Bridging the Retail-Wholesale Divide In Electricity Markets: The Economics of Distributed Energy Resources

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Abstract

Increasing penetration of distributed energy resources (DERs) impacts electric grid operations and utility revenue requirements. Existing retail rate tariffs for commercial customers do not align with utilities' wholesale market purchases of energy, ancillary services, and capacity guarantees, nor do they efficiently convey resource scarcity to customers to alter their consumption and DER deployment decisions. This report seeks to understand the effects that real time pricing has on electricity costs and incentives for DER deployment for small commercial building owners. Our analysis uses historical load data from multiple commercial building types throughout New Jersey to (i) evaluate the relationship between locational marginal prices (LMPs) and consumptive patterns, and (ii) explore the potential benefit of new electrical rate structures with increased granularity in the temporal and geographic dimensions. This assessment of potential savings for customers and utilities can be used to inform future rate design. Our key findings are as follows: (1) retail rates based on LMPs can benefit both distribution utilities and their customers; (2) any new rate introduced must be optional, as varying load attributes at specific sites result in very different experiences under these rates (i.e., almost half of subject sites are worse off); (3) utilities can reduce risk by implementing a retail rate with a real-time price signal.

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INTRODUCTION

In the current electricity market, economic signals do not routinely cross from wholesale to retail players, and vice-versa. For example, in 2013 wholesale power prices in Texas (ERCOT) spiked over $4,000/MW[1] while retail customers were insulated, continuing to pay regulated rates under $85/MW.[2] Attempts to construct signals from the retail side to the wholesale side, such as net energy metering, have questionable efficacy and political tenability.[3] We hypothesize that distributed energy resources (DER) such as distributed solar photovoltaics (PV), battery storage, and demand response (DR) are currently undervalued, and that DERs would more actively proliferate if signals better crossed from the wholesale to retail sides of the market and vice-versa.

As a solution, we explore the potential benefit of new electrical rate structures with increased granularity in the temporal and geographic dimensions. Our analytical model demonstrates the outcomes of various rate structures, and we make general recommendations for rate design based on technical, economic and political feasibility.

The first four sections of the report establish context to ensure readers understand the critical factors that impact rate design and – by extension – affect the proliferation of DERs. The final two sections delve into our quantitative analysis, including conclusions and recommendations for further research.

In Section 1, we present stakeholder perspectives in order to frame the problem with the incentives and pain points of the parties that have the strongest interests in an

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[1] Acclaim Energy Advisors. *Energy Risk Management Questions Raised*. 12 Sept. 2013.
[2] "U.S. Energy Information Administration - EIA - Independent Statistics and Analysis." State Electricity Profiles. 1 May 2014.
[3] Seybert, Ehren. "Introduction to the California Net Energy Metering Ratepayer Impacts Evaluation." California Public Utilities Commission, 2013.

improved approach to compensating DERs. Electric utilities, regulators, state legislatures, commercial customers, and technology providers each have goals and constraints that one must consider in devising rate design solutions that are as politically viable as they are economically and technically sound.

We devote Section 2 to discussing the DER technologies on which we focus – namely DR, solar PV, and battery storage. The proliferation of these technologies has prompted calls for new approaches to rate design; understanding the current state of these technologies, including their respective levels of penetration in electricity markets, is an important part of the rate design discussion.

In Section 3, we introduce the economics of DERs in our focal market, PJM, to clarify market constraints and opportunities that stakeholders face in regard to DERs. Section 4 seeks to elucidate the history and existing state of the art of rate design, providing a backdrop against which we will propose solutions.

Section 5 provides a detailed overview of our analysis, including our methodology, model selection and discussion of results. Finally, in Section 6, we present our conclusions and recommendations for further research. Our key points and recommendations are summarized as follows:

- A retail rate based on locational marginal price (LMP) can benefit both distribution utilities and their customers.
- Specific sites have very different experiences under these rates, mainly driven by load attributes; with almost half being worse off, any rate introduced must be optional.
- Utilities can reduce risk by implementing a retail rate with a real-time price signal.

STAKEHOLDER PERSPECTIVES

Increased deployment of distributed energy resources (DER), including storage, solar PV, and demand response (DR), has made DERs' aggregate impact on the electric grid a significant consideration for consumers, regulators, and utilities. Consumers want low rates, reliable electricity, and increasingly desire energy that comes from clean, renewable resources.[4] Regulators must manage these consumer desires while minimizing cross-subsidization, implementing state policy, and ensuring the financial solvency of utilities. To respond to the desire for clean, renewable electricity, states have implemented a variety of policies that promote DERs, such as renewable portfolio standards (RPS).

Utilities

As retailers of electricity, utilities must manage this increasingly complex mix of DERs and the bidirectional flow of electricity that accompanies it. Meanwhile, utilities must purchase electricity at the retail, net-metered rate from a growing number of distributed endpoints while relying on revenues from block, volumetric rate tariffs to maintain and improve transmission and distribution grids.[5] Recognizing the need to upgrade to smarter grids, utilities must invest significant amounts of capital to modernize their transmission equipment. Broader economic trends render this technological imperative even more difficult. U.S energy consumption growth remains flat due to energy efficiency gains and increasing DER penetration. This "demand erosion" spells trouble for utilities whose revenue requirements were designed with a centralized grid and strong forecasted load growth in mind.

[4] Navigant. "Favorable consumer attitudes toward clean energy have rebounded significantly in the last year, according to Navigant research survey." 2014. Energy Weekly News: 67.
[5] Palensky, Peter and Friederich Kupzog. 2013. "Smart Grids." Annual Review of Environment and Resources 38: 201-226.

Commercial Customers

Utility customers have myriad, often conflicting, demands from their utility. In a study by the Public Utility Commission of Texas, polled utility customers stated strong desires for more renewable energy and energy efficiency, while simultaneously wanting to decrease fossil fuel use, maintain high reliability, and have lower costs. When asked, 71% of residents favored spreading out of the cost of renewables across all customers through higher rates.[6]

However, when customers in Texas were asked what they deemed to be the most important planning goals for the utility, protecting the environment was ranked fourth, behind 1) having enough electricity to meet demand, 2) ensuring all households have access to electricity, and 3) minimizing electricity outages. Achieving the lowest costs was listed last among the five choices, despite a stated low willingness to pay for more renewables.[7] While the study is only of electric ratepayers in Texas, it is illustrative of the disparate demands that utility and regulators must manage when designing rate and incentive programs.

As noted in Bonbright's Principles of Public Utility Rates, rate designers must incorporate not only customers' stated goals, but also their implicit desires.[8] This includes achieving a level of fairness that does not unduly benefit one class of customer over another. Another important principle is a level of simplicity that enables customers both to understand and act upon rate signals.[9] For example, opponents of dynamic pricing argue that it is too onerous for consumers to manage their electricity

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[6] Sloan, Mike, and Gillan A. Taddune. "What Texans Want From Their Electric Utility." Rep. Public Utility Commission of Texas Report. 2001.
[7] Ibid.
[8] Bonbright, James C., Albert L. Danielsen, and David R. Kamerschen.Principles of Public Utility Rates. Public Utility Reports, January 1961.
[9] Ibid.

consumption in response to short-term price signals. While there are multiple benefits to more closely integrating wholesale and retail markets, customers will want to know not only that they can save money in the long run, but also that the system is fair and relatively easy to understand.[10]

Regulators

Regulators exist to serve the public interest. However, expressions of the public interest can conflict, causing confusion for regulators and the bodies they oversee. For example, regulators have traditionally focused on cheap, reliable, and safe electricity; yet, regulators increasingly find themselves focusing on *clean* electricity as well. This can be seen in the increasing number of RPS's throughout the U.S., which have contributed to the growth in renewables.[11] In the past, the innate conflict between these positions has been mitigated by renewables' low penetration on the grid. However, those conflicts are starting to weigh more heavily as regulators see larger adoption of renewables and changing public perceptions. Therefore, they are increasingly forced into making difficult decisions. A good example of this is the vacation of FERC 745, which may reshapes the economics of demand side resources.[12] While it is not always clear how regulators' incentives will play out in regards to DERs, it is certain that they will be forced to weigh in more heavily over the next several years.

State Legislatures

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[10] Alexander, Barbara. "Dynamic Pricing? Not So Fast! A Residential Consumer Perspective." Electricity Journal 23.6 (July 2010): 39-49. Science Direct.

[11] Lawrence Berkeley National Laboratory. "Renewable Portfolio Standards in the United States: A Status Update." Nov. 6th, 2013. Solar Technologies Office.

12 Paulos, B. (2014, 12 18). FERC Order 745 and the Epic Battle Between Electricity Supply and Demand. Retrieved from Powermag.com.

There are multiple incentive types and programs to promote DERs across each state. Sixteen states have special carve-outs for DERs within their RPS', which require utilities to procure renewable energy to meet targets using rebate programs and other financial incentives.[13] Seventeen states have varying levels of personal income tax credits and sixteen states allow corporate income tax deductions to promote DERs. Myriad additional incentives, including sales and property tax exemptions, rebates, grants, and loans exist across the states to make DERs more affordable for consumers.[14]

States also vary widely in their treatment of DERs transacting in markets. Most DERs connect at the distribution level, which is regulated by state public utility commissions (PUCs). Interconnection requirements can either facilitate or discourage DERs, depending on how they are designed. Many states have a fast-track application process that uses a standardized agreement and streamlined safety check process designed for smaller systems. Once connected, these systems generally participate in markets as either a DR resource that reduces customer load or as a production resource that injects power into the grid.[15]

Currently, most behind-the-meter DERs participate in wholesale markets as DR resources. In addition to energy markets, ancillary service and capacity markets are also open to DERs. Because of uncertainty surrounding the recent FERC Order 745 decision, many states and ISOs have taken action to preserve DR. The entities that are currently

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[13] DNV GL. A Review of Distributed Energy Resources. Prepared for the New York Independent System Operator, September 2014.
[14] "Financial Incentives for Renewable Energy." DSIRE. US Department of Energy, Web. 08 Feb. 2015
[15] DNV GL. September 2014.

leading the effort to preserve demand response in wholesale markets are the California ISO (CAISO), NY PUC, and PJM.[16]

Technology Providers

Technology providers have developed products and services to meet customer needs and policy goals. As these needs and goals have changed over time, DER companies have adapted their business models to remain competitive with one another and with other energy sources, including fossil-fired generation provided by utilities. Proposed changes to rate tariffs by utilities and regulators have resulted in pushback by some technology providers who view these changes as direct threats to their economic viability.

Different rate structures can impact the economic viability of certain DERs. A 2012 NREL study found that location is a significant factor that determines the value of a distributed solar system. This is primarily due to differences in electricity prices and rates, rather than characteristics of the solar resource. Disparities result from different feed-in tariff values and demand charges, which are based on peak customer electricity usage during a billing period.[17]

On average, the NREL study found that flat, energy-only rates yielded the highest value for solar, though demand charges coupled with time of use rates, increased solar value compared to just flat, energy-only rates with no demand charges. Energy-only rates with demand charges resulted in the lowest value for solar.[18] Because these rates are enabled by net metering, further discussed in Section 4, changes to net metering

[16] O'Boyle, Michael, and Sonia Aggarwal. "After the D.C. Circuit Court's Invalidation of FERC Order 745, How Can We Pay for Demand Response?" America's Power Plan. 2014.
[17] National Renewable Energy Laboratory, "Impact of Utility Rates on PV Economics." 2012
[18] Ibid.

policy are also opposed by many technology providers, particularly distributed solar companies.[19]

While distributed solar companies oppose higher demand charges and limits to net metering, distributed energy storage companies see demand charges as an important ingredient of their value proposition. According to a 2015 NREL report, "demand charges can constitute more than 50% of a commercial customer's monthly electricity cost." Because energy storage can be used to reduce demand charges, there is significant cost savings opportunity that can be shared by the customer and energy storage provider.[20] Thus, while changes to one part of the rate tariff such as demand charges can make one type of DER uneconomical, it creates a potential business opportunity for another type of DER.

