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Authors
Flores, Robert J
Shaffer, Brendan P
Brouwer, Jacob

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Economic and sensitivity analyses of dynamic distributed generation dispatch to reduce building energy cost

Robert J. Flores, Brendan P. Shaffer, Jacob Brouwer*

Advanced Power and Energy Program, University of California, Irvine, CA 92617, United States

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ABSTRACT

The practicality of any particular distributed generation (DG) installation depends upon its ability to reduce overall energy costs. A parametric study summarizing DG performance capabilities is developed using an economic dispatch strategy that minimizes building energy costs. Various electric rate structures are considered and applied to simulate meeting various measured building demand dynamics for heat and power. A determination of whether investment in DG makes economic sense is developed using a real-time dynamic dispatch and control strategy to meet real building demand dynamics. Under the economic dispatch strategy, capacity factor is influenced by DG electrical efficiency, operations and maintenance cost, and fuel price. Under a declining block natural gas rate structure, a large local thermal demand improves DG economics. Increasing capacity for DG that produces low cost electricity increases savings, but installing further capacity beyond the average building electrical demand reduces savings. For DG that produces high cost electricity, reducing demand charges can produce savings. Heat recovery improves capacity factor and DG economics only if thermal and electrical demand is coincident and DG heat is utilized. Potential DG economic value can be improved or impaired depending upon how the utility electricity cost is determined.

1. Introduction

Distributed generation involves the use of small-scale electrical generators to provide power at the point of use. Shifting from centralized generation to distributed generation provides numerous benefits to individual customers, utilities, and society as a whole, including the potential for increased system efficiency, reliability, and power quality, as well as reduced grid demand, delivery losses, central generation investment, maintenance, expansion, and emissions [1]. Despite these benefits, it is estimated that distributed generation accounts for less than three percent of all installed generation capacity in the United States, with distributed generation smaller than 1 MW accounting for less than 1% [2].

It has been argued that this may be due to electrical standby rates associated with distributed generation (DG), which can effectively increase the cost of utility-supplied electricity whenever a customer installs DG [3] and potentially limit the long term benefits of DG [4]. However, any decrease in profitability caused by such rate structures has only been shown to be prohibitive for those serviced by utilities with moderate to low congestion grids [5]. It has also been argued that the small DG market may be due to mandatory regulatory and interconnection requirements that must be satisfied before DG may be utilized [6]. Regardless of specific causes, the primary barrier for DG installation and use is its cost; as a practical matter, customers will not consider DG in the first instance if it is not shown to be profitable [5,6].

DG is currently not a practical option for everyone, even if it appears to be profitable on average. The practicality of DG depends upon the magnitude and coincidence of electric and thermal demand as compared to the dispatch and control capabilities of available DG systems. DG is typically a more attractive option for commercial and industrial sectors that may be subject to relatively high electric rates and may have coincident heat and power demand. For example, despite the significant variation in rates between regions and providers [2], in California, commercial and industrial customers paid an average of \$0.131/kWh and \$0.098/kWh, respectively in 2010 [7]. Under these circumstances,

Abbreviations: CHP, combined heat and power; DG, distributed generation; FC, fuel cell; GT, gas turbine; HR, heat recovery; ICBA, installed capacity over average building electrical load; ICBM, installed capacity over maximum building electrical load; MTG, microturbine generator; Non-TOU, non time of use; O&M, operations and maintenance; SCE, Southern California Edison; SCG, Southern California gas company; TOU, time of use.

* Corresponding author. Tel.: +1 949 824 1999; fax: +1 949 824 7423.
E-mail addresses: jb@apep.uci.edu, jbrouwer@uci.edu, jb@nfcrc.uci.edu (J. Brouwer).

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DG has the potential to reduce the amount spent on energy when properly matched to the needs of a customer.

Numerous forms of DG that use natural gas are available today. These technologies include small gas turbines (GT), microturbine generators (MTG), and fuel cells (FC) [8]. In addition to electricity, many of these technologies can provide a source of high grade heat for combined heat and power (CHP) [9–11]. They are also capable of providing base load and load following power [12,13] as well as cooling through the use of absorption chillers [14–16]. They can also provide power quality support when used in conjunction with proper power electronics [17].

Investment risks associated with DG include the high volatility of natural gas prices. Predictably, studies concerning the impact of fuel price uncertainty show that the risk of investment increases as the volatility of fuel price increases [18]. It has also been shown that payback is more likely to increase than decrease when faced with electric rate, fuel price, or capital cost volatility [19].

Multiple business models have been developed and presented to take advantage of DG technology in an attempt to create business prospects, including demand shifting, demand response, providing reserve power capacity, and grid balancing. It has also been suggested that the ability to sell and trade on a power exchange market, feed in tariffs, and stable regulations may further improve the business prospects of DG [20,21].

Studies on the economics of DG and CHP establish that detailed information regarding the electrical load, thermal load, characteristics of the DG source, and applicable electric rate structures are necessary to estimate the profitability of a project [22,23]. Further studies demonstrate that both FCs and MTGs are best suited for situations with a large and consistent electrical and thermal load as they take full advantage of all the products of the FC or MTG, and that for situations without a consistent thermal load, it is better to employ a generator with higher electrical efficiency [24,25] or to abandon attempts to recover heat in the DG system design [26]. It was also shown that buildings with low electrical load factors and large heating demand were well suited for GT installation [24].

The current analysis determines when investment in DG technology makes economic sense based upon these considerations and, in particular, includes the new consideration of dynamic dispatch to meet real building demand dynamics. Using previously developed utility rate structure and building energy demand models coupled with the current economic dispatch strategy, a parametric study was conducted to help determine when and why DG investment makes sense. The following parameters are varied in the current study: generator capital cost, generator size, electrical efficiency, operations and maintenance costs (O&M), generator turndown, and heat recovery ability. These parameters were selected due to the significant impact they have on DG investment and DG operation. In addition, there are various DG technology options available on the market today (e.g., microturbine generator, fuel cell) that an investor can select with various values for these parameters. The cost of electricity and fuel also influence the decision to purchase and operate DG. However, it is unlikely that an individual investor can vary the cost of electricity or fuel beyond selecting a service rate provided by the applicable utility.

Only natural gas fired DG with the capability of supplying electricity and heat were considered as they involve less mechanical complexity and cost than systems that also provide cooling, reducing investment risk. Models of electric and natural gas utility rates in Southern California developed by Flores et al. [27] were used. Electric standby rates were included in the analysis. Real electrical and heating load data were extracted from various buildings located throughout Southern California and used to simulate industrial and commercial facility operations. A simple yet effective economic dispatch strategy presented by Flores et al. [27] was applied to the various building models. The cost of supplying building energy using DG and utility energy was then compared to the cost of building energy using only utility supplied energy, allowing for financial analysis of DG investment. Results from the study for generators supplying electricity only and generators supplying electricity and heat are provided. Finally, the effect of switching to the parent rate structure from the standby rate structure is discussed.

2. Models

2.1. Electrical rate structure

Electric rate structures are typically broken down into fixed, energy (aka volumetric), and demand charges. The methods by which these charges are calculated vary amongst utilities and rate structures (e.g., time of use, declining block, and fixed rate). As a result, the calculation of utility costs can vary drastically between utilities and depend strongly upon the specific tariffs that are applied. It is therefore important to capture the general characteristics of an electric rate structure and how it functions as a whole, as opposed to specific individual charges associated with a particular rate structure.

For example, some common rate structures can be broken down into non-time of use (non-TOU) and time of use (TOU) components. Individual charges can change between seasons, with the season that contains highest total utility demand typically comprising higher charges. Non-TOU energy charges consist of a flat rate that applies to all of the energy consumed by a customer while non-TOU demand charges are determined by the largest load recorded for that billing period. As for TOU energy charges, these typically depend upon the time of day in which the energy is consumed. TOU energy rates are generally highest during periods of high demand ("on-peak"), lower for periods of moderate demand ("mid-peak"), and lowest during periods of low demand ("off-peak"). Concerning the demand charges, TOU demand charges are typically determined by the largest demand that is recorded during a specific time period (i.e., time of day) during the billing period.

