The Value of Distributed Generation under Different Tariff Structures

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ABSTRACT

Distributed generation (DG) may play a key role in a modern energy system because it can improve energy efficiency. Reductions in the energy bill, and therefore DG attractiveness, depend on the electricity tariff structure; a system created before widespread adoption of distributed generation. Tariffs have been designed to recover costs equitably amongst customers with similar consumption patterns. Recently, electric utilities began to question the equity of this electricity pricing structure for standby service. In particular, the utilities do not feel that DG customers are paying their fair share of transmission and distribution costs - traditionally recovered through a volumetric ($/kWh) mechanism - under existing tariff structures. In response, new tariff structures with higher fixed costs for DG have been implemented in New York and in California. This work analyzes the effects of different electricity tariff structures on DG adoption. First, the effects of the new standby tariffs in New York are analyzed in different regions. Next generalized tariffs are constructed, and the sensitivity to varying levels of the volumetric and the demand ($/kW, i.e. maximum rate) charge component are analyzed on New York's standard and standby tariff as well as California's standby tariff. As expected, DG profitability is reduced with standby tariffs, but often marginally. The new standby structures tend to promote smaller base load systems. The amount of time-of-day variability of volumetric pricing seems to have little effect on DG economics.

Introduction

Distributed generation (DG), the practice of generating electricity on-site, can be particularly attractive when the waste heat from thermal generating equipment, such as gas turbines and internal combustion engines (ICEs), can be used to offset fuel purchases for heating, cooling, or steam production. Heat recovery technology in connection with DG is commonly referred to as combined heating and power (CHP) or cogeneration. Typically, DG is most economical in applications where it covers the base load electricity and uses utility electricity to cover peak consumption and the load during DG equipment outages, i.e. as standby service. Aside from lower overall energy bills, DG systems can offer additional benefits to adopters, other electric utility customers, and society in general. DG adopters gain improved reliability if their systems are capable of grid-isolated, or islanded, operation. DG can offset or delay the need for building more central power plants or increasing transmission and distribution infrastructure, and can also reduce grid congestion, translating into lower electricity rates for all utility customers. Societal benefits can further include reduced carbon and other pollutant emissions. Iannucci et al.(2002) provides an extensive review of DG benefits.

However, DG is not necessarily a benefit for all players in the electricity sector. Utilities may see customers with on-site generation as problematic because they have different consumption patterns than average customers. For example base loaded CHP systems will make for peakier customers, and peak-shaving CHP systems will make for flatter customers. DG usually requires the site to have the same service capacity from the utility as before installation while the customer is buying less energy, i.e. the load factor on installed utility capacity is reduced. Depending on the operating scheme and relative performance of the DG system and the power plants supplying the grid, fuel consumption, carbon and other pollutant emissions, and noise pollution can all increase or decrease with DG adoption. For these reasons, DG policy needs to encourage applications that benefit the public, while discouraging those from which the public incurs a net cost. Inherent in this is the need to analyze DG costs and benefits and the influence public policy has on DG adoption and operation.

In 2002, the New York State Energy Research and Development Authority (NYSERDA) published a report on the market potential for CHP in New York State (Hedman, Darrow & Bourgeois 2002). The report found 5 GW of CHP enabled DG capacity is currently in operation, mostly at large industrial complexes, and estimates the potential as an additional 8.5 GW, mostly at smaller sites. DG prevalence in New York has been increasing as it becomes economically attractive at smaller scales.

Recently, electric utilities began to question the equity of electricity pricing for standby service. In particular, the utilities did not feel that DG customers were paying their fair share of delivery (transmission and distribution) costs under existing tariff structures. In response, the New York State Public Service Commission (NYSPSC) opened regulatory hearings and ultimately approved a tariff structure for standby service.

This paper examines the effects of tariff structure on DG economics. New York parent, i.e. standard, and standby tariffs are considered, and the New York standby tariff is compared to the different structure of California standby tariffs. Within these tariff structures, three types of volumetric ($/kWh) rates are considered: flat, time-of-use (TOU) and real time pricing (RTP). Tariffs in regions of high, moderate, and low congestion are considered. Finally, sensitivities to the volumetric and demand ($/peak monthly power) charges are examined.

We study the effect of the different tariff structures by using the Distributed Energy Resources Customer Adoption Model (DER-CAM). DER-CAM, developed at the Lawrence Berkeley National Laboratory, is an economic optimization model for DG investment in commercial buildings. For this project, energy loads from a 90-bed hospital are used. The peak electrical load is 1200 kW in the summer, and heating loads are roughly equal to electrical load.

The next section describes the tariffs used in the analysis and the third section describes DER-CAM. Results and conclusions follow.

Electricity Tariff Structures and Modeled Scenarios

Utilities and their regulators design tariffs based on fixed and variable costs, with some adjustments for reasons of policy. The main structural elements of an electricity tariff are typically fixed, volumetric, and demand charges:

- *Fixed charges ($/month)* are invariant fees. They are intended to cover infrastructure supply and delivery costs required by the customer regardless of their monthly energy and capacity consumption.
- *Volumetric charges ($/kWh)* are in proportion to energy consumed and may fluctuate by time of day within the month. They cover the variable costs of producing electricity, such as fuel charges and variable maintenance expenses. Volumetric charges can be

metered as a flat tariff, as TOU with a different price during on-peak and off-peak periods, or as RTP with a different price each hour

- *Demand charges ($/kW)* are levied on the maximum power used during a specified time range, such as over the on-peak hours of a month, regardless of the duration or frequency of that level of consumption. Demand charges are intended to collect the fixed costs of infrastructure shared with other customers in proportion to the capacity each requires.

