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WHO SHOULD OWN AND OPERATE DISTRIBUTED ENERGY RESOURCES?

ADAPTIVE APPROACHES TO DER DEPLOYMENT[1]

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EXECUTIVE SUMMARY

One hot topic at SEPA's 51st State Summit and in public forums since then has been whether utilities should own and operate distributed energy resources (DERs),[2] or whether these functions should be left to third-parties, consumers,[3] or some combination.[4] Under the framework laid out in *An Adaptive Approach to System Optimization*,[5] many different models of ownership and operation can optimize the system, so long as they take an adaptive approach that prioritizes fair compensation, fosters innovation and competition, and provides transparency for all market participants. It is likely that each ownership model has its place, and what is appropriate depends largely on the policy priorities of each region.

This short paper presents a series of case studies seeking to draw experience from different ways of tackling the same problem: how to integrate cost-effective distributed technologies that have run into outdated regulatory models. By reviewing utility-owned and operated DERs, third-party-operated DERs, and customer-operated DERs, this paper identifies strengths and weaknesses in each approach.

CONTENTS

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[1] This is an addendum to the 51st State concept paper entitled *An Adaptive Approach to System Optimization.*
[2] L. Huber, *Why Utility Ownership of Rooftop Solar Should be Explored*, UtilityDive, July 21, 2015. http://www.utilitydive.com/news/why-utility-ownership-of-rooftop-solar-should-be-explored/402645/.
[3] J. Tong & J. Wellinghoff, *Should Utilities Be Allowed to Rate Base Solar?*, UtilityDive, May 11, 2015. http://www.utilitydive.com/news/tong-wellinghoff-should-utilities-be-allowed-to-rate-base-solar/396283/.
[4] S. Aggarwal & M. O'Boyle, *Should Utilities Own Distributed Storage?* Greentech Media, June 29, 2015. http://www.greentechmedia.com/articles/read/should-utilities-own-distributed-battery-storage.
[5] M. O'Boyle, *An Adaptive Approach to System Optimization*, America's Power Plan, prepared for the SEPA 51st State Challenge, Feb. 2015.

Owned by:	Operated to optimize for:	Revenue sources:	Real-world examples:
Utility	Utility operations	Commission-determined (rate-case), Wholesale markets	• California Solar PV Program • Arizona rooftop solar • Borrego Springs Microgrid
Non-Utility	Third party managers	Retail rates, Utility contracts, Wholesale markets	• EcoFactor/NV Energy mPowered Program • DR aggregation in PJM • CAISO DER Provider Participation
	Customer's bill	Retail rates	• ComEd Retail Real-Time Pricing & DR program • SMUD Dynamic Pricing Pilots

The discussion section applies the principles of the original paper to each model of DER ownership. It finds that utility DER programs work best when narrowly tailored to accomplishing public goals, but they must hedge against market power concerns and adapt to emerging technologies to avoid cost overruns. Utilities have been particularly successful in early adoption and demonstration of emerging technologies. On the other hand, third-party and customer-owned DERs excel when they are able to transparently ascertain and access the full value that DERs can provide, whether it is through a dynamic rate design or transparent competitive markets for bulk-system and distribution-level services. The case studies show that customers and third parties will optimize their portfolio of DERs against whatever revenue streams are available.

Above all, any of these models can work so long as the value proposition to each actor aligns with the public interest. By applying the principles articulated in *An Adaptive Approach to System Optimization,* utility regulators can use any of these ownership and operation models to optimize the system and maximize the public interest.

INTRODUCTION

As discussed in *Adaptive Approach to System Optimization*,[6] either a vertically integrated or a market-based structure—if designed well—can achieve optimal deployment of distributed and centralized resources, resulting in a cleaner, more reliable, more affordable electricity system. The principles in the original paper focus on building transparency and adaptability into policy, ensuring that regulators can adapt to changing technologies, political trends, and regulatory models as they emerge.

But within that framework, who should own and operate DERs and their enabling technologies? Should it be properly-incented utilities, who may be able to integrate certain public policy objectives into their operations and can leverage existing customer relationships and trust? Or should it be competitive third-parties and customers, whose effectiveness at optimizing the system often depends on access to data about the precise valuation of DERs? The answer, like rate design and market structure questions addressed in the original paper, depends on the balance of public goals for regulators in each jurisdiction.

Accordingly, this paper provides a series of case studies that isolates different ownership and operation models to glean the pros and cons of each. This paper then briefly applies the principles of the original paper to assess and suggest complementary policies for each model.

MODELS FOR OWNING AND OPERATING DERS

- Utility-Centric – utilities pay for and own DERs, recovering costs (and taking risks) through ratemaking, whether cost-of-service, performance-based, or some hybrid. The value proposition for utilities depends on the regulatory model, but revenue is authorized by the regulator. Leveraging knowledge of the distribution system, the utility deploys and operates the DERs in conjunction with distribution infrastructure to optimize the output of these resources. In restructured areas, the utility may also offer aggregated DERs into the wholesale market, or forego purchases they might otherwise have needed to make.
- Third-party-Centric – Third-parties (i.e. non-utility companies) may operate DERs in conjunction with or separately from utility programs. In the former case, third-parties may operate utility-funded programs to provide services to the distribution system and customers; in the latter, they may derive value by selling aggregated services to utilities or offering those services into wholesale markets.
- Customer-Centric – Rather than operating in conjunction with infrastructure, customer-owned and software-operated systems respond to electricity rates and optimize to reduce and manage electricity bills. The more complicated the rate, the more sophisticated and responsive customers (or—more likely—their management software) must become to maximize the value from DERs.

