An Evaluation of Customer-Optimized Distributed Generation in New England Utility and Real-Time Markets

The full worth of distributed generation systems must be measured not only by the impact on the customer, but also by DG's impact on the grid and surrounding market participants. A case study comparing customer incentives created by utility rates with the real-time prices market in New England provides a new model to quantify the value of customer peak shaving with distributed generation technologies.

Ray C. Duthu and Thomas H. Bradley

Ray C. Duthu *is a graduate research assistant in the Department of Mechanical Engineering at Colorado State University. He is pursuing his Ph.D. research in financial modeling and economic optimization for energy technologies.*

Thomas H. Bradley *is an associate professor of Mechanical Engineering in the College of Engineering at Colorado State University, where he conducts research and teaches a variety of courses in systems engineering, systems architecture, and techno-economic analysis.*

I. Introduction

Much of the previous research in smart grid analysis and customer demand-side management (DSM) agrees that there are quantifiable, specific economic benefits for customers who own and operate distributed generation (DG) facilities (Pedrasa et al., 2010; Walneuski, 2004; Sioshansi et al., 2009; Butler et al., 2003; Thornton and Monoy, 2011; Adhikari et al., 2012). These same studies are far less specific in their analysis of the effect of these technologies on the other stakeholders in the electricity marketplace, including the generation and transmission utility (G&T), the distribution utility, and the rest of society (primarily other customers). Practitioners in this field

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understand that, in general, the most expensive hours to generate and transmit electricity are contemporaneous with the hours of maximum energy demand, and thus we frequently treat customer daily peak shaving, as actuated through utility rates, as an economic and social good (Bayod-Rújula, 2009; Karger and Hennings, 2009; Leadbetter and Swan, 2012; Levron and Shmilovitz, 2012). In this study, we seek to understand how sensitive the economic valuation of DG is to its actuation signal, and whether or not conventional peak-shaving is the optimal customer behavior that yields the maximum benefit to the customer and other stakeholders (Olsen et al., 2013; Hummon et al., 2013).

II. Background

EPRI proposed a market trajectory of DG in 2001 with considerable optimism, predicting that 25 percent of new generation would come from distributed sources by 2010 (Ackermann et al., 2001). Although the integration of DG has not kept up with those goals, the general sense of optimism has persisted, fed both by the quantifiable financial value of DG to the consumer, but also the potential system-level benefits associated with DG facilities (El-Khattam and Salama, 2004). These potential benefits associated with DG and other customer energy systems have been quantified in previous research (Ianucci et al., 2003) and include utility investment deferral, voltage control, line loss reduction, new sources of standby generation, and several others. However, as the prevalence and integration of DG has steadily increased with time, and DG's effect on the grid and the electricity market has become better understood, the value of these ancillary benefits has become more ambiguous (Pepermans et al., 2005; IEA, 2002; de Joode and van Werven, 2005; Newman et al., 2011). Intermittent, non-dispatchable DG sources offer no real benefit to reliability (Newman et al., 2011; Borges, 2012), a DG unit has a better impact on line loss reduction when generating constant power rather than peak-shaving (Marinopoulosa et al., 2011), and adapting the grid to handle high DG integration has a cost: without active management technologies, the grid may not be able to handle multiple customers acting as independent players in the energy market (Peças Lopes et al., 2007). Line safety, power quality, and increased congestion in other systems (such as natural gas pipelines) could create new expenses that may offset DG's benefits (Pepermans et al., 2005). Without customer–utility coordination, improperly sited DG facilities may contribute to issues related to voltage flicker, harmonic distortion, overcurrent protection, capacity limits, etc. (Barker and de Mello, 2000; Coster et al., 2011). Additionally, unless these customers are actively participating in the frequency control market, DG systems will likely exacerbate frequency oscillation during significant events (Peças Lopes et al., 2007). Combined heat and power DG systems, while efficient, are dispatched according to a customer's individual heating and cooling needs and are less responsive to market signals, thereby potentially creating a new layer of difficulty in market demand prediction (Peacock and Newborough, 2006; Kamphuis et al., 2004). Price volatility is another concern: while DSM is often expected to reduce price volatility (Goel et al., 2006), unilateral customer behavior creates a new source of volatility in the market (Roozbehani et al., 2012).

Without customer–utility coordination, improperly sited DG facilities may contribute to issues related to voltage flicker, harmonic distortion, overcurrent protection and capacity limits.

The potential benefits to DG can best be realized, and the potential costs best avoided, through increased customer–utility coordination and cooperation (Barker and de Mello, 2000; Coster et al., 2011; Goett and Farmer, 2003; US Dept. of Energy,

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2007). Coordinated planning between utilities and customers is essential since customers are able to purchase and construct DG facilities on a much quicker timescale than the legal time it takes for a utility to execute projects and grid upgrades (Coster et al., 2011). For example, optimal siting discovery and policy is important to preserve DG's potential ancillary benefits (Georgilakis and Hatziargyriou, 2013), but customers may not be well-informed, and without this increased level of cooperation, utilities do not have any control or input on the siting of customer-owned DG (Barker and de Mello, 2000). Much of the research assumes that customers have perfect information of the electric market while modeling the results of DG siting decisions (Eyer and Corey, 2010), but this is hardly the case under a traditional monthly tariffs rate structure which at best only approximates (and at worst ignores) price effects according to locational and temporal differences. These traditional rates typically are the same for all customers in a large region and split charges between fixed/energy/demand rates, which provide value and incentive towards daily customer DG peak-shaving. Many of the challenges to DG integration hinge on this lack of customer market participation and cooperation with utilities. But, DG systems, when properly incented as smaller, more nimble generation units, may be able to adapt faster and better to changing price signals than utility investment in larger facilities (Manfren et al., 2011). The RTP market is one step towards improvement in customer–utility cooperation as it connects customers to the actual prices in the market and incents optimal DG siting through different regional and distribution-level prices. Previous research has already indicated that the potential valuation of DG technologies would be greatly enhanced in the RTP market (Sezgen et al., 2007).