The electrical rate structures used in this work were based upon the structures used by Southern California Edison (SCE). SCE rate structures for commercial and industrial buildings have TOU energy charges and both non-TOU and TOU demand charges. Energy and demand charges are increased during summer months. For customers with DG, standby rates apply. These rates only affect demand charges and can be broken down into two charges: standby or backup charges which are applied to demand that could be met onsite but is purchased from SCE, and supplemental charges which are applied to demand that surpass onsite capacity and must be purchased from SCE. In addition to being determined by maximum utility demand, standby demand charge rates are also determined by the time of day when maximum utility demand occurs. All SCE utility rates used are further described by Flores et al. [27].

2.2. Natural gas rate structure

Natural gas utilities usually sell their gas in a block structure. These block structures can have a single price for all gas used or comprise up to a three tiered declining block structure, with gas typically becoming progressively cheaper as the customer reaches each new tier. The standard charge is in dollars per therm (unit of heat equivalent to 100,000 BTUs or 1.055×10^8 J). Southern California Gas Company (SCG) is a major provider of natural gas to most customers in southern California, providing a declining block structure for commercial and industrial users. Like many natural gas utilities, SCG's rates take into account the distribution and fuel costs. While distribution costs have been observed to be

Table 1
Main characteristics of acquired building data.

Building name	Building type	Annual average electric load (kW)	Average monthly electric load factor	Average monthly heating (Therms)	Coincident electrical & heating demand (%)	Annual electric utility bill	Average cost of electricity ($/kWh)	Annual natural gas utility bill	Average natural gas price ($/Therm)
UCI Croul	College/ University	201	0.604	2301.4	58.18	$172,544	$0.1065	$8750	$0.5594
US Navy Palmer Hall	Hotel	203.9	0.749	1111.8	95.14	$189,351	$0.0965	$17,166	$0.5956
UCI Bren	College/ University	206.7	0.607	1197.9	34.06	$185,917	$0.1040	$9419	$0.5897
UCI Cal IT^2	College/ University	420.8	0.621	4217.7	14.18	$407,971	$0.1097	$29,203	$0.5193
UCI Natural Science 2	College/ University	447.8	0.611	7761.3	19.60	$430,361	$0.1087	$47,616	$0.4601
UCI Natural Science 1	College/ University	505.7	0.611	6413.3	94.08	$488,402	$0.1120	$40,705	$0.4760
Hyatt Irvine	Hotel	719.2	0.707	13,321.5	99.94	$663,527	$0.1050	$76,685	$0.4317
SCAQMD	Commercial	1011.6	0.570	28,615.3	59.57	$1,016,567	$0.1121	$152,346	$0.4265
St. Regis	Hotel	1367.4	0.740	14,814.1	99.85	$1,225,126	$0.1010	$84,492	$0.3993
Patton State	Hospital	1679.4	0.651	41,393.1	72.79	$1,670,208	$0.1066	$157,895	$0.3979
Loma Linda VA	Hospital	3089.4	0.789	66,474.3	94.74	$2,709,063	$0.0926	$328,076	$0.3949
Long Beach VA	Hospital	3510	0.726	46,819.5	53.76	$3,198,359	$0.1019	$240,892	$0.3921

relatively stable for SCG, fuel costs regularly change depending upon the market price of natural gas. As a result, while natural gas rate structures are relatively simple, changes in fuel cost cause regular variations and introduce uncertainty in customer prices. Prior work has shown that fuel price has a large impact on distributed generation economics. However, due to increased reserves and production of natural gas, prices have been "depressed. . . to the lowest levels in a decade" [28], leading to price projections that remain low in the near future [29]. While energy price projections have been shown to be inaccurate [30], a distributed generation investment that pays back in a reasonable time period should reduce the risk of exposure to natural gas price volatility. As a result, the natural gas rate model used in the current work will follow SCG prices effective June 10th, 2012. This rate structure is as follows: $0.81115/therm for the first 250 therms, $0.56622/therm for the next 3917 therms, and $0.402/therm for all subsequent therms.

2.3. Building models

Building models were developed using electrical load data showing energy consumption in 15 min increments acquired from 39 buildings throughout Southern California, 12 of which had corresponding thermal loads [31]. The captured building data was used directly as building energy models. These buildings were selected for energy monitoring because they represent possible candidates for DG and CHP installations [31]. The electrical data was collected via utility records or an energy management system. Two buildings did have electrical meters installed onsite, but these buildings did not have corresponding thermal loads and were excluded from this study. The thermal loads were determined by using a combination of resistance temperature detectors and ultrasonic flow meters or thermal mass flow meters [31]. Full details on why and how the building energy data was gathered can be found in [31]. Four of these buildings were described previously by Flores et al. [27], and the remaining eight buildings are described in Table 1 and Fig. 1. All 12 building models were used in the parametric study.

Table 1 shows the average electrical load for the year, the average monthly electrical load factor (ratio of average electrical demand and maximum electrical demand), average monthly heating (the average number of therms used for heating per month), the amount of time that both electrical and heating load are coincident (percent of the year that electrical and heating loads occur simultaneously), the annual electric utility bill and average electricity cost using the utility rate and costs presented in Section 2.1, and the annual natural gas utility bill and average natural gas cost using the utility rate and costs presented in Section 2.2. All buildings monitored experienced typical diurnal load behavior, with the highest demand being experienced during on or mid peak periods. Notice that the annual cost of electricity for all buildings is significantly higher than the annual cost of natural gas, highlighting the fact that an equivalent amount of electrical energy is more expensive than natural gas. The coincidence between electrical and thermal demand can also be seen in Fig. 1, ranging from the large and consistent thermal demand for Long Beach VA Hospital to the smaller and less consistent thermal demand for UCI Nat Sci 2.

Data for three of the 12 buildings includes more than 12 months of data (US Navy Palmer Hall: 14 months, Patton State Hospital: 14 months, and Long Beach VA Hospital: 13 months) while one included less than 12 months of data (Loma Linda VA Hospital: 10 months). All eight other data sets have 12 months of energy demand data. Under Southern California Edison rate structures, the summer and winter seasons consist of four and eight months respectively, resulting in a ratio of one summer month to every two winter months. Thus, an economic analysis must consider the ratio of summer to winter months and must be corrected if the recorded building data does not match this seasonal ratio. If this is not accomplished then the cost of electricity can be improperly skewed; extra winter months would depress total potential savings while extra summer months would inflate potential savings if not allocated exactly as they are in the rate structures considered. As a result, additional representative summer and winter months were added to the four building data sets that have more or less than 12 months of energy demand data to create the proper ratio between summer and winter months.

2.4. Economic dispatch strategy

Many prior studies have examined the effect of different dispatch strategies on DG economics. Researchers have examined the effects of electric load following, thermal load following, base-load operation, and other dispatch strategies [11,25,32–34] as well as dispatch schedules determined through optimization [35,36]. Other efforts have focused on optimization methods that determine the DG installation size as well as the DG operation to minimize total cost [5,24,26,37–42]. The current dispatch strategy used for this study is the economic dispatch strategy presented in [27].