The two major components of customer electricity bills are variable electricity supply costs and delivery charges covering infrastructure and service. Historically, although fixed in nature, some delivery costs have been collected by adding them to the volumetric prices for supply. When a class of customers has similar, regular consumption patterns, volumetric delivery prices equitably recover costs and generate some profit from the delivery of electricity. However, if there are significant differences in the usage patterns within a class, volumetric delivery pricing may no longer be fair because customers can use the same amount of energy and at the same time have very different peak loads and hence strain the grid differently. For example, a customer with a flat load profile and one with a peaky profile may consume the same amount of electricity on a daily basis, but the peaky customer will require more infrastructure to meet the peaky load. Electric utilities have argued that their delivery costs do not vary according to installed DG capacity because the same amount of infrastructure is required to meet a DG site's full demand during DG outages as a building without DG. With volumetric delivery pricing, utilities collect revenue on the lower standby power delivered, but not for the infrastructure maintained, leaving some costs un-recovered. This is particularly true when the DG site is located a short distance from the power plant and has transformers and power lines dedicated to it. In this case, the localized infrastructure is not shared among several customers. Further from the power plant, infrastructure is most likely shared among many customers, and the utility capacity required to meet DG outages is not the sum of DG capacities, but rather the statistically likely maximum coincident DG outage capacity.

In 2000, the NYSPSC began hearings on DG tariffs involving the key stakeholders: investor-owned electric utilities (IOUs) and DG adopters, manufacturers, suppliers, and installers. Their objective was to develop standby tariffs that equitably address delivery costs. In 2001, the NYSPSC filed the "Opinion and Order Approving Guidelines for the Design of Standby Service Rates" (NYSPSC 2001). Key points from this filing were:

- Supply charges should remain the same for all customers.
- Standby customers' delivery charges should reflect the different nature of service provided.
- Standby delivery charges should have three components:
  - Contract (fixed) demand fees to recover localized delivery costs.
  - As-used daily demand charges to cover delivery costs further from the site. The daily demand structure should allow assigning costs according to the proportion of infrastructure each customer requires, so standby customers with frequent DG outages will incur higher daily demand charges.
  - Monthly customer charges to recover administrative and service costs, regardless of the customer's peak demand or total consumption.

- Delivery charges should be revenue neutral across classes of customers; the total delivery revenue collected under standby rates should be the same as it was before the rates went into effect, even though some customers will be paying more and others less.
- Standby delivery charges should be based on actual costs and should not be used as part of any incentive program to promote DG as a public policy or to benefit the utility. Such inducements can be addressed through other billing mechanisms.

Typically standby charges increase fixed electricity costs and reduce the marginal cost of purchasing energy. The utility-proposed standby rates came into effect in 2004.

California, another state with relatively high electricity prices, has also dealt with the issue of equitable pricing of standby service. There, utilities charge standby customers under their parent tariff, and include an additional fixed monthly charge for each kW of backup standby capacity provided. Standby customers pay a monthly charge per kW of installed DG capacity. Relative to parent tariffs, New York standby rates reduce the marginal costs of purchasing utility electricity, whereas California's leave marginal costs unchanged. The New York standby tariff eliminates the volumetric delivery rate, reducing the net $/kWh rate from the parent tariff, while the California standby tariff does not. Reducing the marginal cost of purchasing electricity discourages generating it on-site.

The key structural difference between New York and California standby tariffs is in assessing fixed charges. In New York, standby customers pay a fixed delivery charge based on the total load the utility would incur during a DG outage (the peak electricity load of the site), while California standby customers are billed based only on the additional load incurred during an outage (the peak capacity of the DG system). From the customer perspective, the New York fixed $/kW rate is a fixed disincentive to DG adoption (independent of system size), while the California charge is a variable disincentive (increasing with system size increases).

The tariffs impact on DG economics and consequently, on adoption patterns will determine net benefits and costs to customers, utilities, and the public. The first part of this study analyzes the effects of these new rates, under flat, TOU and RTP volumetric tariffs, by finding optimal systems with DER-CAM under actual parent and standby tariffs in three distinct regions of New York with significant differences in electricity costs. Electricity and natural gas tariffs from one IOU (investor owned utility) in each region were collected and used in this project. The regions were classified:

- *High Congestion*, New York City: Consolidated Edison Company of New York, Inc. (ConEd),
- *Moderate Congestion*, Hudson Valley: Orange and Rockland Utilities, Inc. (O&R), and
- *Low Congestion*, Western New York: Niagara Mohawk Power Corporation (NiMo).

A summary of electricity tariffs and rates is provided in Table 1. Natural gas rates were more consistent across the state, with an annual range of 0.020 to 0.035 $/kWh (0.6 to 1.0 $/therm). See Firestone (2005) for more detailed rate information.