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RTP is a relevant and realizable means to improve the value of DG through improved coordination between customers and utilities. RTP and advanced metering are DSM-enabling technologies, but these also rely on increased customer involvement and market participation (Manfren et al., 2011; Owen and Ward, 2006). Advanced metering and correct pricing systems are essential to measuring and tracking DG's ancillary services to the grid and in shifting the grid system from the passively controlled ''top-down'' model to an actively controlled ''bottom-up'' approach which allows greater DG integration (IEA, 2002; de Joode and van Werven, 2005; Kamphuis et al., 2004). Customers in the UK (Wood and Newborough, 2003; Marvin et al., 1999) and Hong Kong (Mah et al., 2012) appear to welcome smart grid technologies, but similar interest may be limited to only a subset of American customers (Alexander, 2010; Merrion, 2011). Whether or not the smart grid and RTP should be optional or mandatory in the United States may be a matter of dispute (Gordon et al., 2006; Alexander, 2010), but previous successes with time-of-use (TOU) rates have demonstrated that customers, when armed with a greater understanding of the factors which determine electricity prices and an improved source of billing information, are capable of shifting their load profiles in order to meet mutually beneficial objectives (Hartway et al., 1999; Faruqui and George, 2005). In a case study in the UK, customers responded positively to instantaneous feedback on electricity use and costs related to appliance use and were able to shift more power use than those customers who only received mailed-in paper feedback (Wood and Newborough, 2003). Customers still have their own priorities, and it is not entirely clear what form future markets will take, but it is clear that some

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change towards a greater flow of information will occur (Bertoldi and Huld, 2006; Houseman, 2005). Already in the American Midwest, customers with ComEd are able to purchase electricity at an optional RTP (ComEd).

For customer-owned distributed generation to succeed, it must exist within a sustainable customer–utility business model – revenues must cover costs, and value must be allocated equitably among the shareholders. DG systems cannot flourish if the costs outweigh the benefits, and these benefits cannot be fully realized without buy-in from both the customer and its utility. Utilities' traditional business models are unprepared to accommodate DG technologies sustainably (Goett and Farmer, 2003; US Dept. of Energy, 2007; Duthu et al., 2014; Block Island Power Company, 2008). These unsustainable markets may create significant potential for economic benefits that may be accrued by DG operators, but ''gaming'' these traditional utility rates comes at a cost to the rest of society. In previous research, the authors developed a case study of municipal generation, transmission, and distribution utilities in the Fort Collins, Colo., region to demonstrate that customer-optimized peak-shaving within traditional pricing and business models can create quantifiable losses for utilities. These losses could be passed back to other customers through higher rates, or utilities may hedge against future DG losses by adjusting the rate structure (such as by deemphasizing demand costs) leaving DG customer–operators with significant stranded costs.

To extend this previous analysis (which only considered demand and energy pricing), we seek to develop a series of case studies inclusive of the ''higher quality'' actuation signal that would incent a DG unit using the RTP market (Collazos et al., 2009). The case study is presented along a continuum of increasing customer information: traditional utility rates, the day-ahead market, the final hourly market, and the 5-min spot price market. This research will compare the customer DG response incented by utility rates at three communities within the New England Independent System Operator (NEISO) region with the DG response incented by the real-time distribution locational marginal prices (DLMP) at each community. We will quantify the potential value of daily peak-shaving incented by utility rates by comparing the customer's optimized DG operation profiles to measure the correlation, value, and market value with a ''more-idealized'' RTP DG dispatch. At the core of this study is the comparison of the relative magnitude of time-of-day price variations against the sharper price spikes that occur on a less predictable timescale.

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III. Methods

This case study will compare an identical customer at three nodal locations within the NEISO region: Portland, Maine (node 4179); Rutland, Vt. (node 4459), and Hartford, Conn. (node 4534). Each of these locations has its own distribution utility: Central Maine Power Company (CMP), Green Mountain Power (GMP), and Connecticut Light and Power (CLP), respectively. The NEISO Web site maintains publicly available historical data for the real-time prices in the day-ahead hourly, final hourly, and final 5-min markets as well as hourly net system demand (NEISO, 2014). The customer in this case study has a load profile geometrically similar to the net system demand but scaled down such that its absolute maximum peak load during 2013 is 350 kW. This customer size compromises between categorizations on the various utilities' rate sheets. It is also appropriately large such that building and operating a DG

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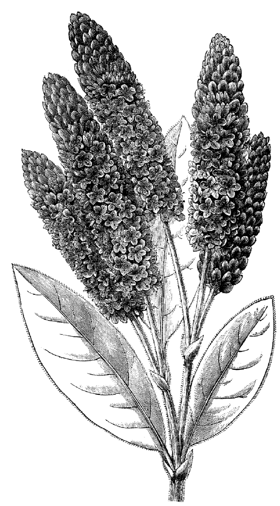
facility of 100 kW primarily focuses on load displacement rather than power insertion (electricity sales) into its local network. This case study will primarily consider the levelized costs for the purchase and operation of a DG facility at $100 and $125 per MWh. These DG costs are slightly higher than has been published for technologies such as microturbines and fuel cells (Nguyen et al., 2014), but energy costs, especially natural gas costs, are higher in New England and show signs of remaining high for the foreseeable future (Ford and Peterson, 2014). The DG facilities in this case study are assumed to be freely dispatchable for use in peak-shaving or electricity sales (Faria and Vale, 2011). These units face a capacity limit based on the size of the unit, but have no temporal (such as with a combined heat and power system), fuel (limited byproduct feedstock), or energy limit (such as a battery).[1]

This case study will take a broad view by considering the hourly RTP signal and utility rates over a multiyear period for Rutland, Vt.; and a more in-depth analysis by considering the most recent 12 months in the analysis for all three regions, utility rates, and RTP types. The broad view or historical analysis will compare monthly trends for the final hourly RTP price, the utility electric rates, as well as the customer behavior while incented by either signal. The in-depth analysis over the final 12 months will compare the DG valuation and dispatch resulting from the various RTP markets and the utility rates at the three different locations.