[6] M. O'Boyle, *An Adaptive Approach to System Optimization*, SEPA 51st State Challenge, Feb. 2015.

Each of these models can of course work in conjunction with the others; utility owned DERs may be operated by both customers and third-parties, with each gaining some revenue in the process. For example, a utility might pay a third party to install and operate a fleet of storage systems at customers' homes, perhaps under constraints decided by the customers themselves. In this example, the utility might recover the capital cost of the storage systems, third parties may receive payment for services rendered, and participating customers may see lower bills.

In addition, the prevailing market structure and rate design will dictate how these revenue streams accrue. Take the last example; under traditional cost of service, the utility may receive a higher return because its capital stock increased, but under performance-based ratemaking, the same utility may achieve higher earnings if the utility-owned project improves performance, e.g. by lowering system load factor, increasing customer participation, improving environmental performance, or even reducing overall system cost by avoiding distribution system upgrades.

Where possible, this paper isolates "pure" examples of each model to compare the results and shed some light on how each can be used to optimize the electricity system.

THE UTILITY-CENTRIC EXPERIENCE

1. Utility-owned DERs in-front of the meter

Between 2009–2010, the California Public Utilities Commission authorized Southern California Edison (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E) to own and operate solar photovoltaic (PV) facilities, as well as to execute solar PV power purchase agreements with independent power producers (IPPs) through a competitive solicitation on large-scale distributed PV arrays between 1-20MW, aiming for a total procurement of 1,100 MW.[7]

The utility-owned portions of the program (~50% of the total) were cancelled before even half of the procurement took place. Though SCE and PG&E ended their programs for different reasons, experience from these programs shows that utility-owned distributed generation (DG) can accomplish certain goals like accelerated market development and demonstration, but they may need to be abandoned if a more innovative approach presents itself.

SCE voluntarily petitioned to stop its programs when it saw that purchasing power competitively from third parties via a reverse auction mechanism was materially cheaper than owning and operating the solar PV themselves.[8] They were losing on price to third-party installers and operators whose revenues depended on being low bidders in the reverse auction. PG&E

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[7] California Public Utilities Commission Solar Photovoltaic Program homepage. http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/Utility+PV+Programs.htm

[8] "Continuing circumstances have made it difficult and less economical to build SPV projects through the UOG portion of the SPVP when SCE could buy renewable energy, generated from SPV technology, at a lower cost through other programs. . . . SCE estimates a reduction of 34 MW in the UOG portion of the SPVP would result in SCE's customers saving approximately $100 million in capital spending, plus $1.4 million/year in O&M costs." Southern California Edison Company's Petition for Modification of Decision No. 12-02-035, July 27, 2012, at 2-3.

cancelled the program in the same year, finding that "cost and administrative efficiencies [would] be achieved through the early termination of the PV Program."[9] Although cost overruns were not cited by PG&E as a reason for early termination,[10] it noted that the CPUC's objectives of ensuring compliance with the state renewable portfolio standard (RPS), market development, and price declines had been achieved for 1–20MW solar PV systems. Both utilities felt it was in the best interest of ratepayers to end the program early and rely on the reverse auction to find third parties to own and operate larger distributed solar PV.

2. *Utility-owned DERs behind the meter*

In 2014, Arizona Public Service (APS) and Tucson Electric Power (TEP), Arizona's two largest investor-owned utilities, petitioned the Arizona Corporation Commission (ACC) to own and operate a fleet of residential rooftop solar systems—10MW and 3.5MW in aggregate, respectively. Unlike California in 2009, solar PV market development is not an issue in Arizona, where hundreds of customers apply for interconnection of their rooftop solar systems every month.[11] Instead, the ACC cited goals like compliance with the state's renewable portfolio standard (RPS), increased access to rooftop solar for low-income customers, and quantification of distribution services associated with utility ownership and control of distributed solar.[12]

To safeguard costs, the ACC requires APS to use competitive bidding through an independent request for proposals (RFP) process, limits the size of the program to minimize commitment to an untested model, and refuses to pre-approve projects, instead subjecting them to prudency review in APS's next rate case.[13] For TEP, the cost safeguards are identical, but $10 million of expenditures was pre-approved as a small pilot.[14] In this way, the pilots are narrowly tailored to the policy goals without immense risk to ratepayers.

However, the APS and TEP programs enable the utilities to compete directly with third parties and individuals interested in installing rooftop solar. By altering the billing relationship unilaterally, these utilities can offer attractive options to lower bills for customers while sharing

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[9] Pacific Gas & Electric Co., Advice Letter 4160-E, The Termination of Pacific Gas and Electric Company's Photovoltaic Program, Dec. 10, 2012, at 6.