Table 1. Summary of 2003 Tariffs for New York IOUs

	tariff componet	units	Consolidated Edison			Orange and Rockland			Niagara Mohawk	
			Flat	***TOU***	***RTP***	***Flat***	***TOU***[+]	***RTP***	***Flat***	***RTP***
Parent Tariff	fixed	($/month)	n/a	n/a		20.25 - 21.75	21.45	20.25 - 21.75	260.15	902
	volumetric	($/kWh)	0.07 - 0.10	n/a	0.01*	0.07 - 0.11	n/a	0.03 - 0.04**	0.05 - 0.07	n/a
	volumetric on-peak	($/kWh)	n/a	0.07 - 0.12		n/a	0.06 - 0.14	n/a	n/a	0.02***
	volumetric off-peak	($/kWh)	n/a	0.05 - 0.07		n/a	0.05 - 0.08	n/a	n/a	0.02***
	demand- all hours	($/kW)	14.75 - 20.74	3.17 - 9.79	9.99 - 12.50	6.29 - 10.76	n/a	6.29 - 10.76	14.97	10.4
	demand- on peak	($/kW)	n/a	14.02 - 24.07	n/a	n/a	6.56 - 15.47	n/a	n/a	n/a
Standby Tariff	fixed	($/month)	63.20 - 74.67			37.49			661.54	2138
	contract	($/kW)	3.91 - 4.62			3.94			9.77	6.9
	volumetric	($/kWh)	0.06 - 0.09	n/a	0.00*	0.055 - 0.95	0.055 - 0.95	0.02**	0.05 - 0.07	0.003***
	volumetric on-peak	($/kWh)	n/a	0.07 - 0.11	n/a	n/a		n/a	n/a	n/a
	volumetric off-peak	($/kWh)	n/a	0.04 - 0.07	n/a	n/a		n/a	n/a	n/a
	daily demand- all hours	($/kW)	0.34 - 1.02			0.28-0.39			0.54	0.38
	monthly demand	($/kW)	5.98 - 8.24	n/a	n/a	n/a		n/a	n/a	n/a
	monthly demand- on peak	($/kW)	n/a	6.37 - 8.52	n/a	n/a		n/a	n/a	n/a

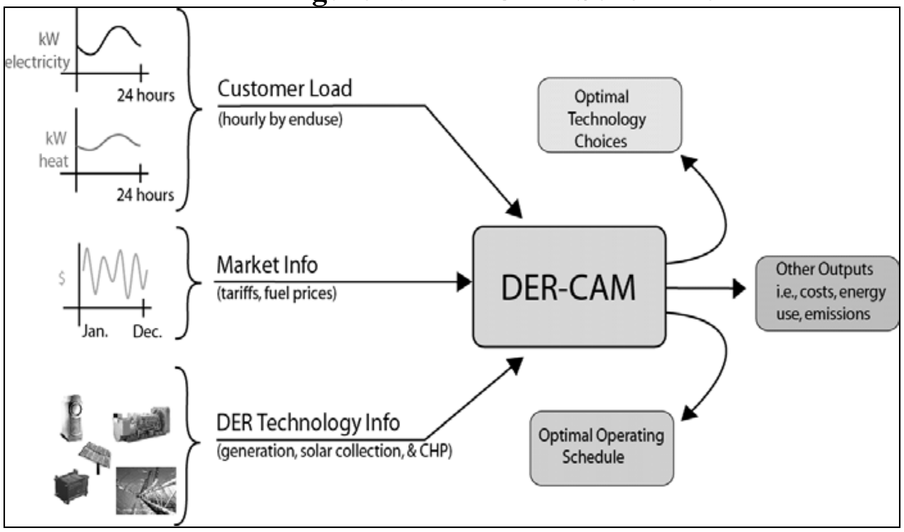
*Customer also pays day ahead hourly locational based marginal price for the New York City NYISO load zone
**Customer also pays day ahead hourly locational based marginal price for the Hudson Valley NYISO load zone
***Customer also pays day ahead hourly locational based marginal price for the Frontier NYISO load zone
[+]Orange and Rockland does not have a TOU standby tariff

While assessing DG adoption under actual New York tariffs offers some insights, the number and complexity of the variables in each scenario make the effects of each variable difficult to identify. Therefore, generic tariffs of varying structures were developed and single-variable sensitivities performed on each generic tariff. Because O&R rates are close to the median for New York State, they became the basis for the generic tariffs. O&R offers flat, TOU, and RTP rates, with a standby rate for the flat and RTP ones. That same standby rate was used to make the generic TOU rate. Additionally, Standby-CA rates came from adding the California state-wide average standby charge ($/kW of installed capacity) to the New York parent tariffs. The sensitivity was performed by varying one parameter (volumetric electricity rates and electricity demand rates) per analysis. Optimal DG systems and annual energy costs are calculated for all three volumetric tariff structures (flat, TOU and RTP), with a parent tariff structure, with New York style standby tariffs and with California style standby tariffs.

