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Evaluation of Existing Customer-owned, On-site Distributed Generation Business Models

This article presents an economic model that studies customer-owned and operated distributed generation facilities. Results show that customer-optimized distributed generation facilities create quantifiable losses for distribution and generation and transmission utilities, and that further work will be required in order to create new business models that equitably share in the potential technical and economic benefits of distributed generation.

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I. Introduction

A variety of Smart Grid analysis and optimization studies have concluded that customer-owned and customer-operated distributed generation (DG) can realize specific economic benefits for utility customers.[1,2,3,4] These studies of DG operation and control have focused on rigorous minimization of customer costs, without consideration for the other stakeholders in the DG transaction. Previous research has already investigated multi-objective optimized solutions that balance customer economics with environmental concerns,[5] but there has been little research that simultaneously considers the economic effects of DG on all of its market participants. If properly sited and implemented,[6] DG

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facilities benefit utilities through grid capacity upgrade/expansion deferrals and reduced demand (i.e. reduced costs), but there is not currently a thorough understanding of the net economic effect of a DG facility for distribution or generation and transmission (G&T) utility stakeholders. Utilities are primary stakeholders in the electrical market and their participation and buy-in to customer-owned DG business models will determine the degree to which the capabilities of DG will be realized in practice.[7]

Existing DG systems' business models[8] function by operating the distributed generator during any time when the levelized cost of generation using the DG resource is lower than the cost to purchase electricity from the utility.[1,2,3,4] Although this business model is simple, transparent, and has been demonstrated to provide value to the electricity customer, the long-term acceptability and viability of DG must account for real-world utility/customer interactions and interdependencies. A complete and effective utility business model is asserted by EPRI to require the following: (1) revenues must cover costs, (2) services must be performed reliably, and (3) costs and revenues must be allocated equitably among the stakeholders.[9]

Fort Collins, Colo., is the site of FortZED, a comprehensive community effort to create a zero-energy district in the downtown and university areas. The FortZED organizations participated in a U.S. Department of Energy Renewable Distributed Systems Integration (RDSI) Smart Grid demonstration. The RDSI attempted to lower the peak electrical load on two active distribution feeders (of approximately 15 MW capacity) by 20–30 percent through the implementation of customer-owned and customer-controlled DG systems. During the development of the demonstration, a first order analysis performed by the Platte River Power Authority (PRPA) using its traditional business models indicated that the FortZED DG program, active for approximately 300 hours/year, could cost PRPA more than $400,000 per year.[10] The primary driver of this financial impact was the reduction in the customer's charges related to coincident peak pricing, and secondarily, reduction in demand charges. This single real-world data point would suggest that traditional utility business models applied to DG may not meet the requirements for an effective business model as defined above. Beyond this local example, this hidden cost of DG is typical for many utilities and it has led to significant utility opposition against DG resources, limiting the use and benefit of these technologies.[11]

> *Currently, there is not a thorough understanding of the net economic effect of a DG facility for distribution or generation and transmission utility stakeholders.*

The goal of this study is to build on this example and the current state of the art in analysis of customer-owned DG systems, to more completely understand how the demands of customer-owned and operated DG function within current business models. This article presents financial models of the utilities involved in FortZED to more comprehensively understand (1) the business model that is currently motivating the development and control of customer-owned and operated DG resources, (2) the means by which utilities' costs and revenues can be affected by the DG resources, and (3) which alternative business models can create economic value from DG technology. Armed with this information, stakeholders for the Smart Grid technology can understand the true costs and benefits of DG to the utilities and other stakeholders.

II. Methods

A. Modeling scope

The financial model discussed in this article was built as a case study representative of DG

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installations that are located within the Fort Collins municipal utility's service region. It models the finances of the customer, the distribution utility, and the generation and transmission utility (G&T) as three separate economic entities. These participants are connected through established rate agreements between the customer and the distribution utility (Fort Collins Utilities Light and Power, or FCU)[12,13] and through contract delivery rates between the distribution utility and the G&T utility, PRPA.[14] These established connections as well as additional information such as PRPA's posted avoided costs[15] for generation provided by Qualifying Facilities as defined in Section 201 of the Public Utilities Regulatory Policies Act provide the mechanisms to track costs and revenues of any DG scenario for each participant using existing methods of value monetization.