[10] In fact, PG&E quoted the capital costs of its utility-owned generation below forecasted levels in the original SPVP petition.

[11] 7,800 APS customers installed rooftop solar in 2014, and over 2,300 applications were received in the first three months of 2015. APS News, *APS: Rooftop Solar Applications up 112% in First Quarter 2015*, Press Release, April 9, 2015. http://www.pinnaclewest.com/files/doc_news/2015/Solar-Applications-Up-in-Q1-(04-09-15).pdf.

[12] Arizona Corporation Commission, Decision No. 74878, *In the Matter of Ariz. Pub. Service Co. for Approval of its 2015 Renewable Energy Standard Implementation Plan for Reset of Renewable Energy Adjustor*, Docket No. E-01345A-14-0250, Dec. 23, 2014, at 5.

[13] Ibid. at 5-6.

[14] Arizona Corporation Commission, Decision no. 74884, *In the Matter of the Application of Tucson Electric Power Co. for Approval of Its 2015 Renewable Energy Standard Implementation Plan*, Docket No. E-10933A-14-0248, Dec. 31, 2014, at 22.

some investment risk with its customers as a whole, and potentially exercise market power.[15] On the other hand, these utilities have an opportunity to support low-income customers and maximize the benefits of DERs by considering location and time-of-use.

3. A Utility-owned and operated microgrid

Borrego Springs is an isolated community in San Diego Gas and Electric (SDG&E)'s most eastern, remote service territory fed only by a single sub-transmission line. Because of the bottleneck of transmission into the area coupled with a history replete with natural disasters like wildfires, lightning, and floods that often disrupt service, Borrego Springs was identified as a prime site for microgrid installation.

In 2013, with over half of funding provided by the Department of Energy (DOE) and the California Energy Commission (CEC), SDG&E completed a five-year demonstration project to operate a microgrid in the area capable of islanding from the rest of the distribution grid. The project materially improved reliability and has already provided power during several outages, including both scheduled maintenance[16] and weather-related outages.[17]

Through the Borrego Springs project, SDG&E channeled the public interest in two ways: it was an early adopter of new technology with high but unproven potential to provide benefits particularly in a high-renewables future, and it improved the service to a previously marginalized remote community while spreading those costs among customers. CPUC staff supported the notion in 2014 that "in some situations, such as those evident in Borrego Springs, utility investments in microgrids to support the delivery of electricity and improve local reliability for their customers may be necessary and prudent."[18] With a mandate to serve all customers at a minimum level of service, the utility can funnel immense resources toward early adoption of new technologies in the locations where their potential to benefit customers is the highest, improving the quality of service and furthering the public interest.

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[15] The extent of this risk depends in APS's case depends on whether the ACC approves the rooftop solar investments.

[16] San Diego Gas & Electric, *Microgrid Powers Borrego Springs to Avoid Major Outage*, June 1, 2015. http://www.sdge.com/newsroom/press-releases/2015-06-01/microgrid-powers-borrego-springs-avoid-major-outage.

[17] On the afternoon of Sept. 6, 2013, intense thunderstorms blew into Borrego Springs and lightning from the storm struck and shattered a power pole on the only transmission line serving the community, cutting electricity to all 2,780 customers. The microgrid resources were able to restore power to 1,060 customers within hours using the onsite power. San Diego Gas & Electric, *Borrego Springs Microgrid Demonstration Project*, (prepared for the California Energy Commission CEC-500-2014-067) Public Interest Energy Research Program, Oct. 2013, at 67.

[18] C. Villareal, D. Erickson, & M Zafar, *Microgrids: A Regulatory Perspective*, California Public Utilities Commission, Policy & Planning Division, Apr. 14, 2014, at 24.

THE THIRD-PARTY-CENTRIC EXPERIENCE

1. *Third-party ownership, operation, and participation in wholesale markets*

Starting in 2009, PJM Interconnection allowed energy efficiency (EE) and demand response (DR) to compete in capacity auctions with conventional power plants.[19] The response has been immense, over 11,000MW of DR participated in PJM's capacity and energy markets in 2013. By opening up participation in wholesale markets to DERs like DR and EE, PJM has stimulated a growing market for third-party-owned resources that can make the grid more reliable, affordable, and clean.

DR aggregators in PJM Interconnection have successfully competed with conventional generation, stimulated a new market for DR, and driven down capacity market prices dramatically. For example, the PJM market monitor found that without DR and EE, the clearing price of the 2017-2018 capacity auction (which took place in 2014) would have increased 137%,[20] costing PJM participants an extra $9.35 billion.[21] While those savings reflect only one sensitivity and not a holistic counterfactual analysis, DR clearly had a large impact on price by simply displacing more expensive generators. Meanwhile in the energy market, reductions in electricity use during the early August heat wave of 2013 produced price reductions estimated to be equivalent to more than $650 million in payments for energy for the week.[22]

This can be contrasted with the Irish model for DER participation in wholesale markets, which forces aggregators or "demand side units" (DSUs) to go through their distribution utilities rather than participate directly in the wholesale market.[23] Unlike PJM, individual customers in Ireland that want to connect to the grid must negotiate individual contracts with the utility to export their power on to the distribution system.[24] Unlike the PJM auction, contract prices are not public information, meaning that utilities can make their own decisions about whether to allow

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[19] *Postcard from the Future: PJM*, America's Power Plan, Aug. 2013. http://americaspowerplan.com/2013/08/pjm/.

