heat-driven refrigeration cycle—to provide air conditioning. The cost and performance characteristics for the single-stage absorptive chiller are shown in Table 3. Also shown are the characteristics of a conventional, direct-expansion air conditioner, which we

Table 1
Energy demands of a hypothetical 22,300 m^2 (240,000 ft^2) hospital in Newark, New Jersey. The bottom half of the table compares the energy intensity from the BCHP model with values from the Commercial Buildings Energy Consumption Survey (EIA, 2006).

	Electrical demand (Non-cooling) (kW_e)	Thermal demand	
		Heating (kW_{th})	Cooling (kW_{th})
Average	712	312	490
Peak	993	1127	2209
	Electrical intensity ($kWh_e/m^2/yr$)	Thermal intensity ($kWh_{th}/m^2/yr$)	
BCHP model	280	122	192
CBECS	255	242[a]	160[b]

[a] CBECS Table E7A. Natural gas use was converted to thermal demand assuming a boiler/furnace efficiency of 0.8.

[b] CBECS Table E6A. Electrical use for cooling was converted to thermal demand for cooling assuming an electrically driven air conditioner with a coefficient of performance of 4.

Table 2
Performance and cost characteristics of 300 kW_e reciprocating engine (EPA, 2008). Costs in 2010 dollars.

Capital cost ($/$kW_e$)	2040
O&M variable ($/$MWh_e$)	16
O&M fixed ($/$kW_e$/yr)	7.4
Electrical efficiency	0.35
Thermal efficiency	0.44

Table 3
Performance and cost characteristics for conventional air conditioners and absorptive chillers. Costs in 2010 dollars. (adapted from Resource Dynamics Corporation, 2003).

Size (kW_{th})	Type	Capital cost ($/$kW_{th}$)	O&M ($/$kW_{th}$/yr)	COP
260	Conventional[a]	230	15	3.4
	Absorption	290	14	0.7

[a] Values for conventional air conditioners are the average of three technology types: air-cooled reciprocating, water-cooled reciprocating, and centrifugal.

assume is displaced when CCHP used. The costs of the two cooling technologies are comparable, though electrically driven air conditioners have a much higher coefficient of performance (COP).

3. Mechanisms for improving the economics of cogeneration

We use our case study to explore several existing and possible future mechanisms for increasing the revenue to cogeneration projects. A brief description of each follows.

3.1. Demand response (FERC Order 745)

In the spring of 2011, the Federal Energy Regulatory Commissions (FERC) issued Order 745, allowing "negawatts", or demand reductions, to compete with traditional sources of supply in wholesale energy markets (FERC, 2011).

Order 745 requires Independent System Operators (ISO) and Regional Transmission Operators (RTO) to compensate demand-side reductions at the marginal cost of energy. This requirement holds only in cases when demand response provides a net benefit to customers (i.e. reduced cost of electricity). The PJM interconnection, the ISO serving New Jersey, found that customers would benefit from demand response when locational marginal prices (LMP) exceed some threshold value—$35 to $40 per MWh depending on the month (PJM, 2011). Based on these threshold values and day-ahead LMPs, we estimate the benefit of demand response to a cogeneration project. Note that only excess generation capacity—beyond normal CHP/CCHP use—counts toward demand response.

3.2. Capacity markets

PJM operates a three-year forward capacity market (the *Reliability Pricing Model*) to ensure that there is sufficient generation to meet peak demand. Participating demand-side resources, such as cogeneration, are paid the auction-clearing price and are contracted to reduce load up to 6 h for no more than ten events during the contracted performance period (June through September three years following the initial auction). As with demand response, normal CHP/CCHP use is not considered a load reduction in the PJM capacity market; only excess generation capacity should be committed into the market.

We estimate the expected value of PJM's capacity market based on historic prices and the duration and frequency of historic reliability events (Appendix A).

3.3. Regulation markets

Generators providing regulation must accommodate the small imbalances between dispatched generators and the constantly changing load. Demand-side resources, such as cogeneration, are allowed to participate in PJM's regulation market if they are capable of responding to a regulation control signal from the system operator. We calculate the revenue from regulation services based on 2008 regulation market-clearing prices, which range from $8 to $590 per MW per hour (PJM, 2009).

3.4. Accelerated depreciation

The capital costs of a cogeneration unit would typically be depreciated over the useful lifetime of the generator, which we assume to be 15 years. Under the Energy Improvement and Extension Act of 2008, cogeneration now qualifies for 5-year depreciation, accelerating the tax benefit to the project owner.

3.5. Pricing CO_2 emissions

Lower CO_2 emissions are one of the commonly cited benefits of cogeneration. In most of the U.S., however, there is currently no financial reward for being a low-carbon technology. With a price on CO_2 emissions (e.g. a tax or cap-and-trade market), dirtier sources of energy will be penalized, giving a relative advantage to cleaner ones.

Europe implemented a CO_2 cap-and-trade program in 2005, with (Phase II) allowance prices averaging around €20 per tonne (metric ton) of CO_2 (Committee on Climate Change, 2008).

In the U.S., a coalition of Northeast and Mid-Atlantic states, including New Jersey, formed the Regional Greenhouse Gas Initiative (RGGI). The RGGI implemented a cap-and-trade program for CO_2 emissions in 2008. Prices from the RGGI auctions have been quite low, averaging around $2.40 per tonne of CO_2 (RGGI, 2010). Similarly, the price of CO_2 in the Chicago Climate Exchange was so low that the market closed in 2010.

We assume a hypothetical policy that prices CO_2 emissions at $20 per tonne, approximately the present price in the EU. Based on the average CO_2 emissions rate from PJM generators (0.6 t CO_2 per MWh_e (EPA, 2007)), we estimate that the retail rate of electricity would increase by approximately $12 per MWh_e. This estimate is quite simplistic. In reality the change in retail rates would depend on the marginal generators, which set the wholesale market price, and on the price elasticity of demand, which has generally been estimated as being very price inelastic (Azevedo et al., 2011; Newcomer et al., 2008).

Under the RGGI program, generators smaller than 20 MW_e would be exempt, giving small-scale cogeneration an advantage over large power plants. To level the playing field, we assume that a comprehensive CO_2 pricing program would also increase the price of natural gas to end-use customers. Based on an emissions rate of 181 kg per MWh_{th}, we estimate that natural gas prices would increase by approximately $3.60 per MWh_{th}.

3.6. Net metering (NM)

NM allows excess electricity from qualifying DG sources to be sold back to the utility. Previous studies have noted the benefits of net metering. For example, Carley (2009) found that NM programs "have a significant marginal effect on distributed generation adoption and deployment", though this study did not include cogeneration. Strachan and Dowlatabadi (2002) credit much of the Netherlands' success with cogeneration to their generous NM rates.