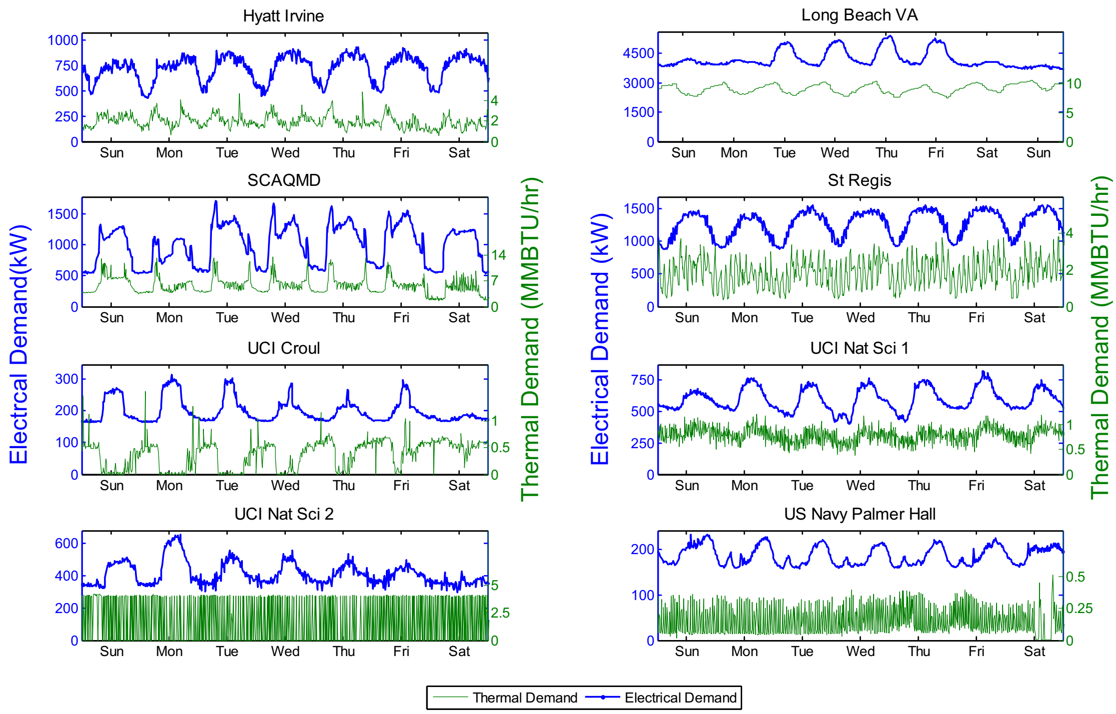

Fig. 1. Representative week of electrical and thermal demand for captured building data.

Table 2
Description of parameters used in the economic dispatch strategy.

Parameter	Description
$Cost_{kWh}$	Cost to produce an electric kWh using DG ($/kWh)
η_e	Rated electrical efficiency of DG
η_t	Percent of fuel energy converted into useable heat
ε_{hr}	Effectiveness of heat recovery from DG
ε_b	Thermal efficiency of boiler
$Cost_{NG}$	Cost of utility natural gas ($/Therm)
$Cost_{O\&M}$	O&M cost of DG ($/kWh)
$Cost_{HR\ O\&M}$	O&M cost of heat recovery ($/kWh)
$Cost_{Boiler\ O\&M}$	O&M cost of boiler ($/kWh)
C_1	Conversion from fuel unit of energy to kWh (kWh/Therm)

The current dispatch strategy differs from simple strategies (electric load following, thermal load following, base-load, etc.) because the economic dispatch strategy dispatches DG when building energy costs are reduced. The current dispatch strategy also differs from optimization methods for two fundamental reasons; the current economic dispatch strategy does not utilize optimization methods, and the current economic dispatch strategy does not need prior knowledge of building energy demand to minimize cost – it is a real-time strategy. While the current economic dispatch strategy cannot quite dispatch DG "optimally", a large portion of the energy savings produced through optimal methods (>90%) can be realized using the current economic dispatch strategy as shown in [27]. In addition, since prior knowledge of building energy demand is not needed, the current economic dispatch strategy can dynamically reduce the cost of building energy in real time. While other optimal dispatch strategies can also dynamically optimize DG operation (see e.g., [35]), the current economic dispatch strategy is simple yet effective.

This dispatch strategy performs four separate functions in order to minimize cost of electricity. Parameters used in the description of the current economic dispatch strategy are shown in Table 2. First, the strategy minimizes demand charges by establishing a demand threshold, and operating DG to stop building electrical demand from surpassing the demand threshold. If the building demand surpasses the demand threshold plus the maximum DG output, additional demand is purchased from the utility, raising demand charges and the demand threshold for the rest of the billing period. Second, if standby electric rates apply, demand shifting occurs by allowing off-peak electrical demand to increase beyond the demand threshold, shifting maximum utility demand to off-peak and demand charge rates to off-peak rates. Third, if demand shifting is not being performed and electrical energy can be produced onsite at a lower cost than available from the utility, DG is used to produce electrical energy. The cost to produce electrical energy is determined by Eq. (1), which includes both fuel and operations and maintenance (O&M) costs.

$$Cost_{kWh} = \frac{C_1 \times Cost_{NG}}{\eta_{elec}} + Cost_{O\&M} \tag{1}$$

Fourth, if demand shifting is not being performed, Eq. (1) is greater than utility electrical energy prices, and building thermal demand exist, DG is used to produce electrical and thermal energy if the cost to produce electrical and thermal energy onsite is less expensive than the otherwise necessary grid electricity and boiler operation required to meet both building electrical and thermal demand. The cost to produce electrical and thermal energy onsite is determined by Eq. (2) which includes fuel and O&M costs for DG operation, as well as the value of the captured heat and the difference in O&M cost for DG heat recovery equipment and a boiler.

$$Cost_{kWh} = \frac{C_1 \times Cost_{NG}}{\eta_e}\left[1 - \frac{\eta_t}{\varepsilon_b}\right] + Cost_{O\&M} + \frac{\eta_t}{\eta_e}\frac{1}{\varepsilon_b}(Cost_{HR\,O\&M} - Cost_{Boiler\,O\&M}) \tag{2}$$

The current economic dispatch strategy is explained in further detail by Flores et al. [27].

The current dispatch strategy assumes that electricity can only be imported, resulting in no DG operation if such operation results in electrical export. The current dispatch strategy produces an operating schedule resolved to 15 minute increments since SCE determines demand charges based off of the buildings highest 15 minute average demand.

2.5. Finance Model

A finance model was developed in order to determine the appropriate cost of capital associated with investment in DG, track the cumulative costs of energy, and find when the cash flow of the investment turns positive in order to determine the economic value of DG investment. The economic value of DG is determined by comparing the savings produced from DG operation to the investment required to purchase the DG.

It was assumed that the loan would cover 80% of the purchase cost of the equipment and that the other 20% would be funded directly by the investor with the monthly payment determined by the following equation:

$$\text{Monthly Debt Payment} = \frac{\text{Principal} \times i}{1-(1+i)^{-n}} \quad (3)$$

where i is the interest rate and n is the debt term. For this study, the interest rate was set to 8% and the debt term was set to 10 years.

Energy cost savings are determined by comparing the baseline (no DG) cost of energy to DG cost of energy. Cost of energy consists of payments to the electric and natural gas utility, with O&M and monthly debt payment included for all DG cases.

Many investment criteria exist for judging the quality of DG investment [43]. One basic criterion is determining when cash flow turns positive (or payback period), which estimates the amount of time required for savings produced by DG to equal the initial investment. While other criteria can include the time value of money, continued financial performance of an investment after payback has been achieved, and associated risk of investment, payback period provides a simple minimum criterion that can gauge strength of DG investment potential; other criteria do not give positive investment reviews unless payback occurs in a timely manner. Payback period is used as criteria to judge the economic value of DG in this study.

3. Parametric study

Focusing on a single generator can help to illuminate the possible economic performance characteristics associated with the proposed dispatch strategies as applied to a particular generator. However, other commercially available technologies have different performance and financial characteristics [8] that could change the conclusions of economic analysis associated with them. With a need to understand the economics of DG technology in general as opposed to the economics associated with a single generator type, a parametric study was first developed to explore the effects of changing the various performance and financial characteristics of the DG system. The parameters that were varied in the parametric study are generator capacity, generator electrical efficiency, generator turndown, capital cost, and cost of O&M. By adjusting these parameters, the economic performance characteristics of a wide variety of DG technologies can be assessed. The current generic analyses can be followed by analyses of a particular building with more advanced models of particular generators and related technologies as desired.