Potentially, this model could analyze different scenarios of DG ownership and operation, such as a utility-owned and remotely dispatched DG facility at a customer location; however, this study will focus primarily on customer-owned DG operation and its effects on distribution and G&T utilities.

B. The business model for customer-owned DG

The customer's desire to independently own, site, and control DG systems derives from the economic incentives available through a DG business model that has been proposed numerous times in the literature.[1,2,3,4]

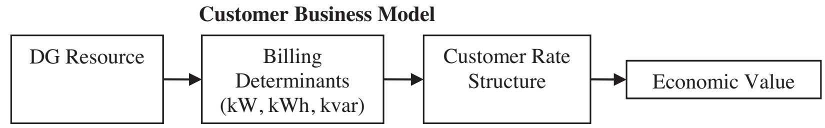

Figure 1: Traditional Customer Business Model for DG

Figure 1 describes this business model conceptually for the operator of an on-site, customer-owned, customer-operated DG resource. Billing determinants and a corresponding rate structure connect the technical abilities of the DG resource to an economic value for the customer. The electrical output of the DG system directly impacts the billing determinants (service connection, kW, kWh, kvar). The rate structure converts the billing determinants into the cost of electricity service ($/connection, $/kW, $/kWh, $/kvar).[9] Overall, the DG resource provides value to the customer by modifying their cost of electricity service.

Although this business model creates a pathway to connect a DG resource with economic value, it restricts the monetization solely to established billing determinants between the customer and the distribution utility. Other potential technical or economic benefits (such as availability of local backup generation, or government incentives[4]) are not monetized by this business model. Within this model, the customer is only able to monetize the purchase and operation of a DG resource through a reduction in total payments to the electric utility.

i. Distributed generation scheduling

Based on an understanding of this business model, the customer-owned DG can be controlled so as to reduce the customer's costs as much as is possible. For this study, the decision of when to operate the DG resource is formulated as a deterministic optimization problem. Daily customer load ($L(k)$) is given in 15-min increments ($k = 1{:}96$), and the DG output power is assumed to be controllable at the same level of discretization ($D(k)$). The billing determinants and daily customer costs for utility demand charges, energy charges, and fixed charges can be calculated as $c(L(k) - D(k))$. The cost of operating the DG resource can be calculated as $e(D(k))$.

Therefore the optimization problem can be stated as: find a control sequence $D(k)$ that minimizes the cost function (f) subject to the following,

Given: $L(k)$

Minimize:

$f = c(L(k) - D(k)) + e(D(k))$

Subject to:

$L(k) - D(k) > 0$, $D(k) > 0$

Since there are no technical (size) limits considered on a potential DG facility, technology or fuel source in this model; the system is constrained so that the customer cannot export power: $L(k) - D(k) > 0$, nor can the DG

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system absorb power: $D(k) > 0$. This problem is solved by using a gradient-based approach to perform coarse optimization, and a pattern search algorithm to perform fine optimization.

Figure 2 shows an example customer seasonal load curve[16] used in this economic model and the affected load curve after a customer optimizes its DG utilization based on its billing structure: one example contains a demand charge on the customer's own peak (FCU GS25),[17] and the other has a more severe penalty on energy use during the distribution utility's coincident peak hour (FCU GS50).[18] In both cases, the customer uses the DG installation to target and displace higher cost electricity during peak hours. This focus on reducing the high cost of peak load is also known as ''peak shaving'' and is a typical mode of operation associated with DG projects.[1,2,3,4]

Figure 3 shows the GS25 customer load curves optimized for levelized costs of DG between 0.07 and 0.15 $/kWh. As the cost to build and operate a DG facility becomes cheaper, the customer can realize an economic benefit by displacing more and more of the peak load until the cost of DG electricity begins to approach the basic energy charge for baseload electricity (in this model, approximately: DG rate = 0.06 $/kWh). This exercise shows that under the traditional customer-owned DG business model, the customer is incented to respond to the relative price difference (cost savings) between its utility rates and its DG installation and fuel costs.