In New Jersey, and most of the U.S., natural gas-fired cogeneration does not qualify for NM (DSIRE, 2010). We evaluate the benefit of net metering assuming that excess electricity from cogeneration is credited at the full retail rate.

4. Model description and assumptions

Results presented here are the output of a Matlab model that estimates the cost-savings of cogeneration, which are assessed relative to conventionally supplied energy (i.e. utility-supplied electricity and natural gas-fired systems for space and water heating). An hourly optimization is used to minimize the cost of meeting the customer's energy demands, either through cogeneration, conventionally supplied energy, or a combination of the two.

Results are given in terms of the lifetime net present value (NPV) of the cogeneration project, based on a 15-year lifetime. The details of the optimization model are included in Appendix B.

4.1. Fuel and electricity prices

Previous work has shown that the economics of cogeneration are heavily dependent on fuel and electricity prices, both of which are highly uncertain over the lifetime of a cogeneration project. We explore the implications of three different energy-price scenarios:

1. Electricity and gas prices are assumed to follow forecast values from 2011 to 2026. Forecast values are taken from the Annual Energy Outlook for commercial customers in the mid-Atlantic region (EIA, 2010f).
2. Electricity and gas prices from a single sample year are assumed to repeat for the life of the cogeneration project. Prices are based on monthly-averaged rates for commercial customers in New Jersey, as reported by the Energy Information Administration (EIA, 2010b, 2010e).
3. A range of energy prices are explored using a Monte Carlo approach, which is based on a random sampling of historic natural gas and electricity prices from 1990 to 2009.

The intention with the Monte Carlo approach is to explore the implications of a wide but realistic range of energy prices. The simulation consists of the following steps: (1) fifteen years between 1990 and 2009 are randomly sampled (years are sampled independently with replacement), (2) energy prices from the sampled years are used to calculate the 15-year NPV for a cogeneration project, and (3) the process is repeated hundreds of times.

While samples are taken on a yearly basis, monthly fuel and electricity prices are used so as to capture seasonal fluctuations. Fuel and electricity prices are sampled as a pair so as to account for the cross-correlation between the two (e.g. high electricity prices are correlated with high fuel prices). Fig. 1 shows an example of fuel and electricity prices from one run of the Monte Carlo method (dashed line).

Each of the above approaches has some drawbacks. Projections of future energy prices are notoriously poor. Smil (2000) notes that energy forecasts have “missed every major shift of the past two generations”. Forecasts also fail to capture the seasonal fluctuations and the volatility seen in historic prices (Fig. 1).

Using actual energy prices from a recent year accounts for seasonal fluctuations but fails to capture year-to-year variations and long-term trends, which could be significant over a 15-year lifetime.

The shortcomings of the Monte Carlo approach are the assumptions that (1) the range of historic energy prices is representative of the range of future prices, (2) prices from any year between 1990 and 2009 are equally likely to occur in the future, and (3) prices in a given year are independent of prices in any other year.

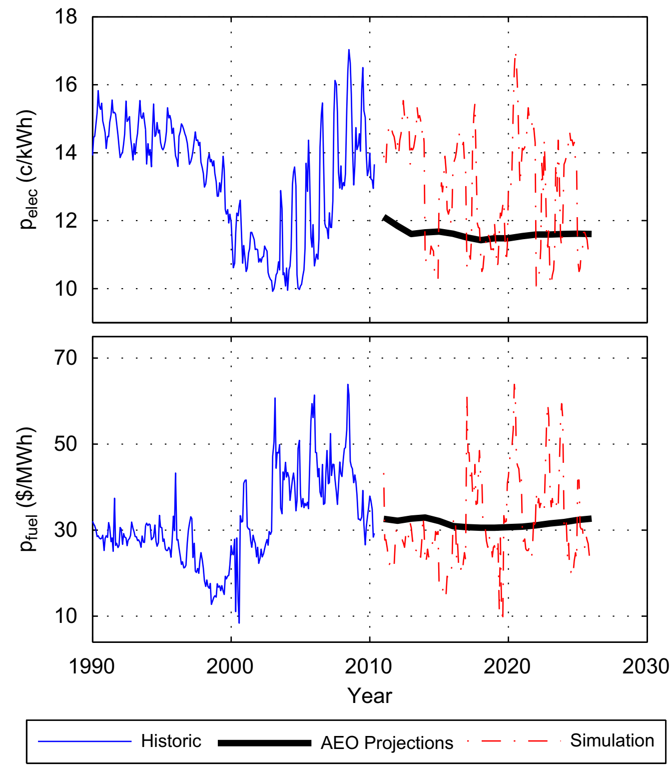

Fig. 1. Natural gas and electricity prices to New Jersey commercial customers from 1990 to 2010 (thin solid line), forecast energy prices for the mid-Atlantic region (thick solid line), and simulated energy prices based on a random sampling of historic energy prices (dashed line). All prices are in 2010 dollars.

Due to obvious concerns with these assumptions, we also explored forecasting future energy prices with autoregressive models (which have their own shortcomings), finding that results from the two methods agreed relatively well. We also note that energy prices, and price volatility, from the Monte Carlo method are reasonably consistent with past values and, in our opinion, give a plausible range for future prices.[1]

Historic and projected electricity prices from the EIA are reported as flat-rate energy charges (e.g. ¢/kWh). However, electricity tariffs for large commercial customers are not so simple. Prices generally have seasonal and time of day adjustments, as well as monthly capacity charges. We adjust the EIA flat-rate electricity prices to construct a more realistic electricity tariff, which is modeled after the 2008 Public Service Electric and Gas Company (PSEG) tariff for large commercial customers in Newark, New Jersey. Details on the adjusted tariff are included in Appendix C.

4.2. Financial parameters

Financial parameters are shown in Table 4. The discount rate is based on a weighted cost of capital, where we assume an 80% debt fraction at 7% interest rate and a 20% equity fraction with a

[1] Our sampling method gives mean electricity prices ranging from 120 to 140 \$/MWh$_e$ and gas prices ranging from 25 to 39 \$/MWh$_{th}$ (lowest and highest lifetime-average prices from 500 runs of the Monte Carlo approach). Using standard deviation as a measure of variability, we find reasonable agreement between the variability of historical prices and those from our sampling method. Based on 500 runs of the Monte Carlo approach, we find standard deviations in lifetime gas prices ranging from 4 to 13 \$MWh$_{th}$. The low end of this range matches the standard deviation of gas prices from 1990 to 1997, a period of stable prices. The high end of our range matches the standard deviation of fuel prices over the past decade.