A. Datasets

Data for the real-time prices in the day-ahead hourly, final hourly, and final 5-min markets as well as hourly net system demand



were acquired from the NEISO. There are occasional lapses in the data record for the 5-min market which are covered through linear interpolation for lapses less than two hours and by duplicating the final hourly price signal for longer lapses. The missing data accounts for less than 0.39 percent of the intervals for the in-depth simulation year. The records for the final hourly market, day-ahead market, and hourly system demand data over that same period are fully sound.

B. Tariff models

The various utility rates available to the customer were compiled from each utility's publicly available ratesheets.

In Portland, Maine, the customer tariff is modeled with distribution costs according to CMP's medium general service at primary voltage (Central Maine Power Company, 2013) and G&T costs set monthly by NextEra Energy Power Marketing (State of Maine Public Utilities Commission, 2013a,b,c). Portland's distribution costs are modeled as per the ratesheet as a split between service, energy, and demand charges. The demand charge is based on the customer's own 15-min peak. NextEra's G&T rates for medium-class customers are represented with a monthly varying energy charge which could theoretically accommodate for seasonal effects or planned plant shutdowns.

The customer tariff in Rutland, Vt., is modeled according to the GMP rates for customers previously covered by the Central Vermont Public Service Corp. before its merger with GMP (Green Mountain Power Corporation, 2013a). These rates also cover service, energy, and demand charges with a declining block rate for the energy charge and a small free block for the first few kW of maximum demand. The demand is also defined as the customer's own 15-min peak.

The Hartford, Conn., customer's tariff is modeled according to CLP's small time-of-day general electric service ratesheet (The Connecticut Light

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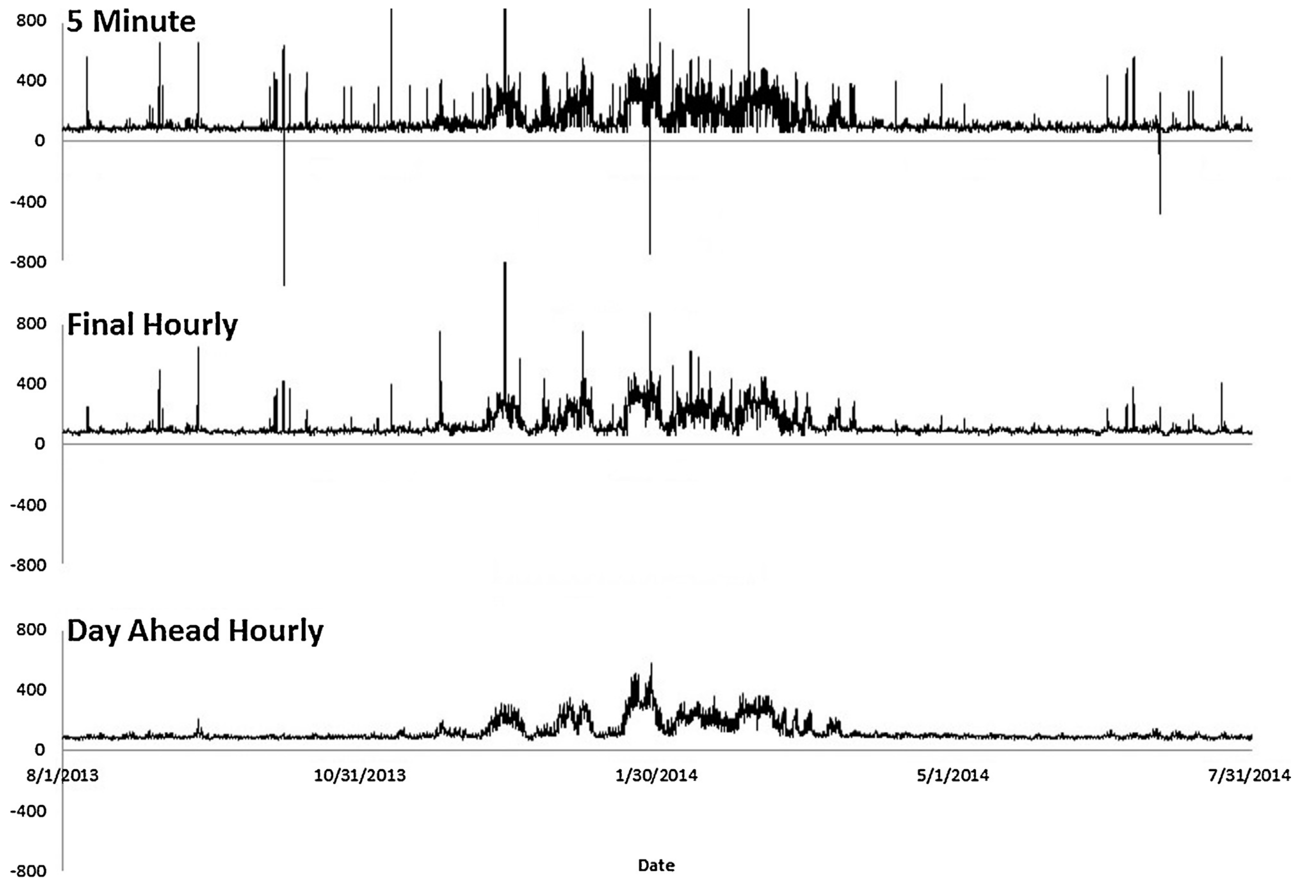

Figure 1: DLMP Comparison ($/MWh) Node 4459 – Rutland, VT

and Power Company, 2014). The rates are split into a variety of small line items charged by either energy or demand, many of the larger of which are split into on-peak and off-peak time regimes. The on-peak regime is defined as weekdays from 12 pm to 8 pm during Eastern Standard Time and 1 pm to 9 pm during Daylight Savings Time. The demand is measured as the customer's highest average 30-min demand during the on-peak hours.