[19] Blackburn, Griselda, Clare Magee, and Varun Rai. "Solar Valuation and the Modern Utility's Expansion into Distributed Generation." The Electricity Journal 27.1 (Jan-Feb 2014): 18-32.
[20] NREL. Deployment of Behind-TheMeter Energy Storage for Demand Charge Reduction. By J. Neubauer and M. Simpson. January 2015. Print. NREL/TP-5400-63162.

TECHNOLOGY OVERVIEW

Electricity markets have been spurred to evolve in recent years by the emergence of new electricity generation, transmission, storage and metering technologies. This section introduces some of the most important technological developments and their impacts on the relationship between the wholesale and retail sides of electricity markets.

Metering Technologies

Electric meters are the primary enabling technology for advanced electricity markets.[21] Advanced metering infrastructure (AMI) meters currently represent the state of the art for meter technologies. Generally, all AMI meters open up the potential for the widespread use of two-way communications to provide a steady flow of granular, time-linked consumption data between the utility and its customer. The change from electromechanical meters to advanced metering infrastructure over the last 18 years has been key to enabling many of the recent changes to the U.S.'s electric grid. Continued improvements in metering capabilities and costs will allow for even more radical rate design.[22]

However, a significant part of the country is still on an "analog grid" without digital metering or controls. This Edison-era grid is limited in capability compared to the next-generation digital grid. More than half of the United States' is still limited by hard infrastructure constraints when it comes to creating new, price-responsive rates.[23]

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[21] Wang, King Min; Cheng, Yu Ju. "Smart Pricing" with and without Smart Meters. Journal of Energy and Power Engineering 7.7 (Jul 2013): 1316.
[22] EEI and AEIC Meter Committees. *Smart Meters and Smart Meter*. Washington DC: Edison Electric Institute, 2011.
[23] "Grid Modernization FAQs." Duke Energy, Web. 09 Feb. 2015.

Battery Storage

The DER technology with the greatest potential for interplay with the grid is battery storage coupled with advanced power electronics and software.[24] Companies such as Stem and Solar City are leading the way in developing energy storage hardware that can interact with the grid.[25] Because batteries can accept and release energy on demand, they are a truly dispatchable DER with the potential to bridge the retail and wholesale sides of electricity markets by reacting to market signals from both sides. For example, Stem has begun bidding distributed storage into the California Independent System Operator (CAISO), explicitly allowing DERs to participate in wholesale electricity markets.[26] While many industry observers are excited about the promise of batteries, they are currently an expensive solution with limited applications, a situation explained by Amory Lovins in his “Storage Necessity Myth” presentation.[27] However, costs have fallen significantly in recent years and boosts to scale such as Tesla’s “gigafactory” promise to further reduce costs.[28]

Commercial Solar

The commercial solar[29] installed base has risen sharply in the U.S. over the past six years. In 2008, 200 MW[30] of commercial solar capacity was installed; by 2014, that number climbed to 1.2 GW installed in a single year, for a cumulative installed base of 5.6 GW for the six-year period. The commercial segment has been essentially flat for the

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[24] Chediak, Mark. "Musk Battery Works Fill Utilities With Fear and Promise."Bloomberg.com. Bloomberg, 5 Dec. 2014.
[25] Manghani, Ravi. "The Future of Solar-Plus-Storage in the U.S." GTM Research. Greentech Media, 18 Dec. 2014.
[26] Cohn, Lisa. "Behind-the-Meter Storage Competes with Generation in California: Pilot." Energy Efficiency Markets. 27 June 2014.
[27] Lovins, Amory. “The Storage Necessity Myth.” Rocky Mountain Institute, 18 Mar. 2014.
[28] "Smooth Operators." The Economist, 06 Dec. 2014. Web. 05 Feb. 2015.
[29] Commercial solar is herein defined as systems that are non-residential and “behind the meter”. Also, unless otherwise stated, all references made are to photovoltaic (PV) solar technology.
[30] All capacity figures are in DC (direct current) format.

past two years, but shows promise for a resumption of growth, driven by expansion in California and the emergence of a market in New York. Forecasts for 2015 and 2016 show an increase in commercial installations to 1.6 GW and 1.9 GW.[31]

One of the main drivers for this increased capacity has been declining costs of commercial solar systems. From 2010 to 2013, the average cost of a commercial solar system declined by 57%, from $7.57/Watt to $3.25/Watt. Much of the cost reduction can be attributed to lower solar panel costs; however, future systems cost reductions are expected to be attributed to lower soft costs (e.g., customer acquisition, permitting) and balance of system costs (e.g., inverters, racking systems).[32]

Demand Response

DR has long been considered a potent solution for dealing with many of the electric grid's restraints.[33] As numerous "aggregators" recruit and coordinate new loads, it has grown accordingly. Proponents and opponents of DR disagree over how DR fits into the resource base and what compensation should be provided. Initially, the Federal Energy Regulatory Commission (FERC) issued Order 745 that proclaimed that DR should be compensated at the marginal cost of generation in the wholesale markets per Congress's order to remove "unnecessary barriers to demand response participation in energy, capacity, and ancillary service markets" in 2005.[34] However, the conflict between different stakeholders came to a head in the DC Circuit Court's 2014 *Electric Power Supply vs. FERC* decision.

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[31] Solar Energy Industries Association (SEIA): *U.S. Solar Market Insight Report 3Q 2014 – Executive Summary*.
[32] H. Blair Kincer, MAI, CRE, Novogradac & Company LLP. *Here Comes the Sun: Solar Energy Price Trends.* Novogradac Journal of Tax Credits, May 2014, Volume V, Issue V.
[33] Medina, Jose, Nelson Muller, and Ilya Roytelman. "Demand Response and Distribution Grid Operations: Opportunities and Challenges." IEEE Transactions on Smart Grid 1.2 (2010): 193-8.
[34] "Electric Power Supply Association v. FERC." 753 F.3d 216 (DC Circuit, 2014).

In that case, FERC argued that there is a split between “wholesale” and “retail” DR where the first is incentivized through payments and the second through price-responsive demand reductions (aka sending price signals). Therefore, FERC acknowledges that it is limited to looking at the first, but that is where their actions stop. In the judges’ majority opinion, the court accedes that DR is a mix between retail (state) and wholesale (federal) jurisdictions, but maintains that FERC is overstepping its boundaries by “attracting” retail customers into the wholesale markets (i.e. its jurisdiction) through incentive payments. This turn of events has created a significant setback for DR, and has introduced an element of uncertainty for the ISOs, which in recent years have relied on DR to reduce grid stress.

DISTRIBUTED ENERGY RESOURCE ECONOMICS IN PJM

This report focuses on the PJM electricity market to analyze DER economics. PJM is appealing because of its diversity of consumers, broad proliferation of DERs, and substantial supply of data. The following section introduces how DERs fit into the PJM market.

There are currently three broad categories of power markets in the U.S.: 1) Energy; 2) Ancillary Services; and 3) Capacity. Within each of these, different market structures provide the actual revenue streams that DERs might access based on services or functions. Furthermore, there are also opportunities for DERs to provide value to stakeholders outside of established markets (e.g., by deferring infrastructure upgrades for a utility or reducing costs for an end user). When looking at the economics of DERs, it is important to consider each technology's ability or inability to tap into some or all of the existing revenue streams.

In recent years, policymakers and regulators have begun to focus more on DERs as technologies have improved and their costs have come down. In some areas, this has resulted in attractive incentives, such as the California Public Utility Commission's (CPUC) mandate for 1.325GW of grid storage by 2020. As markets and policies evolve, it is possible that more opportunities might arise for owners and operators of DERs. For instance, FERC Order 755 states that premiums must be paid to service providers who have higher performance, and DERs such as demand response and batteries can sometimes beat out traditional service providers in capabilities such as ramp rates (both up and down).[35] While it is not yet clear how these new products will affect electricity markets, it is important to capture these additional opportunities going forward.[36]

Current Market Opportunities for DERs in PJM[37]

In compliance with FERC Order 755, detailed above, ISOs across the U.S. have begun to implement market mechanisms whereby smart and fast-responding energy resources can be compensated for their greater performance versus standard, slower-responding resources. The mechanisms implemented in PJM ancillary services markets—in particular for frequency regulation—have created an attractive market opportunity for DERs with certain characteristics, as they can be compensated for improved response time and the ability to regulate up or down. In particular, frequency regulation is an attractive market for DERs, but only up to a certain penetration. Because increasing penetration of DERs reduces the marginal benefit of an additional DER, PJM has identified a target penetration rate for fast-responding resources of approximately 43% (while the other 57% would remain standard resources), above which these smart resources provide no benefit above and beyond a standard hydro or thermal generation resource participating in the frequency regulation market. At current peak demand estimates, the market size for smart frequency regulation resources is about 300 MW, but this number could grow if PJM's original estimates are found to be overly conservative.

The nature of providing frequency regulation means that load increases or decreases only need to happen for short amounts of time, but the relative magnitude of

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[35] "FERC Order 755." 20 Oct. 2011.

[36] Wu, Chenye, Gabriela Hug, and Soummya Kar. "Risk-limiting Economic Dispatch for Electricity Markets with Flexible Ramping Products." Institute of Electrical and Electronics Engineers (26 Feb 2015).

[37] Much of the frequency regulation information conveyed in this section comes from a UBS-hosted conference call with Stasis Energy CEO Steve Lichtin, 12/8/14.

the power output or draw should be high. In general, two-way (up and down) capabilities are those most richly rewarded in PJM's frequency regulation market because one key factor in determining compensation is a "performance score" based on the resource's ability to follow the market signals over the course of an hour. If down regulation is needed but cannot be provided, a resource's performance score would drop dramatically. However, even a resource like DR could have the capability to participate in this market if it is measured versus a non-zero baseline.

RATE DESIGN AND EXISTING SOLUTIONS

Commercial Rate Design

Utility ratemaking involves a two-step process: determining revenue requirements and designing rates. First, regulators work with utilities and ratepayer advocates to define a utility's rate base and determine an adequate rate of return that is additional to the utility's operating costs. Second, revenue requirements are allocated into functions (generation, transmission, and distribution), customer class (residential, commercial, etc.), and connection voltage (primary, secondary, or tertiary).[38] This paper focuses on the possibilities for the second step to increase DER penetration.

Historically, electricity rates have been designed according principles established in a seminal book by James Bonbright, Albert Danielsen, and David Kamerschen in 1961. These Bonbright Principles are: "1) The related, practical attributes of simplicity, understandability, public acceptability, and feasibility of application; 2) Freedom from controversies as to proper interpretation; 3) Effectiveness in yielding total revenue requirements under the fair return standard; 4) Revenue stability from year to year; 5) Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers; 6) Fairness of the specific rates in the apportionment of total costs of service among the different customers; 7) Avoidance of discrimination in rate relationships; 8) Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use—including in the control of the total amounts of service supplied by the company, and in the control of the relative uses of alternative types of service." Ratemakers have also used

[38] Faruqui, Ahmad, and Stephen S. George. "Pushing the Envelope on Rate Design." Electricity Journal 19.2 (March 2006): 33-42.