Table 4
Financial parameters (values adapted from Lemar, 2001).

Project lifetime	15 yr
Federal income tax	35%
State income tax	5%
Property tax	1.5%
Depreciation (straight line)	15 yr
Insurance rate	0.5%
Discount rate	11.6%

30% return expected ($0.8\times 7\%+0.2\times 30\%=11.6\%$). In Section 5.1 we consider discount rates ranging from 6% to 30%.

5. Results: economic performance of cogeneration

Fig. 2 shows results for the base-case cogeneration project (i.e. without demand response, capacity markets, NM, etc.). Results from the Monte Carlo sampling of historic energy prices are shown as a cumulative distribution function (CDF). The expected value of the CHP and CCHP projects are \$13 and \$280 per kW_e with a 44% and 9% probability of a negative NPV.

On the low end of the CDFs are the cases when cogeneration is least attractive, when fuel prices are high and electricity prices are low; the worst-case scenario is an NPV of −\$620 and −\$537 per kW_e for the CHP and CCHP projects. At the high end, when fuel prices are low and electricity prices are high, the NPVs are \$623 and \$1,023 per kW_e. In all cases, the absorptive chiller is a cost-effective addition to the cogeneration project.

Also shown are results based on energy prices from a single sample year—either 2008 or 2009—with the assumption that first-year savings would be achieved annually for the life of the project. There is a wide difference in NPV depending on the base-year chosen for the analysis (from −\$620 to \$164 per kW_e for the CHP project). This emphasizes (1) the sensitivity of cogeneration to energy prices, which vary widely from year to year, and (2) the limitations of using a single sample year to calculate lifetime savings. The latter is a common practice. For example, Medrano et al. (2008) calculate payback periods assuming that “first year savings are achieved every year”, and King and Morgan (2007) use an analysis of 2003 to calculate energy savings over a 25-year lifetime.

Using AEO projected energy prices, the NPV of the CHP project is −\$500/kW_e. Overall, the base-case results show the expected returns are questionable and the energy-price risks are high, as evident by the wide range of the CDFs.

Note that the economics of cogeneration are case-specific because building energy demands, energy prices, and tariff structures differ widely across regions and customer types. Results from this case study may not be representative of other cogeneration projects. Rather, this case study is intended to provide a starting point for evaluating strategies for improving the economics of small-scale cogeneration.

5.1. Sensitivity

Results from a sensitivity analysis are shown in Fig. 3. We use the CCHP unit with 2009 energy prices as the base case, giving an NPV of \$490/kW_e. Parameters were varied individually to find the corresponding impact on NPV. From the base-case values, the thermal and electrical efficiency of the generator and the COP of the absorptive chiller were varied ±25%. The hospital size, capital cost of the generator, and capital cost of the absorptive chiller were varied ±50%.

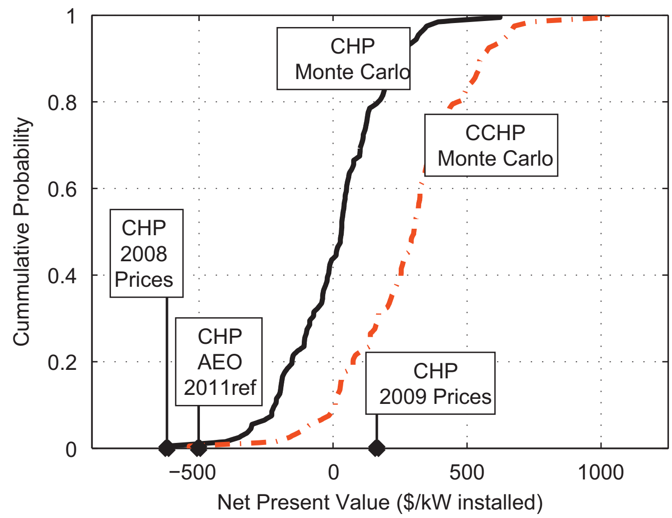

Fig. 2. Cumulative distribution function for net present value of the 300 kW_e cogeneration project. Results are based on (1) a Monte Carlo sampling of historic energy prices, (2) AEO energy price projections, and (3) energy prices from a single sample year—either 2008 or 2009—with the assumption that first-year savings will repeat for the life of the project.

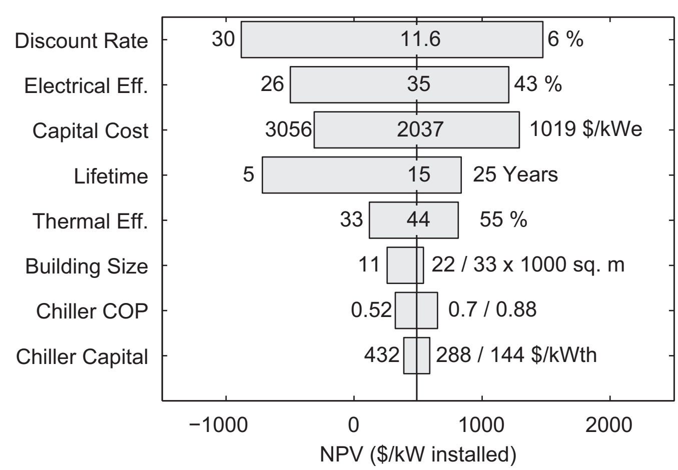

Fig. 3. Sensitivity analysis for CCHP unit with 2009 energy prices.

A wide range was selected for the discount rate, reflecting different ownership scenarios. At the low end, a 6% discount rate may be appropriate for a cogeneration project owned by a utility, which will typically have a low cost of capital (Crane et al., 2011). At the high end, a 30% discount rate reflects an internally financed cogeneration project for a customer with a high hurdle rate. With a similar rational, we consider project lifetimes from 5 to 25 years.

Under these assumptions, the discount rate, electrical efficiency, capital cost of the generator, and project lifetime are the most important parameters. Improving the COP of the chiller by 25% significantly outweighs a 50% cost increase, suggesting that a more efficient—and more expensive—two-stage chiller may be worthwhile.

Also of concern is the affect of energy prices. According to the EIA, supply from the Marcellus shale is expected to keep up with growing demand for natural gas, resulting in stable prices in the mid-Atlantic region (Fig. 1). However, we note that when natural gas prices were at a historic low in 1998, the EIA had a similarly sanguine forecast, which was followed by a decade of rising prices and high volatility.

In the future, a regulatory intervention to shale gas could limit supply and drive prices up. Alternatively, gas production could exceed demand, putting downward pressure on prices. Reflecting these possible extremes, we consider a wide range of gas prices.