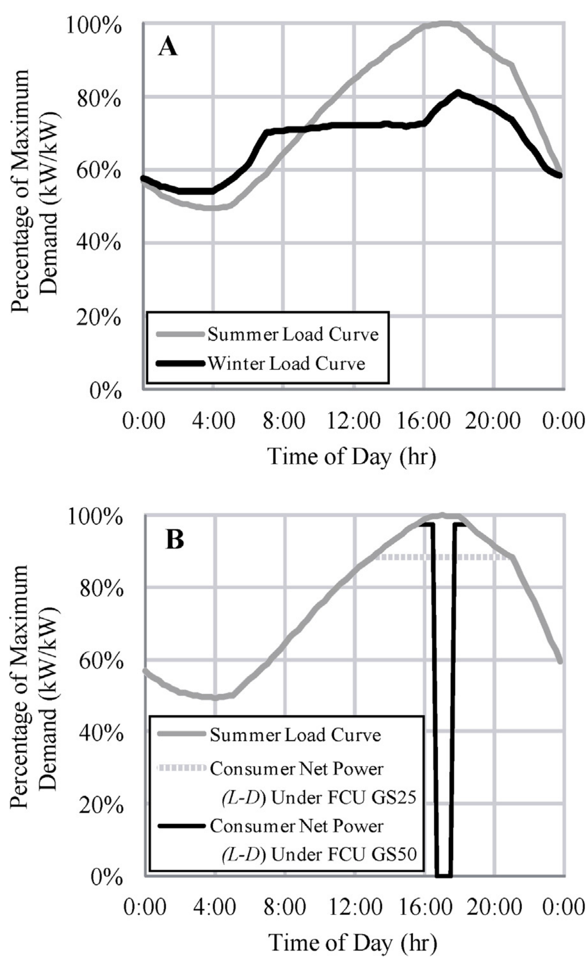

Figure 2: Example of Optimization Input and Output for the Case Study Customer. (A) The customer's power demand curves for summer and winter without DG. (B) The standard summer load curve compared to load curves with DG implementation under either simple peak rates (FCU GS25) or a combined peak and coincident peak rate pricing structure (FCU GS50)

III. Case Study Results

The results presented in the previous section are quite conventional and correspond qualitatively and quantitatively to results presented in the literature on optimal scheduling of DG resources for maximizing customers' benefits. In the following sections, we present the results of the case study in which we consider the effect of this type of generation scheduling on the balance sheet for the customer and for the utility stakeholders.

A. The effect of customer-owned DG on the customer

An illustrative example of the effects of this business model on the customer's balance sheet can be constructed from a case study of a participant in the FortZED RDSI project. This example utility customer resides in Fort Collins as a GS50 customer[12] and operates a

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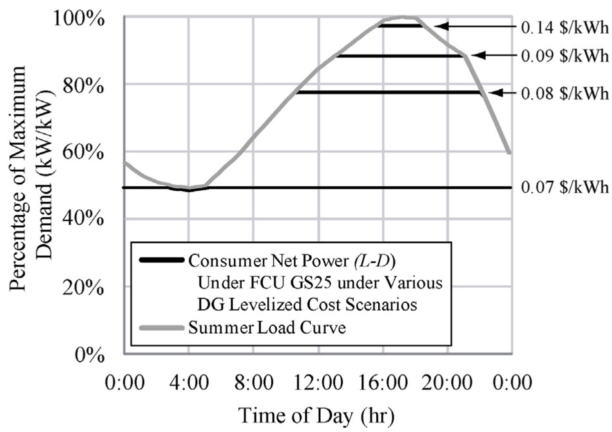

Figure 3: Optimized DG Use Profiles for GS25 Customer During Summer 2012: DG Implementation Increases as DG Cost Decreases

load profile similar to the published average for the PRPA region with a typical peak load of 75 kW at approximately 5:00 PM. This customer will choose to build and operate a dispatchable DG resource so as to realize the maximum possible economic benefit available. For this specific example, we estimate a levelized cost of \$0.11/kWh (including installation, fuel, and operation) for a DG resource.[19] **Table 1** lists the cost elements and billing determinants of the utility-customer rate structure without and with the DG resource.

As shown in Table 1, if the customer does not purchase and use a DG resource, its monthly payment to FCU will be \$2889.79. By using a DG resource and controlling to perform peak shaving as derived and presented in Figures 2 and 3, the customer reduces its billing determinants and therefore its costs to the utility to \$1966.51. The levelized costs of DG operation

Table 1: Calculations Associated with Evaluation of the Customer Business Model for DG.