As the utility rates described above are for distribution level costs, and the RTP market rates are wholesale nodal prices more analogous to G&T costs, some effort must be made to model distribution costs for the modeled RTP market. The formation of distribution level LMPs, or DLMPS, is an ongoing field of research (Sahriatzadeh et al., 2012; Meng and Chowdhury, 2011; Li et al., 2014) without a clear industry precedent. For this research, we have added a modeled cost of distribution to each customer's available RTP based on the difference between the utility rates and the nodal prices for each region. The RTP rates for each region are increased uniformly such that the customer, before owning and operating a DG facility, pays the same total bill over the in-depth period from the start of August 2013 to the end of July 2014, whether or not that customer chooses to pay utility rates or through the RTP market. **Figure 1** shows the resulting DLMP rates that are used for this case study for Rutland, Vt.

C. Customer DG models

The customer's size (max peak of 350 kW) and proposed DG facility size of 100 kW were selected to represent a realizable DG size that might be implemented for peak load reduction, but would not be a significant source of "net metering." The majority of the DG use will be put towards load

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displacement rather than injecting electricity back to the distribution network. The customers in these two models (utility rates and the DLMPs) will follow separate rules for net metering based on the policies of several of the utilities in this region. The customers who pay traditional utility rates can sell electricity back to the grid for monthly billing credits equivalent to their energy charge for electricity (State of Maine Public Utilities Commission, 2012; Green Mountain Power Corporation, 2013b; The Connecticut Light and Power Company, 2012). There is no reimbursement for a negative demand charge or against the fixed rate charges. The levelized distribution charges under consideration for this case study have been selected so that none are below the available energy cost of electricity. This study is more concerned with understanding customer behavior than in exploring the technical constraints of DG, and if a customer can generate electricity more cheaply than its utility's energy (fuel) cost, then there is no reason why it should not generate that electricity without limit. Therefore, with the DG's cost set above the utility energy charge, the utility rates paying customer under consideration in this model will not attempt to net meter and will only utilize the DG facility as a tool to peak-shave its own load. As the customer's load profile matches up with its demand charges and TOU rates in the region, this limitation does not have any material impact on the peak-shaving behavior or total DG valuation for the customers in this study. The RTP customer will also utilize its DG facility to offset its own electricity costs based on its DLMP, and will also be able to sell electricity back to the distribution utility according to the LMP (a lower rate than the DLMP). Two of the utilities in this study already

have a similar mechanism in place for selected customers and small generators (State of Maine Public Utilities Commission, 2004; The Connecticut Light and Power Company, 2006), and this allows the RTP customer to dispatch its own resources according to the ideal situation presented by the RTP market while still preserving some value for the distribution utility who provides the infrastructure for the customer's participation.

IV. Optimization

The customer is expected to optimize their own DG facility with the objective of minimizing the sum of DG operational costs, and electricity purchases from the grid.

As previously stated, the customer's load profile matches the shape of the hourly total system demand for the New England region. Since demand charges are often assessed on 15-min intervals (k), this hourly data was expanded through linear interpolation into 15-min increments ($L(k)$) for the traditional utility customer. Similarly, the signal was expanded into 5-min intervals (m) for the 5-min RTP customer. The DG facility is assumed to be dispatched on whichever is the smallest time window of interest for the customer ($D(k)$, $D(m)$, $D(12^*m)$), that is, a utility customer may dispatch the facility on a 15-min interval in order to properly perform peak shaving, a 5-min RTP customer may dispatch the DG facility for 5-min intervals, and similarly an hourly RTP customer may dispatch the facility on hourly intervals in order to displace or sell electricity.

For this study, the decision of when to operate the DG resource for utility rate customers is formulated as a deterministic optimization problem. 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 $e(D(k))$.

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

$$\begin{aligned}&\text{Given}: \ L(k)\\ &\text{Minimize}: \ f = c(L(k) - D(k)) + e(D(k))\\ &\text{Subject to}: \ L(k) - D(k) > 0,\\ &D(k) > 0\end{aligned}$$

According to the utility rates model, the customer receives certificates against its energy charges for electricity exports to the grid. Therefore, a utility rates customer with a dispatchable DG resource will only export to the grid if it can do so below this utility energy charge. This model does not include an upper boundary on the quantity of fuel or DG dispatch time available to the customer, so this ultimately leads to a DG utilization of 100 percent. In order to maintain a focus on peak-shaving behavior, DG costs below the customer's energy charge which lead to the optimization results that violate the condition against exporting power $L(k) - D(k) > 0$ are not included in this model. Additionally, battery or other types of energy storage facilities are not under consideration for this model (these facilities have both capacity and energy constraints) so therefore the DG system cannot absorb power, under the constraint $D(k) > 0$.

The decision of when to operate the DG resource for a RTP customer is more straightforward. Essentially, a RTP customer has a single decision point: this customer will operate the DG facility if grid supplied electricity is more expensive than its own generation costs. Since the customer is able to purchase electricity at its DLMP and export electricity at the nodal LMP, the decision expands into three possible solutions: (1) the customer will operate the DG facility at full power ($D(m)$ = 100 kW) when the current LMP is above the DG cost, (2) the customer will operate the DG facility at less than full utilization in order to displace only its own load subject to $L(k) - D(k) > 0$ when the DG cost is between the current LMP and DLMP, (3) the customer will not dispatch the DG facility when the DG cost is above the current DLMP. For a DG facility of maximum capacity of 100 kW, the problem can be stated for a 5-min RTP customer with the following where the LMP and DLMP cost functions are represented by $LMP(m)$ and $DLMP(m)$:

$$\begin{aligned}&\text{Given}: \ L(m), \ LMP(m) \ \text{and} \ DLMP(m)\\ &\text{IF}[LMP(m) > e(D(m))], \ \text{then} \ D(m) = 100 \ \text{kW, max DG power}\\ &\text{IF}[LMP(m) < e(D(m)) \ \text{AND} \ DLMP(m) > e(D(m))], \ \text{then} \ D(m) = L(m)\\ &\text{IF}[DLMP(m) < e(D(m))], \ \text{then} \ D(m) = 0\\ &f = DLMP(MAX(0, (L(m) - D(m)))) - LMP(MAX(0, (D(m) - L(m))))\\ &\quad + e(D(m))\end{aligned}$$

where the cost function f is defined by three terms, the remaining energy payments at the $DLMP(m)$ to the utility after energy displacement, value generated for the customer through electric sales/import into the grid at the $LMP(m)$ and new costs imposed by the operation of the DG facility $e(D(m))$. The hourly RTP customers dispatch according to the same decision tree at an interval of one hour or (12*m).