Fig. 4 shows the NPV of the CCHP project for gas prices ranging $\pm$75% relative to 2009 prices (8.5 to 60 \$/MWh$_{th}$). Because electricity prices are often influenced by gas prices, we show scenarios where (1) electricity and gas prices change at the same rate (100%), (2) electricity prices change at half the rate of natural gas prices (50%), and (3) electricity prices do not change in response to gas prices (0%). We assume that only the energy charge for electricity changes, while the demand charge remains constant.

Historically, the correlation between commercial electricity and gas prices in New Jersey has been roughly 30% (dash-dot line). If this relationship continues, a 75% increase in gas prices will result in a 22.5% increase in electricity prices (75% $\times$ 30%), causing the NPV to fall from \$490 to $-$\$212 per kW$_e$. Similarly, a 75% decrease in gas prices would increase the NPV to \$1390/kW$_e$.

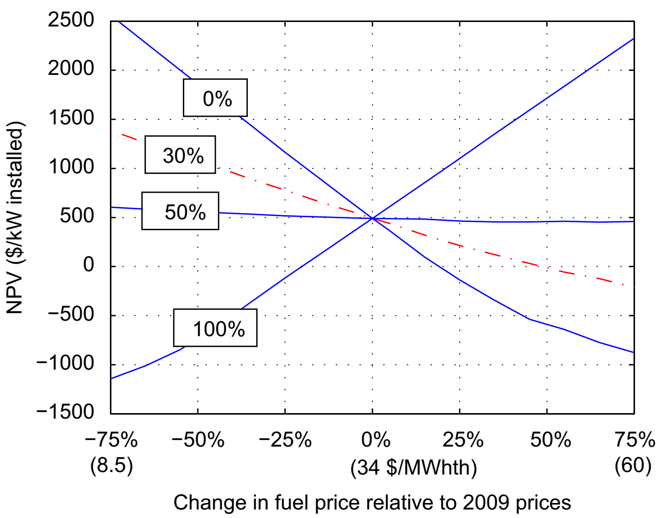

Fig. 4. Sensitivity of CCHP project to changes in fuel and electricity prices. Changes in fuel price are relative to 2009 (average gas and electricity prices of 34 \$/MWh$_{th}$ and 124 \$/MWh$_e$). Historically, the correlation between electricity and gas prices has been roughly 30% (dashed line). Also shown are scenarios where (1) electricity and gas prices change at the same rate (100%), (2) electricity prices change at half the rate of natural gas prices (50%), and (3) electricity prices do not change in response to gas prices (0%).

The economics of the CCHP project remain steady if electricity prices increase or decrease at approximately 50% the rate of gas prices.

6. Increasing revenue to cogeneration

Fig. 5 illustrates the value of five mechanisms for increasing the revenue to a cogeneration project. Using 2009 energy prices, the base-case NPVs are \$165 and \$490 per kW for the CHP and CCHP projects, respectively.

In this case, adding an absorptive chiller to the CHP project adds \$325/kW$_e$ to the lifetime NPV. This result is strongly dependent on the assumption the hospital would avoid the capital cost of a conventional air conditioner when adopting CCHP; without this assumption, the benefit of an absorptive chiller drops to \$164/kW$_e$.

The value of demand response is \$101 and \$64 per kW$_e$ for the CHP and CCHP projects. The benefit to the CHP unit is greater because the generator operates at a lower capacity factor, leaving more capacity available for demand response.

Demand reductions are measured relative to a baseline, which we calculate as the net electrical demand after normal CHP/CCHP use but before the demand response incentives. This baseline is consistent with the spirit of FERC Order 745. In practice, however, the baseline is calculated from historical demand data for the customer, and changes in the baseline will affect demand response payments.

Our case study understates the revenue potential of demand response, which is significant following FERC Order 745. The cogeneration unit in this analysis was sized for base-load operation; as a result, there is limited capacity available for demand response. It is likely that over sizing the generator and using excess capacity for demand response could further improve the economics of the cogeneration project.

Similarly, there is limited excess capacity available for the capacity market. However, demand-side resources are rarely called on (Appendix A) and non-response penalties are lenient. As a result, we find that there is an incentive to overcommit in the capacity market. For our case study, it is most profitable to bid the full 300 kW$_e$ into the market and incur non-response penalties when called on. Based on this strategy, the PJM capacity market adds about \$250/kW$_e$ to the lifetime NPV. The benefit of the capacity market is essentially zero if the customer takes the honest strategy, committing only what they are able to deliver.

Our assessment of regulation markets warrant a few caveats. First, our analysis did not account for the effect of ramping the

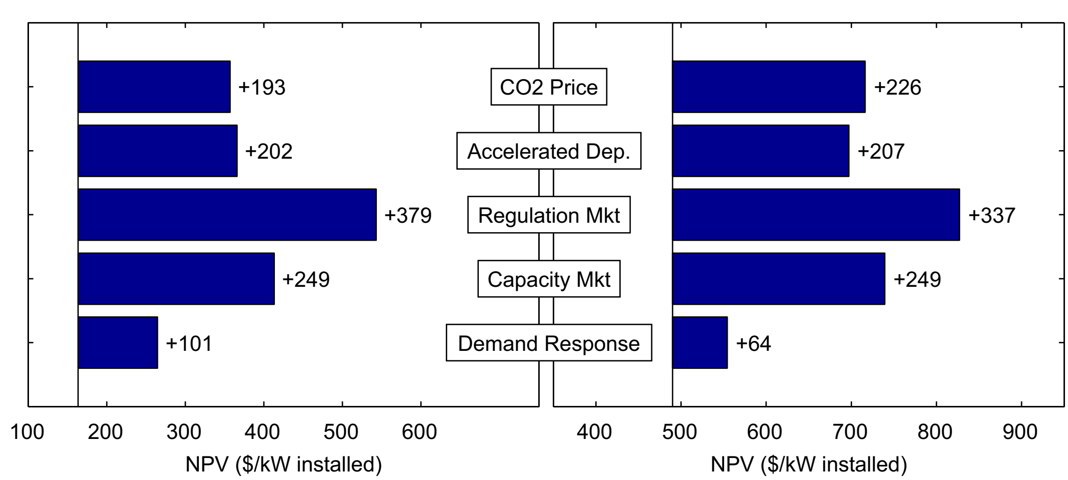

Fig. 5. Net present value of CHP (left) and CCHP (right) with the added benefit of demand response, capacity market revenue, regulation market revenue, accelerated depreciation, and a \$20-per-ton price on CO_2 emissions.

cogeneration unit up and down, which likely reduces the efficiency of the generator. Second, we constrained the amount of regulation to no more than 20% of the generator capacity; it is technically feasible to provide more regulation, but doing so may interfere with the use of cogeneration to meet the hospitals' energy demands. Third, our analysis did not account for the cost of an automated generation controller (AGC), which allows the generator to receive control signals from the system operator. Fourth, previous work suggests that regulation markets may quickly become saturated (see Kempton and Tomic, 2005). Advances in grid-scale battery technology, vehicle-to-grid power, or broad adoption of cogeneration could drive regulation prices down. On the other hand, increased use of intermittent renewables, such as wind and solar power, will likely increase the demand for regulation services.