Various sizes of MTG, GT, and FC systems are commercially available with others being developed. Electrical efficiency varies amongst these systems, with increases in efficiency being projected for most future models. Generator turndown is the ability of DG to operate at part load (e.g., a turndown of 20% translates to a generator that can operate between 80% and 100% of full power or be shut down) can be affected through either generator improvements that maintain performance at part load or by investing in more than one generator. For example, if two microturbines are purchased, one generator can be operated while the other remains non-operational, with the effective turndown of the total onsite generation being over 50%. O&M and capital costs also vary amongst the different models, with costs projected to decrease if further market penetration is achieved. While the portion of capital cost associated with the purchase price of a specific generator is well defined, the portion of capital cost associated with installation labor, materials, construction management, and other fees can vary depending on the complexity of installation; capital costs can be significantly increased if the installation of the generator is difficult. Similarly, O&M costs may contain additional charges, such as the departing load charge used by Southern California Edison, that increase O&M charges beyond what is required to meet basic O&M costs [8]. The parameter ranges were selected based on reports of current and projected DG capabilities [8,9]. The selected parameter ranges encompass typical gas turbine, microturbine, reciprocating engine and fuel cell system values for these parameters. The parameters listed below were varied over the following ranges in the parametric study:

- Generator capacity: 20%, 40%, 50%, 60%, and 80% of maximum building load
- Electrical efficiency: η_{DG} = 23% to η_{DG} = 50%
- Generator turndown: $\text{generator}_{\text{turndown}}$ = 20% to $\text{generator}_{\text{turndown}}$ = 80%
- O&M: $\text{cost}_{\text{O\&M}}$ = \$0.01/kWh to $\text{cost}_{\text{O\&M}}$ = \$0.045/kWh
- Capital cost: cost_{kW} = \$400/kW to cost_{kW} = \$5000/kW

The parametric study is performed by determining the cost of building energy when no DG is used, defining the generator characteristics using the parameters described above, dispatching the DG using the defined characteristics, determining the cost of building energy when using DG, followed by using the financial model to determine the economic performance of the DG. This process is performed for all generator capacity, electrical efficiency, generator turndown, O&M, and capital cost combination for the 12 building models.

4. Results and discussion

The results presented in this paper are specific to the building and DG combinations examined under the specific utility rate structures assessed. However, the DG parameters selected span most available technologies, and the captured building data represent a wide range of building types and load profiles. In addition, the rate structures included are typical of those used around the world. As a result, DG would perform similarly at other buildings if the building energy profile falls within the span of the building energy profiles used in this study and the utility rate structures are similar in magnitude and structure.

4.1. DG supplying electricity only

4.1.1. Efficiency, O&M, and fuel cost effects

The influence of electrical efficiency, O&M, and fuel cost effects are explored in this section for a fixed generator capacity relative to each building load. All installed systems were sized to approximately meet 50% of the maximum building load (165 kW for UCI Bren, 345 kW for UCI Natural Science 2, 850 kW for SCAQMD, and 1300 kW for Patton State Hospital), have a 20% turndown, and have a capital cost of \$2400/KW. Results for UCI Bren, UCI Natural Science 2, SCAQMD, and Patton State Hospital are shown because results from these buildings are representative of results from all 12 buildings. Capacity factors for UCI Bren and Patton State Hospital

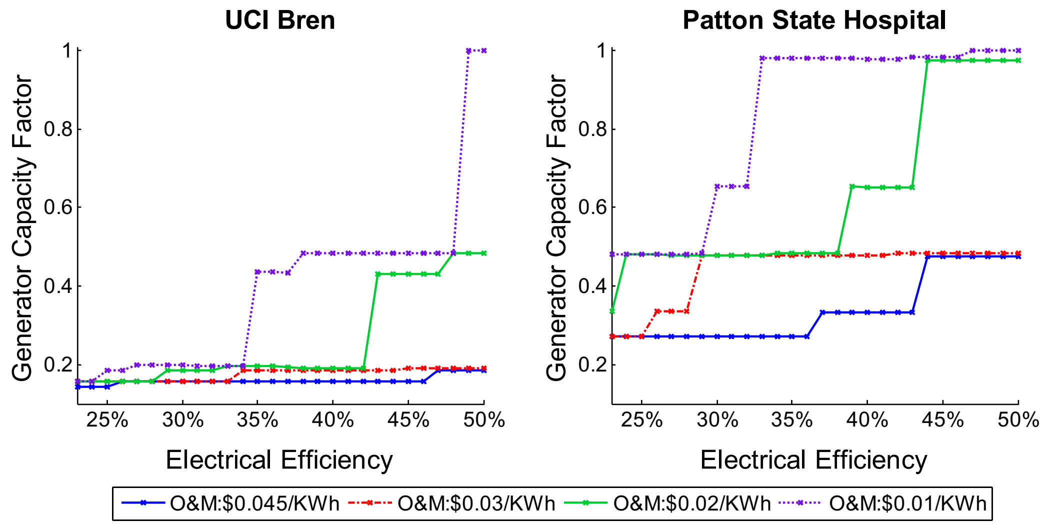

Fig. 2. Capacity factor for (a) UCI Bren and (b) Patton State Hospital using economic strategy. Installed systems are sized to 50% of average building load.

buildings (using measured annual building data) for the current economic dispatch strategy and a generator sized to half the average applicable building load are shown in Fig. 2 as a function of DG electrical efficiency for various O&M charges. Predicted payback for the system installed at UCI Bren versus electrical efficiency and O&M is shown in Fig. 3, as well as the reduction in payback for UCI Natural Science 2 and SCAQMD buildings compared to UCI Bren.

Economic DG operation occurs when the cost of energy for a building can be reduced. Demand charges tend to be sufficiently large that demand charge reduction occurs regardless of the cost of producing energy onsite. However, savings from reduced demand charges decrease if grid electricity is replaced with more expensive electricity generated onsite. During periods when demand reduction is not needed, energy replacement using DG occurs only when energy produced onsite is less expensive than what can be purchased from a utility. In contrast with demand charge reduction, energy replacement dispatch can only occur when the efficiency, O&M cost, fuel cost, and the cost of grid electricity dictate that DG energy is cheaper than grid electricity (and natural gas for heating, when applicable). The capacity factor of an installed system depends upon how much these cost reducing activities can be performed. Notice in Fig. 2 that the capacity factor for all systems is lowest when DG efficiency is low, with demand reduction being the only cost reduction activity available to DG systems with low electrical efficiency. While increasing efficiency reduces operating costs for the DG, the cost of electricity is not continuous and an increase in efficiency does not translate into a linear increase in capacity factor. Rather, for each electrical peak period, an efficiency target must be met in order for energy replacement to become economically viable. This efficiency target is determined by the minimum electrical efficiency required for a generator to produce electricity at a lower cost than what is available from the electric utility. This target is found for a fixed O&M cost for every on-, mid-, and off-peak period. Prior to reaching this efficiency target, increases in efficiency only improve savings during peak periods where energy replacement was already possible. Energy replacement for other periods, however, is not allowed until the applicable efficiency target is surpassed. Once this target has been surpassed, energy replacement is possible for the entire new period, leading to a step increase in capacity factor observed for both building cases of Fig. 2.

The efficiency target for the winter mid-peak electricity price condition is shown in Fig. 4 as a function of O&M costs for various natural gas prices.

A system that does not meet the target presented in Fig. 4 for a given fuel and O&M cost can still potentially provide energy

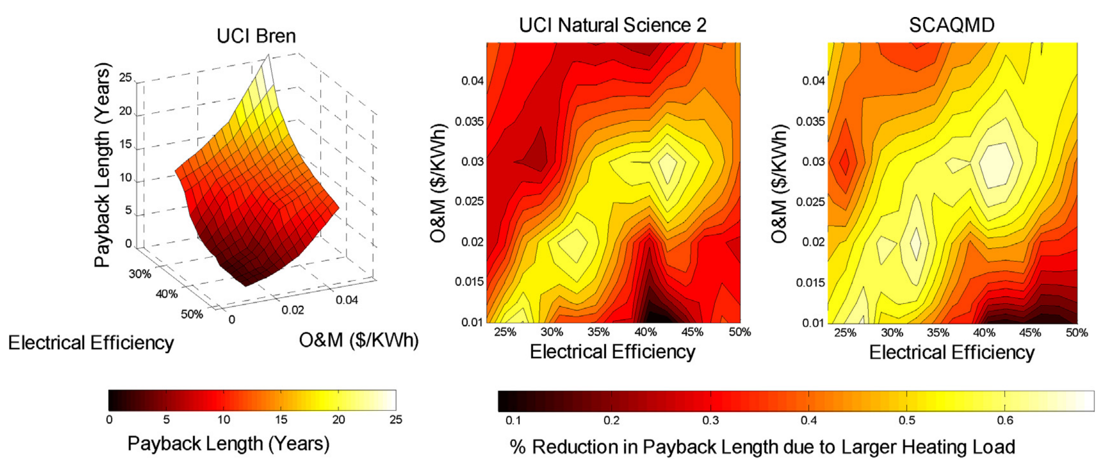

Fig. 3. Payback period plot versus electrical efficiency and O&M for UCI Bren and the corresponding %difference in payback period due to larger heating load for UCI Bren compared to UCI Natural Science 2 and UCI Bren compared to SCAQMD. All buildings have a DG system sized to 50% of the maximum load, have 80% turndown, and cost $2400/kW to install.