V. Results and Discussion

a. Sample results

For a generic customer as portrayed in each of these case studies, the incentives related to the electricity price and billing structure are the primary factors which determine the customer-optimized behavior. Figure 2 compares six of the different billing structures over a sample weeklong period within the in-depth case study: the three different utility rates and the three different RTP timescales for the Rutland, Vt., customer. The solutions for Portland and Rutland are similar, although the customer in Rutland generates significantly more power, and thus shaves more of its peak. The customer in Hartford, Conn., exposed to a steep TOU demand

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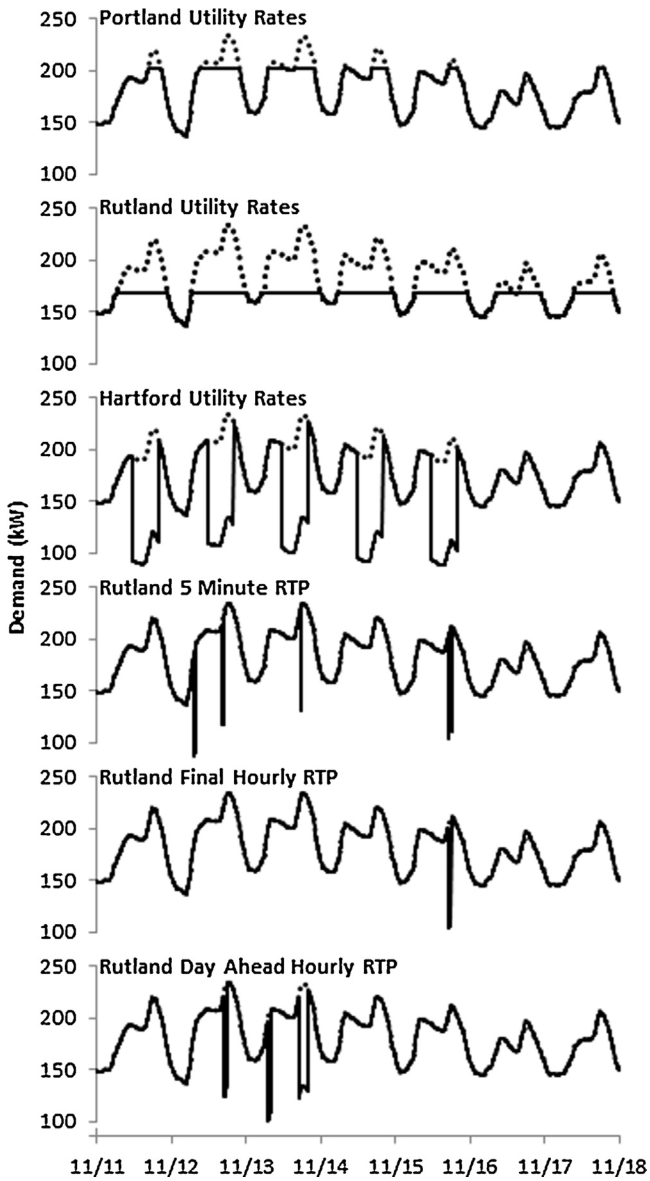

Figure 2: A Comparison of Customer-Optimized DG Use and Peak Shaving for Identical Customers Incented by Three Utility Rates: Portland, ME, Rutland, VT, and Hartford, CT; and Three Different RTP timescales in Rutland, VT (Node 4459) for the week of Nov. 11, 2013 to Nov. 18, 2013

and energy price, optimizes the DG use by treating the entire TOU window as similar to coincident peak pricing, running the DG facility at full power during the higher price window each day. This is regardless of the customer's actual peak or shape of the surrounding system load and based solely on the pre-specified time window associated with the higher TOU rate. Although there are also some differences between the different RTP markets, more immediately obvious is the major differences between the customer-optimized DG response created by traditional utility rates and the responses created by the RTP rates. The RTP signal focuses on fewer, shorter events of a higher DG utilization intensity.

B. Utility rates compared to real-time pricing

The first objective of this study is to compare the dispatch behavior, economics, and summed value that is realized by identical customers incented by either utility rates or RTP. Figure 3 further describes this disconnect between utility rate and RTP incented behavior. We can see graphically that there is no obvious correlation between optimized daily peak shaving and RTP dispatch behavior even at a monthly timescale. Table 1 further quantifies this at the smallest interval common between the two models (15 min for this comparison). This demonstrates the lack of correlation between utility rate incentives and RTP-incented dispatch. Even only comparing the on/off status of the DG facility and disregarding the magnitude of the dispatch shows that daily peak shaving compares unfavorably with the actual needs of the grid described by the RTP market. At approximately a total on/off agreement of 50 percent, the agreement between the utility rate and the RTP customers on the best time to operate the DG facility is no better than random.

The final 12 months under consideration in this simulation were marked by particularly high RTP costs over a protracted period during the

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Table 1: Correlation of Utility Rate Incented DG Dispatch to RTP Incented DG Dispatch.