Monthly Customer Balance Sheet
Schedule GS50, Summer Season 2012

Without DG (Baseline)	Billing Determinant		Rate		Total
Fixed Charge	1	Acct.	21.02	$/Month	$1.02
Demand Charge (co. peak)	74.9	kW	10.36	$/kW	$776.04
Energy Charge	40984	kWh	0.0372	$/kWh	$1524.59
Distribution Charge (peak)	75	kW	5.52	$/kW	$414.00
Tax and Franchise			6%	of subtotal	$164.14
Total Utility Bill					$2899.79
Levelized DG Costs	0	kWh	0.11	$/kWh	$0
Total Customer Costs					$2899.79
With 75 kW DG					
Fixed Charge	1	Acct.	21.02	$/Month	$21.02
Demand Charge (co. peak)	0	kW	10.36	$/kW	$0
Energy Charge	38579	kWh	0.0372	$/kWh	$1435.12
Distribution Charge (peak)	72.3	kW	5.52	$/kW	$399.05
Tax and Franchise			6%	of subtotal	$111.31
Total Utility Bill					$1966.51
Levelized DG Costs	2405.1	kWh	0.11	$/kWh	$264.56
Total Customer Costs					$2231.07
Customer Monthly DG Benefit					**$668.72**
Customer Projected Payback Period					10.9 years

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are considered an offset to the difference in utility costs so that the net benefit of owning and operating the DG resource is $689 per month. As long as this savings justifies a Minimum Acceptable Rate of Return (MARR) analysis on the initial cost of a DG system, this net monthly value gain result justifies the ownership and operation of a customer-owned and controlled DG resource under the assumption that customers will use the least cost means to meet their needs for a required quantity, timing, and power quality of electricity service.

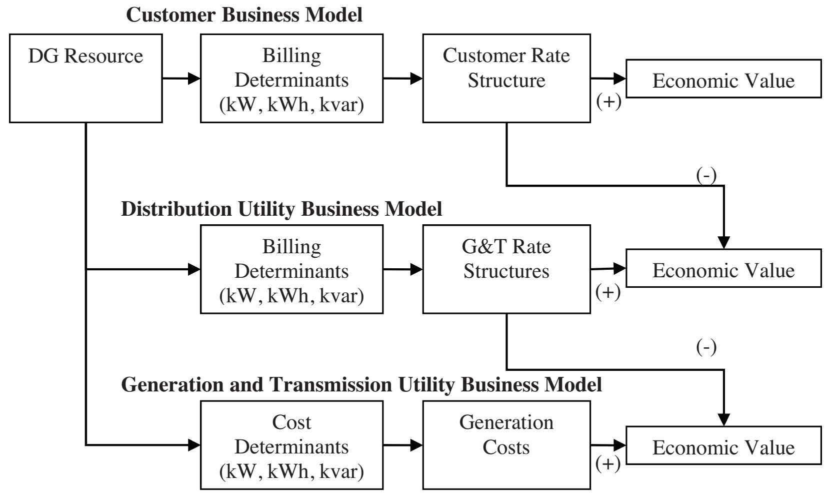

Figure 4: Traditional Customer, Distribution Utility and Generation and Transmission Utility Business Models for DG

B. The effect of customer-owned DG on the utilities

For utilities, the economic effects of an on-site, customer-owned DG resource are more complicated. Figure 4 illustrates the positive and negative economic signals (benefits and costs) of a customer-owned DG resource within the combined customer-utility business model. In this case study, FCU serves the Fort Collins, Colo., area as the municipal distribution utility. Here, we also include a model of the G&T utility. With the exception of a negligible amount of DG (primarily residential roof-top solar panels) FCU purchases 100 percent of its electrical power exclusively from the G&T utility, PRPA. PRPA employs conventional utility-scale generation assets (primarily coal with some hydropower, wind, and natural gas peaking units) to supply FCU as well as some other investor-owned, municipal, and rural-electric cooperative utilities in the region.

As illustrated by the signs associated with the connections in Figure 4, the customer-owned DG resource has both a positive and a negative impact on the economic value realized by the distribution utility. The customer with DG will buy less electricity from the distribution utility (that therefore receives less revenue), but the distribution utility is also obligated to buy less electricity from the G&T utility (and therefore incurs less costs). The characteristics of the billing determinants and the scheduling of the DG resource directly impact whether the sum of these two effects creates or diminishes costs for the distribution utility. In other words, the distribution utility will gain value from the customer-owned DG resource only if money saved from reduced outlays to the G&T is greater than the loss in revenues from decreased electricity sales to the customer. Distribution utility fixed and capital costs are outside of the business model.[20]

G&T utilities obtain revenues from distribution utility payments based on the rate structures and contracts in place between the distribution utility and the G&T utility. The G&T utility's primary costs are concerned with the generation and transmission of electricity. As the DG resource offsets load demanded by the customer, the G&T will sell less electricity to the distribution utility (reduced revenues), but also require less fuel and transmission capacity (reduced costs). The net economic impact is the sum of these two effects. Therefore, similar to the previous case for the distribution utility, we can calculate the net effect of the DG resource by analyzing the separate effects of DG on the costs and revenues of the G&T utility.