That said, we find that the revenue potential from regulation markets is substantial—adding \$379 and \$337 per kW_e. However, not a single demand-side resource has bid into the PJM regulation market as of April 2011, though the market has allowed demand-side participation since May 2006. This suggests that there remains a significant barrier to using cogeneration in the PJM regulation market.

Accelerated depreciation increases the NPV by roughly \$205 per kW_e, though the benefit varies with the assumed discount rate. Based on a 6% discount rate, the value of accelerated depreciation is about \$150/kW_e. We believe that accelerated depreciation is a simple and effective mechanism for improving the economics of cogeneration. See Kranz and Worrell (2001) for a detailed analysis of the affect of depreciation schedules on CHP investments.

At \$20 per tonne, the benefit of pricing CO_2 emissions is \$193 and \$226 per kW_e. However, there is a negligible benefit to cogeneration if carbon prices remain at a few dollars per tonne CO_2, as currently seen in the RGGI market.

In this case, net metering was not beneficial, though this is not generally true. Strachan and Dowlatabadi (2002) found that net metering in the Netherlands "extended DG use to the much larger set of sites with limited electricity base-loads". We found that NM was beneficial for cogeneration when running the analysis with low-rise office and retail commercial buildings.

6.1. Economies of scale

We now expand that analysis to include generators of different types and sizes. Table 5 lists eleven generators—turbines, microturbines, and reciprocating engines—ranging in size from 30 kW_e to 40 MW_e. For each generator, the base-case hospital was scaled such that the cogeneration unit was sized for the base-load thermal demand, consistent with above analysis. The assumed hospital sizes are also shown in Table 5.

Table 5
Size and type of generators and assumed hospital size.

	Generator size (kW_e)	Hospital size (1000 m^2)
Turbines		
	5000	394
	10,000	787
	25,000	1580
	40,000	2257
Micro-turbines		
	30	2.5
	65	5.2
	250	17.8
Recip. engines		
	100	9.8
	300	22.3
	800	60
	3000	184
	5000	268

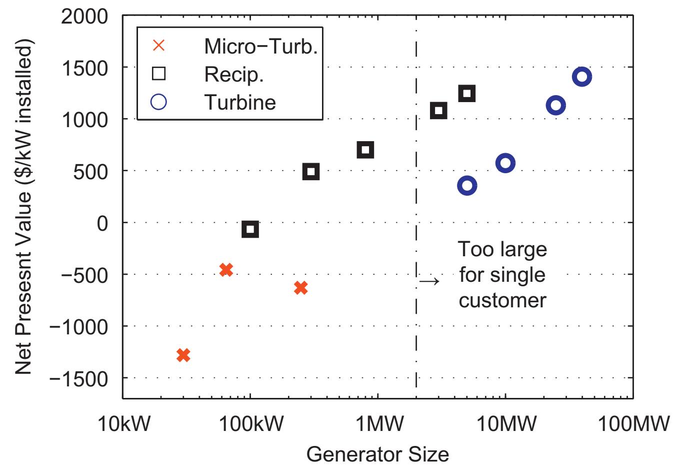

Fig. 6. Economies of scale for CCHP. Results are given as a function of generator size (log scale). Generators of more than several megawatts are unreasonably large for a single hospital but may be appropriate for a microgrid, which would serve a small aggregate of end users.

Aside from the generator and building size, the base-case assumptions are unchanged. Results, based on 2009 energy prices, are shown in Fig. 6 as a function of generator size (log axis).

There is a clear trend favoring larger generators, which tend to have lower unit costs and higher efficiencies (see EPA, 2008). However, it should be noted that some of the generators are far too large for a single hospital. The average hospital in the U.S. is approximately 7000 m^2 (75,000 ft^2)—appropriate for a baseload cogeneration unit of less than one hundred kilowatts. A very large hospital may exceed 100,000 m^2 ($\sim$one million ft^2), which could accommodate a generator of one megawatt or more.

Under the assumptions used here, a 5 MW_e reciprocating engine would operate in a building of approximately 270,000 m^2 ($\sim$3 million ft^2), which is unreasonably large for a single hospital.

One proposed strategy to expand the market for larger cogeneration projects is to allow a single generator to serve aggregates of multiple end-users, in what is called a *microgrid*. King and Morgan (2007) found that microgrids had a significant advantage over single-customer CHP, both because of economies of scale and because aggregating different building types helped smooth the demand profiles. Our analysis simply scales the demand profile for a single hospital. As illustrated in Fig. 6, larger generators outperform smaller ones even without the benefit of aggregating different building types.

These results suggest that microgrids may improve the economics of cogeneration. However, legacy distribution utilities enjoy "exclusive service territories" and as a result, microgrids are currently illegal, or their legal status is ambiguous, in most of the U.S. (King and Morgan, 2003).

7. Mitigating energy-price risks

In the previous section, we evaluated mechanisms for increasing the revenue to cogeneration projects. Many of these mechanisms would add to the expected value, thus making cogeneration more attractive to potential adopters.

However, we believe that energy-price risks remain a significant deterrent. Using a range of fuel and electricity prices, we found that the NPV of the CHP project ranges from −$619/kW to +623/kW (Fig. 2). This indicates that uncertain energy prices make cogeneration a very uncertain investment. In this section, we evaluate the use of feed-in tariffs for mitigating the energy-price risks to a cogeneration project.

Feed-in tariffs are a per kilowatt-hour payment for energy produced from qualifying sources. Payments are usually guaranteed for extended periods, thus protecting energy projects from price volatility (Mitchell et al., 2006). Feed-in tariffs have been widely used to encourage renewable energy resources such as wind and solar generation. While they have been successful, they are also controversial.