PURPA as a cardinal guide. These guidelines were established in the 1978 act because of the widely held belief that retail electricity rates were not correctly designed. The "PURPA guidelines" are: 1) Conservation of energy by users; 2) Efficient use of facilities and resources by utilities; and 3) Equitable rates to consumers.[39]

Today, commercial utility rates generally consist of three types of charges: fixed, demand, and consumption charges. Fixed charges try to recover utilities' fixed costs, including the costs of metering and billing, and do not change with energy consumption. Fixed charges are charged according to a time period – daily, monthly or annually. Demand charges attempt to recover costs associated with generating and delivering maximum power to the customer. Demand charges are calculated on a per-kW basis using a customer's maximum power demand during a certain time period – often a billing cycle or annually – and are recorded over a certain time interval such as 15 or 30 minutes. Consumption charges are variable and recover the utility's costs of providing generation, transmission, and distribution. These charges are based on each kWh of energy consumed and may vary by season or time-of-use tier.[40]

In addition to these three main charges, numerous other charges have been added in recent years to promote policy goals such increasing energy efficiency, reducing peak-time consumption, and supporting greater customer equity. For example, PSEG's commercial electricity tariff includes many such charges beyond expected fixed, demand, and consumptions charges. Three "Societal Benefit" charges combine cost recovery for energy efficiency and renewable energy programs, as well as gas plant remediation. Ten "Green Programs" charges recover revenue requirements for multiple

[39] Hanser, Phillip Q. "Rate Design by Objective." Public Utilities Fortnightly, Sept. 2012.
[40] Campbell, Carolyn. "Rate Design Matters: The Impact of Tariff Structure on Solar Project Economics in the U.S." Greentech Media, May 2013.

different carbon abatement, DR, solar, and energy efficiency programs. A non-utility generation charge recovers costs for above market prices from previously signed power purchase agreements. Further charges for cost recovery include those for transmission, distribution, system control, and securitization of transition bonds.[41]

Myriad additional charges, added complexity within charges, and multiple tariffs within customer classes have resulted in electricity bills that are hard for customers to understand. This results in rates that are difficult for customers to act upon. Because these rate design objectives are complex and sometimes conflicting, they do not effectively convey resource scarcity to customers so that they can alter their consumption or DER purchasing decisions.[42]

Net Energy Metering (NEM)

One of the initial tools proposed to promote DERs was "net metering", a billing mechanism that allows self-generating customers to sell their excess power back to the utility at a guaranteed rate.[43] Net metering was first adopted by a number of states in the early 1980s. The 2005 Energy Policy Act subsequently mandated that all utilities "make available...net metering service to any electric consumer that the electric utility serves." However, in this case "make available" means "to consider", thus seven states still lack any formal net metering policy.[44]

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[41] PSEG Commercial Electricity Tariff Pamphlet

[42] Faruqui, Ahmad, and Stephen S. George. "Pushing the Envelope on Rate Design." Electricity Journal 19.2 (March 2006): 33-42.

[43] Edison Electric Institute. Straight Talk About Net Metering (September 2013): Edison Electric Institute.

[44] Morrison, J. (2006). Retail Rates, Distributed Generation, And The Energy Policy Act Of 2005: Did You Meet Your First Deadline? Management Quarterly, 47(3), 34-43.

Customers and DER advocates appreciate the benefits that have arisen from net metering, including the rapid growth of DERs such as residential solar.[45] However, many electric utilities and state legislatures have come out against net metering because they believe self-generating customers do not pay the full cost to use the electric grid, thus shifting that cost on to customers that do not self-generate. Other potential issues include which utility customer classes are allowed to net meter and how big the generation should be in relation to the customer's usage.[46] This has led to wide-ranging discussions about the optimal way to compensate self-generating customers, including higher fixed charges, lower percentages of the full retail rate, and switching from retail rates to a feed-in tariff based on the value that the DER contributes to the grid.[47]

Net metering conflates two important issues: there is a two-way flow of electrons for the utility to manage optimally and there is an optimal price at which the utility must purchase these electrons. In its current form, net metering uses block, volumetric based pricing to repay customers for their excess production, thereby combining these two issues into one. This creates a misalignment of incentives between the customer and utility, resulting in economic and engineering inefficiencies.[48]

For instance, residential solar panels could be positioned westward facing to maximize production during peak customer load hours, which are usually in the late afternoon and/or early evenings, when the sun is setting. However, most residential systems are designed such that the solar panels face south, which maximizes total

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[45] Lehrman, Matt. "Why the Net Energy Metering Debate Misses the Point." Why the Net Energy Metering Debate Misses the Point. Rocky Mountain Institute, 25 Sept. 2014.
[46] Schmitt, David. "Net Metering: Getting Beyond the Controversy." American Bar (2010): Indiana University School of Law.
[47] Trabish, Herman K. "A Rising Tension: 'Value-of-Solar' Tariff Versus Net Metering." Greentech Media, 10 Apr. 2014.
[48] Lehrman, Matt. "Why the Net Energy Metering Debate Misses the Point." Why the Net Energy Metering Debate Misses the Point. Rocky Mountain Institute, 25 Sept. 2014.

energy production; this means that solar production for most residential systems decreases as system-wide load/demand is increasing. Consequently, the local utility must commit an otherwise greater amount of ramp-up generation to meet system-wide demand.[49] Unbundled, adaptive rate structures can be used to incentivize customers to meet system demand, couple their solar systems with smart inverters and energy storage, and enable better integration with DR.

21st Century Bonbright Principles: Increased Granularity

In 2012, the Rocky Mountain Institute (RMI) initiated eLab after recognizing the need to foster a broad, multi-stakeholder conversation on the future of the electrical grid. The program convenes stakeholders from across the power industry in order to find common ground on the evolution of the grid and its policy frameworks. To create a framework for this conversation, eLab published *Rate Design for the Distribution Edge: Electricity Pricing for a Distributed Resource Future* in April 2014.[50]

The report's proposition is that "block, volumetric pricing (the most common rate structure for residential and small commercial customers) will no longer be able to align stakeholder interests to deliver maximum value to the system over the long term." It also specifically calls out the need for rates to better compensate DERs: "...deployment of new grid technologies and proliferation of myriad distributed energy resources are fundamentally changing the grid. That changing grid requires new rate structures for the distribution edge, better aligned with the evolving 21st century electric grid."[51]

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[49] Pecan Street Research Institute. "Report: Residential Solar Systems Reduce Summer Peak Demand by Over 50% in Texas Research Trial." Pecan Street Inc. Nov. 2013

[50] Glick, Devi; Lehrman, Matthew; Smith, Owen. *Rate Design for the Distribution Edge*. RMI, August 2014.

[51] Ibid.

These rates should as much as possible be unbundled along three categories. The first, “attribute unbundling,” breaks apart the value of energy services into energy, capacity, ancillary services, and other components. The second, “temporal granularity,” proposes to find value in charging for energy services in increments of time that are as precise as is economically feasible. Finally, “locational granularity” calls for recognizing the differing costs and values associated with location of generation and consumption.[52]

New Remuneration Paradigms

Scholars at MIT have analyzed the current state of utility business models in the face of DERs and propose new ways for utilities to structure revenue in the face of these trends.[53] According to their analysis, regulators need new tools to manage uncertainty and incentivize utilities to both accommodate DERs and take advantage of their capabilities. Regulators are handicapped in their access to insight and data about new technologies, while utilities know far more about emerging technologies and the changing use of the grid than their regulators. The regulator is therefore at an informational disadvantage, which exacerbates temptations for utilities to engage in strategic behavior to increase allowed revenues.

To remedy this state of affairs, regulators need: 1) forward-looking tools to overcome information asymmetries and identify the impacts of new technologies on the cost of building and maintaining distribution networks; 2) remuneration mechanisms that incentivize utilities to not only accommodate DERs, but also to take advantage of these new resources in combination with smart grid technologies to reduce system costs

52 Ibid.

53 Jenkins & Pérez-Arriaga (2014). “The Remuneration Challenge: New Solutions for the Regulation of Electricity Distribution Utilities Under High Penetrations of Distributed Energy Resources and Smart Grid Technologies.” CEEPR Working Paper (No. 2014-005). Cambridge, MA: Massachusetts Institute of Technology, September 2014.

and improve performance; 3) to manage the systemic uncertainty they now face while preserving incentives for utilities to be more efficient and safeguard the regulatory compact that prudently-managed regulated firms shall remain financeable.

The authors outline a novel method combining three state-of-the-art regulatory tools. First, an engineering-based reference network model (RNM)[54] designs an efficient distribution network that can accommodate expected growth of DERs as well as new smart grid technologies and practices. In short, the RNM helps the regulator "peer into the future," reducing both information asymmetry and systemic uncertainty. The output from the RNM is an optimized, simulated, base distribution network and its resultant cost (the RNM accounts for cost of capital, discount rate, lifetime of assets, and the cost of losses); this cost serves as the estimated replacement value of the network, which is used to calculate the utility's rate base at the outset of the regulatory period.

The second component entails a menu of profit-sharing regulatory contracts that creates strong incentives for utilities to pursue cost-saving efficiencies, while managing uncertainty by sharing risks between the utility and ratepayers. In addition, if designed correctly, the menu of contracts will preserve "incentive compatibility"—that is, firms will always be better off when they provide regulators with accurate forecasts of their expected costs. This feature further reduces information asymmetries and helps the regulator establish an accurate revenue baseline. Finally, automatic adjustment mechanisms, or "delta factors," which can be used to adjust allowed revenues after the

[54] Domingo, C.M. "A Reference Network Model for Large-Scale Distribution Planning With Automatic Street Map Generation." *IEEE Xplore*.

fact to accommodate deviations in the evolution of network uses (i.e., load growth or DER penetration) from forecasted levels.[55]

Performance-Based Ratemaking (PBR)

Frustrated by a lack of specificity of the current regulatory paradigm and its inability to deliver on sustainability and resiliency goals, some observers have suggested a regulatory model that sets concrete expectations and holds utilities and other electricity market players accountable for reaching those outcomes. Broadly, this approach is known as Performance Based Ratemaking (PBR) and has been used to drive improvements in energy efficiency, plant uptime, carbon emissions and other metrics. In a discussion of PBR trends, Sonia Aggarwal and Edward Burgess claim, “Essentially, PBR is focused on delivering value, rather than accounting for costs.” The most widely acclaimed example of PBR was undertaken in the UK with a “Revenues = Incentives + Innovation + Outputs” or RIIO model. [56]

Reforming the Energy Vision

Partly spurred by the system failures highlighted by Superstorm Sandy[57], the New York Public Service Commission (NYPSC) has begun a regulatory proceeding, “Reforming the Energy Vision,”[58] that proposes ways for utilities to profit from DER proliferation. Its core proposal is for utilities to act as “Distribution System Platform Providers” (DSPPs), offering them the appealing Silicon-Valley-style proposition of

[55] Cossent, Rafael. "Download PDFs." *Implementing Incentive Compatible Menus of Contracts to Regulate Electricity Distribution Investments*. 01 Dec. 2013.
[56] Aggarwal, Sonia, and Edward Burgess. "Performance-Based Models to Address Utility Challenges." The Electricity Journal 27.6 (July 2014): 48-60.
[57] “Hurricane Sandy Is Ushering in a Smarter Power System." The Great Energy Challenge Blog. National Geographic Society, 28 July 2014. 05 Feb. 2015
[58] "14-M-0101: Reforming the Energy Vision (REV)." *14-M-0101: Reforming the Energy Vision (REV)*. New York State Public Service Commission, 05 Feb. 2015.