For our case study, the G&T utility owns coal-powered

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generation resources that it runs at a high availability factor, and natural gas generation resources that it runs as peaking generation. In summer, the utility uses both resources to meet peak demand, and marginal electricity costs are those costs associated with the peaking generation.[21] In winter, the utility uses the coal-powered generation unit at high utilization and sells excess electricity in the electric wholesale market. Thus, in the winter months, the marginal costs of generation are related to the current price of electricity on the Palo Verde trading hub.[22] PRPA combines this price information with the associated plant and transmission infrastructure costs (capacity costs) to publish a set of rates for avoided costs that applies to certain qualifying facilities that supply power to the grid independent of the utility. This model uses these avoided energy and capacity rates to conservatively estimate the total avoided cost for the G&T utility.

The results of this analysis for the traditional business model are presented in **Table 2**. Table 2 completes the previous case study to show the economic impact of the sample customer-owned DG on the distribution and the generation utilities. As shown in Table 1, the customer realizes a net benefit from its optimized use of the DG resource of $668.72 per month. For the distribution utility, this lost revenue is approximately offset by a decrease in its billing determinants and therefore costs from the G&T utility. To the distribution utility, the net value of the customer's DG operation is a negligible −$39.98 per month. The G&T utility loses revenues from lower billing to the distribution utility that is not made up by the reduced costs of purchasing/generating electricity. The net loss to the G&T utility from operation of the customer-owned DG resources is $505.97 per month.

Table 2: Economic Effects of Customer-Owned DG on Distribution and Generation Utilities.

Monthly Utility Balance Sheet Schedule GS50, Summer Season 2012			
Customer (DG Operator)			
Customer Monthly DG Effect			$668.72
Distribution Utility			
Without DG (Baseline)		*With Customer-Owned DG*	
Revenues from Customer	$2725.80	Revenues from Customer	$1848.51
Expenses to Utility	$2192.57	Expenses to Utility	$1355.27
Profit	$533.23	Profit	$493.25
Distributor Monthly DG Effect			$−39.98
Generation and Transmission Utility			
Change to Revenues			$−837.31
Change to Costs			$−331.33
G&T Monthly DG Effect			$−505.97

This analysis demonstrates the means by which distribution and G&T utilities lose economic value through the operation of a customer-owned DG facility.

This analysis is repeated at a range of DG facility costs and for two of the rate structures available to FCU customers (FCU GS25 and FCU GS50). Results are presented in **Figure 5**. In each case, the ratio of the stakeholder's cost increase to its baseline cost (without DG) is plotted to show its sensitivity to DG levelized costs. A positive value to a particular stakeholder implies an economic incentive for customer-owned DG operation. A negative value for a particular stakeholder implies that that stakeholder is losing economic value as a result of the operation of the customer-owned DG. The fraction of monthly energy generated by the DG resource to the customer's monthly baseline energy consumption is also plotted on the same axis.

Figure 5 illustrates a number of results of interest. First, customer-owned DG resources robustly create combined losses for the utility stakeholders (both distribution and G&T utilities) at a variety of customer rate schedules and DG conditions. Second, comparing these results among rate schedules shows that under the current business model, small customers (who would