DG Utilization Correlation at $100/MWh					DG Utilization Correlation at $125/MWh				
2010	2011	2012	2013	2014	2010	2011	2012	2013	2014
0.249	0.305	0.290	0.408	0.303	0.395	0.269	0.327	0.376	0.231

Percent On/Off Agreement at $100/MWh					Percent On/Off Agreement at $125/MWh				
2010	2011	2012	2013	2014	2010	2011	2012	2013	2014
51.7%	41.9%	35.1%	58.1%	53.8%	54.1%	43.2%	43.0%	56.1%	52.1%

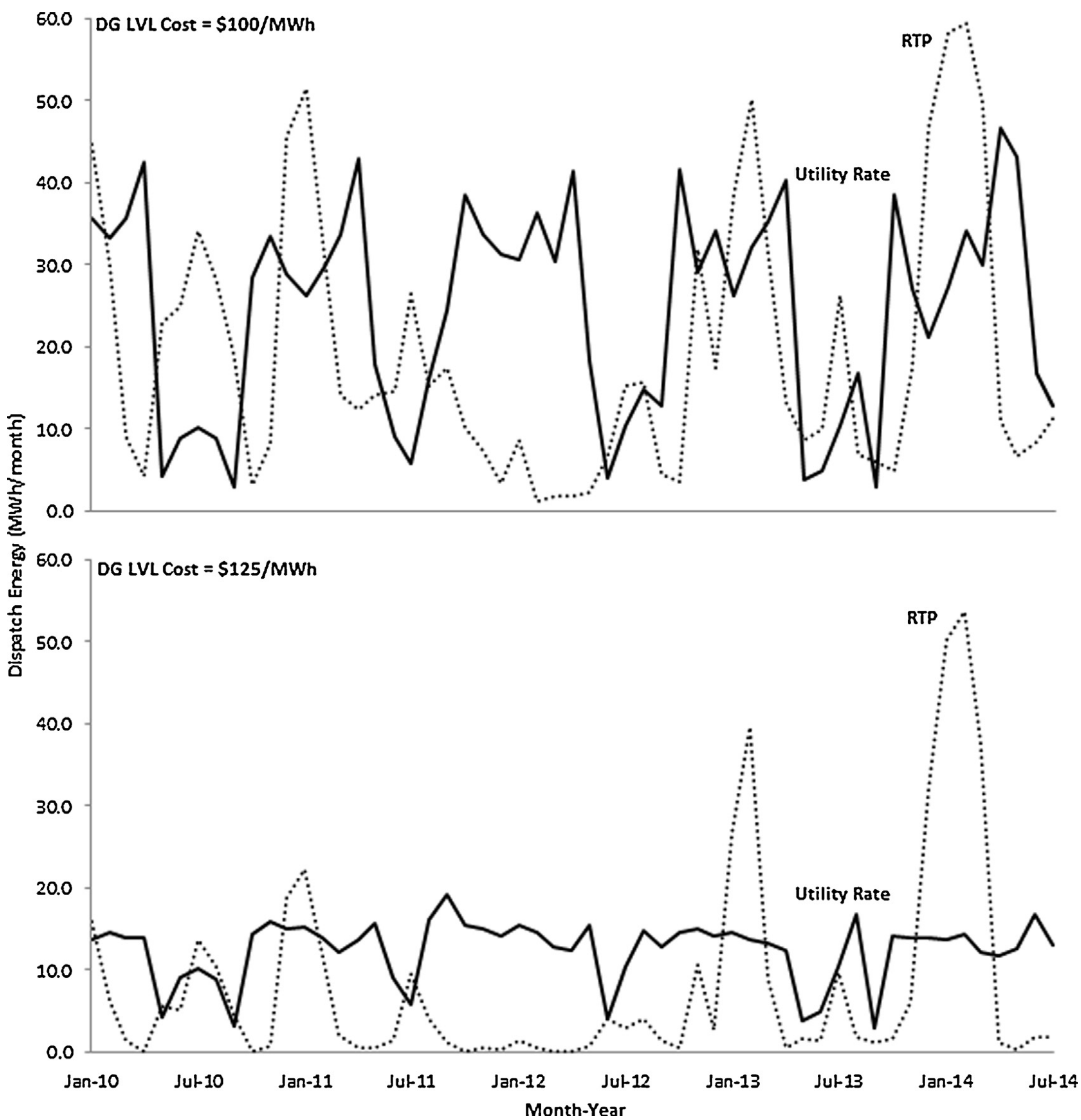

Figure 3: DG Dispatch Comparison in Rutland, VT (Node 4459)

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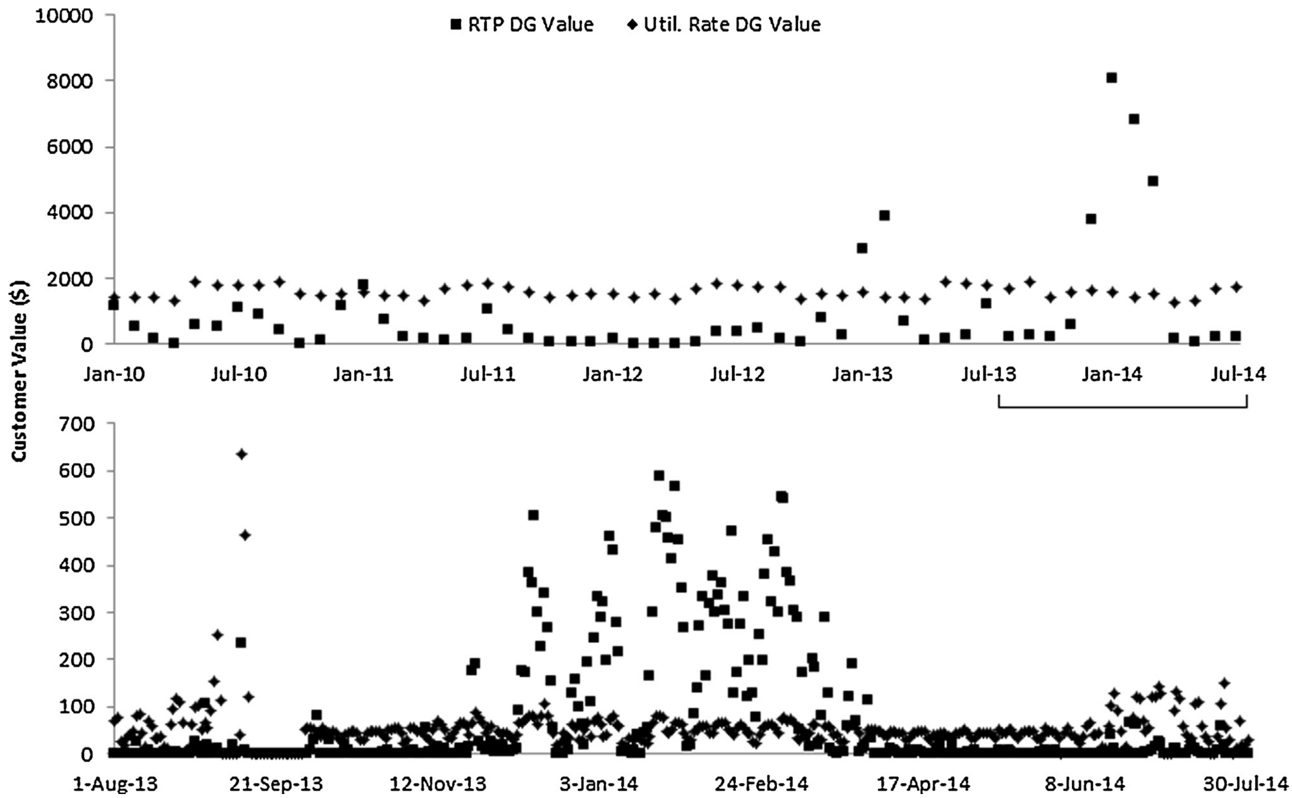