[20] The Independent Market Monitor for PJM, *The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses*, July 10, 2014, at 3.

[21] E. Whieldon, *PJM capacity auction price would have skyrocketed without DR and EE, monitor finds*, SNL Energy, July 11, 2014. https://www.snl.com/InteractiveX/Article.aspx?cdid=A-28626479-10793.

[22] *Early August Demand Response Produces $650 Million Savings in PJM*, PR Newswire, Aug. 17, 2013. http://www.prnewswire.com/news-releases/early-august-demand-response-produces-650-million-savings-in-pjm-56192937.html.

[23] The Irish electricity system is fully deregulated, meaning the distributed system operator (DSO), transmission system operator (TSO), retailers ("Suppliers"), generators, and other aggregators are all separate entities. A. Schoofs*, The Electricity Market in Ireland*, *wattics.com*, Dec. 19, 2014, last visited August 8, 2015. URL: http://www.wattics.com/the-electricity-market-in-ireland/#distribution.

[24] It is worth noting that this is the likely arrangement US providers may need to get used to if the Supreme Court decides to vacate FERC Order 745 this fall. S. Aggarwal & M. O'Boyle, *Trending Topics in Electricity Today—The Value of Demand Response*, America's Power Plan, October 2014. http://americaspowerplan.com/2014/10/the-value-of-demand-response/.

DERs to participate.[25] As a result, the value proposition for DERs is not clear, making it difficult for aggregators to use the resources at their fingertips to optimize the system. In some cases these third-party owners may not be permitted to export services to the grid, despite the benefits they could provide.[26] Nevertheless, the development of Ireland's third-party DR market has been substantial, with DR accounting for about 3.7% of total capacity in the Republic of Ireland.[27]

2. *Utility ownership with third-party operation*

Instead of getting revenue from the wholesale market, this model of non-utility DER ownership relies on retail rate design and utility procurement. In other words, a third party optimizes a fleet of behind-the-meter DERs to provide distribution-level services on behalf of a utility.

One such example is the mPowered program operated by Ecofactor in NV Energy's service territory.[28] The mPowered program is a NV Energy-funded DR and home energy management program using an internet-connected EcoFactor programmable communicating thermostat (PCT) that interacts with the customer's heating, ventilation, and air conditioning (HVAC) system. Using data collected from the connected thermostats, the EcoFactor service runs algorithms to minimize energy consumption that adapt to individual preferences in real time, automatically adjusting the thermostat to a more efficient level in order to reduce wasteful energy usage and reduce demand when the utility signals the need. In exchange for participation, customers receive the EcoFactor thermostat, installation, and automation service subscription free of charge, along with a tariff-based rebate that varies depending on the amount of demand reduction achieved.[29]

On average, Ecofactor reduced customer demand during the 28 peak events in 2013 by 2.4kW/household after accounting for voluntary non-participation.[30] The program achieved even greater demand reductions during the first hour of the three-hour DR period (an average of 3.5kW/household), a proxy for emergency response capacity. Today, the mPowered program represents more than 50,000 devices, driving a significant peak reduction (>100MW), giving NV

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[25] ESB Networks, *How to Connect a Micro-Generator*, last visited February 24, 2015. URL:, http://www.esb.ie/esbnetworks/en/generator-connections/micro_gen_connections.jsp. See also *ESB Networks Distribution Code*, DCC9.9 (Additional Requirements for Dispatchable Demand Customers).
[26] Ibid.
[27] Sem-o.com, *Registered Capacity Report,* July 2015. http://www.sem-o.com/Publications/General/Registered%20Capacity%20Report%20July%202015.xls.
[28] See the NV Energy mPowered homepage: https://www.nvenergy.com/home/saveenergy/rebates/mpowered/.
[29] ADM Associates, *Demand Response Program NV Energy Program Year 2013*, Final Evaluation Report, Prepared for NV Energy, *Application of Nevada Power Company d/b/a NV Energy for Approval of its 2014 Annual Demand Side Management Update Report as it relates to the Action Plan of its 2013-2032 Triennial Integrated Resource Plan*, June 14, 2014, at 88–89.
[30] Ibid. at 154, tbl. 55. On average, 14% of customers refused to participate in each event. For every household that responded, there were approximately 2.8kW in reduction; this takes into account the 1.56 device/household ratio provided earlier in the report. Ibid. at 100.

Energy another option to optimize its electricity system.[31] Meanwhile, the average customer saves 10-15% on her energy bill, including the DR dividend.[32]

mPowered is third-party-managed tool for utilities to access increased flexibility for balancing supply and demand in real time. EcoFactor leverages the utility's ability to market products to its customers, and creates system value by reducing peak load and encouraging conservation. In the future, this program could be coupled with more dynamic rates to maximize customer savings and even better align customer behavior with system value.