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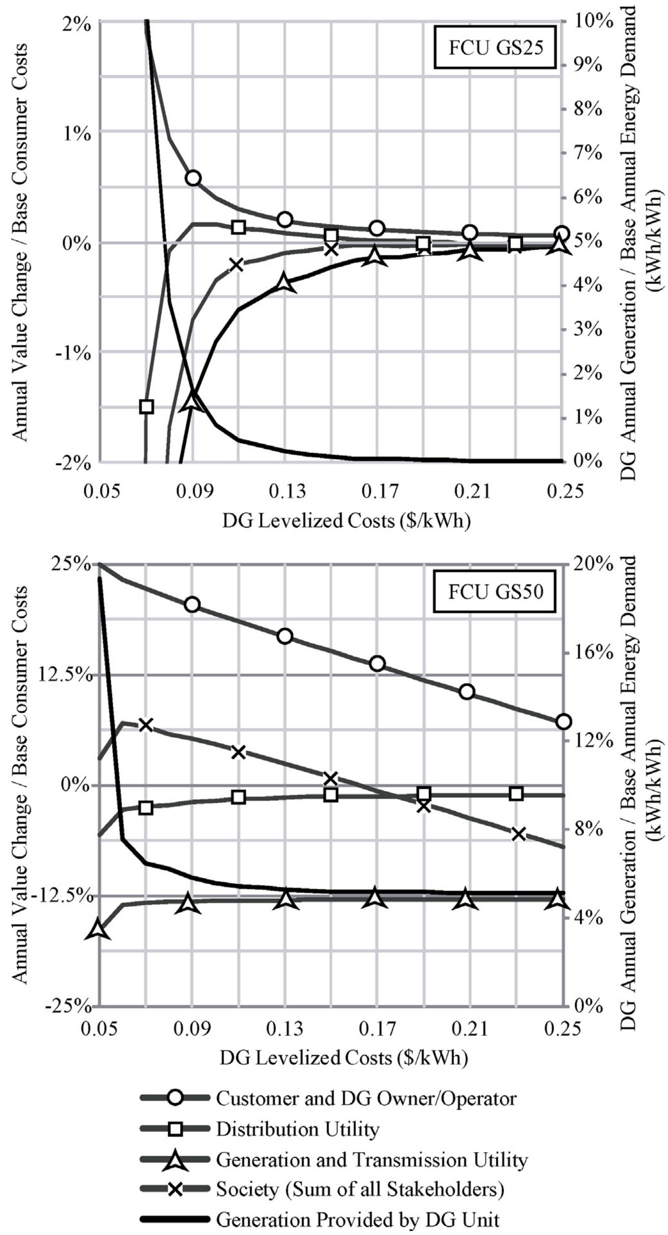

Figure 5: The Economic Effects of Customer-Owned DG Resources on Utilities and Society

operate under the GS25 rate schedule) will realize only small benefits from DG. The value realizable for such a customer is relatively insignificant (less than 2 percent of the customer's annual bill) and is only achievable if DG has very low levelized costs. Only larger customers that are under the GS50 rate structure will realize significant benefits from operating DG. Third, Figure 5 presents a plot of the net benefits to the society (defined as the signed sum of the value to the three stakeholders) as a function of DG levelized costs. For small customers operating DG under the conditions here, the sum of benefits to all stakeholders is uniformly negative, implying that although the customer is incented to operate the DG resource, the sum of costs to society is greater than the sum of the benefits. Whether larger customers operating DG creates benefit or detriment to society depends on the cost of the DG facility – at high cost even optimally dispatched DG creates more total losses than savings.

IV. Discussion

The results for this case study show that with the currently available utility business models, both the distribution and G&T utilities lose value when the DG resource is customer-controlled and -operated. The current business models to monetize the performance of on-site DG fail according to our definition of a complete and effective business model in that they do not allocate costs and benefits equitably among the stakeholders. A few near-term strategies exist to improve the traditional business model for customer-owned and operated DG. For the purposes of this discussion, we have classified them as either competitive or cooperative interactions among the stakeholders.

A. Cooperative business models

A majority of studies of the technological capabilities of DG have hypothesized that cooperative DG business models would evolve that would enable a connection between the technical

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capabilities of DG to economic value.[23] The technical capabilities most commonly ascribed to DG are: generation capacity deferral, transmission capacity deferral, distribution capacity deferral, voltage control or VAR supply, ancillary services (A/S), environmental or emissions benefits, reduction in system losses, energy production savings, reliability enhancement, power quality improvement, combined heat and power, demand (charge) reduction, standby generation, and more. These technical benefits of DG have been quantified by many studies,[23] but there are disconnects between the technical capabilities of customer-owned, on-site DG and the business models that can monetize those benefits. Hypothetically, each of these capabilities could be monetized, but not all by the same entity (some benefits are only applicable to the customers, some are only applicable to the utilities).