"owning the platform."[59] Under this scheme, utilities would not just profit from tariffs on their distribution networks. Instead, they can be like eBay, profiting from the activities of participants across their market. Detailed policy proposals have yet to emerge from the REV process, but initial "straw man" proposals are due in 2015.[60]

Real Time Pricing

According to many economists, real-time pricing (RTP) embodies the most direct approach to encourage price-responsive demand and/or reduce peak demand, and should therefore be the chief focus of policymakers' efforts to improve wholesale and retail electricity markets.[61] More than 70 utilities in the U.S. have offered voluntary RTP programs on either a pilot or permanent basis, though most are not well known. In 2004, LBNL conducted a survey of 43 voluntary RTP tariffs offered in 2003. Given its broad scope and use of primary as well as secondary sources in evaluating the effectiveness of RTP programs, the LBNL report's review is fairly comprehensive, and therefore provides valuable insight into how RTP has fared in the field across multiple geographies and customer types.[62]

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[59] Cameron, Claire. "How New York Is Reinventing the Electric Utility." Utility Dive. 05 Feb. 2015.

[60] Bielawski,, Julia. "Schedule Revision and Public Statement Hearings -- Reforming the Energy Vision, Case 14-M-0101." 23 Dec. 2014. E-mail.

[61] Borenstein, Severin. "The Long-Run Efficiency of Real-Time Electricity Pricing," Energy Journal, 26(3). 2005.

[62] There is ample literature on RTP, but most of it has focused on residential programs and and/or takes a primarily theoretical approach. One example of this is Hunt Alcott's "Rethinking Real Time Electricity Pricing" (MIT and NYU, Oct. 2009). Alcott performs an econometric evaluation of the first RTP program for residential customers, which has operated in Chicago since 2003 (and is included in the 2004 LBNL study discussed herein). The central finding is that, although RTP can cause peak energy reduction with no net load shifting (i.e., households' reduce consumption during peak price hours, with no net increase in consumption during low price hours), the peak energy conservation is outweighed by the RTP program's information and contracting costs (i.e., installation of smart meters and customer engagements) and therefore fails to provide a net welfare benefit.

The key findings, as they apply to the subject research and taken directly from the report, are as follows:

1. "Although several programs achieved a significant level of participation, most did not. In 2003, a total of 2,700 non-residential customers, representing more than 11,000 MW of peak demand, were enrolled in RTP programs. However, only three programs had more than 100 non-residential participants or more than 500 MW enrolled, accounting for 80% of all load enrolled in RTP.
2. Most RTP programs were not broadly and proactively marketed. Forty percent of the programs in the survey reportedly had not been marketed at all. The other 60% had been marketed to some degree, but generally were targeted to a relatively narrow group of eligible customers: typically the largest customers, with opportunities for load growth, flat load profiles, and on-site generation.
3. Participation in most RTP programs was dominated by large industrial customers, with modest participation by large institutional customers.
4. Quantitative information on participants' price responsiveness was scarce. Most program managers indicated that RTP participants' price response had not been formally evaluated, and therefore the information was currently unknown.
5. Customers that responded to RTP prices generally employed relatively low-tech strategies or onsite generation resources.
6. RTP programs reportedly achieved load reductions equal to 12-33% of participants' aggregate peak demand, across a wide range of prices. Among eight programs with more than 20 participants, six reportedly generated load reductions in the range of 12-22% of participants' combined non-coincident peak demand, while the other two generated load reductions of approximately 33%."

ANALYSIS & MODEL

Statement of Objectives

At its core, this project seeks to understand the benefits of DERs to different stakeholders when the true economics of the grid are reflected in newly designed rate tariffs. To assess those impacts, our team is looking at the differential effect of DER penetration on existing rates as well as hypothetical redesigned rates that offer real-time pricing (RTP) based on LMPs. Because all ratemaking is local, we focus on New Jersey's PSEG utility, which operates in the PJM electricity market. PSEG is an attractive territory because of New Jersey's relatively favorable policy in regard to DERs, and because PJM is a mature electricity market that offers rich data sets and other desirable characteristics such as robust capacity markets. While our focus is on medium and large commercial customers, our research and suggestions are intended to be useful to all retail segments. Our objectives are to:

1. Understand how price changes in the wholesale market would, if passed through as a signal to retail customers, impact retail prices and demand, particularly for retail customers with DERs;
2. Estimate the differences between utilities' costs and revenues across time and customer size based on level of DER adoption;
3. Determine regulatory and economic "best practices" for reducing this divide by finding "win-win" scenarios that benefit both the utility and the end-user, and then identify their similarities.

To accomplish those goals, we pursue three areas of inquiry:

1. Does RTP better align customer choices with the benefits and costs that DERs contribute to the electric grid?

2. What can utilities and their regulators do to improve commercial customer participation in power markets?
3. What site characteristics most affect the site performance under various rate and DER scenarios?

Methodology

To assess the impact of new retail rates on the connection between retail and wholesale electricity markets and the differential benefits of DER penetration under existing and redesigned rates, we use historical load data, historical LMP data, simulated DER deployments, and variations in proposed rate tariffs that are connected to wholesale markets via LMP. Based on those inputs, two key outputs are calculated: i) total cost to the electricity consumer; and ii) net revenue of the utility, as calculated by the revenue received from the electricity consumer minus the cost of service incurred by the utility.[63] However, we also estimate several metrics to evaluate the effect of DERs on a site-specific basis such as: peak load and load factor. Analysis of those metrics shows that the strongest links to site attributes are i) correlation between electricity costs and load factors and ii) correlation between DER benefit and peak load.

A successful rate reform must satisfy two key criteria. First, it must not make the utility worse off; that is, the utility's net revenue must be greater than or equal to its net revenue under the current rate structure, whether or not its customers choose to adopt DERs. Second, the customer must have the *ability* to be better off under the new rate, either with or without deploying DERs. In other words, *a successful rate reform does not simply redistribute wealth from the utility to its customers or vice versa*. Instead, it

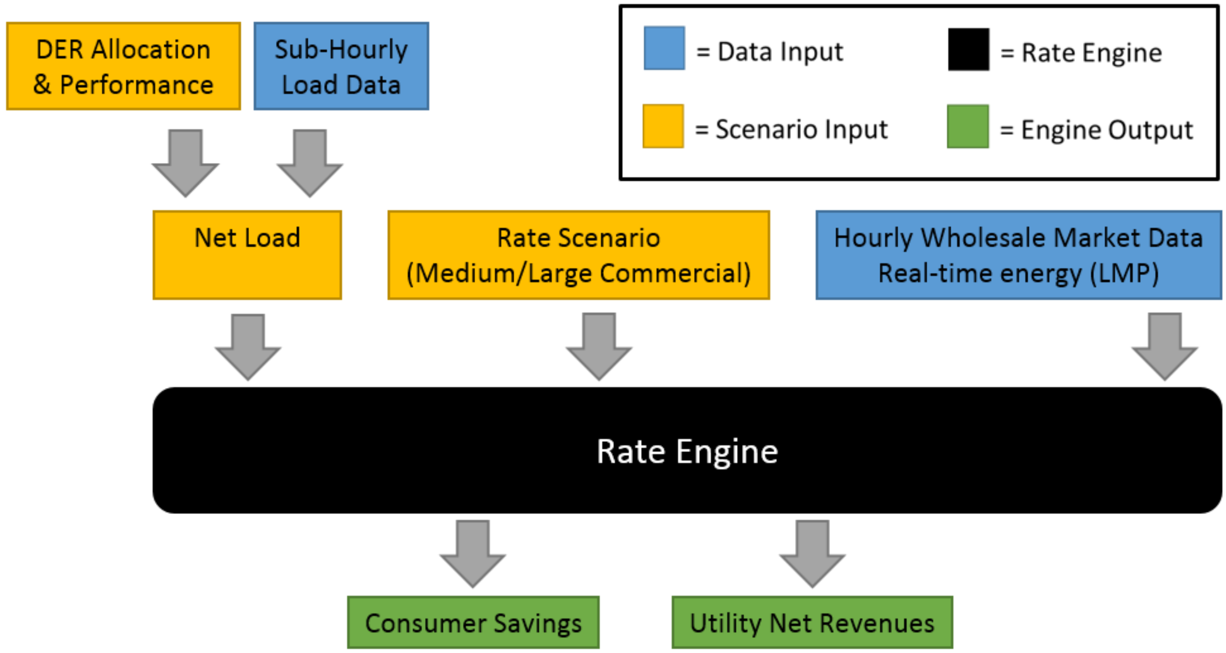
[63] For this analysis, we assume the utility owns the distribution infrastructure, but must procure all generated electricity via wholesale markets (even if it procures from another arm of itself). We consider scenarios in which the utility does and does not own the transmission infrastructure.

drives efficiency gains that make both parties better off by reducing cash flows passed through to generators and other upstream suppliers.

On the wholesale side, this analysis focuses solely on energy markets, excluding the effects of non-energy markets including capacity, ancillary services, etc. This means that, in effect, the only meaningful market signal that our rate reform can reflect is the LMP. As such, the main rate revision we examine in our model is one based almost entirely on LMP. In this revision, a customer's monthly costs would be a multiple of the hourly LMP multiplied by the energy consumption, where the exact multiple is a number that allows us to satisfy our rate reform criteria. In cases where the utility does not own transmission, we consider a scenario where transmission-related demand charges are also passed through to the customer in addition to the LMP multiple. These transmission-related charges remain unchanged from the current rate.

Our model contains a "rate engine" that takes commercial building load data, rate tariff structures, and assumption-based DER contributions as inputs, and outputs a total cost per unit energy (and power), per unit time of consumption. For rate tariff structures, we used the existing PSEG commercial rate tariff as well as two variants of RTP tariffs based on LMPs. This results in cost calculations for both existing and proposed rates. Using this, we can compare the existing rate and our proposed rate structures based on the metrics outlined above.Error! Reference source not found.

Figure 1: Rate Engine Schematic



This schematic illustrates the analytical process that yields our initial results. Sub-hourly load data and LMP data are combined with DER and rate parameter assumptions to generate cost outputs for the customer and the utility, as well as the utility's net revenue (the difference between the two).

To examine the performance of different rate structures under different combinations of DER attributes and load, we created 240 scenarios, which are broadly described in the table below (see detailed description in the appendix):

Table 1: Overview of parameter changes during scenario analysis

DESCRIPTION OF PARAMETER	SOLAR PV	DEMAND RESPONSE	BATTERY
Solar On?	On/Off		
DR On?		On/Off	
Battery On?			On/Off
DR LMP Threshold		65% - 85% of LMP price distribution	
DR % of Load		10% - 20% of Load	
Power: Energy			1:1 vs. 1:2
Battery Capacity (% of Peak)			15% - 25%
Peak Shaving, # of Monthly Peaks to Shave			25 peaks
Charge for Energy Arbitrage			20% - 30% of LMP price distribution
Discharge for Energy Arbitrage			70% - 80% of LMP price distribution

*Some of these variations in parameters overlapped with eachother on a given run of our model

For each scenario we simulate DER operations under each of various rate designs to obtain and compare the performance metrics described above (i.e. utilities' revenues and consumers' costs). The rate engine is designed to handle flexibly a variety of rate structure features, not just those found in PSEG's "large commercial rate" that lies at the center of our analysis.