Opponents argue that feed-in tariffs are expensive and economically inefficient, requiring ratepayers or taxpayers to subsidize expensive energy projects. For example, German feed-in tariffs for solar are exceptionally lavish, paying six to eight times the market price of electricity (The Economist, 2010). On the other hand, advocates argue that fossil fuel sources have high externality costs, which society pays indirectly. For example, the health impacts from the dirtiest power plants cost an estimated 25 ¢/kWh (NRC, 2010). Better to fund clean energy, it is argued, than pay the health and environmental costs resulting from conventional energy sources.

Evaluating the costs, benefits, and efficiency of feed-in tariffs is beyond the scope of this study. Rather, we evaluate the effectiveness of feed-in tariffs at reducing the risks to a cogeneration project. We compare two feed-in tariff designs. The first is a fixed-rate tariff, which guarantees a per kilowatt-hour payment for all electricity produced from a cogeneration unit. The second is a two-part tariff that includes an energy payment, which adjusts with fuel prices, as well as an annual capacity payment.

7.1. Fixed-rate FIT

We set the first FIT to 12 ¢/kWh for the life of the project. The rate was chosen so as to equal the average retail rate from the sample period used in the Monte Carlo analysis (this is the average energy charge, which does not include the demand charge, as discussed in Appendix C). While the two rates do not have to be equal, this allows a fair comparison against the base-case results.

While the fixed-rate FIT eliminates all uncertainty with regard to electricity prices, it does nothing to account for volatile fuel prices. As shown in Fig. 7, the fixed-rate FIT does not effectively reduce the risks to the cogeneration project.

The FIT could be increased so as to guarantee a positive NPV. For our case study, this would require a FIT of roughly 15 ¢/kWh. Such a generous FIT is above the marginal operating cost of the generator, making it attractive to run cogeneration for straight electricity. Doing so reduces the net efficiency of the cogeneration unit. For example, the net efficiency of the generator is 79% (35% electrical+44% thermal); with a FIT of 15 ¢/kWh, the net efficiency drops to 64% (35% electrical+29% thermal).

At such efficiencies, combined-cycle power plants and high-efficiency furnaces would better achieve the goals of reducing emissions and increasing efficiency (Allison and Lents, 2002).

7.2. Two-part FIT

The second FIT we consider is a two-part tariff designed to eliminate the risks of volatile fuel prices. The FIT consists of an energy and capacity payment:

$$p_{FIT\_2} = \left(\frac{p_{fuel}}{\eta_{cogen}} - \frac{HPR}{\eta_{boiler}} p_{fuel} + V_{O\&M} \right) 1.1 \quad (\$/\text{kWh}) \tag{1}$$

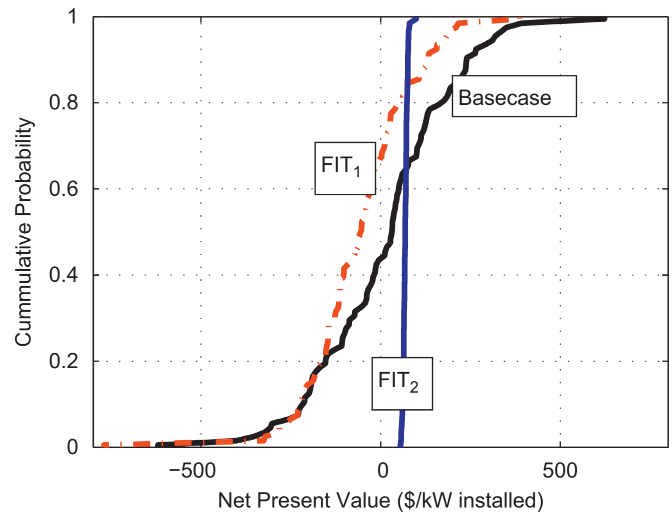

Fig. 7. Comparison of feed-in tariffs for cogeneration. FIT_1 is a fixed-rate tariff, which guarantees 12 ¢/kWh for the life of the project. FIT_2 is a two-part tariff that includes an annual capacity payment and an energy payment that adjusts with fuel price.

$$Payment(rate, \ lifetime, \ CapEx) + F_{O\&M} \quad (\$/\text{kW/yr}) \tag{2}$$

Eq. (1) gives the energy payment, where p_{fuel} is the cost of natural gas to commercial customers ($/MWh), η_{cogen} is the electrical efficiency of the generator, *HPR* is the heat-to-power ratio of the generator, η_{boiler} is the efficiency of the displaced boiler, and $V_{O\&M}$ is the variable operation and maintenance cost.

The energy payment is set 10% above the cost of running the generator if the co-produced heat can be used (i.e. the marginal cost minus the value of the co-produced heat). This gives a relatively low energy payment so as to discourage running cogeneration for straight electricity. The capacity payment (Eq. (2)) covers the fixed costs of the generator. The capacity payment is a function of the discount rate, project lifetime, capital cost of the generator, and the fixed O&M costs ($F_{O\&M}$).

With the two-part FIT, the NPV is unaffected by volatility in fuel and electricity prices, as shown in Fig. 7. The NPV is slightly above zero, meaning that the cogeneration owner gets a small profit beyond the 30% return on equity that was assumed in the discount rate. The two-part FIT also results in much higher efficiencies. With the two-part FIT, the average net efficiency is roughly 78%, compared to 65% for the other two cases shown.

For the two-part FIT, the average energy payment is 7 ¢/kWh and the fixed payment is $340/kW$_e$ annually. By dividing the fixed cost by the annual electricity production, we get an equivalent electricity cost of 12.8 ¢/kWh$_e$ (including the energy payment).

In this case, the equivalent energy cost of the two-part FIT is slightly higher than the other two cases shown. However, the cost of the FIT is strongly dependent on the discount rate used in the analysis. If a FIT can greatly reduce the risk of a cogeneration investment, then the cost of capital should decrease; banks may be willing to lend money at a lower interest rate or accept a higher debt-to-equity ratio, and the project owner may be willing to accept lower returns. Thus, a lower discount rate may be appropriate. The equivalent energy cost would also decrease with higher capacity factors because the fixed costs are spread over a greater number of kilowatt-hours.