Distributed Energy Resources Customer Adoption Model

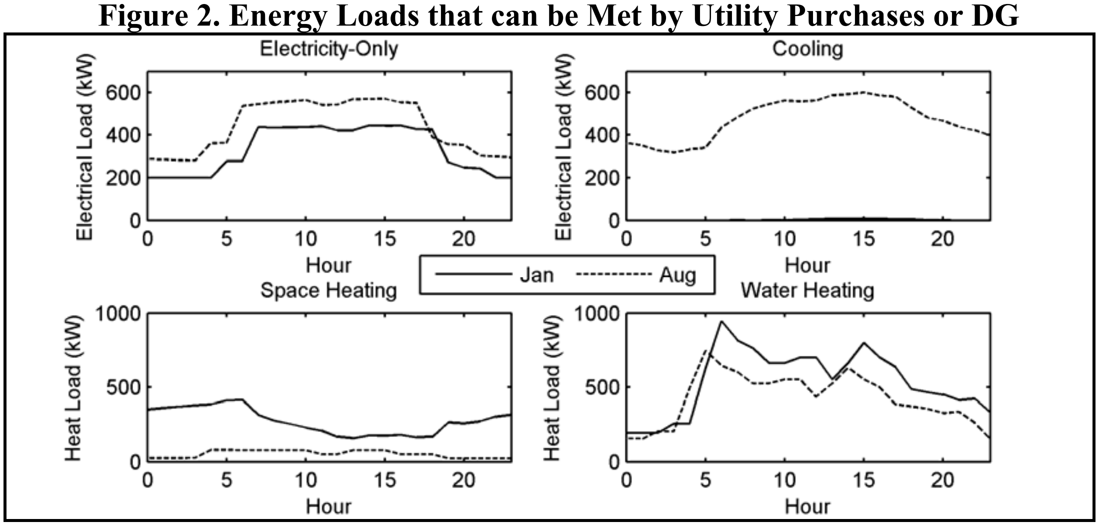
This study used DER-CAM to examine the economic potential for DG in New York State under parent and standby tariffs, and to determine the effects of tariff structure on DG adoption. Developed at Lawrence Berkeley National Laboratory, DER-CAM is software designed to factor many variables into determining the DG investment decision that minimizes the annual costs , including capital costs, for a given site with a maximum payback constraint. The DER-CAM solution provides both the optimal generating equipment and the optimal operating schedule. Optimal DG system includes capacity and combination of units with and without heat recovery and absorption chillers. The optimal operating schedule gives a basis to estimate energy costs, utility electricity consumption, and carbon emissions. Input to DER-CAM includes the site's hourly end-use energy demand, electricity and natural gas supply costs, and DG technology adoption options. DG generation technology options include PV, natural gas fueled ICEs, microturbines, gas turbines, and fuel cells. By matching thermal and fuel cell generation to heat exchangers and absorption chillers, heat recovered from natural gas driven generators can be used to offset heating and cooling loads. Figure 1 shows a high-level schematic of DER-CAM. Bailey (2002) provides a more detailed description of the model.

Figure 1. DER-CAM Schematic



DG investment options for this version of DER-CAM are: microturbines (60 kW), natural gas engines (60 kW, 100 kW, 300 kW and 1000 kW), fuel cells (200 kW) and photovoltaics (50 kW). All thermal generators can either be installed to satisfy only electrical load, electrical and heating (via heat exchanger) loads, or electrical, heating, and cooling (via heat exchanger and absorption chiller) loads. More detailed DG technology data can be found in Firestone (2004). For this study, a typical candidate for DG adoption was desired: a small facility with a peak electric load near one MW and similar sized heating and electrical loads. The chosen prototype was a 90-bed hospital, with peak electrical loads of 1200 kW in the summer, and heating loads roughly equal to electrical loads. Energy loads that can be met by DG are displayed in Figure 2. In addition, the building has a natural gas load for heating and cooking of up to 900 kW.

Figure 2. Energy Loads that can be Met by Utility Purchases or DG



Results

DER-CAM first assessed economically optimal investment decisions for the prototype hospital under the following scenarios (abbreviations of scenario in parentheses): flat volumetric charges (FLT), time-of-use volumetric charges for peak and off-peak hours (TOU), day-ahead hourly volumetric charges (RTP), scenarios in which DG investments were not allowed (No inv), scenarios in which DG investments were allowed and the parent tariff was applied (Inv), and scenarios in which DG investments were allowed and the appropriate New York standby tariff was applied (Standby). Only combinations actually present in current tariffs were considered.

Figure 3 shows the resulting annual energy bills under each tariff, broken down into utility electricity bills, utility natural gas bills, and DG costs (amortized capital costs plus maintenance costs). The annual energy bill is increased with standby charges in five of the seven cases and reduced in two. It should be noted that for three of the five cases where the energy bill increases, the increase is minor. For the ConEd and the O&R tariffs, DG is an attractive investment for all three volumetric metering methods and for both the parent demand tariffs and the standby tariff. In Niagara Mohawk, however, DG reduces costs with a flat tariff and parent demand tariffs and with RTP and standby charges. As can be seen in the graph there are large differences in the energy costs between the energy tariffs, with or without DG, especially for ConEd.

The effect of the tariffs on optimal capacity is similar. Standby tariffs discourage DG capacity in five of the seven cases where parent and standby tariffs exist, and only encourage DG capacity in one of them (see Figure 4). The higher fixed and lower volumetric costs under standby rates reduce the marginal cost of utility electricity and, therefore, DG offsets to utility purchase are less economically attractive. To pay off under standby rates, DG must be efficiently utilized. This encourages smaller DG systems with higher load factors. In relation to this, it is important to realize that a higher capacity does not necessary mean that DG is a more attractive investment to the developer. The ConEd RTP case clearly illustrates this: even though the parent demand tariff structure leads to an optimal system with 600 kW CHP and 600 kW of electricity capacity versus a 300 kW CHP system with the standby tariffs, the 300 kW CHP system on the standby tariff structure results in lower energy costs. Under a standby tariff system, with reduced ability to reduce demand charges, the additional capacity was redundant. A developer might find this attractive because the capital investment is lower.

While standby rates tend to discourage DG capacity, higher energy prices and demand charges in more congested areas encourage it. Figure 3 shows this: in low-congestion, low-priced western New York State, NiMo tariffs encourage the least DG capacity, while in high-congestion, high-priced New York City, ConEd rates encourage the highest, much of it generating electricity only.