3. Striking the balance between wholesale and distribution revenue streams

Today, third parties optimize their fleet of DERs for the bulk system *or* the distribution system, but usually not both. Market structures are evolving, but are not yet fully formed, and there are fundamental questions to be answered before third parties can reap the full value of DERs at both the distribution- and bulk-power-scales simultaneously.

The first question is whether these systems can truly provide both distribution-level services and bulk-level services. For example, can a fleet of DERs provide ramping and voltage regulation at the same time? If the answer is no, a second question arises; how often the two conflicting services are needed at the same time. These two questions can be answered relatively concretely by engineers who experiment with the capabilities of DERs acting in concert.

The most difficult question is whether markets are coordinated such that the performance requirements of one (e.g. the wholesale capacity market) do not preclude performance in the other (e.g. local voltage stability). Finding ways to access both value streams is crucial if third party aggregators of DERs hope to compete on equal footing with traditional infrastructure to meet grid needs.[33]

The California Independent System Operator (CAISO) is now allowing DER aggregators of all types to participate in wholesale markets, so long as they surpass a minimum 500KW aggregate capacity threshold.[34] While there are some limitations on the type and location of the DERs,[35] this provides another revenue stream for third-party DER owners and operators to more effectively compete with conventional generation. The CAISO measure is complemented by the

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[31] NV Energy's peak electricity load for its Southern service territory was 5,572MW in 2014; there are approximately 800,000 customers in its service territory. https://www.nvenergy.com/brochures_arch/Power-Facts.pdf.

[32] See mPowered homepage, note 28.

[33] See O'Boyle, *An Adaptive Approach to System Optimization*, at 13. One principle of an adaptive market structure is to "[c]reate a level playing field for competition between all resources, regardless of their type, technology, size, location, ownership and whether or how they're regulated, allowing supply and demand resources to compete head-to-head."

[34] California ISO, *Expanded Metering and Telemetry Options Phase 2: Distributed Energy Resource Provider*, Draft Final Proposal, June 10, 2015. The proposal was approved by the CAISO Board of Governors on July 16, 2015.

[35] Ibid. The CAISO proposal caps the size of DER aggregations across multiple nodes to no more than 20MW, and insist that all resources responding to a dispatch order move in the same direction either up or down. Aggregators are also prohibited from combining different types of DERs within a single aggregation.

California Public Utilities Commission (CPUC) initiative to improve DER integration and valuation on the distribution level via distributed resource planning.[36] The CPUC's goal for this program is:

> *"a regulatory framework, developed by the Commission, to enable utility customers to most effectively and efficiently choose from an array of demand-side and distributed energy resources taking into consideration the impact and interaction of such resources on the system as a whole as well as on an individual customer's energy usage."*[37]

New models like the Energy Box[38] or other dynamic retail market structures under development like those in New York[39] hope to access both value streams as well. As energy management software and DER service offerings evolve along with more adaptive rate design and market structures, the current inefficiencies created by disconnected bulk- and distributed systems may decrease.

THE CUSTOMER-CENTRIC EXPERIENCE

While customer-owned and operated DERs rival utility- and third-party markets in aggregate size,[40] the diversity of experience is relatively small and boils down to one key factor: rate design. Except in very limited cases (like large loads' direct participation in wholesale markets)[41], customers installing DERs reap value by managing their utility bills. From the customer perspective, investments are rational when bill reductions offset the cost and when rates are stable, allowing a long-term pay-off. From a system-wide perspective, DER investments are rational when the revenues and avoided costs from the investment exceed the price paid for DER services. Ideally these two rationales would be in perfect alignment—then we would have rate design optimized for DERs.

Instead, rate design that fails to reward optimal behavior is the norm. Most jurisdictions still use static pricing that emphasizes uniformity, simplicity, and stability over optimizing each

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[36] California Public Utilities Code, Section 769, 2015. "Not later than July 1, 2015, each electrical corporation shall submit to the commission a distribution resources plan proposal to identify optimal locations for the deployment of distributed resources." Section 769 was added to the Public Utilities Code by Assembly Bill 327 (Stats. 2013, ch. 611). Subsequent distribution resource planning took place under *Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning,* R.14-08-013, Feb. 6, 2015.

[37] *Proposed Decision Adopting an Expanded Scope, a Definition, and a Goal for the Integration of Demand Side Resources*, Proposed Decision of Commissioner Michael Florio, R-14-10-003, Filed Aug. 13, 2015, at 14.

[38] J. Wellinghoff, J. Tong, & J. Hu, *The 51st State of Welhuton*, 51st State Challenge, Feb. 27, 2015.

[39] See generally, Reforming the Energy Vision, New York Public Service Commission. http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument.