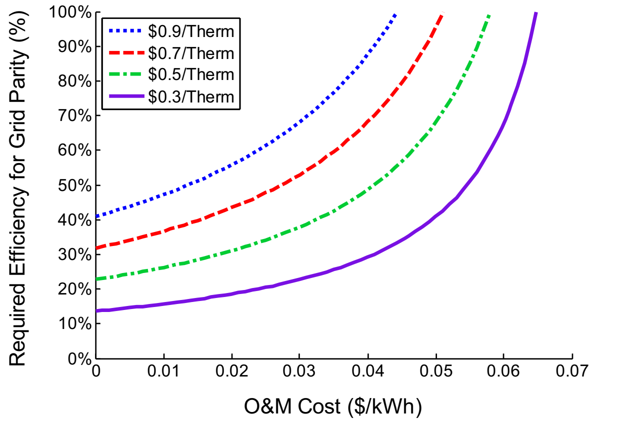

Fig. 4. Required DG electrical efficiency to reach parity with an electricity price of $0.07505/kWh during the winter mid-peak period versus O&M cost for various natural gas prices.

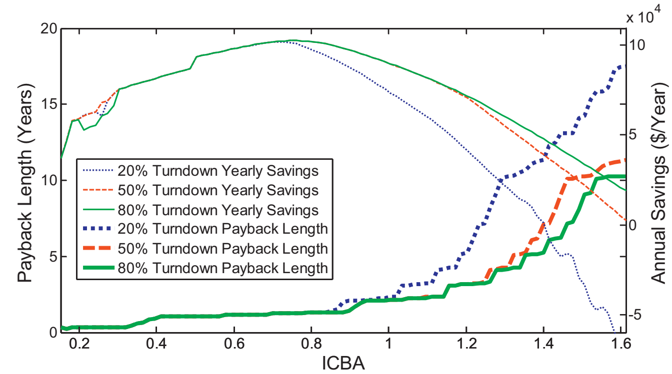

Fig. 5. Impact of increased capacity on annual savings and payback for UCI Cal IT^2. System has an electrical efficiency of 50% and O&M cost is $0.01/kWh. Capital cost of DG was $2400/kW.

replacement during more expensive summer on- and mid-peak periods.

Another way to improve capacity factor is through reduced O&M costs. For both buildings of Fig. 2, higher O&M costs suppress DG operation but the effects differ between the buildings. While UCI Bren struggles to have a capacity factor higher than 20% for high O&M cost conditions, Patton State Hospital achieves a capacity factor of nearly 50% at the same O&M cost conditions. Reducing O&M costs to $0.03/kWh leads to capacity factors of 50% at 30% efficiency for the UCI Bren building. The difference between the $0.03/kWh and $0.045/kWh charge is exactly the departing load charge (a variable O&M cost) that is currently applied to buildings serviced by SCE.

While much can be explained using the electrical energy rate structures and O&M costs, there is a fundamental difference between the capacity factors of the two buildings shown in Fig. 2 because of the building operating characteristics throughout the year. Patton State Hospital has a native thermal load that is 34.6 times larger than the thermal load for UCI Bren and the electrical and thermal demands of Patton State Hospital are much less dynamic than those of the UCI Bren building. Despite these differences, both buildings use the same natural gas rate structure (i.e., before the least expensive Tier 3 is available, 4163 therms of Tier 1 and Tier 2 natural gas must be consumed). Patton State Hospital readily consumes all of the Tier 1 and Tier 2 natural gas, but UCI Bren can only get to Tier 2 pricing of natural gas. Due to this difference, the fuel available to Patton State Hospital is less expensive than that of UCI Bren, which leads to increased capacity factor.

Other buildings display similar trends due to larger native thermal load. Two of these buildings are the UCI Natural Science 2 building (6.5 times larger thermal load than UCI Bren) and the South Coast Air Quality Management District (SCAQMD) building (23.9 times larger thermal load than UCI Bren). UCI Bren, UCI Natural Science 2, and SCAQMD have an electrical load factor of approximately 0.6. If similarly sized DG is installed at these three buildings, demand charge reduction operation will be similar. Larger thermal loads lead to reaching Tier 3 natural gas prices for a greater portion of the building energy demands and a lower average fuel cost. Thus, the Patton State Hospital and SCAQMD buildings experience lower gas cost than UCI Natural Science 2, which experiences lower gas cost than UCI Bren.

The relationship between capacity factor and payback can be seen when comparing Fig. 3 to Fig. 2 for the UCI Bren building. Capacity factor increases primarily when energy replacement dispatch can occur. Further dispatch of a system beyond demand reduction does not occur until savings can be generated first during other peak times and second at off-peak times. Anything that contributes to lower cost of operation including higher efficiency, lower O&M, or achieving lower fuel costs, contributes toward increasing capacity factor while reducing the length of the payback period. This behavior is typical for all 12 buildings.

As payback period increases in Fig. 3, a gradient shift at ten years occurs for UCI Bren. Financing payments end after 10 years, and energy savings that were previously funding loan payments are realized by the investor, instantaneously increasing net savings. This sudden reduction in energy costs causes the brief gradient reduction, which appears as a plateau at about the height of 10 years across the payback period surface plot. As efficiency drops or O&M charges increase beyond this point, payback periods again begin to steeply increase.

When compared to UCI Bren in Fig. 3, payback is reduced for UCI Natural Science 2 and SCAQMD for all electrical efficiencies and O&M costs considered in the current analyses, highlighting the benefit of reduced fuel costs due to quick access to the least expensive Tiers of natural gas. Maximum benefit is seen for generators that had a payback length of approximately 10 years for UCI Bren. Decreasing the fuel price improves economics during demand reduction activity while also enabling energy replacement dispatch for both the UCI Natural Science 2 and SCAQMD buildings, thus reducing payback period for the entire range of efficiency and O&M costs considered. SCAQMD experiences the largest improvements to payback due to an even larger thermal load than UCI Natural Sciences 2. This reduction in payback period occurs despite the greater total DG investment required for installation at UCI Natural Science 2 (2.1 times greater than UCI Bren) and SCAQMD (5.15 times greater than UCI Bren).

4.1.2. Installed capacity and turndown

The effects of varying DG capacity and turndown is explored in this section while electrical efficiency and O&M costs are held constant. The payback length and total annual savings (with loan payments included) versus installed DG capacity over average building electrical demand (ICBA) of three generators with electrical efficiency of 50%, O&M of $0.01/kWh, and capital cost of $2400/kW with different turndown capabilities are shown in Fig. 5 for UCI Cal IT^2. Notice that for this particular case of high efficiency and low O&M costs, the electrical energy produced onsite is always cheaper than purchasing electrical energy from the grid (even with relatively high capital cost of $2400/kW). Table 3 shows the amount of installed capacity in terms of ICBA that maximizes annual energy savings and the ICBA that minimizes electrical utility cost for all buildings using DG with electrical efficiency of 50%, O&M of $0.01/kWh, and capital cost of $2400/kW.

Table 3
ICBA comparison of installed capacity required to reach maximum annual energy savings and installed capacity required to reach minimum electrical utility cost under the parent electrical rate structure. System has an electrical efficiency of 50% and O&M cost is $0.01/kWh. Capital cost of DG is $2400/kW.

Building	Maximum savings (ICBA)			Minimum electrical utility cost (ICBA)		
	20% turndown	50% turndown	80% turndown	20% turndown	50% turndown	80% turndown
Hyatt Irvine	0.654	0.668	0.668	0.954	1.09	1.24
Loma Linda VA	0.622	0.622	0.622	0.927	1.194	1.194
Long Beach VA	0.761	0.761	0.761	0.895	1.175	1.175
Patton Hospital	0.724	0.785	0.785	0.755	1.17	1.54
SCAQMD	0.907	0.924	1.076	0.991	1.294	1.479
St Regis	0.875	1.007	1.007	0.901	1.127	1.233
UCI Bren	0.798	0.798	0.798	0.878	1.245	1.421
UCI Cal IT^2	0.715	0.76	0.76	0.76	1.156	1.338
UCI Croul	0.755	0.755	0.755	0.894	1.311	1.511
UCI Nat Sci 1	0.703	0.734	0.734	0.812	1.203	1.484
UCI Nat Sci 2	0.801	0.817	0.817	0.832	1.248	1.294
US Navy Palmer Hall	0.837	0.917	0.917	0.877	1.196	1.196

Table 4
ICBA comparison of installed capacity required to reach maximum annual energy savings versus installed capacity required to reach minimum electrical utility cost. System has an electrical efficiency of 25% and O&M cost is $0.03/kWh. Capital cost of DG is $2400/kW.