A comparison of Figure 3 to Figure 4 also indicates that the volumetric pricing structure has less effect on DG economics than the actual price of electricity: for O&R, annual electricity costs are comparable for all three structures (flat, TOU, and RTP) and DG capacity is the same. For ConEd, annual electricity costs are greatest under the TOU structure and least under the RTP structure – installed capacity is correspondingly greatest under the TOU structure and least under the RTP structure. In Niagara Mohawk, DG is only installed under RTP rates and with the standby tariff.

Figure 3. Total Annual Energy Cost under Various Tariffs

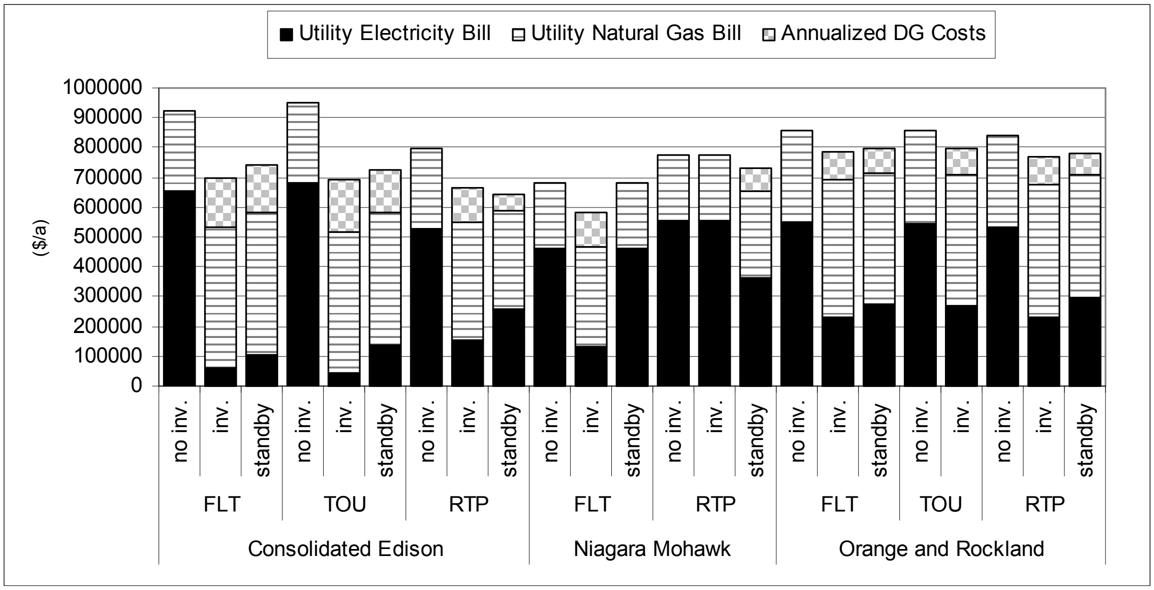
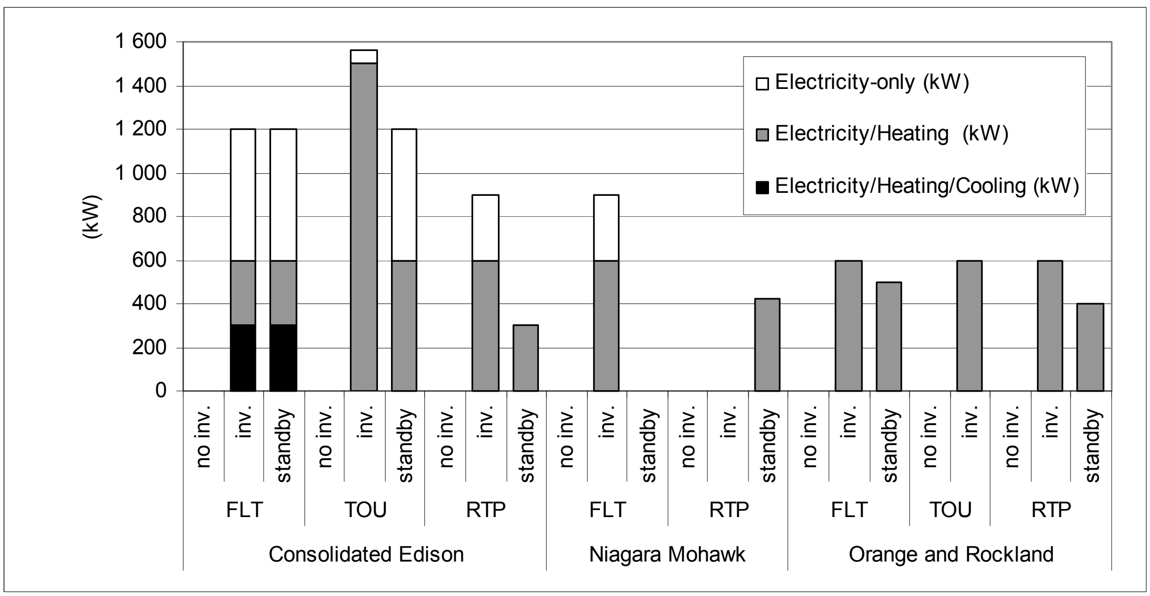