[40] G. Barbose & N. Darghouth, *Tracking the Sun VIII*, Lawrence Berkeley Nat'l Lab & U.S. Dep't of Energy, Aug. 2015, at tbl.1 & fig. 5. According to the report, which tracks third-party ownership and customer ownership, a majority of residential (60%), small non-residential (64%) and large non-residential (61%) distributed solar PV systems are customer owned as of 2014. Cumulative installation data was created by combining raw data from Table 1 (yearly installation) and Figure 5 (yearly distribution between customer-owned and third-party-owned DG PV) in *Tracking the Sun VIII*.

[41] See PJM Discussion, above.

customer's behavior. But now that technology can simplify the process of optimizing demand against more complex and cost-related rate structures, it may be time for an update.

1. Customer-owned and operated DERs with dynamic rates

ComEd's Residential Real time Pricing (RRTP) program is an effort to better align customer consumption with the time-variant value of electricity. Under RRTP, the volumetric portion of customer bills tracks the real-time price of energy on the PJM wholesale energy market; customers can view that information in their homes or online and respond by curtailing energy use when it is most expensive. To enable more savings and better price responsiveness, ComEd offers two tools: an automated HVAC control program and price alerts if a certain price is exceeded.[42] The program also provides tips on cutting energy costs and a personalized online account to track whether customers are saving under the program.[43]

The automation and informational aspects of the program help align customer choices with grid optimization, but ComEd could still do a lot more to take advantage of the full range of value DERs can provide. On the positive side, ComEd's program produces significant benefits for the bulk system by moderating locational energy and capacity market prices near participants.[44] It also consistently produces savings for customers,[45] and customer satisfaction is consistently high.[46]

However, the program has so far failed to take advantage of emerging technology that can help improve customer responses to price signals, and in fact ComEd's RRTP customers remain remarkably low-tech according to the following customer survey results:

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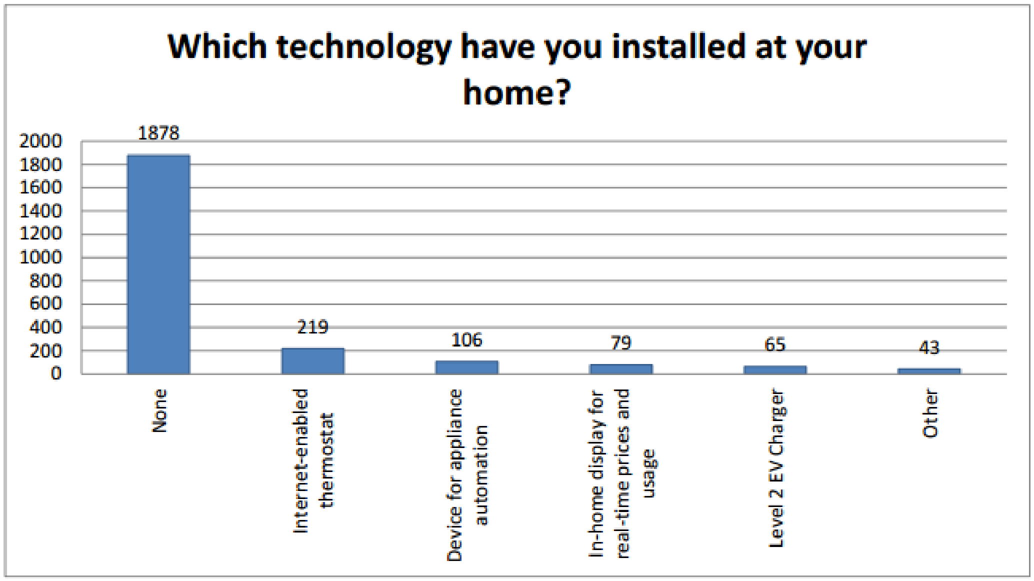
[42] The ComEd Residential Real-time Pricing Program Guide to Real-Time Pricing 2015-2016, at 9. https://rrtp.comed.com/wp-content/uploads/2015/08/RRTP_Guide-2015-2016-final.pdf.
[43] Illinois Citizens Utilities Board, *CUBFacts: ComEd's Real-time Pricing Program*, June 2015. http://www.citizensutilityboard.org/pdfs/ConsumerInfo/RealTimePricing.pdf.
[44] Klos Energy Consulting, *Updated Net Benefits of ComEd Residential Real Time Pricing Program: Report for Calendar Year 2014*, submitted to Elevate Energy, Compliance Filing of Commonwealth Edison Company, Case No. 11-0546, Filed April 30, 2015. On average, the program saves its participants 15 percent on electricity supply costs, compared to customers on a fixed volumetric rate. https://rrtp.comed.com/faqs/. These are separate from the delivery charge and additional taxes and fees, which also make up a significant portion of the bill.
[45] Elevate Energy, *ComEd Residential Real-Time Pricing Program 2014 Annual Report*, at 3, Compliance Filing of Commonwealth Edison Company, Case No. 11-0546, Filed April 30, 2015.
[46] 77% of customers were satisfied in 2014 despite high prices and low savings caused by polar vortex price spikes. Ibid at 24.



Source: Elevate Energy, *ComEd Residential Real-Time Pricing Program 2014 Annual Report*

The RRTP only varies with wholesale energy prices, and fails to account for other value to the distribution system. Because of this, the RRTP does relatively little to make DERs more attractive to customers, particularly because ComEd's rates are so low. Nevertheless, the RRTP program moves incrementally toward fair value for DERs and strengthens the link between customer choices and system optimization.