Fig. 8 shows the equivalent energy cost for the two-part FIT across a range of capacity factors and discount rates. Our case study had a 67% capacity factor and a 11.6% discount rate,

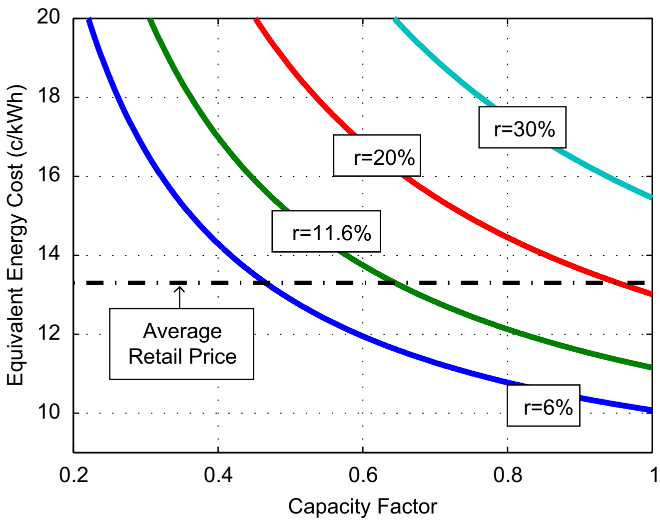

Fig. 8. Equivalent energy cost of two-part FIT for 300 kW_e CHP unit. Results are given across a range of discount rates and capacity factors. Fixed payments were converted to energy costs by dividing the fixed payments by the energy produced. Average retail price is that paid by commercial customers in New Jersey (EIA, 2010d).

resulting in an equivalent energy cost of approximately 13 ¢/kWh_e, roughly equal to the current retail rate. Fig. 8 shows that equivalent energy costs could quite reasonably drop below the retail price of electricity at higher capacity factors and lower discount rates.

7.3. Designing feed-in tariffs for cogeneration

The two preceding sections provided illustrative examples of two FITs applied to a single cogeneration project. In general, we offer the following suggestions for designing feed-in tariffs for cogeneration.

First, energy payments should adjust with fuel prices; without this adjustment, a FIT will not effectively reduce the risks to a cogeneration project.

Second, energy payments should not be too generous. Excessive energy payments may encourage the use of cogeneration for straight electricity, or encourage the adoption of low-efficiency cogeneration units. On the other hand, a FIT with low energy payments will be less effective at spurring adoption. The parameters in Eq. (1)—specifically *HPR* and η_{cogen}—could be adjusted to find a suitable balance.

Third, with low energy payments, a fixed capacity payment will be needed to make cogeneration economically attractive. The combination of an adjustable energy payment and fixed capacity payment can, if properly designed, completely eliminate the energy-price risks to a cogeneration project.

8. Conclusions

Based on a case study of a hospital in New Jersey, this paper evaluates strategies for improving the economics of small-scale cogeneration. We find that (1) an absorptive chiller was a cost-effective addition to the CHP project, (2) there is an incentive to overcommit in the capacity market due to lenient non-response penalties, (3) there is significant revenue potential in new demand-response programs (following FERC Order 745), though sizing cogeneration for base-load operation limits the excess capacity available for such programs, (4) there is significant revenue potential in the PJM regulation market, though demand-side resources are yet to participate, (5) a price on CO_2 emissions will make cogeneration more attractive relative to conventional, utility-supplied energy, and (6) accelerated depreciation is an easy and effective mechanism for improving the economics of cogeneration.

We argue that uncertainty in fuel and electricity prices present a significant risk to cogeneration projects. Feed-in tariffs are one proposed strategy for mitigating these risks. We find that guaranteeing a fixed electricity payment does not effectively mitigate energy-price risks. Further, an excessively generous feed-in tariff may encourage cogeneration to operate for straight electricity, potentially reducing the efficiency to the point that there is no longer a social-benefit argument for cogeneration. We show that a two-part feed-in tariff, with an annual capacity payment and an energy payment that adjusts with fuel costs, can eliminate energy-price risks.

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Appendix A. Expected value of capacity revenue

Table A1 shows annual auction revenues (AAR) from the PJM's capacity market, the *Reliability Pricing Model*. The weighted average AAR is approximately \$52,000 per MW per year. Demand-side resources that fail to respond to a reliability event are penalized one-fifth of the ARR per failure, but not more than the total AAR. We calculate the expected value of the ARR as follows:

$$EV(AAR) = \sum_{k=0}^{5}\left[P(non\text{-}response = k)\frac{5-k}{5}\right]AAR \tag{A1}$$

where k is the number of reliability events that the customer fails to fulfill their committed demand reduction. *P*(*non-response*) is the probability of such a failure, which we calculate based on the frequency and duration of historic reliability events (Table A2).

Table A1
Annual auction revenue (AAR) from PJM's capacity market (Bowring, 2009).

Delivery year	Capacity Region	AAR (\$/MW-yr)	Percent of annual total
2008–09			
	RTO	41,300	61%
	EMAAC	53,000	27%
	SWMAAC	66,800	12%
2009–10			
	RTO	37,200	43%
	MAAC+APS	68,800	45%
	SWMAAC	79,600	12%
2010–11			
	RTO	63,600	97%
	DPL	65,100	3%
2011–12			
	RTO	40,200	100%
Weighted average		52,000	

Table A2
Historic reliability events in PJM. Note that these events did not necessarily apply to the entire PJM interconnection, so the actual probability of DG being called on is less than estimated here (Walawalkar et al., 2010).

Year	Emergency events in PJM	Event durations
2000	2 (May 8th and May 9th)	5:10, 6
2001	4 (July 25th, August 8th, 9th and 10th)	3:56, 5:30, 6:30, 3:40
2002	3 (July 3rd, 29th, 30th)	6.4:50.6
2003	None	0
2004	None	0
2005	2 (July 27th, Aug 4th)	5:10, 2:45
2006	2 (Aug 2nd, 3rd)	6:33, 5:00
2007	1 (Aug 8th)	5:15
2008	None	0

Appendix B. Optimization of cogeneration use

We optimize the dispatch of the cogeneration unit to maximize the lifetime net present value (Eq. (B1)), which is assessed relative to the cost of conventional, utility-supplied energy:

$$NPV = -CapEx + \sum_{yr=0}^{14} \frac{\overbrace{TC_{conventional,yr} - TC_{cogen,yr}}^{\text{annual cost savings from cogen}}}{(1+r)^{yr}} \tag{B1}$$

$$TC_{conventional,yr} = \sum_{m=1}^{12} \sum_{h=1}^{n} \left[\frac{p_{fuel,m}}{\eta_{boiler}} H_{demand,m,h} + \cdots p_{elec,m,h}\left(E_{demand,m,h} + \frac{C_{demand,m,h}}{COP_{AC}}\right)\right] + Demand\ charge_{yr} \tag{B2}$$