Building	Maximum savings (ICBA)			Minimum electrical utility cost (ICBA)		
	20% turndown	50% turndown	80% turndown	20% turndown	50% turndown	80% turndown
Hyatt Irvine	0.136	0.136	0.136	1.036	1.254	1.417
Loma Linda VA	0.191	0.191	0.191	0.927	1.27	1.27
Long Beach VA	0.267	0.267	0.267	0.908	1.389	1.389
Patton Hospital	0.216	0.231	0.246	0.755	1.201	1.54
SCAQMD	0.521	0.706	0.723	1.008	1.496	1.748
St Regis	0.252	0.345	0.411	0.914	1.365	1.365
UCI Bren	0.319	0.319	0.319	0.926	1.517	1.517
UCI Cal IT^2	0.259	0.259	0.259	0.821	1.278	1.612
UCI Croul	0.17	0.17	0.17	0.925	1.665	1.665
UCI Nat Sci 1	0.25	0.234	0.234	0.828	1.312	1.64
UCI Nat Sci 2	0.154	0.154	0.154	0.847	1.294	1.649
US Navy Palmer Hall	0.146	0.16	0.213	0.877	0.877	0.877

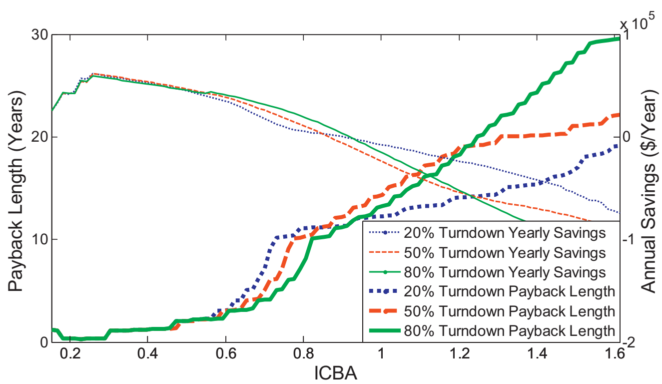

Fig. 6. Impact of increased capacity (higher ICBM and ICBA) on annual savings and payback for UCI Cal IT^2. DG system has an electrical efficiency of 25% and O&M cost is $0.03/kWh, and installed capital cost of $2400/kW.

A contrasting case to Fig. 5 is presented in Fig. 6 for a DG system with much lower electrical efficiency of 25%, higher O&M costs of $0.03/kWh, and the same capital cost of $2400/kW for UCI Cal IT^2. This scenario presents a situation where electricity produced onsite is always more expensive than grid electricity and the only cost reducing activity available to the DG system is demand charge reduction. Table 4 shows the amount of installed capacity in terms of ICBA that maximizes annual energy savings and the ICBA that minimizes electrical utility cost for all buildings using DG with electrical efficiency of 25%, O&M of $0.03/kWh, and capital cost of $2400/kW.

In Fig. 5, turndown only has an effect when installed capacity is close to equaling or surpassing the average building load. At this size of installation, all lower turndown machines experience reduced operation due to being oversized for the load and the inability to export additional electricity. Only the 80% turndown generator can continually operate. Due to the low load factor of the UCI Cal IT^2 building (i.e., more dynamic loads), DG turndown percentage is more valuable for UCI Cal IT^2 than for other buildings with higher load factors beyond an ICBA of approximately 0.8, resulting in increased annual savings for generators with high turndown at large capacities.

Capacity factor also suffers as installed generation increases in Fig. 5. Low turndown generators often remain inactive due to being oversized for the load, reducing capacity factor. High turndown machines experience a low capacity factor due to increased part load operation. For generators sized above the average building load, the full capacity is seldom used, with the additional capacity remaining unused and stranded for the most part. While increased capacity of the system has the capability of producing cost efficient electricity, only a portion of the installation can consistently provide this service, putting the burden to payback the system investment upon only a fraction of the generator output. The electric utility bill is nearly erased for the high turndown machine, but the cost of electricity has just been shifted from an electric utility payment to a financing payment. As a result, the annual savings decrease and payback period is increased under these circumstances.

Maximum annual savings occur at below where the installed capacity is equal to the average building load. Capacity factor for this DG installation is near one (see Fig. 5), with nearly identical operation amongst the generators considered regardless of their turndown capabilities. The full cost reducing potential is achieved for these generators that are sized to meet just below the average building demand primarily because the full capacity can be consistently used without exporting electricity.

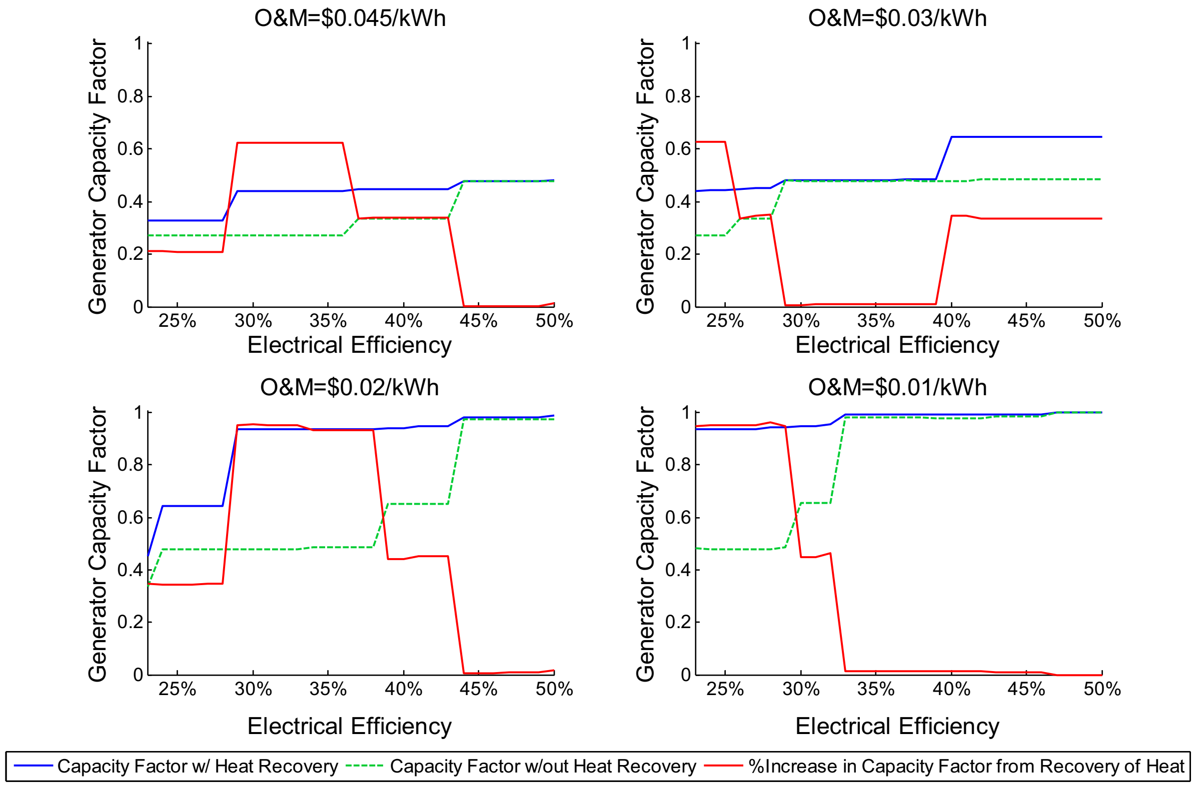

Fig. 7. Capacity factor for Patton State Hospital with HR using economic strategy by O&M cost. Installed systems are sized to 50% of average building load.