Rate Designs Considered

1. **LMP Markup.** As the single most economics-driven metric available to the team, a multiple of the current LMP is the foundation of all the rates we explore. As discussed above, this input ranges from 2x to 5x.
2. **Distribution Demand Charges.** Since LMPs do not generally include distribution-level charges, some rates modeled allow PSEG's distribution-related charges to flow through.

Data Inputs

1. **Building Load Data.** Energy data for 13 buildings come from two sources: three privately obtained from Agilis Energy (years 2010-2012) and 10 from publicly accessible data provided by EnerNOC.[64] Their time resolutions are 15-minute and 5-minute, respectively. The buildings represent typical commercial building loads in PJM territory: retail stores, schools and office buildings, as shown in Table 2.

[64] "Data." EnerNOC Open. Web. 20 Feb. 2015.

Table 2: Site Data

SiteID	Industry	Sub-Industry	Sq. Ft	Zip Code	First Date	Last Date	LMP Node	Solar Site
E-718	Light Industrial	Food Processing	28,138	08837	1/1/2012	1/1/2013	48683	NJ-N
E-808	Light Industrial	Food Processing	76,915	18938	1/1/2012	1/1/2013	48840	NJ-C
E-111	Education	School	92,179	08056	1/1/2012	1/1/2013	40243219	NJ-S
E-153	Education	School	105,215	18940	1/1/2012	1/1/2013	48940	NJ-C
E-92	Education	School	105,530	18940	1/1/2012	1/1/2013	48940	NJ-C
E-275	Education	School	108,405	08648	1/1/2012	1/1/2013	48765	NJ-C
E-9	Commercial	Office	169,420	07821	1/1/2012	1/1/2013	119117431	NJ-N
E-12	Commercial	Office	179,665	08081	1/1/2012	1/1/2013	49834	NJ-S
E-29	Commercial	Mall	377,537	08809	1/1/2012	1/1/2013	49329	NJ-C
E-10	Commercial	Mall	1,029,798	08081	1/1/2012	1/1/2013	49834	NJ-S
A-BETH1	Commercial	Office			1/1/2011	1/1/2012	49718	DC
A-BETH2	Commercial	Office			1/1/2013	1/1/2014	49718	DC
A-DC	Commercial	Office			1/1/2010	1/1/2012	5021016	DC

The 13 building types used in our analysis range from malls, schools and offices to food processing plants.

2. **LMP Data.** LMP data were obtained from PJM's "Data Miner" web application[65]. The data are hourly LMPs associated with nodes closest to the building sites we model. Note that LMPs are calculated at 5-minute intervals. We attempted to obtain this more granular LMP data from PJM, but conversations with PJM revealed that i) historical 5-minute data is unavailable except to market participants, and ii) settlements are made with the hourly LMP instead of the 5-minute LMP, so the hourly LMP is more relevant for cost calculations. Even so, more granular LMP data would be useful as a market signal, but we were unable to obtain it.

3. **Rate Tariff Data.** The rate tariff for PSEG's large commercial buildings was obtained and tabulated into a set of parameters.[66] Parameters incorporated into the rate engine include per-kWh, per-kW (monthly peak), and fixed charges

[65] "Data Miner." PJM. Web. 20 Feb. 2015.
[66] PSEG Rate Tariff database.

classified by transmission, distribution, or generation costs. Many parameter values vary by time of day and month of year, and some parameters also have tiers, i.e. different rates for different levels of use. The rate engine accommodates all of these variations.

4. **Solar Generation Data.** Insolation data was obtained from NREL's System Advisor Model database.[67] Insolation for the model years was obtained for 2010-2012. Three sites across various latitudes in New Jersey were selected, as well as one site in the DC metro area. To obtain half-hourly generation data, insolation data was run through the SAM model for a hypothetical 100-kW DC solar array.

DER Assumptions:

1. **Demand Response.** We assumed that each building has a fixed percentage of its load available for DR activities, and that it will activate DR when LMP reaches a certain threshold expressed as a percentile. As a base case, we assume that DR resources are activated for the top quartile of LMPs, and that they reduce building load by 15%. It is also assumed that this is an effective load reduction, not a load shift, and hence consumption is not shifted to other times of lower LMPs. These assumptions are based on Albadi's 2008 survey of DR markets.[68] Our analysis also considers a range of parameter values around the base case, ranging from 10% to 20% load reduction and 75% to 90% threshold for LMP.
2. **Battery System.** When modeling the battery system, we assume all buildings have already made capital investments into intelligent energy storage hardware and software that can react to signals including solar energy production, LMPs,

[67] NREL System Advisor Model.
[68] Albadi, M.h., and E.f. El-Saadany. "A Summary of Demand Response in Electricity Markets." Electric Power Systems Research 78.11 (2008): 1989-996.

and DR participation. Based on conversations with an industry participant with substantive experience in battery storage sizing and economics,[69] we estimate batteries are sized to handle an hour of 25% of peak load. For example, a building with peak load of 200 kW would have a battery with a capacity of 50 kWh. Our study includes a sensitivity analysis on this assumption.

To simulate battery deployment, we design algorithms driven by peak shaving and energy arbitrage. The peak shaving algorithm is given first priority to use the battery's available capacity; the energy arbitrage algorithm is subsequently given access to the battery. While an iterative calculation would be ideal to allow full use of the battery for peak shaving across an entire month's peaks, the algorithm is simplified by directing the battery to shave the top 25 monthly peaks as a base case. This allows for significant usage of the battery resource for peak shaving.

For energy arbitrage under the existing rate scenario, the battery discharges during the last four hours of a peak period, up to an amount creating a net load of zero, then charges immediately during "Off Peak" without creating a new maximum peak for the month. For energy arbitrage under the proposed LMP-driven rate, in the base case the battery discharges during the top 70% of LMPs and recharges during the bottom 30% of LMPs. These settings are modified in our sensitivity analysis.

We also assume a battery efficiency of 90% and, in the base case, a power-energy ratio of 1:2. This setting is also modified in our sensitivity analysis.

[69] Extracted from a phone interview with Willem Fadrhonc (Duke MEM/MBA '12). Mr. Fadrhonc spent over 2 years at Stem, a leading battery storage technology and software provider focused on the commercial customer segment.

3. **Solar Array.** Buildings are assigned the solar generation profile nearest their location, and the solar array is sized based on the minimum of two criteria. The first is a New Jersey law that requires net load of an electricity customer to be greater than or equal to zero for a calendar year (i.e., solar generation cannot exceed building load for the year). The second is roof space. Roof space data was included for buildings in the EnerNOC data set; roof space estimates for the Agilis buildings are based on DOE's Commercial Reference Building Models of National Building Stock.[70]
4. **Capital Costs.** We assume major capital needed to implement DERs, such as solar PV systems and power electronics for DR and battery storage, are already in place at the time of analysis. These are therefore treated as sunk costs and not factored into the analysis. One output of the analysis is a breakeven calculation that identifies upper bounds on capital costs in order for DERs to be economical.

Outputs

The model is designed to take in a given rate design and output hourly cost to customer and cost to the utility. The model is used to compare these outputs across a variety of scenarios, including most importantly:

The base case with no DERs:

1. Independent (one-by-one) activation of DERs:
   a. Solar PV
   b. Energy Storage
   c. Demand Response
2. Stacked activation of DERs (Solar, Storage, and DR)

[70] DOE Commercial Reference Building Models of National Building Stock

Hypotheses

We hypothesize that:

1. Some LMP-driven rates will satisfy the criteria that neither utilities nor their customers (on average) are worse off.
2. Depending on the site and the site-dependent performance of DERs, some customers will benefit less from DERs under an LMP-driven rate reform versus the current rate, while others will benefit more (i.e., current rates may incentivize inefficient, though still beneficial, DER deployment).
3. LMP-driven rates will decrease the difference between the benefits customers gain from DERs and the benefits gained by utilities (i.e., LMP-driven rates will align incentives between customers and utilities with respect to DERs).

RESULTS

The following table shows the best model outcome for each rate design scenario:

Table 3: Model Results by Rate Scenario

RATE SCENARIO	LMP Multiple	200%	300%	400%	500%	300%
	Demand Charges	N	N	N	N	Y
DER STRATEGY WITH LARGEST TOTAL BENEFIT	Solar?	1	1	1	1	1
	DR?	1	1	1	1	1
	Battery?	1	1	1	1	1
	DR LMP Threshold	85%	85%	85%	85%	85%
	DR % of Load	20%	15%	20%	20%	10%
	Battery P:E Ratio	1:2	1:2	1:2	1:2	1:2
	Battery Capacity (% of Peak)	25%	25%	25%	25%	25%
	Battery Arb. Lower Bound (LMP)	20%	20%	20%	20%	20%
	Battery Arb. Upper Bound (LMP)	80%	80%	80%	80%	80%
	Customer Benefit	5.06	0.02	2.34	0.97	1.76
	Utility Benefit	-3.22	0.90	-0.49	0.87	0.03
RESULTS	Total Benefit	1.84	0.92	1.84	1.84	1.78
	Win-Win?	N	Y	N	Y	Y

From these results, we see that while some rate scenarios did not yield mutually beneficial outcomes, three scenarios did. Overall, from an analysis of 240 combinations of rate adjustments and DER performance scenarios, we find that 35 combinations (14%) satisfy our “win-win” criteria of allowing both the utility and its customers to be better off under the new rate design.

Figures 2a and 2b plot the results of these model runs, showing the successful runs in the first quadrant where both customer and utility benefit are positive. Upon examining the range of scenarios that generated successful results, the majority of these fell into a set of rate design parameters including a 5x LMP multiple. This indicates that, in this particular example of PSEG large commercial rates, a rate driven purely by LMPs must generate revenue five times in excess of the pure LMP allocated to generators in order to make the utility whole (as compared to the current status quo).