$$TC_{cogen,yr} = min \sum_{m=1}^{12} \sum_{h=1}^{n} \left[\overbrace{E_{cogen,m,h}\left(\frac{p_{fuel,m}}{\eta_{cogen,m,h}} + V_{O\&M}\right)}^{\text{generator operating cost}} + \overbrace{\frac{p_{fuel,m} H_{boiler,m,h}}{\eta_{boiler}}}^{\text{boiler operating cost}} + \cdots + p_{elec,m,h}\underbrace{(E_{buy,m,h} + E_{buyAC,m,h} - E_{sell,m,h})}_{\text{utility-supplied electricity after NM}} - \underbrace{p_{reg,m,h}(R_{up,m,h} + R_{down,m,h})}_{\text{regulation payment}}\right] + Demand\ charge_{yr} - CapPMT_{yr} \tag{B3}$$

where

$$\eta_{cogen,m,h} = \eta_{peak}\left[\beta_0 + \beta_1\left(\frac{E_{cogen,m,h}}{E_{max}}\right) + \beta_2\left(\frac{E_{cogen,m,h}}{E_{max}}\right)^2\right] \tag{B4}$$

$$Demand\ charge_{yr} = \sum_{m=1}^{12} \underbrace{max(E_{buy,m,\forall h} + E_{buyAC,m,\forall h})}_{\text{monthly peak electricity demand}} DC_m \tag{B5}$$

subject to:

$$E_{cogen,m,h} + E_{buy,m,h} - E_{sell,m,h} = E_{demand,m,h} \tag{B6}$$

$$\underbrace{HPRE_{cogen,m,h}}_{\text{heat from cogen}} + \underbrace{H_{boiler,m,h}\eta_{boiler}}_{\text{supplemental heat from boiler}} \geq H_{demand,m,h} \tag{B7}$$

$$\underbrace{HPRE_{cogen,m,h}COP_{chiller}}_{\text{cooling from cogen}} + \underbrace{COP_{AC}E_{buyAC,m,h}}_{\text{supplemental cooling from AC}} \geq C_{demand,m,h} \tag{B8}$$

$$E_{cogen,m,h} + R_{up,m,h} \leq E_{max} \tag{B9}$$

$$E_{cogen,m,h} - R_{down,m,h} \geq E_{min} \tag{B10}$$

$$[E_{cogen,m,h},\ R_{up,m,h},\ R_{down,m,h},\ H_{boiler,m,h}] \geq \mathbf{0} \tag{B11}$$

Eq. (B2) is the annual cost of meeting the hospital's energy demands with conventional, utility-supplied energy. Eq. (B3) is the minimized cost of meeting the customer's energy demands with cogeneration. Eq. (B4) gives the electrical efficiency of the generator ($\eta_{cogen,m,h}$), which is adjusted from its peak efficiency (η_{peak}) when the generator operates at partial load (see EPA, 2008).

Eq. (B5) gives the annual demand charge, based on the hospitals monthly peak power demand and the utility demand charge.

Eqs. (B6)–(B11) give the constrains of the optimization problem. Eqs. (B6)–(B8) ensure that the customers' demand for electricity (E_{demand}), heating (H_{demand}), and cooling (C_{demand}) are met, either through cogeneration or conventional boilers or air conditioners.

Eqs. (B9) and (B10) ensure that the electrical output of the generator does not exceed the nameplate capacity or fall below some minimum threshold. Eq. (B11) simply ensures that variables are non-negative.

The optimization problem is solved for each hour for a fifteen-year lifetime (more than 130,000 h). Because the objective function is nearly always monotonic within regions of the feasible domain, we find the optimal solution by checking the transition points between regions. These points include (1) where the thermal output of the generator is equal to the thermal demand of the customer, (2) where the electrical output of the generator is equal to the electrical demand of the customer, (3) a constraint boundary, or (4) the generator is off. We verified a sample of the results using a mixed integer nonlinear programming method and found that the two methods agreed within a fraction of a percent. Each hour was solved independently and startup and shutdown costs were not accounted for.

Nomenclature:

$CapEx$	capital costs (\$)
$CapPMT$	annual auction revenue from PJM capacity market (\$/MW/yr)
C_{demand}	cooling demand (MWh_{th})
COP	coefficient of performance (conventional AC unit or absorptive chiller)
E_{buy}&E_{sell}	electricity bought from and sold to the utility (MWh_e)
E_{buyAC}	electricity bought for running conventional air conditioner (MWh_e)
E_{cogen}	electrical output of cogeneration unit (MWh_e)
E_{demand}	non-cooling electrical demand (MWh_e)
E_{min}	minimum operating load of generator (MW_e)
E_{max}	maximum generator output (MW_e)
h, m, yr	hour, month, year
H_{boiler}	heat output from conventional boiler (MWh_{th})
H_{demand}	heating demand (MWh_{th})
HPR	heat-to-power ratio of generator
p_{fuel} & p_{elec}	natural gas and electricity prices (\$/MWh_{th}&\$/MWh_e)
p_{reg}	regulation market-clearing price (\$/MW_e-h)
r	discount rate
R_{up}&R_{down}	generation dedicated into the regulation market (MW_e per hour)
$V_{O\&M}$	variable, non-fuel operation, and maintenance costs (\$/MWh_e)
β	coefficients for part-load efficiency curve
η_{boiler}	efficiency of conventional boiler
η_{peak}	peak electrical efficiency of cogeneration unit

Appendix C. Time-of-use and demand charges for utility-supplied electricity

Historic and projected electricity prices from the EIA are reported as flat-rate energy charges (e.g. ¢/kWh), which we adjust to

Table B1
Assumed electricity tariff. p_{EIA} is the energy-only price reported by the EIA, which is adjusted to account for the added demand charge as well as seasonal and time-of-use differences. The tariff was modeled after the 2008 PSEG tariff for large commercial customers.

	October–May		June–September	
	Energy (¢/kWh)	Demand ($/kW$_{peak}$)	Energy (¢/kWh)	Demand ($/kW$_{peak}$)
On-peak	$p_{EIA} \times 0.91 \times 1.03$	3.9	$p_{EIA} \times 0.91 \times 1.32$	7.2
Off-peak	$p_{EIA} \times 0.91 \times 0.77$		$p_{EIA} \times 0.91 \times 0.88$	

construct a more realistic electricity tariff. The adjusted tariff is shown in Table B1, where p_{EIA} is the energy-only electricity price reported by the EIA. Capacity charges were adopted directly from the 2008 Public Services Electric and Gas Company (PSEG) tariff for large commercial customers in Newark, New Jersey. Two adjustment factors are applied to the EIA energy price. The first adjustment factor (0.91) reduces the energy price to account for the addition of the capacity charges; the second factor adjusts the average price for time-of-use and seasonal differences.

As a check, we compare the adjusted EIA electricity prices with those from past PSEG tariffs. The adjusted EIA electricity prices based on this method are within 5% of the 2008 PSEG rates and within 1% of 2009 PSEG rates.

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