The amount of capacity that minimizes annual energy costs is heavily dependent on the building demand profile. Table 3 shows the amount of installed capacity in terms of ICBA that maximizes annual energy savings. A wide range of desirable ICBA values are seen across the range of buildings tested. However, maximum savings always occur when installed capacity is at or below the approximate average building electrical demand. In addition, increased DG capacity can be increased if turndown is increased for many, but not all buildings.

In Fig. 6, capacity factor is increased only through demand charge reduction, and as DG capacity increases, demand shifting abilities are improved, which both lead to increased savings. However, increased capacity also requires that more electrical energy be generated for maximum demand charge reduction. Higher turndown machines achieve maximum demand reduction with less energy produced compared to low turndown machines, reducing losses from producing expensive electrical energy onsite. Regardless, as capacity increases, more electrical energy must be generated onsite to achieve maximum demand reduction, which for the case of a low efficiency machine reduces savings created through demand charge reduction and demand shifting. As capacity increases, lower turndown generators are again unable to operate due to export constraints while high turndown generator operation continues unhindered. Ironically, by blocking operation of low turndown generators, annual savings are flipped with low turndown machines creating greater annual savings due to their inability to operate.

Fig. 6 presents the annual savings achieved by DG installation at the UCI CalIT^2 building, which include financing payments that disappear after 10 years. At the completion of 10 years, financing payments disappear, allowing negative net savings in Fig. 6 to turn positive and allowing for payback to occur.

For generators with low efficiency and high O&M (like that explored in this section and presented in Fig. 6), demand charge reduction and demand shifting are the only possible cost reducing dispatch strategies. Hence it is financially advantageous to perform these functions by replacing as little energy as possible, so that increasing capacity beyond what is needed to perform demand shifting is undesirable. As a result, the cases with the lowest payback period and best annual savings are those with low ICBA.

4.1.3. Heat recovery

The effects of heat recovery are explored in this section. Figs. 7 and 8 show the increase in capacity factor due to heat recovery for Patton State Hospital and US Navy Palmer hall respectively. Heat recovery (HR) replaces thermal loads that would have been met by the firing of a natural gas boiler with heat produced during DG operation. Additional savings from HR can enable operation of a generator that previously could not compete with the grid when producing electricity only. This has a strong effect on the efficiency target presented in Fig. 4, leading to lower efficiency generators that can reach parity with utility grid electricity prices due to their ability to provide recoverable heat. As HR increases, the efficiency target is lowered, as shown in Fig. 9 for various HR percentages and two natural gas price conditions ($0.7/therm and $0.5/therm).

The economic benefit of HR does come with burdens of additional capital investment, integration with other building equipment, and other design, installation and operating challenges. The thermal load must be coincident with the electrical load and sufficiently large to utilize the heat produced by the DG system [44]. If these requirements are not met, then the economic benefit of HR does not exist. This is particularly important during summer on- and mid-peak operating conditions as well as winter mid-peak when the price of electricity is most expensive. If the generator is relying on HR to make energy replacement possible, operation depends upon the coincidence of electrical and thermal demand and utilization of DG thermal energy unless thermal energy storage is included. For electric only systems already capable of energy replacement, HR can further improve capacity factor and savings if coincidence and high thermal demand exist.

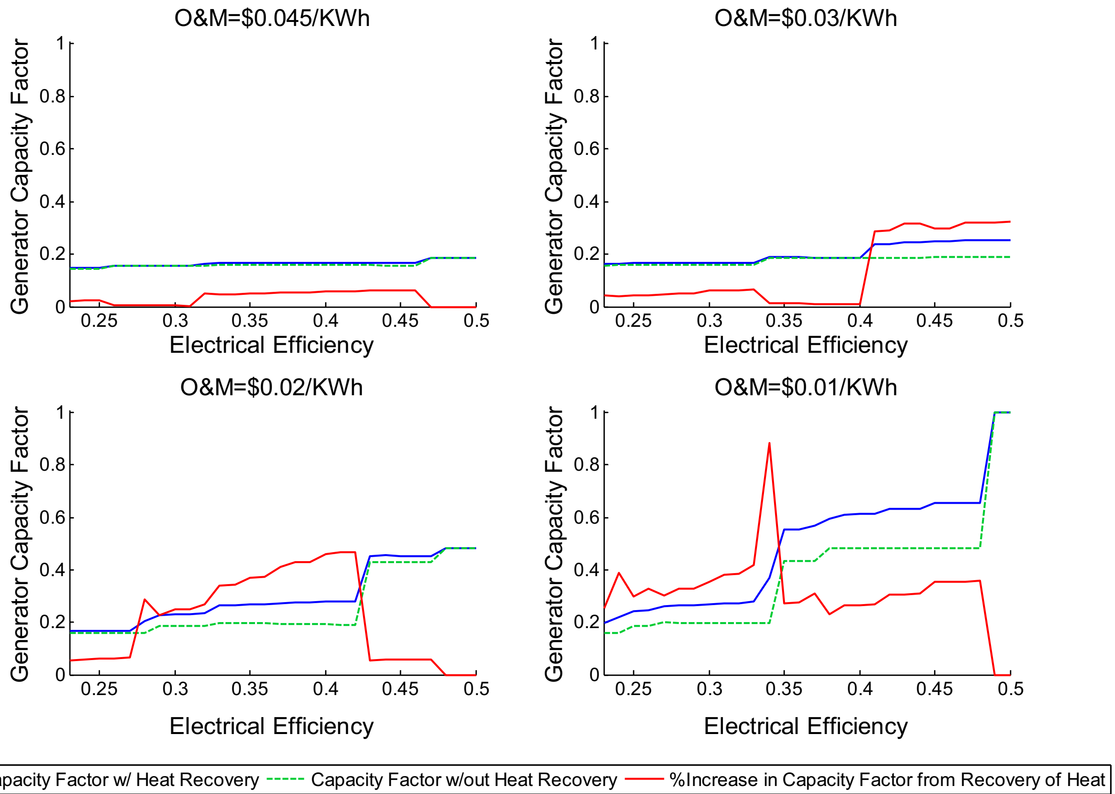

Fig. 8. Capacity factor for US Navy Palmer Hall with HR using economic strategy by O&M cost. Installed systems are sized to 50% of average building load.

The effect that HR has on capacity factor depends upon the building and characteristics of the installed DG. For example, UCI Bren has a small thermal load characterized by sporadic thermal demand with 34% of thermal demand that coincides with the electric demand. Due to a lack of coincidence and small thermal demand, heat produced by any DG is not likely to be well utilized. Thus, very little DG system operation will occur even with HR despite the economic possibility of cost effective electrical and thermal energy replacement dispatch. As a result, the capacity factor for UCI Bren when DG exhaust heat is captured is nearly identical to the capacity factor for UCI Bren using DG that provides electricity only, as presented in Fig. 2.

For buildings with high levels of coincidence between electrical and thermal loads and sufficient thermal demand, increased capacity factor is not always guaranteed; the DG must be able to surpass the efficiency target shown in Fig. 9 in order for dispatch to actually occur. Fig. 7 shows the increase in capacity factor due to HR for Patton State Hospital when using the current economic dispatch strategy. Patton State Hospital has a large thermal demand that is 74% coincident with the building electrical demand. As seen in Fig. 7, increases to capacity factor vary significantly depending upon the DG electrical efficiency and O&M costs. Some DG systems experience large increases in capacity factor due to heat recovery for all O&M costs, while others experience no change at all. Despite having a highly coincident thermal demand that is large enough to utilize the heat produced by DG, increases in capacity factor do not occur for all DG systems considered. Primarily, DG with high electrical efficiency, high O&M cost of $0.03/kWh, or a large electric-only capacity factors do not achieve higher capacity factors due to HR. Most other DG systems experience an increased capacity factor due to HR.