Figure 4. Economically Optimal DG Systems under Various Tariffs



Sensitivities to Volumetric and Demand Metered Electricity Charges

The sensitivity tests were conducted on two of the energy cost components for the nine different rates: volumetric electricity ($/kWh) and demand charges ($/kW). In each test, one parameter was varied as a percentage of the base case value. Figure 5 displays the installed capacity for each scenario in the volumetric electricity rate sensitivity. As expected, volumetric rates can make or break DG adoption. If they decrease below 80% of their current values, almost no DG adoption is seen. However, if rates increase to 160% of their current values, significant DG adoption occurs under all tariff structures. For the Flat and RTP structures, DG adoption capacity increases gradually from zero to 1000 kW as volumetric rates increase from 80% to

160%. However, this increase is much sharper under TOU structures, and starts approximately at the base case rates. As expected, the parent tariffs encourage larger DG installations than the respective standby tariffs. For the TOU structures, the shift from parent tariff to New York style standby shifts the threshold price for installation from 90% to 120% of base case volumetric electricity rates.

Figure 6 shows the total annual energy cost for each scenario, including all utility electricity and natural gas purchases, as well as annualized capital and maintenance costs for the DG system selected. As volumetric prices increase, DG systems are used to insulate customers from increased energy costs. For the TOU New York standby structure (TOU_NY), the spike in energy costs at 120% of base case volumetric rates is due to the payback period constraint in DER-CAM. While lower annual energy bills could be achieved by larger DG investment at this point, the payback period would be too long. However, when volumetric rates increase further, the payback period on DG systems is reduced, and larger systems are installed, thus reducing energy costs, sometimes even with increasing energy prices.

The second sensitivity analysis tested electricity as-used demand rates. These are the as-used monthly demand rates under parent tariff and California standby tariff structures, and the as-used daily demand rates under New York standby tariff structures. For each of the nine structures, DER-CAM varied as-used demand rates from 30% to 300% of the base case values in increments of 10%. In all cases, parent tariffs encourage significantly more DG installation than standby tariffs (Figure 7). Clearly, demand charges are an effective way to influence the level of DG installation. The TOU New York standby (TOU_NY) tariff particularly discourages on-site generation capacity, although after as-used daily demand charges surpass 200%, DG installation quickly catches up to the levels other rate structures encourage.

Figure 8 displays the energy costs with various levels of the demand charge. The energy costs are always lowest for the parent demand tariffs. New York and California tariffs give similar costs under a flat tariff, while under a TOU tariff the Californian style leads to lower energy costs, and in the RTP the New York style lead to lower costs than the Californian. Note that under all volumetric structures the New York style tariff leads to higher energy costs for fairly low tariffs. This is a pattern also seen in the volumetric sensitivity and indicates that the New York style tariff can be a barrier against adoption in regions with low to medium electricity price. The reason for this can be that the Californian tariff is proportional to the size of the system, while the New York version leaves all DG developers with the same increase in fixed costs. Therefore, the New York style will be a larger barrier for systems that would otherwise have a more marginal profitability.

The O&R rates gave similar energy costs for flat, TOU and RTP volumetric tariffs without DG. As a result of the fact that the energy costs have been similar across the different volumetric tariffs with and without DG systems installed, the volumetric tariff structure does not seem very important for DG profitability. Intuitively, TOU or a RTP tariff should be more beneficial to the economics of DG than a flat tariff because of the higher on-peak electricity costs, and this is often the case. However, for a large enough difference between the flat volumetric rate and the marginal cost of DG electricity, flat tariffs are more beneficial to DG economics that TOU or RTP tariffs. This implies that there is a range of marginal costs of DG electricity in which there is little difference between DG economics of the various volumetric structures.