2. Customer-owned DERs with automation technology and dynamic rates

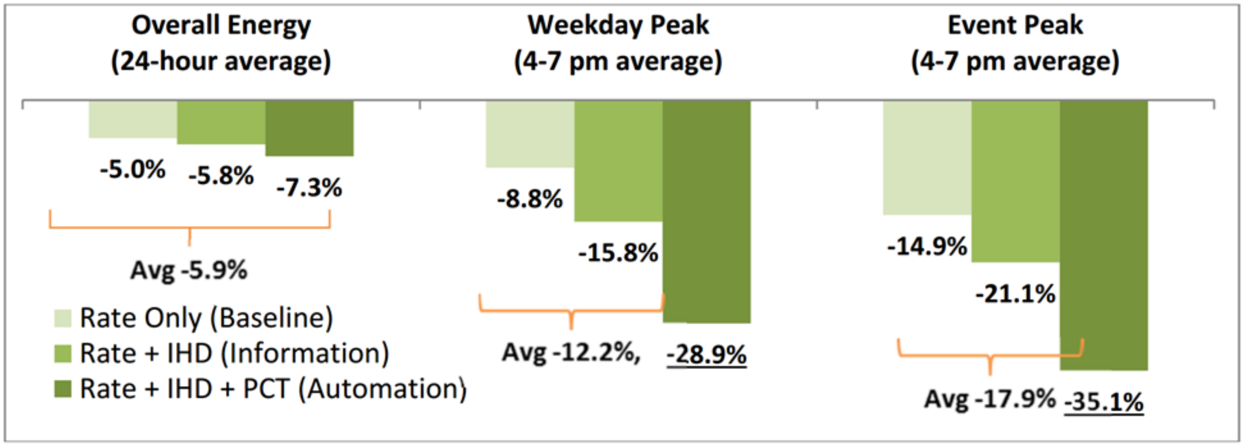
Technology can enable consumers to better optimize their behavior against smart rate designs. When automation technology is paired with rates designed to promote optimal deployment of customer DERs, as in the Sacramento Municipal Utility District (SMUD) Multifamily Summer Solutions (MSS) Study, the results can be powerful. MSS Study participants were placed on a time-varying rate, which combined SMUD's off-peak rate with higher peak rates every weekday from 4–7pm and very high critical peak rates when temperatures reached 100 degrees and the system was most stressed.[47]

Participants were then split into three groups to determine the importance of automation in optimizing customer behavior against the rate: 1) a time-of-use, critical peak period (TOU-CPP) rate; or 2) the TOU-CPP rate plus an in-home display (IHD) showing real-time energy use, cost information, conservation tips, and conservation messaging; or 3) the TOU-CPP rate and the IHD,

[47] SMUD's tier-1 off-peak retail rate was of $0.07kWh, the every-weekday peak price was $0.27/kWh, and a critical peak price of $0.75/kWh was implemented during 4–7pm on critical system peak events.

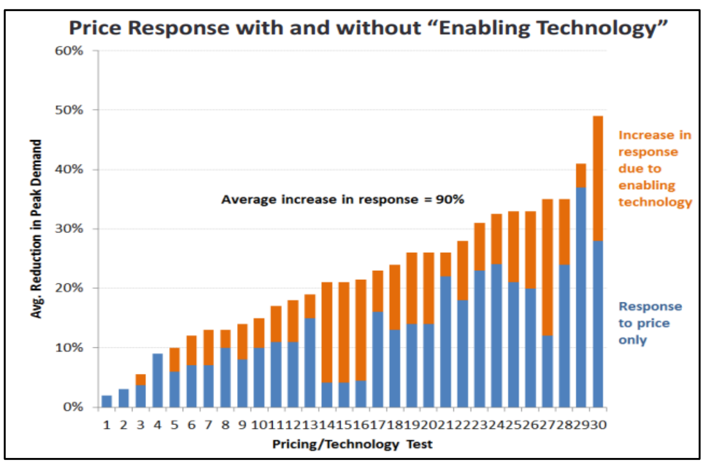
plus a programmable communicating thermostat (PCT) that could be set to automatically respond to the TOU rate and CPP events.[48]

The results showed that compared to the other groups, automation technology nearly doubled customer response to the time-varying rate:



Source: ACEEE, 2014

The SMUD study demonstrates a recurring theme in many studies of demand management. A meta-study by the Brattle Group showed that automation and/or in-home displays significantly boosted customer price response across thirty different studies, by an average of 90%.[49]



Source: Brattle Group, 2014.

Considering peak reduction is the main way that demand response provides system benefits, getting automation technology paired with more adaptive rate design can help customers optimize their consumption habits and increase the effectiveness of these programs.