Utilities have had difficulties monetizing DG technologies perhaps because these benefits do not rely on the traditional utility business models of economies of scale and economies of scope. Rather, DG depends on economies of mass production, of proximity to the loads that they serve, and of ease of operation.[24] The differences between traditional utility business models and the capabilities of DG suggest that cooperative interactions will require a complete revision of the business models for all stakeholders as well as some degree of technical development in siting and scheduling that can allow DG to achieve a positive societal benefit.

B. Competitive business models

More typically, competition among the stakeholders informs the development of new business models. As detailed in the results section, DG resources can provide economic benefits to the customer to the detriment of the distribution and generation utilities. In many real-world cases where DG installations have been proposed or implemented, we have found that utilities have chosen to restructure their rates in order to reduce their exposure to DG-generated losses.

The economics of a customer-owned distributed generation facility typically involves a large initial capital investment repaid over a projected period through reduced payments to an electricity provider. The length of these payback periods and the ultimate return on a DG investment is heavily dependent on the predictability of the electric rates between the customer and the utility. Small changes to rate structure can have a profound impact on the economics of a DG system, even pushing it outside of the definition of a ''sound investment'' for the customer.

As an example, the G&T utility in our FortZED case study, PRPA, has significantly shifted its contract rates between 2011 and 2012. The new 2012 rates deemphasize coincident peak charging ($/kW) in favor of an increase to the energy charge ($/kWh). The distribution utility, FCU, has also passed through a general restructuring of its rates including changes to the demand, energy, seasonal, and block rates. Though multiple issues and negotiations certainly precipitated these changes, it is clear that it will have a large impact on DG recovery periods for customers and the distribution utility, and will thus be of interest to this model. Table 3 illustrates the economic impacts of these changes on a customer's projected payback period.

In this example, a customer sites and installs a DG facility in 2011 and projects a payback period of 6.3 years. After the first year (with only five years and four months until payback remaining), the utility switches the customer to the 2012 rates which reduces the customer's

Table 3: Comparisons Within the DG Payback Period Analysis using 2011 and 2012 Rates.

Payback Period Analysis	GS50 Customer	75 kW DG Resource
Capital Cost = $651/kW	Variable Cost = $0.11/kWh	Inflation = 3%/year
Payback Projected with 2011 rates		6.3 years
Payback Projected with 2012 rates		10.9 years

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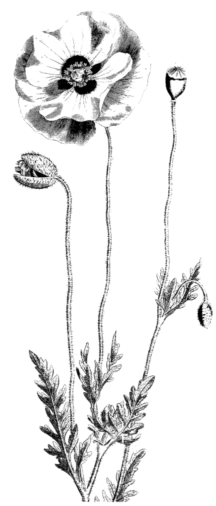
ability to gather value from the DG resource and delays the remaining payback period by nearly four years (10 total years until payback under this rate switchover scenario). This example used a larger customer with coincident peak pricing rates. This problem becomes even more complicated for a smaller-sized customer paying normal peak demand rates, in these cases, the customer will size a DG resource according to 2011 rates and find that under new rates, their payback period lengthens to beyond 20 years.

V. Conclusions

While a patchwork of inconsistent regulations require some U.S. utility companies to promote energy efficiency (EE), distributed generation (DG), and renewable energy (RE) projects, regulators and utilities have not widely implemented new business models that financially reward utility companies for selling less electricity or delivering more renewable electricity. This project has evaluated a set of financial models for sample utility companies to understand the degree to which their revenues and finances will, in fact, be impacted by DG projects. This research demonstrates the need for new business models and rate structures between utilities and customers that can provide a healthy, sustainable incentive for well-sited and operated DG facilities.

The case study of PRPA/FCU and our model customer can facilitate the introduction, evaluation, and development of new business models specific to our case study. Through the development of generalized methods for business plan proposal and analysis, this work has provided a means to understand the true costs and



benefits to stakeholders in this type of Smart Grid demonstration. Our future work will focus on quantifying and developing new electricity market business models that better internalize the costs and benefits of distributed generation projects between the three major market participants (G&T, distribution utilities, and customers) tailored to conditions in other utility companies' service territories.■

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20. Customer-sited and controlled DG facilities still require the same quality and quantity of distribution connections, billing, and service personnel. Proposed distribution-system benefits of DG are only available with distribution system-optimized DG siting and control.

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Currently, there is not a thorough understanding of the net economic effect of a DG facility for distribution or generation and transmission utility stakeholders.

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