Figure 2a: Annual Benefit to Utilities and Customers of Rate Scenarios

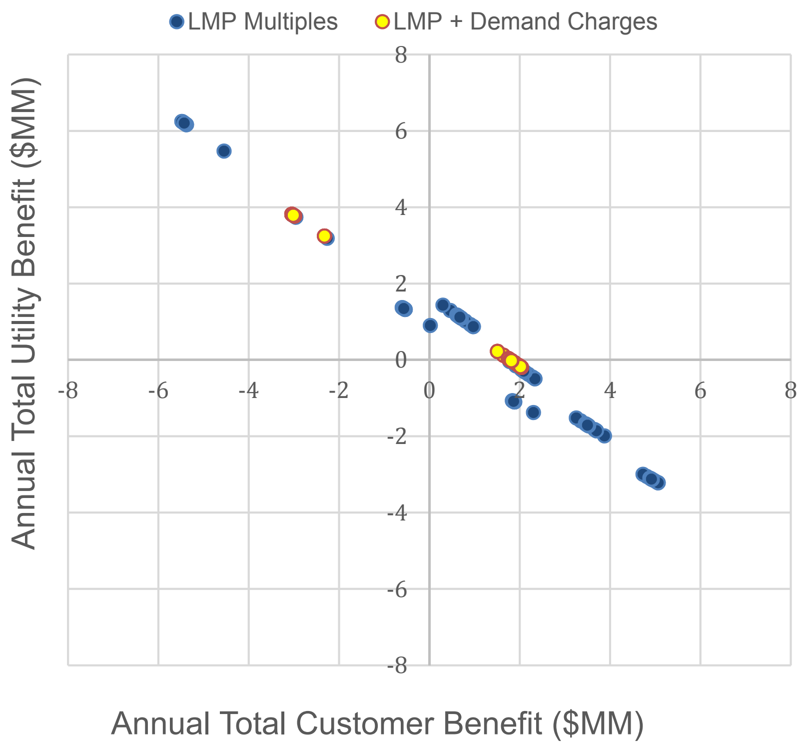
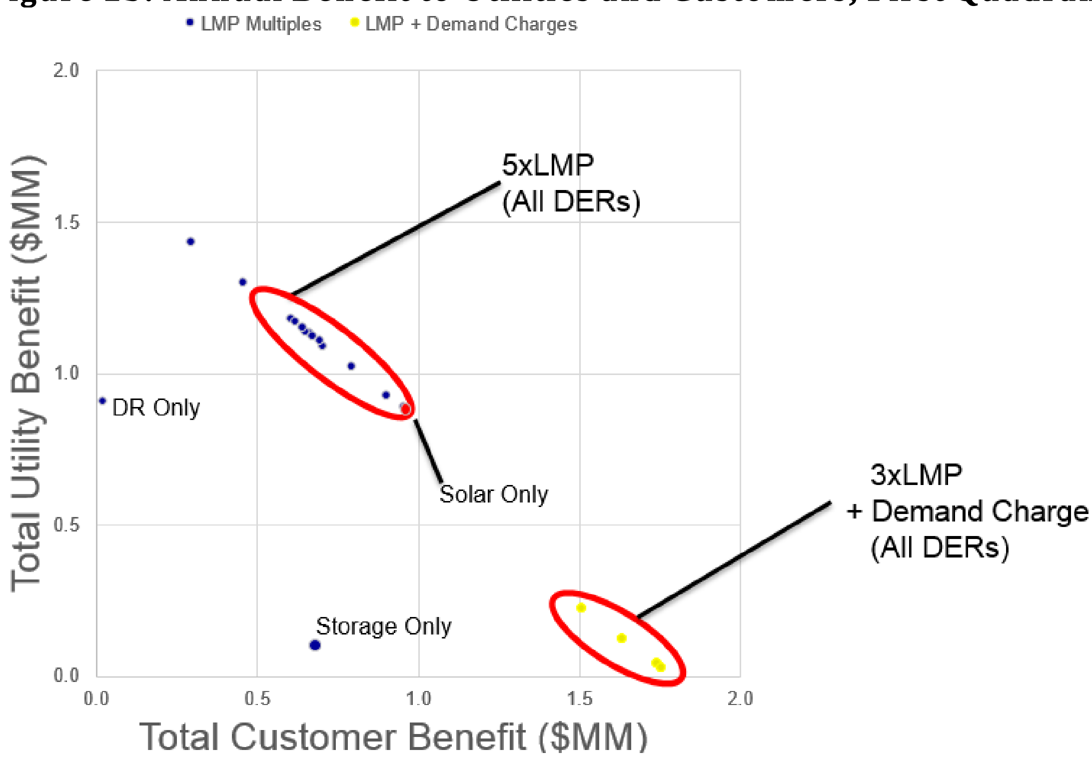


Figure 2b: Annual Benefit to Utilities and Customers, First Quadrant



The scatter plot in Figure 2a illustrates the results of our 240 model runs. Figure 2b shows the 35 results found in the first quadrant in greater detail, indicating they are win-win scenarios that give both utilities and their customers the opportunity to be better off under the new rate.

In addition to the 5x LMP multiple, the analysis also identifies a combination of 3x LMP and some persisting demand charges from the current PSEG rate as satisfying our win-win criteria. The persisting demand charges are those associated with distribution, since infrastructure allocation at this level of the power grid is not captured in LMP prices as readily as transmission-level allocation.

Finally, the analysis does yield results in the first quadrant that are generated by single DERs (i.e., demand response only, solar only, and storage only). The demand response results generally align closer to the y-axis, indicating that the utility accrues significant benefit while the customers are only slightly above zero total annual benefit. Meanwhile, storage alone drives customer benefit much more than it drives utility benefit. Solar alone drives utility and customer benefit almost equally. While these outcomes are to some degree a result of the assumptions upon which our model relies, this is still an interesting finding and points to the possibility that, from a utility perspective, behind-the-meter storage may be a less desirable resource deployment than either solar or DR. More research is needed in this area.

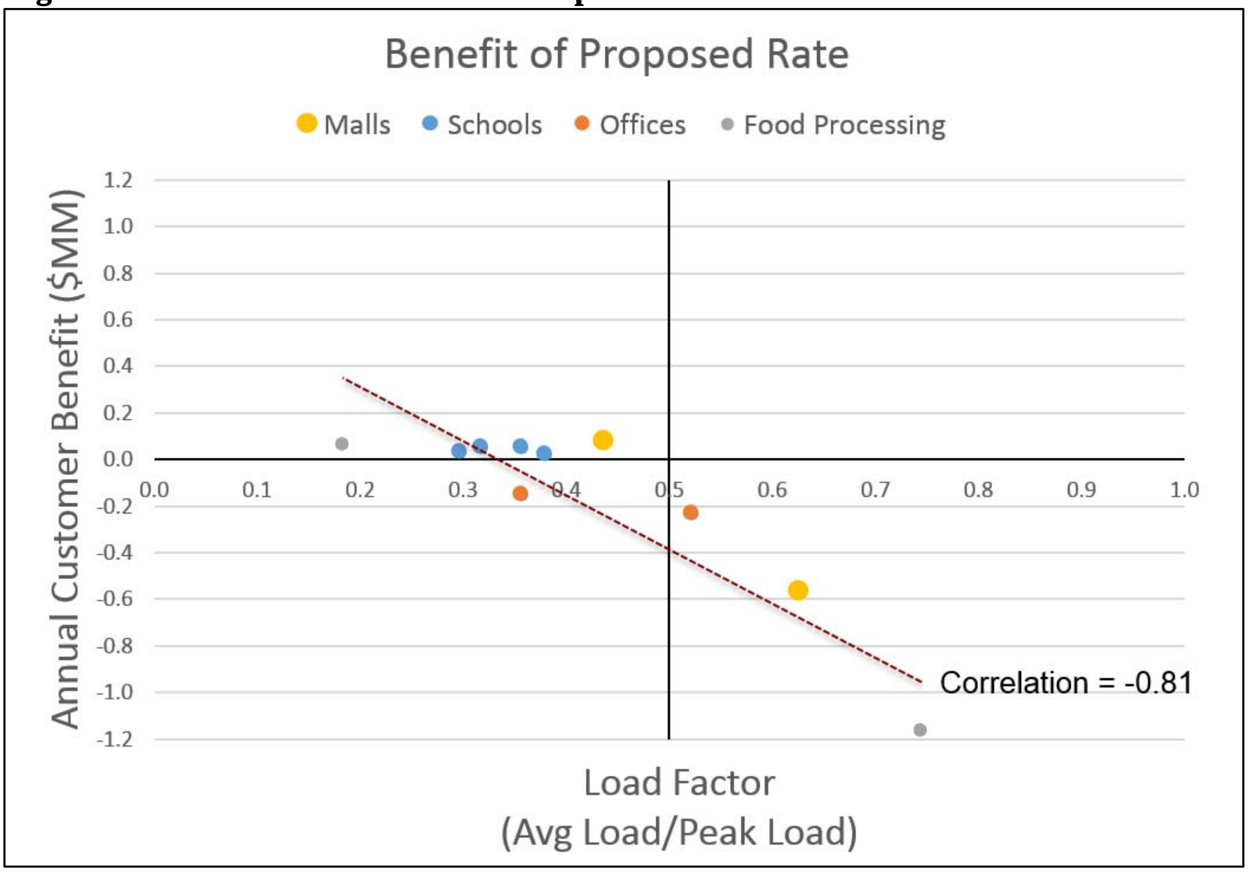
Ultimately, we are able to identify strategies that allow both utilities and customers to be better off under multiple scenarios, which is a significant initial finding.

Site-Level Results Discussion

After assessing the performance of a number of rate design frameworks, we attempt to identify site characteristics that create a promising environment for DERs and for new rates. To this end, we examine the benefits of different types of DERs under the new rate as well as the existing rate. Specifically, we take a single scenario and assess the performance of specific building types within that scenario.

In selecting a scenario to explore more closely, we focus on the scenario's performance along two dimensions: (1) magnitude of total benefit and (2) equity of benefit distribution. In other words, we identify the scenario with the best combination of value creation size and how value creation equity. The run explore scored eighth in total benefit and fourth in equity of benefit; this run included a 5x LMP multiple and deployment of all three DERs. Figure 3 shows site-level benefits attributed to a change in the electricity rate design, in millions of dollars saved annually, versus load factor of the site.

Figure 3: Site-Level Benefits of Proposed Rate vs. Site Load Factor

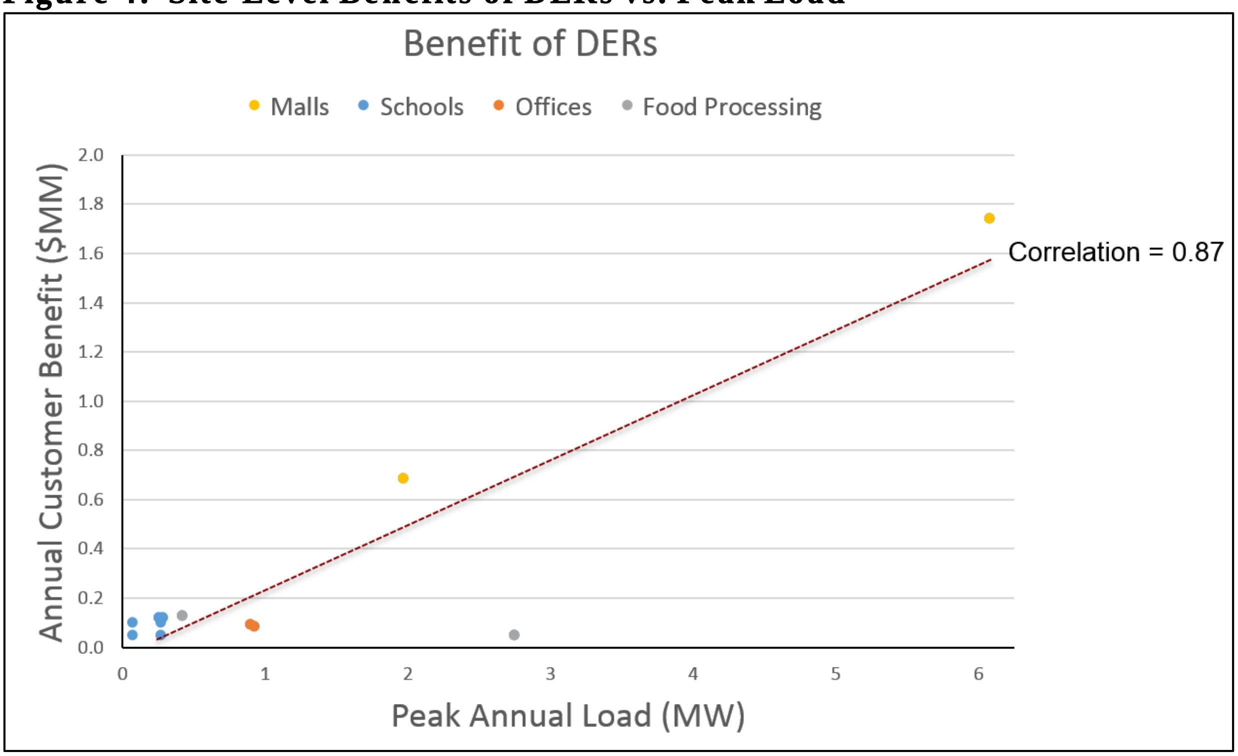


The above figure shows rate benefits to each site, color-coded by building type, in the scenario selected for further investigation. Customer benefit is calculated as the least-cost option (DERs or no DERs) under the original rate minus the least-cost option under the proposed rate. Load factor plays an important role in determining site performance, and some sites with high load factor are significantly worse off under this rate than under the current rate tariff.