Figure 4: Customer DG Value Comparison at a DG Levelized Cost of $100/MWh, Monthly (2010–2014) and Daily (Aug. 2013–Jul. 2014); Rutland VT (Node 4459)

winter. Figure 4 shows the difference this makes in the monthly DG valuation across the broad 4.5-year view as well as daily across the final 12 months. This valuation disagreement is vital to quantifying the impact of daily peak shaving. Electricity cannot be stored on the grid, if the RTP market is accepted as an ideal, then the earlier months when the traditional rates customer is gathering more value than the RTP customer represent that customer removing more value from the market than it could possibly provide from the DG resource. Likewise, the daily peak shaving customer is unable to adequately respond to a significant technical or economic network event and fails to dispatch and gather value once additional generation is more desperately needed during the high price months at the end of the simulation time window.

Customer peak-shaving requires everyday customer involvement in the electric grid in order to maintain a low monthly peak demand, but as the RTP

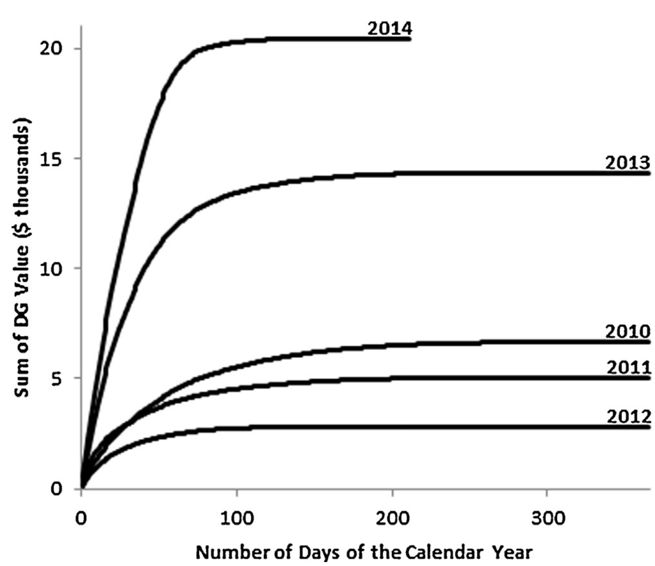

Figure 5: Sorted Sum of Daily Final Hourly RTP Customer DG Values in Rutland, VT (Node 4459) for a Levelized DG Cost of $100/MWh

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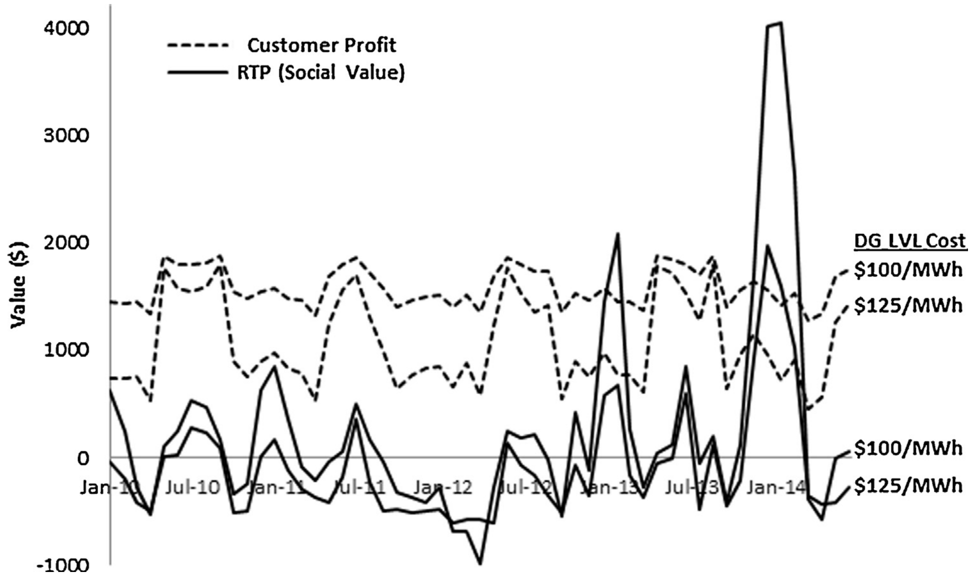

Figure 6: RTP Value of Customer Optimized Utility Rates Incented Dispatch; Rutland, VT (Node 4459)

market demonstrates in **Figure 5**, the actual need for customer support is far less than everyday use. Figure 5 displays the sorted sum of customer DG value (by day) for each of the years under consideration in the model. The majority of DG value in the RTP market is obtained during a relatively small fraction of the days in the calendar year. The DG valuation reaches at least 63.2 percent of its total value on day 54 in 2010, day 36 in 2011, day 26 in 2012, and day 35 in 2013; while at least half of the days of each year offer little to no opportunity for DG dispatch or value. Additionally, each year offers a significantly different opportunity and incentives for a DG customer in the RTP market, which would be difficult for a utility rate to match equitably for all customers in a traditional market.