For generators that require HR to make energy replacement possible, coincidence must exist along with a large enough thermal demand to make sure that HR produces savings during energy

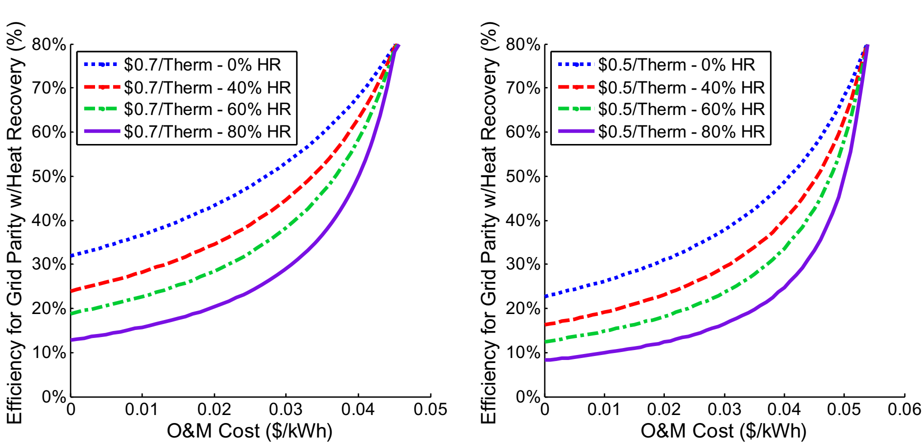

Fig. 9. Required DG electrical efficiency to reach parity with grid electricity price of $0.07505/kWh during mid-peak period with various amounts of waste heat recovery.

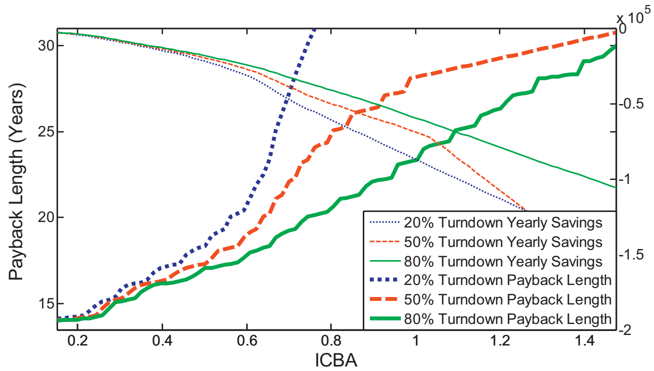

Fig. 10. Impact of increased capacity on annual savings and payback for UCI Cal IT[2] under parent electric rate structure. System has an electrical efficiency of 50% and O&M cost is $0.01/kWh. Capital cost of DG was $2400/kW.

replacement. If the thermal demand is not large enough, electrical and thermal energy replacement is still limited, regardless of coincidence. For example, the US Navy Palmer Hall has a thermal demand that is consistent but small. The increase in capacity factor versus electrical efficiency due to heat recovery for US Navy Palmer Hall is shown in Fig. 8 for various O&M costs. While the small thermal demand creates an economic barrier to DG adoption due to high natural gas cost, savings due to heat recovery are small from a lack of utilization of the DG thermal product. An increase in capacity factor is experienced for low O&M generators with higher electrical efficiencies because higher efficiency generators produce less heat, making it easier for the building thermal demand to utilize the available heat. However, nearly no increase in capacity factor is seen for low efficiency generators, regardless of O&M cost, due to a low heat utilization. Also, almost no increase in capacity factor is seen for high O&M generators due to their inability to break the efficiency targets required to provide any type of energy replacement.

4.1.4. *Parent electrical rates vs. standby electrical rates*

Under parent electrical rate structures, the effects of varying DG capacity and turndown is for high electrical efficiency and low O&M is similar to what is seen in Fig. 5. When electrical efficiency is decreased and/or O&M increases, results under parent rate structures start to differ from standby rate results. This is shown in Fig. 10, which shows annual savings and payback length for DG with low electrical efficiency and high O&M (similar to the scenario shown in Fig. 6).

The foregoing results found using standby electric rates show that even if DG has low electrical efficiency and high O&M cost, savings can be realized under standby rate structures due to the value of reducing demand charges, or shifting maximum utility demand toward mid- and off-peak periods, as shown in Fig. 6 and discussed in Section 4.1.2. These dispatch strategies allow for large savings from small generators regardless of their ability to produce electrical and thermal energy at a lower cost than that available from the utilities. However, customers must typically attain local utility approval before the standby rate structure is applied. The local utility may elect to continue to apply the parent rate structure if sufficient DG capacity is not installed or if the DG capacity does not replace a substantial portion of the building energy demand. If the local utility decides to retain the parent rate structure then the value of demand shifting is eliminated.

The electrical energy charges of the standby and parent rate structures are the same. As a result, DG electrical energy replacement with or without HR does not change if the parent rate structure is applied. DG capable of any form of energy replacement under standby rates are still capable of energy replacement under the parent rates. If a specific DG is capable of energy replacement operation, significant savings and a short payback length can still be realized. Such DG typically have high efficiency, low O&M costs and reasonably low capital costs.

As the ability to provide energy replacement deteriorates when DG systems exhibit low electrical efficiency and/or high O&M, the economic value of DG diminishes significantly when one cannot save money by demand shifting under the parent rate structures. While this type of DG installation may be able to produce significant savings under standby rates, as seen in Fig. 6, switching the same building and DG combination to parent rate structures essentially eliminates short payback periods, as shown in Fig. 10. DG with low electrical efficiency and high O&M are unable to produce savings that are large enough to meet the financing cost and the initial investment, resulting in an annual loss during the life of the loan. Once the loan has been paid off, positive annual savings are achieved, but payback does not occur until after 14 years for the lowest level of installed capacity investigated here. Increasing capacity reduces annual savings, resulting in an even longer payback period. If a short payback period is desired without changing electrical efficiency or O&M, either the capital cost of the DG must be reduced or the investment should not be made.

Despite operating under parent rate structures that change the value of DG, some DG installations can still provide economic benefits. Generators capable of high electrical efficiency with lower O&M cost retain much of their value regardless of rate structure due to their ability to produce low cost energy. However, as electrical efficiency decreases and O&M increases, the DG value proposition disappears faster under parent rate structures compared to standby rate structures.

5. Conclusions

A parametric study was performed to examine when and why DG investment makes sense. Six disparate factors concerning DG operational capabilities and costs were varied. Previously developed models of utility rate structures, building energy demand, and a cost minimizing dispatch strategy were used to determine economically favorable DG dispatch and the corresponding savings. The main findings of this analysis are:

- When only operating DG to minimize the cost of electricity, the DG system capacity factor is strongly influenced by electrical efficiency, O&M costs, and fuel prices. Electrical efficiency and O&M are highly dependent on the DG technology deployed. Fuel prices for commercial and industrial buildings depend on the amount of natural gas used by the building. A large local demand for heat is critical to improving DG economics when using a declining block natural gas rate structure. The large heat demand allows for less expensive fuel to be used sooner in each billing period, decreasing the average price of fuel used to operate the DG in that billing period.
- The amount of DG capacity that can be installed before further capacity results in reduced savings depends on the ability of the generator to reduce costs. For high cost generators capable only of demand reduction and demand shifting, installing capacity beyond what is required to maximize demand shifting results in reduced savings and an extended payback length. As generator operating costs decrease, further capacity can be installed. However, even DG capable of always producing electricity at a lower cost than what is available from the electric utility experiences diminished annual savings if capacity beyond the average building load is installed. For all DG, installing capacity beyond the recommended limits shifts the burden to pay back the full system capital cost to a fraction of the generator.

- If the DG capacity limits are not surpassed, generator turndown has a marginal effect on the savings produced by DG with current typical utility rate structures. If the limit is surpassed, turndown affects the ability of the generator to provide energy at a low cost. For generators capable of providing electricity at a lower cost than the utilities, high turndown allows for operation when building energy demand is low. Conversely, for generators capable of providing demand reduction only, low turndown generators are blocked from operation during periods of low energy demand, stopping the production of expensive DG system energy.
- Increasing heat recovery lowers the efficiency target that is required for cost effectiveness compared to that required for electric only operation. However, a large thermal demand that coincides with electrical demand is essential to utilize the heat produced by DG. Full utilization of available heat can lead to an increased capacity factor if heat recovery results in the generator surpassing the lowered efficiency target.
- Using the parent electric rate instead of the standby electric rate significantly reduces the economic value of DG which primarily creates value through demand reduction and demand shifting. Although energy costs are similar between these two electric rate structures, DG must be capable of producing low cost energy in order to retain economic value.
- In general, this study supports the idea that DG can be economically viable for buildings similar to the 12 buildings used in this study. However, the type and amount of DG installed must coincide with how DG reduces the cost of energy.

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