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[48] Vicki Wood et al., *Behavior vs. Automation: The Impacts of "Set It and Forget It" in the Multifamily Sector*, American Council for Energy Efficient Economy 2014 Summer Study on Energy Efficient Buildings, 2014, at 7-355.
[49] S. Sergici, *Dynamic Pricing: Transitioning from Experiments to Full-Scale Deployments*, The Brattle Group, Presented to the National Governors Association at the Michigan Retreat on Peak Shaving to Reduce Tasted [sic] Energy, August 6, 2014.
http://www.nga.org/files/live/sites/NGA/files/pdf/2014/1408MichRetreatDynamicPricing_Sergici.pdf.

DISCUSSION

Each of these case studies draws experience from different ways of tackling the same problem: how to take advantage of cost-effective distributed technologies that have run into outdated regulatory models. Any of these ownership models can achieve system optimization so long as the value proposition to each actor aligns with the public interest.

Owned by:	Operated to optimize for:	Revenue sources:	Real-world examples:
Utility	Utility operations	Commission-determined (rate-case), Wholesale markets	• California Solar PV Program • Arizona rooftop solar • Borrego Springs Microgrid
Non-Utility	Third party managers	Retail rates, Utility contracts, Wholesale markets	• EcoFactor/NV Energy mPowered Program • DR aggregation in PJM • CAISO DER Provider Participation
	Customer's bill	Retail rates	• ComEd Retail Real-Time Pricing & DR program • SMUD Dynamic Pricing Pilots

The utility-owned and operated model provides a platform for demonstration and accelerates public policy goals like market development and early adoption, as in the case of the California SPVP and Borrego Springs Microgrid. However, when utility-owned DERs play in competitive markets, they may either crowd out competitors or result in inferior performance. In either case, these programs must adapt to emerging technologies and avoid cost overruns.

One way to do this is by tying program-related utility revenue to performance.[50] This minimizes the investment risk for customers when utilities own and operate DERs. Another way is to allow utilities to pilot DER ownership, in parallel with third-party alternatives, with clear metrics for performance.[51] Regulators can reevaluate the programs periodically, as was the case with California's SPVP and Arizona's rooftop solar programs.

One emerging example of this kind of comparative piloting is Central Hudson's recent proposal to own and operate community solar in parallel to SolarCity as part of a demonstration project

[50] See generally S. Kihm, R. Lehr, S. Aggarwal, & E. Burgess, *You Get What You Pay For: Moving Toward Value in Utility Compensation. Part One - Revenue and Profit*, America's Power Plan, June 2015.
[51] See, e.g., S. Aggarwal, E. Gimon, & H. Harvey, "A New Approach to Capabilities Markets: Seeding Solutions for the Future," *Electricity Journal*, Vol. 26, Issue 6, July 2013.

under New York's Reforming the Energy Vision initiative.[52] This pilot program will allow comparison of a third-party community solar model with a utility-owned model. SDG&E also recently proposed two sister pilot programs under its distributed resource plan that will compare a customer-centric storage model that includes a dynamic rate with utility-owned and operated storage.[53] Each will help to define the evolving boundaries of the "natural monopoly" and competition on the distribution system.

Likewise, the third-party and customer-centric models can improve performance if the available revenue streams are better aligned with the public interest, and if third-parties can access system data from utilities. For example, the EcoFactor program could be paired with dynamic rates to increase signals to customers, and go further than just demand response. With home automation already integrated, EcoFactor or other third parties might offer whole-home energy systems that include other DERs like solar or storage to minimize customer bills and increase utility flexibility to manage variability and peak demand.

Customer-centric programs could also improve if customers can get paid for the full value DERs provide to the bulk and distribution systems, including external values like environmental benefits. The RRTP program, for example, might evolve to include a varying distribution charge that compensates customers for on-site generation on top of avoided energy costs. Value of Solar Tariffs in Minnesota[54] and Austin Energy[55] are examples of how this can work in practice for a specific resource (distributed solar), but the dynamic interaction between the bulk system and distribution optimization still requires refinement.

CONCLUSION

The original principles articulated in *An Adaptive Approach to System Optimization* can help guide experimentation with all of these models of DER ownership and operation. Fair valuation of DERs is key to ensuring they can compete with centralized generation to meet system needs at least cost. Likewise, integration of new technologies through any model should be iterative to minimize the risk to utility customers. To the extent possible, new rate design should be coupled with enabling technologies and third-party data access to ensure that complementary technologies can help customers optimize their bills and maximize system benefits. No one model will fit every state or utility; but each model can move toward system optimization.

[52] *Central Hudson's Report Regarding the REV Collaborative*, Cases 14-E-0318, 14-G-0319, N.Y. Pub. Serv. Comm'n, May 1, 2015, p. 3-21.

[53] Application of San Diego Gas & Electric Company (U 902 E) For Approval of Distribution Resource Plan, A.15-07-___, July 1, 2015, at 73–77.

[54] MN Department of Commerce, *VOS Methodology*, April 1, 2014. http://mn.gov/commerce/energy/images/DRAFT-MN-VOS-Methodology-111913.pdf.

[55] Clean Power Research, *The Value of Distributed Photovoltaics to Austin Energy and the City of Austin*, Austin Energy, 2006. See also http://www.solaraustin.org/wp-content/uploads/Solar-Programs.pdf.