After investigating a number of correlations between site-level performance and both site- and rate-specific attributes – ranging from LMP volatility and level to site load volatility and level – our analysis finds that the strongest correlation is with load factor, defined as average load divided by annual maximum peak load. This metric has a strongly negative correlation with site performance under the LMP-driven rate, such that no buildings with load factor greater than 0.5 outperformed the status quo. What this tells us is that while the utility will be better off under this scenario, and customers *en masse* will be better off, some individual customers would lose. This suggests that an introduction of a real-time price signal such as LMP-driven rates cannot be forced, but rather must be optional. Customers must be afforded the choice to stay on the current rate tariff, if preferred.

Our analysis also examines the impact of DERs as a whole on both customer and utility benefit. Figure 4 shows site benefit of DERs versus site peak annual load.

Figure 4: Site-Level Benefits of DERs vs. Peak Load



The above figure shows DER benefits at each site, color-coded by building type, within the scenario selected for further investigation. Customer benefit is calculated as the least-cost option (original or proposed rate) without DERs minus the least-cost option with DERs. Peak load is highly correlated with customer benefit.

Peak load is most highly correlated with customer benefit of DERs; here, it is evident that a site with higher peak load will generally have a higher benefit from DERs. This makes sense because higher peaks allow for more peak shaving, generate a larger battery system in our model, and enable greater participation in DR markets.

In assessing the relative benefits of our proposed rate and of DERs, we find that it is site-specific attributes related to a site's load profile that generally correlate with a site's benefit from the new rate or from DER implementation. This is an important finding because when introducing an LMP-driven rate option, sites are able to understand *ex ante* what kind of savings they should expect, and whether making the switch could be a money-saving proposition.

Results from the Utility Perspective

From the utility's perspective, shifting to an LMP-driven rate could be advantageous from both risk management and cost recovery perspectives. As LMP volatility is passed through to customers, the utility is no longer left to absorb occasionally large disparities between the LMP and the flat rate the utility charges its customers. Instead, LMP spikes incentivize load reductions that then impose negative feedback on the LMP, potentially dampening the spike altogether. This facet of the LMP-driven real-time rate reduces the utility's downside exposure and protects it from wholesale market price spikes. Figures 5a and 5b below provide an illustration of this concept.

Figure 5a: Utility Revenue & Cost for Sample Week, Current Rate Scenario

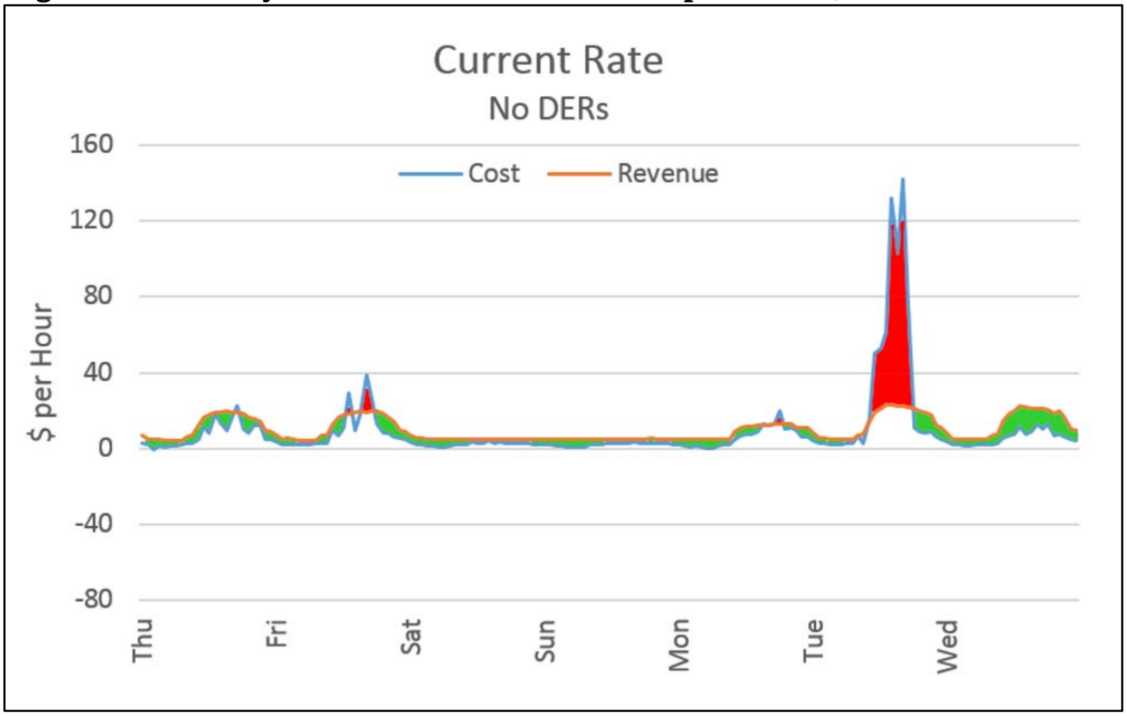
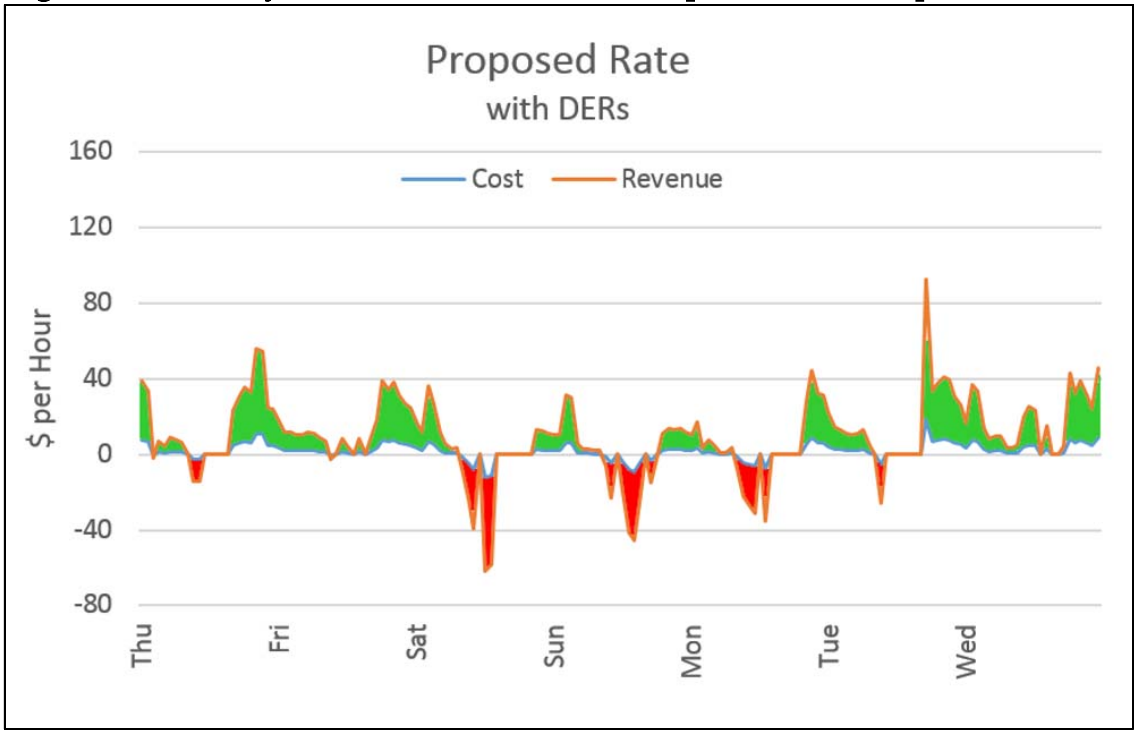


Figure 5b: Utility Revenue & Cost for Sample Week, Proposed Rate Scenario



These figures show how DERs and the proposed rate would benefit PSEG from a risk management perspective. What begins as a largely negative period for the utility under the current rate, where LMP greatly exceeds remuneration from customers for consumption, becomes a relatively normal period of revenue generation for the utility.

Figures 5a and 5b show the utility's hourly cost and revenues over the course of a week under the original rate without DERs and under the proposed rate with DERs, respectively. Periods of net loss are in red, while periods of net gain are in green. The utility loses significantly more in a shorter period under the current rate, while losses in the new rate with DERs are more regular, of a lesser magnitude, and generally stem from net metering (i.e., cost and revenue are negative). Furthermore, under the proposed rate with DERs, the utility's cost recovery is more secure, especially as net metering rules begin to weaken.

CONCLUSIONS

Our concluding remarks apply our results to the stakeholders we discuss previously: commercial and industrial ("C&I") end users; the distribution utility; and regulators.

Commercial Customers

For end users, an additional, optional rate is almost certainly a good thing. A rate design like the LMP multiple allows roughly half of C&I customers to save money versus the status quo with load control and the use of DERs. Furthermore, we find that sites can generally understand whether they should switch to a new rate before doing so, based on site-specific load attributes; this facilitates the decision of whether to switch rates. We do ignore the costs of DER implementation in our analysis, and of course this element needs to be addressed in any future research on this topic. We propose identifying break-even costs of implementation by DER technology as a practical approach to understanding whether and when DERs would be economical for a given site.

Utilities

From a utility perspective, we find that introducing an LMP-driven RTP rate can make the utility better off in the aggregate, and can help the utility avoid periods of extreme loss. We find that this shift could be a welcome defense against the diminishing revenues the utility experiences from the proliferation DERs, particularly solar, as it passes LMP volatility through to end users.

Regulators

As we have demonstrated, an LMP-driven retail rate for electricity can benefit both utilities and customers. For this reason, regulators should encourage the introduction of new, more economically accurate rates and help guide the process of establishing the precise nature of those rates. We have identified a likely range of rate attributes within which both customers and the utility can be better off, but regulators must take on this work in greater detail.

Overall, this analysis has sought to identify potential rate-based solutions to the retail-wholesale divide in electricity markets, and to understand the role that DERs would play in bridging that divide in a way that makes distribution utilities and their commercial and industrial customers better off. Our initial findings are promising, showing that (i) new rates can in fact make both parties better off; (ii) DERs magnify the potential benefit; and (iii) utilities can also use rate design as a risk management strategy. While more research is needed to assess the exact rate structures that should be deployed, we can now conclude that a rate based purely on LMP multiples can incentivize DERs while benefiting utilities and their customers.