Figure 5. Installed DG Capacity for Volumetric Electricity Rate Sensitivity

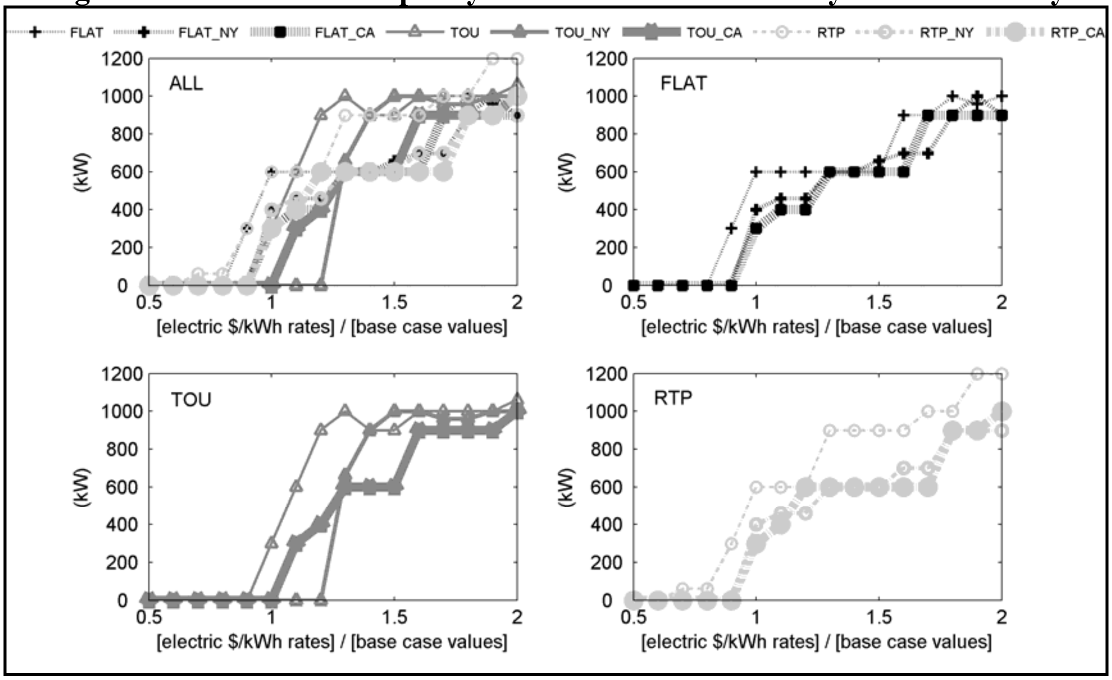


Figure 6. Total Annual Energy Cost for Volumetric Electricity Rate Sensitivity

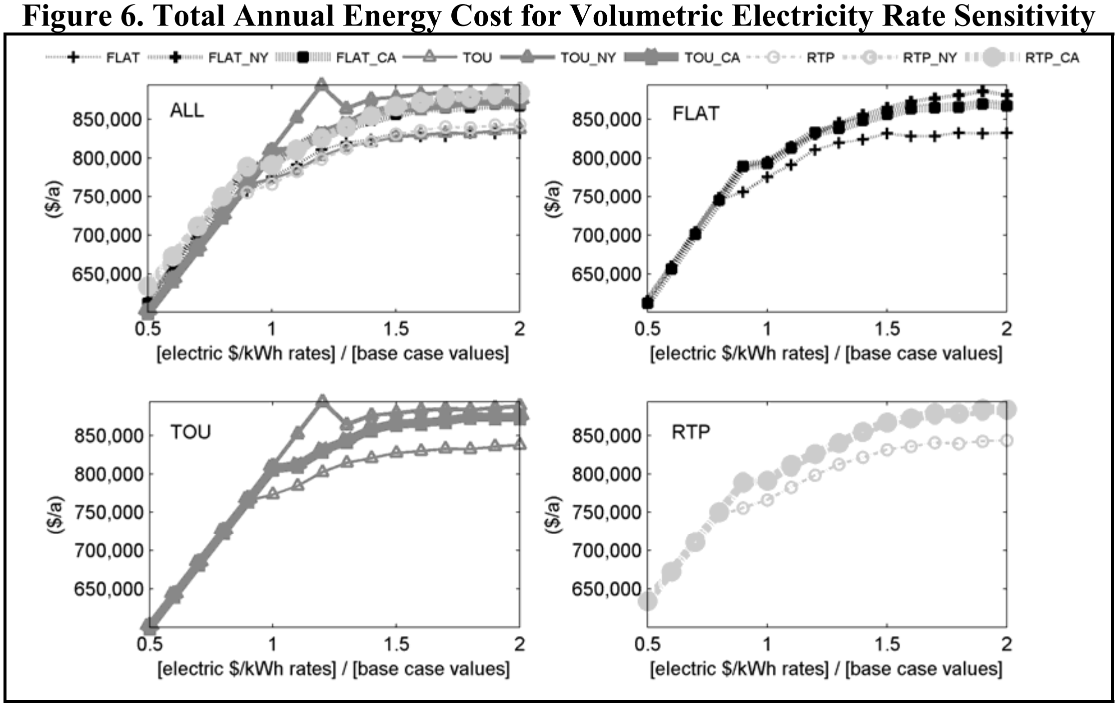


Figure 7. Installed DG Capacity for As-Used Demand Rate Sensitivity

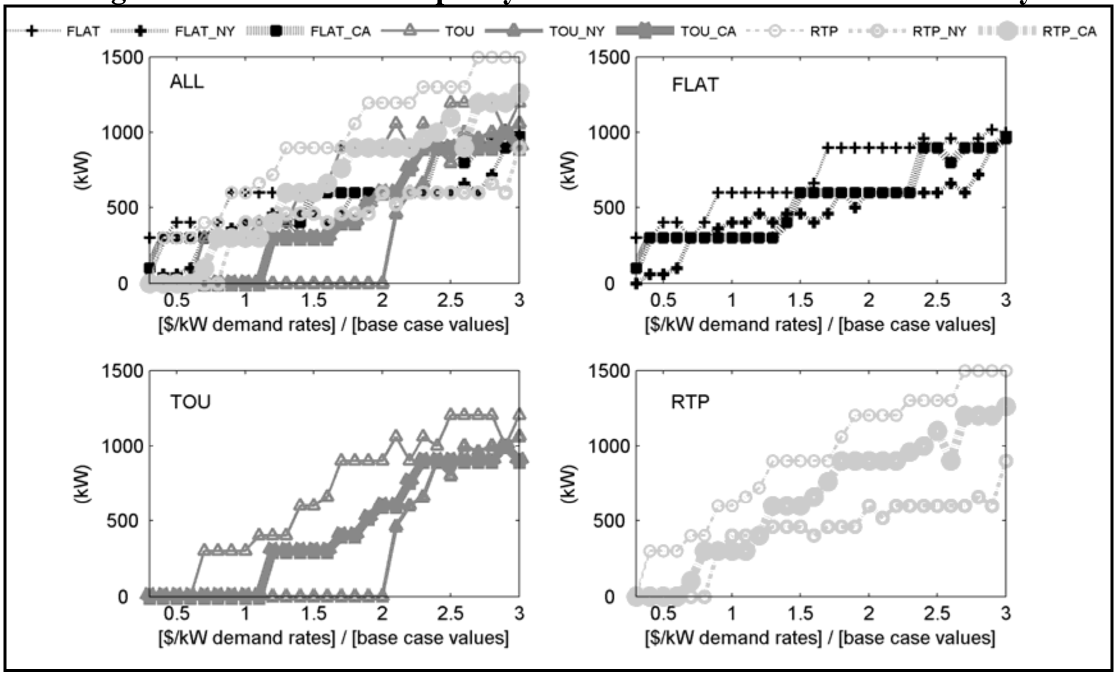
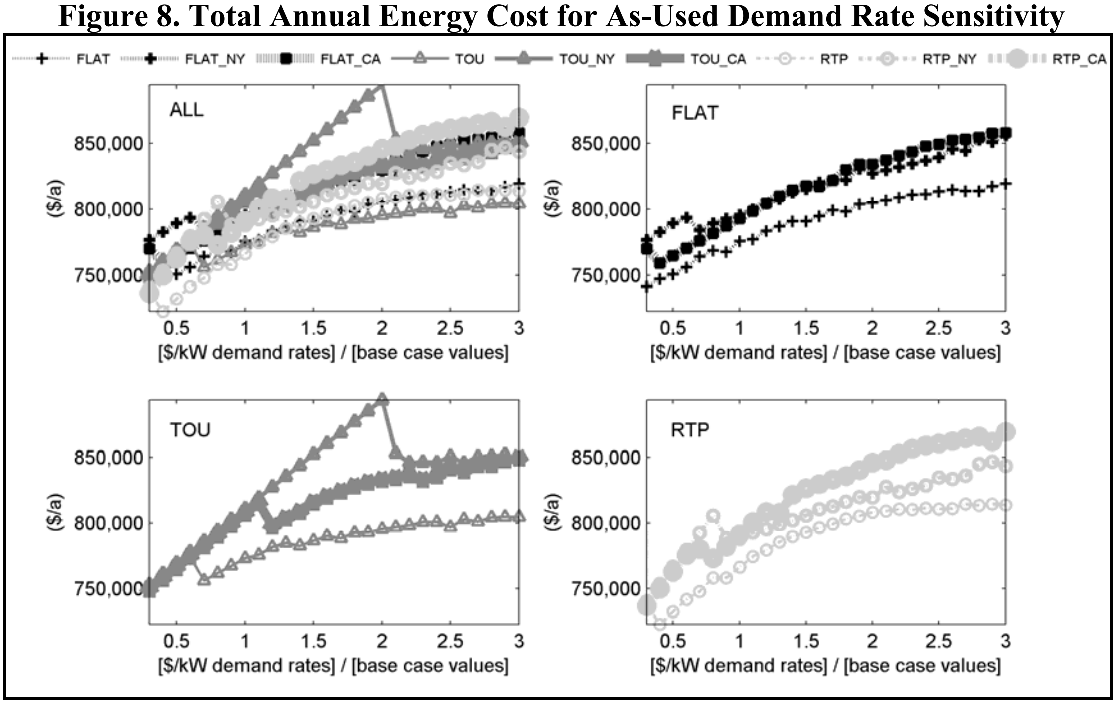


Figure 8. Total Annual Energy Cost for As-Used Demand Rate Sensitivity



Discussion and Conclusions

Standby customers consume utility electricity differently than if they purchased all of their power from the utility. The IOUs of New York State have successfully argued that because of this difference, standby customers should be charged differently than standard customers. As shown in this paper, altering electricity tariff structure affects the economic incentives to invest in DG. Understanding how these incentives change, and the resulting implications to customers, utilities, the public, and the environment is key to developing an effective DG policy.

Because standby tariffs simultaneously increase fixed utility electricity charges and decrease marginal utility costs, they are disincentives to DG investment. Standby rates tend to encourage base-loaded units (ones that are generating power most of the time) because on-site generation has a reduced ability to reduce demand charges, as a part of them are fixed. Consequently DG-capacity is less worthy. Although in general reducing the optimal size, standby tariffs only in two of seven cases lead to major changes in profitability for the DG developer. It should also be noted that daily demand charges instead of monthly charges can make demand charges and, therefore, energy bills more predictable and less risky for DG developers because of the reduced losses associated with DG outages. Analyzing the effects of the tariff structures on volatility in the energy costs is an interesting topic for further research.

From the perspective of a customer who wants to minimize expected costs, exemption from standby tariffs is desirable in most cases; in New York, systems under 1 MW that maintain an overall system efficiency of 60% or greater qualify customers for exemption. Also exempt are customers with fuel cells or DG systems fueled by renewable resources, sustainably-managed biomass, or methane waste. For larger customers, systems with high capital costs and low marginal energy costs may be more desirable under standby tariffs than under parent tariffs.

The sensitivity analyses demonstrate that as-used demand charges are proportionally more significant under typical parent tariffs (monthly demand) than under standby tariffs (daily demand). Parent tariffs' high cost of daytime demand encourages peak shaving (installing larger systems to operate only at peak demand hours), while the more reasonable standby tariff charges do not. However, for the tariffs considered, the price of electricity has a greater effect on DG system size than do the actual rate structures. The volumetric rate structure does not appear to be significant, while the standby structure does tend to reduce the capacity of DG systems. Given that standby tariffs imposed by the utilities will be based on cost, this study can be used to suggest countermeasures that public agencies can take to encourage desired levels of DG capacity installation. Adjusting the marginal cost differential between DG electricity production and utility purchase can effectively do this.

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