Figure 6 describes a metric of peak-shaving economic performance by inputting the utility rate incented DG dispatch signal into the RTP market. This quantifies the actual RTP market value customer daily peak-shaving incented by utility rates. The actual value of the customer's daily dispatch does not match the value attributed to it through the utility rates. The final result for a DG cost of $100/MWh over the 4.5-year period is that the utility rate customer's DG dispatch was worth less than 7 percent of its utility rate valuation to the market. At $125/MWh, the utility rate incented dispatch nets a negative market value, essentially increasing electricity prices in the market by frequently dispatching higher cost DG incorrectly during relatively low price periods.

C. Sensitivity to regional and price information

A comparison of three regions under study during the 2013–2014 period shows that these different utility tariff models or rate structures can lead to significantly different customer incented DG value and behavior. If we consider the higher resolution 5-min RTP as the highest quality price signal that describes the dispatch requirements of the electric grid, then the correlation between the DG utilization as incented by the other rate structures and the 5-min RTP is a metric of the effectiveness of the other rate structures. As shown in **Figure 7**, the statistical correlation between the final hourly RTP DG use and the 5-min RTP DG use varies between 0.863 and 0.922 across the three regions in the study, representing a relatively high correlation between the two dispatch schedules. The statistical correlation of the day ahead hourly and the 5-min RTP DG use is lower, ranging from 0.623 in Hartford to 0.827 in Portland. The utility rates in each region incent a

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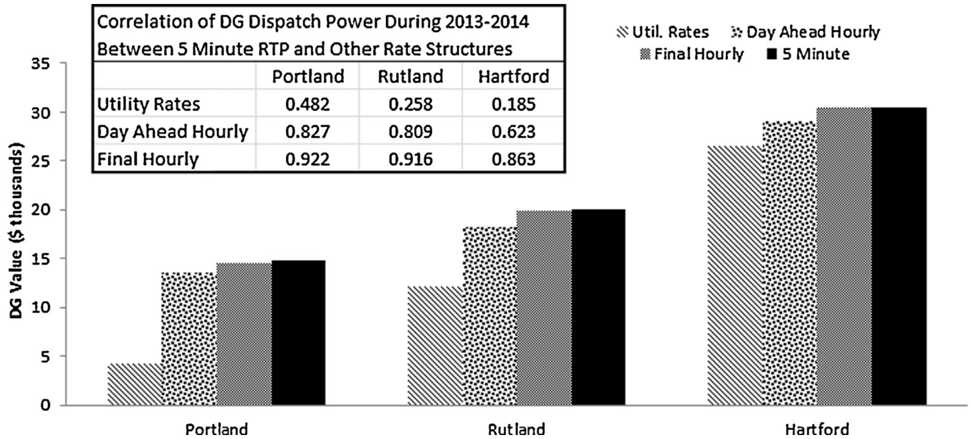

Figure 7: A Comparison of Optimally Dispatched Customer DG Value and Utilization at a Levelized DG Cost of $125/MWh (Aug. 2013–Jul. 2014)

DG use that correlates very poorly (0.185 in Hartford, 0.258 in Rutland, and 0.482 in Portland) with the 5-min RTP DG signal.

These results demonstrate that the poor correlation of DG use between utility rates and the RTP market extends beyond just the rates for customers in Rutland, Vt., but is robust across a variety of utility rates and market structures. As previously suggested in Figure 2, the daily peak shaving customers dispatch their facilities on more days and for greater total time intervals than the RTP customer, but frequently for smaller, less intense output. The DG customer is more focused on short-interval, high-cost periods that call for full DG dispatch. This continuum analysis of increased customer information also demonstrates that there is a measurable difference in optimized behavior between the three different RTP signals under consideration. The differences between traditional utility rates and the RTP market do not appear to be an issue, which could be addressed through more complex utility rate structures. For example, the Hartford customer arguably has the most complicated rate structure in this study based on its TOU energy rate and demand charge. Despite this complexity, the Hartford DG customer has the poorest correlation between its dispatch and the ideal (5-min RTP) dispatch while simultaneously ''gaming'' the most profit from its DG resource.

These results have demonstrated that there exist fundamental differences in behavior, economics, and summed value between daily peak shaving incented by traditional utility rates and the RTP market. If the RTP market is held as an ideal, then these results demonstrate that utility rates, which have been the subject of DG optimization and evaluation research, do not incent the behavior that can be considered a social good for the utilities and other surrounding customers.

VI. Conclusions

Customer-owned and operated DG systems are a new technological resource that will continue to develop in the new energy marketplace. There are numerous financial, policy, and technical issues related to DG that may either provide new benefits or costs to society. This project has evaluated some of the differences between customer incentives in utility rate and RTP markets in order to quantify some of the potential benefits and costs associated with one of the primary drivers for customer-owned DG systems: daily electricity peak-shaving. This research demonstrates the need to move policy and customer–utility interactions beyond the traditional business models in order to adapt to new technologies such as these DG systems.

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This study demonstrates that there are quantifiable and very significant differences between the DG dispatch of a RTP customer and a rate-incented customer. The two incented dispatches are so poorly correlated that a customer can create more costs than benefits in the marketplace through daily peak shaving (disregarding technical or ancillary benefits/costs). In this study, utility rates allow DG system operators to gain profits disproportionate to their contributions by ‘‘gaming’’ the demand charge. On the other hand, the RTP market allows DG customers to realize a comparable profit while realizing benefits for all market participants.

Sustainable business models for DG require further research and policy development for DG to gain greater utility acceptance and to achieve higher levels of grid integration. The technical factors relating to DG systems are very site-specific and will require greater customer–utility participation, but this research demonstrates that the financial impacts can be improved by making customers better, more informed participants in the electricity market. Future work could improve the assessments made here by developing a better method for determining the actual DLMP for a customer and by increasing the time period under consideration in order to better compare the total payback and valuation between the two cases.■

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Endnote:

1. Theoretically, at low enough DG costs, these units could be run at full utilization for the entire case study time period, but obviously, this is not a particularly interesting peak-shaving regime, nor does it help quantify the value of daily peak-shaving. If a customer can reliably and safely generate electricity more cheaply than a utility's base energy cost, then there is no reason to dispute DG's value to society.

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