APPENDIX A: TOPICS FOR FURTHER RESEARCH

Several lines of inquiry merit further investigation. Future research would benefit from the following:

1. **Calculate breakeven DER costs:** Since DER prices are in a state of rapid flux, incorporating costs into our analysis would have made the analysis obsolete in a short period of time. It is possible, however, to calculate the prices at which DERs are economically viable under different rate structures. Such an analysis would help guide an understanding of which LMP multipliers are most likely to lead to DER proliferation as technology costs evolve.
2. **Expand the number of market signals considered:** Our analysis examined power and energy demand's effect on power pricing. It left out certain power market elements, including ancillary services. Incorporating a value for ancillary services could especially impact the treatment of energy storage, which some observers predict will be an important participant in ancillary services markets.
3. **Increase geographic scope:** Our analysis focused on PSEG territory within PJM, largely because of data availability. Further analysis should expand across the U.S., at the least incorporating analysis from each ISO. This geographic expansion would be extremely challenging since it would require incorporation of new data, new rate structures, new policy regimes and even new weather patterns.
4. **Perform optimization:** Our analysis identified LMP multiples with varying levels of customer/utility benefit by creating and comparing scenarios. Given more time and resources, we would have used MatLab or another software package to identify the optimal LMP multiple and DER configurations to deliver the most customer and utility benefit.

APPENDIX B: DETAILED TABLE OF SCENARIO ANALYSIS

Detailed description of scenarios analyzed by the model. Blue highlight represents our base case and yellow represents deviations from the base case. There are overlaps where a given scenario had multiple parameters that were changed, as shown below.

Run	LMP Markup %	Distribution Demand Charges ($/kW)	Delivery Carve-Out Charges ($/kWh)	Solar On?	DR On?	Battery On?	DR LMP Threshold	DR % of Load	Power: Energy	Battery Capacity (% of Peak)	Peak Shaving, # of Monthly Peaks to Shave	Energy Arbitrage, Lower LMP Threshold	Energy Arbitrage, Upper LMP Threshold
1	400%	0	0	1	1	1	75%	15%	1:2	25%	25	20%	80%
2	200%	0	0	1	1	1	75%	15%	1:2	25%	25	20%	80%
3	300%	0	0	1	1	1	75%	15%	1:2	25%	25	20%	80%
4	500%	0	0	1	1	1	75%	15%	1:2	25%	25	20%	80%
5	200%	0	0	1	0	0	75%	15%	1:2	25%	25	20%	80%
6	300%	0	0	1	0	0	75%	15%	1:2	25%	25	20%	80%
7	400%	0	0	1	0	0	75%	15%	1:2	25%	25	20%	80%
8	500%	0	0	1	0	0	75%	15%	1:2	25%	25	20%	80%
9	200%	0	0	0	1	0	75%	15%	1:2	25%	25	20%	80%
10	300%	0	0	0	1	0	75%	15%	1:2	25%	25	20%	80%
11	400%	0	0	0	1	0	75%	15%	1:2	25%	25	20%	80%
12	500%	0	0	0	1	0	75%	15%	1:2	25%	25	20%	80%
13	200%	0	0	0	0	1	75%	15%	1:2	25%	25	20%	80%
14	300%	0	0	0	0	1	75%	15%	1:2	25%	25	20%	80%
15	400%	0	0	0	0	1	75%	15%	1:2	25%	25	20%	80%
16	500%	0	0	0	0	1	75%	15%	1:2	25%	25	20%	80%
17	400%	0	0	1	1	1	75%	10%	1:2	25%	25	20%	80%
18	400%	0	0	1	1	1	75%	20%	1:2	25%	25	20%	80%
19	400%	0	0	1	1	1	65%	10%	1:2	25%	25	20%	80%
20	400%	0	0	1	1	1	65%	15%	1:2	25%	25	20%	80%
21	400%	0	0	1	1	1	65%	20%	1:2	25%	25	20%	80%
22	400%	0	0	1	1	1	85%	10%	1:2	25%	25	20%	80%
23	400%	0	0	1	1	1	85%	15%	1:2	25%	25	20%	80%

24	400%	0	0	1	1	1	85%	20%	1:2	25%	25	20%	80%
25	400%	0	0	0	0	1	75%	15%	1:2	20%	25	20%	80%
26	400%	0	0	0	0	1	75%	15%	1:2	15%	25	20%	80%
27	400%	0	0	1	1	1	75%	15%	1:1	25%	25	20%	80%
28	400%	0	0	0	0	1	75%	15%	1:1	25%	25	20%	80%
29	400%	0	0	0	0	1	75%	15%	1:1	20%	25	20%	80%
30	400%	0	0	0	0	1	75%	15%	1:1	15%	25	20%	80%
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136	300%	1	1	0	0	1	75%	15%	1:2	25%	25	20%	80%
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139	300%	1	1	1	1	1	65%	10%	1:2	25%	25	20%	80%
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146	300%	1	1	0	0	1	75%	15%	1:2	15%	25	20%	80%
147	300%	1	1	1	1	1	75%	15%	1:1	25%	25	20%	80%

148	300%	1	1	0	0	1	75%	15%	1:1	25%	25	20%	80%
149	300%	1	1	0	0	1	75%	15%	1:1	20%	25	20%	80%
150	300%	1	1	0	0	1	75%	15%	1:1	15%	25	20%	80%
151	300%	1	1	1	1	1	75%	15%	1:2	25%	25	30%	70%
152	300%	1	1	0	0	1	75%	15%	1:2	25%	25	30%	70%
153	300%	1	1	1	1	1	75%	15%	1:1	25%	25	30%	70%
154	300%	1	1	0	0	1	75%	15%	1:1	25%	25	30%	70%
155	300%	1	1	1	1	1	75%	15%	1:1	20%	25	30%	70%
156	300%	1	1	0	0	1	75%	15%	1:1	20%	25	30%	70%
157	300%	1	1	1	1	1	75%	15%	1:1	15%	25	30%	70%
158	300%	1	1	0	0	1	75%	15%	1:1	15%	25	30%	70%
159	300%	1	1	1	1	1	75%	15%	1:2	20%	25	30%	70%
160	300%	1	1	0	0	1	75%	15%	1:2	20%	25	30%	70%
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175	300%	1	1	0	0	1	75%	15%	1:1	20%	25	20%	80%
176	300%	1	1	0	0	1	75%	15%	1:1	15%	25	20%	80%
177	300%	1	1	1	1	1	75%	15%	1:2	25%	25	30%	70%
178	300%	1	1	0	0	1	75%	15%	1:2	25%	25	30%	70%

179	300%	1	1	1	1	1	75%	15%	1:1	25%	25	30%	70%
180	300%	1	1	0	0	1	75%	15%	1:1	25%	25	30%	70%
181	300%	1	1	1	1	1	75%	15%	1:1	20%	25	30%	70%
182	300%	1	1	0	0	1	75%	15%	1:1	20%	25	30%	70%
183	300%	1	1	1	1	1	75%	15%	1:1	15%	25	30%	70%
184	300%	1	1	0	0	1	75%	15%	1:1	15%	25	30%	70%
185	300%	1	1	1	1	1	75%	15%	1:2	20%	25	30%	70%
186	300%	1	1	0	0	1	75%	15%	1:2	20%	25	30%	70%
187	300%	1	1	1	1	1	75%	15%	1:2	15%	25	30%	70%
188	300%	1	1	0	0	1	75%	15%	1:2	15%	25	30%	70%
189	300%	1	1	1	1	1	75%	10%	1:2	25%	25	20%	80%
190	300%	1	1	1	1	1	75%	20%	1:2	25%	25	20%	80%
191	300%	1	1	1	1	1	65%	10%	1:2	25%	25	20%	80%
192	300%	1	1	1	1	1	65%	15%	1:2	25%	25	20%	80%
193	300%	1	1	1	1	1	65%	20%	1:2	25%	25	20%	80%
194	300%	1	1	1	1	1	85%	10%	1:2	25%	25	20%	80%
195	300%	1	1	1	1	1	85%	15%	1:2	25%	25	20%	80%
196	300%	1	1	1	1	1	85%	20%	1:2	25%	25	20%	80%
197	300%	1	1	0	0	1	75%	15%	1:2	20%	25	20%	80%
198	300%	1	1	0	0	1	75%	15%	1:2	15%	25	20%	80%
199	300%	1	1	1	1	1	75%	15%	1:1	25%	25	20%	80%
200	300%	1	1	0	0	1	75%	15%	1:1	25%	25	20%	80%
201	300%	1	1	0	0	1	75%	15%	1:1	20%	25	20%	80%
202	300%	1	1	0	0	1	75%	15%	1:1	15%	25	20%	80%
203	300%	1	1	1	1	1	75%	15%	1:2	25%	25	30%	70%
204	300%	1	1	0	0	1	75%	15%	1:2	25%	25	30%	70%
205	300%	1	1	1	1	1	75%	15%	1:1	25%	25	30%	70%
206	300%	1	1	0	0	1	75%	15%	1:1	25%	25	30%	70%
207	300%	1	1	1	1	1	75%	15%	1:1	20%	25	30%	70%
208	300%	1	1	0	0	1	75%	15%	1:1	20%	25	30%	70%
209	300%	1	1	1	1	1	75%	15%	1:1	15%	25	30%	70%

210	300%	1	1	0	0	1	75%	15%	1:1	15%	25	30%	70%
211	300%	1	1	1	1	1	75%	15%	1:2	20%	25	30%	70%
212	300%	1	1	0	0	1	75%	15%	1:2	20%	25	30%	70%
213	300%	1	1	1	1	1	75%	15%	1:2	15%	25	30%	70%
214	300%	1	1	0	0	1	75%	15%	1:2	15%	25	30%	70%
215	300%	1	1	1	1	1	75%	10%	1:2	25%	25	20%	80%
216	300%	1	1	1	1	1	75%	20%	1:2	25%	25	20%	80%
217	300%	1	1	1	1	1	65%	10%	1:2	25%	25	20%	80%
218	300%	1	1	1	1	1	65%	15%	1:2	25%	25	20%	80%
219	300%	1	1	1	1	1	65%	20%	1:2	25%	25	20%	80%
220	300%	1	1	1	1	1	85%	10%	1:2	25%	25	20%	80%
221	300%	1	1	1	1	1	85%	15%	1:2	25%	25	20%	80%
222	300%	1	1	1	1	1	85%	20%	1:2	25%	25	20%	80%
223	300%	1	1	0	0	1	75%	15%	1:2	20%	25	20%	80%
224	300%	1	1	0	0	1	75%	15%	1:2	15%	25	20%	80%
225	300%	1	1	1	1	1	75%	15%	1:1	25%	25	20%	80%
226	300%	1	1	0	0	1	75%	15%	1:1	25%	25	20%	80%
227	300%	1	1	0	0	1	75%	15%	1:1	20%	25	20%	80%
228	300%	1	1	0	0	1	75%	15%	1:1	15%	25	20%	80%
229	300%	1	1	1	1	1	75%	15%	1:2	25%	25	30%	70%
230	300%	1	1	0	0	1	75%	15%	1:2	25%	25	30%	70%
231	300%	1	1	1	1	1	75%	15%	1:1	25%	25	30%	70%
232	300%	1	1	0	0	1	75%	15%	1:1	25%	25	30%	70%
233	300%	1	1	1	1	1	75%	15%	1:1	20%	25	30%	70%
234	300%	1	1	0	0	1	75%	15%	1:1	20%	25	30%	70%
235	300%	1	1	1	1	1	75%	15%	1:1	15%	25	30%	70%
236	300%	1	1	0	0	1	75%	15%	1:1	15%	25	30%	70%
237	300%	1	1	1	1	1	75%	15%	1:2	20%	25	30%	70%
238	300%	1	1	0	0	1	75%	15%	1:2	20%	25	30%	70%
239	300%	1	1	1	1	1	75%	15%	1:2	15%	25	30%	70%
240	300%	1	1	0	0	1	75%	15%	1:2	15%	25	30%	70%